scarps on the fan deposits at about the 6-m contour suggests that very little deposition has occurred since 1857 at this site. Judging from the fan contours, slip on the secondary faults which produced these scarps may have included as much as 1 m of strike slip. Thus the $2\frac{1}{2}$-m gully offset within the principal fault zone must be viewed as a minimum value for the 1857 fault slip.

Secondary faulting. Aside from small secondary faults within the main 1857 rupture zone, some faults within a kilometer or two of the San Andreas fault

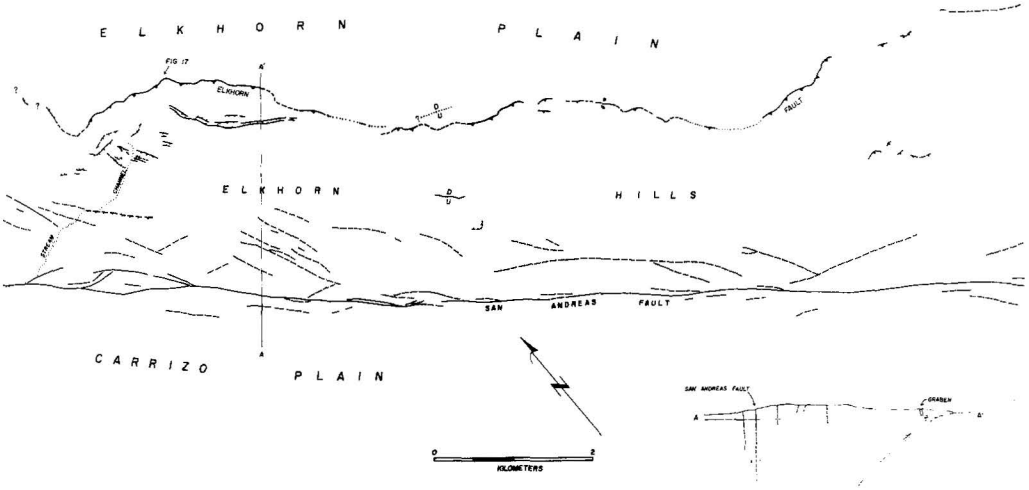


FIG. 16. The Elkhorn and San Andreas faults, southern Carrizo Plain. San Andreas traces are from Vedder and Wallace (1970); Elkhorn traces are from interpretation of aerial photography. Traces are dashed where approximate, dotted where concealed.

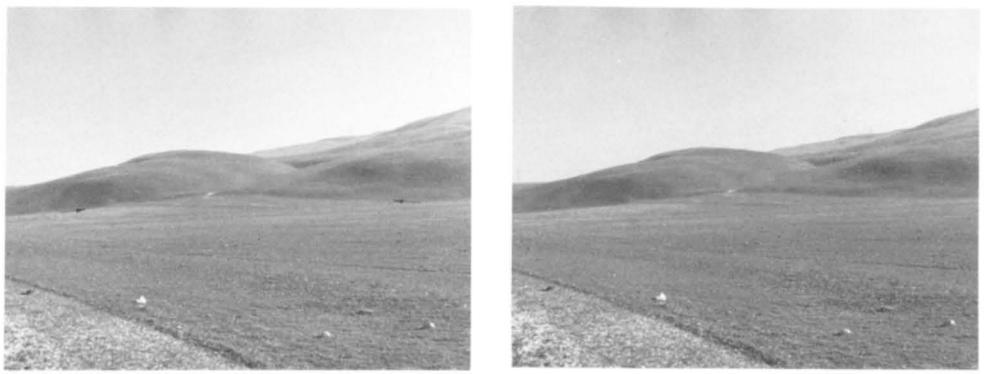


FIG. 17. Small (~1 m) scarp partly in young alluvium at the base of the Elkhorn Hills may have formed in 1857. Stereoscopic view is toward the south from the main road that traverses the Elkhorn Plain. See Figure 16 for location.

probably slipped in 1857. Most of these faults are less than a kilometer long and show little or no evidence of lateral slip and evidence for no more than a few centimeters of dip slip in 1857. Therefore, their contribution to 1857 fault slip probably is negligible for present purposes of analysis.

Along two reaches of the San Andreas fault, however, secondary faulting and deformation probably amount to a significant percentage of the strike slip on the main trace. From about Littlerock Creek through Leona Valley (see Figure 5), the geomorphic expressions of the Nadeau, Littlerock, and North Branch San Andreas

faults, parallel to the San Andreas fault, are generally fresh enough to warrant suspicion that they slipped in 1857 (based on aerial photograph reconnaissance and on personal communication with D. Beebe and J. Kahle, California Division of Mines and Geology, 1976). The lack of small gully offsets along these traces suggests that 1857 offsets are no more than about 1 m. One meter of slip on these faults would almost eliminate the embayment in the slip curve along this 30+-km reach.

Near the southern end of the Carrizo Plain, the San Andreas fault is the southwestern boundary of the 15-km-long Elkhorn Hills (Figure 16). Most of the northeastern base of the Elkhorn Hills displays scarps indicative of thrust faulting. Thus, the Elkhorn Hills appear to constitute a crustal block that has risen between the San Andreas and the thrust fault, herein named the Elkhorn fault. Large linear grabens and closed depressions within the Elkhorn Hills indicate that a great deal

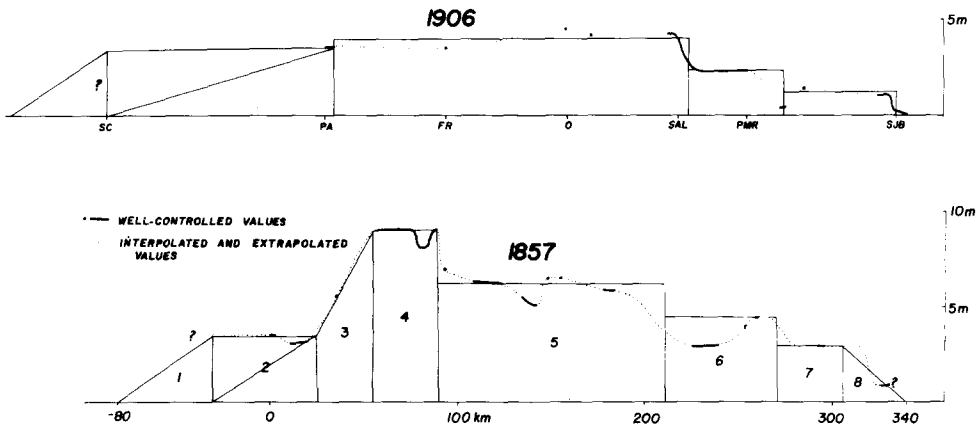


FIG. 18. Simplified slip functions for the 1857 and 1906 earthquakes. Displacements of 1906 simplified and corrected from Lawson and others (1908), Jordan and others (1907), and unpublished field notes of J. C. Branner and students, Stanford University Archives. The numbered rectangles correspond to those segments in Table 3 used to calculate the seismic moment of the 1857 earthquake. Along the 1906 rupture, SC = Shelter Cove, PA = Pt. Arena, FR = Ft. Ross, O = Olema, SF = San Francisco, SAL = San Andreas Lake, PMR = Page Mill Road, and SJB = San Juan Bautista.

of internal deformation has taken place also.

Small scarps in Holocene (?) alluvial deposits along the Elkhorn fault are so fresh as to suggest they may have formed during the 1857 event (Figure 17). Alluviation since that event has obscured any clear indication of a lateral-slip component on this fault. However, it seems very unlikely that the latest event on the sinuous, very low-angle thrust could have included more than 1 m of lateral slip.

Many of the faults within the Elkhorn Hills also display relatively young scarps and, in several closed depressions, many fissures and sinkholes related to "piping" are demonstrably historic.

The evidence for ongoing deformation of the Elkhorn Hills suggests that substantial lateral deformation within the hills may have accompanied the 1857 event. Thus, the change from 9 to 7 m of lateral slip along the San Andreas fault in this region (see Figure 5) may be less abrupt when measured across the entire zone of deformation.

DISCUSSION AND CONCLUSIONS

Taken together, the youngest offsets along the south-central reach of the San Andreas fault indicate that 1857 fault slip ranges from 3 to 9½ m along the central

300 km of the rupture length (Figure 5). Historical records indicate that the total length of rupture may be as great as about 400 km—from near San Bernardino to the San Benito/Monterey County line.

The mild intensity of the 1857 earthquake at San Bernardino gives ample reason to doubt that the coseismic rupture extended farther southeast than Cajon Pass. The four offsets of approximately 1 m documented near San Bernardino (Figure 5) may have been produced by 1857 afterslip. There is a slim possibility that they originated during the moderate 1907 earthquake. Alternatively, the offsets may be related to activity prior to 1857. The most reasonable estimate of the coseismic length of rupture appears to be about 360 km—from Cajon Pass, northwest of San Bernardino, to the head of Cholame Creek.

TABLE 2

SIMPLIFIED DISPLACEMENTS FOR THE 1857 EARTHQUAKE

i	Segment	Length, L (km)	Displacement, u
1	San Benito Co. line to Cholame Creek	50	150 cm/0
2	Cholame Creek to Km-25	55	340/170
3	Km-25 to Km-55	30	620
4	Km-55 to Km-90	35	900
5	Km-90 to Km-210	120	620
6	Km-210 to Km-270	60	450
7	Km-270 to Km-305	35	300
8	Km-305 to Km-340	35	150

TABLE 3

COMPARISON OF THE 1906 AND 1857 EARTHQUAKE DISPLACEMENT PARAMETERS

	1906	1857
Length of rupture	420 to 470 km	360 to 400+ km
Average displacement	2.8 to 3.2 m	4.5 to 4.8 m
Depth of rupture	10 km	10 to 15 km

The line drawn through the smallest local offset values in Figure 5 indicates the most reasonable fault slip function for the 1857 event. Where data are lacking or ambiguous, a double line indicates favored possibilities.

Several measurements fall below the envelope of 1857 slip values. Among these, features at sites 34, 35, 111, 141, and 142 are offset on only one of two or more overlapping fault strands. Sites 86 and 87 may also display offsets less than the total local 1857 offset for this reason.

Size of the 1857 earthquake. The 1857 slip curve appears to be composed of at least four distinct, relatively flat segments joined by short segments with steep gradients (Figure 18). Separating the 1857 rupture into these segments of length L_i and displacement u_i (Table 2), a seismic moment, m_o, for the earthquake can be calculated

$$m_0 = \mu Z \sum_{i=1}^{8} L_i u_i.$$

This moment includes any afterslip. The depth of rupture, Z, is assumed to be 10 km, fault slip is considered to be uniform with depth and the shear modulus, μ, is 3×10^{11} dynes/cm^2. The seismic moment thus calculated is 5.8×10^{27} dyne-cm. A more conservative estimate, 5.3×10^{27} dyne-cm, excludes segment 1 and assumes that the rupture ended near the head of Cholame Creek.

A recent study of microearthquake activity along the 1857 reach of the fault suggests that "the activity extends down to 15 km or so" (H. Kanamori, written communication, 1977). Thus, 15 km may be a better estimate of the depth of coseismic faulting in 1857 than 10 km. Substituting 15 km for 10 km as the depth of rupture gives $8.8 \geqq m_0 \geqq 8.0 \times 10^{27}$ dyne-cm. Considering the uncertainties in depth of rupture, length of rupture, and slip values at depth, the seismic moment cannot be more precisely defined than $8.7 \geqq m_0 \geqq 5.3 \times 10^{27}$ dyne-cm. This compares with $4.3 \geqq m_0 \geqq 3.5 \times 10^{27}$ dyne-cm, similarly calculated for the great California earthquake of 1906, using a 10-km depth of rupture. Geodetically measured deformation seems to preclude a rupture depth greater than 10 km for the 1906 earthquake (Thatcher, personal communication, 1977).

A comparison of 1906 and 1857 rupture dimensions and amount of slip (Table 3) suggests that the magnitude, M_S, of the 1857 event may have been slightly larger than that of the 1906 event ($M = 8\frac{1}{4}$, Gutenberg and Richter, 1954).

Possible implications of the irregular nature of fault slip associated with the 1857 earthquake. The irregular nature of fault slip associated with the 1857 earthquake raises intriguing questions about long-term slip patterns. If slip rates over a several hundred- or thousand-year period are approximately equal throughout the length of the fault system, those segments which slipped only 3 to 4 m in 1857 must be characterized, between 1857-type events, by activity enabling them to "catch up" to the 6- to $9\frac{1}{2}$-m slip levels experienced along the central portions of the 1857 rupture. That is, slip events of several meters might occur two to three times more frequently along those segments which experienced two to three times less slip in 1857. This hypothesis is supported by an apparent difference in average late Holocene recurrence intervals along the fault. At Pallett Creek, near Valyermo, where 1857 displacement is about $4\frac{1}{2}$ m, the average interval has been about 160 years for the past 1400 years (Sieh, 1978). At Wallace Creek, in the Carrizo Plain, where 1857 displacement is about $9\frac{1}{2}$ m, the average interval for the past 3,400 years has been about 255 years or less (Sieh, 1977, Ch. 2).

An alternative hypothesis is that associated geological structures might enable long-term slip to differ between two segments of the fault. Slip along the White Wolf-Pleito thrust system, for example, might allow long-term differences in slip between the segments of the San Andreas northwest and southeast of Tejon Pass.

Comparison of long-term slip rates determined at a number of widely spaced localities along the fault and dating of specific events at these localities would help answer these questions. The determination of long-term slip rates and specific dates of ancient large earthquakes is thus the subject of ongoing studies.

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Towards quantifying subsurface methane emissions from energy wells with integrity failure

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ABSTRACT

The expansion of petroleum resource development has led to growing concern regarding greenhouse gas emissions from fugitive gas migration, which occurs at some wells due to well integrity failure. In this study, we quantify methane surface expression and emissions resulting from gas migration using a number of complementary techniques, and thereby evaluate surface expression processes as well as the strengths and limitations of the monitoring techniques. Methane emissions were found to be highly localized and variable over time. Injected gas reached the surface via preferential pathways through the soils and also along an installed groundwater monitoring well. Cumulative emissions were estimated from flux chamber measurements to be 3.8–6.5% of the injected gas; whereas eddy covariance (EC) data inferred approximately 26% of the injected gas was released to the atmosphere. Together these methods provide enhanced interpretation of surface expression at the site, advance our understanding on fugitive gas migration from integrity compromised energy wells and provide insights to improve monitoring and detection strategies with a view to reducing future greenhouse gas emissions. Moreover that, up to 75% of fugitive gas released at the site remained in the subsurface, shows that capillary barriers will mitigate greenhouse gas emissions from leaky wells; however, may infer greater potential for impacts on groundwater resources, if present.

1. Introduction

The unintentional release of natural gas from energy wells has been well documented and remains a challenge for active, abandoned, and orphaned wells (Bachu, 2017; Boothroyd et al., 2016; Cahill et al., 2019; Chafin, 1994; Davies et al., 2014; Ingraffea et al., 2020; Soeder, 2018; Vengosh et al., 2014). This leakage typically occurs as a result of well integrity failure (e.g., imperfect cementation or casing failure) causing a loss of zonal isolation and providing pathways from gas bearing formations toward the surface (Dusseault and Jackson, 2014). Released gas usually moves toward the surface through two pathways: 1) outside of the energy well casing, referred to as gas migration (GM) or 2) within the annuli of the multiple well casings comprising an energy well bringing natural gas directly to the surface, for example within the surface casing, referred to as surface casing vent flow (SCVF). Released natural gas, which is mainly composed of methane (CH_4) and other higher-chain hydrocarbons, is able to migrate vertically via buoyancy-driven forces and may intersect valuable groundwater resources or be released to the atmosphere (Cahill et al., 2017; CCA, 2014; Forde et al., 2018; Van De Ven and Mumford, 2020a; Vengosh et al., 2014).

With the expansion of petroleum resource development in relatively populated regions of North America, public concern about GM's impact on the environment has increased in recent years, including potential impacts to groundwater quality (aqueous expression), safety risks from gas entering into water wells and/or buildings, and greenhouse gas emissions to the atmosphere (surface expression) (Barth-Naftilan et al., 2018; Bousquet et al., 2006; Caulton et al., 2014; Davies et al., 2014; Jackson et al., 2013b; Llewellyn et al., 2015; Soeder, 2018; Van De Ven

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and Mumford, 2020a). Despite previous studies investigating GM and wellbore-integrity failure, incidence rate, controlling mechanisms, and overall quantity of mass released in the form of aqueous and surface expression are still not well understood (Brandt et al., 2014; Brantley et al., 2014; Kemp et al., 2016; Kirschke et al., 2013; Schneising et al., 2014; Schwietzke et al., 2016). The impacts of fugitive gas on groundwater and the atmosphere are difficult to quantify because of uncertainties associated with determining: 1) where the natural gas originates, 2) the leakage rates, 3) the duration of the leak, and 4) the distribution of migration pathways in the subsurface (Cahill et al., 2019; Vengosh et al., 2014). These uncertainties in the processes and mechanisms driving gas migration make it difficult to detect and monitor the environmental expression of GM in the field.

A great deal of emphasis has been placed on quantifying aqueous expression by academics, practitioners and regulators in many jurisdictions, calling for groundwater monitoring prior to and after energy well development and production (CCA, 2014; Molofsky et al., 2016, 2013). Additionally, aqueous expression has been the focus of forensic groundwater investigations in areas of suspected GM (Jackson et al., 2013a, 2013b; Li and Carlson, 2014; Schout et al., 2017; Soeder, 2018; Vidic et al., 2013) and controlled gas releases (Cahill et al., 2017, 2018; Forde et al., 2019b). Recently, in a field experiment conducted by Cahill et al. (2017), natural gas was released into a relatively homogeneous, unconsolidated sand aquifer and it was found that the injected gas migrated both vertically toward the surface but also laterally, travelling greater distances than expected, as a result of subtle contrasts in the geological strata.

Despite the significant impact that gas reaching the surface may have on climate change, human health (Alahmad and Khraishah, 2020; Macey et al., 2014; Rabinowitz et al., 2015), and safety, surface expression has also been studied, but less than aqueous expression. To gain a deeper understanding of gas migration mechanisms leading to surface expression, CH_4 soil efflux has been measured using long-term dynamic flux chambers and soil gas monitoring wells during controlled releases, near active energy-well pads, and storage sites (Fleming et al., 2021; Forde et al., 2019a, 2019c; Lyman et al., 2020). The release of CH_4 to the surface is highly episodic (dictated by the media through which the gas flows and also atmospheric controls, i.e., barometric pressure fluctuations) and spatially heterogeneous (Forde et al., 2019a; Van De Ven and Mumford, 2020b). In addition to CH_4, carbon dioxide (CO_2) effluxes have also been measured using chambers, and compound-specific isotopes samples collected from soil gas monitoring wells. These data can be used to assess the oxidation of CH_4 to CO_2 in both the saturated and unsaturated subsurface.

The episodic and spatially heterogeneous nature of surface expression observed for GM, suggests that discrete efflux techniques such as chambers and soil gas monitoring wells, may not capture the entire surface expression of a GM event (Forde et al., 2018). Additionally, chambers cannot measure all potential emission sources at a site, for example SCVFs or gas which is released along subsurface infrastructure, including monitoring and water-supply wells. For other applications including quantifying CH_4 emissions from landfills (e.g., Mønster et al., 2019), lakes and rivers (e.g., Schubert et al., 2012), wetlands (e.g., Peltola et al., 2019), rice paddy fields (e.g., Alberto et al., 2014), thermokarst lakes (e.g., Skeeter et al., 2020) and enteric emissions from feedlots (e.g., Bai et al., 2015; Coates et al., 2018; Flesch et al., 2007; Laubach et al., 2013), eddy covariance (EC) systems have become a frequently used and reliable technique, since they provide a non-invasive, integrated measurement for a larger source area at high temporal frequency (Baldocchi, 2003). To the best of the authors' knowledge, EC has not been employed to study the integrated surface expression of CH_4 associated with subsurface GM. EC is also advantageous to investigate large episodic releases associated with poorly characterized migration pathways through the subsurface, or sources which carry gas to the atmosphere not through soils (e.g., SCVFs, monitoring wells).

Although most commonly used in experiments with homogeneous flux sources, the increasing developments in flux footprint modeling have led to the application of EC in experiments with non-uniform flux sources, as expected for sites impacted by fugitive gas releases. It has become increasingly recognized that EC flux measurements can rarely be taken as representative of the surface fluxes as such, and high-resolution flux footprint analysis is required to better understand how these measurements relate to the emissions at the surface (Reuss-Schmidt et al., 2019; Tuovinen et al., 2019). A flux footprint is the transfer function that explains the importance of a certain point in space (down-scaled area) to the measurement made at the EC tower. In two dimensions (x and y) it can be expressed as:

$$F(0,\ 0,\ z_m) = \iint Q(x,\ y) f'(x,\ y,\ z_m)\,dx\,dy \tag{1}$$

where $F(0, 0, z_m)$ is the flux measurement made by the EC sensor located at height z_m, $Q(x, y)$ is the source flux at the soil surface within a down-scaled area, and the weighting factor $f'(x, y, z_m)$ is the flux footprint. The footprint function, f', is always specific to the measurement height z_m, and hence the explicit mention of z_m in the equation will be henceforth omitted for simplicity. Mønster et al. (2019) described the flux footprint, or the contributing emission area, as having a droplet shape with the tower located at the top of the droplet and the upwind footprint distance normally being approximately 100 times the measurement height (Xu et al., 2014).

Some studies make use of the parameter "sensor location bias" following Schmid (1997) to define the spatial representativeness of the flux footprint by comparing the footprint-weighted and "equally" weighted surface emissions (e.g., Chen et al., 2009; Reuss-Schmidt et al., 2019). The development of simpler flux footprint models, and their use in conjunction with EC has reduced the need for elaborate backward Lagrangian stochastic models and measurements or modelling of atmospheric statistics by the user. These simpler models are based on semi-empirical parameterizations of Lagrangian based footprint models (e.g., Hsieh et al., 2000; Kljun et al., 2015). These, in addition to some analytical models (e.g., Kormann and Meixner, 2001; Schuepp et al., 1990) provide a much faster, versatile, and less computationally complex way to process large EC datasets. Therefore, based on these advancements, EC provides a potentially strong means of quantifying emissions associated with subsurface GM from energy wells with integrity failure.

Although previous studies have provided findings to significantly improve our understanding of GM and surface-efflux processes, further study is needed in regions of current oil and gas development, especially in areas with heterogeneous subsurface lithologies (Cahill et al., 2017, 2019; Chao et al., 2020). These conditions prevail in northeast British Columbia, which as part of the Western Canada Sedimentary Basin (WCSB) is an area of active petroleum resource development, hosting some 25,000 energy wells. Also, it is important to assess methods to characterize the overall surface expression of GM and therefore the risk that GM presents to the environment, and in particular though greenhouse gas emissions to atmosphere.

In this study, we focus on characterizing methane emissions across the land-atmosphere boundary during a controlled natural gas injection, intended to simulate the release of fugitive gas into the shallow subsurface (<30 m) as a result of an energy well integrity failure along the depth of a well. Methane emitted to the atmosphere was quantified using both automated dynamic flux chambers and an EC system. Additionally, to help infer subsurface GM pathways and CH_4 oxidation processes, gas samples collected at depth-discrete intervals in the unsaturated zone were analyzed to determine their isotope ratios. The controlled injection experiment offered a unique opportunity to not only measure surface expression as a result of diffuse GM but also the release of gas directly to the atmosphere. This opportunity was unintentionally provided by monitoring well MW2 (discussed further below), which introduced a

direct preferential pathway for gas from the saturated zone to the atmosphere. The existence of this pathway provided the opportunity to study how distinct emission pathways impacted monitoring techniques and interpretation. In this context, the specific objectives of this study were to: (i) quantify fugitive gas CH_4 emissions to the atmosphere from a highly heterogeneous subsurface environment, (ii) assess the fate of simulated fugitive natural gas migrating through the unsaturated zone, and (iii) evaluate different techniques to quantify fugitive gas through comparison of estimated cumulative emissions to the surface and (iv) determine how these methods can support each other for characterization of effluxes from point sources related to subsurface GM.

2. Materials and methods

2.1. Site and injection description

The study site was located in the uplands of the Peace region, 15 km northeast of the town of Hudson's Hope in northeast British Columbia, Canada (Cahill et al., 2019; Chao et al., 2020). The site, extensively characterized by Chao et al. (2020), is typical of glacial-derived unconsolidated, confined groundwater systems located in the WCSB, therefore, the site provides an ideal setting to assess the impact of gas migration in an area of significant oil and gas exploration and production (Best et al., 2019; Cary, 2019; Chao et al., 2020; Hartman and Clague, 2008; Levson, 2008). The near surface (30 m bgs and above) comprises of a 12 m thick laterally extensive, confining silty diamict of low permeability (~10^{-8} m s^{-1}) (Chao et al., 2020). The upper 1–2 m of the diamict is oxidized and shows signs of desiccation cracks/fractures. The diamict overlays a more permeable layer (10^{-6} to 10^{-4} m s^{-1}) ranging between 10 and 15 m of heterogeneous interbedded sands, clays and silts (see Chao et al., 2020, 2021 for a more detailed description of the heterogeneous near-surface geology). The piezometric surface is located between 1.0 and 1.5 m below the ground surface, which is shallow relative to other regions where GM may also occur (e.g., Forde et al., 2019a). The interpreted groundwater flow direction is from northwest to southeast, based on hydraulic head measurements from five observation wells at the site.

A gas injection well was installed by drilling a sonic core hole at a 45-degree angle from the surface to the base of the aquifer at a depth of 26 m (Fig. 1). The northeast to southwest dip of the injection well was roughly orthogonal to the groundwater flow direction. The gas was injected into the aquifer through a porous polyethylene (20 μm) sparge screen (0.6 m length and 0.05 m diameter, Schumaprobe spargepoint) installed at the bottom of the injection well. Over 69 days between 12 June, 2018, and 20 August, 2018, a synthetic natural gas was injected where it migrated upwards, eventually through the entire thickness of the system. The injected gas was synthesized to match the gas of the underlying Montney resource play within the area, composed of 85% methane, 8% ethane, and the remaining 7% was composed of propane, carbon dioxide, nitrogen, and helium (see Supplementary Material) (Cahill et al., 2019). A total of 4357 mol (STP, 0 °C and 1 atm) of the gas mixture was injected using an in-line mass flow controller (Red-y smart GSC-C9SA-BB26) at a constant rate of 67 mol day^{-1} (STP, 1.5 m^3 day^{-1}). The constant flow rate injection condition thus provided sufficient pressure to exceed the hydrostatic and displacement pressure in the surrounding sediments.

2.2. Description of migration pathways to the surface

Injected gas was able to migrate through the subsurface system, then

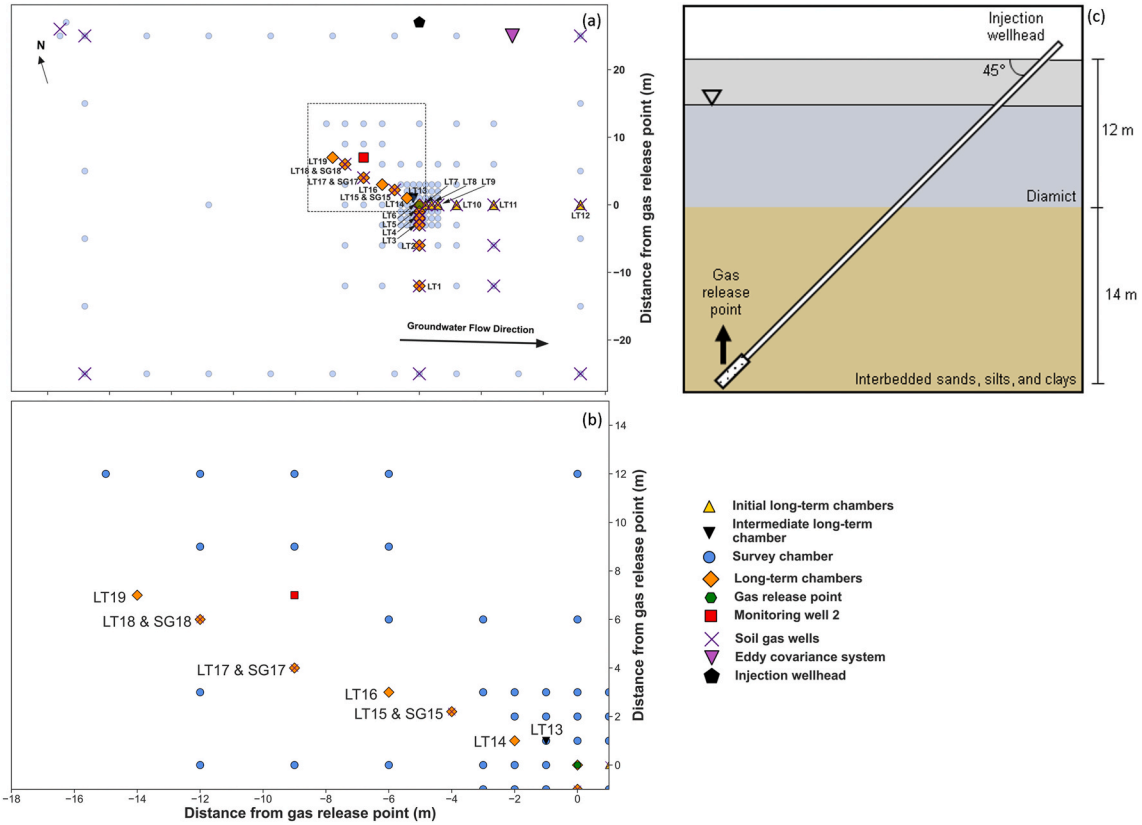


Fig. 1. (a) Monitoring network at the field site, with long-term and survey chamber locations, location of the eddy-covariance system, groundwater monitoring well 2 (MW2), soil gas monitoring wells, the gas release point, injection wellhead and the direction of groundwater flow are depicted and (b) expanded region encompassing the 10 m × 10 m area where the CH_4 effluxes were concentrated. Dashed box in (a) shows the area presented in (b). (c) Depth profile from the injection wellhead to the injection point 26 m below surface (northeast to southwest), showing 45° dip of the injection well.

was expressed at the surface via diffusive and advective transport mechanisms through the soil to the atmosphere. However, free-phase gas was also observed to be emanating from an installed groundwater monitoring well (MW2, wellhead extending ~1 m above the ground) during the active injection of synthetic natural gas. Multiple monitoring wells were installed at the site as part of the larger study to understand gas dissolution and fate resulting from gas migration in this heterogeneous system (Chao et al., 2021). MW2 was a multilevel monitoring well installed 10 m northwest of the gas release point (Fig. 1). The well comprised three screened intervals (12.2, 15.2, and 19.1 mbgs), each isolated with valves to limit any leakage to the surface. The composition of the gas emitted from the wellhead was analyzed and was confirmed to be similar to that of the injection gas. This unexpected pathway from a screened interval where free-phase gas was present in the subsurface, provided evidence that pathways of anthropogenic origin may be unintentionally introduced at sites of suspected gas migration by the installation of wells. This pathway provided the opportunity to study surface expression both from GM through the natural ground but also emissions directly to the atmosphere through the leaking wellhead. The following analysis will therefore consider both migration pathways, and provide insights into the combined effects on monitoring techniques and inferred emissions at fugitive gas sites.

2.3. Soil-gas effluxes

To measure localized, real-time effluxes over the duration of the injection experiment, twelve automated long-term dynamic closed chambers were installed across the site and operated from 3 May to July 26, 2018 (see LT1-LT12 in Fig. 1 for locations). The chambers were placed on PVC collars with a surface area of 317.8 cm^2 inserted 10 cm into the soil and measured both CH_4 and CO_2 effluxes. To capture background soil gas effluxes, data collection began 13 days prior to initiating the injection. Once injection began, minimal effluxes were detected from the down-gradient spoke of the chamber network so LT7-LT12 were relocated up-gradient along a spoke outward from the gas release point in the northwest direction (new locations LT13-18, Fig. 1). Additionally, LT13 was relocated again to LT19 on 8 August. Continuous CH_4 and CO_2 efflux measurements from this final chamber arrangement began on 27 July for LT13 to LT18 and on 8 August for LT19 (in lieu of LT13). The chambers were connected to a multiplexer (LI-8150, LI-COR Inc., Lincoln, NE, USA), which fed the gas to an infrared gas analyzer (IRGA) (LI-8100A, LI-COR Inc.) that measured H_2O_{vapour} and CO_2 mixing ratios, and an extended-range (0.01–100,000 ppm) GHG analyzer (GGA 907-0011, Los Gatos Research Inc., San Jose, CA, USA) that measured H_2O_{vapour}, CO_2 and CH_4 mixing ratios in the chamber headspace. The dynamic closed (non-steady-state) chamber method determines effluxes of CO_2 and CH_4 by analyzing the rates of gas concentration change in the chamber headspace over a specified measurement period (see Supplementary Material) (Jassal et al., 2012; Kutzbach et al., 2007; Pirk et al., 2016). Based on the technique, the chambers were able to detect effluxes as low as 9×10^{-4} μmol m^{-2} s^{-1} and 9×10^{-2} μmol m^{-2} s^{-1} for CH_4 and CO_2, respectively. Long-term chambers were permanently installed, and measurements were collected continuously in a round-robin fashion every 60 min with a single measurement taking approximately 5 min.

In addition to the long-term chamber measurements, spatially extensive but temporally discrete survey measurements (see Fig. 1 for locations) were collected with a portable survey chamber (LI-8100-103, LI-COR Inc.) connected to an IRGA (LI-8100A, LI-COR Inc.) that measured H_2O_{vapour} and CO_2 mixing ratios and an ultraportable greenhouse gas analyzer (915-0011, Los Gatos Research Inc.) that measured H_2O_{vapour}, CO_2 and CH_4 mixing ratios. A total of 14 rounds of survey efflux measurements were taken between 1 June and September 28, 2018 (several rounds during each 2–3 day sampling campaign, approximately every two to four weeks). For each survey event, measurements were collected from 105 locations on the monitoring grid. Calculation of the effluxes from both the long-term and survey chamber data is described in the Supplementary Material.

2.4. Eddy-covariance flux measurements

An EC tower was placed in the northeast corner of the site and was operational from 11 June until 7 November, 2018. A solar array, which provided power for the system was located roughly 10 m northwest of the tower. A hut was constructed ~20 m west of the tower for storing essential equipment and also as the hub of the injection control system. The EC instrumentation consisted of an open-path CH_4 analyzer LI-7700 (LI-COR Inc.), enclosed-path CO_2 analyzer, LI-7200 (LI-COR Inc.) and a 3-D sonic anemometer, CSAT3B (Campbell Scientific Inc., Logan, UT). High-frequency (20 Hz) turbulence measurements in the atmospheric surface layer were used to obtain 30-min block-averaged site-integrated fluxes of CH_4 (F_m) using the SmartFlux 2 system which was housed in the Analyzer Interface Unit (LI-7550). This flux represents the site-integrated flux within the flux footprint of the tower. Details of the computation of fluxes can be found in the Supplementary Material. The fluxes of CO_2 (F_c), sensible heat (H) and latent heat (λE) were also similarly computed. This manuscript will focus on measurements and analysis for CH_4 (F_m) fluxes, while the use of measurements of H, λE, and climate measurements of R_n and G, were restricted to evaluating energy balance closure for the CH_4-flux measurement technique (see Supplementary Material for more detail). To ensure a complete understanding of driving forces at the site, a climate system was also installed, details and results can be found in Supplementary Material.

Site-wide flux data collected was post-processed and quality assurance checks were performed on the data using the quality flags provided by the EddyPro software (based on Mauder and Foken, 2004). The data were filtered using a friction velocity (u_*) threshold of 0.08 m s^{-1} (threshold was determined by examining the plot of night-time F_c vs u_*) for cases of low-mixing, generally occurring during night-time. Measurements of F_m were also rejected if they were found to be inconsistent with the temporally adjacent observations when performing manual quality control. Additionally, a favorable wind direction was necessary to estimate the methane emissions associated with the gas injection. To ensure this, the wind rose was analyzed. To consider the methane flux associated with the injection experiment, the data corresponding to a wind direction range of 215°–305° were chosen, so that MW2 was roughly in the center of this range (259°). This resulted in 20% of the total measurements collected being valid for further analysis. Finally, to assess the background fluxes independent of the controlled gas release, those corresponding to winds from the east, roughly diametrically opposite the release zone of the tower were used. Positive CH_4 fluxes for east winds were generally low, less than 0.01 μmol m^{-2} s^{-1}. Hence, no corrections were made to account for background, before proceeding with the down-scaling of EC measurements. Filtering for low u_*, wind direction and manual quality control led to further reduction in valid data points, reducing the temporal coverage to approximately 10% of the total collected measurements.

2.5. Down-scaled flux analysis

As a result of emissions associated with the injection experiment being concentrated in a small area within the flux footprint of the EC system, down-scaling of EC methane fluxes (F_m) was required to estimate the localized methane emissions. Making use of flux footprint analysis was necessary to compute fluxes which are more representative of the local emissions. To apply the transfer function of Eq. (1) for the purpose of determining the leakage flux from a known emission area (assuming the source is constrained within that area, to be referred to as the down-scaled area), we write it as (for a given sensor height, z_m):

$$F_m = \iint_{\text{Footprint}} Q(x,y) f'(x,y)\, dxdy \quad (2)$$

To constrain all emissions within the down-scaled area, $Q(x, y)$ is defined as:

$$Q(x,y) = Q_{avg} g(x,y) \quad (3)$$

where $g(x, y)$ is some binary emissions distribution function (value of 1 indicates that the coordinate x, y is within the down-scaled area and 0 that it is not) over which the average flux for the down-scaled area (Q_{avg}) applies. Since the source pattern of methane within the down-scaled area is not known, an average flux is assumed over this area. Determining the distribution of emissions within this area is challenging and beyond the scope of this study. For this analysis, it was assumed that the fluxes were uniform within the down-scaled area, and that no significant fluxes existed outside that chosen area. Combining Eq. (2) and (3) and moving the constant, Q_{avg} outside the double integral, we get:

$$F_m = Q_{avg} \iint_{\text{Footprint}} g(x,y) f'(x,y)\, dxdy \quad (4)$$

We can then numerically integrate these fluxes over the down-scaled area:

$$F_m = Q_{avg} \sum_x \sum_y g(x,y) f'(x,y) \Delta x \Delta y \quad (5)$$

where $\Delta x \Delta y$ is the area of a single pixel. From Eq. (5), Q_{avg} can be obtained as:

$$Q_{avg} = \frac{F_m}{\sum_x \sum_y g(x,y) f'(x,y) \Delta x \Delta y} \quad (6)$$

Computation of the flux footprint function, $f'(x, y)$ used the semi-empirical parameterized flux footprint model, developed by Kljun et al. (2015), and is based on the Lagrangian Stochastic model (LSM) of Kljun et al. (2004). Unlike other existing LSM based parameterizations (e.g., Hsieh et al., 2000), Kljun et al. (2015) realized that it is not viable to apply a single parameterization to all real-scale footprints, and hence defined a universal non-dimensional footprint, with the idea that these non-dimensional footprints collapse to a universal curve or a narrow ensemble of curves. They achieved this following the Buckingham π dimensional analysis to scale the footprint estimates of the Backward Lagrangian Particle Dispersion Model (LPDM-B), and to scale the two components (crosswind integrated footprint and the crosswind dispersion) separately. Therefore, the two-dimensional flux footprint function $f'(x, y, z_m)$ can be computed as:

$$f'(x,y,z_m) = \overline{f_y}(x) \frac{1}{\sigma_y \sqrt{2\pi}} \exp\left(\frac{-y^2}{2\sigma_y{}^2}\right) \quad (7)$$

where x is the alongwind distance, y is the crosswind distance, $\overline{f_y}(x)$ is the crosswind integrated footprint, and σ_y the standard deviation of the crosswind distance (see the Supplementary Material for a detailed description for calculation and parameters used). The crosswind integrated footprint, $\overline{f_y}(x)$, is computed as:

$$\overline{f_y}(x) = \frac{\widehat{F}^{y^*}}{z_m} \left(1 - \frac{z_m}{h}\right) \frac{u_*}{\overline{u}(z_m) k} \quad (8)$$

where $\widehat{F}^{y^*}$ is the universal non-dimensional parameterized crosswind integrated footprint, h is the atmospheric boundary layer height, $\overline{u}(z_m)$ is the mean wind velocity at the measurement height and k is the von Karman constant. It should be noted that the parameters within Eqs. (7) and (8) are dependent on time (i.e., climate conditions during each time interval). Therefore, $f'(x, y, z_m)$ is not constant and must be explicitly calculated for each time interval.

It should also be noted that emissions from a near-by wetland and an abandoned well 2 km to the northwest of the EC tower were considered as a possibility prior to conducting the injection experiment. However, upon conducting the flux footprint analysis described, it was found that the distances to these sources were too large to be of consequence to the eddy fluxes.

2.6. Soil-gas monitoring wells

Soil-gas samples for measurement of gas concentration and stable isotopes were collected from 22 soil gas monitoring wells distributed across the site (Fig. 1), each with ports at 0.45 and 1.15 m bgs. The wells were sealed and isolated with bentonite to prevent connection with the atmosphere. The soil-gas tubing consisted of 0.635 cm (1/4″) outer diameter polyethylene tubing fitted with a 2.54 cm (1") long fine mesh screen (88.9 μm opening size. P/N: McMaster Carr 9318T47) at the bottom and a gas-tight ball valve at the top. A total of 13 sampling rounds were conducted between June 1 and September 13, 2018 and an additional sampling round was completed in June 2019. Gas composition (C_1 to C_3 alkanes) was analyzed at the Isotope Science Lab (ISL, University of Calgary) using a Scion 450/456 gas chromatograph (GC). The lower detection limit for hydrocarbon gases is 1 ppm and for non-hydrocarbon gases 50 ppm. Analytical precision and accuracy for gas composition analysis was ±2.5% of the reported concentrations. Stable carbon isotope ratios $^{13}C/^{12}C$ of CH_4, C_2H_6, C_3H_8 and CO_2 (see Supplementary Material) and the stable-hydrogen $^2H/^1H$ of CH_4, C_2H_6, and C_3H_8 were also quantified at the ISL using continuous-flow isotope-ratio mass spectrometry. Isotopes were measured using a Thermo Trace GC (and GC Ultra for the stable-hydrogen isotopes) – GC-IsoLink system interfaced to a Thermo Scientific MAT 253 mass spectrometer via a Thermo Conflo IV. The final isotopic ratio results are expressed as δ values using per mil notation relative to the international V-PDB and V-SMOW standards (for ^{13}C and ^2H, respectively) with an associated accuracy of ±0.5‰ for $\delta^{13}C$ and ±2‰ for δ^2H and a detection limit of 1000 ppmv for $\delta^{13}C$.

3. Results and discussion

3.1. Spatiotemporal distribution of effluxes using chamber method

Background CH_4 effluxes prior to the synthetic natural-gas injection measured using both spatial surveys and long-term chambers showed that CH_4 effluxes were low, near or below detection limit ($\pm 2 \times 10^{-3}$ μmol m^{-2} s^{-1}) with evidence for CH_4 uptake into the soil across most of the site. Based on the observed natural conditions, no consistent spatial pattern of CH_4 effluxes prior to injection was discerned.

CH_4 effluxes greater than 0.01 μmol m^{-2} s^{-1} were first detected during a spatial survey on 25 July (43 days after the start of injection), 12 m upgradient (northwest) of the gas release point at a location with no installed long-term chambers. The emergence of the injection gas 12 m away from the gas release point highlights that GM is significantly influenced by subsurface heterogeneities and hydrostratigraphy, in this case resulting in lateral gas transport against the direction of groundwater flow. It was also noted that these elevated effluxes were observed in the direct vicinity of an installed groundwater monitoring well (MW2, as discussed in Section 2.2, Fig. 2).

To collect higher temporal resolution efflux data where survey data detected elevated effluxes, the down-gradient long-term chamber spoke (comprising six chambers, LT7-LT12) was relocated to align with the region of elevated effluxes on 26 July. Therefore, high-temporal resolution efflux measurements following 26 July will be the focus of this section. From 27 July to 22 August, the magnitude of the CH_4 effluxes for LT14-LT19 generally increased continuously from background levels to 4 μmol m^{-2} s^{-1} despite the injection terminating on 19 August. For LT1-LT6, measured methane effluxes generally remained similar to background levels (Figure S8 to S10).

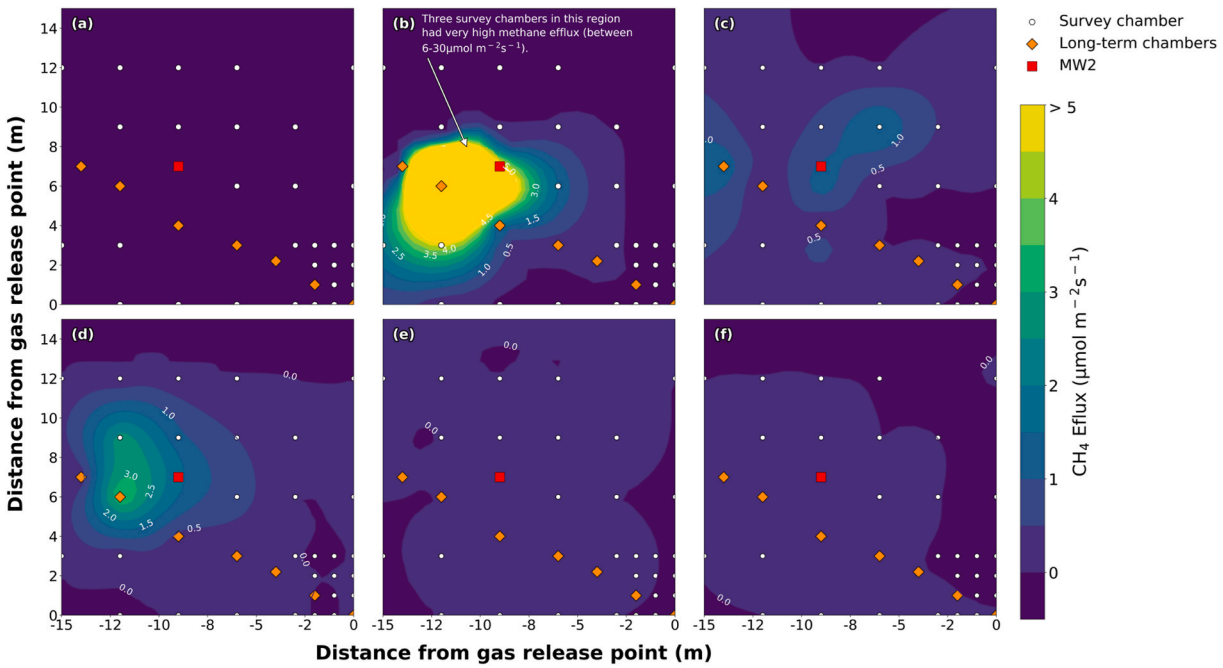


Fig. 2. Spatial distribution of CH_4 effluxes (μmol m^{-2} s^{-1}) taken from survey measurements on (a) 6 June (pre-injection), (b) 27 July (during active injection), (c) 11 August (during active injection), (d) 18 August (prior to shut-down), (e) 13 September (post-injection), and (f) 28 September (post-injection), 2018. Location of survey and long-term chambers and groundwater monitoring well MW2 are also shown.

For LT14-LT19, where elevated effluxes were measured, effluxes were episodic through the day, ranging from slightly elevated values (0.01 μmol $m^{-2}s^{-1}$) to values as high as 8 μmol $m^{-2}s^{-1}$ (Fig. 3). Some influx of CH_4 was observed (negative fluxes) suggesting uptake by the soil. This variability in CH_4 effluxes throughout the day was believed to be influenced by gas accumulation in the subsurface, accompanied by subsequent episodic releases, in-line with observations of previous studies (Cahill et al., 2017; Forde et al., 2018; Van De Ven and Mumford, 2020b). Survey chamber data agreed well with the long-term chambers, showing variably elevated methane effluxes contained within a 10 m × 10 m area centered around MW2 (Fig. 2). After 22 August, the CH_4 effluxes began to decrease rapidly until they reached background levels in early September.

The highly episodic methane effluxes measured for LT14-LT19 are expected based on the heterogeneous nature of the subsurface. Gas flow towards the ground surface is governed by buoyancy, capillary, and viscous forces (Frette et al., 1992; Gurevich et al., 1993). Based on the high degree of variability of the displacement pressures associated with the heterogeneous subsurface at the site (Chao et al., 2020), movement of gas is believed to be obstructed by capillary barriers, causing build-up and lateral spreading of the free-phase synthetic natural gas under a confining layer in the saturated zone (Cahill et al., 2017; Van De Ven and Mumford, 2020a, 2020b). The arrival of gas at the surface indicates that the gas pressure was sufficient to overcome capillary forces, allowing free phase gas to migrate to the surface along preferential pathways, creating highly localized advective migration toward the unsaturated zone (Anderson et al., 2009; Chao et al., 2020; Forde et al., 2018; Selker et al., 2007; Tomlinson et al., 2003). Once the active injection ceased, the subsurface free phase gas plume maintained sufficient pressure, leading to continued releases at the surface for nearly two weeks. Subsequently, free phase gas was no longer able to maintain sufficient pressure to overcome capillary forces, leading to a decline in effluxes until they could no longer be detected at the surface (Cahill et al., 2017; Klazinga et al., 2019; Van De Ven et al., 2020).

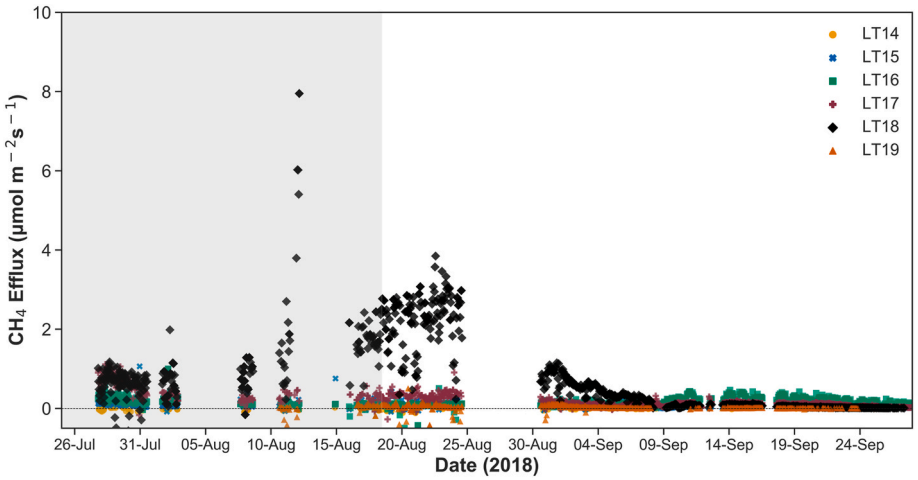


Fig. 3. CH_4 effluxes (μmol m^{-2} s^{-1}) measured by six long-term chambers (LT14-LT19). The grey-shaded area indicates duration of gas injection.

Observed CO_2 effluxes did not correlate to the spatial distribution of CH_4 effluxes (Figure S11). There were significant spatial variations of observed CO_2 effluxes during background measurements ranging from 0.1 to 5.0 μmol m^{-2} s^{-1}. Over the entire measurement period, CO_2 effluxes ranged from 0.1 to 12.5 μmol m^{-2} s^{-1}. The CO_2 effluxes followed a commonly observed trend, with CO_2 effluxes increasing in late spring and peaking at the end of July when temperatures were highest (e.g., Fenn et al., 2010; Thierron and Laudelout, 1996; Witkamp, 1966), then decreasing as temperatures decreased later in the year, a pattern which can likely be attributed, at least in part, to seasonal variations in natural soil respiration. A study of well pads with confirmed GM in northeast BC reported CO_2 efflux values between 0.5 and 32.0 μmol m^{-2} s^{-1} (Forde et al., 2019c). Studies conducted in natural environments such as boreal forests and grasslands of northern Canada have reported CO_2 effluxes from soil respiration to be highly spatially variable and ranging from low positive effluxes to 14.0 μmol m^{-2} s^{-1} (Domisch et al., 2006; Felice et al., 2018; Gulledge and Schimel, 1998; Niinistö et al., 2011; Rayment and Jarvis, 2000; Subke et al., 2009). The CO_2 effluxes measured during this experiment were generally in the range of CO_2 effluxes reported in the literature for natural soil respiration without a clear signal that is attributable to the controlled release. In addition, during every measurement period (prior, during, or after injection), the soil CO_2 effluxes measured for all chamber locations followed a diurnal pattern with lower CO_2 effluxes generally occurring at night, indicating that these fluctuations are related to daily variations in natural soil respiration processes.

Similar studies have shown that surface CO_2 effluxes can be used as an indicator for microbially mediated degradation of petroleum hydrocarbons (Molins et al., 2010; Sihota et al., 2011, 2013) and the oxidation of CH_4 to CO_2 (Cahill et al., 2017; Forde et al., 2018). However, based on the magnitude of the CO_2 fluxes alone, it is not possible to discern if the elevated CO_2 fluxes were due to increased soil respiration related to elevated temperatures or a result of CH_4 oxidation.

3.2. Temporal fluxes observed by EC

EC measurements were made throughout the injection period, continuing for roughly 2.5 months after the injection ceased (until 7 November 2018). There was clear indication of elevated EC flux measurements (F_m) for winds coming from west-southwest (red data points in Fig. 4). This agrees with the findings from observations of methane

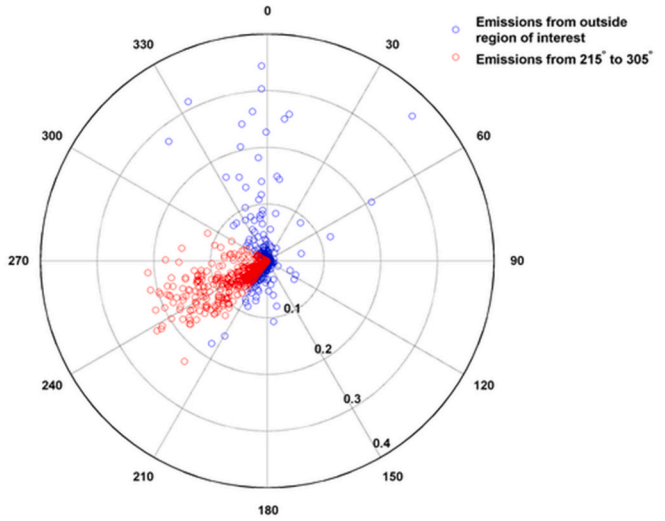


Fig. 4. Polar scatter plot for EC measurements of methane flux (F_m) prior to down-scaling. Values for the different radial distances are in μmol m^{-2} s^{-1}. Red data points represent fluxes from the selected wind direction sector of 215°–305° and the blue data points represent all other directions.

being released from MW2 and the long-term dynamic chamber measurements of surface effluxes from the soil in this region. High flux events corresponding to winds from the north (Fig. 5) were removed from the analysis as they were not the result of the injection experiment and were attributed to the possibility of vehicles and cattle (at times northwest of the tower).

F_m values filtered for wind directions corresponding to the injection experiment (215°–305°), were close to background until early July and then increased (Fig. 5). F_m continued to increase steadily, then peaked in mid-August at values of 0.23 μmol m^{-2} s^{-1}. After this, fluxes decreased until late September and returned to background levels until the end of the measurement period. No significant dependence of these measurements on climate parameters (soil temperature, soil volumetric water content, air temperature, and barometric pressure) was observed.

The temporal variation in F_m was consistent with that of the chambers. However, a decrease in EC fluxes occurred immediately following the cessation of gas injection on 19 August, whereas some chambers (i.e., LT16, 17 and 18) showed continued increases until 22 August. This observation provides evidence that the EC system measured a dominant source of methane that was not captured by the chambers. Furthermore, methane EC fluxes corresponding to the entire footprint were lower in magnitude than the effluxes measured at locations covered by the chambers. This is expected because F_m accounts for the entire footprint measured by the tower, while emissions associated with the release experiment are not homogeneous across the entire footprint. In addition, the area of the footprint is substantially larger than the area measured by the chambers. To make a meaningful comparison between the fluxes measured by EC and the chambers, the EC data was downscaled to the area of elevated emissions (down-scaled area).

3.3. Down-scaled source fluxes

The EC methane fluxes were down-scaled to quantify the localized fluxes associated with the injection experiment. To do so, *a priori* information on the location of emissions within the footprint was derived from the effluxes measured with the long-term dynamic chambers and observance of gas leakage from MW2. Chamber measurements were made in a 14 m × 12 m survey grid around MW2 (Fig. 2), and as stated above, the effluxes were found to be mostly constrained in a 10 m × 10 m area centered at MW2.

EC flux measurements and wind direction confirmed that the positive fluxes were highest in magnitude when the winds were directly from west-southwest (~250°), which was roughly the direction in which MW2 was located with respect to the EC tower (~259°). Based on this information and the chamber results, a 10 m × 10 m area surrounding MW2 was selected to be the down-scaled source area of emissions and it was assumed that the EC measurements solely resulted from this area. Therefore, we define $g(x, y) = 1$ (see equations (3)–(5)) within this downscaled area (grey area, Fig. 6) and $g(x, y) = 0$ everywhere else. Flux footprint analysis was then used to estimate the magnitude of the emissions from this region (following an approach similar to that discussed by Prajapati and Santos (2018).

As a result of down-scaling, a new Q_{avg} time-series was obtained, which better represents emissions in the source area than the measured value, F_m, time-series (Fig. 7). Peak down-scaled methane flux reached values of 8.1 μmol m^{-2} s^{-1}. Contrasting this peak to the maximum F_m measured (0.23 μmol m^{-2} s^{-1}), highlights the importance of knowing the location of regions of elevated emissions within the footprint and the dimensions of this region. Without this knowledge, it is difficult to evaluate the true magnitude of local emissions associated with GM.

3.4. Fate of natural gas in the vadose zone

To understand the fate of injected synthetic natural gas and to confirm the source, stable carbon and hydrogen isotope samples collected from soil gas wells were analyzed (Whiticar, 1999). Three

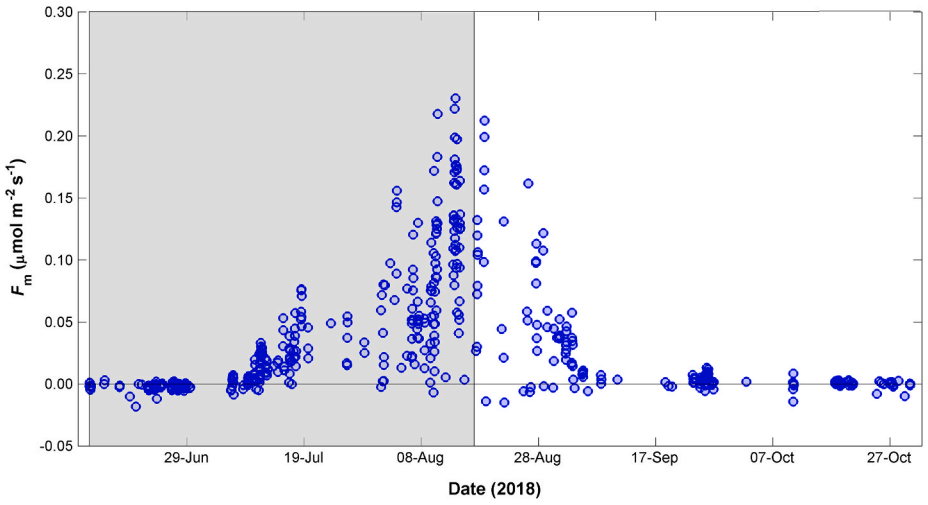


Fig. 5. Half-hourly EC measurements of methane flux (F_m) filtered to exclude measurements for wind directions outside the range, 215°–305° (i.e., the direction of elevated emissions) prior to down-scaling. Grey-shaded area indicates duration of gas injection.

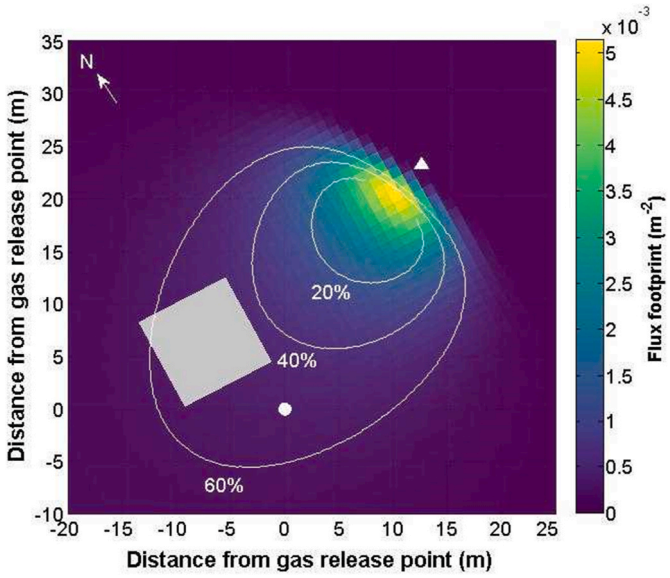


Fig. 6. Conceptualization of the flux footprint function for a single half-hour during monitoring, 18:30 h PST, 20 August 2018. The triangle represents the EC system and the circle indicates the injection point. The grey square represents the 10 m × 10 m area of elevated emissions used for down-scaling. The white lines indicate the 20%, 40%, and 60% flux footprint contours.

soil-gas wells (SG15, SG17 and SG18) had sufficiently high concentrations (>0.1% v/v of CH_4) during 14 of the sampling events for analysis of stable-carbon isotope ratios of CH_4 and only samples from SG17 and SG18 had sufficiently high concentrations for analysis of stable-hydrogen ratios. Samples with >0.1% (v/v) of CH_4 also contained detectable concentrations of C_2 and C_3. Due to the low CH_4 background concentrations (below detection limit) in all soil-gas wells, it was not possible to determine background $\delta^{13}C$–CH_4 and $\delta^{2}H$–CH_4 values for the field site, however, comparison can be made with injected gas. The isotopic ratios of the synthetic natural gas were $\delta^{13}C$–$CH_4 = -40.3‰$ and $\delta^{2}H$–$CH_4 = -151.6‰$. In comparison, the isotopic ratios of the gas samples collected from gas monitoring wells SG15, SG17 and SG18 were less negative than observed in the injection gas ($\delta^{13}C$–CH_4 ranged between −31.8‰ and −19.3‰, while $\delta^{2}H$–CH_4 varied between −144.5‰ and −89.3‰, with no discernible trend based on the depth of the sample). The $\delta^{13}C$–CH_4 values obtained were on average −27‰ (Fig. 8). Considering that there are no other significant sources of CH_4 at the site, the isotopic signature observed in samples from gas monitoring wells are indicative of microbial CH_4 oxidation. The less negative values are the result of an enrichment of ^{13}C in CH_4 due to the kinetic isotope effect which results in the preferential selection of ^{12}C during microbial oxidation (Alperin et al., 1988; Whiticar, 1999; Whiticar et al., 1986).

Soil-gas samples that had the greatest concentrations of CH_4, corresponded to periods when the greatest CH_4 effluxes were observed at the surface using the chamber method. These samples with higher CH_4 concentrations (and therefore surface effluxes) had $\delta^{13}C$–CH_4 values more similar to the injection gas than samples with lower CH_4 concentrations. This illustrates that during periods of high efflux, a smaller proportion of the gas was oxidized compared to lower efflux conditions, likely due to shorter residence times during advective migration of gas toward the surface. This phenomenon was also observed in similar experiments by Forde et al. (2018).

The average $\delta^{2}H$–CH_4 values of the measured samples was −120‰, which is also indicative of microbially mediated CH_4 oxidation, leading to an enrichment of ^{2}H in CH_4 due to the kinetic isotope effect, similar to the stable-carbon isotopes (Coleman et al., 1981; Feisthauer et al., 2011; Whiticar, 1999). The isotopic data suggests the occurrence of aerobic oxidation that could not be identified via gas effluxes or soil gas concentration measurements despite the relatively thin unsaturated zone (1.0–1.5 mbgs), which cannot be expected at all sites where GM may occur. This implies that some of the increases in CO_2 effluxes during and following the controlled release were due to oxidation of CH_4 and other hydrocarbon compounds and is further supported by $\delta^{13}C$–CO_2 measurements (see Figure S12 in the Supplementary Material).

3.5. Cumulative surface expression

The cumulative methane emissions during the synthetic natural gas injection estimated with dynamic flux chambers were compared to those estimated with EC starting after the long-term chambers were relocated on 27 July. Cumulative emissions could then be compared over the same time period. However, fluxes were detected by EC already in June and early July, such that the total site-wide cumulative emissions were greater.

For the chamber method, the measured effluxes from each chamber associated with gas migration through the subsurface were integrated over discrete areas assuming consistent effluxes over a surface area which spanned half the distance to the next nearest chamber. Because the long-term chambers did not cover the entire impacted area (10 m × 10 m, centered around MW2), a correction factor was applied to the

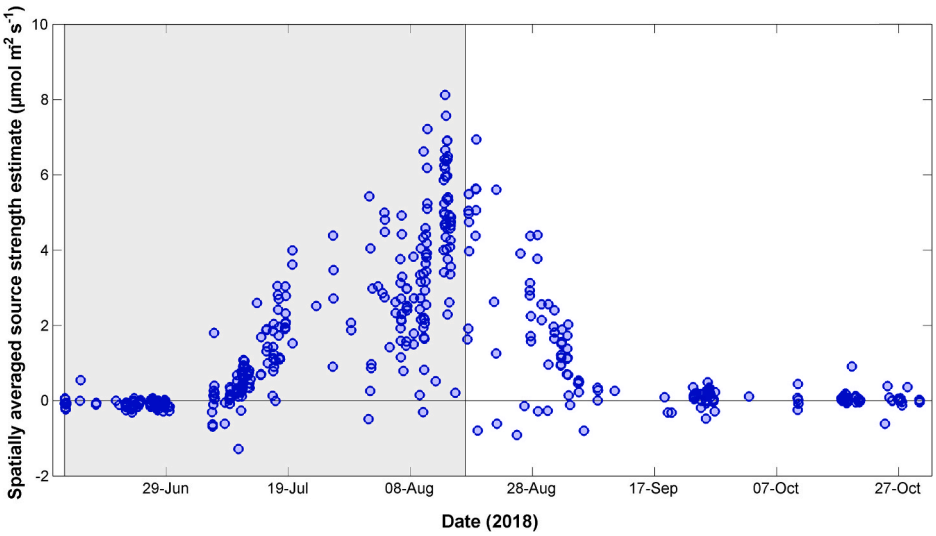


Fig. 7. Down-scaled methane fluxes, i.e., source flux (Q_{avg}) time-series. Grey-shaded area indicates duration of gas injection.

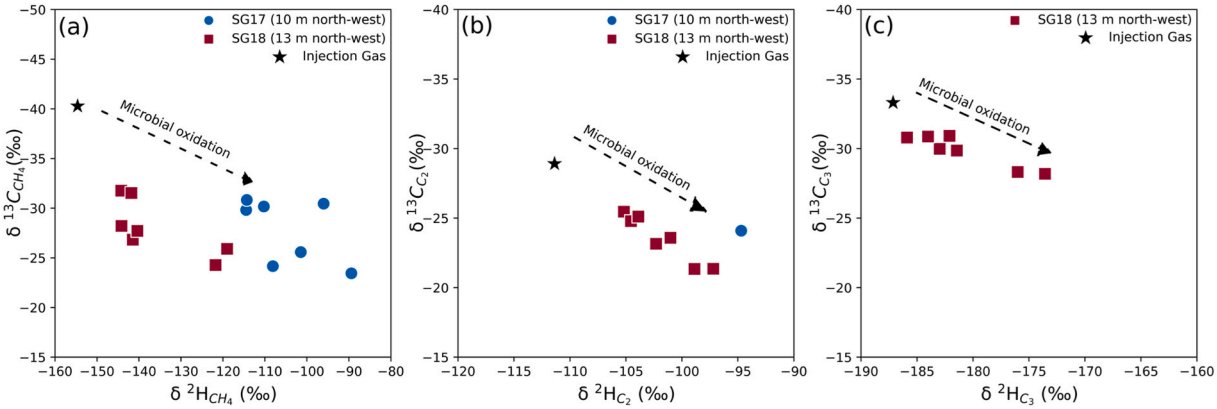


Fig. 8. Stable carbon isotope analysis for soil gas wells showing (a) $\delta^{13}C$–CH_4 plotted against the $\delta^{2}H$–CH_4, (b) $\delta^{13}C$–C_2 plotted against the $\delta^{2}H$–C_2 and (c) $\delta^{13}C$–C_3 plotted against the $\delta^{2}H$–C_3. Dashed arrows represent the general trajectory for microbial oxidation of C1, C2, and C3 (Whiticar, 1999).

long-term chamber data, guided by survey chamber data (see Supplementary Material for detailed description). To determine this factor, total emissions were calculated from each of the 12 observation times when fluxes were measured using both the long-term chambers and the survey chambers. The percentage of mass captured by the long-term chambers relative to the total mass captured by the survey grid was found to range from 28 to 46%. Based on these percentages, upper and lower limits for the cumulative emissions derived solely from the high temporal resolution long-term chamber data were estimated. A more detailed description of these calculations can be found in the

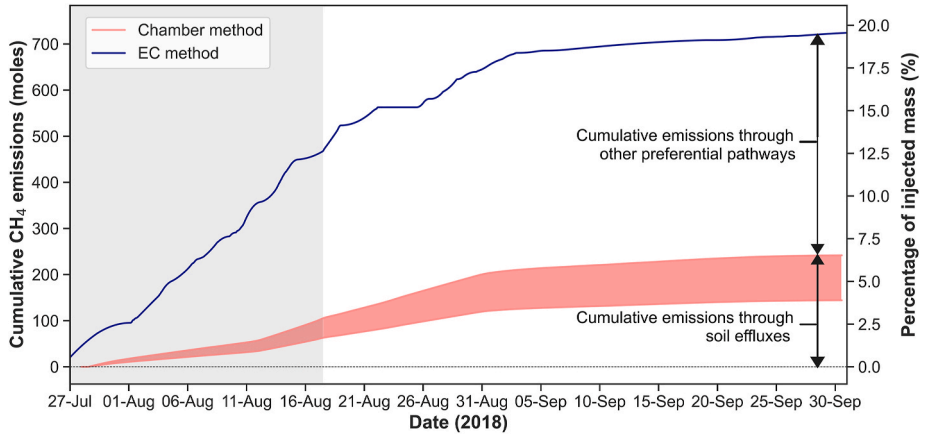


Fig. 9. CH_4 cumulative emissions (mol) captured using the chamber method (effluxes through soil) and by the EC system (emissions through soil and other preferential pathways, including MW2). Grey-shaded area indicates duration of gas injection.

Supplementary Material. Based on this approach, the cumulative CH_4 emissions was found to range between 144 and 242 mols (Fig. 9), accounting for 3.8–6.5% of the injected CH_4.

The down-scaled CH_4 flux captured by the EC system was also integrated to calculate cumulative mass released at the surface (see the Supplementary Material). The resulting down-scaled fluxes measured were integrated over the down-scaled area of the site (10 m × 10 m) and the time period between 27 July and the end of the experiment. As expected, using the EC method, the cumulative CH_4 emissions were greater than that of chamber method (Fig. 9). The cumulative mass flux measured using the EC system was 726 mols; 19.6% of the mass injected in the subsurface was expressed at the surface during this time period. If the integration was completed for the entire experiment the cumulative emissions derived from the EC measurements were 976 mol, or 26.3% of the CH_4 injected. It should be noted that these estimates assume that no expression occurred outside the observation area as defined by the flux footprint, which is reasonable based on analysis of all data collected at the site.

Not unexpectedly, the comparison of the chamber method to the EC method to calculate the cumulative methane emissions at the surface shows substantial differences (Fig. 9). This is expected because the chambers can capture high temporal resolution soil efflux measurement only in the area of the surface on which the chamber is installed (317.8 cm^2). Therefore, based on previous literature (Forde et al., 2018) and the findings of this study, when efflux patterns are heterogeneous, unless chambers cover the entire zone of efflux, the total site-wide emissions will not be accurately characterized. In contrast, the EC method is able to measure the integrated fluxes over the entire area within the flux footprint of the system (dependent on the terrain, atmospheric conditions, height of the release point, and installation of the system). Therefore, measurement using EC is not limited by the heterogeneous spatial effluxes expected of gas migration through heterogeneous subsurface systems, capturing emitted CH_4 through preferential pathways, while accounting for areas with limited emissions. In addition, in this study the EC method was expected to yield greater cumulative emission estimates because EC could detect efflux from MW2, which the chambers could not. Unlike the chamber method, the EC system has the potential to capture sources of methane emitted from the subsurface that were not directly from the soil.

The cumulative emissions estimated using the chamber method, are limited by the number of chambers deployed and also the ability to interpolate representative effluxes over the surface. The cumulative emissions estimated using EC system are sensitive to external variables including wind direction and frictional velocity causing variation in the flux footprint. For the experiment conducted, the wind direction and mixing conditions were most favorable for measurement of fluxes ~10% of the time after filtering. Therefore, based on the sparse temporal dataset it is expected, that integrated fluxes and therefore cumulative emissions estimate using the EC method are also uncertain. This, however, highlights the importance of location selection for the EC system at sites of suspected gas migration. It is vital that the system be placed in a location which is often downwind of the area with suspected emissions. Alternatively, multiple EC towers or open-path instruments (e.g., laser dispersion spectroscopy and Fourier Transform Infrared spectroscopy) can be used to provide a more comprehensive picture of site wide emissions, irrespective of wind directions.

This analysis provides evidence that surface emissions occurred, despite the presence of the confining diamict layer. For this site, emissions to the atmosphere amount to approximately 25% of injected gas. The occurrence of these emissions is indicative of vertical discontinuities in the upper 10 m thick confining diamict, suggesting the existence of preferential gas pathways through the confining layer to the unsaturated zone and surface. However, there were insufficient data to determine whether emissions were due to naturally occurring preferential pathways already present prior to the installation of the monitoring network and commencement of gas injection, or whether emissions occurred along preferential pathways caused by the installation of groundwater monitoring wells across the site. Analysis of the subsurface conducted by Chao et al. (2020), indicated that sand lenses and other intra-diamict features, root pathways, and fracturing are present in the upper confining layer, which may be responsible for natural preferential migration pathways. However, chamber efflux data indicated that much of the emissions occurred near one of the installed monitoring wells. Despite the uncertainty in the total mass expressed at the surface and the nature of the migration pathways, our data also indicate that approximately 75% of the injected gas was retained in the subsurface below the diamict layer at this site. This finding is supported by geophysical and hydrogeological surveys conducted at the site which corroborate that a significant quantity of gas was trapped below the diamict layer, with evidence of extensive lateral migration (Cary, 2019; Chao et al., 2021).

4. Conclusions

The controlled natural gas release conducted in this study, provided better understanding of the surface expression of GM in heterogeneous geological settings and implications for detection and monitoring techniques for surface expression. The surface expression of elevated CH_4 effluxes and soil gas concentrations resulting from GM were highly localized. These data also show that fugitive emissions may occur upgradient of the injection location, implying that gas can readily migrate against the direction of groundwater flow and may show considerable lateral mobility. Isotopic analysis of soil gas well sampling suggested that oxidation of injected natural gas occurred within the system.

In addition to GM moving through soils to the atmosphere, injected gas was found to reach the surface through an installed groundwater monitoring well. This constructed preferential pathway was shown to provide a direct route for injected gas from the saturated zone to the atmosphere. Using long-term dynamic chambers and EC methods, an approximate estimate of the proportion of cumulative emissions from GM through soil was 33% (percentage of total mass emitted, captured by the chambers), with the remainder (66%) travelling along other pathways to the surface, likely associated with MW2. This finding presents evidence that site investigation to identify and characterize suspected gas migration may cause non-natural migration pathways, leading to more substantial surface expression of natural gas and inadvertently enhancing GHG emissions to the atmosphere.

The observed spatiotemporal pattern of effluxes, gas concentration, and stable isotopes in this study are common across many areas impacted by GM and clearly demonstrates that monitoring and detection of surface expression of GM is challenging. This study provided a valuable assessment of surface monitoring methods for GM emissions. Each technique provided data to assess surface expression. Specifically, survey chambers were able to identify localized areas of elevated soil effluxes at time-discrete points during the injection. The long-term chambers provided high temporal-resolution data to understand the soil effluxes during and after the injection experiment. Soil gas wells allowed for stable isotope analysis to determine whether hydrocarbon oxidation was occurring. Finally, the EC system allowed for site-wide integrated emissions of methane to be measured at high temporal resolution, integrating the many possible point-sources of CH_4 to the atmosphere. While employing one of these techniques at a site with suspected or confirmed GM will provide insight, enhanced interpretation was gained by coupling these approaches.

To the best of the authors' knowledge, this study provided the first integrated use of multiple techniques to detect emissions of fugitive gas migration, including EC measurements, which have not previously been used for this application. The use of EC provided valuable data which can be supportive in gaining scientific knowledge and quantification of cumulative surface expression at impacted sites. Although beyond the scope of this study, consideration of uncertainties associated with EC should be considered for specific applications (see for Burba, 2013 for

detailed discussion).

Overall, the data of this study show that despite the low-permeability near-surface soils (diamict), a portion of injected gas reached the ground surface and was emitted to the atmosphere. Gas migration may have been facilitated by disturbances introduced through the installation of monitoring wells across the experimental site but may also have occurred along natural pre-existing pathways. Based on the data presented here, emissions amounted to around 25% of the gas injected. Although not likely, additional emissions may have occurred beyond the observation area. Nevertheless, our data also suggests that around 75% of the injected gas was retained in the subsurface. This finding is corroborated by the widespread presence of gas in the subsurface at the conclusion of the experiment identified with geophysical and hydrogeological methods (Cary, 2019; Chao et al., 2021). In summary, these findings indicate that gas migration through low-permeability material along naturally occurring or anthropogenic preferential pathways can occur. However, our results also indicate that in low permeability, heterogeneous geologic environments, particularly glacially-derived sediments typical of the WCSB, a large portion of fugitive gas released at depth from leaky wells may remain in the subsurface. The presence of low permeability surficial sediments, even if imperfect, may act as a capillary barrier mitigating greenhouse gas emissions, while simultaneously inferring greater risks to groundwater resources, if present.

Credit author statement

Julia V. Soares: Formal analysis; Investigation; Methodology; Validation; Visualization; Writing – original draft. **Chitra Chopra:** Formal analysis; Investigation; Methodology; Validation; Visualization; Writing – original draft. **Cole J.C. Van De Ven:** Formal analysis; Validation; Visualization; Writing – original draft; Writing – review & editing. **Aaron G. Cahill:** Conceptualization; Funding acquisition; Investigation; Project administration; Resources; Supervision; Writing – review & editing. **Roger D. Beckie:** Conceptualization; Funding acquisition; Project administration; Resources; Supervision; Writing – review & editing. **T. Andrew Black:** Conceptualization; Funding acquisition; Investigation; Methodology; Supervision; Writing – review & editing. **Bethany Ladd:** Investigation; Project administration; **K. Ulrich Mayer:** Conceptualization; Funding acquisition; Methodology; Project administration; Resources; Supervision; Validation; Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apr.2021.101223.

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SCEDC (/index.html)

Southern California Earthquake Data Center (/index.html)

For the SCSN Visit (https://www.scsn.org/)

Earthquake Information

Chronological Earthquake Index

Fort Tejon Earthquake

TYPE OF FAULTING: right-lateral strike-slip (../graphics/animations/right-lateral-animation.gif)
TIME: January 9, 1857 / about 8:20 am PST
LOCATION: 35° 43' N, 120° 19' W about 72 km (45 miles) northeast of San Luis Obispo, about 120 km (75 miles) northwest of Bakersfield, as shown on the map (epicenter location uncertain).
MAGNITUDE: MW 7.9 (approx.)
LENGTH OF SURFACE RUPTURE: about 350 km (217 miles)

AVERAGE SURFACE OFFSET: about 5 meters (15 feet)

The Fort Tejon earthquake of 1857 was one of the largest earthquakes ever recorded in California, and left an amazing surface rupture scar over 350 kilometers in length along the San Andreas fault (sanandreas.html). Yet, despite the immense scale of this quake, only two people were reported killed by the effects of the shock -- a woman at Reed's Ranch near Fort Tejon was killed by the collapse of an adobe house, and an elderly man fell dead in a plaza in the Los Angeles area.

The fact that only two lives were lost was primarily due to the the nature of the quake's setting; California in 1857 was sparsely populated, especially in the regions of strongest shaking, and this fact, along with good fortune, kept the loss of life to a minimum. The effects of the quake were quite dramatic, even frightening. Were the Fort Tejon shock to happen today, the damage would easily run into billions of dollars, and the loss of life would likely be substantial, as the present day communities of Wrightwood, Palmdale, Frazier Park, and Taft (among others) all lie upon or near the 1857 rupture area.

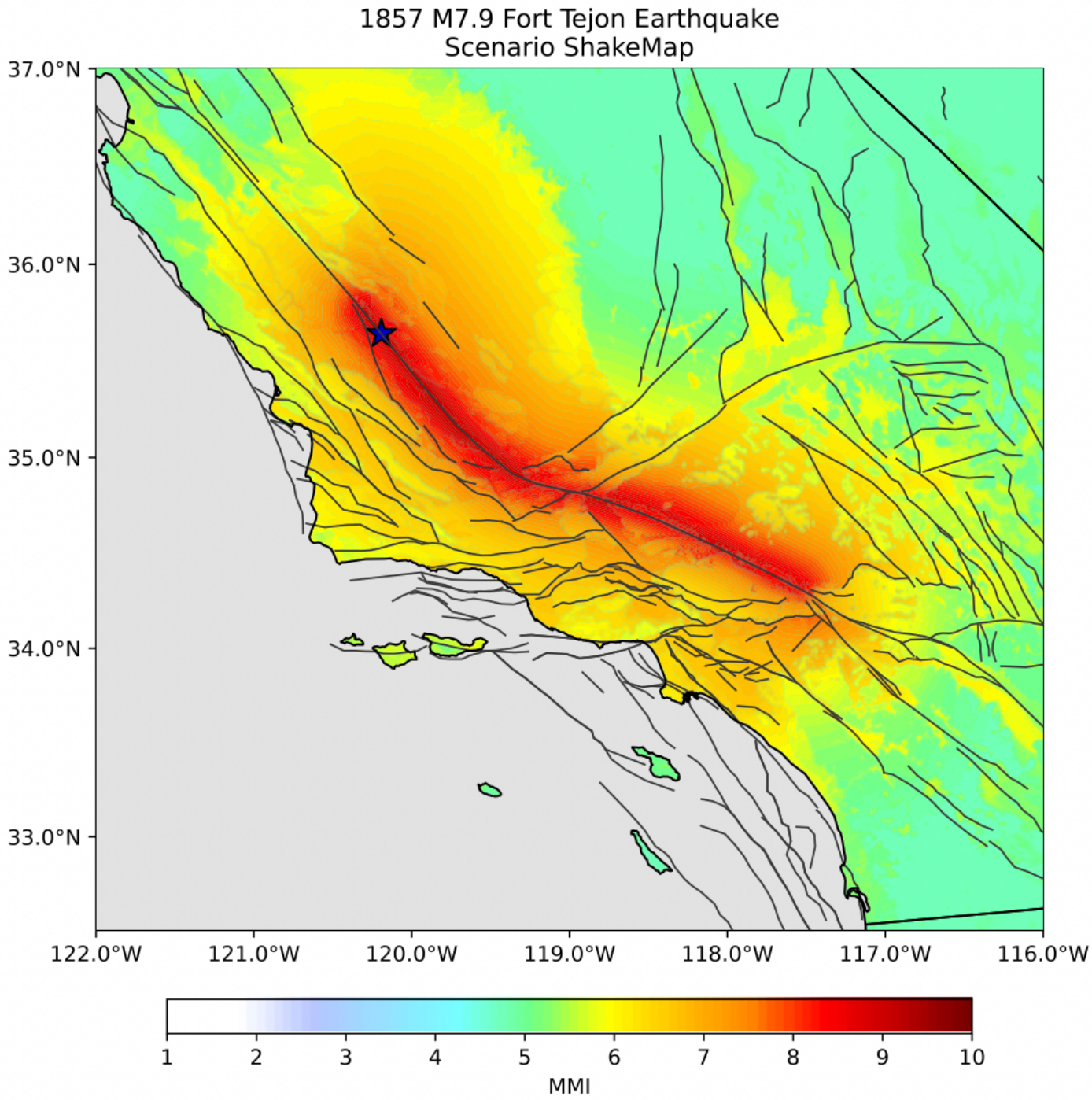
As a result of the shaking, the current of the Kern River was turned upstream, and water ran four feet deep over its banks. The waters of Tulare Lake were thrown upon its shores, stranding fish miles from the original lake bed. The waters of the Mokelumne River were thrown upon its banks, reportedly leaving the bed dry in places. The Los Angeles River was reportedly flung out of its bed, too. Cracks appeared in the ground near San Bernadino and in the San Gabriel Valley. Some of the artesian wells in Santa Clara Valley ceased to flow, and others increased in output. New springs were formed near Santa Barbara and San Fernando. Ridges (moletracks) several meters wide and over a meter high were formed in several places. In Ventura, the mission sustained considerable

damage, and part of the church tower collapsed. At Fort Tejon, where shaking was greatest, damage was severe. All around southern and central California, the strong shaking caused by the 1857 shock was reported to have lasted for at least one minute, possibly two or three!

The surface rupture caused by the quake was extensive. The San Andreas (sanandreas.html) fault broke the surface continuously for at least 350 km (217 miles), with an average slip of 4.5 meters (15 feet), and a maximum displacement of about 9 meters (30 feet) (possibly greater) in the Carrizo Plain area. Kerry Sieh (1978) noted that the **Elkhorn Thrust**, a low-angle thrust fault near the San Andreas (sanandreas.html), may have slipped simultaneously in the 1857 quake -- an observation that a team of researchers (1996) have recently used to support the idea that future movements along the San Andreas fault zone (sanandreas.html) might produce simultaneous rupture on thrust faults in and near the Los Angeles area, causing a terrible "double earthquake".

The location of the epicenter of the Fort Tejon earthquake is not known. As the name suggests, one idea is to locate it near the area of strongest reported shaking -- Fort Tejon. However, because there is evidence that foreshocks to the 1857 earthquake may have occurred in the Parkfield area, it is located on this map near the northwestern end of the surface rupture, just southeast of Parkfield, near Cholame. (Note: locating it near Fort Tejon would also have caused interference on the map between this quake's symbol and that of the 1952 Kern County quake (kern1952.html). Hence, for both these reasons, the Cholame location was chosen.)

Below is a map of rupture of 1857 earthquake with epicenter marked by a star. The part of the San Andreas fault which exhibited surface rupture during the earthquake is shown in red.



References (refs.html#fort)

Caltech (https://www.caltech.edu)

Seismological Laboratory California Institute of Technology (https://www.seismolab.caltech.edu/)

USGS science for a changing world (https://earthquake.usgs.gov/)

ANSS (https://www.usgs.gov/natural-hazards/earthquake-hazards/anss-advanced-national-seismic-system)

Cal OES GOVERNOR'S OFFICE OF EMERGENCY SERVICES (https://earthquake.ca.gov/)

nehrp (https://www.nehrp.gov/)

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Induced seismicity during the 2012 Newberry EGS stimulation: Assessment of two advanced earthquake detection techniques at an EGS site

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ABSTRACT

To improve the microearthquake detection capability during the 2012 Newberry enhanced geothermal system (EGS) demonstration, we applied two advanced earthquake detection algorithms to the continuous seismic data. These techniques have the power to detect microearthquakes within the seismic noise that would otherwise be missed using traditional techniques. We compare the efficacy of a matched field processing algorithm with a multi-channel waveform correlation algorithm. Both methods identified between 60%–80% more events, with each slightly outperforming the other in different seismic noise contexts. Incorporating either template-matching technique into a seismic processing routine could therefore effectively increase the sensitivity of the seismic network without changes to the existing hardware. Additionally, lowering the magnitude of completeness would significantly add to the number of events that could subsequently inform future decision making at the reservoir level.

1. Introduction

To engineer a sustaining subsurface geothermal system that provides clean and renewable energy, enhanced geothermal system (EGS) technologies must create and maintain a hot subsurface reservoir that allows for robust fluid circulation loops between injection and production wells (Brown et al., 1999). The creation of this reservoir requires the injection of fluids into the subsurface at optimal pressures and temperatures to construct a complex interconnected fracture network based on the pre-existing fractures within the matrix (Evans et al., 1999). This enhancement of permeability within the subsurface due to fluid injection is typically accompanied by microearthquakes (Terzaghi, 1923), whose location and source mechanism can be a dynamic indication of where fractures are being re-activated, or created, and the extent of the stimulated zone (Jeanne et al., 2014; Rutqvist et al., 2016). Therefore, microseismic mapping is a useful tool to characterize the development of the subsurface fracture geometry of the reservoir. Traditional earthquake detection and location techniques often are used to identify microearthquakes in real-time since they are fast and easy to implement (Ambuter and Solomon, 1974; Allen, 1978). However, most commonly used detection algorithms (*e.g.* STA/LTA detectors) can miss a significant number of small events that are on the detection threshold where the amplitude of the microseismic signal is at approximately the same level as that of the background ambient noise or the coda amplitude of a recent larger event (Trnkoczy, 2002).

As an alternative to traditional power detectors, template-based detection algorithms have successfully identified small earthquakes in difficult signal processing environments by using array-based waveform correlation techniques (Gibbons and Ringdal, 2006). These template-based techniques require a collection of representative, high signal-to-noise ratio (SNR) earthquake waveforms recorded across a seismic network in the frequency band of interest. These master templates are subsequently used to detect events within the noise that are similar in form, and thus similar in location and mechanism, to the original detector. Template-based algorithms have been employed with great success to identify small microearthquakes ($M_L > -4$) during hydraulic

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fracturing treatments (Lengliné et al., 2017; Meng et al., 2018), small events during particularly energetic aftershock sequences (Peng and Zhao, 2009; Lengliné et al., 2012), repeating earthquakes on creeping fault interfaces (Templeton et al., 2009; Chen et al., 2013), and seismic events within the slow earthquake family (*i.e.*, tremor, low-frequency earthquakes, and very low-frequency earthquakes) (Shelly et al., 2007; Maceira et al., 2010; Matsuzawa et al., 2015; Han et al., 2018).

To take advantage of the increase in sensitivity afforded by these template-based techniques, we apply two different earthquake template-matching algorithms to the continuous seismic data recorded before, during, and after the approximately 7-week 2012 Newberry Volcano EGS fluid injection program. We apply the matched field processing (MFP) earthquake detection algorithm (Harris and Kvaerna, 2010; Wang et al., 2015) and a general multi-channel waveform correlation algorithm (Shelly et al., 2007; Gibbons et al., 2007) to 13 months of data from the Newberry EGS site between 01 September 2012 and 30 September 2013. The original Newberry earthquake catalog identified 235 events (Foulger and Julian, 2013; LBNL, 2016). The template-matching techniques identified 218 additional events during the same time period, or approximately 93% more events. The MFP earthquake detection algorithm identified 150 additional events during the study period and the waveform correlation algorithm identified 186 additional events, with the majority of the new events being identified by both methods. The significant increase in the number of detected microearthquakes during and after the 2012 stimulation improved our knowledge of the spatiotemporal behavior of the subsurface fracture network at the Newberry EGS site relative to wellhead pressure and stimulation water flow volume. More generally, this study shows that relatively straightforward additions to seismic processing routines can significantly increase the number of detected microearthquakes, lower the magnitude of completeness, and add new information that could improve future stimulation strategies.

2. Study Area

The Newberry Volcano EGS Demonstration Project was located on the western flank of Newberry Volcano. Newberry Volcano is a large shield volcano situated to the east of the High Cascade Range and located within the High Lava Plains of central Oregon (Christiansen and McKee, 1978). High heat flow (Blackwell et al., 1983; Frone et al., 2014), due to a magma chamber beneath the volcano (MacLeod and Sherrod, 1988; Beachly et al., 2012) with magma injections recurring roughly every 200,000 years (Frone et al., 2014) and as recently as in the last 100 years (Dzurisin, 1999), make the Newberry Volcano an attractive site for geothermal energy development. In 1995, CalEnergy drilled two deep geothermal exploration wells on the northwestern flank of Newberry Volcano, identifying a large geothermal anomaly but no exploitable conventional geothermal resource (Spielman and Finger, 1998). More recently in 2008, Davenport Newberry drilled two geothermal wells (NWG 55-29 and NWG 46-16) on the western flank of Newberry Volcano and confirmed high subsurface temperatures at depth (*i.e., 300 °C at 2.7*–3.1 km depth), low fracture density, low permeability, and the absence of hydrothermal fluids within the footprint of the Newberry EGS site (Cladouhos et al., 2011; Frone et al., 2014). To increase fracture permeability in well NWG 55-29, a fluid stimulation program spanning approximately 7 weeks in 2012 was implemented to hydroshear the existing fractures (Cladouhos et al., 2009), keeping water pressures below the minimum principle stress to avoid hydraulic fracturing of the reservoir. The 2012 injection program consisted of 3 discrete stimulation stages, the first of which began 16 October 2012 and the last of which concluded 07 December 2012.

To record the expected induced microseismicity within the reservoir due to the stimulation program, a network of seismometers was deployed on the surface and within boreholes to capture the seismic signals. The AltaRock Energy Phase 2 Newberry Microseismic Network consisted of 8 3-component IESE borehole sondes containing 2-Hz Oyo Geospace HS-1 geophones installed to depths of 200–250 m and 7 3-component IESE posthole sondes containing 2-Hz Oyo Geospace HS-1 at 1 m depth (Fig. 1). The sample rate of the continuous data was 250 samples per second recorded on Geotech Instruments SMART-24R dataloggers.

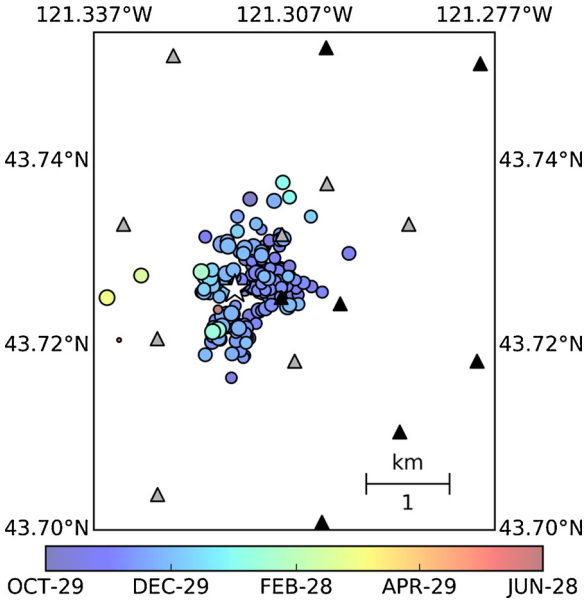


Fig. 1. Map view of original catalog events plotted as circles color coded by date. Surface and borehole seismic stations are indicated by black and grey triangles, respectively. The surface location of the stimulation well NWG 55-29 is indicated by the white star.

3. Data and methods

3.1. Earthquake catalogs and waveform data

Two earthquake catalogs for the Newberry EGS site were produced during the time period of this investigation, 01 September 2012 to 30 September 2013. For this study, we combined the Foulger Consulting earthquake catalog (Foulger and Julian, 2013) and the Lawrence Berkeley National Laboratory (LBNL) Newberry caldera EGS online catalog (Lawrence Berkeley National Laboratory (LBNL, 2016) to create the primary original earthquake catalog (Figs. 1 and 2). Between the beginning of the study period and 18 February 2013, we consider the

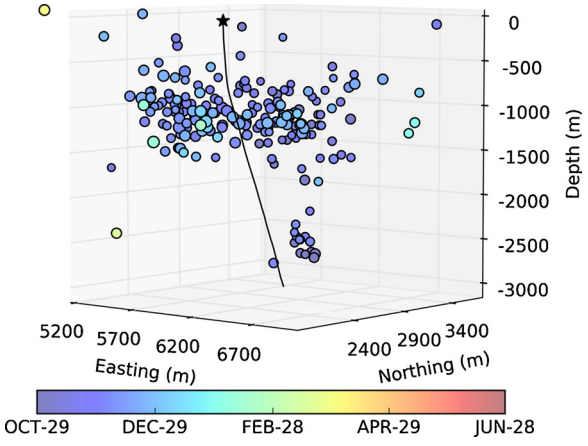


Fig. 2. Depth view of original catalog events plotted as circles color coded by date. The black line indicates the location of the wellbore with depth. The surface location of the stimulation well NWG 55-29 is indicated by the black star.

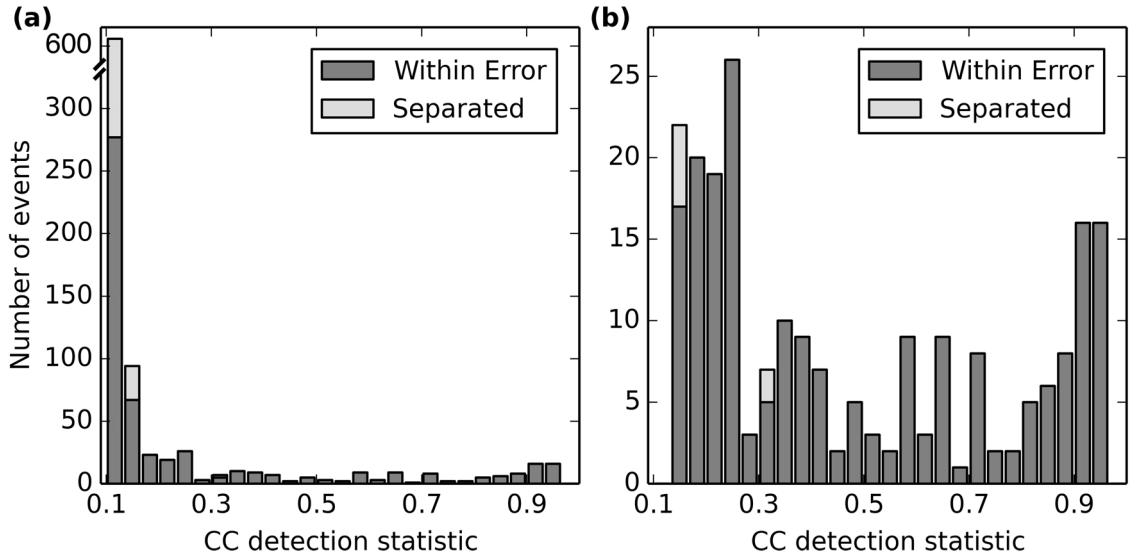


Fig. 3. Graphical results from a subset of the cross-correlation threshold levels investigated: (a) 8x MAD and (b) 14x MAD. At lower thresholds, a higher percentage of template are linked whose locations do not overlap within their horizontal location errors (light grey bars). At higher thresholds, most matching templates also have matching locations, within the expected errors (dark grey bars). Notice discontinuous y-axis in (a) for clarity.

Foulger Consulting catalog to be the authoritative catalog. After this date, we consider the LBNL online catalog to be the authoritative catalog. The reason for merging the catalogs is that although the LBNL online catalog spanned the entire time period of the study, it also identified fewer events than the Foulger Consulting earthquake catalog during concurrent time periods. For example, there were only 7 events in the LBNL catalog that were not also identified in the Foulger catalog of shorter duration. We use the LBNL catalog primarily to fill in the time gap between the end of the Foulger Consulting catalog and the end of the study period. The total number of events in our merged catalog is 235. Continuous waveform data is available from all stations in the AltaRock Energy Phase 2 Newberry Microseismic Network for the time period spanning this study, but data from only 7 of the 8 borehole seismometers were used in this investigation since they had the lowest noise levels.

3.2. Template-based earthquake detection

All events in the original earthquake catalog were initially considered for use as master templates. Events were excluded from the master event collection if they did not have high SNR of the entire event on at least 12 individual seismic channel components (*e.g.*, clear signals on all three-components at four borehole seismic stations with no overlapping events). Correlations were calculated in the lowest frequency band for which the majority of master templates displayed high SNR. At the Newberry EGS site, low-frequency noise below approximately 10 Hz was commonly observed across the network in addition to almost continuous 30 Hz and 60 Hz electrical machine and power-line noise. Based on these observations, we chose the 10–20 Hz frequency band for detecting microearthquakes. We chose a low frequency band for detection due to probable event waveform decorrelation at higher frequencies. Previous studies have shown that cross-correlations at higher frequencies for the same set of events generally tend to have lower correlation coefficients. Wavelengths are shorter at higher frequencies and scattering effects on observed waveforms become more prominent if events are not exactly co-located (Gibbons et al., 2007). No other deselection criteria based on magnitude, mechanism or location was taken into consideration. Using these criteria, we identified 74 events out of the original 235 catalog events as master events to be employed in our data processing scheme.

We apply two different template-based earthquake detection algorithms to the data. A general multi-channel waveform correlation code implemented via the PyWCC python code, and the MFP algorithm (Harris and Kvaerna, 2010; Wang et al., 2015) were applied to the Newberry EGS data to determine the differences and similarities between these two techniques using a shared set of data and master event templates.

PyWCC can compute waveform cross-correlations on multiple-component seismic data across a network of sensors and calculates a normalized cross-correlation. We chose an 8.2 s master template window starting at the origin time of the master event. The choice of window size was determined by inspection of the master events to ensure that P and S wave energy of even the largest events would be included in the templates. Linear trends in the master event waveform data are removed, the mean is removed, and waveforms are filtered between 10 and 20 Hz. Similar pre-processing is applied to the continuous data. Cross correlations for each channel are calculated in the frequency domain to increase computational efficiency. A running correlation coefficient between the master template and the continuous data is calculated and a detection is called if it is above a threshold value (described below). Multiple detections across the network for the same potential detection are associated and the master template with the highest correlation coefficient is paired with the event. Newly detected events are visually verified by eye and given preliminary locations matching that of the master event that identified it.

The PyWCC threshold level is a multiple of the daily average of the median absolute deviation (MAD) of the mean cross-correlation coefficient. To determine the most appropriate threshold value to use on Newberry data, we tested 9 different values between 7 and 15 times the MAD, similar to the range of thresholds applied in previous studies (Meng and Peng, 2014; Shelly, 2017), on the known template events. We correlated the events against each other and applied each of the 9 threshold values to the results (Fig. 3). We determined the optimal threshold by identifying the value at which at least 95% of the matching templates were co-located within their error bars. We determined that 14 times MAD was the optimal threshold value based on this criteria. Lower threshold values produced a higher percentage of template matches between non-adjacent events (*i.e.*, pairs of events whose location, within their horizontal location errors, do not overlap and who subsequently tend to have lower detection statistic values since they are located further away from each other). We hypothesize that these detections are actually low-level matches between the general

background noise that is unavoidable within each of the templates.

The second template-matching algorithm that we apply to the data is the MFP technique (Bucker, 1976; Baggeroer et al., 1993). For events with a more complicated source mechanism, empirical MFP is expected to produce more robust results than waveform correlation (Harris and Kvaerna, 2010). Our particular empirical MFP scheme is described in detail in Wang et al. (2015). We will briefly describe it here. MFP calculates the wavefield structure of the known template events by decomposing the signals into a large number of narrowband components. Assuming the narrowband components are statistically independent, MFP processes the bands independently, performing a matching operation band by band, and combines the results incoherently across all bands (Harris and Kvaerna, 2010; Wang et al., 2015). This makes MFP sensitive to the spatial structure of the signal, dominated by the source mechanism and the source-receiver path, but not the temporal structure, dominated by the source time history of the template event (Harris and Kvaerna, 2010). Similar to that in Wang et al. (2015), we use a symmetric analysis window centered on the origin time of the master event. Each quarter of the template window is 8.2 s long, with the first and last quarters near zero and the center maximum at 1. We remove the trend and mean of the master event waveforms and filter the waveforms into narrow bands (0.12 Hz wide) in the 10–20 Hz range. Similar pre-processing is applied to the continuous data. A detection is called if the detection statistic of a template is greater than the threshold value. We determined the optimal threshold value by testing 4 different thresholds between 2 and 5 times the average detection statistic value. We again match the template events against each other and apply these 4 threshold values to the results (Fig. 4). We choose the lowest threshold value for which over 95% of the templates match with other templates within their horizontal location error estimates. Based on this criterion, we choose a threshold of 5 times the average MFP detection statistic to apply to the continuous dataset when calling detections. For detections that matched with multiple master events, the detector with the largest detection statistic is paired with the new event. Newly detected events are visually verified by eye and given preliminary locations matching that of the master event that identified it.

3.3. Magnitude

We calculate duration magnitudes, M_d, for newly identified events, calibrating the magnitude scale using the moment magnitudes (M_w) of events in the original catalog. To perform the calibration, we first remove the mean and trend from the waveforms of events in the original earthquake catalog. The envelope of the original microearthquake signals are calculated and subsequently smoothed by 125 samples by computing a central moving average to remove fine-scale amplitude fluctuations within the signal. The mean amplitude of the signal over a 0.1 s moving window is calculated and compared to the mean amplitude of the noise measured over a 2.0 s window starting 0.5 s prior to the P-phase arrival. When the amplitude of the signal falls to within 5% of the mean noise level, the end of the event is declared. Event durations (τ) are measured from the S-phase until the signal end declaration (Båth, 1981), using the maximum trace amplitudes as the starting point. Signal durations are averaged over all vertical component records for each event, including only records for which there is no significant noise or other overlapping events within the coda of the waveform in the calculation. A model for the best linear fit between the log_{10} average event duration ($\bar{\tau}$) and the original catalog event moment magnitudes was determined (Fig. 5). The model was then applied to the new events which were processed in a similar manner. Duration magnitudes were

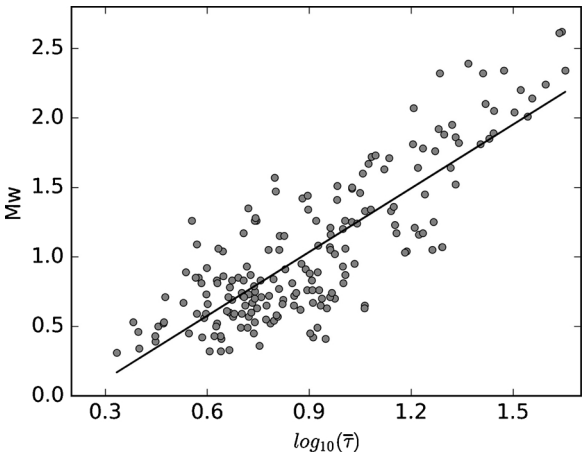


Fig. 5. Regression relationship between original catalog moment magnitudes and log_{10} of the average duration for each event across all stations. The gray circles represent the original catalog events. The regression line is plotted as the black line.

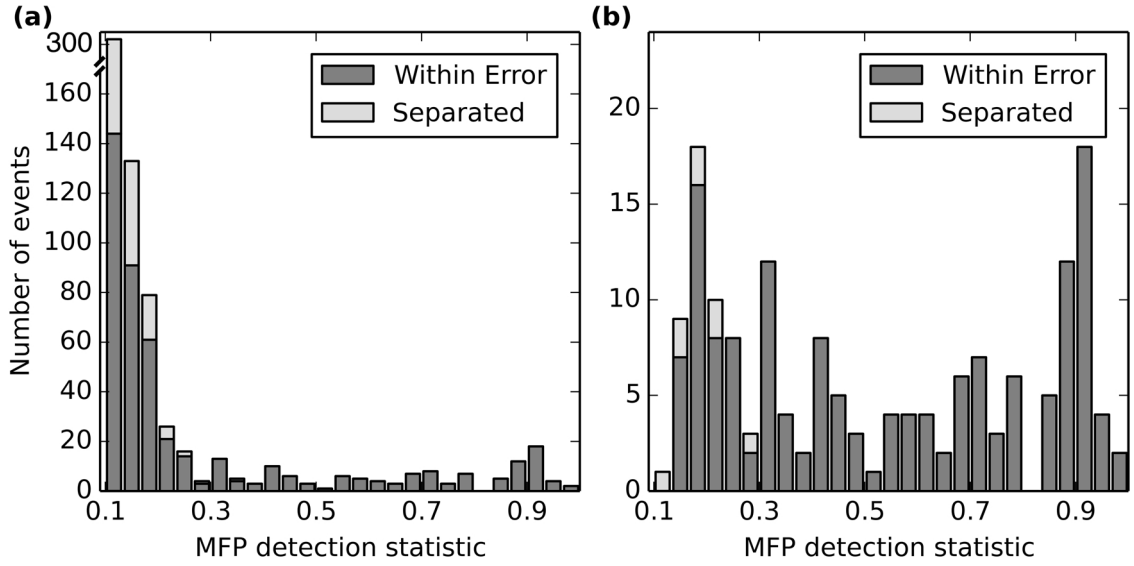


Fig. 4. Graphical results from a subset of the MFP threshold levels investigated: (a) 2x the daily average detection statistic and (b) 5x the daily average. At lower thresholds, a higher percentage of templates are linked whose locations do not overlap within their horizontal location errors (light grey bars). At higher thresholds, most matching templates also have matching locations, within their horizontal errors (dark grey bars). Notice discontinuous y-axis in (a) for clarity.

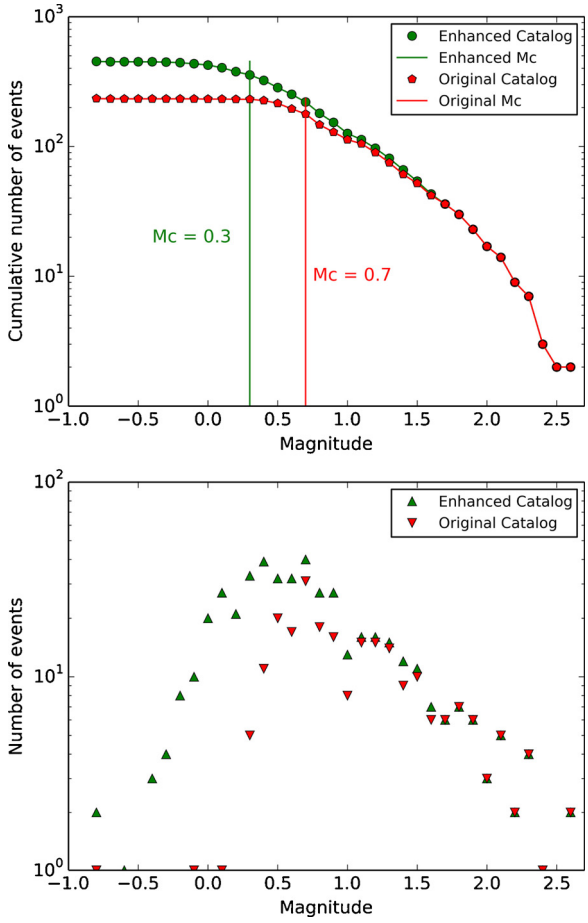


Fig. 6. Frequency-magnitude distribution plots. (a) Comparison between the cumulative number of events in both the enhanced catalog and original catalog. The magnitude of completeness (Mc) was lowered to 0.3 by using the enhanced catalog. (b) Number of events within each 0.1 magnitude bin for both the enhanced and original catalogs.

able to be determined for all new microearthquakes using the model relationship.

4. Results

4.1. New event characteristics

The original catalog reported 235 events between 01 September 2012 and 30 September 2013. 218 new events, or ˜93% more events, were identified by the two advanced earthquake detection algorithms combined. Using the magnitude relationship calibrated from the Newberry EGS original event catalog, duration magnitudes of all new events are calculated (Fig. 6). In general, new event magnitudes tend to be smaller than events that were originally detected. The magnitude of completeness (Mc) was lowered to magnitude 0.3. Mc was determined using the goodness-of-fit method (Wiemer and Wyss, 2000) on both the original and enhanced earthquake catalogs. The enhanced catalog included new events determined by both methods.

New events occurred both before and after the time period of the original template event. An example of a newly detected event that occurred before its corresponding master template is shown in Fig. 7. Although different noise sources obscure the signal in the time domain, the event can be identified more clearly in the frequency domain. Also identifiable on some of the channels is the 30 and 60 Hz electrical machine and power-line noise.

Comparing the distribution of newly identified events during and after the stimulation, we can see that templates which identify many events occur within both the deep and shallow reservoirs (Figs. 8 and 9). During the stimulation, events occur roughly evenly distributed horizontally around the stimulation well. After the stimulation however, all seismicity ceases southeast of the wellhead while the remaining seismically active regions are generally reduced in intensity. Seismicity is also seen to briefly migrate into previously aseismic areas within the footprint of the reservoir.

4.2. Comparison of detection methods

MFP identified 150 additional events (or 64% more events) and PyWCC identified 186 additional events (or 79% more events). The distribution of magnitudes that each technique was able to identify was generally similar (Fig. 10). The majority of the events that were solely identified by PyWCC occurred during a period of active injection, while the MFP code was able to identify proportionally more events well after injection ceased (Fig. 10). No new events were identified before the stimulation commenced on 16 October 2012. This unequal sensitivity in detection suggests that these different template matching techniques can be expected to modestly outperform each other in different seismic noise contexts.

4.3. Comparison with well data

The 2012 stimulation program at well 55-29 was the first stimulation conducted at the Newberry EGS site. 13 days after the start of the program, and after the first peak in average wellhead pressure (WHP) occurred, the first seismic event was recorded. Subsequently, the number of microearthquakes generally correlates with the average WHP, although a delay is often observed between a peak in the WHP and a peak in the number of observed microseismic events at the site (Fig. 11). The stimulation ended on 07 December 2012. A minor peak in WHP follows the end of the fluid stimulation and is due to an attempt to air-lift the water in the hole and induce thermally-driven self-flow of the well. This peak in WHP caused by air-pressure is also followed by a peak in the microseismicity, primarily due to newly identified extremely small events that were detected during the course of this study. After the air compressors were shut down and the well head opened, the WHP returned to zero and maintained this value until the start of the second stimulation in 2014 (Cladouhos et al., 2013). The seismicity rate also declined a few weeks after the fluid and subsequent air stimulation to approximately 1–2 microearthquakes a month by the end of the study period. This indicates that microseismicity at Newberry is not solely influenced by the amount of stimulation fluid injected during stimulation periods.

5. Discussion

Various template-based detection algorithms have been successfully applied to difficult signal processing environments in the literature (Gibbons and Ringdal, 2006; Shelly et al., 2007; Templeton et al., 2008; Meng and Peng, 2014). Here we compare the efficacy of two advanced earthquake detection template-matching algorithms before, during and after the 2012 active stimulation program at the Newberry Volcano EGS site in central Oregon. We identify 218 more events, or approximately 93% more events, occurring between 01 September 2012 and 30 September 2013. The MFP method identified 64% more events while PyWCC identified 79% more events. PyWCC is observed to have increased detection sensitivity during the stimulation period while the MFP algorithm identified proportionally more events post-stimulation, suggesting that PyWCC can modestly outperform MFP in increased seismic noise environments typically encountered during stimulation periods. This suggests that MFP is slightly more sensitive to the assumption of stationarity, the assumption that all energy within the observation window is emanating from a single source region, than

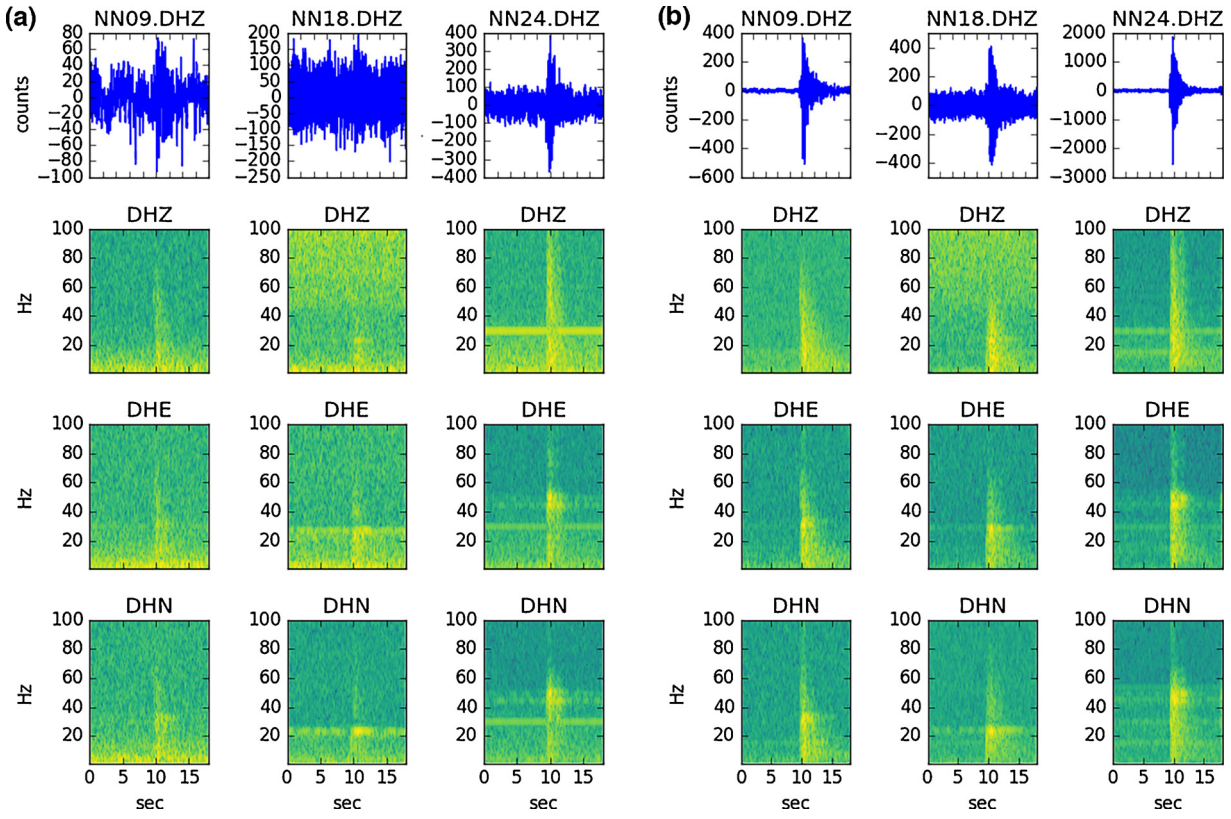


Fig. 7. Example data from: (a) a newly detected M0.34 event that occurred on 19 November 2012 01:17:04.09 and (b) the corresponding M0.65 template event that occurred on 06 December 2012 17:18:46.90. Each column contains plots from one station. The first row shows the vertical component in the time domain. The second, third and fourth rows show spectrograms of the vertical and two horizontal components.

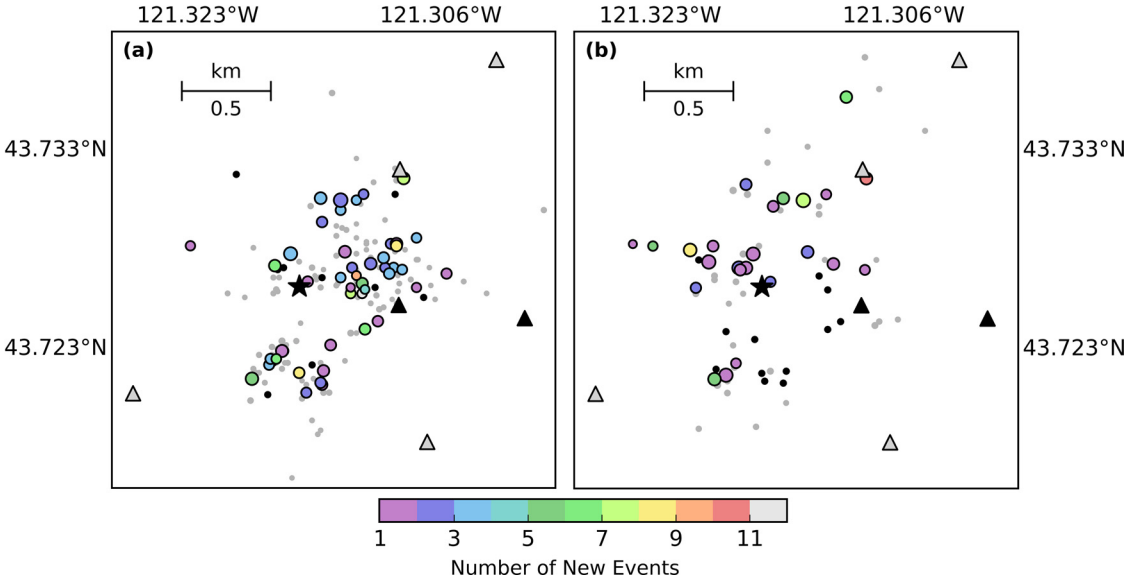


Fig. 8. Map view plots showing the number of newly detected events as filled circles: (a) during the stimulation and (b) after the stimulation. Catalog events are plotted as small grey cirlces. Master events that did not detect any new events during the time period are plotted as small black circles. Surface and borehole seismic stations are indicated by black and grey triangles, respectively. The surface location of the stimulation well is indicated by the black star.

PyWCC. After the stimulation, when the chance of having events from significantly different source regions throughout the reservoir is lessened, the strength of the MFP algorithm, with its ability to detect greater variations in source time history of subsequent events, becomes more prominent.

Using the combined expanded earthquake catalog, we study the spatiotemporal variations in seismicity during and after the 2012 Newberry EGS stimulation. At the start of the study, no detectable microearthquakes occurred either during the ~6 weeks preceding the start of the stimulation program or during the first 13 days of the stimulation. On day 14 the first event occurred within the lower reservoir and subsequent microseismicity was located roughly evenly distributed around the stimulation well. Relocations from a subset of the 2012 events showed that events within the lower reservoir appear to

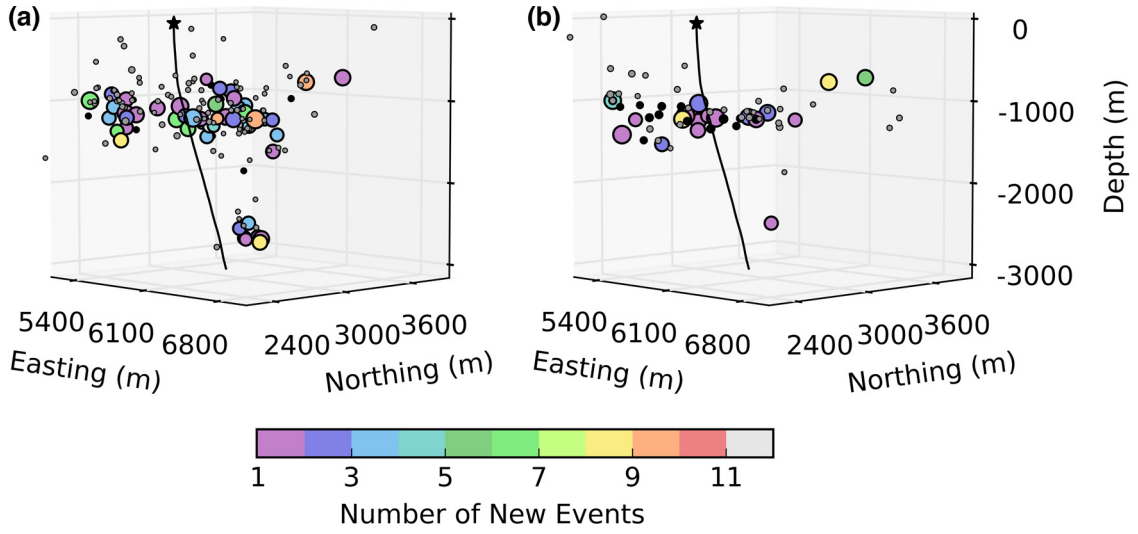


Fig. 9. Depth view plots showing the number of newly detected events as filled circles: (a) during the stimulation and (b) after the stimulation. Catalog events are plotted as small grey circles. Master events that did not detect any new events during the time period are plotted as small black circles. The surface location of the stimulation well is indicated by the black star and the subsurface location of the well is indicated by the black line.

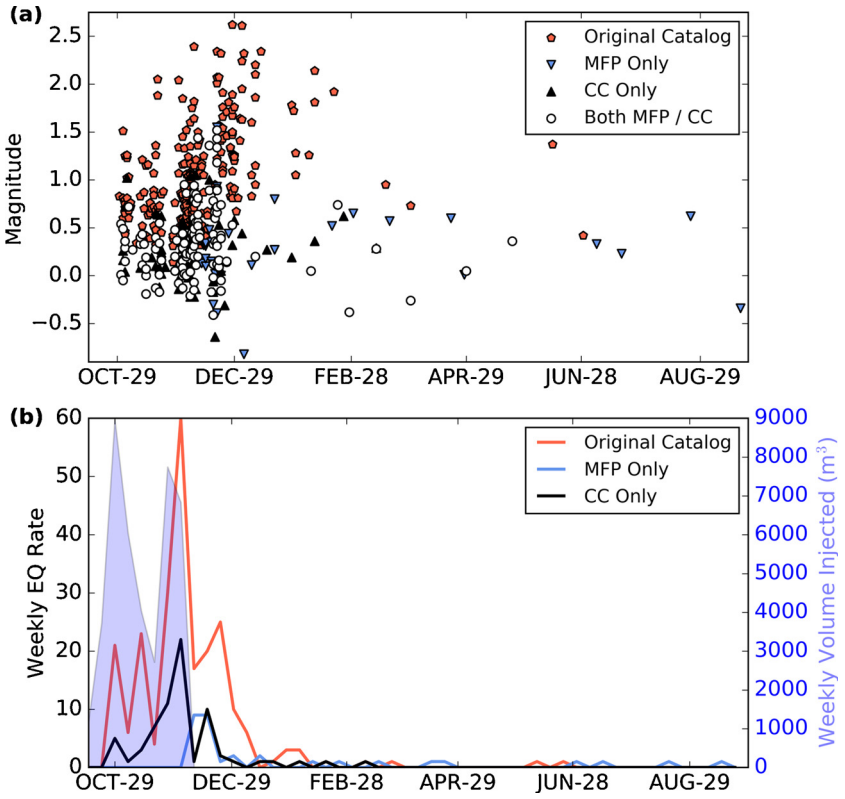


Fig. 10. (a) Magnitude of events through time since the start of injection on 16 October 2012 subdivided by identification method: MFP only, CC only, or both. Newly detected events are generally of smaller magnitude than those detected in the original catalog. (b) Broad comparison of the weekly number of original catalog, MFP only, and CC only events compared to the weekly injected volume. Events identified by both MFP and CC are excluded in this comparison.

preferentially occur at the contacts between rock types, suggesting that fluid flow was occurring preferentially along pre-existing weaknesses in these regions (Aguiar and Myers, 2018). The majority of the new microearthquakes however occurred in the upper reservoir, which was inadvertently created due to a leak in the well casing that occurred during the stimulation program (Cladouhos et al., 2016). All new events tended to be of smaller magnitude than the events that were detected using the standard earthquake detection techniques. A comparison between the total number of seismic events per day and the daily average WHP shows that there was a general relationship between the WHP and the number of seismic events, with the peak in seismicity being often slightly delayed from the peak in the average WHP.

6. Conclusions

Seismicity at Newberry was seen to be more closely associated with well pressure and not solely influenced by the amount of stimulation fluid injected during stimulation periods. After the stimulation, all seismicity ceased in the region southeast of the wellhead. Seismicity continued at a decreased rate in all other regions, but was observed to briefly migrate into previously aseismic areas within the footprint of the reservoir. In general however, the overall seismicity rate declined after the stimulation until it reached approximately 1–2 microearthquakes a month by the end of the study period approximately a year later. Additionally, both template-matching algorithms identified

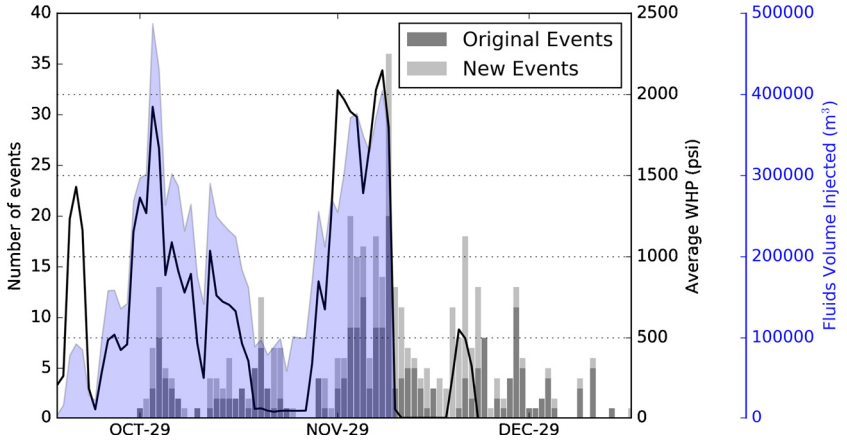


Fig. 11. Comparison of the daily number of seismic events, daily average well head pressure, and daily fluid injection volume for the first 90 days since the stimulation start date. The number of original catalog events are plotted as dark grey bars and the number of newly detected events are plotted as light grey bars. The daily average well head pressure is plotted as the black line and the daily volume of fluid injected is in blue (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article).

significantly more events than the traditional earthquake detection algorithm alone. Based on this finding, it would be reasonable to add any type of template-matching algorithm into a seismic processing program to effectively decrease the detection threshold of any existing seismic network. Lowering the magnitude of completeness would significantly add to the number of events that could subsequently inform future decision making at the reservoir level or be input into statistical seismological algorithms for further analysis. This information would allow for the improvement of future stimulation strategies to optimize heat extraction and maximize resource production.

Data availability and Resources

The Newberry Volcano EGS seismic waveform data and original earthquake catalog for the 2012 injection program is publicly available for research purposes from T. Cladouhos. The Lawrence Berkeley National Laboratory Newberry caldera earthquake catalog can be obtained online from http://fracture.lbl.gov/Newberry/locations.txt (last accessed July 2018). The updated microearthquake catalog created during this study is available for download from the online U.S. Department of Energy Geothermal Data Repository. The PyWCC seismic waveform cross-correlation tool is available for download via GitHub (https://github.com/templetond/pywcc). Figures created using Python Matplotlib (Hunter, 2007).

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Recommended Practices for Managing Induced Seismicity Risk Associated with Geologic Carbon Storage

D. C. Templeton, M. Schoenball, C. Layland-Bachmann, W. Foxall, Y. Guglielmi, K. Kroll, J. Burghardt, R. Dilmore, J. White

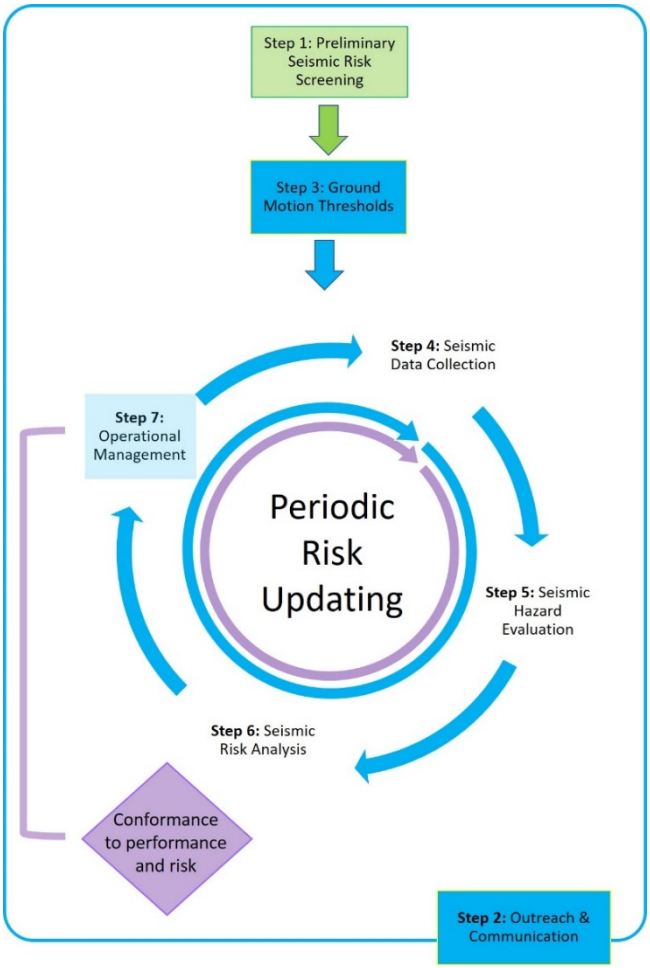
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Recommended Practices for Managing Induced Seismicity Risk Associated with Geologic Carbon Storage

2 December 2021

U.S. DEPARTMENT OF ENERGY | NATIONAL ENERGY TECHNOLOGY LABORATORY

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Recommended Practices for Managing Induced Seismicity Risk Associated with Geologic Carbon Storage

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Acronyms, Abbreviations, and Symbols

Term	Description
2D	Two-dimensional
3D	Three-dimensional
ANSI	American National Standard Institute
ATLS	Adaptive traffic light system
CO_2	Carbon dioxide
CEUS	Central and Eastern United States
CEUS-SSC	Central and Eastern United States – Seismic Source Characterization
DOE	Department of Energy
DSHA	Deterministic seismic hazard analysis
EGS	Enhanced geothermal system
EPA	U.S. Environmental Protection Agency
FTA	Federal Transit Administration
GCS	Geologic carbon storage
GEM	Global Earthquake Model
GMM	Ground motion model
GPS	Global positioning system
GRID	Geothermal risk of induced seismicity diagnosis
IRIS-DMC	Incorporated Research Institutions for Seismology Data Management Center
ISO	International Organization for Standardization
LANL	Los Alamos National Laboratory
LBNL	Lawrence Berkley National Laboratory
LLNL	Lawrence Livermore National Laboratory
M_C	Minimum magnitude of completeness
MMI	Modified Mercalli intensity
MRI	Magnetic resonance imaging
M_w	Earthquake moment magnitude
NEIC	National Earthquake Information Center
NETL	National Energy Technology Laboratory
NRAP	National Risk Assessment Partnership
O&C	Outreach and communication

Acronyms, Abbreviations, Symbols (cont.)

Term	Description
PAGER	Prompt Assessment of Global Earthquakes for Response
PGA	Peak ground accelerations
PGV	Peak ground velocity
PISC	Post-injection site care
PNNL	Pacific Northwest National Laboratory
PSHA	Probabilistic seismic hazard analysis
PSHF	Probabilistic seismic hazard forecast
PSZ	Perturbed stress zone
RMS	Root-mean-square
ROC	Region of concern
SA	Spectral acceleration
SNR	Signal-to-noise ratio
TLS	Traffic light system
UCERF	Unified California Earthquake Rupture Forecast
USDW	Underwater source of drinking water
USGS	United States Geological Survey

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EXECUTIVE SUMMARY

The geologic storage of carbon dioxide (CO_2) is one method to help reduce or eliminate atmospheric CO_2 emissions. The sequestered CO_2 is originally captured from the atmosphere or from a stationary industrial source and subsequently injected into a deep subsurface porous rock formation. To facilitate the successful deployment of field scale carbon storage projects, the U.S. Department of Energy (DOE) is developing tools and protocols for defensible, science-based frameworks to quantify and mitigate risks associated with the long-term storage of CO_2.

This protocol specifically addresses the risk of induced seismicity due to injection in a geologic carbon storage (GCS) site. This integrated and risk-based protocol is a product of the U.S. DOE Fossil Energy's National Risk Assessment Partnership (NRAP), a multi-year collaborative research effort of Los Alamos National Laboratory (LANL), Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), National Energy Technology Laboratory (NETL), and Pacific Northwest National Laboratory (PNNL).

These recommended practices describe a set of 7 steps to evaluate, manage, communicate, and mitigate the risk of induced seismicity at GCS sites. The base methodology of the recommended practices follows a framework similar to the *Protocol for Addressing Induced Seismicity Associated with Enhanced Geothermal Systems* (Majer et al., 2012), developed for the Geothermal Technology Office of the U.S. DOE.

These recommended practices present a framework to systematically assess the induced seismicity risk and quantify the associated uncertainties. These recommendations are based on current research and are sufficiently general to allow for modification and application to a variety of different types of sites. The substance of the recommended practices contained herein includes both technical and non-technical issues, and covers all operational stages of the GCS project lifecycle. They start at the preliminary risk assessment phase, continue through site assessment and characterization, include best practice communication and seismic monitoring plan methodologies, discuss the evaluation and mitigation of seismic hazard and risk, and closes with an exploration of operational management plans, which conclude when the induced seismicity risk abates back to background level.

The focus of these recommendations is on actively managing the risks associated with induced seismicity by developing an actionable risk management plan that starts at the project proposal stage and continues through site closure through an iterative assessment and improvement process. The audience of this document is expected to include all interested stakeholders (e.g., operators, project developers, regulators, and the general public) and is expressly written to be accessible to this broad range of partners.

This document is intended to disseminate knowledge gained through recent advances in the science of induced seismicity hazard and risk assessments, to provide updates based on recent experience gained by similar corollary injection-induced seismicity cases, and most importantly to establish a uniform framework to carry out a successful induced seismicity risk management plan for carbon storage projects in the future. These recommendations do not directly address any domestic or international regulations or standards. A complementary NRAP report makes recommendations for the assessment and management of environmental subsurface risks associated with unwanted fluid migration at GCS sites (Thomas et al., 2021) and should be referred to in order to address those additional GCS site risks.

INTRODUCTION

Geologic carbon storage (GCS) is a technology promising negative greenhouse gas emissions by injecting captured carbon dioxide (CO_2) into deep subsurface rock formations for long-term storage, thereby removing CO_2 from the atmosphere and sequestering it in underground reservoirs of porous rock. GCS is one cutting edge climate solution that can help address the global climate crisis. An inherent risk associated with this technology, however, is induced seismicity. Injection operations can modify the existing subsurface conditions thereby creating the potential for induced seismic events. Risks associated with that potential induced seismicity must be appropriately assessed and managed for GCS to be successful (White and Foxall, 2016). The goal of this document is to provide a suite of recommended practices to effectively evaluate, manage, communicate, and mitigate the induced seismicity hazard and risks associated with GCS projects. These recommended practices will serve as general guidelines to proactively deal with induced seismicity issues, setting expectations for operators, regulators, and the general public. While each carbon storage project will be unique and will require a custom approach, these general science-based recommended practices can be used as a starting point for any site-specific induced seismicity risk management plan.

These recommended practices follow general risk management approaches and apply them to the induced seismicity problem (Fischhoff, 2015). The general risk management process involves:

- Preliminary risk analysis to identify and assess potential hazards
- Complete risk analysis for a more formal estimation of the magnitude of the risks
- Complete risk assessment to evaluate the acceptability of the risks
- Consideration of control mechanisms to mitigate risks
- Monitoring to assess if actual observations follow expected behavior
- Effective risk communication with potentially affected stakeholders across all project stages

A similar base methodology is followed in the *Protocol for Addressing Induced Seismicity Associated with Enhanced Geothermal Systems* (Majer et al., 2012; 2016), developed for the Geothermal Technology Office of the U.S. Department of Energy (DOE) to address each of these areas. Here, the geothermal protocol is adapted to include insights from recent scientific developments in state-of-the-art evaluation, mitigation strategies, and modify the focus to highlight issues specific to GCS. The recommended practices for addressing induced seismicity associated with subsurface injection can be subdivided into the following 7 steps:

Step 1: Preliminary Seismic Risk Screening Evaluation

Step 2: Outreach and Communication

Step 3: Ground Motion Thresholds

Step 4: Collection of Seismicity Data

Step 5: Hazard Evaluation of Natural and Induced Seismic Events

Step 6: Risk-Informed Decision Analysis

Step 7: Operational Management of Induced Seismicity Risks

This document is structured such that each of the seven steps includes: a) a Purpose section, b) a Recommended Practices section, and c) a Supporting Information section. While the Purpose section briefly describes the role of each step in the overall induced seismicity management plan, the Recommended Practices section serves as a list of actionable items to fulfill in order to successfully address the induced seismicity risk. Finally, the Supporting Information section describes the reasoning behind the recommendations in detail and includes references to the pertinent scientific literature.

While this document strives to be as quantitative as possible and outline actions, methods, and procedures that represent the application of current state-of-the-art best practices, it is recognized that additional approaches and methods will be developed in the future and that these recommended practices will inevitably evolve. Additionally, this document attempts to take a policy-neutral position such that the recommendations do not attempt to specifically address current policies or regulations. Specific tools and methods are not prescribed here and are, therefore, left to the discretion of the user of this recommended practice guide.

1. STEP 1: PRELIMINARY SEISMIC RISK SCREENING EVALUATION

1.1 PURPOSE

The purpose of this step is to determine an initial probability of success of candidate sites before investment of substantial resources, here initial success is defined as the ability to inject and sequester the supercritical CO_2 into a deep geologic formation without inducing significant seismic activity of concern for the operators and other stakeholders. The preliminary seismic risk screening evaluation is based on simple methods and acceptability criteria with the goal of determining a go/no-go decision for future planning. Investigations should focus on any issues that could impede a candidate site's licensing or acceptance by local stakeholders due to seismic risk factors. The preliminary evaluation should be conducted with sufficient rigor to allow the operator to make an informed decision as to whether a site is a good candidate for further study and potential development. Information resulting from this preliminary evaluation can also be used to support early technical communications with local stakeholders. This step assumes that an overall candidate site selection screening—based on geology, hydrology, and other physical considerations—has already been completed.

1.2 RECOMMENDED PRACTICES

1.2.1 Preliminary Classification of Site-Specific Seismic Risk

1.2.1.1 A preliminary site-specific seismic risk assessment should be completed to qualitatively classify potential seismic risk into one of four general categories: (I) Very Low, (II) Low, (III) Medium, or (IV) High (Table 1). This assessment should include, but is not limited to:

a) A review of local, state, and federal laws and regulations relevant to seismicity
b) A review of prior cases of injection-induced seismicity in comparable operational and geological settings
c) An initial estimate of the Region of Concern
d) A listing of the potential impacts to the local community within the Region of Concern
e) An estimation of the magnitude of the potential impacts
f) An assessment of local stakeholder risk tolerance
g) An integrated assessment of the overall preliminary seismic risk of the planned operation, based on a weighted combination of factors (a)–(f)

Table 1: Overall Preliminary Seismic Risk Categories with Recommended Go/No-Go Decisions (Modified from Majer et al., 2012)

I. Very Low:	II. Low	III. Medium	IV. High
Proceed with planning	Can proceed with planning, but may require additional analysis to confirm.	Probably should not proceed at this site, but additional analysis might support proceeding.	Do not proceed.

1.3 SUPPORTING INFORMATION

1.3.1 Preliminary Classification of Site-Specific Seismic Risk

Seismic risk is formally evaluated based on a combination of the seismic hazard, the level of exposure of the population and built environment to the seismic hazard, and the vulnerability to shaking of the buildings and infrastructure within the risk area (McGuire, 2004). However, Step 1 is not intended to require extensive calculations, comprehensive research, or the development of extensive databases on seismicity and building vulnerabilities. It is instead a qualitative assessment of seismic risk, providing an informed but subjective evaluation based on simple bounding methods to determine if a project may have some obvious flaws that may prevent success in the short or long term.

The screening analysis for some projects may be quite clear. For example, a planned low-volume injection at a remote site with no active hazardous faults or local seismicity, and broad stakeholder approval, could be categorized as a clear Level I, while fluid injection at a heavily populated site with multiple mapped active faults and little public support could be a clear Level IV (Table 1). For those projects in all but category Level IV, which should be discarded after initial screening, this process will also highlight the aspects contributing to risk that will need to be addressed if the project were to move forward. If a candidate site is ultimately selected, a more detailed and complete seismic risk analysis will need to be subsequently performed. Each site is individual and will require customized treatment.

(a) Review of Local, State, and Federal Laws and Regulations

The relevant local, state, and federal laws and regulations should be assessed to determine if any effects of induced seismicity, however minor or unlikely, are barred. An assessment of damage liability requirements should also be made. At a minimum, documentation should include a list of the laws and regulations reviewed.

(b) Review of Prior Injection-Induced Seismicity Cases

To obtain a broad qualitative evaluation of the susceptibility of the site to induced seismicity, a review of prior cases of GCS injection-induced seismicity should be completed. This assessment should include a review of previous GCS sites with injection-induced seismicity, suspected induced seismicity, or no measured seismicity, ideally in a similar geologic province and reservoir size as that of the project. If no relevant GCS cases can be identified, the assessment should also include a review of studies investigating induced seismicity associated with other types of fluid injection operations in similar hydro-mechanical settings, such as at gas injection projects for example (Cesca et al., 2014; van Thienen-Visser and Breunese, 2015). In these cases, a description of how the operation and/or fluid mechanics are different from GCS should be included.

The purpose of this review is to attempt to incorporate regional-scale and operational trends associated with induced seismicity (Skoumal et al., 2018; Weingarten et al., 2015; Scanlon et al., 2019). Examples of observed trends can include the abundant induced seismicity in Oklahoma connected to wide-spread wastewater disposal in the Arbuckle group and the lack of injection-induced seismicity in the Williston Basin in north-central United States where large-scale fluid disposal is also occurring (Skoumal et al., 2018). Similarly, operational trends that influence the likelihood of injection-induced seismicity should be documented (Weingarten et al., 2015; Scanlon et al., 2019). This evaluation will allow the operators to incorporate general trends into

the decision-making process since the causative mechanisms of induced seismicity and the geomechanical conditions at injection sites are diverse and involve many poorly constrained or unknown parameters. Significant uncertainties as to the likelihood of inducing seismicity can persist even after careful characterization as it may not be fully understood why some operations can cause significant induced seismicity while others do not. A matrix approach, where a variety of factors (e.g., injected volumes, depth, reservoir formations, level of natural tectonic seismicity, etc.) are identified and compared may be able to provide a structured mechanism by which to view and organize the information for this qualitative assessment (e.g., Trutnevyte and Wiemer, 2017).

Documentation should include an overview description of the sites used for comparison including a justification for why the selected sites are suitable for comparison to the project site (e.g., geologic setting, population density, building stock, etc.). Furthermore, operational parameters (e.g., injection duration, total injected fluid volume, maximum injection pressure, nature of injected fluid, etc.) and a description of previously observed induced seismicity should also be provided from those sites. Induced seismicity at comparative sites should also be quantified by the rate and cumulative number of earthquakes above a given minimum magnitude of completeness (M_c) as well as the maximum observed earthquake magnitude. The frequency magnitude distribution, which describes the occurrence rate of earthquakes across a range of magnitudes, of the observed seismicity should also be described to understand the productivity (i.e., the rate of seismic activity in a pre-defined spatio-temporal volume) and the potential of the seismicity. For reference, the M_c is the minimum magnitude above which all earthquakes in a certain area are expected to be reliably detected and located. M_c can depend on many factors including subsurface attenuation, site noise, and the distribution of the seismic monitoring network. M_c can also have a time-varying component, since M_c is progressively reduced as the density of a seismic monitoring network is increased over time. The spatial and temporal evolution of M_c, and the uncertainties associated with the M_c estimate, should be noted to add context to the evaluation of historical observations and to describe the propagation of these uncertainties when calculating seismicity parameters, such as the b-value in Gutenberg-Richter distributions (Woessner and Wiemer, 2005; Hutton et al., 2010).

(c) Region of Concern of Potential Seismic Events

An estimate of the Region of Concern (ROC) should be prepared. The ROC defines the ground surface area that could be negatively impacted by induced seismic events occurring at depth throughout the lifetime of the project. In practice, the ROC can be governed by many factors, such as the reservoir size, local geology/hydrology, distance to known faults, natural background seismicity, the in-situ state of stress, potential induced seismicity magnitudes and locations, and expected fluid injection rates, volumes, and injection pressure. In practice, the ground surface area that could be negatively impacted by these seismic events would be expected to expand as the fluid injection program progresses and the CO_2 migrates away from the wellbore. The ROC however describes the total area of concern over the lifetime of the project, but may still be updated over time as new data becomes available. In this Step however, the goal is to obtain only a first order approximation of the ROC. An estimate of the potential maximum magnitude induced seismic event, the location of such an event, the ground motions associated with such an event, and an estimate of the ground motion threshold above which negative impacts would occur are critical to estimating the ROC.

To produce a first order estimate of the maximum magnitude injection-induced seismic event, it is necessary to make simplifying assumptions. One assumption that can be made is that the induced event would be spatially limited by the extent of the pore pressure perturbation zone, thus scaling with the total volume of fluid injected (McGarr, 2014; Shapiro et al., 2011; Yeck et al., 2015). This assumption would produce a lower bound on the actual potential maximum magnitude induced seismic event, since it ignores site-specific stress conditions and tectonic factors that have been shown to be important at other locations (Bhattacharya and Viesca, 2019). Other maximum magnitude models attempt to incorporate tectonic constraints on maximum earthquake size (van der Elst et al., 2016; Galis et al., 2017; Norbeck and Horne, 2018). These tectonic constraints attempt to incorporate the observation that subsurface stress changes propagate much further out than subsurface pore-pressure changes and that these stress changes would then be interacting with the pre-stressed crust around the reservoir. Observations from hydraulic fracturing projects, for example, using relatively small fluid volumes have been linked to a M_w4.6 earthquake in Canada (Atkinson et al., 2016). Similarly, injection of a rather modest fluid volume associated with an enhanced geothermal system (EGS) has been connected to a M_w5.4 earthquake in Pohang, South Korea (Kim et al., 2018; Lee et al., 2019; Yeo et al., 2020). The largest induced earthquake to date attributed to fluid injection activities documented in the scientific literature is a M_w5.8 event in central Oklahoma (Barbour et al., 2017).

An alternative method to estimate the size of potential injection-induced events at the sites under consideration at this early stage would be to use comparable fluid injection scenarios from similar geological conditions. An operator may also consider a series of scenario earthquakes (e.g., an M_w3.5, M_w4.5, and M_w5.5 at reservoir or basement depth) to assess how the ROC may vary with the often significant uncertainty associated with the maximum event size.

The hypothetical location of the maximum magnitude event, or scenario events, should be assumed for this estimate. For example, it may be appropriate to assume that early in the injection program, induced events would only occur near the injection zone. A discussion of where induced events may occur later in the injection program should be included. For example, some induced earthquakes due to fluid injection in the central U.S. appear to be connected to injection areas located tens of kilometers away, but along trends consistent with regional basement structures (Peterie et al., 2018).

Ground motion estimation for the assumed maximum magnitude event sizes at the assumed locations using general empirical relationships or comparable events is also acceptable at this stage. Broadly applicable empirical ground motion relationships between key parameters (magnitude, distance, surface shear wave velocity, etc.) and earthquake ground motions (peak or spectral acceleration, velocity, displacement, Mercalli intensity, etc.) are available for both tectonic events and more recently for induced events (for example, see Petersen et al. (2018) for a list of commonly used ground motion models (GMM) included in the creation of the U.S. national seismic hazard maps or McNamara et al. (2018) for an evaluation of GMMs for induced and tectonic events in the Central and Eastern U.S.). GMMs specifically developed for induced events should be preferentially chosen or developed when possible (Bommer et al., 2016). Also, whenever possible, site-specific parameters that consider local characteristics and geology should be included within the simplified scope of this step. Applying several potentially appropriate GMMs to this calculation would also be advisable to attempt to account for uncertainties within the models. Augmenting an existing seismic network could also be considered in order to help inform these preliminary analyses.

After the expected ground motions are calculated for an area, an estimate of the ground motion threshold above which negative impacts would occur in the region, such as where ground motions are expected to be recorded above the background noise level, would define the preliminary ROC. The ROC would subsequently be modified as new information is collected in this and later steps.

At a minimum, documentation for this Step should include: 1) an estimate of one or more potential maximum magnitude seismic events that could be induced by fluid injection in the reservoir; 2) an estimate of the locations where these events could occur; 3) an estimate of the ground shaking that could be associated with such events along with a description of how the shaking was calculated; 4) an estimate of the ground motion threshold above which negative impacts would be expected to occur; and 5) a description and estimate of the key uncertainties in the above preliminary analyses (e.g., GMMs, M_c, maximum magnitude event size, etc.).

(d) Potential Impacts to the Local Community Within the Region of Concern

Potential impacts to the local communities located within the ROC should be identified. These should include physical damages, social disturbances, nuisance, economic disruption, and the effects of secondary environmental hazards (landslides, liquefaction, seiches, etc.). This assessment should be carried out with early input from local stakeholders to ensure it includes all impacts that are of concern, thus building consensus and trust between all parties. Impacts of concern may vary depending on if the region's population has previously been exposed to some level of natural seismicity and if the buildings and infrastructure have been built using earthquake resistant designs.

Preliminary estimates of the population distribution and building/infrastructure inventories within the ROC should be determined. A crude order of magnitude estimate of the building inventory within the ROC is acceptable at this stage. Inventory data can include the number of residential buildings, commercial buildings, government facilities, schools, historical buildings, religious facilities, essential facilities (fire stations, police stations, hospitals, emergency operation centers, etc.), transportation lifelines (highways, airports, rail, ports, bridges, etc.), utilities (water, electricity, sewage, etc.), and potentially hazardous facilities (tank farms, refineries, dams, levees, liquefied natural gas plants or storage areas, chemical plants, nuclear plants, pipelines containing hazardous materials, unreinforced masonry buildings, etc.) (NRC, 1989).

At a minimum, documentation should include: 1) a description of potential impacts; and 2) an estimate of the number of people, structures, and industries that might be exposed to impacts of concern within the ROC. Particularly fragile or high-consequence infrastructure should be highlighted.

(e) Estimation of Potential Impact Magnitudes

A description of the potential impacts due to at least two induced events of different magnitudes, including a representative average induced seismicity magnitude event and the estimated worst-case scenario maximum magnitude event, should be included. Potential impacts can include a description of the number of people and structures that would reasonably be expected to be affected by each of the scenario events and the type of impact that would be reasonably expected. This can be based on the estimated ground motions that would be produced by the events, the population and preliminary building inventory estimates, and potential event

locations. For the estimated worse-case scenario event, a general scenario loss model, providing estimates of economic losses and fatalities using general global models and databases, should also be performed (e.g., Jaiswal and Wald, 2011). There are various methodologies available for the estimation of losses due to larger earthquakes, including those focused on rapid estimations for large global earthquakes, based on differing factors of increasing complexity. All methods require some engineering and seismological expertise in order to interpret the results. Framing the comparison in terms of the impact due to a series of scenario events of increasing magnitude can provide a structured way to present the information.

Additionally, a preliminary comparison between potential impacts due to natural tectonic events and potential induced events should be conducted. An assessment or literature search should identify any tectonic events that may have occurred in the region and a map and catalog should be created for seismic events which have occurred within at least 200 km from the reservoir. This should include a description of their locations, mechanisms, and a description of the network and catalog quality. Baseline expected ground motions from one or more representative natural (tectonic) seismicity can be estimated using available data and simplified methods reliable enough to give an order of magnitude estimate. These potential ground motions and potential impacts can be estimated similar to the induced events and subsequently compared. The definition of what level of ground shaking could potentially cause a negative impact should be clearly stated (e.g., peak ground acceleration $\geq$ 0.01 g, Modified Mercalli Intensity $\geq$ III, etc.). This preliminary analysis could also start to illuminate if natural tectonic seismicity may be of concern for the site's infrastructure or reservoir as well.

Alternatively, the long-term probabilistic seismic hazard across the U.S. can be obtained from the regularly updated national hazard maps (USGS, 2019; Petersen et al., 2018; Petersen et al., 2014). In the past United States Geological Survey (USGS) hazard maps also included short-term probabilistic seismic hazard forecasts for the central and eastern U.S., but no new maps have been published since 2018. These baseline estimates could then be qualitatively compared with the induced seismicity ground motion estimates, recognizing that this is not a like-for-like comparison, but rather a general comparison of the two.

Documentation should include, at a minimum: 1) a description (map, tables, etc.) of the number of people and the number and type of structures that might be affected by each of the events; 2) the type of impact (nuisance, possible cosmetic building damage, possible minor or significant structural damage, etc.) to be expected based on ground motion estimates; 3) a qualitative comparison between the baseline hazard/ground motions from natural seismicity and the expected ground motions from the induced seismic events and, if applicable, expected ground motions from scenario natural tectonic events; 4) a description (time, location, and magnitude) of any nearby seismic events up to at least 200 km from the reservoir along with a description of the network and catalog quality; and 5) a description and estimate of the key uncertainties in the above preliminary analyses.

(f) Assessment of Local Stakeholder Risk Tolerance

The level of stakeholder concern regarding the project, used to calibrate the risk scale to an individual location, should be assessed with the understanding that different communities may have different risk acceptance levels. Incorporation of stakeholder input allows for a more robust socio-technical approach to risk governance, even at this early stage. It should be noted that the process of soliciting input regarding risk can itself change how people perceive risk (e.g., by

raising concerns about a risk they were not previously aware of or alleviating concerns by knowing that competent personnel are looking into the issue). Therefore, the solicitation process should be planned and carried out with care, ideally by an individual or team with experience in this specialist area (e.g., social scientists). The solicitation process should also highlight the positive impacts of the project, such as the benefits of releasing less greenhouse gases into the atmosphere and any local benefits.

Documentation should include a determination of the level of impact perceived to be acceptable by all stakeholders (regulators, community, operator, etc.) for each of the risk factors.

(g) Overall Seismic Risk of the Planned Operation

An integrated assessment of the seismic risk of the planned operation is developed by combining the information from the technical and social factors. Outreach and transparency play an important role in the determination of overall seismic risk. The threshold for unacceptable risk is project- and operator-specific and is dependent upon a host of factors.

There are many methods by which the overall seismic risk related to an individual site may be assigned to the broad seismic risk categories specified in Table 1: (I) Very Low, (II) Low, (III) Medium, or (IV) High. Individual risks can be categorized and ranked in terms of the likelihood of occurrence and the severity of the consequence. Acceptability criteria needs to be clearly defined for the various risk factors in each of the categories. The more specific the criteria, the easier it will be to communicate the risks to all stakeholders. One such method is to create a grid and define what each category of risk would entail for each of the potential impacts, similar to the Geothermal Risk of Induced seismicity Diagnosis (GRID) method proposed for Switzerland (Trutnevyte and Wiemer, 2017).

Documentation should include a summary of the project and of the dominant risk issues, the preliminary seismic risk category for the project and a description of the factors that went into determining the risk category, the final decision regarding whether or not to pursue the project, and a brief discussion of the factors which influenced the decision-making process. Key uncertainties that would substantially alter the current assessment should be noted.

2. STEP 2: OUTREACH AND COMMUNICATION

2.1 PURPOSE

The purpose of this step is to develop an induced seismicity component to a project's general Outreach and Communication (O&C) program to facilitate communication and maintain positive relationships with stakeholders (e.g., community leaders, governmental agencies, tribal governments, regulators, public safety officials, non-governmental organizations, the general local community, etc.). Across all stages of project planning, operation, and decommission, it is critical that stakeholders are kept informed and that their input is considered and acted upon in a timely and meaningful way. Stakeholder acceptance is a necessary component of any project. A successful O&C program will help facilitate that goal. Each O&C program will be site-specific and will require a custom approach. This section describes a general set of principles and engagement options founded on both the theory of stakeholder engagement as well as informed by previous experience with siting major energy and non-energy projects.

2.2 RECOMMENDED PRACTICES

2.2.1 Site-Specific Outreach and Communication Program

2.2.1.1 A site-specific O&C program should be implemented and reviewed annually. The program should include an induced seismicity component based on the following principles:

a) Institution of a broad-based participatory process
b) Broad agreement that the project is an improvement over the status quo
c) Broad stakeholder consensus regarding the project plan
d) Communication with stakeholders that stringent safety standards are being met
e) Commitment to fully address negative aspects of the project with stakeholders
f) Commitment to develop and maintain stakeholder trust

2.3 SUPPORTING INFORMATION

2.3.1 Site-Specific Outreach and Communication Program

There is no one size fits all approach to O&C. It is expected that each project dealing with the potential for induced seismicity will need to prepare an individualized O&C plan that addresses the specific local issues associated with the project site (GWPC and IOGCC, 2017) and the requirements within the Risk-Based Mitigation Plan (Step 7). It is expected that the effort expended on this step may vary significantly from site to site. Any O&C program should strive to adhere to the general working principles associated with the theory of stakeholder engagement and to build on previous experience associated with siting major energy and non-energy projects to achieve fair and efficient consensus building amongst all stakeholders (Kunreuther and Suskind, 1991). The O&C program should also integrate concepts of relationship management theory between organizations and the public so as to establish and maintain a positive and mutually beneficial relationship with the local community and other stakeholders (Ledingham and Bruning, 1998; Ledingham, 2003). The induced seismicity component described herein is expected to be part of the general outreach, communication, and education plan for GCS projects (NETL, 2017). The O&C plan should be reviewed in its entirely at least annually to ensure that it

is meeting stakeholder needs. The O&C plan should also be periodically evaluated. This evaluation could include developing surveys, semi-structured ethnographic interviews, and/or media and social media analyses to help determine the success of the plan amongst the local community and other stakeholders.

(a) Institution of a Broad-Based Participatory Process

Stakeholder groups (e.g., local communities, governmental agencies, tribal governments, regulators, public safety officials, non-governmental organizations, etc.) who may be impacted by injection-induced seismicity associated with the project should be identified early in the process and preliminary discussions should be held to explain the project and determine stakeholder concerns. In particular, people and organizations who have the trust of the community at large should be engaged in these early discussions. These early-stage discussions could focus on communicating with elected and other local officials, and with various local civic organizations. At later stages, representatives from all stakeholder groups, including the community at large, should be invited to participate in the project at the appropriate level. Evaluating opinions and concerns in the early stages of the project will ensure that the outreach is responsive to the stakeholder community.

(b) Broad Agreement that the Project is an Improvement Over the Status Quo

General stakeholder acceptance of a project typically starts with an agreement that the project is needed (Meller et al., 2018). Public education and outreach efforts can include information regarding the consequences of not moving forward with the project (i.e., maintaining the status quo), in particular emphasizing the impact to the community's citizens. Discussions should include the relevant policies and context, including how the project could meet broader societal goals in addition to meeting local stakeholder needs as well.

(c) Stakeholder Consensus Regarding the Project Plan

All stakeholders should have the opportunity to communicate their comments and concerns to ensure that the project plan is ultimately beneficial to the local community. Technical expertise should be augmented with local knowledge. Alternative approaches, along with their short-term and long-term implications should be included in public discussions and framed in both technical and non-technical language, depending on the audience involved. Vigorous public debate about the pros and cons of the project also should be supported. Gaining an in-depth understanding of the diverse concerns of the community will allow the project proponents to gain better insights into how the project can support the community. This information exchange will also help provide context into the reasons behind the underlying views of the community about the project risks and benefits.

Information that should be disseminated to stakeholders over the course of the project includes: a general overview of the project, the motivation for conducting the project, what potential surface structures might look like, how the project was funded, and who is on the team. It might be desirable to include public institutions (e.g., USGS, public universities) and private organizations (e.g., consulting companies) selected to provide third-party assessments or peer-reviews in the discussions. This information should be disseminated during all phases of the project.

Specific seismic related information to include in stakeholder interactions should include explanations about:

a) Why induced seismicity may occur

b) The history of induced seismicity in other applications
c) The similarities and differences between induced seismicity and natural earthquakes (e.g., frequency, location, etc.)
d) The potential risks to the community
e) The risk mitigation strategies, including a description of the thresholds that will be used for triggering mitigation strategies
f) The monitoring systems (e.g., seismic monitoring and fluid injection monitoring) and associated analyses to be performed
g) Where to obtain more information about seismicity data gathered by the operator (e.g., frequently updated website with earthquake catalog information)

Even early communications should clearly distinguish the differences between potential induced seismicity associated with GCS and other types of subsurface fluid injection projects, such as wastewater injection and hydraulic fracturing. From the beginning, local communities and other stakeholders should be kept informed about induced seismicity in general and about what they could expect in particular.

(d) Communication with Stakeholders that Stringent Safety Standards are Being Met

Stakeholders should be informed of all best practice safety standards with respect to induced seismicity mitigation that will be implemented at the project site. This should include all mandated actions and best practice recommendations, as detailed in the Risk-Based Mitigation Plan (Step 7), and responsibilities of the local safety officials. Moreover, the communication team should ensure that robust communication mechanisms exist between the project and local safety officials both prior to and during any potential seismic event of concern to help the local communities mitigate, prepare, and respond to any potential felt seismic events. Stakeholders should also have an opportunity to recommend additional safety standards that would be of importance to the local host community.

(e) Commitment to Fully Address Negative Aspects of the Project with Stakeholders

To prepare for potential future negative impacts (e.g., nuisance vibrations, property damage, etc.), stakeholders should be fully informed of all potential negative impacts and come to an agreement as to how to report potential negative impacts (e.g., a call-in phone line, webpage, etc.) and the forms of compensation and mitigation measures that would be acceptable if such an event were to occur. This will ultimately be documented in the Risk-Based Mitigation Plan (Step 7). Any discussion of induced seismicity risks should be framed in the proper context, potentially through a comparison with the local natural seismicity or other common risks.

(f) Commitment to Develop and Maintain Stakeholder Trust

Lack of trust between groups can become a barrier to reaching consensus and acceptance of a project. Project proponents should address potential sources of mistrust (e.g., lack of local support, previous negative experiences, general suspicions toward government, industry and other institutions, etc.) through a vigorous and open O&C plan that is started early in the process. This process should be ongoing throughout the lifetime of the project.

Communication with stakeholders should occur on a regular basis at a frequency that is acceptable to the stakeholders. Special meetings may need to be arranged to specifically address time-sensitive community concerns outside of regularly scheduled meetings. Meetings should be

accessible to all stakeholders, with some held outside of regular working hours to accommodate members of the general public. Additionally, communication between technical and non-technical parties should be inclusionary and open to the greatest extent possible, avoiding the creation of opaque communication environments ladened with detailed technical language. The communication language and style should be periodically evaluated with key stakeholders providing feedback. Lastly, third-party monitoring of seismicity (e.g., by the USGS or other institutions) or a commitment to ensure that all data will be publicly available could assure stakeholders of unbiased and reliable results. This information can be documented in the Collection of Seismicity Data (Step 4).

The communications delivered to the public, particularly concerning real or perceived risks, should be coordinated by a central team to maintain consistent messaging, especially if the project developer is made up of several operators, agencies, and sub-contractors. The communication team should have clearly defined roles and responsibilities. Communication strategies that address specific potential scenarios should be created prior to operations to decrease response time following an event or activity of concern. The effectiveness of communication campaigns that support the Risk-Based Mitigation Plan (Step 7) and their impact on different target groups should be carefully reviewed and evaluated (Marti et al., 2020). The communication team should be able to call upon a multi-disciplinary group of people who are involved in key decision-making aspects of the project. These individuals could include project managers, scientists, government officials, company spokespersons, safety personnel, and technical service providers. The communications team should ensure that requests for information are fulfilled in a timely manner, including drafting and maintaining responses to frequently asked questions.

Local stakeholders should feel that there are easy methods in which to communicate their concerns and that their concerns are being addressed. This can include having a local project office or visitor center open to the community, engaging in various social media campaigns to inform the local populations about the project, holding public meetings and site visits to discuss both technical and non-technical issues, and having regularly updated open communication pathways (e.g., website, newsletters, articles in local newspapers with updates, email list, phone hotline, etc.) to advise stakeholders as to the state of current operations at the site and to solicit feedback.

Outreach activities should focus on educating the public about the facts of the project and technology involved. Outreach activities should also include aspects of earthquake awareness, education, and preparedness, especially in areas that may not typically experience natural seismicity. In areas where large historic earthquakes may have produced felt ground motions, outreach should particularly include those aspects in the earthquake education and risk discussions. In areas where natural earthquakes are not part of the region's background knowledge, earthquake education would be particularly important (e.g., discussing the importance of securing water heaters and heavy furniture to the walls, discussing actions to take if shaking were to start, highlighting the fact that people in different buildings or doing different types of activities may experience different levels of ground shaking even for the same event, etc.) Ideally, public meetings and site visits should be held before operations start at the site, before injection begins, and periodically during the injection program.

Documentation associated with the O&C program should be annually reviewed and should include: 1) a list of relevant stakeholders; 2) an archive of official documentation associated with

the program, including letters of endorsement from different stakeholder groups; and 3) a description of the O&C plan, including a list of individual team members.

3. STEP 3: GROUND MOTION THRESHOLDS

3.1 PURPOSE

The purpose of this step is to determine site-specific ground motion thresholds to minimize nuisance and damage risks. These threshold levels should be determined after careful assessment of the local conditions and stakeholder risk tolerance. Existing standards specifying ground motion criteria for nuisance and damage risks should be evaluated so as to comply with any pertinent regulations instituted by other industries, such as mining and construction. Information from this Step will be used for the design of a seismic monitoring program (Step 4), and as a site-specific baseline against which subsequent induced seismicity hazard and risk analyses results (Steps 5 and 6) can be juxtaposed. Additionally, a subset of the threshold levels identified in this Step may be used to inform the "traffic light" threshold levels within the risk-based induced seismicity mitigation plan (Step 7).

3.2 RECOMMENDED PRACTICES

3.2.1 Review of Existing Standards and Criteria

3.2.1.1 A review of international, federal, state, and local ground motion standards and criteria relating to nuisance and damage due to ground shaking should be conducted. This review should include, but should not be limited to:

a) Reviewing local, state, and federal ordinances applicable within the ROC relating to ground motions.
b) Reviewing existing standards and criteria for ground motions developed for other industrial activities so as to ensure conformance with any pertinent standards and regulations.
c) Reviewing ground motion thresholds typically associated with both cosmetic damage and structural damage for buildings and infrastructure, typically stated in terms of peak ground accelerations (PGA), peak ground velocity (PGV), or spectral acceleration (SA).

3.2.1.2 A review of the standards and criteria relating to the limits of human perception of ground motions should be conducted.

3.2.2 Assessment of Site-Specific Conditions

3.2.2.1 A site-specific assessment of the existing environmental conditions within the ROC should be conducted to determine a baseline level of ground vibrations due to existing local activities and industries.

3.2.2.2 A site-specific assessment of the building stock within the ROC should be conducted. This assessment should include, but should not be limited to, the number and type of residential buildings, commercial buildings, fragile or historical buildings, and general infrastructure within the ROC.

3.2.2.3 An assessment of the level of ground shaking that could potentially interfere with industrial and institutional land uses within the ROC should be conducted. This assessment should include, but should not be limited to, sensitive industrial and commercial activities, research activities, medical activities, and wildlife habitats.

3.2.3 Designation of Site-Specific Ground Motion Thresholds

3.2.3.1 At a minimum, four types of ground motion threshold levels should be designated. They should include

a) The ground motion threshold for reaching an unacceptable nuisance risk level, based on the human perception of ground shaking within the ROC
b) The ground motion thresholds associated with both cosmetic and structural damage of infrastructure and building stock within the ROC
c) The ground motion thresholds for sensitive equipment (e.g., industrial, commercial, medical, etc.) and institutional land uses
d) The ground motion thresholds stipulated in federal, state, or local regulations applicable within the ROC

3.3 SUPPORTING INFORMATION

3.3.1 Review of Existing Standards and Criteria

Federal, state, and local standards regarding ground motions should be reviewed to determine if any regulatory criteria are applicable within the ROC. Ground motions from injection-induced seismicity at shallow depths could be of similar frequency and vibration content as those associated with construction, mining, mass transit, and other similar industries. To a first order, the experience and criteria developed for these industries could also be applied to the induced seismicity case and should be investigated.

A review of the human limits to the perception of ground vibrations should also be conducted. To describe events that do not cause damage but disrupt the local public, the nuisance risk concept has been introduced for induced seismicity (i.e., Foulger et al., 2018). Even small events might cause felt ground shaking that may pose a nuisance and cause anxiety to the local population, and potentially generate resistance to the project. This may be particularly true in areas that do not experience relatively frequent natural seismicity. Human perception of ground motion can vary with the individual, the physical setting, and the type of ground motion. The nuisance risk due to small events should be evaluated based on site-specific information and stakeholder input. Guidelines for assessing the human response to vibration have to a certain extent been explored in the induced seismicity context (Bommer et al., 2006; Douglas and Aochi, 2014; Schultz et al., 2021b). They have also been more rigorously, although more generally explored by American National Standard Institute (ANSI) S2.71-1983 (ANSI, 2020) Guide to the Evaluation of Human Exposure to Vibration in Buildings. This standard corresponds to International Organization for Standardization (ISO) 2631, parts 1 and 2 (ISO 2003). Similarly, the Federal Transit Administration (FTA, 2006) and the California Department of Transportation (Caltrans, 2020) have also established relevant standards and recommendations for both transient sources (e.g., single isolated vibration events) and frequent intermittent sources (e.g., events with frequent interrupted periods of continuous vibration) (Table 2).

Lastly, a review of threshold ground motion levels which may cause cosmetic damage or structural damage to different types of buildings and infrastructure should be reviewed. For example, although it has been observed that vibrations between 125 mm/sec to 250 mm/sec PGV will not cause damage to reinforced concrete structures, vibrations between 150 mm/sec and 275 mm/sec can cause cracking of free-standing masonry walls and could therefore be included as a

potential ground motion threshold level (Dowding, 1996; Siskind et al., 1980; Siskind, 2000). Threshold ground motion levels can also be inferred from field observations; however, care should be taken to exclude field observations of damage due to medium-to-large magnitude earthquakes since these may not be reliable indicators of damage due to smaller magnitude events as the durations, number of cycles of motion, and energy content would all be lower. Ground motion thresholds associated with potential soil settlement which may disrupt structure foundations should also be reviewed. It is to be expected that the levels of ground shaking associated with cosmetic or structural damage would be significantly higher than the levels of ground shaking that would constitute only a nuisance to the local population. Additionally, it should be noted that these damage threshold values by themselves would not automatically mean that damage will ensue, just that the necessary conditions have been met.

Table 2: Potential Guideline Vibration Annoyance Criteria for Transient and Frequent Intermittent Sources (Caltrans, 2020)

Human Response	Maximum PGV Transient Source	Maximum PGV Frequent Intermittent Source
Barely perceptible	0.04 in./sec [1.02 mm/sec]	0.01 in./sec [0.25 mm/sec]
Distinctly perceptible	0.25 in./sec [6.35 mm/sec]	0.04 in./sec [1.02 mm/sec]
Strongly perceptible	0.90 in./sec [22.86 mm/sec]	0.10 in./sec [2.54 mm/sec]
Severe	2.00 in./sec [50.80 mm/sec]	0.40 in./sec [10.16 mm/sec]

Documentation should include: 1) a list of any relevant federal, state, or local standards regarding ground motions that are applicable within the ROC; 2) a list of any standards or criteria relating to ground motions in similar industries; 3) a list of the ground motion thresholds relating to human perception; and 4) a catalog of ground motion threshold levels for which cosmetic and structural damage could potentially occur for a range of building and infrastructure types.

3.3.2 Assessment of Site-Specific Conditions

An assessment of the existing environmental conditions within the ROC should be conducted to determine the existing baseline level of ground motions associated with existing local activities and industries, such as vibrations associated with mass transit.

An assessment of the building and structure types within the ROC should also be conducted, with particular attention paid to identifying fragile structures, historical structures, and other structures of particular importance to the local community. Particularly in regions of low natural seismic hazard, the building stock may not be engineered to withstand ground shaking and so even moderate earthquakes may lead to significant damage. These structures should be identified and grouped by their construction attributes, physical condition, age, and any other factors which may affect their behavior during a seismic event. Several general building classification frameworks have been developed, for example by Hazus, Prompt Assessment of Global

Earthquakes for Response (PAGER), and Global Earthquake Model (GEM) (NIBS, 2003; Porter, 2005; Gallagher et al., 2013); however, site-specific classifications are strongly encouraged.

Lastly, an assessment of sensitive local industrial equipment, activities, and institutional land use areas which may be impacted by elevated levels of ground shaking should be conducted within the ROC. For example, medical equipment such as magnetic resonance imaging (MRI) machines or other hospital equipment have stringent requirements on the levels of acceptable vibrations, which can be below the level of felt ground shaking.

Documentation should include: 1) a report on the existing baseline level of ground motions associated with existing local activities and industries; 2) a listing of the building and structure types within the ROC categorized in the same manner as the building and infrastructure ground motion threshold catalog; and 3) a listing of the sensitive local industrial equipment, activities, and institutional land use areas that may be impacted by elevated levels of ground shaking, along with the maximum acceptable ground shaking threshold levels of each.

3.3.3 Designation of Site-Specific Ground Motion Thresholds

At a minimum, four ground motion threshold levels should be quantified in this step. They are (in no particular order): 1) the threshold for humans to perceive ground shaking; 2) cosmetic and structural damage to each type of building and infrastructure within the ROC; 3) ground motions that may affect local industrial and institutional land uses within the ROC; and 4) ground motions that are stipulated in federal, state, or local regulations that are applicable within the ROC. These ground motion levels should be determined after careful assessment of the regulations, local conditions, and careful evaluation of stakeholder risk tolerance. Additionally, when designating nuisance levels of ground shaking, these can depend on the amplitude of the shaking, the duration of shaking, and the number of shaking episodes.

Documentation for this step should include: 1) a description of the type of threshold levels, 2) the maximum ground shaking value or range of values for each threshold level, and 3) the supporting documentation used to determine the threshold.

4. STEP 4: COLLECTION OF SEISMICITY DATA

4.1 PURPOSE

The purpose of this step is to gather seismicity data that will be used for three related but different needs. The first need is to accurately assess and periodically re-assess the natural and induced seismic hazard and risk associated with the project. The second is to aid in the effective and rapid detection and characterization of induced seismicity occurring in the Perturbed Stress Zone (PSZ). The final need is to provide accurate data for input into induced seismicity mitigation plans (e.g., conventional or adaptive traffic light systems). In short, observed seismicity will be used not only to estimate and mitigate the hazard and risk at the site, but also to aid in reservoir characterization and management. Not included in this step is the collection or analysis of active seismic and other data required to characterize the subsurface reservoir system and its surroundings. However, the results of those efforts would certainly be necessary when estimating the seismic hazards (as described in Step 5).

4.2 RECOMMENDED PRACTICES

4.2.1 Seismic Activity Before Operations

4.2.1.1 Previous seismic activity should be characterized within a region of at least 200 km radius around planned injection operations. Elements of the seismicity characterization should include, but are not limited to, collecting existing information from:

a) Catalogs of instrumentally recorded earthquakes from national, state, or regional agencies
b) Historical records of earthquakes and observed fault ruptures, including but not limited to, historical earthquake catalogs, and newspaper and other contemporary records, and published reports of field geological investigations
c) Fault maps and fault characterizations, including but not limited to, scientific maps and publications
d) Paleoseismic fault displacement data, including but not limited to, published trenching studies
e) Previous induced earthquake activity, including but not limited to, earthquake catalogs and scientific publications investigating possible induced activity

4.2.1.2 Prior to commencing injection operations, a seismic monitoring network (as described in Section 4.2.2) should be operated for preferably 1 year or longer, but at least for 6 months.

4.2.2 Seismic Monitoring Network Design

4.2.2.1 A local seismic monitoring network should be installed and should have the following minimum requirements:

a) The seismic network should include a combination of weak-motion seismometers and strong-motion accelerometers
b) Each seismic station should consist of 3 orthogonal sensor components and record with a timing accuracy of 1 ms or better

c) The network should be able to record and locate seismicity in the PSZ with at least a 2-sigma location accuracy of 0.5 km in the horizontal direction and 1.0 km in the vertical direction
d) Seismic monitoring networks should be designed, and stations located such that ground velocities of 600 nm/s can be recorded with a signal-to-noise ratio of at least 6 in the frequency range 5–40 Hz within the ROC
e) The velocity model used to locate earthquakes should be calibrated using calibration shots or similar methods

4.2.3 Seismic Monitoring Network Operation and Reporting

4.2.3.1 The seismic monitoring network operation should be set up so that:

a) Seismic waveform data should be analyzed in near-real time to detect, associate, locate, and determine magnitudes of seismic events
b) The seismic monitoring network should continuously operate during the operational phase of the project and throughout the seismic post-injection site care (PISC) period
c) The operator should ensure that raw seismic data waveform, associated metadata, and event catalogs are archived throughout the lifetime of the project

4.2.4 Public Reporting and Engagement

4.2.4.1 The operator should provide a summary report on observed induced seismicity at least annually. This report should be made publicly available.

4.2.4.2 Earthquake catalogs should be made available in near-real time to the public through a web interface. The web interface should:

a) Provide information on each event including, but not limited to, the event origin date and time, 3D location, magnitude, number of stations used to compute the location, maximum azimuthal gap, distance of closest station to the event, root-mean-square (RMS) travel time residual, location uncertainty, and whether the event has been reviewed by a seismologist
b) Allow automatic queries to retrieve event information by computer systems of third parties
c) Include implementation of standard seismological data formats such as miniSEED, and data request and transfer schemas, such as FDSN StationXML and ArcLink

4.2.4.3 Continuous raw seismic data waveforms should be transmitted to a public data repository, such as the Incorporated Research Institutions for Seismology Data Management Center (IRIS-DMC), in near-real time.

4.2.4.4 The waveform data should be accessible to the public from an online data repository without limitations, excepting for a reasonable embargo period to ensure quality control.

4.2.4.5 The operator should supply additional seismic network metadata including, but not limited to, instrument locations, instrument data sheets, and instrument response functions.

4.2.4.6 The operator should supply additional related information including, but not limited to, the seismic velocity model and the seismic phase picks used for computation of the event locations.

4.3 SUPPORTING INFORMATION

4.3.1 Seismic Activity Before Operations

The first step in understanding the potential for induced seismicity from a new project is to identify any nearby past and present seismicity and the faults on which it originates. These data will be needed to: 1) perform the induced seismic hazard and risk analyses (Steps 5 and 6) initiated during the planning stage of the project; and 2) compare to any potential induced seismicity observed during the operation stage. A region much larger than the ROC (minimum of 200 km radius) is chosen to ensure that wider regional trends are considered in the seismic hazard assessment. This consideration reduces the possibility of overlooking infrequent but possibly large events that could still impact the local hazard.

Seismic monitoring networks operated by national, state, or regional entities can provide information on larger events occurring in a region. The National Earthquake Information Center (NEIC) for example, has a goal of detecting and locating events in the U.S. that are greater than M_w2.5–M_w3.0, depending on the geographic region. However, processing of smaller events may take up to several weeks, or information on them may not be reported due to poor data quality or their signal can be masked by larger events. In general, this level of monitoring is not sufficient for monitoring induced seismicity. Routine detection of small events in the immediate vicinity of the injection site is necessary to detect problematic developments as early as possible.

Historic reports of significant earthquakes can provide important information on time periods that predate instrumental recording. For rare events that occur once every few hundred to thousands of years, this may be the only evidence of seismic activity. Of course, the absence of historic reports of significant earthquakes does not necessarily indicate that no faults exist, that no earthquakes occurred in the past in the region, or that induced seismicity would not occur in the future. Geologic characterization of faults active in the Quaternary and paleoseismic studies of known faults enables inclusion of prehistoric earthquakes and complements the characterization of historical seismicity.

Evidence of anthropogenic earthquake activity should also be investigated. If the targeted region has a history of induced seismicity, this would be a strong indication of a critically stressed crust, i.e., relatively small perturbations to the subsurface stress field may be sufficient to induce seismicity. Such cases would need to be carefully scrutinized.

As indicated above, national, state or regional seismic networks are typically not sensitive enough to detect the level of seismic activity that should be recorded at local sites. Therefore, installing or augmenting an existing local monitoring network may be required in order to understand the response of the project site to injection operations. It is important to quantify the level of seismic activity before operations commence at the same detection level as will be used during injection operations. Recognizing that natural seismicity rates can vary over time, the local seismic network should begin operating as early as possible. One year or longer is recommended, but a minimum of 6 months of pre-injection monitoring is suggested.

4.3.2 Seismic Monitoring Network Design

The seismic monitoring network should be designed to detect and characterize seismicity occurring in the PSZ volume, down to at least M1, and should be able to record all expected felt ground motions due to those events effectively and rapidly. The PSZ is the three-dimensional (3D) subsurface region originating at the injection wells with perturbed pressure and stress in which seismicity could occur in a critically stressed crust. The PSZ could be estimated, for example, by creating a hydro-mechanical model of the reservoir injection scenarios and determining where the Mohr-Coulomb stress changes would exceed a pre-determined critical stress threshold (Figueiredo et al., 2015). The PSZ will also be expected to expand over time as the fluid migrates. As such, it would be expected that stations could be added to the seismic network over time to expand the network to adequately cover the evolving PSZ. Collecting and analyzing the necessary seismic data requires the appropriate sensors, electronics, network design, and computational capability. With regard to the sensors, local monitoring networks should include a combination of high-gain sensors, which can optimally record weak ground motions from small local earthquakes, and low-gain accelerometers, which can optimally record strong ground motions from nearby larger earthquakes. Two common types of high-gain sensors include broadband seismometers and geophones (Trnkoczy et al., 2002). Broadband seismometers typically have a wider frequency passband than geophones, can record lower frequency ground motion, and can therefore more accurately measure event magnitudes and peak ground velocities of induced seismic events (Yenier et al., 2016). Broadband seismometers are, therefore, the preferred high-gain instrument for monitoring induced seismicity. Strong ground motion instruments (i.e., accelerometers) more accurately measure the forces associated with larger earthquakes. Accelerometers can be located near sensitive structures to monitor for potential large ground motions at critical locations and should be able to measure strong ground motions up to at least 1 g.

Each seismic station should measure ground motion in three orthogonal directions (e.g., up-down, north-south, and east-west) to fully capture the movement of the seismic waves as they travel through the earth. The data should be recorded using at least a 24-bit digital data acquisition system and a global positioning system (GPS)-based field timing system to achieve the required timing accuracy of at least 1 ms. The instruments should be able to record the dominant frequencies of the earthquakes.

When designing the seismic network, it is best to strive for as much sensitivity and accuracy as is economically possible for optimal earthquake detection, association, location, and magnitude determination of both small microseismic events and the largest potential events that may occur due to injection activities. Azimuthal gaps between the seismic stations greater than or equal to 120 degrees should be avoided. To record seismicity within the PSZ, it is expected that the footprint of the seismic network would need to extend beyond the PSZ. The network should be designed to record and locate seismicity in the PSZ with at least a 2-sigma (i.e., 2 standard deviation) location accuracy of 0.5 km in the horizontal direction and 1.0 km in the vertical direction. These uncertainty values include the formal location uncertainty given by the location software and also any unmodeled uncertainties of the velocity model. The precision of locations in any subsequently relocated earthquake catalog, assuming that the original catalog was not systematically biased, may be significantly smaller, allowing for identification of fault structures.

The seismic network should be designed to clearly record events that originate in the PSZ subsurface volume. Wiemer et al. (2017) suggest that for sedimentary basins this would require

measurement of ground velocity amplitudes as small as 600 nm/s with a signal-to-noise ratio (SNR) of at least 6 within the frequency range of 5–40 Hz; i.e., the noise level at each recording site should not exceed 100 nm/s. This criterion should enable a magnitude of completeness on the order of M1 to be achieved. To ensure the desired maximum noise level, Groos and Ritter (2010) recommend that background noise should be measured at each candidate recording site for least 7 days and a noise analysis be carried out prior to the installation of permanent instrumentation. The noise level should also be continuously assessed during the operational phase of the project and throughout the PISC period.

Seismic stations should be sited using commonly accepted procedures (e.g., Trnkoczy et al., 2002; Plenkers et al., 2015) to assure good mechanical contact with the ground and adequate protection of the equipment. If possible, the sensor should be installed below the weathered and alluvial layers in bedrock geology. If high-quality surface sites are not available, the use of shallow borehole installations (80–150 m depth) would be necessary to minimize background noise.

Velocity model uncertainties can lead to major uncertainties in earthquake locations, particularly in depth. These uncertainties can be reduced by calibrating the velocity model using one or more calibration shots (e.g., small explosions in a wellbore at target depth) (Akram and Eaton, 2013), or similar methods. Additionally, if available, subsurface velocity information from active seismic surveys or borehole sonic logs should be integrated into the seismic velocity model used for event location.

4.3.3 Seismic Monitoring Network Operation and Reporting

Making the monitoring effort transparent to regulators and the public by providing seismic waveform and earthquake catalog data to the public in near-real time is an important step to maintain the support of the local community, facilitate project oversight, and allow scientists to further analyze the data. While there may be legitimate operational reasons to briefly embargo data to ensure quality control and accuracy of interpretation, it is highly recommended that an open-access data approach be taken when engaging with the public. This will improve community trust and also improve the overall state-of-knowledge in the induced seismicity research community. The seismic monitoring network should be operating continuously during the pre-operational background assessment phase, during the operational phase of the project and throughout the seismic PISC period. Additionally, the operator should ensure that the continuous raw seismic data and event catalogs are archived throughout the life of the project and until the end of the seismic PISC. Magnitudes in event catalogs should preferably be calculated as moment magnitudes, although it is acknowledged that this is not always straightforward, particularly in areas that have not historically had earthquakes (Edwards and Douglas, 2014). In these cases, the reporting of local magnitudes may be necessary.

4.3.4 Public Reporting and Engagement

The operator should provide a summary report on observed induced seismicity at least annually. This report should be made publicly available. Additionally, earthquake catalogs should be made available in near-real time to the public through a web interface. This waveform data should be accessible to the public without limitations, excepting for a reasonable embargo period to ensure quality control (e.g., Salvage et al., 2021).

Archiving raw waveform data in near-real time at data centers, such as IRIS-DMC, can help with long-term storage and facilitate easy access by third parties. In particular, the IRIS-DMC has been certified as a trusted repository by the International Council for Science World Data System and is a common repository for seismic waveform data and station metadata information in the U.S. Additionally, seismic data protocols such as SEEDLink for real time seismic waveform data transfer or ArcLink for waveform data and station metadata transfer are highly recommended. Standard seismic data formats, such as miniSEED, are also recommended. The use of standard data schemas, such as FDSN StationXML for station metadata and QuakeML for event and phase data, and standard coordinate reference systems is strongly recommended. Sensor and station metadata documentation should include, but may not be limited to, instrument coordinates, instrument response functions, compression type, sampling rate, gain factors, etc. The operator should also supply any related information (such as the seismic velocity model, magnitude calculation method and if applicable the relationship to M_w, instrument data sheets, changes to the processing routine, replacement of any equipment, equipment failures, etc.) in the seismic summary report that is produced at least annually. Pertinent changes to the seismic network and processing routine should also be updated on the online web interface as changes occur, including reporting when, or if, the catalog is recalculated due to new information. If significant new information were to be obtained, such as a new velocity model, it would be recommended to retroactively correct the earthquake catalog.

Beyond standard seismic processing techniques, advanced data processing can often prove useful. This may include earthquake relocations using more advanced techniques, such as the double-difference relocation method, which reduces the uncertainty introduced by the velocity model between sources and receivers and utilizes only the relative travel times between neighboring events (Waldhauser and Ellsworth, 2000; Trugman and Shearer, 2017). Earthquake relocation can provide improved understanding of what drives the local seismicity and its relation, if any, to fluid injection. Examples of other advanced analyses include the determination of focal mechanisms or moment tensors, which describe the orientation and sense of slip on the earthquake source plane that provide additional constraints on the sources of the seismicity.

5. STEP 5: HAZARD EVALUATION OF NATURAL AND INDUCED SEISMIC EVENTS

5.1 PURPOSE

The purpose of this step is to estimate the ground shaking hazard at the proposed site and within the ROC due to natural tectonic seismicity and the additional hazard due to induced seismicity using probabilistic seismic hazard analysis (PSHA). Assessing the ground shaking hazard from natural seismicity will provide a baseline from which to evaluate the additional hazard from induced seismicity. Once the surface ground shaking hazard is quantified, associated secondary hazards such as liquefaction, slope failure, caprock integrity, or the potential opening of fault leakage pathways, can be subsequently evaluated in separate procedures. This step should be performed before any operations are initiated at the site. Results from this seismic hazard evaluation will be input into the subsequent Risk-Informed Decision Analysis (Step 6). Additionally, these seismic hazard analyses will need to be updated as new information and model enhancements become available, especially during the early evaluation period of the project, as described in the Risk-Based Mitigation Plan (Step 7).

5.2 RECOMMENDED PRACTICES

5.2.1 Baseline Hazard from Natural Seismicity

5.2.1.1 A site-specific PSHA should be conducted in accordance with current practice of earthquake hazard estimation to evaluate the baseline hazard from natural tectonic seismicity. Input into the PSHA should include, but should not be limited to, the following:

a) A database of potentially damaging earthquake sources that may impact the ROC, that experienced activity during the Quaternary Period, including fault-specific sources and areal sources where appropriate
b) Spatial, temporal, and frequency-magnitude distribution models for each seismic source
c) Region appropriate GMMs for tectonic earthquakes as a function of at least earthquake magnitude and travel path
d) Information from geological, geophysical, and topographical studies within the PSZ should be included to incorporate local site responses

5.2.1.2 Results from the PSHA should include multiple hazard curves and hazard maps to report the results from the baseline seismic hazard analysis due to natural seismicity before injection operations commence.

5.2.1.3 A seismic hazard report should be prepared, if required by the regulatory agency, by a licensed professional having demonstrated competence in the field of seismic hazard assessment. The seismic hazard report should contain site-specific assessments of the seismic hazard affecting the project and relevant sites within the ROC. The report should identify any known seismic hazards that could adversely affect relevant sites within the ROC in the event of an earthquake. The contents of the seismic hazard report should include, but should not be limited to, the following:

a) A project description

b) A description of the geologic, geotechnical, and geophysical conditions within the ROC, including an appropriate site location map
c) An evaluation of site-specific seismic hazards based on geological and geotechnical conditions in accordance with current standards of practice
d) The name(s) and qualifications of the report preparer(s)

5.2.1.4 Prior to approving the project, the appropriate regulatory agency should independently review the seismic hazard report to determine the adequacy of the hazard evaluation. The reviews should be conducted by a licensed professional having demonstrated competence in the field of seismic hazard assessment.

5.2.1.5 The site-specific PSHA should be updated and re-submitted for approval to the appropriate regulatory agency as needed if significant new information pertinent to the hazard evaluation becomes available.

5.2.2 Additional Hazard from Induced Seismicity

5.2.2.1 Site-specific short-term 1-year probabilistic seismic hazard forecasts (PSHF) should be conducted in accordance with current practice to evaluate the hazard from induced and natural seismicity. Information gathered for the PSHF should include, but should not be limited to:

a) Input originally obtained for the PSHA (5.1.1)
b) Site-specific reservoir and caprock properties and operation parameters such as: the initial geometrical features of the subsurface reservoir; thermal and chemical properties of the reservoir and fluids; hydraulic and mechanical properties of the reservoir and caprock; stress and pressure state of the reservoir and caprock; and planned injection and pressure build rates

5.2.2.2 Results from the short-term PSHF should include multiple hazard curves and hazard maps to report the results from the additional seismic hazard due to potential induced seismicity.

5.2.2.3 The site-specific short-term 1-year seismic hazard forecast report should be prepared by a licensed professional having demonstrated competence in the field of seismic hazard evaluation (if required by the regulatory agency). The short-term seismic hazard forecast report should contain site-specific evaluations of the short-term seismic hazards affecting the site from both induced and natural earthquakes. This is in contrast to the report called for in Section 5.2.1.3, which includes only natural events. The short-term seismic hazard forecast report should also identify any known seismic hazards sources that could adversely affect relevant sites within the ROC in the event of an earthquake. The contents of the short-term seismic hazard forecast report should include the same items as those listed under 5.1.3.

5.2.2.4 Prior to approving the project, the appropriate regulatory agency should independently review the short-term seismic hazard forecast report to determine the adequacy of the hazard evaluation. The review should be conducted by a licensed professional having demonstrated competence in the field of seismic hazard assessment.

5.2.2.5 The short-term PSHF should be updated and re-submitted for approval to the appropriate regulatory agency annually, or more frequently as needed.

5.3 SUPPORTING INFORMATION

5.3.1 Baseline Hazard from Natural Seismicity

5.3.1.1 Overview

Although there could be many sources of potential seismic hazards at a particular site (e.g., ground shaking, fault offsets, soil liquefaction, landslides, etc.), for this purpose the baseline seismic hazard will focus exclusively on ground shaking hazards associated with natural tectonic seismic events that could impact the site infrastructure (to inform any hazard mitigation procedures) and the local population (to allow for ease of comparison of the hazard and risk associated with existing natural seismicity and any induced seismicity). Additional hazards can be incorporated at a later time, if needed (NRC, 1988).

Two general approaches have been developed for analyzing the seismic ground shaking hazard at a particular site: deterministic, which focuses on specific earthquake scenarios without considering their likelihood to reoccur; and probabilistic, which incorporates all seismic events that may impact a site and includes information on their recurrence times and uncertainties in source characterization and recurrence. A deterministic seismic hazard analysis (DSHA) may be useful when describing potential effects to stakeholders due to its more straightforward formulation. A PSHA allows for a broader understanding of the overall seismic hazard and can be input into subsequent seismic risk analyses (Cornell, 1968; McGuire, 2004). As such, PSHA is recommended when calculating the baseline seismic hazard at a particular GCS site due to natural tectonic seismicity.

PSHA involves obtaining, through a formal mathematical process, the level of a selected ground motion parameter (e.g., PGA, PGV, etc.) that has a selected probability of being exceeded (e.g., 0.01% probability, 10% probability, etc.) during a specified time interval (e.g., 50 years, 5,000 years, etc.) at a particular location due to future earthquakes. In practice, several different ground motion parameters over a range of different probabilities and time intervals can be calculated for a particular site. Hazard curves visualize those exceedance probabilities and allow for different sites to be easily compared.

A variety of computer programs are publicly available which can be used to perform site-specific PSHA, such as the free and open-source software OpenQuake Engine (Pagani et al., 2014). Several others have also been validated by the Pacific Earthquake Engineering Research Center, including the OpenSHA program (an open-source program originally conceived by Ned Field of the USGS), the HAZ program (a free program originally developed by Norman Abrahamson at UC Berkeley), and EZ-FRISK (a licensed program available through Risk Engineering Inc.) (Hale et al., 2018). Some available codes do not convert the rate of exceeding a given ground motion intensity to the probability of exceeding a given ground motion intensity within the code itself, so this step must be conducted in post-processing (Hale et al., 2018). This last step requires estimating the probability distribution of time between earthquake occurrences and, to date, is almost always assumed to be Poissonian.

The hazard and risk analyses in Steps 5 and 6 will help better define the ROC. The ROC was preliminarily estimated in Step 1. The ROC defines the ground surface area that could be negatively impacted by seismic events occurring at depth throughout the lifetime of the project. Throughout the lifetime of the project, it is also expected that the PSHA analysis will need to be updated if future geological, seismological, or geophysical investigations reveal significantly

new and different information than that used in the original analysis. The ROC may also expand or contract due to new information. Additionally, since some parameters of the natural and induced seismic hazard analyses should be similarly aligned to ensure consistency, those performing the two analyses should either be the same entity or they should be in frequent communication.

5.3.1.2 PSHA Inputs

Information from three general input categories are required for PSHA. They are a) earthquake source locations and geometry, b) spatial, temporal, and frequency-magnitude (recurrence) models for each of the earthquake sources, and c) source-site-appropriate earthquake GMMs, with adjustments for local site response conditions.

(a) Earthquake seismic sources that could constitute a ground motion hazard to the local communities, operational infrastructure, or to the subsurface reservoir itself should be identified and incorporated in the PSHA. PSHA seismic sources fall into two general categories: fault-specific sources and areal sources (SSHAC, 1997).

For fault-specific sources, the current criteria for defining an "active", "potentially active", or "capable" fault varies between different U.S. government regulatory agencies (Jennings and Bryant, 2010). For this purpose, at a minimum, faults that have exhibited coseismic surface deformation within the past 1.6 million years, (i.e., the Quaternary time period as defined by the 1983 Geologic Time Scale) should be included as a fault-specific source. The USGS maintains a U.S. Quaternary Fault and Fold Database, which is a source for faults used in the National Seismic Hazard Maps, and which could serve as a starting point for the PSHA analysis (USGS, 2006). Surface fault location, fault length, strike, dip direction and dip angle, slip rate, and slip sense (strike-slip, normal, or reverse/thrust) are included in this database, although the quality and level of completeness of information available for each source varies. Information should be closely scrutinized and augmented with additional geological, geomorphological, geodetic, geophysical, and seismological data, including review of recent literature when available. Supplementary information from regional investigations, such as the Unified California Earthquake Rupture Forecast (UCERF) project for California or the Central and Eastern United States – Seismic Source Characterization (CEUS-SSC) project for the CEUS, have developed region-specific databases that can be important sources of more detailed information (CEUS-SSC, 2012; Field et al., 2013). Nevertheless, site specific studies will most likely be necessary. Additional information for fault-specific sources, particularly within the PSZ, that will be needed for a site-specific PSHA would be: 1) the down-dip length and subsurface geometry of the fault; 2) the identification of any blind faults (i.e., faults that do not have a surface expression); and 3) an indication of any of fault segmentation, which may pose a limit on the rupture length (e.g., Field et al., 2013; SSHAC, 1997).

Areal seismic sources are distinct volumes within the Earth's crust that encompass concentrated zones of seismicity, seismic sources defined by regional seismotectonic characteristics, or areas with potential for general background earthquakes. Areal sources can account for the possibility of earthquakes occurring on faults that are not currently mapped or to account for known large earthquakes that have yet to be associated with a particular mapped fault. Areal sources are defined by their lateral and subsurface extents

and slip sense (strike-slip, normal, or reverse/thrust). Geologic, geophysical, and seismological data can be used to identify local and regional areal sources (SSHAC, 1997).

A 3D structural and stratigraphic model of the PSZ should be developed. It should include faults and fractures that could be sources of future seismicity. Inputs into the 3D model could include information from drilling logs, wellbore image logs, seismic reflection data, seismic tomography, potential field data, etc.

Each seismic source can be characterized by multiple plausible configurations, each with an associated weight or credibility (SSHAC, 1997). Lastly, regional and site investigations used to identify seismic sources for input into the PSHA should have a resolution at least consistent with a 1:5,000 scale map above the subsurface reservoir and a scale of 1:50,000 above the PSZ for best fidelity (U.S. Nuclear Regulatory Commission, 2007).

(b) For each seismic source, models of the spatial, temporal, and earthquake frequency-magnitude distributions should be determined in order to appropriately characterize each source (SSHAC, 1997).

The spatial distribution models for earthquake sources are used to calculate the distance distribution between potential future events and sites within the ROC. For fault-specific sources, the spatial distribution model describes the potential event locations across the fault. Potential locations can be represented as either point sources on a two-dimensional (2D) or 3D fault plane or as a rupture area with finite dimensions. Spatial distribution models for areal sources can either be uniformly distributed over the entire zone, which would allow for the possibility of incorporating future earthquakes within regions of little observed historical seismicity, or they can attempt to match the historical earthquake catalog, usually with some degree of spatial smoothing (Abrahamson, 2006). Estimating distances for area-type finite fault seismic sources requires subjective assumptions of fault rupture details (strike, dip, and rupture area) and should be well documented.

The selection of a model for the temporal distribution of earthquakes for each seismic source is usually Poissonian, which assumes that each earthquake occurs independently in time from each other (e.g., Cornell, 1968; NRC, 1988).

Earthquake recurrence (frequency-magnitude) models provide information on the relative frequencies of occurrence of seismic events of different magnitudes, between a pre-selected minimum earthquake magnitude of concern up to a pre-determined maximum magnitude that the source is considered capable of producing. The minimum magnitude threshold is typically considered the smallest magnitude event that can generate potentially damaging ground motions (Bommer and Crowley, 2017). When conducting the natural and induced seismic hazard analyses, the same, or very similar, lower threshold magnitudes should be used. The maximum magnitude is a key parameter in earthquake recurrence models but is often poorly constrained. For fault-specific sources, the maximum earthquake magnitude can either be derived using empirical relationships between magnitude and one or more key fault parameters (e.g., surface displacement, fault rupture length, rupture area, etc.) (Slemmons, 1977; Bonilla et al., 1984; Wells and Coppersmith, 1994; Stafford, 2014; Allen and Hayes, 2017; Thingbaijam et al., 2017) or observationally through the use of the historical seismic catalog. Maximum earthquake

magnitude estimates for areal sources are particularly challenging since potential fault dimensions are extremely difficult to determine. In practice, the maximum earthquake magnitude is often presented as a distribution of potential values, rather than as a single value, based on the available information (SSHAC, 1997). When conducting the natural and induced seismic hazard analyses, the maximum magnitude values could be the same or independent from each other.

Earthquake recurrence relationships for fault-specific sources can include information from both earthquake catalogs, which provide information on smaller magnitude, higher frequency events, and paleoseismic/geologic information, which provides information on larger magnitude, lower frequency events. Common earthquake recurrence models include the truncated exponential model—a form of the classical Gutenberg-Richter model (1944) that assumes spatial and temporal independence of events—and the characteristic earthquake model, which often combines the Gutenberg-Richter model for smaller magnitude events with a characteristic maximum event that displays a different recurrence behavior (Youngs and Coppersmith, 1985; Gutenberg and Richter, 1944).

Earthquake recurrence relationships for areal source zones typically use de-clustered historical catalogs as the primary source of information. Truncated exponential models are often used to combine the observed data with the estimate of maximum magnitude to determine the recurrence parameters (SSHAC, 1997).

(c) Site-appropriate earthquake GMMs specify the estimated ground shaking at a particular site as a function of, at least, the magnitude, distance of potential seismic events, and, indirectly, the local tectonic regime (e.g., Boore and Atkinson, 2008). Other factors that should be incorporated include focal mechanism, hanging wall effects, and event depth. Additionally, local site effects can dramatically influence the amplitude, duration, and frequency content of ground shaking at a particular site and should be incorporated into the model. These site factors can include local geologic and soil characteristics, topographic influences, and soil non-linearity (SSHAC, 1997). One way that earthquake GMMs can incorporate local site response is through the use of V_s30, the average shear-wave velocity (V_s) in the top 30 m of the subsurface. The V_s profile at a site can be obtained through a range of common geophysical methods (Idriss et al., 2018).

A wide variety of peer reviewed GMMs exist (e.g., Bozorgnia et al., 2014; PEER, 2015). A careful selection of the most appropriate site-specific models should be conducted, which should include a comparison between any available relevant observed data and the calculated model results, recognizing that caution must be exercised in interpreting results if extrapolating GMMs outside of their magnitude validity ranges due to a lack of more appropriate GMMs (Beauval et al., 2012; Idriss et al., 2018). Additionally, to ensure consistency between the natural and induced seismic hazard analyses, the GMMs should be the same between the two. Recognizing that this could be quite difficult, it may therefore be necessary to use different GMMs in the two cases, but to verify that for common magnitudes and depths, they yield comparable predictions.

5.3.1.3 PSHA Results

The primary products of the PSHA are seismic ground motion hazard curves that show the estimated probability of exceedance per unit time (typically annually) on the vertical axis and different levels of the selected ground motion parameter on the horizontal axis (Figure 1). Low

levels of ground motion are exceeded relatively often (higher probability), while high levels of ground motion are exceeded rarely (lower probability).

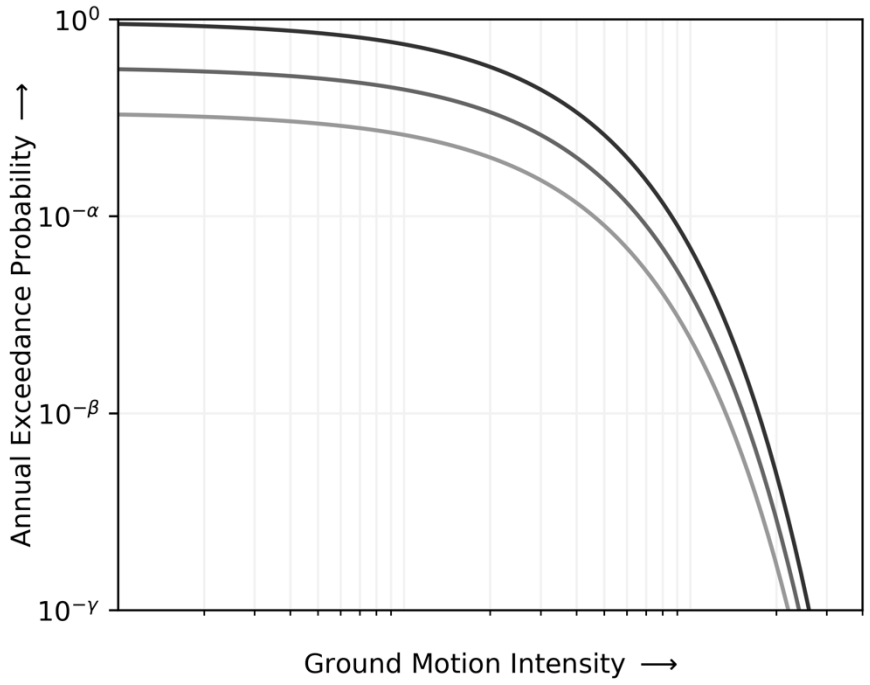


Figure 1: Example seismic hazard curve specifying the probability of exceedance (theoretically between 0–1) as a function of increasing ground motion intensity (e.g., PGA, spectral acceleration, etc.). An annual exceedance probability of 1 would indicate an expected 100% chance of exceeding the specified ground motion intensity.

The ground motion parameters most frequently selected for the presentation of PSHA results are PGA, PGV, or SA at selected periods. Results given in terms of PGA or response SA can be compared to seismic design regulations and building codes, while results given in terms of PGV can be compared to cosmetic and structural building damage criteria, criteria for vibration sensitive research and manufacturing facilities, and with human activity interference criteria (Petersen et al., 2014; Rutqvist et al., 2014).

Estimates of uncertainty can be captured on the hazard curves. For example, epistemic uncertainties (i.e., uncertainties arising from the potential of having a range of input sources, GMMs, and other input parameters that could be appropriate at a particular site) can be estimated using logic trees which allow for the incorporation of different combinations of models and parameter ranges into the hazard analysis (e.g., NRC, 2012b; NRC, 2018). The subsequently calculated hazard curves would then be based on different, but defensible, underlying assumptions which, when plotted together, can illustrate the effect of these uncertainties on the results. The mean hazard curves can be plotted along with two or more associated confidence band curves, such as the 5% and 95% percentile curves (SSHAC, 1997). When presenting uncertainty in this manner, a description of the center and range of technically defensible interpretations should be included in the discussion.

Furthermore, PSHA result maps should show earthquake ground-shaking levels for several annual exceedance frequencies or return periods. Hazard maps present a more complete overview of the hazard and may be easier to comprehend in a more general sense. PSHA maps may show the various earthquake ground-shaking levels with a fixed probability of exceedance over a specified time period. One important value to define a priori would be the lowest annual frequency of exceedance for which ground motions of interest should be evaluated, again recognizing that this minimum value should be common between the natural and induced seismic hazard analyses. For reference, for the design of critical facilities, the annual frequencies of exceedance of interest are generally in the range of 10^{-4} to 10^{-5} (NRC, 2018).

5.3.1.4 PSHA Report

The site-specific seismic hazard report should contain sufficient information to allow the regulatory agency's technical reviewer(s) to satisfactorily evaluate the potential for seismic ground shaking hazards (CGS, 2008).

(a) The project description should include at minimum the stated purpose of the project and a listing of the owners and operators.

(b) The geologic, geodetic, geotechnical, and geophysical descriptions of the site should include at minimum: a physical description and map of the carbon storage reservoir and PSZ; 3D cross-section(s) of the reservoir including locations of known drinking water aquifers; a description of the geologic and tectonic setting of the site; a description and map of the seismic monitoring network and an estimate of the minimum magnitude of completeness; a description and map of any wells located within the PSZ; a description of any published or unpublished site-specific or regional investigations pertinent to the evaluation; and a description of any site-specific investigations undertaken during the course of the evaluation.

(c) In addition to presenting the PSHA results, the PSHA report should document and justify all assumptions, data, methods, models, uncertainties, and input parameters. The report should include all sources of information, both published and unpublished, that were used in the analysis. Specific effort should be applied to effectively communicating the effect of the uncertainties (both epistemic and aleatory) on the results so as to develop a true understanding of the seismic hazard.

    The database of potential sources of damaging earthquakes should include potential locations, a description, parameter value ranges, and the stated basis for the identification of the seismic sources. The earthquake recurrence relationships should include the frequency of observed earthquakes with associated statistical error bars, the recurrence intervals from paleoseismic data, and (if applicable) the mean recurrence curves derived from the slip rate and magnitude-distribution model should be included (SSHAC, 1997). The PSHA report should also include a description of the spatial, temporal, and earthquake recurrence models and parameters for each source. A description of the GMMs, input parameters, and the reason for choosing particular models should also be documented. If a new site-specific GMM is derived, a full description of the development of the new model should be included. Predictions from the GMMs should be compared to relevant recorded data to determine the fidelity of the calculated results.

A logic tree capturing the epistemic uncertainties in the source and GMMs should also be included along with the assigned model and parameter weights representing the relative merit of each of the alternatives. Logic trees allow for the incorporation of the full range of viable alternative source models, recurrence parameters, maximum magnitudes, GMMs, etc. A Monte Carlo approach can be used with logic trees, for example, to sample the uncertainty space of model parameter values and of ground motion model aleatory uncertainties (natural random variability). Monte Carlo methods can be used to sample the distributions whether they are represented by discrete branches or continuous distributions. Logic trees are discrete representations of probability distributions where many branches could potentially be replaced by continuous distributions. The chosen procedure should be carefully documented since the assessment of epistemic uncertainties can be equivocal, given its dependence on expert judgement and data availability. These uncertainties can then be propagated into the subsequent risk assessment so that decision makers can make better informed decisions.

(d) The name(s) and qualifications of the report preparer(s), who should have competence in the field of seismic hazard evaluation, should be included in the report documentation.

5.3.1.5 PSHA Review

The technical review by the appropriate regulatory agency is a critical part of the evaluation process. The regulatory reviewer ensures compliance with existing laws and current standards of practice to protect both regulatory and stakeholder interests. The reviewer should be familiar with the investigative methods employed and the techniques available to perform the analysis; however, it would be appropriate for reviewers to ask for the opinion of others more qualified in specialty fields if necessary. Reviews should be based on logical and defensible criteria. Guidelines for the report and any supplementary material should be made available to applicants beforehand. This information should cover procedures, report formats, and levels of appropriate investigative detail that will expedite the review and approval of the project (CGS, 2008).

5.3.1.6 PSHA Update

Site-specific PSHA reports to the regulatory agency should be updated if future geological, seismological, or geophysical investigations reveal significant new and different information than that used in the original PSHA, such as new seismic sources or improved GMMs.

5.3.2 Additional Hazard From Induced Seismicity

5.3.2.1 Overview

The probabilistic short-term seismic ground shaking hazard forecast is determined generally the same as for the long-term approach, with adjustments made for different source and GMMs to accommodate the differences between induced and natural seismicity. For example, the range of mechanisms which can induce seismicity at a local fluid injection site (e.g., pore pressure changes due to fluid injection, temperature and chemical changes within the reservoir host rock caused by the fluids, and poro-elastic stress changes) can be, but are not necessarily, different than the mechanisms which typically create natural tectonic earthquakes.

These short-term site-specific seismic ground shaking hazard forecasts, incorporating both natural and induced seismicity, should be periodically computed during the lifetime of the project. These forecasts should ideally be for 1-year duration or shorter, depending on the

planned injection schedule. These short-term forecasts are, however, difficult to calculate since induced or potentially induced earthquakes can vary rapidly in space and time based on anthropogenic activity. The seismic response to injection can also vary drastically among nearby sites or even between different injection depth intervals. These factors make it difficult to extrapolate values, although regional trends in the seismic response may exist. While it may be possible to make some estimates ahead of the initial injection program, real forecasting power requires actual observations of the seismic response to injection tests to calibrate and validate the forecasting models and assumptions made in the initial assessment.

Estimating the frequency-magnitude characteristics of induced seismicity, which are likely to be time- and space-dependent, before injection starts is a significant challenge since not all of the geological and geomechanical factors that govern the seismic response of a site can be accurately quantified at this stage. Because of this, in this time period before injection starts, either a full probabilistic hazard analysis or a pseudo-probabilistic hazard assessment could be appropriate (Cornell, 1968; Edwards et al., 2021). It would only be during this relatively brief time period, and only if an appropriate range of possible earthquake recurrence models could not be identified, where a pseudo-probabilistic hazard assessment using scenario events would be acceptable. After collection of sufficient post-injection data only a PSHF would be appropriate.

The PSHF will necessarily need to be systematically checked, updated, and predictions continuously calibrated against new observations. A new risk analysis (Step 6) will most likely be necessary as well if the PSHF significantly changes. This may change the ROC as well and new data and models become available. To ensure consistency between the PSHF and the PSHA, those performing the two analyses should either be the same entity, or they should be in frequent communication.

5.3.2.2 PSHF Inputs

Similar to the long-term approach, information from three general input categories are required for the PSHF. They are: a) earthquake source locations and geometry; b) spatial, temporal, and recurrence (frequency-magnitude) models for each of the earthquake sources; and c) site and scale-appropriate earthquake GMMs with adjustments for local site conditions.

(a) Earthquake sources, both natural and induced, that could constitute a ground motion hazard to the local communities or operation infrastructure should be identified and input into the PSHF. Both fault-specific sources and areal sources should be identified, similar to the procedure for the long-term approach.

Differences from the PSHA analysis arise in that slip on faults and fractures may be induced by the injection program due to changes in the in-situ normal stress field from pore pressure changes, and changes in normal and shear stress from poroelastic stressing and mass loading. Characterization of the local and regional stress field is therefore necessary to identify which features are more likely to be triggered. The characterization of the stress field can be estimated from in situ stress measurements (e.g., hydraulic fracturing, borehole breakouts, and core-induced fractures), and is also needed for other aspects of the project development. Characterization of the strain rate near faults may also be useful (Hussain et al., 2018). Earthquake focal mechanisms can provide information on the principal stress directions and their relative, but not absolute, magnitudes. With knowledge of the in-situ stress field, a Mohr-Coulomb stress analysis can be performed to assess the critical stress required to trigger slip on favorably oriented

faults and compare that to the expected stress changes due to the fluid injection program in order to identify potential induced earthquake sources (e.g., Walsh and Zoback, 2016). However, it must be noted that the distributions of stress and material properties at the reservoir scale can be highly heterogeneous and are generally poorly constrained. Therefore, uncertainties remain about the potential to reactivate an individual identified source.

(b) Spatial, temporal, and earthquake recurrence models for induced seismicity are conceptually similar to the those used in conventional PSHA but must consider differences between natural and induced seismicity in occurrence characteristics (Petersen et al., 2016). Temporal models, for example, must consider expanding beyond the conventional stationary Poissonian model to consider earthquake occurrence that varies in space and time, which means that the short-term hazard due to injection is inherently non-stationary. The construction of these models is an area of active research.

Developing an occurrence model for induced seismicity is the most challenging task in assessing the hazard. Induced seismicity results from the interaction between the fluid injection parameters and the in situ lithologic, structural, hydrologic, and thermal conditions. These are challenging characteristics to evaluate because of the difficulty in imaging the subsurface and its inherent heterogeneity. Earthquake occurrence models for induced seismicity can be based on statistical, physics-based, or hybrid approaches, all of which use different input and calibration data (e.g., Dieterich et al., 2015; van der Elst et al., 2016; Broccardo et al., 2017). Some approaches were reviewed by Gaucher et al. (2015). Recently, the approaches that include physical models have gained more attention since they can integrate more site-specific hydromechanical information into the seismic hazard analyses (Langenbruch et al., 2018; Norbeck and Rubinstein, 2018; Zhai and Shirzaei, 2018; Dempsey and Riffault, 2019; Grigoratos et al., 2020a, 2020b) and appear to more accurately forecast the hazard than observational models alone (Rubinstein et al., 2021).

Determining the range of anticipated minimum and maximum magnitude events that may be of concern is more difficult for sources of induced earthquake. The minimum magnitude considered in typical PSHAs for engineering design is often in the range of M_w 4.5–5.0, since empirical data indicate that smaller events seldom cause structural damage. However, since induced events are typically shallower, smaller magnitude events will most likely also be of concern (Bommer et al., 2006), not least because events as small as about M_w2 can contribute to the nuisance risk and also to cosmetic damage. When conducting the natural and induced seismic hazard assessments, it is recommended to use the induced seismicity minimum magnitude threshold, or something very close to it, for both analyses, assuming it to be the lower threshold. For maximum magnitude estimates, an evaluation of the sizes, nature and spatial distribution of pre-existing fractures and faults, the local stress field in the volume of rock surrounding the injection wells, and the estimated characteristics of the pore pressure and poroelastic fields due to injection need to be considered. Alternatively, various simple empirical relationships have also been developed to estimate the maximum magnitude of an induced earthquake based on, for example, the inferred dimensions of the stimulated volume, total injected fluid volume, or on probabilistic approaches based on the seismic activity rates (McGarr, 2014; Shapiro et al., 2011; Yeck et al., 2015). However, these proposed relationships

generally do not take into consideration tectonically influenced, yet anthropogenically induced, ruptures on critically stressed faults that extend beyond the perturbed pressure and stress volume (van der Elst et al., 2016; Galis et al., 2017; Norbeck and Horne, 2018). When conducting the natural and induced seismic hazard assessments, the maximum magnitude threshold value could be the same or independent from each other.

(c) Site-appropriate earthquake GMMs, similar to those used in conventional PSHA, should specify the estimated ground shaking at a particular site as a function of (at a minimum) the magnitude and distance (e.g., Novakovic et al., 2018). Additional considerations for induced seismicity sources include the fact that injection-induced earthquakes are often more shallow than typical natural tectonic events, which increases the level of ground shaking for comparable sized events. The majority of the existing GMMs however, were created assuming tectonic sources and as such may not be well suited for induced seismicity. Significant work has been done to incorporate induced seismic sources in GMMs and it is essential that this work is included in the PSHF (e.g., Douglas et al., 2013; Atkinson, 2015; Bommer et al., 2017; Cremen et al., 2020). Additionally, to ensure consistency between the natural and induced seismic hazard analyses, the GMMs should be the same between the two. Recognizing that this could be quite difficult, it may therefore be necessary to use different GMMs in the two cases, but to verify that for common magnitudes and depths, they yield comparable predictions.

5.3.2.3 PSHF Results

Primary results of the PSHF include seismic ground motion hazard curves that show the estimated probability of exceedance per unit time (typically annually) on the vertical axis and different levels of the selected ground motion parameter on the horizontal axis for a particular location. For the short-term approach, ground motion parameters suggested for the presentation of PSHF results are PGA, PGV, SA or pseudo-spectral velocity, and perhaps modified Mercalli intensity scale (derived from PGA or PGV) (Rutqvist et al., 2014; Petersen et al., 2016; Petersen et al., 2018).

As with PSHA, estimates of uncertainty can be captured on the hazard curves. One-year hazard models produced by the USGS of the CEUS report only the mean hazard curve due to the complexity of the methodology. Uncertainties can be captured however using, for example, a bootstrapping approach to quantify the variability in the short term estimated hazard curves, or a logic tree approach (Mousavi et al., 2018; Petersen et al., 2016). Regardless, when plotting the seismic hazard curves, the rationale behind the input choices and a description of the range of technically defensible interpretations should be included with the results.

PSHF result maps could show the various earthquake ground-shaking levels with a fixed probability of exceedance over a specified time period. Alternative measures of ground shaking intensity include Modified Mercalli Intensity (MMI), PGV, a time history of motion, or the duration of strong shaking. One important value to define a priori would be the lowest annual frequency of exceedance for which ground motions of interest should be evaluated, again recognizing that this minimum value should be common between the natural and induced seismic hazard analyses.

5.3.2.4 Short-Term Seismic Hazard Analysis Report

The site-specific short-term seismic hazard report should contain sufficient information to allow the regulatory agency's technical reviewer(s) to satisfactorily evaluate the potential for short-term seismic ground shaking hazards.

The PSHF report should follow the same guidelines as the PSHA report outlined above. The PSHF report should be similar in structure to the PSHA report, with the only significant difference being the inclusion of details associated with the anticipated injection program. If a pseudo-probabilistic hazard assessment was opted for prior to injection, the pre-injection report should follow a similar format to the PSHA report, where appropriate.

5.3.2.5 Short-Term Seismic Hazard Analysis Review

The technical review by the appropriate regulatory agency is a critical part of the evaluation process. The regulatory reviewer ensures compliance with existing laws and current standards of practice to protect both government and community interests. The reviewer should be familiar with the investigative methods employed and the techniques available to perform the analysis, however it would be appropriate for reviewers to ask for the opinion of others more qualified in specialty fields. Reviews should be based on logical and defensible criteria. Guidelines for the report and any supplementary material should be made available to applicants beforehand. This information should cover procedures, report formats, and levels of appropriate investigative detail that will expedite the review and approval of the project (CGS, 2008).

5.3.2.6 Short-Term Seismic Hazard Analysis Updates

Site-specific PSHF reports to the regulatory agency should be updated annually or more frequently if future geological, seismological, or geophysical investigations reveal significantly new and different information than that used in the original PSHF, or if the observed induced seismicity is significantly different from initial expectations of induced seismicity. If prior to injection a pseudo-probabilistic hazard assessment was conducted instead of a PSHF, a PSHF report should be delivered to the regulatory agency 1-year after injection start.

6. STEP 6: RISK-INFORMED DECISION ANALYSIS

6.1 PURPOSE

The purpose of this step is to add elements to the project plan that are based on rigorous and credible estimates of the seismic risk associated with the design, operation, and closure of a carbon storage project. This will include identification and quantification of the seismic risks, an evaluation of their acceptability by stakeholders, and a final determination as to the most favorable options. Ground shaking due to geologic carbon storage operations may impact the quality of people's lives, the built environment, and the economy in several ways, therefore, the risk needs to be evaluated. The risk analysis will need to be time-dependent to account for the expected time varying stress conditions in and around the reservoir due to the sequestered CO_2. Conceptually, this step is similar to the preliminary seismic risk assessment in Step 1; however, instead of aiming for an order of magnitude assessment, a more precise estimate of risk is required. Once the seismic risks have been evaluated, associated risks, such as brine or CO_2 contamination of underground drinking water sources, can be subsequently determined. Results from the risk informed decision analysis described here will be tightly coupled with the risk management framework described in Step 7.

6.2 RECOMMENDED PRACTICES

6.2.1 Seismic Risk from Natural Seismicity

6.2.1.1 A site-specific seismic risk analysis should be conducted to determine the baseline risk from natural tectonic seismicity. This assessment should include, but should not be limited to, the following:

a) Incorporation of seismic hazard results from natural tectonic seismicity
b) Identification of assets and activities that could be adversely affected by natural tectonic seismic activity within the ROC
c) Characterization of the vulnerability of the assets and activities to the natural tectonic seismic hazard within the ROC
d) Quantification of the seismic risk due to natural tectonic seismicity. At a minimum this should include a mean or median estimate in addition to confidence intervals on expected annual losses due to seismic activity

6.2.2 Seismic Risk from Induced Seismicity

6.2.2.1 A site-specific seismic risk analysis should be conducted to determine the risk from induced seismic events. This assessment should include, but should not be limited to, the following:

a) Incorporation of seismic hazard results from induced seismicity (Step 5.2)
b) Identification of assets and activities that could be adversely affected by induced seismic activity within the ROC
c) Characterization of the vulnerability, including nuisance vulnerability of the assets, activities, and local communities, to the induced seismic hazard within the ROC

d) Quantification of the seismic risk due to induced seismicity. At a minimum this should include a mean or median estimate in addition to confidence intervals on expected annual losses due to seismic activity

6.2.3 Risk Informed Decision Analysis

6.2.3.1 Evaluate and compare site-specific seismic risks and make risk-informed decisions concerning the project plan based on the risk-tolerance of the affected stakeholders.

6.3 SUPPORTING INFORMATION

6.3.1 Seismic Risk from Natural Seismicity

Seismic risk is calculated from three main contributing factors: (1) the seismic hazard at locations within the ROC; (2) the collection of exposed assets, activities, and communities at those locations; and (3) their vulnerability to the hazard (McGuire, 2004). As an example of the interplay between these three factors, consider a location next to an active earthquake fault which has a high potential for damaging ground shaking (high seismic hazard), but which has only one untenanted building located within the ROC (low exposure) that has been seismically retrofitted to withstand the anticipated maximum magnitude event (low vulnerability). In this case, it could be determined that the overall seismic risk in that particular location would be low.

Seismic risks from natural tectonic earthquakes in particular describe the harm or loss that would be likely due to exposure to natural seismic hazards. These risks can be measured in a number of ways, including direct economic losses (dollar loss due to the repair and replacement costs of physical assets), indirect economic losses (losses due to interruptions to the supply chain), downtime, and the potential number of injuries and fatalities (FEMA, 1989, 2013).

Calculating the risk due to natural seismicity will allow for a quantitative comparison between the accepted natural seismicity risks and the potential additional induced seismicity risks associated with the project. The calculated risks also enable an a priori risk-cost-benefit analysis for the considered operation.

(a) Incorporation of Seismic Hazard Results from Natural Tectonic Seismicity

One of the three major inputs into the seismic risk analysis are the hazard curves for natural seismicity generated from the PSHA conducted in Step 5.1. For the seismic risk analysis, it should be noted that since the risk depends strongly on the anticipated ground shaking that can occur, just using the median hazard often leads to an underestimation of the risk and so the mean hazard curve should be used instead (McGuire et al., 2005; Muntendam-Bos et al., 2015). Additionally, hazard curves from a scenario-based approach using Monte Carlo analysis will be needed to create a stochastic catalogue of events

(b) Identify Assets and Activities that could be Adversely Affected by Tectonic Seismicity

Assets and activities within the ROC that could be adversely affected by exposure to natural tectonic seismicity should be identified. Some of these assets and activities may be relatively straightforward to include, such as the number of potentially affected people and structures (e.g., residential housing, community facilities, government facilities, schools, historical buildings, religious facilities, critical infrastructure, commercial facilities, industrial facilities, medical facilities, essential facilities, transportation lifelines, utilities, potentially hazardous facilities, the

GCS injection infrastructure, etc.) (NRC, 1989). There are publicly available general building stock databases and well-accepted direct and indirect methods to supplement general database information (Anagnos et al., 2012). General building information should include the geographic location, construction classification, the category of seismic resistance, the economic value of the building, the number of occupants, and the type of occupancy of the building (FEMA, 1989). Buildings and structures of the same type may be grouped together for analysis and reporting purposes in larger studies (FEMA, 1989). It may also be useful to assess the pre-existing conditions of certain highly vulnerable properties or to consider an incentive program whereby local residents can perform a self-assessment of their property before operations start so as to obtain a more accurate determination of any pre-existing conditions.

The socioeconomic impact from damaged infrastructure and business operation interference can also be included using standard tools (FEMA, 2018). Social, economic, and personal well-being rely heavily on the reliability of complex and often interconnected utility networks (e.g., telephone, internet, water, gas, electricity, public transportation systems, etc.) that are vital to both business and personal needs. Any damage leading to operational malfunctions (e.g., internet service becoming unavailable) can create interruptions that should be included in the risk analysis. These types of losses should include, but are not limited to, 1) the loss of the utilities themselves, 2) business interruptions caused by the loss of the basic utilities, and 3) business interruptions due to a lack of supplies.

The determination of the ROC when identifying these assets and activities should be based on a maximum acceptable level of expected surface ground motions. In projects where there are residents within the assessment area, the choice of a ground motion threshold could be based on the ground shaking level associated with human perception (Step 3) (Bommer et al., 2006; Caltrans, 2020; Schultz et al., 2021b). A site-specific computer simulation of expected levels of ground shaking due to hypothetical events could therefore help delineate the ROC.

(c) Vulnerability Potential of the Assets and Activities to the Seismic Hazard

The vulnerability of the identified assets and activities within a particular site to the seismic hazard should be quantified through a vulnerability assessment of the area. The most appropriate relationships correlating ground shaking intensity, resulting damage, and associated losses (e.g., economic losses, downtime, injuries, fatalities, etc.) at the site will need to be chosen for input into the seismic risk assessment. The evaluation of the anticipated losses as a function of ground motion intensity can be achieved either directly by using vulnerability functions or indirectly through the use of fragility functions (Rossetto et al., 2015; Silva et al., 2013, Porter, 2020). Vulnerability functions directly relate ground motion intensity to anticipated losses (Figure 2). Fragility functions, on the other hand, relate ground motion intensity to the probability of damage and are often expressed as either loss ratio curves, damage probability matrices, or fragility curves (Figure 3). Therefore, when using fragility functions, appropriate damage-to-loss functions are also needed to link the anticipated losses with ground shaking intensities (FEMA, 1989). Additionally, in the literature, these vulnerability and fragility functions are often also referred to as curves, and it is worth noting that more research has been conducted on fragility functions than on vulnerability functions.

The vulnerability of standard construction is a long-documented field and there are many tools publicly available. Standard vulnerability models applicable to natural tectonic earthquakes are included in publicly available software packages for seismic loss estimation, such as Hazus

(FEMA, 2013). Commercially available seismic risk analysis codes may provide more detailed vulnerability assessment information. Additionally, databases of vulnerability and fragility functions for economic losses, downtime, and casualties associated with natural tectonic earthquakes are publicly available (Rossetto et al., 2015; Yepes-Estrada et al., 2016; Martins and Silva, 2020). Lastly, when accounting for property losses, either replacement costs or market value can be used in the calculations, with the choice clearly stated.

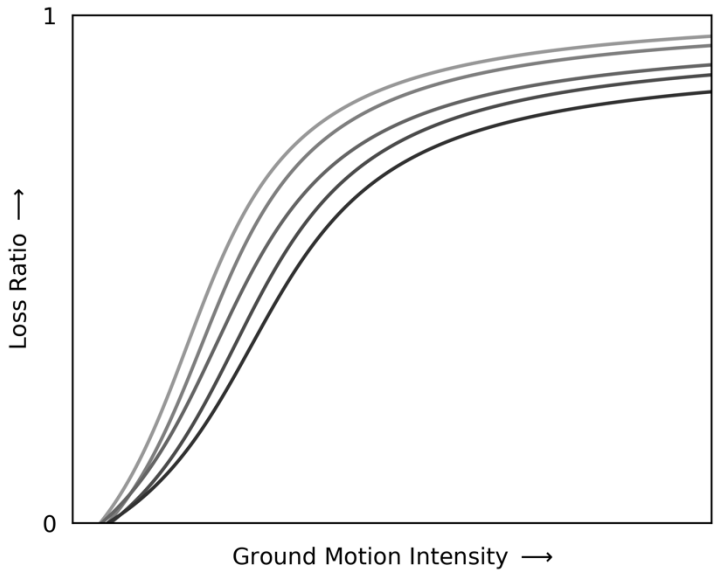


Figure 2: Example seismic vulnerability functions specifying the loss ratio (i.e., anticipated repair costs normalized by the replacement value) of various assets or asset classes, illustrated as individual grey lines, as a function of increasing ground motion intensity (e.g., PGA, spectral acceleration, etc.) A loss ratio of 1 would indicate that the repair of an asset would equal the replacement cost.

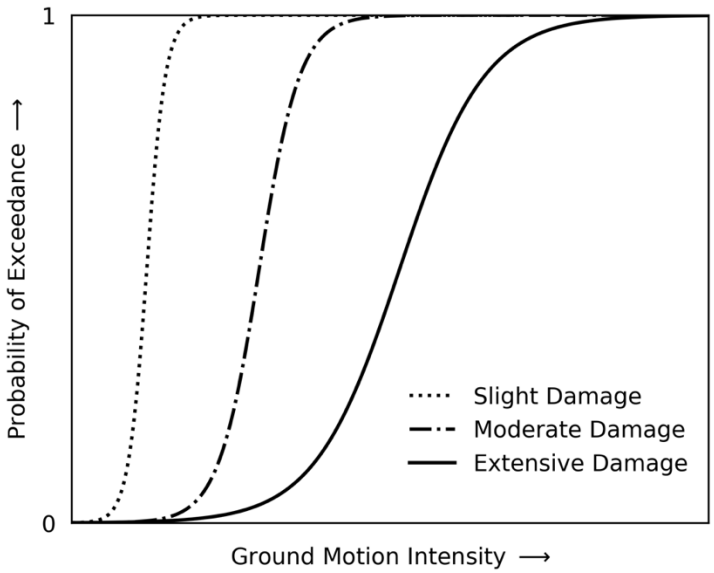


Figure 3: Example seismic fragility functions representing the probability of exceeding a given damage state (e.g., slight damage, moderate damage, extensive damage, etc.) as a function of increasing ground motion intensity (e.g., PGA, spectral acceleration, etc.) A probability of exceedance of 1 would indicate that the damage state is expected to happen at that ground motion intensity.

(d) Quantification of Seismic Risk Due to Natural Tectonic Seismicity

Regional or global seismic risk models, such as the GEM (Silva et al., 2020), can be used to gain a broad understanding about the risk of natural seismicity in the area; however, a site-specific seismic risk assessment due to natural seismicity should also be conducted. Seismic risk analysis can provide results in a variety of forms (Jonkman et al., 2003). These can include the mean annualized loss (the mean annual frequency with which the loss in question occurs), the mean annual number of damaged buildings, the probability that at least a certain level of loss will be exceeded during a specific period of time, the probable maximum loss, the local personal risk metric (e.g., the annual probability of fatality for a hypothetical person who is continuously present inside a building), and many others. Some of these results can only be obtained using a stochastic catalogue of events generated from the seismic hazard model (e.g., Van Elk et al., 2019). Results can be provided as individual risk curves or as maps that show results for each type of loss of concern for the region of concern.

There are a variety of seismic risk assessment software packages available to assess seismic risk due to natural tectonic seismicity. Some are open and freely available (FEMA, 2013; Lang et al., 2007; Porter and Scawthorn, 2007; Trendafiloski et al., 2009; Pagani et al., 2014; Silva et al., 2014; Silva et al., 2018), while others are provided by commercial risk management companies that can also perform the analysis for a fee.

6.3.2 Seismic Risk from Induced Seismicity

The induced seismicity seismic risk analysis will facilitate sound and efficient decision making relating to induced seismicity. Seismic risk assessment methodologies applied to a site in the design phase, for example, can highlight unacceptable potential future damages due to a

particular proposed well location, injection plan, etc. Therefore, prior to operations, plans can be modified and the risk iteratively re-assessed so as to come to a risk level acceptable to stakeholders (Silva et al., 2021).

Previously, much of the research into, and applications of, induced seismic risk had focused on the impact of lower-probability, higher-impact moderate-to-large earthquakes (Grigoratos et al., 2021). Moving forward, injection-induced seismicity risk is beginning to more frequently incorporate smaller magnitude earthquakes which may cause significant nuisance to the local population, but only relatively minor physical damage to structures (van Elk et al., 2019; Edwards et al., 2021).

Although the fundamentals of risk estimation do not change for small ground motion events, the models used in the characterization of these risks will need to be calibrated for the lower amplitudes of ground shaking and shorter distances often associated with induced seismic events. For example, physical damage to structures will have to account for the appearance of small cracks and other minor architectural damage in addition to more severe structural damages. Also, human perception of low amplitude ground shaking, and the associated nuisance need to be considered as elements of the risk. The nuisance produced by small vibrations will depend not only on the amplitude and dominant frequency of the ground shaking, but also on how often the events occur.

The induced seismicity risk assessment will also need to include a time-dependent component governed by the time dependent nature of the induced seismic hazard. The risk will often change due to operational changes at the site, changes in the exposure within the ROC (e.g., population changes, new building creation, or structural strengthening of existing buildings), changes in the tolerance of risk at the site, or with the addition of new information (van Elk et al., 2019). Additionally, the hazard and risk analysis should be revisited periodically during the operational period of the project and after site closure, especially if observed seismicity differs significantly from the expected location or rate. Additionally, since forecasting the vigor of a site's seismogenic response prior to the start of injection is difficult, there should be a dedicated effort at the beginning of injection to evaluate and model the seismogenic response based on the observations in near real-time, which will inform and help refine the initial hazard and risk analyses (Wiemer et al., 2017). After the early evaluation period, the probabilistic seismic risk assessment should also be periodically updated as new data arrives.

Specific plans should be made for the involvement of key stakeholders throughout the study. Additionally, experts unaffiliated with those conducting the risk analysis should provide periodic independent guidance and review over the course of the study that should address its goals, the seismic hazard analysis, the asset and activity inventory-defining process, the vulnerability functions, and the final results. This will increase confidence in the results of the study and conform to generally accepted validation procedures (FEMA, 1989).

(a) Incorporation of Induced Seismic Hazard Results

Induced seismicity hazard curves generated from the PSHF conducted in Step 5.2 will be the primary input into the induced seismicity risk analysis. Hazard curves for multiple seismic hazard forecasts based on varying injection operational scenarios should be included to create alternative estimates of seismic risk to inform project planning (e.g., different injection well locations, differing fluid flow path lithologies, modifications to injection pressure and volumes, etc.).

(b) Identification of Assets and Activities Adversely Affected by Seismicity within the ROC

Similar as for the tectonic seismicity, assets and activities within the ROC that could be adversely impacted by exposure to induced seismicity should be identified and a pre-assessment performed to the degree feasible. In addition to the negative impacts considered in relation to natural seismicity, impacts resulting from lower magnitude induced events, such as interference in human activity (e.g., sleep disturbance, creaking walls, enjoyment of recreation or entertainment, etc.), minor cosmetic damage, or psychological effects (e.g., anxiety due to the frequent occurrence of felt earthquakes), must also be included. The definition of the ROC could be based on a maximum acceptable level of expected surface ground motions associated with these lesser impacts.

(c) Characterization of the Vulnerability of the Assets and Activities to the Seismic Hazard

Development of fragility and vulnerability functions in general deal primarily with damage and losses (e.g., economic losses, downtime, injuries, fatalities, etc.) resulting from medium-to-large earthquakes. Vulnerability functions specific to the site and other nearby locations will need to be developed, and in particular need to include the impacts from relatively low levels of ground shaking outlined above.

The interference with human activities should also include nuisance, which refers to the annoyance that is created by low-level ground shaking that does not necessarily generate physical damage on the built and natural environment but can be felt by humans. Repeated vibration or noise, even of very small amplitude, can negatively impact people's way of life and well-being. This type of impact is difficult to quantify and there is as yet no well-established methodology to do so for induced seismicity. At present, following practices from other fields is recommended such as mining, geothermal energy production, or transportation. This would include using ground motion or noise criteria determined in Step 3 to be used in the formulation of vulnerability functions. An estimate of the annual probability of the number or percentage of people mildly, normally, or severely inconvenienced by the induced seismicity would be ideal.

(d) Quantification of Seismic Risk Due to Induced Seismicity

The seismic risk analysis can provide results in a variety of forms to address the different aspects of risk that are of importance to the various stakeholders. The choice of which risk metrics to focus on will also determine which aspects of the hazard and risk assessment should receive additional consideration (Bommer et al., 2015). The assessment of seismic risk due to induced seismicity should be site specific and adaptable in the case of new information. It will depend on the calculated seismic hazard, including the influence of operational factors (e.g., different injection programs, different injection formations, etc.), on the number and nature of exposed assets and activities that may be impacted, and on the determination of their level of vulnerability to the hazard. The risk analysis and resulting risk metrics should be similar in form to the tectonic seismicity for ease of comparison.

The seismic risk assessment will need to include hazards from both large and small seismic events. Seismic risk assessment methodologies and software have largely been developed assuming only larger tectonic events are the events of concern. Subsequently however, seismic risk assessments due to induced seismicity have started including the risks associated with smaller events as well. Additionally, a probabilistic seismic risk analysis, using time-dependent induced seismicity forecast models and a logic tree approach will permit epistemic uncertainties

in the induced seismicity risk assessment to be incorporated in a more cohesive manner (Mignan et al., 2015).

6.3.3 Risk Informed Decision Analysis

The evaluation of the seismic risk due to induced seismicity is expected to depend significantly upon the project plan and would be expected to be updated as more information becomes available during the lifetime of the project. Therefore, determination of the project plan specifics should occur in conjunction with the risk assessment. This risk informed planning can help with decisions such as evaluating wellbore placement and operational injection plans. Using the site-specific seismic risk analysis, risk-informed decisions for the project plan based on the risk-tolerance of the affected stakeholders can be made. Effort should be made to appropriately communicate the uncertainty present in the risk assessment to stakeholders and decision makers. Risk-tolerance matrices are one method that can balance the level of risk tolerance of stakeholders with the expected benefits of the project (Walters et al., 2015). Risk-tolerance matrices allow for an estimation of the intersection between the anticipated risks and stakeholder tolerance for those risks.

Documentation should include the data used to inform the risk analysis, how the data were analyzed to determine risk, the results of the risk analysis (including uncertainties), and how management decisions will be determined based on the results of the risk analysis. This should include the types of losses considered, how the extent of the ROC was determined, the kinds of structures and facilities included in the analysis, a description of the vulnerability of sites within the ROC to the natural and induced seismic hazards in terms of impacts on the assets and activities, and a description of the sources of uncertainties in the analysis. The hazard and risk analyses should be presented in similar terms (e.g., PGA, PGV, etc.). Results can be presented as an estimate of the total loss expected annually (monetary, downtime, annoyance, injuries, casualties, etc.), losses expected as a function of time from the start of operation (with uncertainty ranges), and as a geographic map showing the spatial distribution of expected value losses in the region as a function of time and for several annual probabilities of exceedance. Variations of these results should be included when discussing different project plan options being considered.

7. STEP 7: OPERATIONAL MANAGEMENT OF INDUCED SEISMICITY RISKS

7.1 PURPOSE

The purpose of this step is to create and implement a site-specific, real-time plan to monitor, assess, control, and mitigate the risks associated with induced seismicity during and after fluid injection. The framework of the risk-based mitigation plan should be based on a traffic light system (TLS), which can provide clear and direct actions to take in response to given situations according to pre-determined criteria. The plan should be in place before injection operations commence and before any level of induced seismicity may be observed. This risk-based mitigation plan for induced seismicity is expected to be one component of a more comprehensive risk management plan covering the entire project.

7.2 RECOMMENDED PRACTICES

7.2.1 Induced Seismicity Mitigation Plan

7.2.1.1 The operator should create a site-specific induced seismicity mitigation plan based on a TLS framework. The TLS framework should include, but should not be limited to:

a) At least three response levels, indicating operation as usual (green), heightened awareness and reassessing and modifying as appropriate of injection operations (yellow), and stopping injection (red)
b) Clear threshold level criteria defining when an increase in response level is necessary
c) A clear description of mandatory and optional actions and procedures at each of the response levels
d) A description of the conditions, actions, and procedures necessary to reduce the response level to a lower level
e) Adequate near real-time data input from the seismic monitoring network

7.2.1.2 The induced seismicity mitigation plan should be operational throughout the active operation of the site and through the end of the seismic PISC period.

7.2.1.3 The induced seismicity mitigation plan should be endorsed by the Expert Panel and approved by the regulatory agency.

7.2.1.4 A reduction in the response level should occur when recommended by the Expert Panel and approved by the regulatory agency.

7.2.2 Expert Panel

7.2.2.1 An Expert Panel should be created whose purpose is to provide evidence-based information and recommendations pertaining to the induced seismicity risk posed by the project.

7.2.2.2 The Expert Panel should be comprised of representatives from the operator, local stakeholders, the regulatory agency, and appropriate independent subject matter experts. The chairperson should be selected from the independent subject matter experts.

7.2.2.3 Should there be other active or planned projects involving fluid injection that jointly contribute to a composite PSZ, representatives of the respective operators should be additional

members on the Expert Panel. The regulatory agency should approve the members and the chairperson of the Expert Panel.

7.2.2.4 The Expert Panel should convene at least annually to independently review past seismic activity, the appropriateness of the seismic monitoring network and operation, updated hazard and risk assessments, and the current induced seismicity mitigation plan. The operator should supply the Expert Panel with all reports and information necessary to perform the review.

7.2.3 Early Evaluation Period

7.2.3.1 The first year of injection operations should be considered an Early Evaluation Period.

7.2.3.2 The Expert Panel should convene at least weekly during the first month of the Early Evaluation Period and at least monthly during the following 5 months of the Early Evaluation Period to review the seismogenic and hydraulic site response and to verify the continued appropriateness of the induced seismicity mitigation plan, including the hazard and risk assessments originally performed in Steps 5 and 6 prior to injection operations.

7.2.3.3 Reduction of the review schedule during the Early Evaluation Period after the first 6 months should be approved by the regulatory agency.

7.2.3.4 Injection operations should ramp up gradually during the Early Evaluation Period and the Expert Panel may recommend to the regulatory agency that injection activities be slowed or halted if warranted.

7.2.4 Seismic PISC

7.2.4.1 The default duration of the seismic PISC should be the duration of the regular PISC after the end of injection operations.

7.2.4.2 The Expert Panel should make a recommendation whether or not to modify the seismic PISC period, considering the seismic response of the site during and after active injection.

a) The regulatory agency may approve a reduced, or require an increase in, the duration of the seismic PISC.

b) The seismic PISC period should not end before pressure and stress perturbations in and surrounding the reservoir have stabilized and observed seismicity approaches tectonic baseline levels.

7.2.5 Liability and Insurance

7.2.5.1 The operator should be insured against potential damages associated with induced seismicity or demonstrate sufficient assets to self-insure for potential damage outlays consistent with the estimated seismic risk.

7.2.5.2 Levels of insurance coverage should be set based on the estimated induced seismicity risk and should be re-evaluated annually.

7.2.5.3 Liability for the consequences of induced seismic events should be shared among operators whose estimated PSZ extends to the epicenter of a damaging or felt event.

7.3 SUPPORTING INFORMATION

7.3.1 Induced Seismicity Mitigation Plan

An Induced Seismicity Mitigation Plan should be in place before any injection operations begin. The framework of the plan should be based on a TLS protocol. A TLS, as defined here, is a risk management tool which serves several purposes: it communicates the status of the project; it specifies predefined actions that should occur in order to attempt to prevent large magnitude induced events, and it prompts the operator to consider changes to the operations if a concerning trend of seismic activity has been observed. The TLS status should be made easily available to both the operators and the public. A TLS will typically have three or more response levels, corresponding at a minimum to: a continuation of operations as planned (green), heightened awareness and revisiting of injection operations due to concerning observed seismicity or trends (yellow), and stopping of injection due to an unacceptable level of induced seismicity (red). In a TLS, the status of a project is continuously evaluated with the goal of avoiding induced seismicity that could endanger the local population or damage infrastructure (NRC, 2012a). For example, during the Basel EGS project, their yellow level was triggered due to a medium size seismic event, which caused them to reduce their injection rate. Ongoing seismic activity increased the level to red, which lead to a cessation of the injection program. However, unfortunately, a magnitude M_w3.4 could not be prevented with the TLS (Haering et al., 2008).

A traditional TLS, such as that used in the Basel EGS project, typically defines the actions to be taken solely in response to the occurrence of certain observed criteria (e.g., the occurrence of a seismic event above a certain magnitude or a level of surface ground shaking above a certain threshold). A major shortcoming of traditional TLSs is that they are not forward-looking and do not provide a forecast of future seismic activity. Adaptive traffic light systems (ATLS) and physics-based forecasting methods, however, can help to inform operation decisions, such that elevated risk levels might not be reached in the first place (Figure 4).

An ATLS is fully probabilistic, incorporates new data on the fly (automatically as much as possible) to update geomechanical and seismicity forecasting models, and integrates hazard, exposure, and vulnerability into the automatic system (Wiemer et al., 2014; Mignan et al., 2017; Langenbruch et al., 2020). In this way the hazard and risk calculations originally produced in Steps 5 and 6 can be automatically updated as new data and models become available. An ATLS incorporates not only the past observations of seismicity but produces projections of seismicity rates based on the actual or projected injection and production rates in a reservoir (e.g., Bachmann et al., 2011). Although the deployment of an ATLS is currently an active research topic, operators are encouraged to implement the most up-to-date system with a site-specific forecasting method that is adapted to the local conditions. This would allow for a more proactive management approach to induced seismicity compared to the reactive approach in traditional TLS. Additionally, an ATLS could potentially be used to optimize operations in addition to minimizing seismicity by providing forecasts based on different injection scenarios.

In both TLSs and ATLSs, the threshold criteria determining when an increase in response level is necessary should be defined such that they allow effective intervention to prevent the traffic light from reaching the highest response level requiring a full stop of the operation (Kao et al., 2018). Threshold criteria that could be added to a site-specific plan include: a basic magnitude threshold criteria; a peak ground velocity threshold (such as those determined in Step 3) (Bommer et al., 2006); the identification of a concerning seismic trend (such as observed seismicity delineating a

potential fault capable of producing an event of concern) (Lee et al., 2019); a comparison with magnitude exceedance probabilities (van der Elst et al., 2016; Shapiro et al., 2010; Langenbruch et al., 2016); a comparison with calculated seismic risk criteria (Douglas and Aochi, 2014; Mignan et al., 2015); a comparison to economic loss criteria (Langenbruch et al., 2020); or public response (Wiemer et al., 2017).

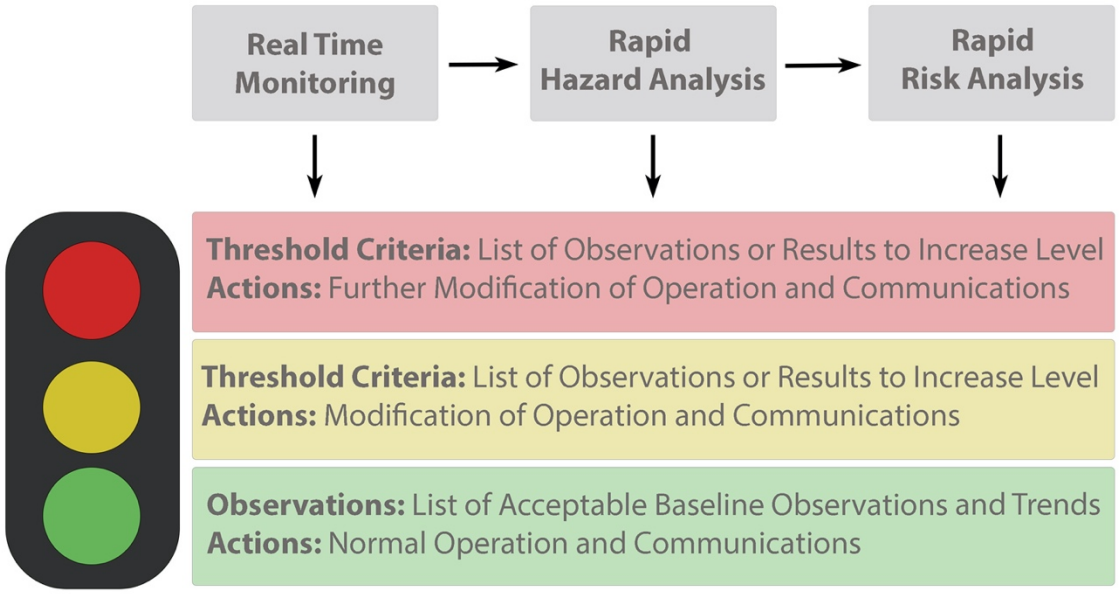


Figure 4: Example adaptive traffic light system. Real time seismic, hydraulic, and operational monitoring can either directly increase the response level or indirectly help inform rapid hazard and risk analyses which may prompt a change in response level due to updated results.

When selecting the threshold criteria, two points need to be considered: (1) the magnitude-frequency relationship of earthquakes (Gutenberg and Richter, 1944); and (2) the temporal delay between changes in injection operations and the response of seismic activity. Regarding the first point, it has been observed that for every tectonic earthquake of a given magnitude occurring in a volume of the Earth's crust about 10 times as many earthquakes one magnitude unit smaller are expected to be observed. For example, for every 100 M_w1 earthquakes, on average 10 M_w2 earthquakes and one M_w3 earthquake are expected to be observed. This behavior is embodied by the Gutenberg and Richter (1944) relationship with a b value approximately equal to 1. This empirical rule generally holds for induced seismicity as well, although the precise relationship may vary from site to site and can vary during the injection cycles (e.g., Bachmann et al., 2012; Martínez-Garzón et al., 2014,). If using magnitude thresholds, Schultz et al. (2020) argue that the yellow light threshold should be set 2 magnitude units below the red light. Using this criterion and assuming a Gutenberg-Richter b value of 1, 99% of the cases would be expected to present an opportunity to initiate mitigation measures to avoid the highest response state and in only 1% of the cases would the traffic light be expected to jump from green to red, skipping the yellow level. Additionally, b values greater than 1 at a site, as found in some EGS co-injection and post-injection settings (Bachmann et al., 2012), would be expected to lead to even fewer cases of jumping directly from green to red. Recent research has also focused on risk-based approaches

for choosing appropriate red-light thresholds at certain types of fluid injection sites (Schultz et al., 2021a).

Regarding the second point and particularly for typical GCS long-term injections, the pressure plume potentially causing seismicity may reach many kilometers or tens of kilometers away from the injection point (Goebel et al., 2017; Peterie et al., 2018). While the pressure around the injection well may fall rapidly in response to reductions of the injection rate, it may continue to rise further away, where earthquakes may continue to be induced by small pressure perturbations. It may be months or longer for changes in the injection operations to take effect, especially if seismicity has already been observed far away from the injection point. It has been observed in several injection projects that the largest events occurred after injection ceased, which can be explained in part by the continuing propagation of pressure plumes and delayed aftershocks (Dieterich et al., 2015). Event triggering by poroelastic stress changes rather than directly by elevated pore pressure is subject to the same temporal behavior as described above. In addition, aftershock sequences may produce seismicity several years after their mainshock.

At the normal "green" TLS operating state, routine operation of the real-time monitoring system should also include more detailed analysis of potential pre-monitory seismicity. These detailed analyses should include enhanced event detection (e.g., through template matching) (Skoumal et al., 2014; Chamberlain et al., 2018; Templeton et al., 2020), precise relative relocation (Waldhauser and Ellsworth, 2000; Trugman and Shearer, 2017), and focal mechanism analyses to identify fault planes. Additionally, seismological signatures indicating the possibility of fault rupture may also be visible in the data, as it was for example in the Pohang EGS case (Ellsworth et al., 2019). At this early stage, potentially concerning trends such as an injection pressure increase (even if it is still within normal ranges), incremental increases in induced earthquake magnitudes that are still below the threshold level, and the observation of evolving patterns of seismicity (such as clusters or delineations of faults), can be evaluated so as to initiate potential mitigation measures before more concerning induced seismicity is induced. The information from these studies should be made available to the Expert Panel so that they can make appropriate recommendations.

Operation at elevated alert levels should include informing the regulatory agency and other project stakeholders. Observed seismicity should be further analyzed in order to understand the causative mechanisms and inform the choice of potential mitigation steps. Should the alert level continue to increase due to ongoing seismicity, injection should be reduced or stopped, and other steps taken to ensure the safety of the site and local populations.

Once seismic activity has been induced above a threshold level there is only a limited range of possible operational procedures that may be able to mitigate further seismicity. The operator can modify the injection operation by reducing injection rates or volume, stopping injection, producing from the injection well, or producing fluid elsewhere with the goal of reducing the pressure at a location distant from the original injection well to potentially steer the pressure plume. The efficacy of active pressure management is an area of active research (Kroll et al., 2020).

With any of these changes to operations it should to be acknowledged that they may take a significant amount of time until a geomechanical effect is achieved. Hence, it is important to implement low enough traffic light thresholds in order to react early enough to avoid damaging levels of seismicity.

It is important to document a clear procedure that would allow for the reduction of the response level of a traffic light framework. The conditions to be met for reducing the response level will vary from site to site. However, in every case the observed seismicity should be carefully analyzed along with the pertinent operational parameters and geomechanical models to understand what conditions led to the heightened alert level. This analysis should engage the appropriate specialists, including seismologist, geologists, and engineers to review available data and if necessary, design and conduct engineered trials to inform operating procedure adjustments. Subsequently, subsurface models should be modified to determine what has changed from the initial assumptions and determine how operations can be modified such that a higher response level will not be reached. The Expert Panel should recommend, and the regulatory agency should approve, any reduction in the response level at a site.

All traffic light frameworks are dependent on adequate near real-time seismic monitoring. While a traditional TLS may be operated successfully with a magnitude of completeness about 0.5 units below the lowest threshold criteria defined in the site-specific plan, a prospective ATLS greatly benefits from a much lower completeness. Seismic forecast models that are incorporated into ATLS perform best when their statistical features (e.g., b-values or seismicity rate variations) are based on the lowest completeness achievable. These lower magnitude events are also necessary for near-real-time evaluation of the effectiveness of enacted risk mitigation protocols and for a more rapid identification of potential signs of fault activation.

7.3.2 Expert Panel

An Expert Panel should be formed to provide evidence-based information and recommendations pertaining to the induced seismicity risk posed by the project. The panel should serve as a forum in which the operator, the regulatory agency, other stakeholders, and independent subject matter experts will be able to monitor and assess the induced seismicity and develop recommendations for necessary operational responses, such as changes to the injection operations, increased seismic monitoring, more detailed analyses, and other mitigation measures. Expert panels and expert elicitations have proven successful particularly in the presence of substantial epistemic uncertainties, such as at a greenfield site and investigating the potential for induced seismicity (Trutnevyte and Azevedo, 2018).

The Expert Panel is tasked with: recommending for approval the induced seismicity mitigation plan prior to subsurface injection; recommending actions on an as-needed basis during injection and during the seismic PISC period; recommending actions after a change to the response level; and recommending the lowering of a response level. The Expert Panel is expected to review, at least annually, the induced seismicity mitigation plan, the appropriateness of the seismic monitoring network and operation, updated hazard and risk assessments, and the detailed seismological analyses that will be routinely conducted by the operator.

Because the ROC may be extensive, it may overlap with other uses of the subsurface or with the ROC of another GCS project or other injection operations. If several ROCs overlap, the probability of inducing seismicity is determined by the sum of individual project's contributions (Dempsey and Riffault, 2019). Therefore, the task of managing induced seismicity should be addressed by a larger group of stakeholders including representatives from all subsurface projects whose ROCs may overlap.

7.3.3 Early Evaluation Period

The first year of injection operations should be considered an early evaluation period. During the early evaluation period, the seismogenic and hydrologic behavior of the target reservoir and underlying basements units should be analyzed to calibrate, verify, and/or update the pre-injection models and parameters. Forecasts of the level of induced seismicity derived from pre-injection assessment using estimated values are likely to be of limited value without this calibration and verification step. Therefore, the Expert Panel should convene, virtually or in person, at least weekly during the first month of the early evaluation period and monthly during the following 5 months to assess the appropriateness of the models, input parameters, the induced seismicity mitigation plan, and to recommend modifications if necessary. If no seismicity is observed meetings can be adapted to simple check ins.

During this critical time, the relative changes in pressure and stress may be at their greatest. Therefore, it is suggested that injection operations should be gradually increased and that any increases in the planned injection rate be recommended by the Expert Panel. The Expert Panel should be empowered to recommend a slowing or halting of injections to the regulator if hazardous conditions warrant it.

7.3.4 Seismic PISC

The PISC duration is defined as the time period following cessation of CO_2 injection in which appropriate monitoring and other actions are needed to ensure that any underwater source of drinking water (USDW) is not endangered. With regard to induced seismicity, the Expert Panel may recommend implementing a seismic PISC which may have a duration that is different from the PISC. It may be reduced or extended relative to the PISC in order to account for the different requirements of the induced seismicity mitigation plan. For example, if only very low levels of induced seismicity were detected during the active injection phase of the project, the Expert Panel may be justified in recommending an earlier end to the seismic PISC than for the PISC. If, however, significant seismicity was observed, it may be required to continue execution of the induced seismicity mitigation plan throughout and beyond the PISC period. Determinations should be based on two factors: (1) stabilization of pressure and stress perturbations to steady-state values; and (2) clear demonstration that the seismic frequency-magnitude behavior is approaching baseline tectonic conditions. For example, at the site of the Basel EGS there has been observed seismicity for over 10 years following shut-in after a fluid-injection program that lasted only 2 weeks (Herrmann et al., 2019).

During the seismic PISC, seismic monitoring, the outreach and communication program, and the implementation of the Induced Seismicity Mitigation Plan should continue, maintaining the number of monitoring stations and review procedures. Additionally, during the seismic PISC, the schedule of review meetings by the Expert Panel may be reduced if deemed appropriate by the Expert Panel. This should require approval by the regulatory agency.

7.3.5 Liability and Insurance

Liability and compensation coverage for damages cause by induced earthquakes should be included in the Induced Seismicity Mitigation Plan as a last means of indirect mitigation. Such indirect mitigation has been used in EGS contexts in the past (Giardini, 2009). Further, having insurance and a compensation scheme in place prior to operations may significantly increase public acceptance for a subsurface injection project. Operators should be sufficiently covered or

demonstrate sufficient assets to self-insure against damages from induced seismicity. Insurance coverage for potential losses at the median annual exceedance probability of 10^{-4} or greater have been suggested for EGS (Wiemer et al., 2017). The amount of coverage should be re-evaluated annually. In the case of a damaging event there are often legal disputes about who is at fault. This may occur specifically in cases where several operators have overlapping ROCs. Assigning a single operator to be at fault would ignore the fact that pressure diffusion from several injection sources is additive (e.g., Dempsey and Riffault, 2019). An induced event could occur because of the sum of all injection operations in its vicinity. Therefore, it is recommended that operators pay contributions to an insurance fund that would compensate for any damages resulting from induced seismicity in a shared ROC. Operators who expect to have overlapping ROCs should negotiate these details in advance of injection.

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APPENDIX I - TERMINOLOGY

2-sigma: The two standard deviation uncertainty.

Region of Concern (ROC): The expected ground surface area around an injection well where there could be a negative impact due to potential seismic events occurring in the perturbed stress zone (PSZ) throughout the lifetime of the project.

Area of Review (AOR): The region around an injection well where USDWs may be endangered by the injection activity.

Geologic Carbon Storage (GCS): The long-term containment of a gaseous, liquid, or supercritical carbon dioxide stream in subsurface geologic formations.

Peak Ground Acceleration (PGA): Maximum ground acceleration that occurs at a particular location due to a seismic event and is typically expressed as a fraction of gravitational acceleration (g).

Peak Ground Velocity (PGV): Maximum ground velocity that occurs at a particular location due to a seismic event.

Perturbed Stress Zone (PSZ): The subsurface region around an injection well with perturbed pressure and stress in which seismicity could occur in a critically stressed crust. This zone is expected to expand over time as the subsurface fluid migrates away from the injection point.

Post-Injection Site Care (PISC): Appropriate monitoring and other actions (including corrective action) needed following cessation of injection to ensure that USDWs are not endangered. PISC monitoring must continue until it can be demonstrated that the site poses no further endangerment to USDWs. The default duration for PISC, as stated in the U.S. Environmental Protection Agency (EPA) guidelines, is 50 years.

Seismic PISC: The PISC that relates to the Induced Seismicity Mitigation Plan. The seismic PISC duration may be decoupled from the duration of the general PISC depending on the seismic response of the site during active injection.

Underground Source of Drinking Water (USDW): An aquifer or portion of an aquifer that supplies any public water system or that contains a sufficient quantity of ground water to supply a public water system, and currently supplies drinking water for human consumption, or that contains fewer than 100,000 mg/l total dissolved solids and is not an exempted aquifer.

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APPENDIX II –NRAP TOOLS AND PUBLISHED STUDIES RELEVANT TO RECOMMENDED PRACTICS

Recommended Practice	Relevant NRAP Tools	Published NRAP Applications
PRELIMINARY SEISMIC RISK SCREENING EVALUATION	GMPIS	• Coblentz, D.; Lee, R.; Wilson, J.; Bradley, C. *Kimberlina, California Site Characterization for Applications to Potential Induced Seismicity*; NRAP-TRS-III -007-2017; NRAP Technical Report Series; U.S. Department of Energy, National Energy Technology Laboratory: Morgantown, WV, 2017; pp 56.
OUTREACH AND COMMUNICATION		[No NRAP studies relevant to this topic have been published to date.]
GROUND MOTION THRESHOLDS		[No NRAP studies relevant to this topic have been published to date.]
COLLECTION OF SEISMICITY DATA	PSMT	• Chen, T.; Huang, L. Optimal design of microseismic monitoring network: Synthetic study for the Kimberlina CO_2 storage demonstration site. *International Journal of Greenhouse Gas Control* **2020,** *95*, 102981. https://doi.org/10.1016/j.ijggc.2020.102981 • Chen, Y.; Huang, L.; EGS Collab Team. Optimal design of 3D borehole seismic arrays for microearthquake monitoring in anisotropic media during stimulations in the EGS Collab project. *Geothermics* **2019,** *79*, 61–66.
HAZARD EVALUATION OF NATURAL AND INDUCED SEISMIC EVENTS	SoSAT	• Appriou, D. *Assessment of the geomechanical risks associated with CO_2 injection at the FutureGen 2.0 Site*; PNNL-28657; Pacific Northwest National Laboratory, Richland, WA; 2019. • Burghardt, J. Geomechanical Risk Assessment for Subsurface Fluid Disposal Operations. *Rock Mechanics and Rock Engineering* **2018,** *54*, 2265–2288. DOI: 10.1007/s00603-018-1409-1.
RISK-INFORMED DECISION ANALYSIS	RiskCat	• California Energy Commission. Investigation of Potential Induced Seismicity Related to Geologic Carbon Dioxide Sequestration in California; Report No. CEC-500-2017-028; August 2017. https://ww2.energy.ca.gov/2017publications/CEC-500-2017-028/CEC-500-2017-028.pdf (accessed Dec 24, 2019).
OPERATIONAL MANAGEMENT OF INDUCED SEISMICITY RISKS	STSF	• Bachmann, C. E.; Wiemer, S.; Woessner, J.; Hainzl, S. Statistical analysis of the induced Basel 2006 earthquake sequence: introducing a probability-based monitoring approach for Enhanced Geothermal Systems. *Geophysical Journal International* **2011,** *186*, 793–807. 10.1111/j.1365-246X.2011.05068.x. • Hainzl, S.; Ogata, Y. Detecting fluid signals in seismicity data through statistical earthquake modeling. *J. Geophys. Res.* **2005,** *110*, B05S07. DOI:10.1029/2004JB03247.

Where: GMPIS – Ground Motion Prediction applications to potential Induced Seismicity, PSMT – Passive Seismic Monitoring Tool, SOSaT – State of Stress Analysis Tool, and STSF – Short-Term Seismic Forecasting Tool

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NRAP is an initiative within DOE's Office of Fossil Energy and is led by the National Energy Technology Laboratory (NETL). It is a multi-national-lab effort that leverages broad technical capabilities across the DOE complex to develop an integrated science base that can be applied to risk assessment for long-term storage of carbon dioxide (CO_2). NRAP involves five DOE national laboratories: NETL, Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), Los Alamos National Laboratory (LANL), and Pacific Northwest National Laboratory (PNNL).

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NRAP Technical Report Series

A Project Lifetime Approach to the Management of Induced Seismicity Risk at Geologic Carbon Storage Sites

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Abstract

The geologic storage of carbon dioxide (CO_2) is one method that can help reduce atmospheric CO_2 by sequestering it into the subsurface. Large-scale deployment of geologic carbon storage, however, may be accompanied by induced seismicity. We present a project lifetime approach to address the induced seismicity risk at these geologic storage sites. This approach encompasses both technical and nontechnical stakeholder issues related to induced seismicity and spans the time period from the initial consideration phase to postclosure. These recommendations are envisioned to serve as general guidelines, setting expectations for operators, regulators, and the public. They contain a set of seven actionable focus areas, the purpose of which are to deal proactively with induced seismicity issues. Although each geologic carbon storage site will be unique and will require a custom approach, these general best practice recommendations can be used as a starting point to any site-specific plan for how to systematically evaluate, communicate about, and mitigate induced seismicity at a particular reservoir.

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Introduction

Geologic carbon storage (GCS) is one technology that can reduce CO_2greenhouse gas emissions to the atmosphere by utilizing favorable hydrogeologic conditions to sequester CO_2 into the subsurface. However, increased subsurface fluid injection activity has led to an uptick of seismicity at some fluid injection sites, including near wastewater disposal sites, hydraulic fracturing sites, and engineered geothermal systems (EGS; Ellsworth, 2013; Keranen and Weingarten, 2018; Templeton *et al.*, 2020). This induced seismicity has raised concerns about the scalability of GCS considering the seismic hazard and risk associated with far-reaching subsurface pressurization and adjacent basement rocks (Zoback and Gorelick, 2012; White and Foxall, 2016).

Few commercial scale GCS sites exist that can be used as prototypes to study the induced seismic response. Two well-studied examples are the Illinois basin–Decatur (IDBP) project and the associated Illinois Industrial Carbon Capture and Sequestration Sources (IL-ICCS) project. To date, combined they have injected 2.8 million tons of CO_2 into the Mt. Simon saline sandstone reservoir and have detected nearly 20,000 seismic events with magnitudes between −2.1 and 1.2, although none have been felt at the surface (Williams-Stroud *et al.*, 2020). The IL-ICCS project moved the injection to a shallower zone in which a higher injection rate could be sustained with substantially lower seismic activity.

Although those two projects have been a success story in terms of induced seismicity management, a systematic strategy for dealing with induced seismicity is needed to be able to scale up, both in number and in injection volumes. This strategy should additionally be able to incorporate the fact that several GCS sites may be operating simultaneously within the same basin for extended periods of time, thus potentially posing a hazard to a much larger region. Zhou *et al.* (2010) modeled a scenario for 20 injection sites in the Illinois basin spaced approximately 30 km apart, each injecting about 5 Mt/yr over 50 yr. The modeled pressure behavior is observed to have an early stage in which individual injection well pressurizations do not interfere. This is followed by an intermediate phase in which transient pressure interference is observed between the injection sites and is followed by a final phase in which a continuous pressure buildup is driven by the combined behavior of all injection sites within the basin.

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Therefore, having a common systematic framework in which to evaluate, manage, communicate about, and mitigate the risk of induced seismicity will be necessary to help facilitate the expansion of GCS. The EGS community has previously taken this approach by adopting a proactive set of protocols and recommended practices for induced seismicity management (Majer *et al.*, 2012, 2016; Wiemer *et al.*, 2017). We have created a set of GCS focused recommended practices based on the EGS approach of Majer *et al.* (2012, 2016), as many of the induced seismicity issues are similar and a project lifetime approach is also used, which is essential for GCS sites. We add to their base recommendations by incorporating important lessons learned over the last decade and including details specific to GCS. The substance of the recommended practices contained herein includes both technical and nontechnical issues. Subsequently, we summarize recent key learnings that helped to inform our method and present the seven steps included in our approach. The recommendations described herein are also discussed more thoroughly and with greater detail in an expanded technical report available online (Templeton *et al.*, 2021).

Key Lessons Learned in the Last Decade

Regions with low to moderate natural seismic activity may produce induced earthquakes in excess of M 4

Prior to 2009, Oklahoma and Kansas had shown very little seismic activity. Although the national seismic hazard map (Petersen *et al.*, 2008) identified a slightly elevated hazard, the area would not have been classified as high hazard. However, the start of large-scale wastewater disposal into the Arbuckle group initiated significant earthquake activity across an area about 200 km in width, including an **M** 5.8 event in Pawnee, Oklahoma, in September 2016 (Chen *et al.*, 2017; Schoenball *et al.*, 2018). Other examples of industrial activities inducing larger magnitude events include an **M** 5.3 event in the Raton basin (Rubinstein *et al.*, 2014), an **M** 4.1 event offshore the coast of Spain (Cesca *et al.*, 2014; Cesca *et al.*, 2021), an **M** 4.1 event in Alberta, Canada (Schultz *et al.*, 2017), and an **M** 5.4 earthquake connected to an EGS development in Pohang, South Korea (Lee *et al.*, 2019). Though GCS sites have not seen comparable seismicity, the hazard exists and should be considered.

Seismogenic response to fluid injection may vary strongly from site to site and between different injection intervals

In the case of Oklahoma, Langenbruch *et al.* (2018) have shown that the probability of fluid injection to induce earthquakes may vary significantly across spatial distances on the order of tens of kilometers. In addition, at the Pohang EGS site, the seismic response to injection in two boreholes, for which injection interval was less than 1 km apart, was markedly different although injected fluid volumes were comparable (Lee *et al.*, 2019). At the Decatur GCS site, a large number of small events were induced by injection into the lower Mt. Simon Sandstone, whereas fewer events were induced by injection at a higher injection rate in the shallower middle Mt. Simon Sandstone in the same borehole (Williams-Stroud *et al.*, 2020).

Regional trends of the seismogenic response to fluid injection do exist

Although it is difficult to forecast the induced seismic response to fluid injection at a new site, operating experience collected at neighboring field sites can often be applied to other local projects. For example, there have been several examples of regional trends, both for large seismic responses (e.g., the Arbuckle formation in Oklahoma and Kansas) and for almost no seismic response (e.g., the Williston basin in parts of Montana, North Dakota, South Dakota, and Canada) associated with nearby fluid injections (Skoumal *et al.*, 2018).

Seismicity may be induced tens of kilometers away from large-scale injection

Long-distance seismicity has been observed, for example, in Oklahoma (Keranen *et al.*, 2014; Goebel *et al.*, 2017; Schoenball *et al.*, 2018) and Kansas (Peterie *et al.*, 2018). The occurrence of seismicity farther away from injection implies that stress changes much smaller than 1 MPa may be sufficient to trigger seismicity even in naturally quiescent areas. Recent studies, involving hydromechanical modeling, indicate that effective stress changes on the order of 100 kPa or less can found near earthquake hypocenters, which supports the observation of long-distance seismicity (Keranen *et al.*, 2014; Barbour *et al.*, 2017; Norbeck and Rubinstein, 2018; Zhai *et al.*, 2020).

Even faults capable of magnitude 5 earthquakes may be previously unknown

In many of the induced seismicity cases, faults that hosted even the largest events >**M** 5 were not known beforehand. This is not exclusive to induced seismicity cases. Even natural events, such as the 2014 Napa earthquake, often occur on blind faults (Brocher *et al.*, 2015). This can be related to the difficulty of imaging faults in basement rocks or the lack of vertical offset in the sedimentary overburden from subvertical strike-slip faults. Even focused efforts on imaging the fault that produced the **M** 5.8 Pawnee earthquake on 3D seismic data produced ambiguous results (Kolawole *et al.*, 2019).

Induced seismicity is driven by high fluid volume injection

Weingarten *et al.* (2015) and Schultz *et al.* (2018) show that the potential for inducing earthquakes in wastewater disposal and hydraulic fracturing, respectively, correlates positively with the total injected fluid volume and the rate of injection. Although large-scale wastewater disposal has occurred in Oklahoma since at least 1995, seismicity has only been observed when the volume has been increased significantly. This is the case

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since the beginning of 2006 in central Oklahoma and 2012 in northern Oklahoma. Based on this observation of long-term, low-rate fluid injection in Oklahoma with no observed seismic response before 2009, Langenbruch and Zoback (2016) postulate the existence of a threshold injection rate below which no triggering of earthquakes would be observed.

The Approach

We integrate these key lessons learned into a set of recommended actions that make up a project-wide and project-lifetime approach to induced seismicity risk management, specifically at GCS sites. We follow general risk management approaches (Fischhoff, 2015) and apply them to the induced seismicity case. The recommended practices can be subdivided into seven steps:

Step 1: Preliminary seismic risk screening evaluation.
Step 2: Outreach and communication.
Step 3: Thresholds of ground motion for damage and vibration.
Step 4: Collection of seismicity data.
Step 5: Hazard evaluation of natural and induced seismic events.
Step 6: Risk-informed decision analysis.
Step 7: Operational management of induced seismicity risks.

Step 1—Preliminary seismic risk screening evaluation

The preliminary seismic risk screening evaluation step aims to determine a preliminary seismic risk category for one or more GCS sites that are being considered for future significant investment. If one of the candidate sites is ultimately selected, it will be necessary to subsequently complete a more detailed seismic risk analysis. The preliminary screening can be subdivided into seven focus areas highlighted subsequently.

Review of local, state, and federal laws and regulations. The relevant local, state, and federal laws and regulations should be assessed to determine if the effects of induced seismicity, however minor or unlikely, are barred. An assessment of damage liability requirements should also be conducted at this time.

Review of prior injection-induced seismicity cases. To obtain a qualitative evaluation of the susceptibility of the candidate site to induced seismicity, a seismicity review of nearby or similar GCS projects across a wider regional trend should be completed. If no similar GCS cases can be identified, the assessment should instead focus on a review of other fluid injection projects, such as gas injection projects, in similar hydromechanical settings (Cesca *et al.*, 2014; van Thienen-Visser and Breunese, 2015).

Region of concern of potential seismic events. A preliminary estimate of a region of concern (ROC; i.e., the ground surface area that could be negatively impacted by induced seismic events) should be determined. This will require an estimate of the potential maximum magnitude-induced seismic event (M_{max}), the potential locations of such an event, and any surface ground motions associated with it. At this early stage, simplifying assumptions in the input parameters will be necessary. For example, it could be assumed that M_{max} would be spatially limited by the extent of the pore pressure perturbation zone (Shapiro *et al.*, 2011; McGarr, 2014; Yeck *et al.*, 2015), by local tectonics and stress (van der Elst *et al.*, 2016; Galis *et al.*, 2017; Norbeck and Horne, 2018; Li *et al.*, 2021), or simply by similarity to observed events in similar settings. The hypothetical location of the maximum magnitude event will also need to be assumed, taking into consideration any local tectonic trends and the observation that induced seismicity events can occur even tens of kilometers away from injection sites. For the ground-motion estimates, ground-motion models (GMM) specifically developed for induced events should be preferentially chosen or developed when possible (Bommer *et al.*, 2016). The ROC could then initially be defined as the area over which felt ground motions could occur.

Potential impacts within the ROC. Items and activities that may be impacted within the ROC can include physical damages to buildings and infrastructure, social disturbances, nuisance, economic disruption, and the effects of secondary environmental hazards (landslides, liquefaction, seiches, etc.) (National Research Council [NRC], 1989). This assessment should be carried out with early input from local stakeholders to ensure it includes all items and activities of concern, thus building consensus and trust between all parties. Preliminary estimates can include the population distribution in the region and simple building inventories taken from existing databases. Impacts of concern may vary depending on whether the region's population has previously been exposed to some level of natural seismicity and whether the buildings and infrastructure have been built according to appropriate seismic building codes.

Estimation of potential impact magnitude. A qualitative estimation of the magnitude of potential impacts should be calculated and can, for example, encompass the number of people who would feel an M_{max} event and the number of structures that could potentially be damaged by it. A general scenario loss model, providing estimates of economic losses and fatalities using global models and databases, should also be performed (Jaiswal and Wald, 2011). In addition, framing the comparison in terms of the impact due to a series of scenario events of increasing magnitude can provide a structured way to present the information.

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TABLE 1
Overall Preliminary Seismic Risk Categories with Recommended Decision Pathways

Very Low	Low	Medium	High
Proceed with planning	Can proceed with planning but may require additional analysis to confirm	Probably should not proceed at this site, but additional analysis might support proceeding	Do not proceed

Adapted from Majer *et al.* (2012).

Assessment of local stakeholder risk tolerance. The level of stakeholder concern regarding the project, used to calibrate the risk scale to an individual location, should be assessed with the understanding that different communities may have different seismic risk acceptance levels and that these risk acceptance levels may differ based on real or perceived risk associated with the GCS technology. Incorporation of stakeholder input allows for a more robust sociotechnical approach to risk governance, even at this early stage. Stakeholders can include community leaders, governmental agencies, tribal governments, regulators, public safety officials, nongovernmental organizations, the general local community, and so on.

Overall seismic risk of the planned operation. An integrated assessment of the seismic risk of the planned operation can be developed by combining the information from the technical and social factors. There are many methods by which the overall seismic risk related to an individual site may be assigned to broad seismic risk categories, such as those specified in Table 1. One such method is to create a grid and define what each category of risk would entail for each of the potential impacts, similar to the Geothermal Risk of Induced seismicity Diagnosis (GRID) method proposed for Switzerland (Trutnevyte and Wiemer, 2017). Ultimately, the threshold for an unacceptable risk would be project specific and dependent upon a host of factors.

Step 2—Outreach and communication

A GCS-induced seismicity component to a project's general Outreach and Communication (O&C) program to facilitate communication and maintain positive relationships with stakeholders will need to be developed. Across all stages of project planning, operation, and decommission, it is critical that stakeholders are kept informed and that their input is considered and acted upon in a timely and meaningful way. There is no one size fits all approach to O&C. It is expected that each project will need to prepare an individualized O&C plan that addresses the specific local issues associated with the project site (Ground Water Protection Council and Interstate Oil and Gas Compact Commission [GWPC and IOGCC], 2017) and that it will also include any requirements made within the risk-based mitigation plan (step 7). Nonetheless, any O&C program should strive to adhere to the general working principles associated with the theory of stakeholder engagement and to build on previous experience associated with siting major energy and nonenergy projects to achieve fair and efficient consensus building amongst all stakeholders (Suskind, 1990). This should include the institution of a broad-based participatory process, obtaining broad agreement that the project is an improvement over the status quo, obtaining stakeholder consensus regarding the project plan, providing adequate communication with stakeholders that stringent safety standards are being met, making a commitment to both fully address negative aspects of the project with stakeholders, and committing to develop and maintain stakeholder trust. All O&C programs should also incorporate an induced seismicity and GCS education component.

Step 3—Ground-motion thresholds

Site-specific ground-motion thresholds, which would minimize nuisance and damage risks, will need to be determined. These nuisance and damage thresholds should be determined after assessment of the local population distribution, building conditions, and stakeholder risk tolerance. Information from this step will be used for the design of a seismic monitoring program (step 4) and as a site-specific baseline against which subsequent induced seismicity hazard and risk analyses results (steps 5 and 6) can be juxtaposed. In addition, a subset of the threshold levels identified in this step may be used to inform the traffic light threshold levels within the risk-based induced seismicity mitigation plan (step 7).

Review of existing standards and criteria. Federal, state, and local standards regarding ground motions should be reviewed to determine if any regulatory criteria are applicable within the ROC. In addition, ground-motion thresholds relevant to the nuisance risk (i.e., Foulger *et al.*, 2018) should be reviewed. Finally, a review of threshold ground-motion levels that may cause cosmetic damage or structural damage to different types of buildings and infrastructure within the ROC will be necessary.

Assessment of site-specific conditions. An assessment of the building and structure types within the ROC should also be conducted, using the preliminary assessment conduced in step 1 as a starting point. Particular attention should be paid to identifying fragile structures, historical structures, and other structures of particular importance to the local community. Particularly in regions of low natural seismic hazard, the building stock may not be engineered to withstand ground shaking and so even moderate earthquakes may lead to significant damage. In addition, an assessment of sensitive local industrial equipment, activities, and institutional land use areas that may be impacted by elevated levels of ground shaking should be conducted within the ROC.

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Designate site-specific ground-motion thresholds. At least four ground-motion threshold levels should be quantified. They are (in no particular order): (1) the threshold for humans to perceive ground shaking; (2) cosmetic and structural damage thresholds for each type of building and infrastructure within the ROC; (3) ground motions that may affect local equipment and activities within the ROC; and (4) ground-motion limits that are stipulated in federal, state, or local regulations.

Step 4—Collection of seismicity data

Seismic data needs to be gathered, analyzed, and archived during the lifetime of the GCS project. These data are needed for varying activities. One is to accurately assess and periodically reassess the natural and induced seismic hazard and risk associated with the project. A second is to aid in the rapid and effective detection and characterization of the seismicity at the site. This is especially needed as input into induced seismicity mitigation plan protocols (e.g., traffic light systems).

Seismic activity before operations. To understand the potential for induced seismicity at a new project location, it will be necessary to first identify any nearby past and present seismicity in the area and the faults on which they originate. A region much larger than the ROC should be chosen to explore to ensure that wider regional trends are considered in the seismic hazard assessment. This consideration reduces the possibility of overlooking infrequent but possibly large events that could impact the local hazard. National, state, or regional seismic networks are typically not sensitive enough to detect the level of seismic activity that should be recorded at local sites. Installing or augmenting an existing local monitoring network will be required to understand the response of the project site to injection operations. The local network should be active for at least 6 months–1 yr prior to operations commencing. GCS operators who are working in the same basin should cooperate to share data.

Seismic monitoring network design. The seismic monitoring network should be designed to detect and characterize seismicity down to at least **M** 1 and should be able to record all expected felt ground motions at the surface due to those events. Local monitoring networks should include a combination of high-gain sensors, which can optimally record weak ground motions from small local earthquakes, and low-gain accelerometers, which can optimally record strong ground motions from nearby larger earthquakes. The network should be designed to record and locate seismicity with at least a 2-sigma location accuracy of 0.5 km in the horizontal direction and 1.0 km in the vertical direction. The network should be equally sensitive across the ROC because it should be able to measure even strongly varying seismogenic responses between different GCS injection sites within the same basin. Various approaches are available to help design such seismic networks at local and regional scales (e.g., Kraft *et al.*, 2013).

Seismic monitoring network operation and reporting. The seismic monitoring network should be operating continuously from the preoperational background assessment phase until postclosure when the level of detected seismicity approaches the background rate. Although there may be legitimate operational reasons to briefly embargo data to ensure quality control and accuracy of interpretation, it is highly recommended that an open-access data approach for the waveforms and earthquake catalogs be taken when engaging with the public and any other GCS operators working in the same basin. This will improve community trust and the overall state-of-knowledge of the GCS reservoir and of GCS-induced seismicity in general. In addition, summary reports should be made publicly available at least annually, which could include information on recent observed induced seismicity, the seismic network metadata, any related seismic information, such as the applied seismic velocity model, and results from any advanced analysis conducted on the data, such as event relocation or moment tensor analysis.

Step 5—Hazard evaluation of natural and induced seismic events

The purpose of this step is to estimate the ground shaking hazard at the proposed site and within the ROC due to natural tectonic seismicity and the additional hazard due to induced seismicity using probabilistic seismic hazard analysis (PSHA). Assessing the ground shaking hazard from natural seismicity will provide a baseline from which to evaluate the additional hazard from induced seismicity. This step should be performed before any operations are initiated at the site, repeated as needed during the early evaluation period, and at least yearly thereafter. Results from this seismic hazard evaluation will be input into the subsequent risk-informed decision analysis (step 6).

Baseline hazard from natural seismicity. The baseline seismic hazard will focus exclusively on ground shaking hazards associated with natural tectonic seismic events that could impact the site infrastructure (to inform any hazard mitigation procedures) and the local population (to allow for ease of comparison of the natural and induced hazard and risk). PSHA is recommended when calculating the baseline seismic hazard at a particular GCS. PSHA involves obtaining, through a formal mathematical process, the level of a selected ground-motion parameter (e.g., PGA, PGV, etc.) that has a selected probability of being exceeded (e.g., 0.01% probability, 10% probability, etc.) during a specified time interval (e.g., 50, 5000 yr, etc.) at a particular location due to future earthquakes. A variety of computer programs are publicly available that can be used to perform site-specific PSHA, such as the free and

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open-source software OpenQuake Engine (Pagani *et al.*, 2014). Several others have also been validated by the Pacific Earthquake Engineering Research Center, including the OpenSHA program, the HAZ program, and EZ-FRISK (Hale *et al.*, 2018). These hazard and risk analyses will also help better define the ROC. Throughout the lifetime of the project, it is expected that the PSHA analysis will need to be updated if future geological, seismological, or geophysical investigations reveal significantly new and different information than that used in the original analysis.

Additional hazard from induced seismicity. The probabilistic short-term seismic ground shaking hazard forecast for GCS-induced seismicity is determined generally the same as for the long-term approach, with adjustments made for different source and GMMs to accommodate the differences between induced and natural seismicity. These short-term forecasts, incorporating both natural and induced seismicity, should be periodically computed during the lifetime of the project. These forecasts should ideally be for one-year duration or shorter, depending on the planned injection schedule. In addition, it is recognized that although it may be possible to make some estimates ahead of the initial injection program, real forecasting power requires actual observations of the seismic response to injection tests to calibrate and validate the forecasting models and assumptions made in the initial assessment. Because of this, and only in the time period before injection starts, either a full probabilistic hazard analysis or a pseudoprobabilistic hazard assessment could be appropriate (Cornell, 1968; Edwards *et al.*, 2021). The short-term probabilistic seismic hazard forecast will necessarily need to be systematically checked and updated. Predictions will need to be continuously calibrated against new observations. If different GCS operators are working in the same basin, it is recommended that they share input parameters and models (e.g., 3D geological models) that inform their short-term forecasts.

Step 6—Risk-informed decision analysis

Conceptually, this step is similar to the preliminary seismic risk assessment in step 1; however, instead of aiming for an order of magnitude assessment, a more precise estimate of risk is required. Results from the risk informed decision analysis described here will be tightly coupled with the risk management framework described in step 7.

Seismic risk from natural seismicity. Seismic risk is calculated from three main contributing factors: the seismic hazard at locations within the ROC; the collection of exposed assets, activities, and communities at those locations; and their vulnerability to the hazard (McGuire, 2004). Calculating a site-specific risk due to natural seismicity will allow for a quantitative comparison between the accepted natural seismicity risks and the potential additional induced seismicity risks associated with the project. Seismic risk analysis can provide results in a variety of forms and should be tailored to the site (Jonkmann *et al.*, 2003). There are a variety of seismic risk assessment software packages available to assess seismic risk due to natural tectonic seismicity. Some are open and freely available (Lang *et al.*, 2007; Porter and Scawthorn, 2007; Trendafiloski *et al.*, 2009; Federal Emergency Management Agency [FEMA], 2013; Pagani *et al.*, 2014; Silva *et al.*, 2014, 2018), whereas others are provided by commercial risk management companies that can also perform the analysis for a fee.

Seismic risk from induced seismicity. The induced seismicity seismic risk analysis will facilitate sound and efficient decision making relating to induced seismicity. Seismic risk assessment methodologies applied to a site in the design phase, for example, can highlight unacceptable potential future damages prior to operations, when plans can be more easily modified and the risk iteratively reassessed so as to come to a risk level acceptable to stakeholders (Silva *et al.*, 2021). Early on, much of the research into, and applications of, induced seismic risk had focused on the impact of lower probability, higher impact moderate-to-large earthquakes (Grigoratos *et al.*, 2021). Moving forward, injection-induced seismicity risk began to more frequently incorporate smaller magnitude earthquakes, which may cause significant nuisance to the local population but only relatively minor physical damage to structures (van Elk *et al.*, 2019; Edwards *et al.*, 2021). Although the fundamentals of risk estimation do not change for small ground-motion events, the models used in the characterization of these risks will need to be calibrated for the lower amplitudes of ground shaking and shorter distances often associated with induced seismic events. In addition, the hazard and risk analysis should be revisited periodically during the operational period of the project and after site closure, especially if observed seismicity differs significantly from the expected location or rate.

Risk-informed decision analysis. Risk-informed decision analysis can facilitate decision making both prior to and during injection operations. Risks associated with different injection programs, especially those considered high-volume or high-rate flows, which have been shown to increase the potential for induced seismicity, can be independently evaluated and assessed. Incorporating the risk tolerance of the stakeholders with the risk analysis results will allow for informed decision making at all levels. Risk-tolerance matrices are one method that can estimate the intersection between the risk tolerance of stakeholders with the expected benefits of the project (Walters *et al.*, 2015). The risk tolerance of the local stakeholders may be able to be modified through outreach and education associated with the O&C program (step 2) by demystifying the GCS technology.

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Step 7—Operational management of induced seismicity risks

A site-specific, real-time plan to monitor, assess, control, and mitigate the risks associated with induced seismicity during and after fluid injection is necessary. The framework of the risk-based mitigation plan should be based on a traffic light system (TLS), which can provide clear and direct actions to take in response to given situations according to predetermined criteria.

Induced seismicity mitigation plan. An induced seismicity mitigation plan should be in place before any injection operations begin. The framework of the plan should be based on a TLS protocol with at least three or more response levels corresponding to a continuation of operations as planned (green); heightened awareness and revisiting of injection operations due to concerning observed seismicity or trends (yellow); and stopping of injection due to an unacceptable level of induced seismicity (red) (NRC, 2012). Although a traditional TLS typically defines the actions to be taken solely in response to the occurrence of certain observed criteria (e.g., the occurrence of a seismic event above a certain magnitude or a level of surface ground shaking above a certain threshold), an adaptive traffic light systems (ATLS) with physics-based forecasting methods, can help to inform operation decisions, such that elevated risk levels might not be reached in the first place (Fig. 1). An ATLS is fully probabilistic, incorporates new data automatically as much as possible, and naturally integrates hazard, exposure, and vulnerability into the system (Wiemer *et al.*, 2014; Mignan *et al.*, 2017; Langenbruch *et al.*, 2020). In this way the hazard and risk calculations originally produced in steps 5 and 6 can be automatically updated as new data and models becomes available.

Expert panel. An expert panel should be formed to provide evidence-based information and recommendations pertaining to the induced seismicity risk posed by the project. The panel should serve as a forum in which the operator, the regulatory agency, other stakeholders, and independent subject matter experts will be able to monitor and assess the induced seismicity and develop recommendations for necessary operational responses, increased seismic monitoring, more detailed analyses, and other mitigation measures. Expert panels and expert elicitations have proven successful particularly in the presence of substantial epistemic uncertainties, such as at a greenfield site and investigating the potential for induced seismicity (Trutnevyte and Azevedo, 2018). Because the ROC may be extensive, it may overlap with other uses of the subsurface or with the ROC of another GCS project or other injection operations. If several ROCs overlap, the probability of inducing seismicity is determined by the sum of individual projects contributions (Dempsey and Riffault, 2019). Therefore, the task of managing induced seismicity should be addressed by a larger group of stakeholders including representatives from all subsurface projects for which ROCs may overlap.

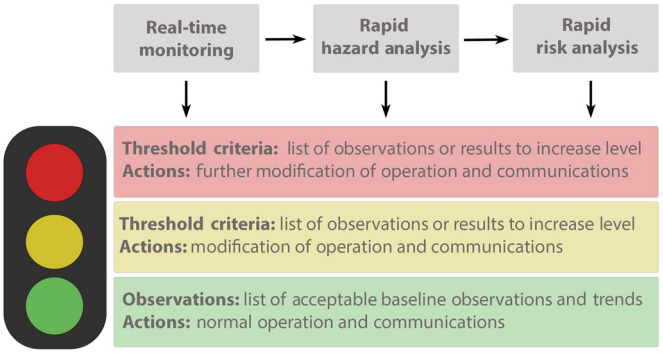


Figure 1. Example adaptive traffic light system. Real time seismic, hydraulic, and operational monitoring can either directly increase the response level or indirectly help inform rapid hazard and risk analyses that may prompt a change in response level due to updated results. The color version of this figure is available only in the electronic edition.

Early evaluation period. The first year of injection operations should be considered an early evaluation period. During the early evaluation period, the seismogenic and hydrologic behavior of the target reservoir and underlying basements units should be continually analyzed to calibrate, verify, and/or update the preinjection models and parameters. Forecasts of the level of induced seismicity derived from preinjection assessment using estimated values are likely to be of limited value without this calibration and verification step.

Late evaluation period. After operations cease at the site, seismic monitoring, the O&C plan, and the induced seismicity mitigation plan should continue until the pressure stabilizes, stress perturbations achieve steady-state values, and it is established that the seismic frequency–magnitude behavior is approaching baseline tectonic conditions, as measured in step 4.

Liability and insurance. Liability and compensation coverage for damages cause by GCS-induced earthquakes should be included in the induced seismicity mitigation plan as a last means of indirect mitigation. Such indirect mitigation has been used in EGS contexts in the past (Giardini, 2009). Operators should be sufficiently covered or demonstrate sufficient assets to self-insure against damages from induced seismicity. In areas where several GCS operators are active, an induced event may occur because of the sum of all activity in the vicinity (e.g., Dempsey and Riffault, 2019). Therefore, it may be sensible for operators to pay contributions to an insurance fund that would then compensate for any damages resulting from induced seismicity in a shared ROC.

Conclusions

GCS is a technology that promises to remove greenhouse gas emissions from the atmosphere by injecting captured CO_2 into

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deep subsurface rock formations for long-term storage. One inherent risk associated with this technology is induced seismicity. Here we present a suite of seven recommended focus areas, which when combined would be able to help evaluate, manage, communicate, and mitigate the induced seismicity hazard associated with GCS projects. These recommended practices can serve as general guidelines to proactively deal with induced seismicity issues, setting expectations for operators, regulators, and the public. Although each carbon storage project will be unique and will require a custom approach, these general science-based recommended practices can be used as a starting point for any site-specific induced seismicity risk management plan.

Data and Resources

No data were used in this article.

Declaration of Competing Interests

The authors acknowledge that there are no conflicts of interest recorded.

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DOT	US Department of Transportation
PHMSA	Pipeline and Hazardous Materials Safety Administration
OPS	Office of Pipeline Safety – Accident Investigation Division

Principal Investigator	Wesley Mathews
Acting Accident Investigation Director	Chris Ruhl
Date of Report	May 26, 2022
Subject	Failure Investigation Report - Denbury Gulf Coast Pipelines, LLC – Pipeline Rupture/ Natural Force Damage

Operator, Location, & Consequences

Date of Failure	February 22, 2020
Commodity Released	Carbon Dioxide
City, County and State	Satartia, Yazoo County, MS
OpID and Operator Name	32545, Denbury Gulf Coast Pipelines, LLC
Unit # and Unit Name	75379 – MS-2
WMS Activity ID	20-176125
Milepost (MP) / Location	MP 6.6 / Pipeline Stationing 348+63
Type of Failure	Natural Force Damage
Fatalities	None
Injuries	None
Description of Area Impacted	Rural, “Could Affect” High Consequence Area (HCA) - Other Populated Area
Total Costs	$ 3,947,009

Key Points

- On February 22, 2020, a carbon dioxide (CO_2) pipeline operated by Denbury Gulf Coast Pipelines LLC (Denbury) ruptured in proximity to the community of Satartia, Mississippi. The rupture followed heavy rains that resulted in a landslide, creating excessive axial strain on a pipeline weld.
- Carbon dioxide is considered minimally toxic by inhalation and is classified as an asphyxiant, displacing the oxygen in air. Symptoms of CO_2 exposure may include headache and drowsiness. Individuals exposed to higher concentrations may experience rapid breathing, confusion, increased cardiac output, elevated blood pressure, and increased arrhythmias. Extreme CO_2 concentrations can lead to death by asphyxiation.
- When CO_2 in a super-critical phase (which is common for CO_2 pipelines) releases into open air, it naturally vaporizes into a heavier than air gas and dissipates. During the February 22 event, atmospheric conditions and unique topographical features of the accident site significantly delayed dissipation of the heavier-than-air vapor cloud. Pipeline operators are required to establish atmospheric models to prepare for emergencies—Denbury's model did not contemplate a release that could affect the Village of Satartia.
- Local emergency responders were not informed by Denbury of the rupture and the nature of the unique safety risks of the CO_2 pipeline. As a result, responders had to guess the nature of the risk, in part making assumptions based on reports of a "green gas" and "rotten egg smell" and had to contemplate appropriate mitigative actions. Fortunately, responders decided to quickly isolate the affected area by shutting down local highways and evacuating people in proximity to the release. Denbury reported on its PHMSA F 7000.1 accident report that 200 residents surrounding the rupture location were evacuated, and forty-five people were taken to the hospital. Denbury also reported that to the company's knowledge, one individual was admitted to the hospital for reasons unrelated to the pipeline failure. No fatalities were reported.
- This event demonstrated the need for:
    - Pipeline company awareness and mitigation efforts directed at addressing integrity threats due to changing climate, geohazards, and soil stability issues.
    - Improved public engagement efforts to ensure public and emergency responder awareness of nearby CO_2 pipeline and pipeline facilities and what to do if a CO_2 release occurs. This is especially important for communities in low-lying areas, with certain topographical features such as rivers and valleys.

Executive Summary

On February 22, 2020, at 7:06 p.m. Central Standard Time (CST[1]), Denbury's 24-inch Delhi (Delhi) Pipeline ruptured, releasing liquid CO_2 that immediately began to vaporize at atmospheric conditions. The site of the rupture was on the northeast side of Highway 433 (HWY 433), approximately one mile southeast of Satartia, Mississippi. Denbury subsequently reported the rupture released an estimated total of 31,405[2] barrels of CO_2. Following the accident, investigators from the Pipeline and Hazardous Material Safety Administration's (PHMSA's) Accident Investigation Division (AID) and Southwest Regional Office, conducted an investigation, including an onsite investigation.

Liquid CO_2 vaporizes when released to the atmosphere. Carbon dioxide vapor is 1.53 times heavier than air, and displaces oxygen, so it can act as an asphyxiant to humans and animals. The National Institute for Occupational Safety and Health has established that concentrations of 40,000 parts per million (ppm) are immediately dangerous to life and health. The Occupational Safety and Health Administration has established 5000 ppm as a permissible exposure limit, which is an 8-hour time-weighted average. The weather conditions and unique topography of the accident site prevented the CO_2 vapor from rapidly dispersing and allowing a plume to form that migrated toward Satartia. Upon learning of the pipeline rupture, Yazoo County Office of Emergency Management (Yazoo County OEM) shut down HWY 433 to all traffic and evacuated the area. Local authorities evacuated approximately 200 people near the rupture, including the entire town of Satartia (around 50 residents), and three homes across the Yazoo River. According to Denbury's PHMSA F 7000.1 accident report, forty-five people sought medical attention at local hospitals, including individuals who were caught in the vapor cloud while driving a vehicle. One individual was admitted to the hospital for reasons unrelated to the pipeline failure. There were no fatalities.

The pipeline failed on a steep embankment adjacent to HWY 433, which had recently subsided. Heavy rains are believed to have led to a landslide, which created axial strain on the pipeline and resulted in a full circumferential girth weld failure. After the accident, Denbury, under PHMSA's oversight, cut out the failed sections of pipe and sent them to Det Norske Veritas' (DNV) Columbus, Ohio laboratory for metallurgical analysis. DNV confirmed the initial onsite observations of a girth weld failure.

PHMSA's investigation also revealed several contributing factors to the accident, including but not limited to, Denbury not addressing the risks of geohazards in its plans and procedures, underestimating the potential affected areas that could be impacted by a release in its CO_2 dispersion model, and not notifying local responders to advise them of a potential failure.

System Details

Denbury's Delhi Pipeline, on which the failure occurred, consists of 77 miles of 24-inch diameter pipeline, the majority of which is located within Mississippi. The entire Delhi Pipeline system flows east to west, beginning at the Jackson Dome in Mississippi and terminating in Delhi, Louisiana. Denbury primarily uses the CO_2 for enhanced oil recovery (EOR) for Denbury Resources Inc. onshore oil wells. The pipeline is controlled from the Denbury control room located in Plano, Texas.

[1] All times are reported in CST unless otherwise noted.

[2] Denbury reported a total release volume of 31,405 barrels in Form PHMSA F-7000.1, Accident Report – Hazardous Liquid Pipeline Systems, dated November 25, 2020. The actual release volume likely exceeded this amount due to a valve operation error, however, Denbury has not confirmed and reported any new release volume to PHMSA.

Following the Delhi Pipeline rupture, two of Denbury's local oilfields were cut off from its CO_2 supply and assumed non-EOR operation while the pipeline remained out of service. One oilfield returned to full EOR operation before repairs were made to the Delhi Pipeline as the oilfield had an alternate supply of CO_2. The other oilfield conducted non-EOR operations until the pipeline was repaired and returned to service in October 2020.

Stupp Corporation manufactured the pipe in 2007 and Denbury installed it in 2009. The pipe was manufactured to API 5L X80 grade, with an electric resistance welded (ERW) longitudinal weld seam, a 0.469-inch wall thickness on the mainline pipe, 0.540-inch wall thickness on the bored pipe section under roads, which was 240 feet in length and more than 30 feet below HWY 433. The pipe is coated with fusion bonded epoxy (FBE) and was installed by horizontal directional drill. During construction, Denbury welded the pipe joints using an API 1104 qualified welding procedure. The procedure specified using an E6010 electrode root pass, followed by an E9018 electrode hot pass, then E10045 electrode for subsequent passes.

The maximum operating pressure of the Delhi Pipeline is 2160 pounds per square inch gauge (psig). At the time of the rupture, Denbury was operating the Delhi Pipeline at an estimated pressure of 1400 psig, which was above the 1070 psig needed to maintain CO_2 in a supercritical state.

Denbury's control room isolated the failed pipeline section by remotely operating the mainline block valves (MLBVs) at Redwood, Satartia, and Tinsley. There is approximately 9.55 miles of pipe between the Tinsley and Satartia MLBVs, which are the two MLBVs closest to the rupture.

Events Leading up to the Failure

According to the National Weather Service (NWS), accumulated rainfall data between January 1, 2020, through February 29, 2020 (60 days) for each of the cities of Greenville, Greenwood, Vicksburg, and Jackson, Mississippi – which form a relative square (Figure 1) around Satartia and Yazoo County[3] – was 17.43 inches, 19.41 inches, 23.2 inches, and 23.36 inches of rain, respectively. The amount of rain recorded in these four cities was between 7.44 and 13.63 inches above the annual historical average for the same 60-day timespan. Significant variations in environmental/climate conditions such as ambient temperatures and rainfall can impact soil stability and erosion patterns. Landslides are typically associated with periods of heavy rain, particularly in susceptible areas with the right combination of slope and soil-type. On May 26, 2022, PHMSA issued an updated Advisory Bulletin to remind operators of gas and hazardous liquid pipelines of the importance of identifying and mitigating risks caused by changes in environmental and geological conditions on their pipeline facilities.

[3] Neither Yazoo City, Satartia, nor Yazoo County had historic NWS data for the desired date range.

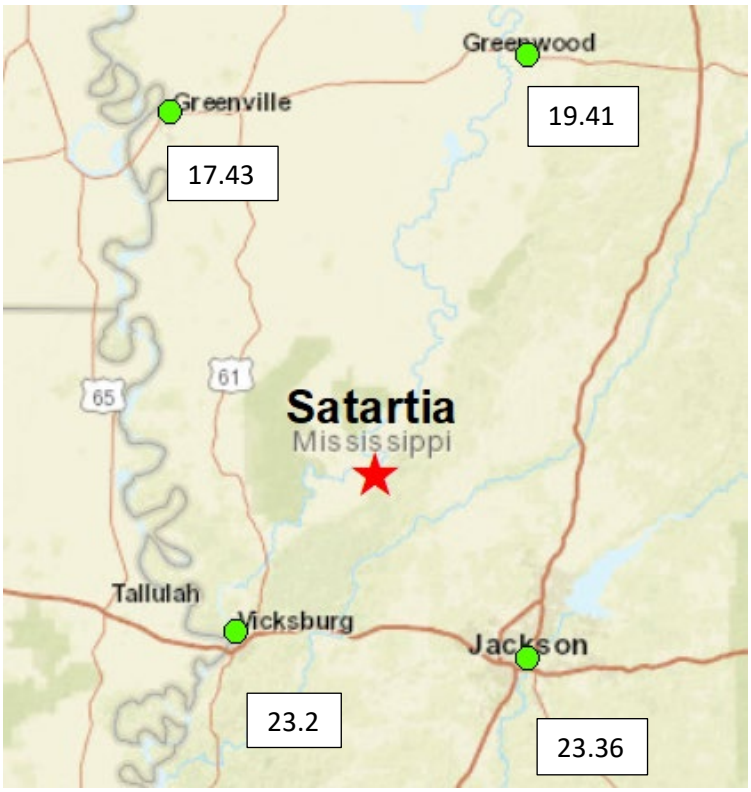


Figure 1: Map of Cities Relative to Satartia and Their Respective Rain Totals Between January 1, 2020, and February 29, 2020

On November 9, 2018, the Delhi Pipeline experienced a girth weld rupture at a valve location during pipeline reloading activities, and not attributed to natural force damage. Laboratory analysis indicated the release was the result of large thermal differential stresses being exerted on the pipeline from CO_2 loading at two different locations at the same time. The pipe between the two loading points shrank due to chilling from the CO_2, causing the girth weld connecting the pipeline to the valve body to rupture. The report found no evidence of inadequate mechanical properties or chemical composition anomalies in the ruptured weld. Denbury updated their procedure to prevent similar occurrences.

Prior to the accident, on November 8, 2019, Yazoo County first responders practiced a full-scale county response during a drill for a rail accident, however Denbury was not a participant in the drill. Local responders believe that the drill prepared them to respond to this event. Denbury had not conducted any drills with local responders since Denbury's modeling had not identified that Satartia would be impacted by a rupture of the pipeline.

Emergency Response

The Delhi Pipeline was operating normally prior to the February 22, 2020 accident.

Approximated Timeline

The following timeline was developed utilizing information provided by the Yazoo County OEM, [4] Denbury, and PHMSA investigator notes.

On February 22, 2020:

- 7:06 p.m. – Denbury's 24-inch pipeline ruptured.
- 7:07 p.m. – Denbury's control room was alerted by its supervisory control and data acquisition (SCADA) system of a pressure drop.
- 7:14 p.m. – Denbury control room remotely closed three MLBVs (one MLBV at Tinsley Station, which is upstream of the rupture site, and two MLBVs at Satartia and Redwood, which are downstream of the rupture).
- 7:15 p.m. – Denbury control room received SCADA confirmation that the MLBVs were closed.
- 7:15 p.m. – Yazoo County OEM dispatcher received an initial report of a "foul smell and green fog across the highway." Based on that information, responders responded under the assumption there was a possible chlorine leak and began contacting people from the local water utility company.
- 7:17 p.m. – Yazoo County OEM dispatcher received a call regarding a person possibly having a seizure. Responders began contacting personnel responsible for a nearby water well as the description of the report indicated chlorine gas.
- 7:19 p.m. – Denbury dispatched personnel to attempt to confirm MLBVs were closed successfully and to identify the location of the release.
- 7:26 p.m. – HWY 433 was ordered closed by local officials due to belief a chlorine leak was occurring.
- 7:30 p.m. – A responder commented that it sounded like a gas line had erupted. It was around this same time that another responder fielded a call from someone in the area who could hear a loud roar. This led the responders to believe that the accident was not chlorine gas related. First responders redirected their efforts to a possible CO_2 and hydrogen sulfide release, based on the initial first-hand reports from community members.
- 7:30 p.m. – First responders accessed a plume model generated by the NWS correlating local meteorological data with product type which indicated the CO_2 would move from the release site directly toward Satartia. Responders then called for the evacuation of Satartia. The scope of the response expanded as the CO_2 cloud dispersed, requiring an Incident Command (IC), commanded by the Chief of the District Three Volunteer Fire Department.
- 7:39 p.m. – Yazoo County OEM closed Highway 3 to traffic (intersection with HWY 433 is about 2/3-mile northwest of the rupture site).
- 7:43 p.m. – IC confirmed Denbury's CO_2 pipeline had ruptured; however, no one could get close to the release site due to the ongoing release of CO_2.
- 7:48 p.m. – Denbury's Tinsley Station Manager was contacted by IC and informed that Denbury's pipeline had ruptured. IC made Denbury aware of the response measures being taken. Denbury informed the IC that the Jackson Dome formation was shut down and that company personnel had been dispatched to check that the MLBVs were closed.

[4] The events entered in the Yazoo County OEM recording system are time stamped upon entry and may be delayed by seconds or minutes from the actual time of the event.

- 7:57 p.m. – Yazoo County OEM blocked off Mechanicsburg Road (around two miles southeast of the rupture site; intersects with HWY 433).
- 7:58 p.m. – According to Yazoo County OEM records, the Mississippi Department of Environmental Quality (MDEQ) contacted the Center for Toxicology & Environmental Health (CTEH) requesting technicians be dispatched to the rupture site with air monitoring equipment.
- 8:06 p.m. – The first Denbury representative arrived near the rupture site after confirming MLBV closures.
- 8:24 p.m. – Yazoo County OEM dispatch confirmed the second Denbury representative arrived near the rupture site.
- 9:06 p.m. – A Denbury representative from the Plano, Texas office called the National Response Center (NRC) to report their Delhi Pipeline had ruptured, releasing an estimated 222 barrels of liquid carbon dioxide (Report No. 1271847).
- 9:25 p.m. – Representatives from the CTEH and Denbury's environmental contractor E3 Environmental (E3) arrived on scene to conduct air monitoring to support the IC.
- 10:25 p.m. – Tinsley MLBV was completely closed.[5]
- 10:30 p.m. – CTEH initiated real-time air monitoring.

On February 23, 2020:

- 1:49 a.m. – The IC established a warming shelter at a local middle school for evacuees.
- 8:00 a.m. – Evacuees were allowed to return home. Air monitoring services were extended to anyone who requested the service. Evacuees were encouraged to vent their homes by opening doors and windows. The closure of HWY 433 was lifted after heavy equipment was used to clear mud that was deposited by the rupture.
- 11:34 a.m. – Real-time air monitoring concluded.

On February 24, 2020:

- 6:56 p.m., Denbury called the NRC and made the PHMSA required 48-hour update (Report No. 1272001). The update stated 21,873 barrels of liquid CO_2 had been released.[5]

Personnel from the Vicksburg Fire Department, including paramedics, District Three Volunteer Fire Department, Pafford EMS, Mississippi Emergency Management Agency, CF Industries, MDEQ, Madison County Fire Department, Warren County Fire Department, NWS, Local Police Departments, Yazoo County OEM, CTEH, E3, and Denbury participated in the emergency response efforts.

Local emergency responders utilized regular media, social media posts, phone calls, and door-to-door checks to notify homeowners and affected individuals of the CO_2 release.

A total of approximately 200 people were evacuated, which included those who were evacuated out of the area and those who were not allowed to pass through the area. During post-accident interviews, PHMSA learned that individuals on HWY 433 and in the area nearest to the migrating CO_2 vapor cloud experienced vehicle engine issues. This included individuals in a vehicle off of HWY 433, who succumbed to the effects of exposure to the released CO_2 and required emergency assistance to be evacuated. PHMSA also learned that one of two residents living in a dwelling in closest proximity to the pipeline rupture

[5] Denbury reported an updated estimate of 31,405 barrels to PHMSA on November 25, 2020.

passed out upon investigating the cloud. She later came-to and was able to evacuate to safety with her partner. Denbury reported a total of forty-five people sought medical attention at local hospitals.

Emergency Response Air Monitoring Plan

CTEH (Denbury's third-party contractor) in consultation with the IC developed an air monitoring plan to ensure the safety of response personnel, the community, and site characterization. CTEH implemented the plan to monitor for concentrations of CO_2, hydrogen-sulfide (H_2S), and oxygen (O_2) using handheld real-time instrumentation throughout the community and within homes of residents who requested monitoring. Air monitoring was conducted from 10:30 p.m. on February 22, 2020, until approximately 11:30 a.m. on February 23, 2020. Monitoring was performed using calibrated RAE Systems instruments made by Honeywell.

Carbon dioxide is considered minimally toxic by inhalation, unless in higher concentrations. CO_2 is classified as an asphyxiant, displacing the oxygen in breathing air. Symptoms of CO_2 exposure may include headache and drowsiness. Those exposed to higher concentrations may experience rapid breathing, confusion, increased cardiac output, elevated blood pressure, and increased arrhythmias. Extreme CO_2 concentrations can lead to death by asphyxiation.

In the hours after the rupture, after outdoor ambient air CO_2 levels continuously measured below 5,000 ppm, responders performed initial indoor assessment monitoring within residences and church buildings potentially impacted by the accident. During initial indoor assessments, CO_2 concentrations ranged from 200 through 28,000 ppm, with six detections exceeding 5,000 ppm. In these instances, occupants of these structures were advised to open doors and windows to allow ventilation to dissipate the concentration of CO_2 and not to enter prior to re-assessment. No subsequent CO_2 readings in the hours after the accident were recorded above 3,500 ppm during re-assessments.

According to firsthand accounts, as well as secondhand accounts from first responders, there was a "rotten eggs" odor associated with the CO_2 release and gas plume. A rotten eggs odor can be attributed to the presence of H_2S, which is naturally occurring in the geologic formation that serves as a source of the CO_2 in the pipeline. PHMSA reviewed the CTEH air monitoring results and did not identify any observed readings of H_2S by monitoring equipment. The monitoring equipment's detection limit for H_2S was 0.1 ppm.

Summary of Return-to-Service

Prior to repairing the pipeline, Denbury contracted an engineering firm to develop plans to cutout the failed section of pipe and to mitigate potential future land movement. Denbury installed soil shoring along HWY 433 to stabilize the area. PHMSA evaluated the repair plan and monitored its execution.

On September 1, 2020, Denbury began replacing the failed pipe section, and on September 26, Denbury welded the new sections of pipe into the pipeline at the accident location. Mannesmann Line Pipe manufactured the newly installed 80-foot section of 24-inch nominal diameter pipe in 2019. The pipe is API 5L X70 grade, has 0.562-inch wall thickness and an ERW longitudinal weld seam, and is coated with FBE.

Denbury restarted the pipeline on October 26, 2020. Prior to the restart of the pipeline, Denbury provided PHMSA with a proposed restart plan for review and approval. Concurrently with Denbury's repair and restart efforts, PHMSA conducted an inspection of Denbury's pipeline operations, which resulted in the

issuance of various enforcement actions, including a Notice of Probable Violation in connection with this accident.[6]

Investigation Details

On February 23, 2020, at 10:09 a.m., a PHMSA AID investigator from Oklahoma City arrived at the intersection of HWY 433 and Highway 3 to meet with Denbury representatives and emergency response organizations. The group then proceeded to the site of the rupture (Figure 2). By that time, the IC had demobilized, and roadblocks had been removed. Denbury crews were in the process of setting up caution fencing and slowing traffic on HWY 433 for public and worker safety. The rupture crater was on the northeast side of HWY 433 (Figure 2).



Figure 2: Vehicle is Parked on HWY 433 - The White is Ice Generated by the Release of CO_2 - The Blue Arrow Points North (Aerial Drone Photograph Courtesy of the Mississippi Emergency Management Agency)

[6] CPF 4-2022-017-NOPV, dated May 26, 2022.

The topography along the pipeline right-of-way (ROW) in this area is a steep hill that rises from the valley containing the Big Black River to the east, goes relatively flat across the crest of the hill containing HWY 433, and then slopes downward toward the valley containing the Yazoo River to the west.



Figure 3: Crater Created by the Rupture Containing Fallen Debris (dry ice, and the failed pipe sections) (Blue Arrow is Pointing at the Pipeline Separation)

The pipeline separated at a girth weld. The pipeline self-excavated due to the discharge of CO_2. The auto refrigeration generated by the CO_2 discharge and accompanying chance in phase covered the area with a thick layer of ice (Figures 2, 3, and 4). The upstream section of pipe was not covered in ice, and a slightly jagged edge was observed on the rupture edge (Figure 4). The crater was an estimated 40-feet-deep on the downstream (HWY 433) side and about four-feet-deep on the upstream side.



Figure 4: The failed pipe sections shown separated by a few inches.

Upon release, the CO_2 transitioned from a liquid to a gaseous phase resulting in a refrigeration effect. Although the pipeline was shut down by 7:15 pm, the remaining contents of the pipe continued to vent to the atmosphere for several hours. The CO_2 was heavier than air[7] and followed a path downhill. CO_2 moved down the slope to the east and remained in the bowl of the crater. As the discharged volume increased, and without significant winds to disperse the CO_2, the CO_2 moved over the crest of the hill then west into the valley, reaching Satartia.

Plume Model

First responders utilized a plume model generated by the NWS to base the decision to evacuate Satartia (Figure 5).

[7] CO_2 has a density approximately 1.53 times that of air in standard atmospheric conditions.

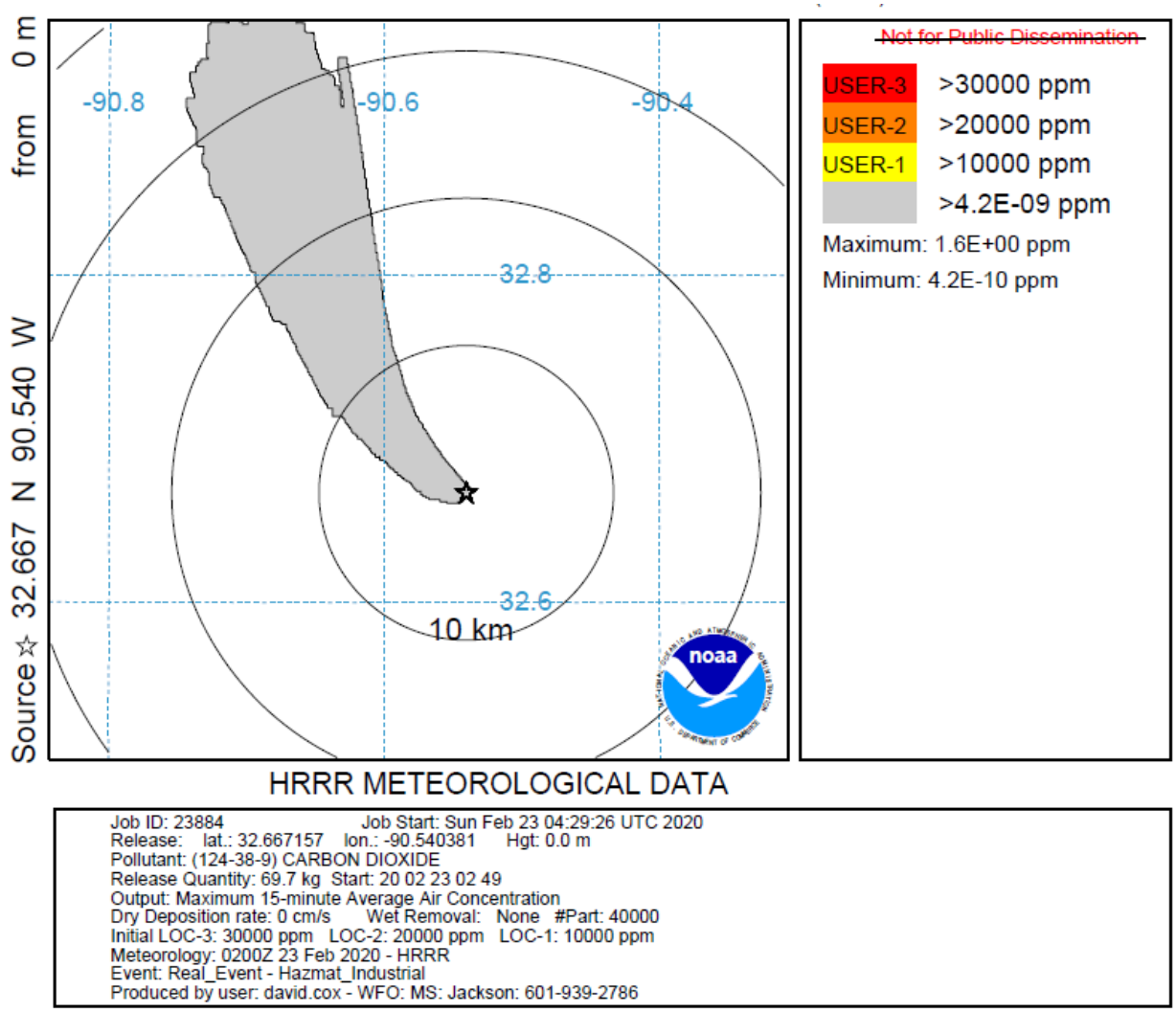


Figure 5: This Chart Shows the Plume Model Data Generated by the National Weather Service/NOAA - The Model Indicates the Direction a Plume or Cloud of CO_2 Would Have Followed from Ground Level While Dissipating, According to Atmospheric Data at the Time of the Release - Each Ring is 10 Kilometers (Satartia is Less Than Two Kilometers Northwest of Release Site, Indicated by the Star)[8]

Prior to the accident in 2011, Denbury had contracted a third-party company to generate an affected radius model for a potential CO_2 release. Denbury used the model to generate a zone along the pipeline ROW to identify pipeline segments which were within or "could affect" an HCA and to develop its Public Awareness Program (PAP).[9] The model established a zone for the Delhi Pipeline (Figure 6) that left Satartia outside of the affected radius, and therefore the pipeline segment was not identified by Denbury as a "could affect" HCA. Additionally, Satartia was not included in Denbury's PAP or considered in any local

[8] The NWS approved inclusion of the chart within this report and clarified that "Not for Public Dissemination" (in the upper right-hand corner) pertains to real-time emergency response utilization, due to inherent uncertainties with several variables.
[9] Required by 49 CFR § 195.440.

emergency response plans. The rupture location was one mile from the center of Satartia, where the entire town was evacuated.



Figure 6: Topographical Map Showing the Delhi Pipeline (Green) and Denbury's Buffer Zone (Red) on Either Side of the Pipeline and the Proximity to Satartia (Blue Star Indicates the Rupture Site)

Soil and Geohazards

The soil at the failure location is identified as a loess soil typical to the area and was relatively saturated due to the recent heavy rainfall. Dry patches of the soil observed later were powdery, confirming the loess to be silty and clayey, indicating the soil would be prone to absorb water as well as collapse or slump under the right conditions.[10] Vertical erosion of the steeply sloped hillside, made heavier by water saturation, produced enough axial loading on the pipeline to cause the girth weld to fail.

On February 23, 2020, representatives from the Mississippi Department of Transportation assessed the condition of the crater's edge along HWY 433. They determined the highway was at risk of further land movement due to current and future soil saturation from rainfall, the weight of the trees at the edge of the crater, and the HWY 433 ROW was impinged upon by the rupture. Crews were dispatched to cut down the trees and mitigate the risk of additional land movement. Soil instability along roads is not unusual in the region. The PHMSA AID investigator observed road damage from unstable soil slumping away from a road along roadways leading to the accident site. Denbury representatives mentioned that, along the Delhi pipeline, they experience two to three issues per year involving land movement. Denbury's Integrity Management Program (IMP)[11] identified "geo-technical hazards" (geohazards) as a potential risk to its pipelines but lacked additional details concerning threat assessment or preventative/mitigative measures for its operational pipelines such as: using in-line inspection tools with inertial measurement unit sensors, conducting bending strain analysis, or conducting geohazard assessments. Denbury's operations and

[10] Loess soil has a relatively high porosity (typically around 50-55%) and often contains vertical capillaries that allow the sediment to fracture and form vertical bluffs. The loess bluffs tend to erode vertically.
[11] Required by 49 CFR § 195.452.

maintenance (O&M) procedures also lacked substantive information regarding geohazard identification, assessment, remediation, and training for employees. Additionally, Denbury's pipeline patrolling program to address federal regulations[12] was commonly performed by aerial patrol. Records indicate that patrols were made at regular intervals, but no geohazards were identified at the rupture location.

In response to this rupture, PHMSA initiated a specialized review of Denbury's IMP and O&M activities. PHMSA's investigation identified that Denbury did not address the risk of geohazards to the pipeline and take adequate preventive and mitigative measures prior to the accident. PHMSA has made specific recommendations for the development of the company's geohazards program, which the company has initiated.

Welding Procedure

Denbury hired DNV prior to the construction of the pipeline to develop its welding procedure. The welding procedure was developed to API 1104, 20th edition and was qualified. The procedure utilized an E6010 electrode root pass, an E9018G electrode hot pass and E10045 electrode filler and cap pass. In 2009, a welding procedure utilizing an E10045 electrode was a pipeline construction industry leading development. Prior industry practice was to utilize cellulosic-type electrodes.

Laboratory and Root Cause Analyses

Once shoring was installed at the rupture site, the upstream pipe was excavated, and two failed pipe sections were cut out. On March 11, 2020, the two failure samples were secured and shipped to DNV's laboratory in Columbus, Ohio for metallurgical analysis. Denbury worked with Mears to provide DNV with a testing protocol to facilitate analysis. Mott MacDonald performed a site-specific soil movement analysis to estimate soil loading on the pipeline and perform a stress analysis. Mears performed a Root Cause Analysis utilizing the above information, coupled with information from original construction documentation, site observations, operating and maintenance records, and related information.

Denbury reported the results of the metallurgical findings and stress evaluations in a written accident report on the PHMSA Form 7000.1 and indicated soil movement upstream of the failure location induced axial stresses sufficient to cause an overload condition, and the soil movement was promoted by unusually heavy rainfall. There were no material defects observed with the pipe or the failed weld which could have contributed to the failure.

PHMSA notes the failed girth weld exhibited both ductile and brittle fracture appearances. A typical overload condition in these circumstances is expected to be ductile, unless the grain structure of the steel is susceptible to brittle failure, or the material has been chilled below its transition temperature from ductile to brittle behavior. A failure scenario whereby a leak initiates, and the refrigeration effect associated with vaporization of the liquid CO_2 results in a brittle failure is plausible, although a distinct failure origin within the girth weld was not identified.

Findings and Contributing Factors

PHMSA has determined that the failure of the Delhi Pipeline was a result of soil movement which caused excessive axial loading leading to failure at the girth weld. Area topography, soil type, and large amounts of rain over the preceding months saturated and vertically eroded the loess soil on the side of the hill above the pipeline. It is unclear whether prevalent warmer temperatures in the two months preceding the heavy rainfall could have contributed to the soil instability as well.

[12] Required by 49 CFR § 195.412.

Contributing factors include:

- Denbury's O&M procedures did not appear to address the potential for pipeline damage due to soil instability despite having prior experience with and knowledge of land movement risks.
- Denbury's IMP did not appear to address integrity threat identification and/or assessment for geohazards or preventative or mitigative measures.
- Denbury's aerial patrols did not identify a geohazard at the failure location prior to the accident.
- Denbury's CO_2 dispersion model underestimated the potential affected area that could be impacted by a release. As a result, the pipeline segment was not identified as a "could affect" HCA, and Satartia was not included in Denbury's PAP.
- Denbury did not notify local responders advising them of a potential failure. Local responders contacted Denbury approximately 40-minutes after the rupture. This led to confusion in understanding circumstances associated with the emergency and hindered the ability of first responders and community members to safely navigate the emergency.

Appendices

Appendix A Map

Appendix B NRC Reports Nos. 1271847 and 1272001

Appendix C PHMSA 7000.1 Final Report

Appendix D Mears Metallurgical and Root Cause Failure Analysis

Appendix E CTEH Air Monitoring Summary Report

Appendix A Map



Figure 7: An ArcGIS-generated Satellite Map with the Site of the Rupture Marked by the Red Star (the Insert Map on the Bottom Right Shows the Rupture Site Location Within the State of Mississippi)

Appendix B NRC Report No. 1271847

Mathews, Wesley (PHMSA)

From: HQS-SMB-NRC@uscg.mil
Sent: Thursday, May 21, 2020 12:28 PM
To: Mathews, Wesley (PHMSA)
Subject: NRC#1271847

NATIONAL RESPONSE CENTER 1-800-424-8802
*** For Public Use ***
Information released to a third party shall comply with any
applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1271847

INCIDENT DESCRIPTION

*Report taken by NRC on 22-FEB-20 at 22:06 ET.
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
Incident was discovered on 22-FEB-20 at 19:07 local incident time.
Affected Medium: AIR / ATMOSPHERE

SUSPECTED RESPONSIBLE PARTY

Organization: DENBURY GULF COAST PIPELINE

PLANO, TX 75024

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION

32.658 County: YAZOO
-90.537
City: SATARTIA State: MS
Distance from City: 1 MILES
Direction from City: SE
OFF HWY 433

RELEASED MATERIAL(S)

CHRIS Code: CDO Official Material Name: CARBON DIOXIDE
Also Known As:
Qty Released: 222 BARREL(S)

DESCRIPTION OF INCIDENT

CARBON DIOXIDE RELEASED FROM A 24 INCH PIPELINE DUE TO AN UNKNOWN CAUSE AT THIS TIME. CALLER STATES THE CONTROL ROOM NOTICED A PRESSURE DROP AT 1907 AND PERSONNEL VERIFIED LEAK AT 2046. CALLER ALSO STATES THERE WERE EMERGENCY RESPONDERS ONSITE AS WELL WHEN THEIR PERSONNEL ARRIVED ONSCENE.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: NO Sent to Hospital: Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:NO Who Evacuated: Radius/Area:

Damages: UNKNOWN

Closure Type	Description of Closure	Hours Closed	Direction of Closure

Air: NO

Road: YES HWY 3; HWY 433; EAGLE BEND RD; PERRY CREEK RD — Major Artery:YES
Waterway:NO

Track: NO

Passengers Transferred: NO
Environmental Impact: UNKNOWN
Media Interest: NONE

REMEDIAL ACTIONS

VALVES WERE IMMEDIATELY SHUT AFTER IDENTIFICATION OF PRESSURE DROP.
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

ADDITIONAL AGENCIES NOTIFIED

Federal:
State/Local:
State/Local On Scene:
State Agency Number:

NOTIFICATIONS BY NRC

CENTERS FOR DISEASE CONTROL (GRASP)
22-FEB-20 22:14

DEPT OF HEALTH AND HUMAN SERVICES (SECRETARY'S OPERATION CENTER (SOC))
22-FEB-20 22:14
AZ OFFIC OF INTEL AND ANALYSIS (FIELD INTELLIGENCE AND INTEGRATION DIVISION)
22-FEB-20 22:14
DHS DEFENSE THREAT REDUCTION AGENCY (CHEMICAL AND BIOLOGICAL TECHNOLOGIES DEPARTMENT)
22-FEB-20 22:14
MS DEPT OF HOMELAND SECURITY (I&A FIELD OPS)
22-FEB-20 22:14
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
22-FEB-20 22:14
U.S. EPA IV (MAIN OFFICE)
22-FEB-20 22:17
U.S. EPA IV (EPA RRT4)
22-FEB-20 22:14
GULF STRIKE TEAM (MAIN OFFICE)
22-FEB-20 22:14
JFO-LA (COMMAND CENTER)
22-FEB-20 22:14
MS ANALYSIS AND INFORMATION CENTER (FUSION CENTER)
22-FEB-20 22:14
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
22-FEB-20 22:14
NOAA RPTS FOR MS (MAIN OFFICE)
22-FEB-20 22:14
NTSB PIPELINE (MAIN OFFICE)
22-FEB-20 22:14
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
22-FEB-20 22:14
PIPELINE & HAZMAT SAFETY ADMIN (HAZARDOUS MATERIAL ACCIDENT INVESTIGATION)
22-FEB-20 22:14
DOI FOR REGION 4 (MAIN OFFICE)
22-FEB-20 22:14
REPORTING PARTY (RP SUBMITTER)
22-FEB-20 22:14
SECTOR LOWER MISSISSIPPI RIVER (AUTO NRC NOTIFICATIONS)
22-FEB-20 22:14
SHELBY SHERIFF'S OFFICE (CRIMINAL INTELLIGENCE UNIT)
22-FEB-20 22:14
MS EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
22-FEB-20 22:14
TEXAS FUSION CENTER (COUNTER TERRORISM)
22-FEB-20 22:14
USCG DISTRICT 8 (MAIN OFFICE)
22-FEB-20 22:14
USCG DISTRICT 8 (PLANNING)
22-FEB-20 22:14

ADDITIONAL INFORMATION

THE ROAD CLOSURES ARE STILL ONGOING.

*** END INCIDENT REPORT #1271847 ***

Report any problems by calling 1-800-424-8802

PLEASE VISIT OUR WEB SITE AT

https://gcc01.safelinks.protection.outlook.com/?url=http%3A%2F%2Fnrc.uscg.mil%2F&data=02%7C01%7Cwesley.mathews%40dot.gov%7Cb811754707c84b89d3e308d7fdabecad%7Cc4cd245b44f04395a1aa3848d258f78b%7C0%7C0%7C637256787161489692&sdata=MzcfYqeN1ZIbmwqa6VXKF9L%2FqieIW0kTmcl30E8JTvk%3D&reserved=0

Appendix B NRC Report No. 1272001

Mathews, Wesley (PHMSA)

From: HQS-SMB-NRC@uscg.mil
Sent: Thursday, May 21, 2020 12:30 PM
To: Mathews, Wesley (PHMSA)
Subject: NRC#1272001

NATIONAL RESPONSE CENTER 1-800-424-8802
*** For Public Use ***
Information released to a third party shall comply with any
applicable federal and/or state Freedom of Information and Privacy Laws

Incident Report # 1272001

INCIDENT DESCRIPTION

*Report taken by NRC on 24-FEB-20 at 19:56 ET.
Incident Type: PIPELINE
Incident Cause: UNKNOWN
Affected Area:
Incident was discovered on 22-FEB-20 at 22:06 local incident time.
Affected Medium: AIR / ATMOSPHERE

SUSPECTED RESPONSIBLE PARTY

Organization: DENBURY GULF COAST PIPELINE

PLANO, TX 75024

Type of Organization: PRIVATE ENTERPRISE

INCIDENT LOCATION
OFF HWY 433 County: YAZOO
City: SATARTIA State: MS
Distance from City: 1 MILES
Direction from City: Latitude: 32° 39' 28" N

Longitude: 090° 32' 13" W

RELEASED MATERIAL(S)
CHRIS Code: CDO Official Material Name: CARBON DIOXIDE
Also Known As:
Qty Released: 21873 BARREL(S)

DESCRIPTION OF INCIDENT
///THIS IS A PHMSA 48HR UPDATE TO NRC REPORT 1271847///

UPDATE: THE CORRECT LAT/LONG FOR THE INCIDENT IS 32.65785 NORTH AND
-90.53695 WEST.
TWO HUNDRED PRIVATE CITIZENS WERE EVACUATED FROM THEIR HOMES IN THE

AREA OF THE RELEASE.
FORTY FIVE PEOPLE WERE TAKEN TO A HOSPITAL. THE NUMBER OF PEOPLE TAKEN TO A HOSPITAL DUE TO INJURIES IS UNKNOWN
TWO PEOPLE ARE STILL AT THE HOSPITAL AS OF 24-FEB-20. THE RELEASE WAS COMPLETELY SECURED AT 23:08HRS ON SATURDAY THE 22-FEB-20. ROAD CLOSURES AND EVACUATION ORDER WAS LIFTED AT 08:00AM ON SUNDAY FEBRUARY 23RD. THE TOTAL AMOUNT OF THE RELEASE WAS DETERMINED TO BE 21,873 BARRELS OF CARBON DIOXIDE GAS. THE EVACUATION RADIUS WAS .25 MILES. TV NEWS AND POSSIBLY NEWSPAPERS IN THE LOCAL AREA AS WELL AS NATIONAL NEWS REPORTED THE INCIDENT. RELEASE DURATION WAS 4 HOURS. PHMSA, MS OIL AND GAS, MS DEQ WERE NOTIFIED. MS DEQ, STATE POLICE, LOCAL FD, LOCAL PD, EMS AND HWY PATROL WERE ALL ON SCENE.

ORIGINAL REPORT: CARBON DIOXIDE RELEASED FROM A 24 INCH PIPELINE DUE TO AN UNKNOWN CAUSE AT THIS TIME. CALLER STATES THE CONTROL ROOM NOTICED A PRESSURE DROP AT 1907 AND PERSONNEL VERIFIED LEAK AT 2046. CALLER ALSO STATES THERE WERE EMERGENCY RESPONDERS ONSITE AS WELL WHEN THEIR PERSONNEL ARRIVED ONSCENE.

INCIDENT DETAILS

Pipeline Type: TRANSMISSION
DOT Regulated: YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water: NO
Pipeline Covered: UNKNOWN

IMPACT

Fire Involved: NO Fire Extinguished: UNKNOWN

INJURIES: YES 45 Sent to Hospital:45 Empl/Crew: Passenger:
FATALITIES: NO Empl/Crew: Passenger: Occupant:
EVACUATIONS:YES 200 Who Evacuated: EVERYONE Radius/Area:.25 Mile(s)

Damages: NO

Closure Type	Description of Closure	Hours Closed	Direction of Closure

Air: NO

Road: YES HWY 3; HWY 433; EAGLE BEND RD; PERRY CREEK RD Major Artery:YES

Waterway:NO

Track: NO

Passengers Transferred: NO
Environmental Impact: UNKNOWN
Media Interest: HIGH

REMEDIAL ACTIONS

VALVES WERE IMMEDIATELY SHUT AFTER IDENTIFICATION OF PRESSURE DROP
Release Secured: YES
Release Rate:
Estimated Release Duration:

WEATHER

ADDITIONAL AGENCIES NOTIFIED

Federal: PHMSA
State/Local: MS DEQ, MS OIL AND GAS, SATATE POLICE
State/Local On Scene: MS DEQ, STATE POLICE, PD, FD, EMS
State Agency Number:

NOTIFICATIONS BY NRC

AGCY TOXIC SUBST & DISEASE REGISTRY (HHS)
24-FEB-20 20:22
CENTERS FOR DISEASE CONTROL (GRASP)
24-FEB-20 20:22
DEPT OF HEALTH AND HUMAN SERVICES (SECRETARY'S OPERATION CENTER (SOC))
24-FEB-20 20:22
AZ OFFIC OF INTEL AND ANALYSIS (FIELD INTELLIGENCE AND INTEGRATION DIVISION)
24-FEB-20 20:22
DHS DEFENSE THREAT REDUCTION AGENCY (CHEMICAL AND BIOLOGICAL TECHNOLOGIES DEPARTMENT)
24-FEB-20 20:22
MS DEPT OF HOMELAND SECURITY (I&A FIELD OPS)
24-FEB-20 20:22
DOT CRISIS MANAGEMENT CENTER (MAIN OFFICE)
24-FEB-20 20:22
EPA HQ EMERGENCY OPERATIONS CENTER (MAIN OFFICE (AUTO))
24-FEB-20 20:22
EPA HQ EMERGENCY OPERATIONS CENTER (AFTER HOURS SECONDARY)
24-FEB-20 20:36
U.S. EPA IV (MAIN OFFICE)
24-FEB-20 20:32
U.S. EPA IV (EPA RRT4)
24-FEB-20 20:22
GULF STRIKE TEAM (MAIN OFFICE)
24-FEB-20 20:22
INFO ANALYSIS AND INFRA PROTECTION (MAIN OFFICE)
24-FEB-20 20:22
JFO-LA (COMMAND CENTER)
24-FEB-20 20:22
MS ANALYSIS AND INFORMATION CENTER (FUSION CENTER)
24-FEB-20 20:22
NATIONAL INFRASTRUCTURE COORD CTR (MAIN OFFICE)
24-FEB-20 20:22
NOAA RPTS FOR MS (MAIN OFFICE)
24-FEB-20 20:22
NRC COMMAND DUTY OFFICER (MAIN OFFICE)

24-FEB-20 20:50
NTSB PIPELINE (MAIN OFFICE)
24-FEB-20 20:22
OCCUPATIONAL SAFETY & HEALTH ADMIN (MAIN OFFICE)
24-FEB-20 20:22
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY (AUTO))
24-FEB-20 20:22
PIPELINE & HAZMAT SAFETY ADMIN (OFFICE OF PIPELINE SAFETY WEEKDAYS (VERBAL))
24-FEB-20 20:34
PIPELINE & HAZMAT SAFETY ADMIN (HAZARDOUS MATERIAL ACCIDENT INVESTIGATION)
24-FEB-20 20:22
DOI FOR REGION 4 (MAIN OFFICE)
24-FEB-20 20:22
REPORTING PARTY (RP SUBMITTER)
24-FEB-20 20:22
SECTOR LOWER MISSISSIPPI RIVER (AUTO NRC NOTIFICATIONS)
24-FEB-20 20:22
SHELBY SHERIFF'S OFFICE (CRIMINAL INTELLIGENCE UNIT)
24-FEB-20 20:22
MS EMERGENCY MANAGEMENT AGENCY (MAIN OFFICE)
24-FEB-20 20:22
TEXAS FUSION CENTER (COUNTER TERRORISM)
24-FEB-20 20:22
USCG DISTRICT 8 (MAIN OFFICE)
24-FEB-20 20:22
USCG DISTRICT 8 (PLANNING)
24-FEB-20 20:22

ADDITIONAL INFORMATION
///THIS IS A PHMSA 48HR UPDATE TO NRC REPORT 1271847///

*** END INCIDENT REPORT #1272001 ***
Report any problems by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT
https://gcc01.safelinks.protection.outlook.com/?url=http%3A%2F%2Fnrc.uscg.mil%2F&data=02%7C01%7Cwesley.mathews%40dot.gov%7Cb126276307c640ca447f08d7fdab7b17%7Cc4cd245b44f04395a1aa3848d258f78b%7C0%7C0%7C637256785273758601&sdata=wEB2Wbm6RWfQw9nm5l8g20CXFahn0HprioWivv3i1Uo%3D&reserved=0

Appendix C PHMSA 7000.1 Final Report

NOTICE: This report is required by 49 CFR Part 195. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day that such violation persists except that the maximum civil penalty shall not exceed $1,000,000 as provided in 49 USC 60122.		OMB NO: 2137-0047 EXPIRATION DATE: 8/31/2020
U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration	**Original Report Date:**	03/21/2020
	No.	20200087 - 34574 --- (DOT Use Only)

ACCIDENT REPORT - HAZARDOUS LIQUID PIPELINE SYSTEMS

A federal agency may not conduct or sponsor, and a person is not required to respond to, nor shall a person be subject to a penalty for failure to comply with a collection of information subject to the requirements of the Paperwork Reduction Act unless that collection of information displays a current valid OMB Control Number. The OMB Control Number for this information collection is 2137-0047. All responses to the collection of information are mandatory. Send comments regarding this burden or any other aspect of this collection of information, including suggestions for reducing the burden to: Information Collection Clearance Officer, PHMSA, Office of Pipeline Safety (PHP-30) 1200 New Jersey Avenue, SE, Washington, D.C. 20590.

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the PHMSA Pipeline Safety Community Web Page at http://www.phmsa.dot.gov/pipeline/library/forms.*

PART A - KEY REPORT INFORMATION

Report Type: *(select all that apply)*	**Original:**	**Supplemental:**	**Final:**
		Yes	**Yes**
Last Revision Date:	11/25/2020		
1. Operator's OPS-issued Operator Identification Number (OPID):	32545		
2. Name of Operator	DENBURY GULF COAST PIPELINES, LLC		
3. Address of Operator:			
3a. Street Address	5851 LEGACY CIRCLE SUITE 1200		
3b. City	PLANO		
3c. State	Texas		
3d. Zip Code	75024		
4. Local time *(24-hr clock)* and date of the Accident:	02/22/2020 19:07		
5. Location of Accident:			
Latitude / Longitude	32.65785, -90.53695		
6. National Response Center Report Number (if applicable):	1271847		
7. Local time *(24-hr clock)* and date of initial telephonic report to the National Response Center (if applicable):	02/22/2020 20:51		
8. Commodity released: *(select only one, based on predominant volume released)*	CO2 (Carbon Dioxide)		
- Specify Commodity Subtype:			
- If "Other" Subtype, Describe:			
- If Biofuel/Alternative Fuel and Commodity Subtype is Ethanol Blend, then % Ethanol Blend:			
- If Biofuel/Alternative Fuel and Commodity Subtype is Biodiesel, then Biodiesel Blend e.g. B2, B20, B100			
9. Estimated volume of commodity released unintentionally (Barrels):	9,532.00		
10. Estimated volume of intentional and/or controlled release/blowdown (Barrels):	21,873.00		
11. Estimated volume of commodity recovered (Barrels):			
12. Were there fatalities?	No		
- If Yes, specify the number in each category:			
12a. Operator employees			
12b. Contractor employees working for the Operator			
12c. Non-Operator emergency responders			
12d. Workers working on the right-of-way, but NOT associated with this Operator			
12e. General public			
12f. Total fatalities (sum of above)			
13. Were there injuries requiring inpatient hospitalization?	No		
- If Yes, specify the number in each category:			
13a. Operator employees			
13b. Contractor employees working for the Operator			
13c. Non-Operator emergency responders			
13d. Workers working on the right-of-way, but NOT associated with this Operator			
13e. General public			
13f. Total injuries (sum of above)			

14. Was the pipeline/facility shut down due to the Accident?	Yes
- If No, Explain:	
- If Yes, complete Questions 14a and 14b: *(use local time, 24-hr clock)*	
14a. Local time and date of shutdown:	02/22/2020 19:15
14b. Local time pipeline/facility restarted:	10/26/2020 12:30
- Still shut down? (* Supplemental Report Required)	
15. Did the commodity ignite?	No
16. Did the commodity explode?	No
17. Number of general public evacuated:	200
18. Time sequence *(use local time, 24-hour clock)*:	
18a. Local time Operator identified Accident - effective 7- 2014 changed to "Local time Operator identified failure":	02/22/2020 20:20
18b. Local time Operator resources arrived on site:	02/22/2020 20:20

PART B - ADDITIONAL LOCATION INFORMATION

1. Was the origin of the Accident onshore?	Yes
If Yes, Complete Questions (2-12)	
If No, Complete Questions (13-15)	
- If Onshore:	
2. State:	Mississippi
3. Zip Code:	39194
4. City	Not Within a Municipality
5. County or Parish	Yazoo County
6. Operator-designated location:	Milepost/Valve Station
Specify:	6.6
7. Pipeline/Facility name:	Delhi
8. Segment name/ID:	Delhi
9. Was Accident on Federal land, other than the Outer Continental Shelf (OCS)?	No
10. Location of Accident:	Pipeline Right-of-way
11. Area of Accident (as found):	Underground
Specify:	Under soil
- If Other, Describe:	
Depth-of-Cover (in):	360
12. Did Accident occur in a crossing?	No
- If Yes, specify type below:	
- If Bridge crossing –	
Cased/ Uncased:	
- If Railroad crossing –	
Cased/ Uncased/ Bored/drilled	
- If Road crossing –	
Cased/ Uncased/ Bored/drilled	
- If Water crossing –	
Cased/ Uncased	
- Name of body of water, if commonly known:	
- Approx. water depth (ft) at the point of the Accident:	
- Select:	
- If Offshore:	
13. Approximate water depth (ft) at the point of the Accident:	
14. Origin of Accident:	
- In State waters - Specify:	
- State:	
- Area:	
- Block/Tract #:	
- Nearest County/Parish:	
- On the Outer Continental Shelf (OCS) - Specify:	
- Area:	
- Block #:	
15. Area of Accident:	

PART C - ADDITIONAL FACILITY INFORMATION

1. Is the pipeline or facility:	Interstate
2. Part of system involved in Accident:	Onshore Pipeline, Including Valve Sites
- If Onshore Breakout Tank or Storage Vessel, Including Attached Appurtenances, specify:	
3. Item involved in Accident:	Weld, including heat-affected zone
- If Pipe, specify:	
3a. Nominal diameter of pipe (in):	24
3b. Wall thickness (in):	.540

3c. SMYS (Specified Minimum Yield Strength) of pipe (psi):	80,000
3d. Pipe specification:	API 5L
3e. Pipe Seam , specify:	Longitudinal ERW - High Frequency
- If Other, Describe:	
3f. Pipe manufacturer:	Stupp Corporation
3g. Year of manufacture:	2007
3h. Pipeline coating type at point of Accident, specify:	Field Applied Epoxy
- If Other, Describe:	
- If Weld, including heat-affected zone, specify. If Pipe Girth Weld, 3a through 3h above are required:	Pipe Girth Weld
- If Other, Describe:	
- If Valve, specify:	
- If Mainline, specify:	
- If Other, Describe:	
3i. Manufactured by:	
3j. Year of manufacture:	
- If Tank/Vessel, specify:	
- If Other - Describe:	
- If Other, describe:	
4. Year item involved in Accident was installed:	2009
5. Material involved in Accident:	Carbon Steel
- If Material other than Carbon Steel, specify:	
6. Type of Accident Involved:	Other
- If Mechanical Puncture – Specify Approx. size:	
in. (axial) by	
in. (circumferential)	
- If Leak - Select Type:	
- If Other, Describe:	
- If Rupture - Select Orientation:	
- If Other, Describe:	
Approx. size: in. (widest opening) by	
in. (length circumferentially or axially)	
- If Other – Describe:	Guillotine Type Failure

PART D - ADDITIONAL CONSEQUENCE INFORMATION

1. Wildlife impact:	No
1a. If Yes, specify all that apply:	
- Fish/aquatic	
- Birds	
- Terrestrial	
2. Soil contamination:	No
3. Long term impact assessment performed or planned:	No
4. Anticipated remediation:	No
4a. If Yes, specify all that apply:	
- Surface water	
- Groundwater	
- Soil	
- Vegetation	
- Wildlife	
5. Water contamination:	No
5a. If Yes, specify all that apply:	
- Ocean/Seawater	
- Surface	
- Groundwater	
- Drinking water: *(Select one or both)*	
- Private Well	
- Public Water Intake	
5b. Estimated amount released in or reaching water (Barrels):	
5c. Name of body of water, if commonly known:	
6. At the location of this Accident, had the pipeline segment or facility been identified as one that "could affect" a High Consequence Area (HCA) as determined in the Operator's Integrity Management Program?	No
7. Did the released commodity reach or occur in one or more High Consequence Area (HCA)?	Yes
7a. If Yes, specify HCA type(s): *(Select all that apply)*	
- Commercially Navigable Waterway:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	

- High Population Area:	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Other Populated Area	Yes
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	No
- Unusually Sensitive Area (USA) - Drinking Water	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
- Unusually Sensitive Area (USA) - Ecological	
Was this HCA identified in the "could affect" determination for this Accident site in the Operator's Integrity Management Program?	
8. Estimated cost to Operator – effective 12-2012, changed to "Estimated Property Damage":	
8a. Estimated cost of public and non-Operator private property damage paid/reimbursed by the Operator – effective 12-2012, "paid/reimbursed by the Operator" removed	$ 225,899
8b. Estimated cost of commodity lost	$ 11,130
8c. Estimated cost of Operator's property damage & repairs	$ 3,504,518
8d. Estimated cost of Operator's emergency response	$ 205,462
8e. Estimated cost of Operator's environmental remediation	$ 0
8f. Estimated other costs	$ 0
Describe:	
8g. Estimated total costs (sum of above) – effective 12-2012, changed to "Total estimated property damage (sum of above)"	$ 3,947,009

PART E - ADDITIONAL OPERATING INFORMATION

1. Estimated pressure at the point and time of the Accident (psig):	1,402.00
2. Maximum Operating Pressure (MOP) at the point and time of the Accident (psig):	2,160.00
3. Describe the pressure on the system or facility relating to the Accident (psig):	Pressure did not exceed MOP
4. Not including pressure reductions required by PHMSA regulations (such as for repairs and pipe movement), was the system or facility relating to the Accident operating under an established pressure restriction with pressure limits below those normally allowed by the MOP?	No
- If Yes, Complete 4.a and 4.b below:	
4a. Did the pressure exceed this established pressure restriction?	
4b. Was this pressure restriction mandated by PHMSA or the State?	
5. Was "Onshore Pipeline, Including Valve Sites" OR "Offshore Pipeline, Including Riser and Riser Bend" selected in PART C, Question 2?	Yes
- If Yes - (*Complete 5a. – 5f below)* effective 12-2012, changed to *"(Complete 5.a – 5.e below)"*	
5a. Type of upstream valve used to initially isolate release source:	Remotely Controlled
5b. Type of downstream valve used to initially isolate release source:	Remotely Controlled
5c. Length of segment isolated between valves (ft):	50,406
5d. Is the pipeline configured to accommodate internal inspection tools?	Yes
- If No, Which physical features limit tool accommodation? (*select all that apply)*	
- Changes in line pipe diameter	
- Presence of unsuitable mainline valves	
- Tight or mitered pipe bends	
- Other passage restrictions (i.e. unbarred tee's, projecting instrumentation, etc.)	
- Extra thick pipe wall (applicable only for magnetic flux leakage internal inspection tools)	
- Other -	
- If Other, Describe:	
5e. For this pipeline, are there operational factors which significantly complicate the execution of an internal inspection tool run?	Yes
- If Yes, Which operational factors complicate execution? (*select all that apply*)	
- Excessive debris or scale, wax, or other wall buildup	

- Low operating pressure(s)	
- Low flow or absence of flow	Yes
- Incompatible commodity	
- Other -	
- If Other, Describe:	
5f. Function of pipeline system:	> 20% SMYS Regulated Trunkline/Transmission
6. Was a Supervisory Control and Data Acquisition (SCADA)-based system in place on the pipeline or facility involved in the Accident?	Yes
If Yes -	
6a. Was it operating at the time of the Accident?	Yes
6b. Was it fully functional at the time of the Accident?	Yes
6c. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	Yes
6d. Did SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	Yes
7. Was a CPM leak detection system in place on the pipeline or facility involved in the Accident?	No
- If Yes:	
7a. Was it operating at the time of the Accident?	
7b. Was it fully functional at the time of the Accident?	
7c. Did CPM leak detection system information (such as alarm (s), alert(s), event(s), and/or volume calculations) assist with the detection of the Accident?	
7d. Did CPM leak detection system information (such as alarm (s), alert(s), event(s), and/or volume calculations) assist with the confirmation of the Accident?	
8. How was the Accident initially identified for the Operator?	CPM leak detection system or SCADA-based information (such as alarm(s), alert(s), event(s), and/or volume calculations)
- If Other, Specify:	
8a. If "Controller", "Local Operating Personnel", including contractors", "Air Patrol", or "Ground Patrol by Operator or its contractor" is selected in Question 8, specify:	
9. Was an investigation initiated into whether or not the controller(s) or control room issues were the cause of or a contributing factor to the Accident?	Yes, specify investigation result(s): (select all that apply)
- If No, the Operator did not find that an investigation of the controller(s) actions or control room issues was necessary due to: *(provide an explanation for why the operator did not investigate)*	
- If Yes, specify investigation result(s): *(select all that apply)*	
- Investigation reviewed work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	Yes
- Investigation did NOT review work schedule rotations, continuous hours of service (while working for the Operator), and other factors associated with fatigue	
Provide an explanation for why not:	
- Investigation identified no control room issues	Yes
- Investigation identified no controller issues	Yes
- Investigation identified incorrect controller action or controller error	
- Investigation identified that fatigue may have affected the controller(s) involved or impacted the involved controller(s) response	
- Investigation identified incorrect procedures	
- Investigation identified incorrect control room equipment operation	
- Investigation identified maintenance activities that affected control room operations, procedures, and/or controller response	
- Investigation identified areas other than those above:	
Describe:	

PART F - DRUG & ALCOHOL TESTING INFORMATION

1. As a result of this Accident, were any Operator employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
1a. Specify how many were tested:	

1b. Specify how many failed:	
2. As a result of this Accident, were any Operator contractor employees tested under the post-accident drug and alcohol testing requirements of DOT's Drug & Alcohol Testing regulations?	No
- If Yes:	
2a. Specify how many were tested:	
2b. Specify how many failed:	

PART G – APPARENT CAUSE

Select only one box from PART G in shaded column on left representing the APPARENT Cause of the Accident, and answer the questions on the right. Describe secondary, contributing or root causes of the Accident in the narrative (PART H).

Apparent Cause:	G2 - Natural Force Damage

G1 - Corrosion Failure - only one **sub-cause** can be picked from shaded left-hand column

Corrosion Failure – Sub-Cause:	
- If External Corrosion:	
1. Results of visual examination:	
- If Other, Describe:	
2. Type of corrosion: *(select all that apply)*	
- Galvanic	
- Atmospheric	
- Stray Current	
- Microbiological	
- Selective Seam	
- Other:	
- If Other, Describe:	
3. The type(s) of corrosion selected in Question 2 is based on the following: *(select all that apply)*	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
4. Was the failed item buried under the ground?	
- If Yes :	
4a. Was failed item considered to be under cathodic protection at the time of the Accident?	
If Yes - Year protection started:	
4b. Was shielding, tenting, or disbonding of coating evident at the point of the Accident?	
4c. Has one or more Cathodic Protection Survey been conducted at the point of the Accident?	
If "Yes, CP Annual Survey" – Most recent year conducted:	
If "Yes, Close Interval Survey" – Most recent year conducted:	
If "Yes, Other CP Survey" – Most recent year conducted:	
- If No:	
4d. Was the failed item externally coated or painted?	
5. Was there observable damage to the coating or paint in the vicinity of the corrosion?	
- If Internal Corrosion:	
6. Results of visual examination:	
- Other:	
7. Type of corrosion *(select all that apply)*: -	
- Corrosive Commodity	
- Water drop-out/Acid	
- Microbiological	
- Erosion	
- Other:	
- If Other, Describe:	
8. The cause(s) of corrosion selected in Question 7 is based on the following *(select all that apply)*: -	
- Field examination	
- Determined by metallurgical analysis	
- Other:	
- If Other, Describe:	
9. Location of corrosion *(select all that apply)*: -	
- Low point in pipe	
- Elbow	
- Other:	

- If Other, Describe:	
10. Was the commodity treated with corrosion inhibitors or biocides?	
11. Was the interior coated or lined with protective coating?	
12. Were cleaning/dewatering pigs (or other operations) routinely utilized?	
13. Were corrosion coupons routinely utilized?	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Tank/Vessel.	
14. List the year of the most recent inspections:	
14a. API Std 653 Out-of-Service Inspection	
- No Out-of-Service Inspection completed	
14b. API Std 653 In-Service Inspection	
- No In-Service Inspection completed	
Complete the following if any Corrosion Failure sub-cause is selected AND the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
15. Has one or more internal inspection tool collected data at the point of the Accident?	
15a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage Tool	
Most recent year:	
- Ultrasonic	
Most recent year:	
- Geometry	
Most recent year:	
- Caliper	
Most recent year:	
- Crack	
Most recent year:	
- Hard Spot	
Most recent year:	
- Combination Tool	
Most recent year:	
- Transverse Field/Triaxial	
Most recent year:	
- Other	
Most recent year:	
Describe:	
16. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
If Yes -	
Most recent year tested:	
Test pressure:	
17. Has one or more Direct Assessment been conducted on this segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident::	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
18. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
18a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	

G2 - Natural Force Damage - only one **sub-cause** can be picked from shaded left-handed column

Natural Force Damage – Sub-Cause:	Heavy Rains/Floods
- If Earth Movement, NOT due to Heavy Rains/Floods:	
1. Specify:	

- If Other, Describe:	
- If Heavy Rains/Floods:	
2. Specify:	Other
- If Other, Describe:	,Soil movement, promoted by unusually high rainfall averages and not a singular event, induced axial stresses sufficient to cause an overload condition.,,
- If Lightning:	
3. Specify:	
- If Temperature:	
4. Specify:	
- If Other, Describe:	
- If Other Natural Force Damage:	
5. Describe:	
Complete the following if any Natural Force Damage sub-cause is selected.	
6. Were the natural forces causing the Accident generated in conjunction with an extreme weather event?	No
6a. If Yes, specify: *(select all that apply)*	
- Hurricane	
- Tropical Storm	
- Tornado	
- Other	
- If Other, Describe:	
G3 - Excavation Damage - only one **sub-cause** can be picked from shaded left-hand column	
Excavation Damage – Sub-Cause:	
- If Previous Damage due to Excavation Activity: Complete Questions 1-5 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	
1. Has one or more internal inspection tool collected data at the point of the Accident?	
1a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run: -	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
2. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
3. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
4. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
5. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
5a. If Yes, for each examination, conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	

Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
Complete the following if Excavation Damage by Third Party is selected as the sub-cause.	
6. Did the operator get prior notification of the excavation activity?	
6a. If Yes, Notification received from: *(select all that apply)* -	
- One-Call System	
- Excavator	
- Contractor	
- Landowner	
Complete the following mandatory CGA-DIRT Program questions if any Excavation Damage sub-cause is selected.	
7. Do you want PHMSA to upload the following information to CGA-DIRT (www.cga-dirt.com)?	
8. Right-of-Way where event occurred: *(select all that apply)* -	
- Public	
- If "Public", Specify:	
- Private	
- If "Private", Specify:	
- Pipeline Property/Easement	
- Power/Transmission Line	
- Railroad	
- Dedicated Public Utility Easement	
- Federal Land	
- Data not collected	
- Unknown/Other	
9. Type of excavator:	
10. Type of excavation equipment:	
11. Type of work performed:	
12. Was the One-Call Center notified?	
12a. If Yes, specify ticket number:	
12b. If this is a State where more than a single One-Call Center exists, list the name of the One-Call Center notified:	
13. Type of Locator:	
14. Were facility locate marks visible in the area of excavation?	
15. Were facilities marked correctly?	
16. Did the damage cause an interruption in service?	
16a. If Yes, specify duration of the interruption (hours)	
17. Description of the CGA-DIRT Root Cause *(select only the one predominant first level CGA-DIRT Root Cause and then, where available as a choice, the one predominant second level CGA-DIRT Root Cause as well):*	
Root Cause:	
- If One-Call Notification Practices Not Sufficient, specify:	
- If Locating Practices Not Sufficient, specify:	
- If Excavation Practices Not Sufficient, specify:	
- If Other/None of the Above, explain:	
G4 - Other Outside Force Damage - *only one **sub-cause** can be selected from the shaded left-hand column*	
Other Outside Force Damage – Sub-Cause:	
- If Damage by Car, Truck, or Other Motorized Vehicle/Equipment NOT Engaged in Excavation:	
1. Vehicle/Equipment operated by:	
- If Damage by Boats, Barges, Drilling Rigs, or Other Maritime Equipment or Vessels Set Adrift or Which Have Otherwise Lost Their Mooring:	
2. Select one or more of the following IF an extreme weather event was a factor:	
- Hurricane	
- Tropical Storm	
- Tornado	
- Heavy Rains/Flood	
- Other	
- If Other, Describe:	
- If Previous Mechanical Damage NOT Related to Excavation: Complete Questions 3-7 ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is Pipe or Weld.	

3. Has one or more internal inspection tool collected data at the point of the Accident?	
3a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year conducted:	
- Ultrasonic	
Most recent year conducted:	
- Geometry	
Most recent year conducted:	
- Caliper	
Most recent year conducted:	
- Crack	
Most recent year conducted:	
- Hard Spot	
Most recent year conducted:	
- Combination Tool	
Most recent year conducted:	
- Transverse Field/Triaxial	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
4. Do you have reason to believe that the internal inspection was completed BEFORE the damage was sustained?	
5. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
6. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident:	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site:	
Most recent year conducted:	
7. Has one or more non-destructive examination been conducted at the point of the Accident since January 1, 2002?	
7a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted:	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	
Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
- If Intentional Damage:	
8. Specify:	
- If Other, Describe:	
- If Other Outside Force Damage:	
9. Describe:	

G5 - Material Failure of Pipe or Weld - only one **sub-cause** can be selected from the shaded left-hand column

Use this section to report material failures ONLY IF the "Item Involved in Accident" (from PART C, Question 3) is "Pipe" or "Weld."	
Material Failure of Pipe or Weld – Sub-Cause:	
1. The sub-cause shown above is based on the following: *(select all that apply)*	
- Field Examination	
- Determined by Metallurgical Analysis	
- Other Analysis	
- If "Other Analysis", Describe:	
- Sub-cause is Tentative or Suspected; Still Under Investigation	

(Supplemental Report required)	
- If Construction, Installation, or Fabrication-related:	
2. List contributing factors: *(select all that apply)*	
- Fatigue or Vibration-related	
Specify:	
- If Other, Describe:	
- Mechanical Stress:	
- Other	
- If Other, Describe:	
- If Environmental Cracking-related:	
3. Specify:	
- If Other - Describe:	
Complete the following if any Material Failure of Pipe or Weld sub-cause is selected.	
4. Additional factors: (*select all that apply*):	
- Dent	
- Gouge	
- Pipe Bend	
- Arc Burn	
- Crack	
- Lack of Fusion	
- Lamination	
- Buckle	
- Wrinkle	
- Misalignment	
- Burnt Steel	
- Other:	
- If Other, Describe:	
5. Has one or more internal inspection tool collected data at the point of the Accident?	
5a. If Yes, for each tool used, select type of internal inspection tool and indicate most recent year run:	
- Magnetic Flux Leakage	
Most recent year run:	
- Ultrasonic	
Most recent year run:	
- Geometry	
Most recent year run:	
- Caliper	
Most recent year run:	
- Crack	
Most recent year run:	
- Hard Spot	
Most recent year run:	
- Combination Tool	
Most recent year run:	
- Transverse Field/Triaxial	
Most recent year run:	
- Other	
Most recent year run:	
Describe:	
6. Has one or more hydrotest or other pressure test been conducted since original construction at the point of the Accident?	
- If Yes:	
Most recent year tested:	
Test pressure (psig):	
7. Has one or more Direct Assessment been conducted on the pipeline segment?	
- If Yes, and an investigative dig was conducted at the point of the Accident -	
Most recent year conducted:	
- If Yes, but the point of the Accident was not identified as a dig site -	
Most recent year conducted:	
8. Has one or more non-destructive examination(s) been conducted at the point of the Accident since January 1, 2002?	
8a. If Yes, for each examination conducted since January 1, 2002, select type of non-destructive examination and indicate most recent year the examination was conducted: -	
- Radiography	
Most recent year conducted:	
- Guided Wave Ultrasonic	
Most recent year conducted:	
- Handheld Ultrasonic Tool	

Most recent year conducted:	
- Wet Magnetic Particle Test	
Most recent year conducted:	
- Dry Magnetic Particle Test	
Most recent year conducted:	
- Other	
Most recent year conducted:	
Describe:	
G6 – Equipment Failure - only one **sub-cause** can be selected from the shaded left-hand column	
Equipment Failure – Sub-Cause:	
- If Malfunction of Control/Relief Equipment:	
1. Specify: *(select all that apply)* -	
- Control Valve	
- Instrumentation	
- SCADA	
- Communications	
- Block Valve	
- Check Valve	
- Relief Valve	
- Power Failure	
- Stopple/Control Fitting	
- ESD System Failure	
- Other	
- If Other – Describe:	
- If Pump or Pump-related Equipment:	
2. Specify:	
- If Other – Describe:	
- If Threaded Connection/Coupling Failure:	
3. Specify:	
- If Other – Describe:	
- If Non-threaded Connection Failure:	
4. Specify:	
- If Other – Describe:	
- If Other Equipment Failure:	
5. Describe:	
Complete the following if any Equipment Failure sub-cause is selected.	
6. Additional factors that contributed to the equipment failure: *(select all that apply)*	
- Excessive vibration	
- Overpressurization	
- No support or loss of support	
- Manufacturing defect	
- Loss of electricity	
- Improper installation	
- Mismatched items (different manufacturer for tubing and tubing fittings)	
- Dissimilar metals	
- Breakdown of soft goods due to compatibility issues with transported commodity	
- Valve vault or valve can contributed to the release	
- Alarm/status failure	
- Misalignment	
- Thermal stress	
- Other	
- If Other, Describe:	
G7 - Incorrect Operation - only one **sub-cause** can be selected from the shaded left-hand column	
Incorrect Operation – Sub-Cause:	
- If Tank, Vessel, or Sump/Separator Allowed or Caused to Overfill or Overflow	
1. Specify:	
- If Other, Describe:	

- If Other Incorrect Operation	
2. Describe:	
Complete the following if any Incorrect Operation sub-cause is selected.	
3. Was this Accident related to *(select all that apply)*: -	
- Inadequate procedure	
- No procedure established	
- Failure to follow procedure	
- Other:	
- If Other, Describe:	
4. What category type was the activity that caused the Accident?	
5. Was the task(s) that led to the Accident identified as a covered task in your Operator Qualification Program?	
5a. If Yes, were the individuals performing the task(s) qualified for the task(s)?	

G8 - Other Accident Cause - only one **sub-cause** can be selected from the shaded left-hand column

Other Accident Cause – Sub-Cause:	
- If Miscellaneous:	
1. Describe:	
- If Unknown:	
2. Specify:	

PART H - NARRATIVE DESCRIPTION OF THE ACCIDENT

On 2/22/2020 at 19:07, the Denbury Control Center (DCC) observed a low-pressure alarm at the Satartia motor operated valve (MOV) location on the Delhi segment. The Control Center Supervisor was notified and at 19:15 the upstream MOV, downstream MOV, and the Satartia MOV were closed by the DCC. Denbury operations personnel were immediately notified by the DCC of low-pressure alarms and valve closures and were mobilized to the area in addition to emergency response contractors. While mobilization of personnel occurred, the DCC closed all CO2 sources to Delhi segment between 19:26 and 19:28. At 19:54, a Denbury representative contacted the Tri-Community Fire Chief, who was on-site and identified himself as the Incident Commander on location acknowledging the incident was being managed in the Unified Command. Denbury personnel arrived on-site at 20:20 to confirm the Delhi segment had experienced a pipeline failure upstream of the Hwy 433 road crossing. At 20:21, a Denbury representative contacted the Yazoo County EMA, who was directing the Yazoo County Sheriffs Department, MS Highway Patrol, and MDOT. The Yazoo County EMA confirmed that they began facilitating the evacuation of residence near Satartia, MS at approximately 19:20. MSDEQ was notified at 19:58. Both MSDEQ and MEMA were on-scene and performing supporting agency roles during the emergency phase of the response (4 hours). At 20:51, the NRC was notified, and the CO2 leak was reported (NRC #1271847). At 21:36 emergency response contractors arrived on-site and began conducting preliminary air-monitoring for response personnel. At 21:55 additional emergency response contractors arrived on-site and began conducting community air monitoring and atmospheric testing in and around the failure site and the City of Satartia and the surrounding area. Air monitoring and atmospheric testing continued throughout the night. At 23:06, Denbury personnel observed no product coming from the failure location. At 0:00 on 2/23/2020, an Operation Period Briefing was conducted by the Unified Command. During the briefing, the incident command team instructed responders to continue air monitoring, conduct reconnaissance within the evacuated areas to ensure no people were left behind, clear the debris and soil off of HWY 433, and begin developing a plan to lift the evacuation. At 06:00 a planning meeting was conducted by the Unified Command. The recon team confirmed all personnel had been evacuated and reported seeing live cows, dogs, and cats throughout the evacuated area. The air monitoring team also reported that CO2 levels were down to ambient levels and the evacuation could be lifted. At 08:00 the Unified Command gave the All Clear, and the roads were opened and residents in the surrounding area were allowed to return to their homes. Personnel and a toxicologist from CTEH were made available to inspect homes prior to the residence re-entry. At 18:39 on 2/24/2020, the NRC was contacted and given a 48-hour update report (NRC #1272001). A total of 200 residents were evacuated and 45 residents were taken to the hospital. To Denburys knowledge, one individual was admitted to the hospital for reasons unrelated to the pipeline failure.

On 3/9/2020 pipeline samples of the failure location were removed, prepared for shipment, and sent to a testing laboratory on 3/11/2020. The results from the laboratory testing were received and shared with PHMSA on 6/26/2020.

Based on the findings of metallurgical and stress evaluations and the evidence of a code compliant pipeline, it is concluded that soil movement upstream of the failure location induced axial stresses sufficient to cause an overload condition and resulted in the pipeline rupture. Soil movement was promoted by unusually high rainfall averages and not a singular rainfall event.

The pipeline segment was repaired and on 10/26/2020 at 12:30 the pipeline was restarted with no issues.

PART I - PREPARER AND AUTHORIZED SIGNATURE

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Date	11/24/2020

Appendix D Mears Metallurgical and Root Cause Failure Analysis



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Study of Root Cause and Contributing Factors

Denbury – Yazoo County

Failure Investigation

Final Report

Revised 9/02/2021

Prepared for:

Denbury Resources Inc.

Prepared by:

Mears Group, Inc.

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September 2, 2021

Denbury Resources Inc.
5320 Legacy Drive
Plano, TX 75024
(214) 662-2536
chad.docekal@denbury.com

Attention: Chad Docekal

Subject: Denbury Delhi 24-inch Transmission Line failure Root Cause Analysis – Final Report, Revised 9/02/2021

Thank you for the opportunity to provide Denbury Resources with root cause investigation and analysis for the Denbury Delhi 24-inch transmission line near Satartia, Mississippi. This revision includes additional appendices providing supporting information and responses to questions provided to Mears 4/7/2021. If you have any questions or comments, please call me at (614) 832-3896.

Sincerely,

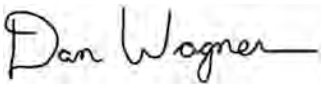
Kevin Garrity
Executive Vice President

Cc: Dan Wagner
Aida Lopez-Garrity
Kurt Lawson

SIGNATURE FORM

Study of Root Cause and Contributing Factors
Denbury – Yazoo County
Failure Investigation
Final Report

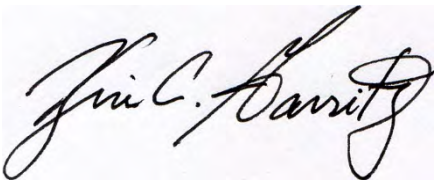
Prepared by:



Dan Wagner – Principal Technical Advisor — 9/02/2021 Date



Aida Lopez-Garrity – Executive Director – Special Projects — 9/2/2021 Date



Kevin C. Garrity, P.E., FNACE – Executive Vice President — 9/2/2021

Executive Summary

Mears Group, Inc. (Mears) was retained by Denbury Resources (Denbury) to support investigation efforts and provide a Root Cause Analysis (RCA) in coordination with their response to a pipeline failure on the Delhi 24-inch Transmission Line near Satartia, Mississippi. The failure is reported to have occurred February 22, 2020, with a rupture approximately 6.59 miles (stationing 348+26) downstream of the Tinsley, MS station.

The investigation into the cause and contributing factors to the Delhi 24-inch failure has been undertaken through the following activities:

- In-Situ investigations at the incident location,
- Corrosion and coating related assessments,
- A review of available documents and information associated with the design, specification, construction, operation and maintenance of the pipeline infrastructure, and
- Laboratory Analysis of the Failure.

Metallurgical Testing and Failure Analysis was performed on three samples of pipe from the failure site. The metallurgical testing laboratory completed the following tests and examinations:

- Physical examination,
- Photographic documentation and videography,
- Magnetic Particle Inspection,
- Scanning electron microscopy,
- Metallographic analysis,
- Hardness testing,
- Mechanical testing, and
- Chemical analysis.

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The results of the metallurgical testing have been analyzed for the purposes of this report and are relied upon in the formulation of the opinions and conclusions expressed in this report.

Based on the findings presented, the pipeline failure occurred at the girth weld due to an overload of axial stress on the weld. A possible contributing factor to the failure may have been axial stresses introduced by movement. These findings are supported by the following:

1. The brittle failure originated at a girth weld. The presence of soft regions with dimples (ductile mode) and cleavage facets (brittle mode) are characteristics typical of a failure from overload conditions.
2. The failure occurred due to axial stresses. There was no indication of a pre-existing defect and a specific failure initiation site was not apparent.
3. The weld metal for both the failed girth weld and the intact weld was found to have lower hardness values than the surrounding pipe materials indicating the weld metal was weaker than the pipe material and thus, more susceptible to overload under axial stress conditions. The findings do not suggest the failure resulted from a welding quality issue.
4. There was no evidence of internal or external corrosion that may have contributed to the failure mode.
5. The mechanical and chemical testing results were in accordance with the requirements for API 5L X-80M PSL 2 line pipe.
6. The microstructure of the pipe material U/S and D/S of the failed girth weld are consistent with modern X-80M PSL 2 line pipe steel.

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Acronyms and Abbreviations

API	American Petroleum Institute
ARO	Abrasion Resistant Overlay
CP	Cathodic Protection
CVN	Charpy V-Notch
D/S	Downstream
EDS	Energy-Dispersive Spectroscopy
ERW	Electric Resistance Welding
FATT	Fracture Appearance Transition Temperature
FBE	Fusion Bonded Epoxy
GW	Girth Weld
HAZ	Heat Affected Zone
HDD	Horizontal Directional Drilling
HF-ERW	High Frequency Electric Resistance Welding
HV	Hardness Value
ID	Inside Diameter
MAOP	Maximum Allowable Operating Pressure
MPI	Magnetic Particle Inspection
NWT	Nominal Wall Thickness
OD	Outside Diameter
PS	Pipe Sample
PSIG	Pounds per Square Inch Gauge
PSL	Product Specification Levels
RCA	Root Cause Analysis
SEM	Scanning Electron Microscope
SMYS	Specified Minimum Yield Strength
TS	Tensile Strength
U/S	Upstream
UTS	Ultimate Tensile Strength

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WT	Wall Thickness
YS	Yield Strength

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1.0 INTRODUCTION

Mears Group, Inc. (Mears) was retained by Denbury Resources (Denbury) to support investigation efforts and provide a Root Cause Analysis (RCA) in coordination with their response to a pipeline failure on the Delhi 24-inch Transmission Line near Satartia, Mississippi. The incident is reported to have occurred on February 22, 2020, when a failure occurred on the 24-inch Delhi Transmission Line, resulting a rupture of the pipeline.

The information, material and documentation reviewed and relied upon in the formation of the findings expressed include:

- Pipe and coating data,
- Alignment Sheets,
- Indirect inspection results,
- Google Earth™ imagery,
- As-built drawings and sketches,
- Onsite inspections,
- Field and laboratory test results,
- Metallurgical examination reports,
- Welding Procedures,
- Stress Analysis Report, and
- Personnel interviews.

The findings expressed are based upon the information reviewed to date and analyses performed to date and may be modified as new or additional information/analysis are considered.

2.0 BACKGROUND

The Delhi 24-inch Transmission Line serves as a carrier of carbon dioxide and is approximately 77.4 miles in length. The pipeline segment begins at the Denbury Tinsley Station in Yazoo County, Mississippi and continues to a meter station near Delhi, Louisiana. An overview of the pipeline segment is provided in Figure 1.

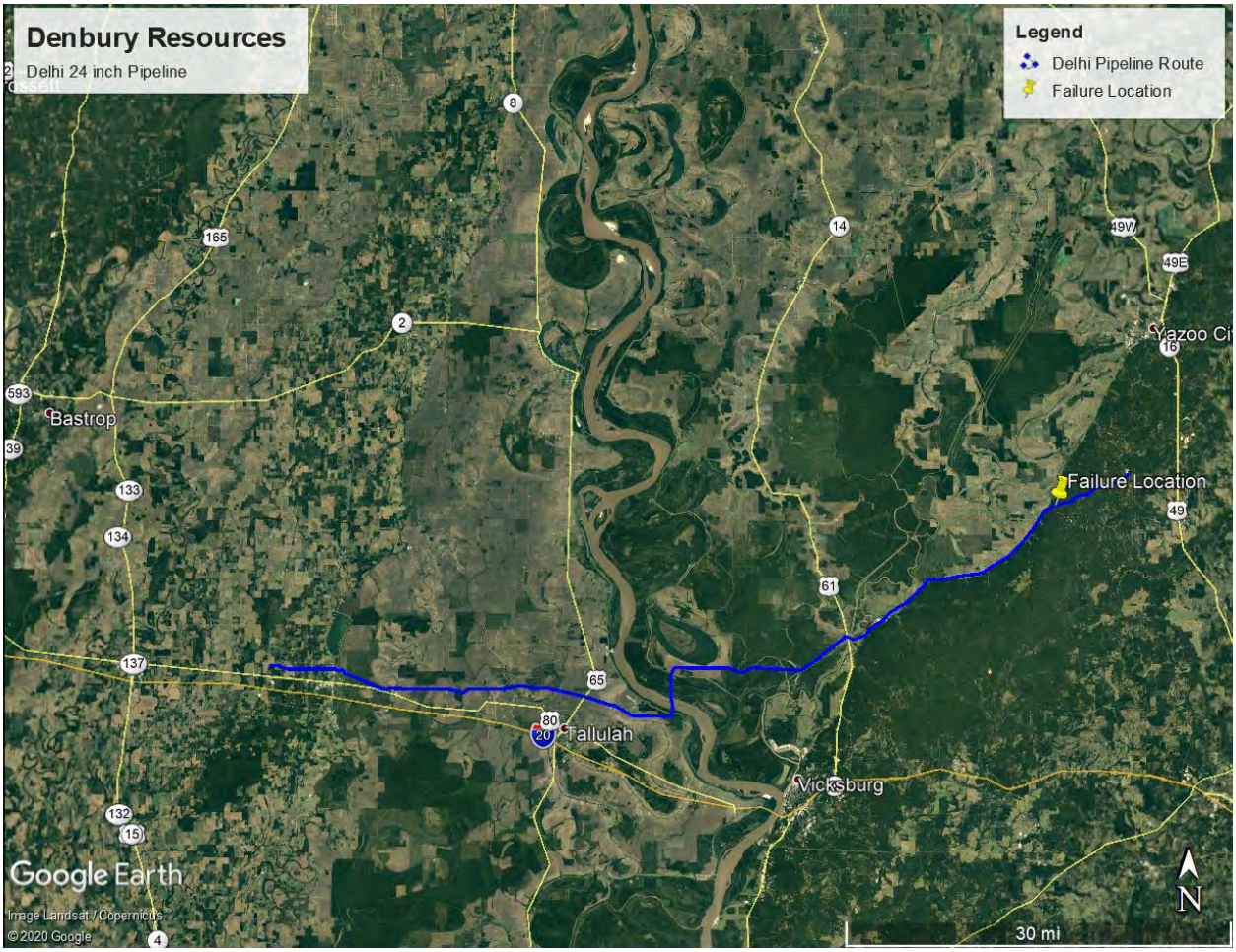


Figure 1. Delhi 24-inch Transmission Pipeline Route

2.1 Pipeline Construction Data

The Delhi 24-inch Transmission Line is documented as installed in 2009, primarily of 0.469-inch wall thickness, API 5L Grade X-80M PSL 2 piping, with a high frequency electric resistance welded (HF-ERW) seam, coated with fusion-bonded epoxy (FBE). Sections of piping installed using slick bore were constructed of 0.540-inch X-80 coated with FBE and an additional layer of abrasion-resistant overcoat (ARO). The pipeline has a diameter of 24 inches. A simplified overview of the pipeline segment is provided in Figure 2.

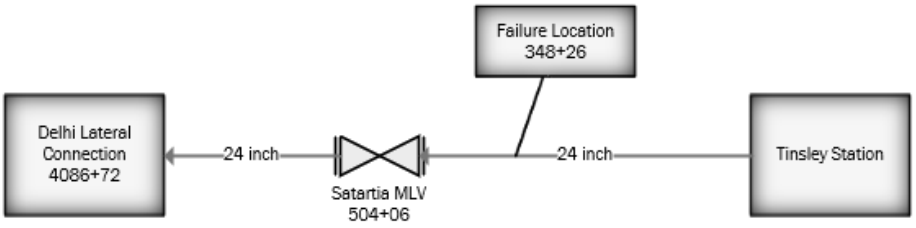


Figure 2. Simplified Delhi 24-inch Transmission Line Diagram

A summary of pipeline information for the Delhi 24-inch Transmission Line in included in Table 1.

Table 1. Pipeline Data

Pipeline Information	Delhi 24-inch Transmission Line
Line Length (miles)	77.4
Pipe Outside Diameter (inches)	24
Pipe Wall Thickness (inches)	0.469, 0.540
Pipe Grade	X-80
Maximum Allowable Operating Pressure (MAOP, psi)	2,160
Normal Operating Stress Level (psi)	1,200-1,450
Pressure at Time of Failure (psi)	1,336
Pipe Seam Type	ERW
Product Carried	Carbon Dioxide (dry)
Pipe Construction Date	2009
Pipe Coatings (type/thickness)	FBE 14-16 mils and ARO 40 mils
Girth Weld Coatings	Liquid Epoxy – SPC-2888

A post-construction hydrostatic pressure test was reported to have been conducted on the piping in January 2009 to a minimum test pressure of 2,908 psig at the Dead Weight Location for 8 hours.

The pipeline is reported to have had impressed current cathodic protection applied since the date of construction with no interference bonds and two continuity bonds at the start and end of the pipeline section.

2.2 Incident Summary

The incident is reported to have occurred after 7:00 p.m. local time, based on resident reports and an evacuation order, on February 22, 2020 near Satartia Mississippi, when a failure occurred at a girth weld, resulting in a rupture of the pipe near a crossing of Mississippi Highway 433 approximately 1 mile southeast of Satartia. The line was shut down and valves closed at approximately 7:17 p.m. as reported by Denbury.

The failure occurred on a pipe section consisting of 24-inch diameter by 0.540-inch wall thickness API 5L Grade X-80M PSL 2 line pipe with a high frequency electric resistance welded (HF ERW) seam. The pipe at the site of the failure was installed using slick bore, coated with FBE/ARO on the pipe and liquid epoxy coating applied on the girth welds. The failure occurred at approximate stationing 348+26, about 6.59 miles downstream of the Tinsley Station at the base of a hill, significantly lower in elevation than the surface of Highway 433. The pipeline normally operates between 1,200 psig and 1,450 psig. At the time of the failure, the pressure at the Tinsley Meter Station (0+00) was 1,336 psig.

A Google Earth™ overview of the failure location is provided in Figure 3.

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Figure 3. Delhi 24-inch Transmission Failure Location

A photo of the failure location post-incident is included in Figure 4.

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Figure 4. Post-Incident Photo of Failure Location (Downstream to Upstream)

3.0 ROOT CAUSE ANALYSIS PROCESS

A failure action sequence was used for the purposes of performing the Root Cause Analysis.

The basic role of a root cause analysis is as follows:

- Collect information.
- Understand what happened.
- Identify the problems that caused the incident.
- Analyze each problem's root causes.
- Look beyond root causes for systemic, cultural, and organizational factors.
- Develop recommendations for remediation to improve performance and prevent repeat incidents.

Since root cause analyses are normally associated with incidents or accidents, much of the existing terminology in use refers to "incidents".

A typical Failure Action Response Sequence adapted from Guidance for Plant Personnel on Gathering Data and Samples for Materials Failure Analysis MTI catalog MTI 9539 is shown in Figure 5.

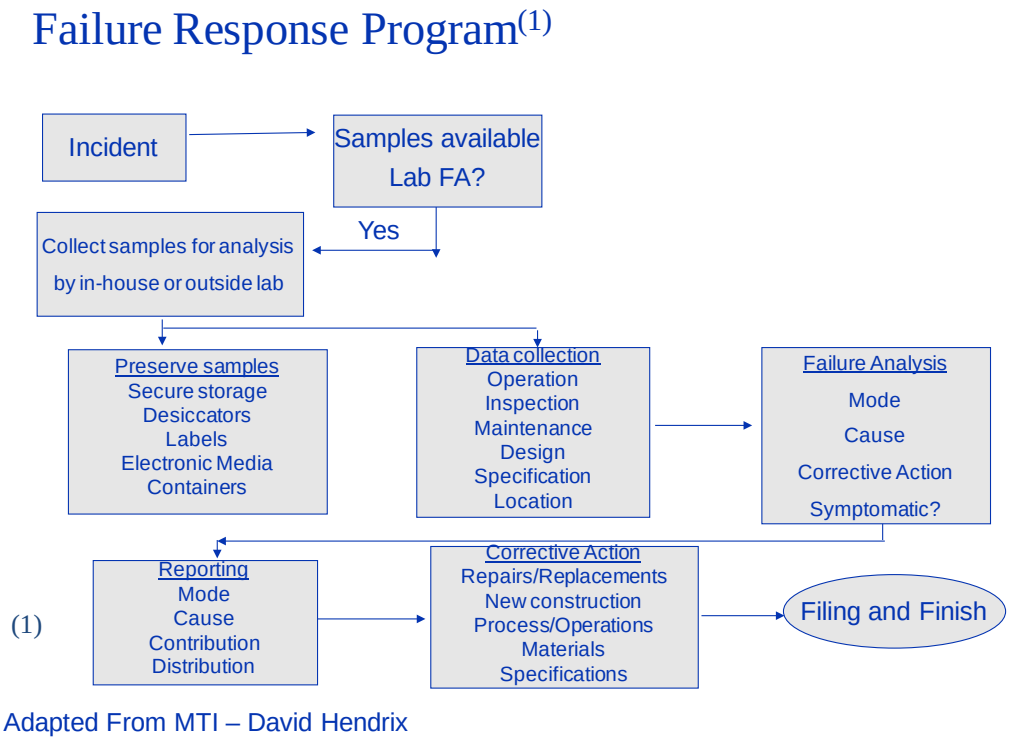


Figure 5. Failure Response Sequence

The root cause analysis focused on identifying the root cause(s) of the pipeline failure and contributing factors.

4.0 DESCRIPTION OF INVESTIGATIVE PROCESS

The investigation into the cause and contributing factors to the Delhi 24-inch Transmission line failure has been undertaken through the following activities:

1. In-Situ investigations at the release location,
2. Corrosion and coating related assessments,
3. A review of available documents and information associated with the design, specification, construction, operation and maintenance of the pipeline infrastructure, and
4. Laboratory failure analysis of the failure.

Metallurgical testing and a failure analysis were performed on three samples of pipe from the release site. The metallurgical testing lab completed the following tests and examinations:

- Physical examination,
- Photographic documentation and videography,
- Magnetic Particle Inspection,
- Scanning electron microscopy,
- Metallographic analysis,
- Hardness testing,
- Mechanical testing, and
- Chemical analysis.

The results of the metallurgical testing have been analyzed for the purposes of this report and are relied upon in the formulation of the opinions and conclusions expressed in this report.
The available information related to construction, prior integrity assessments and cathodic protection was analyzed to assist in establishing the root cause and contributing factors of the failure.

4.1 In-Situ Investigation Findings

On February 27, Mears mobilized to the release location to secure the failed pipe sections for laboratory investigation, perform initial site investigations, and collect information to support the root cause analysis.

Upon arrival, significant response and operational activities had been undertaken to secure the site and prepare for excavation and removal of the pipe section.

From initial visual examination, the failure appeared to have occurred at least 40 feet in elevation below the roadway, with indications of soil subsidence in the vicinity of the failure. The release crater included trees and root debris, but based on the pipeline alignment sheet elevation profile, a significant volume of soil in the slick bore section between the failure and MS Highway 433 had collapsed. The soil in the vicinity of the failure appeared to be extremely wet.

Figure 6 and Figure 7 show the view of the release location as-found on February 27, 2020.



Figure 6. Failure Location (Upstream to Downstream)

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Figure 7. Failure Location (Upstream to Downstream)

Personnel were unable to access the pipe at the failure location due to the depth of the crater and instability of the soil on the downstream side of the crater.

In-situ visual inspection of the exterior surface of the pipe identified a separation of the piping at a girth weld of approximately 8 inches, with slight misalignment between the upstream and downstream joints. Figure 8 provides a close-up of the as-found pipe and coating condition at the separation.



Figure 8. Delhi 24-inch Transmission Line Failure - As-Found Condition at Girth Weld

A protocol was developed for removal of pipe samples in the vicinity of the failure, to include the upstream and downstream sections of the failure and an intact girth weld near the failure location. A copy of the Pipe Collection Protocol is provided in Appendix A.

Removal of the samples began on March 9, 2020. Excavation and removal of an upstream section of piping included the upstream half of the failure and the intact girth weld noted above. This section was approximately 68 feet 5 ½ inches in length.

Figure 9 shows the upstream pipe section being removed from the site.



Figure 9. Upstream Pipe Section During Removal

Following removal of the upstream section, limited excavation and backfill was conducted to allow access to the downstream side of the failure. A section of pipe containing the downstream section of the failure was then removed using a magnesium torch attached to the bucket of an excavator.

Once moved to an accessible location, the pipe sections were documented, samples were cut and prepared for shipment to the laboratory. Figure 10 provides an overview of the pipe sections as removed and prepared for shipment.

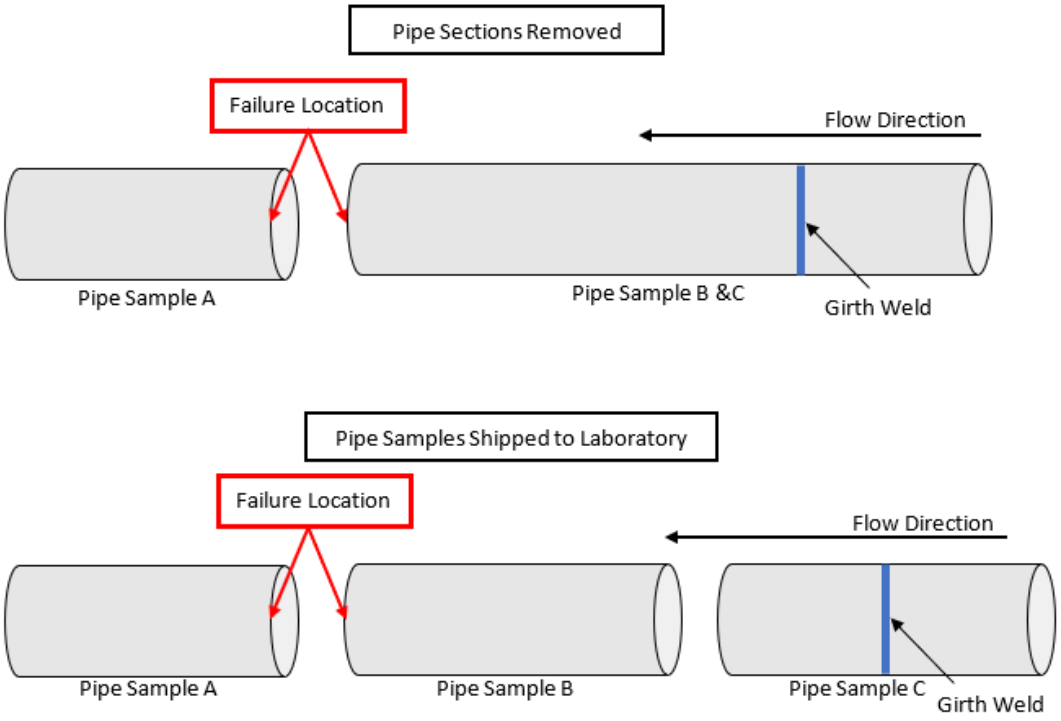


Figure 10. Overview of Pipe Sections and Samples

Visual inspection of the external surface of the pipe sections identified an area of coating damage near the failure, which appeared to have occurred as a result of the failure (no pitting, attached solids, and apparent adhesive failure). No external corrosion was observed and the pipe coating on the remainder of the section appeared to be in excellent condition.

Initial visual inspection of the internal surface of the piping showed no accumulated solids or liquids in the pipe sample and no indications of pitting or corrosion. A view of the internal condition of the pipe section containing samples B & C after removal is provided in Figure 11.

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Figure 11. Internal Condition of Pipe Sample During Removal

Soil samples were collected from the area around the pipe for chemical and microbiological analysis, the failure surfaces were protected with foam insulation, then the pipe samples were wrapped, crated and shipped to the laboratory for metallurgical testing on March 10, 2020. The approximate lengths of the pipe samples were PS A – 6 feet, PS B – 6 feet and PS C – 8 feet.

5.0 LABORATORY INVESTIGATION FINDINGS

Metallurgical Testing and a Failure Analysis was performed on a multiple pipe samples from the release site. The work was conducted under Mears direction by a third-party independent laboratory (DNV GL). The metallurgical testing consisted of the following tests and examinations:

- Physical Examination,
- Photographic documentation and videography,
- Scanning electron microscopy
- Metallographic Analysis,

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- Hardness testing, and
- Chemical analysis.

The metallurgical sampling and testing protocol utilized for the laboratory investigations is included in Appendix B.

5.1 Visual and Nondestructive Examination

The pipe sections were removed from the shipping crates, visually inspected and photographed. As noted above, some of the pipe coating adjacent to the failed girth weld was missing on PS A and PS B. This may be due to the fact that CO2 is in a supercritical state at about 1,000 psig and about 60°F during the transportation before the rupture. The release of CO2 after the rupture from the actual operating conditions to the atmospheric conditions commonly results in an accumulation and flow of dry ice (i.e. -70°F or colder) which may have impacted adhesion to the pipe.

The mill-applied pipe coating (FBE/ARO) was brown in color, with a light blue liquid epoxy applied to the girth welds. Black residue was found adjacent to ends of the pipe samples cut in the field using an acetylene torch. Figure 12, Figure 13 and Figure 14 show the as-received pipe samples after removal from the crates and protective wrappings.

The pipe adjacent to the fracture surfaces and failed girth weld were visually inspected. The fractured surface was flat and generally at a 180-degree angle with no thinning and/or reduction of the affected area. The fracture path traversed or crossed over the weld at various locations.

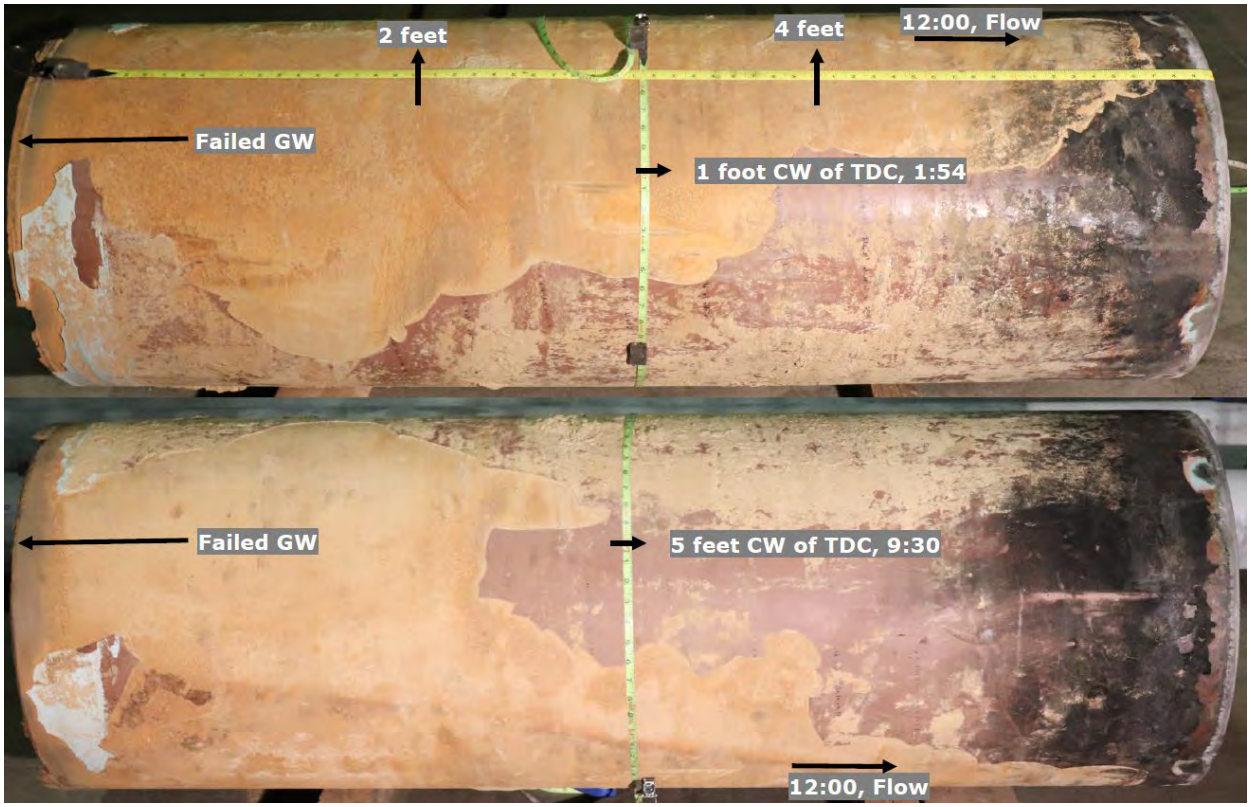


Figure 12. Pipe Sample A (PS A)



Figure 13. Pipe Sample B (PS B)

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Figure 14. Pipe Sample C (PS C)

A photograph of the fracture surface of PS A is provided in Figure 15.

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Figure 15. PS A Fracture Surface (Upstream to Downstream)

Pipe circumferences and diameters were measured at the field-cut ends of the pipe sections, finding no measurable ovality and diameters meeting API 5L tolerances for the 24-inch diameter pipe. Wall thicknesses were between 0.530 inches and 0.540 inches, which meet API 5L tolerances for pipe with a nominal wall thickness (NWT) of 0.540 inches.

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The intact girth weld (PS C) was grit blasted and MPI was conducted on the external and internal surfaces. No crack-like indications were identified.

After detailed visual inspection and measurements were collected, the pipe samples were aligned and evaluated to identify locations for further sampling and metallurgical analyses. An overview of the locations selected for metallography (M, MU), fractography (S), mechanical and chemical analyses is provided in Figure 16.

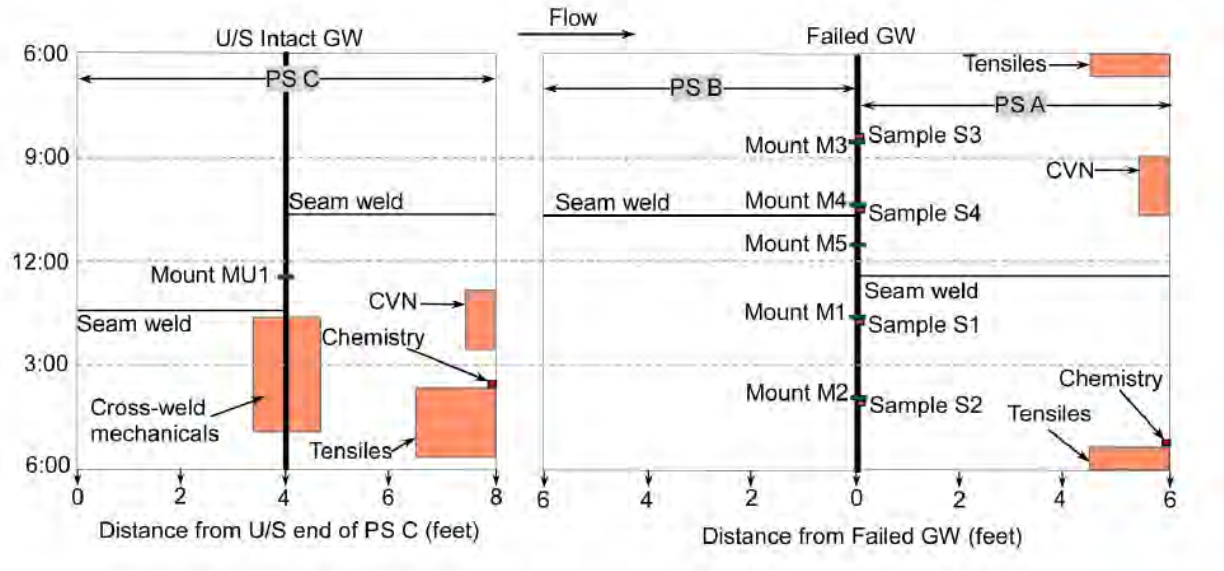


Figure 16. Laboratory Testing and Sample Schematic

5.2 Defect Examination

The internal and external surfaces of the failed girth weld were cleaned with a soft bristle brush to for more detailed examination. Five areas were selected for metallurgical analyses of the failed girth weld (PS A, PS B) and one area from the intact girth weld in PS C. The fracture surface consisted of smooth regions and rougher surfaces that varied in thickness throughout the rupture face. An example of these regions is provided in Figure 17. There was no evidence of pre-existing manufacturing flaws. It was not possible to determine the exact location of the failure initiation process due to the lack of chevrons on the fracture surface.

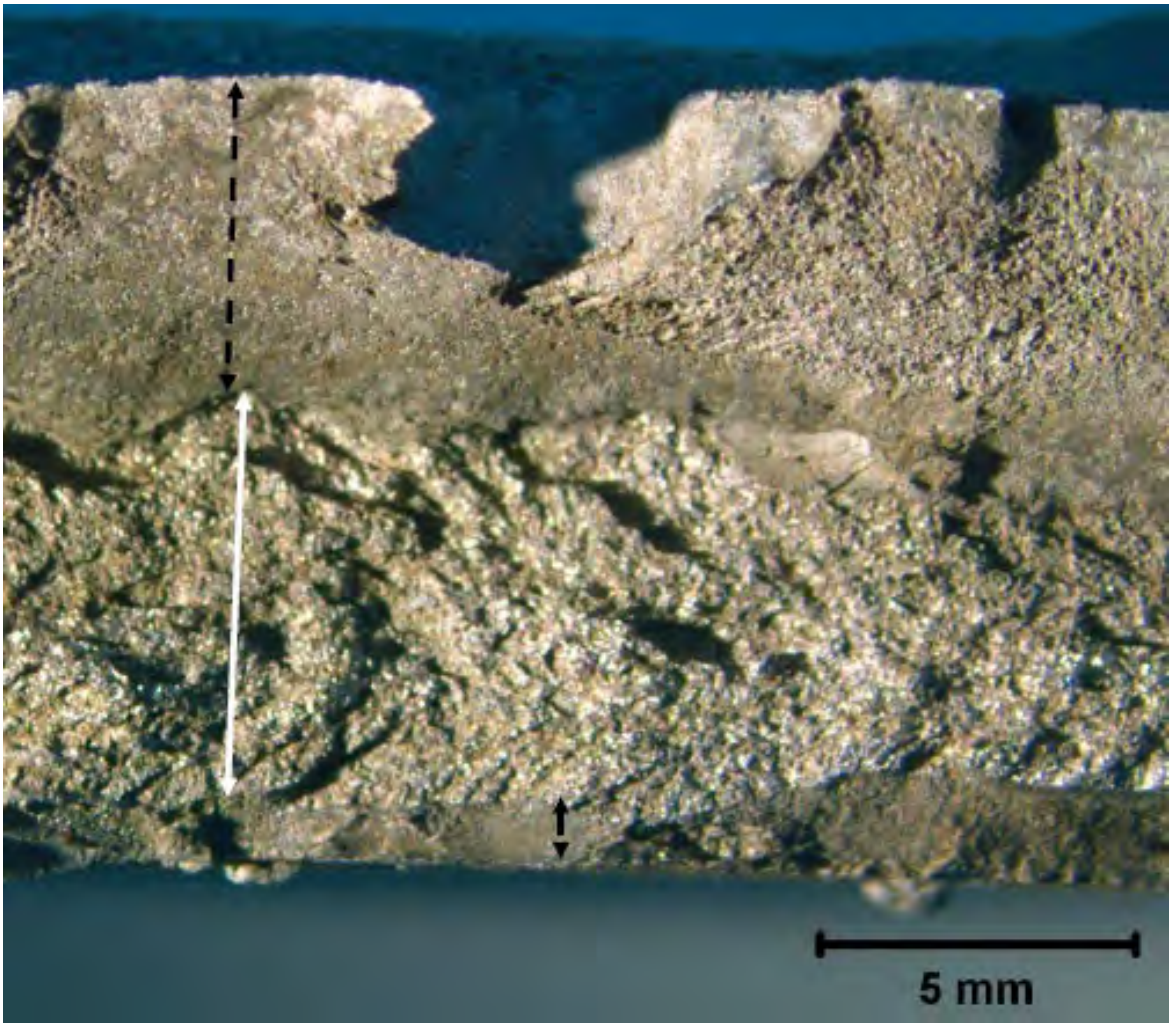


Figure 17. Image of Sample S2 - Smooth (Black Arrow) and Rough (White Arrow) Regions

5.3 Metallography and Fractographic Examination

Upon removal of the samples discussed above, the samples were evaluated utilizing standard microscopy techniques including stereographic evaluations, microscopic evaluation and scanning electron microscopy. Five (5) axial and cross-sections were removed from the failed girth weld and one (1) from the intact weld for metallographic analysis. Some of the samples contain fracture paths at a shear angle (fracture path through the smooth surfaces) and other show the fracture path perpendicular to the free surface and regions of shear failure (fracture surface is rough).

These samples are shown in Figure 18.

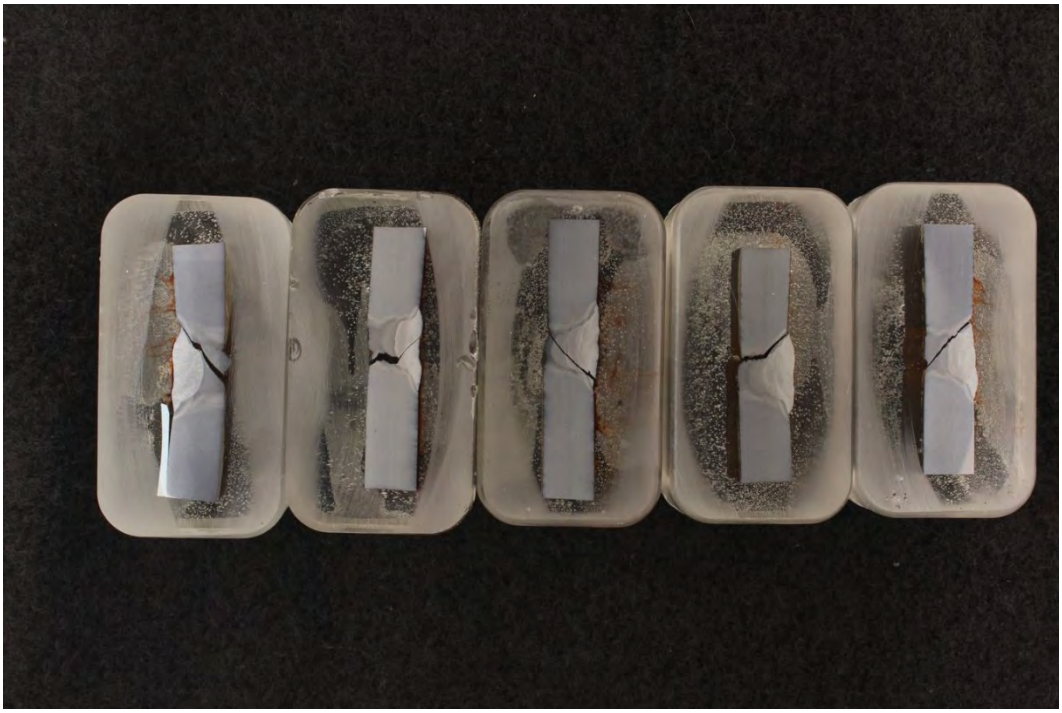


Figure 18. Metallurgical samples M1 through M5

5.3.1 Metallurgical Sample 1

Sample M1 contains a fracture path at a shear angle. This sample was removed from the girth weld at the 1:35 o'clock orientation (see Figure 19).

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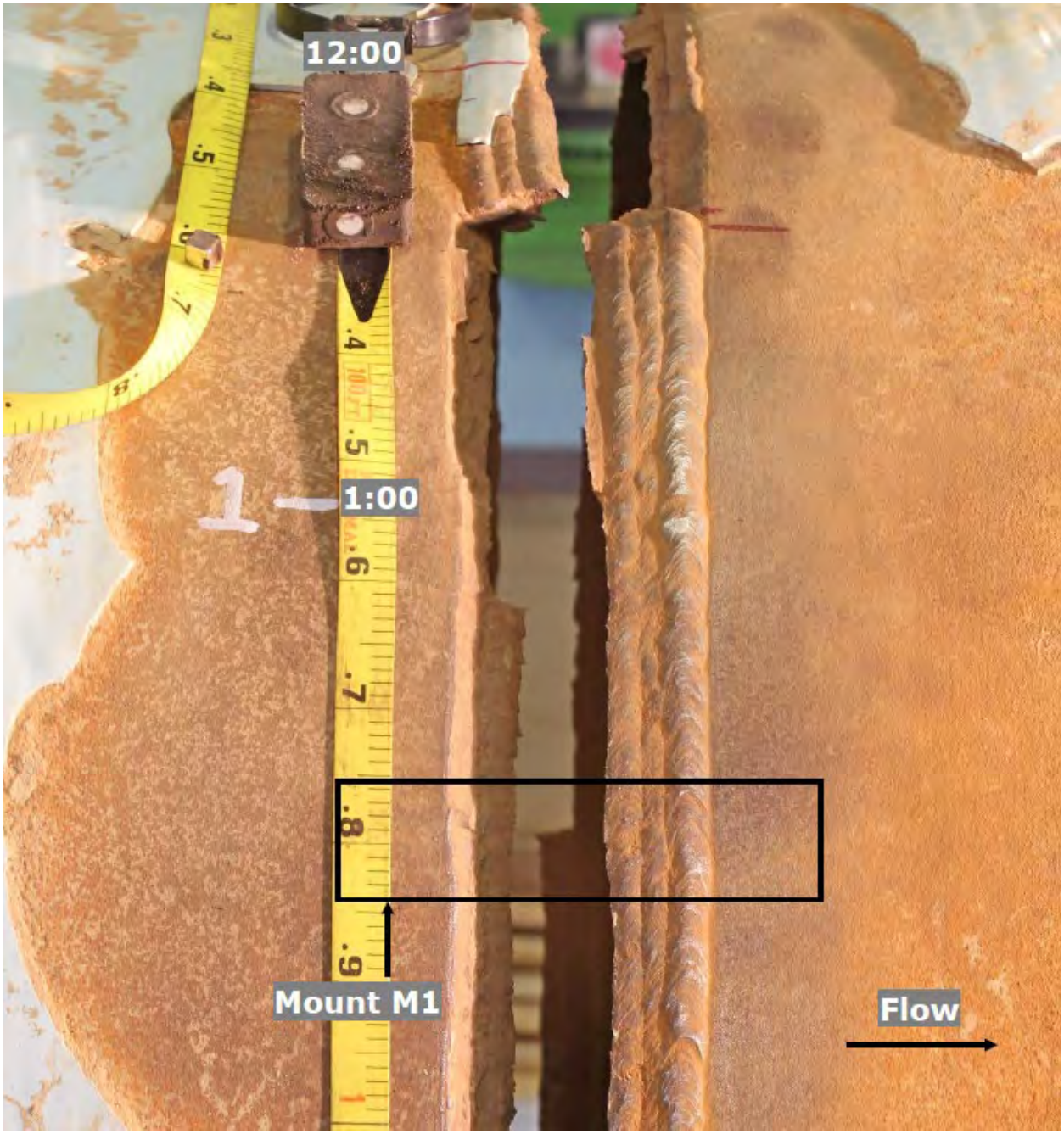


Figure 19. Overview of Mount M1

The fracture path of this sample is located in the HAZ near the toe of the weld at the OD surface. An image of the cross section of sample M1 is provided in Figure 20.

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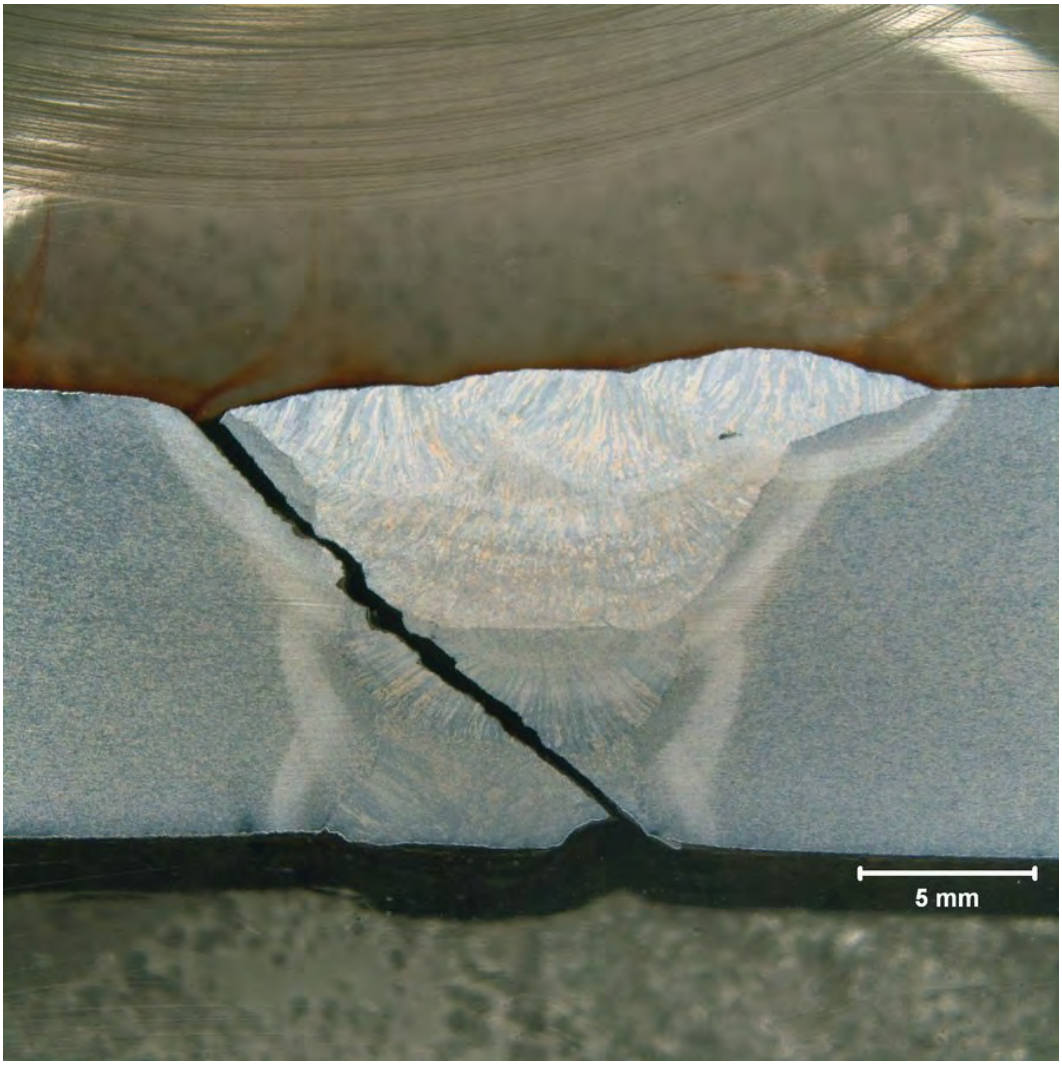


Figure 20. Representative Cross-Section from Sample M1

There is no indication of excessive porosity and/or inclusions. It shows a slight misalignment of the high-low weld of approximately 4.3% of the NWT. Higher magnifications are provided in the laboratory report which show grain elongation due to the cold work that took place during the rupture process. This is consistent with ductile overloading. The microstructure is typical of modern X80 line pipe. A close-up of sample M1 is provided in Figure 21.

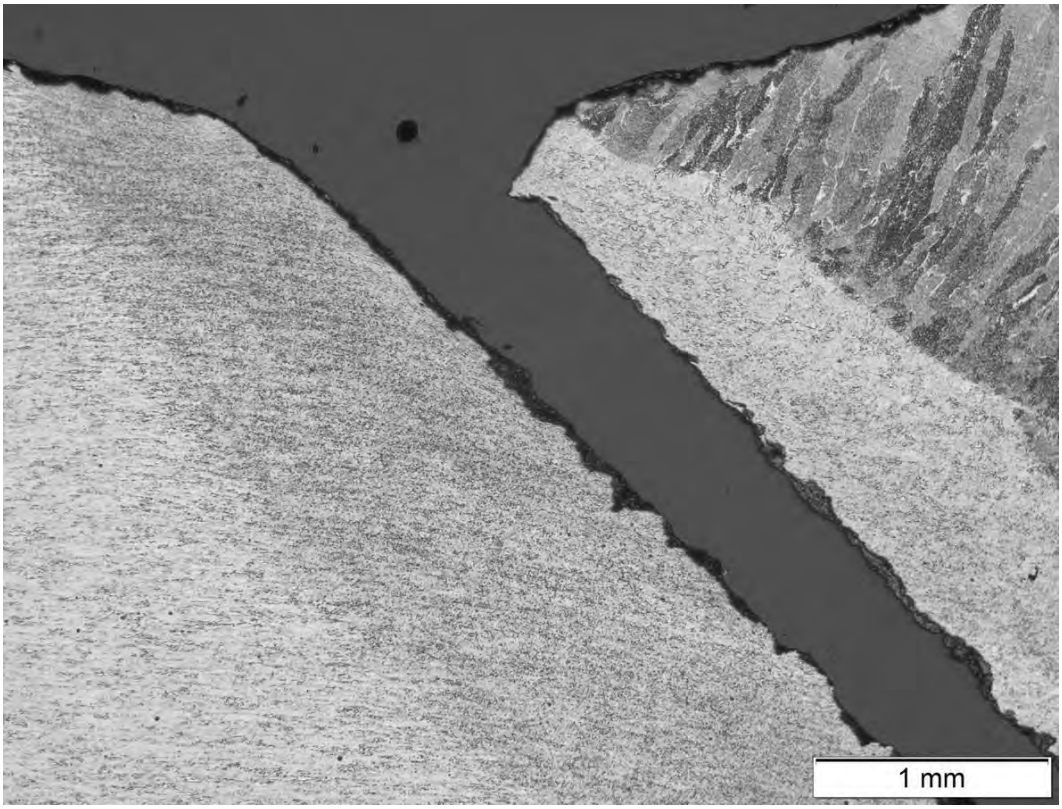


Figure 21. Close-Up of Sample M1

5.3.2 Metallurgical Sample 2

Sample 2 contains regions where the fracture path is perpendicular to the free surface and regions of shear failure. This sample was taken from the GW at the 3:55 o'clock orientation (see Figure 22).

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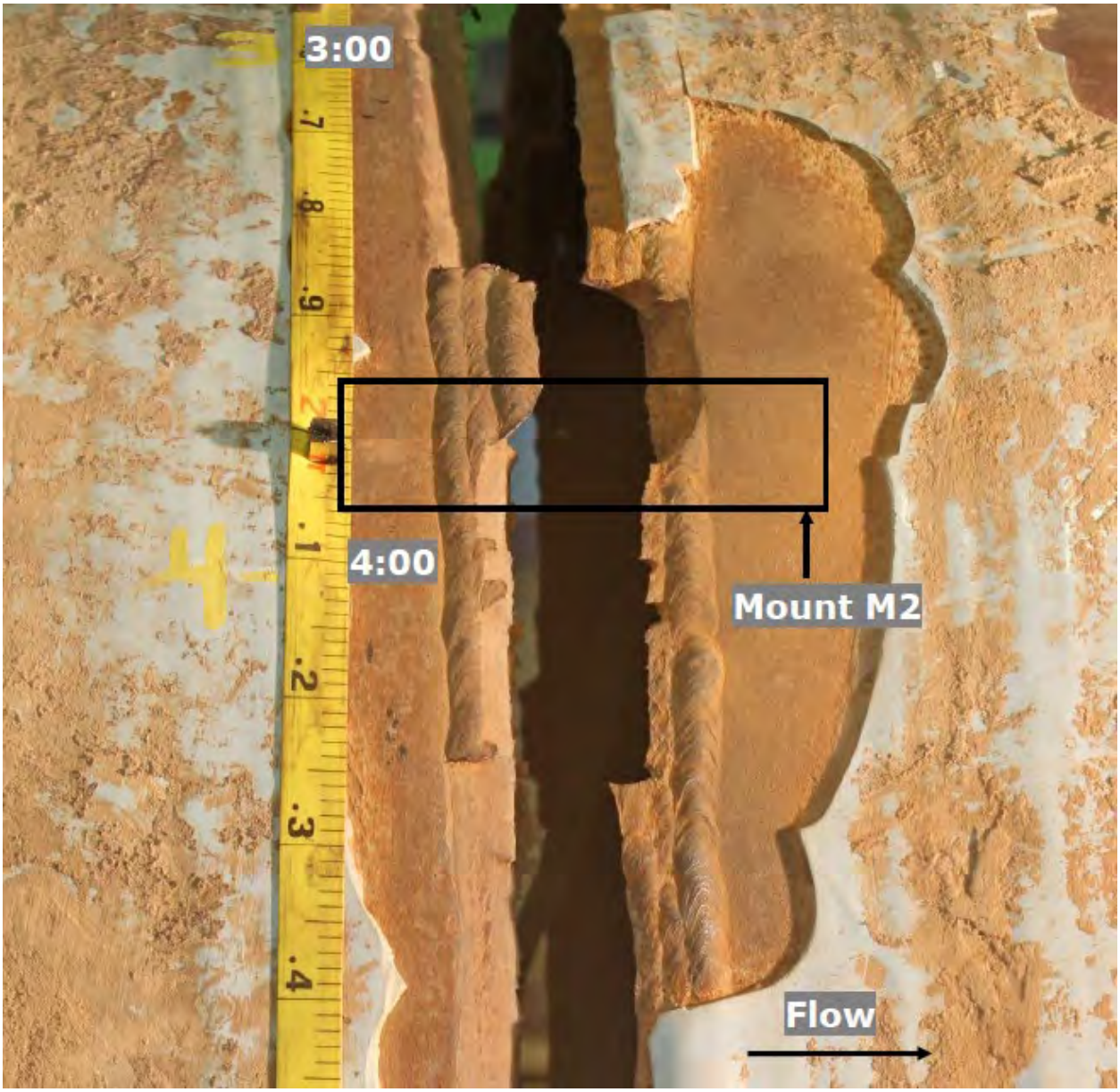


Figure 22. Overview of Mount M2

The cross section of M2 includes both the weld metal and HAZ. The cross section of sample M2 is provided in Figure 23.

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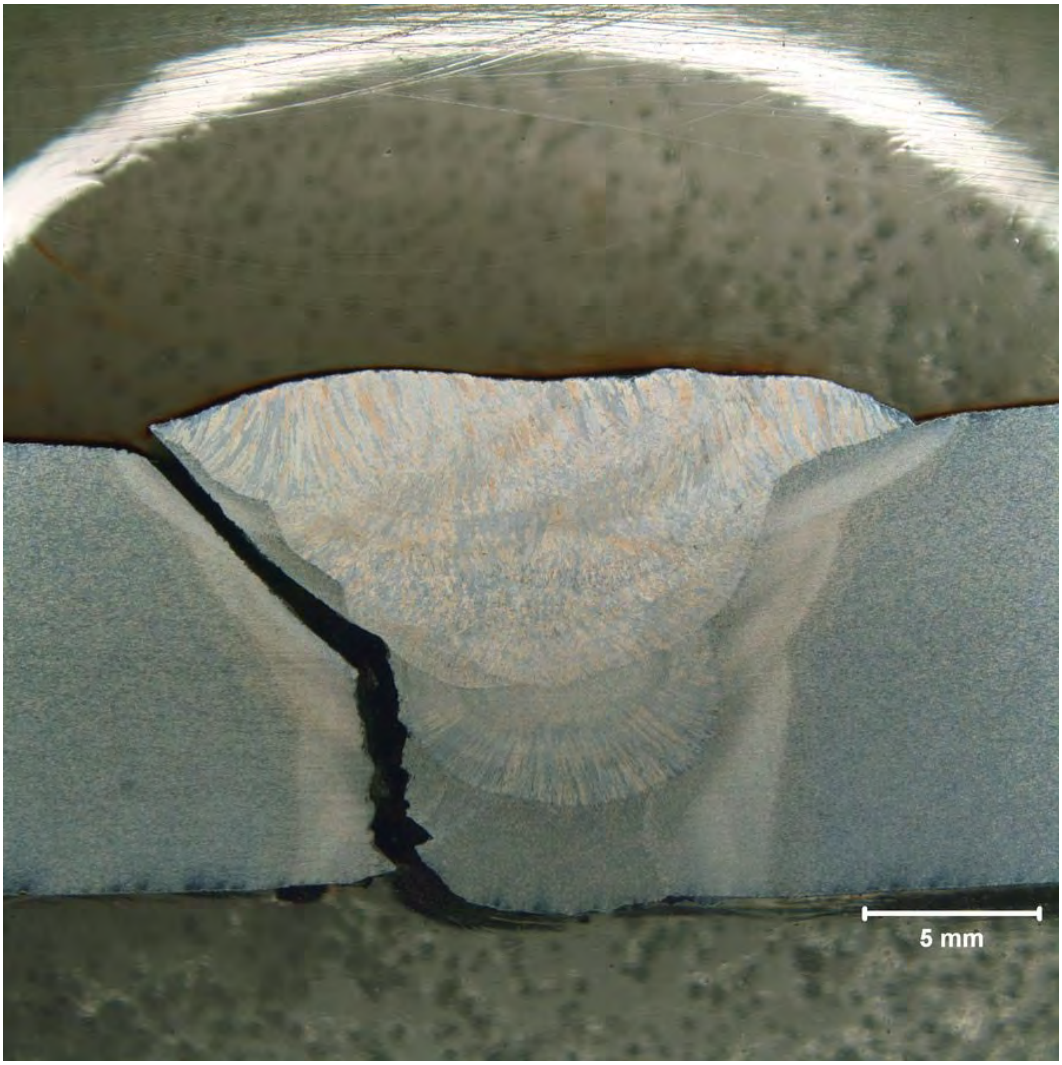


Figure 23. Representative Cross-Section from Sample M2

There are both smooth and rough regions in this sample. The high-low weld misalignment at this location is approximately 6.9% of the NWT. The fracture path at this location was mainly located at the HAZ. Fractography in the SEM shows the presence of a smooth region containing dimples (typical of ductile behavior) and cleavage facets (typical of brittle behavior) in the rough region. Some fissures were also found in the area where cleavage facets were located. These fissures are usually seen in girth weld overload areas (see Figure 24).

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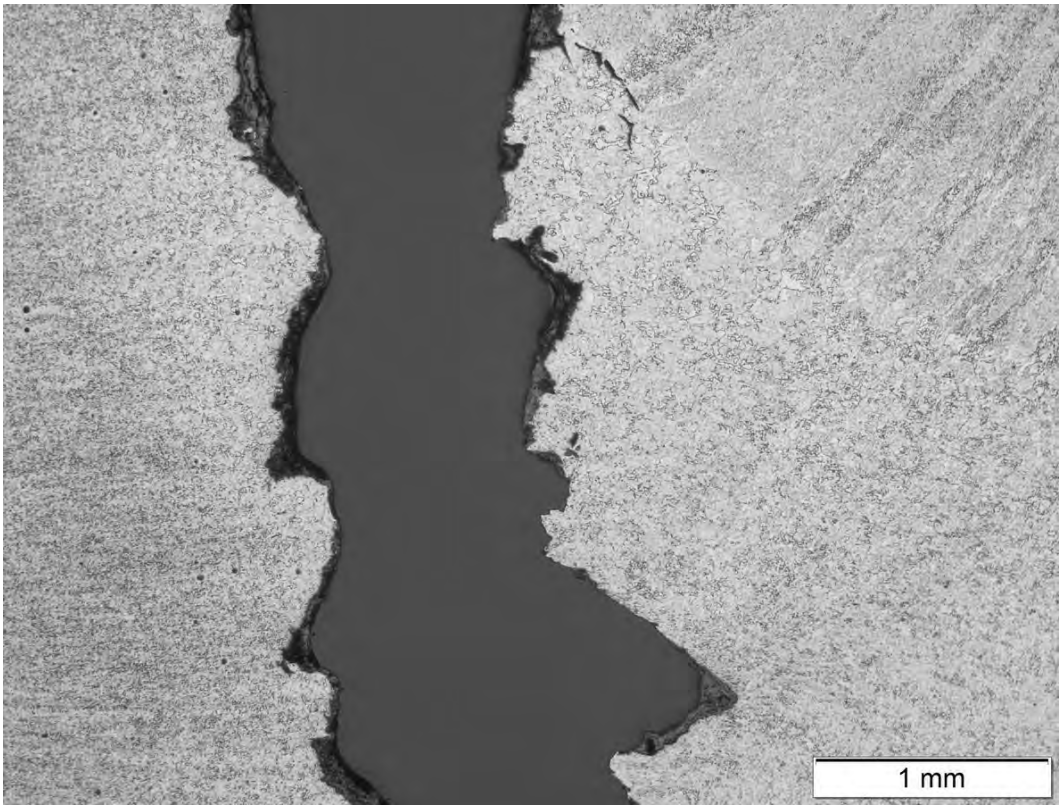


Figure 24. Close-Up of Sample M2

5.3.3 Metallurgical Sample 3

This sample was removed from the failed GW at the 8:35 o'clock orientation (Figure 25).

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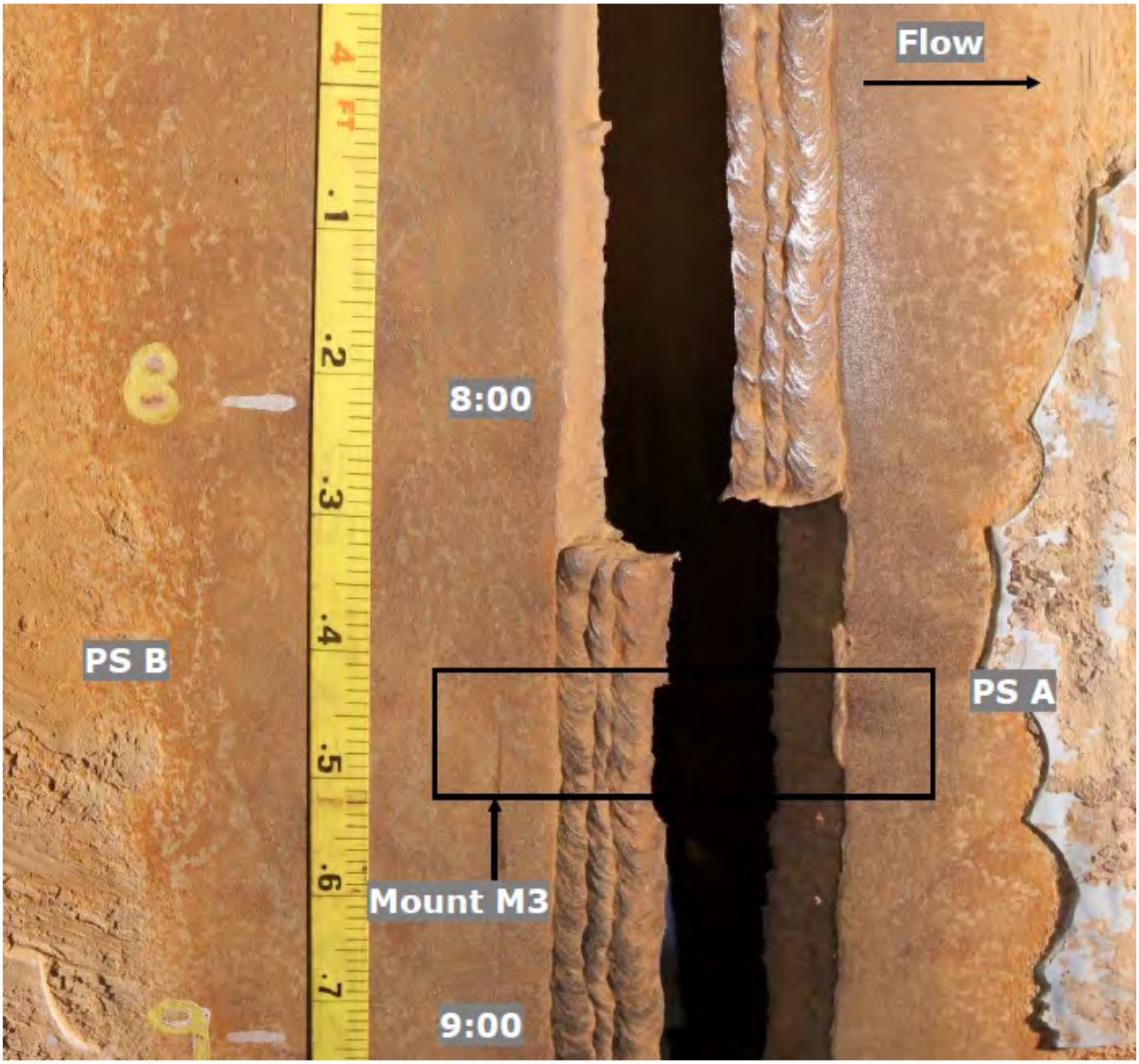


Figure 25. Overview of Mount M3

The fracture path is at a shear angle and mainly located in the weld metal. The morphology of the weld is similar to samples M1 and M2. The high-low weld misalignment at this location was approximately 2.6% of the NWT. The microstructure is consistent with the findings in samples M1 and M2 (see Figure 26 and Figure 27).

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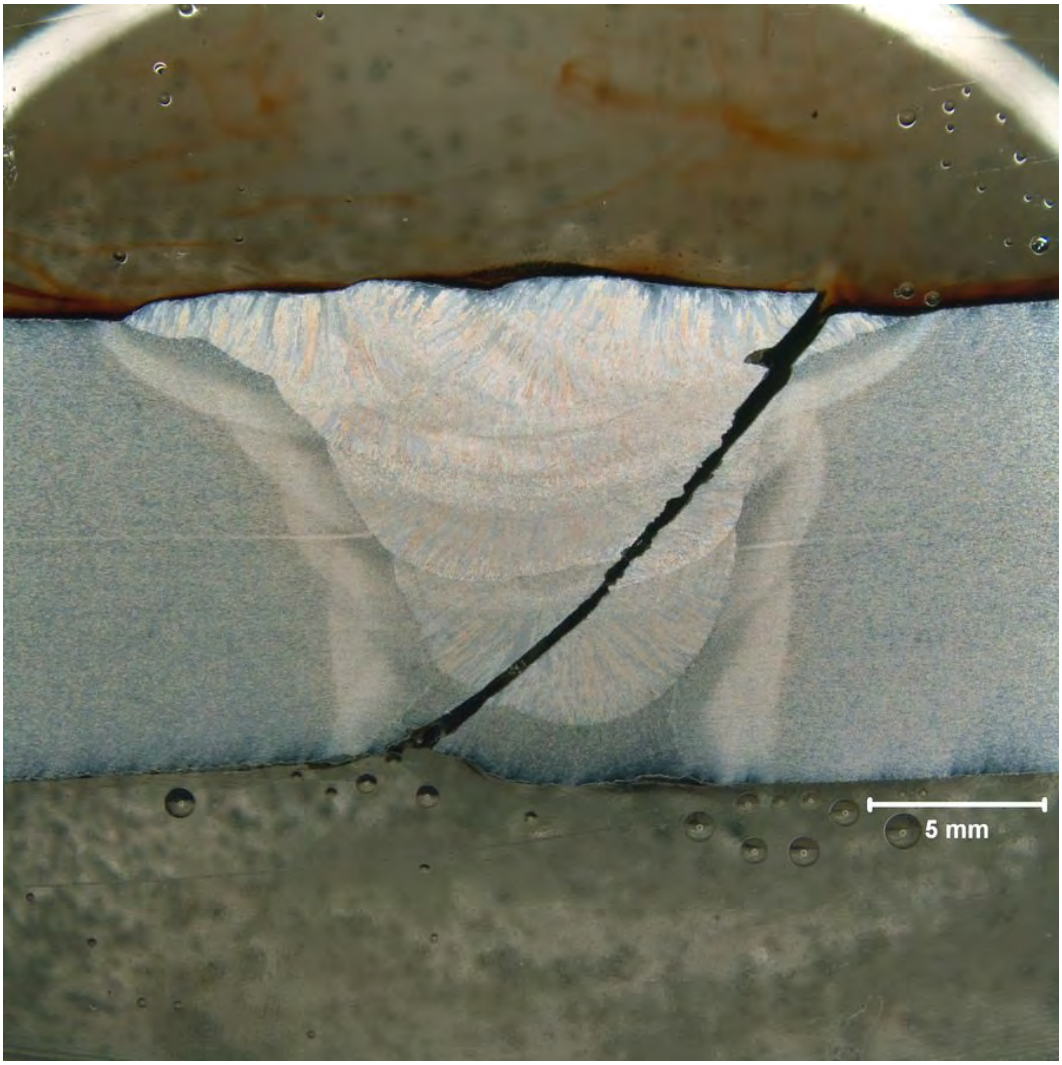


Figure 26. Location of Mount M3

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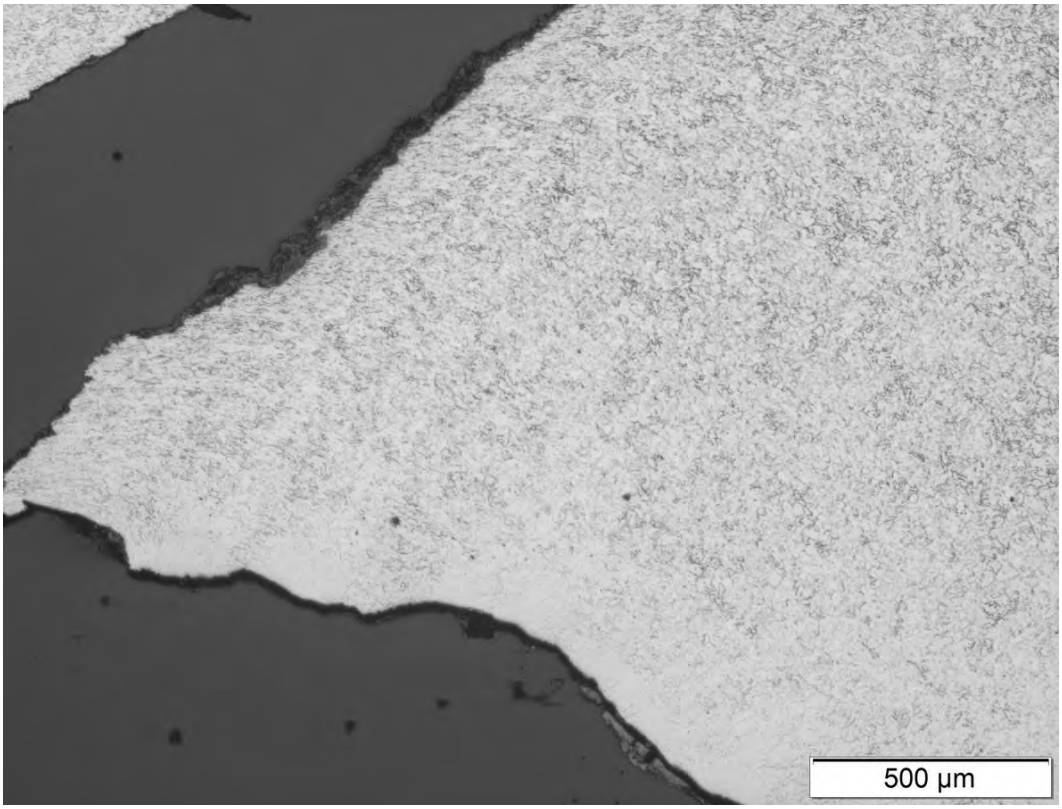


Figure 27. Close-Up of Sample M3

5.3.4 Metallurgical Sample 4

Sample M4 was removed from the failed GW at the 10:24 o'clock orientation. An overview of sample M4 is provided in Figure 28.

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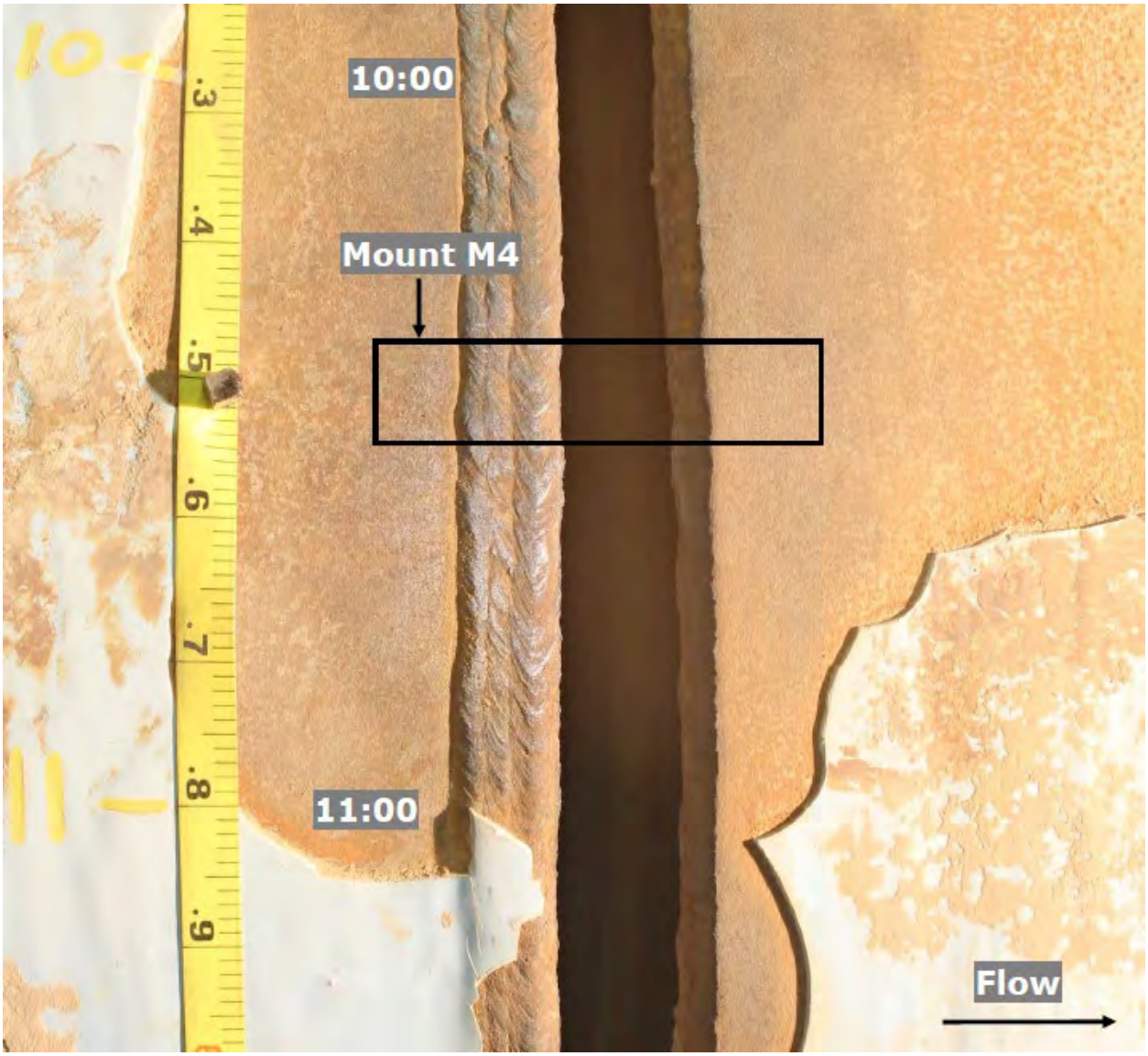


Figure 28. Overview of Mount M4

There is a smooth shear angle region and a rough region. The fracture path at this location is mainly in the HAZ. (see Figure 29).

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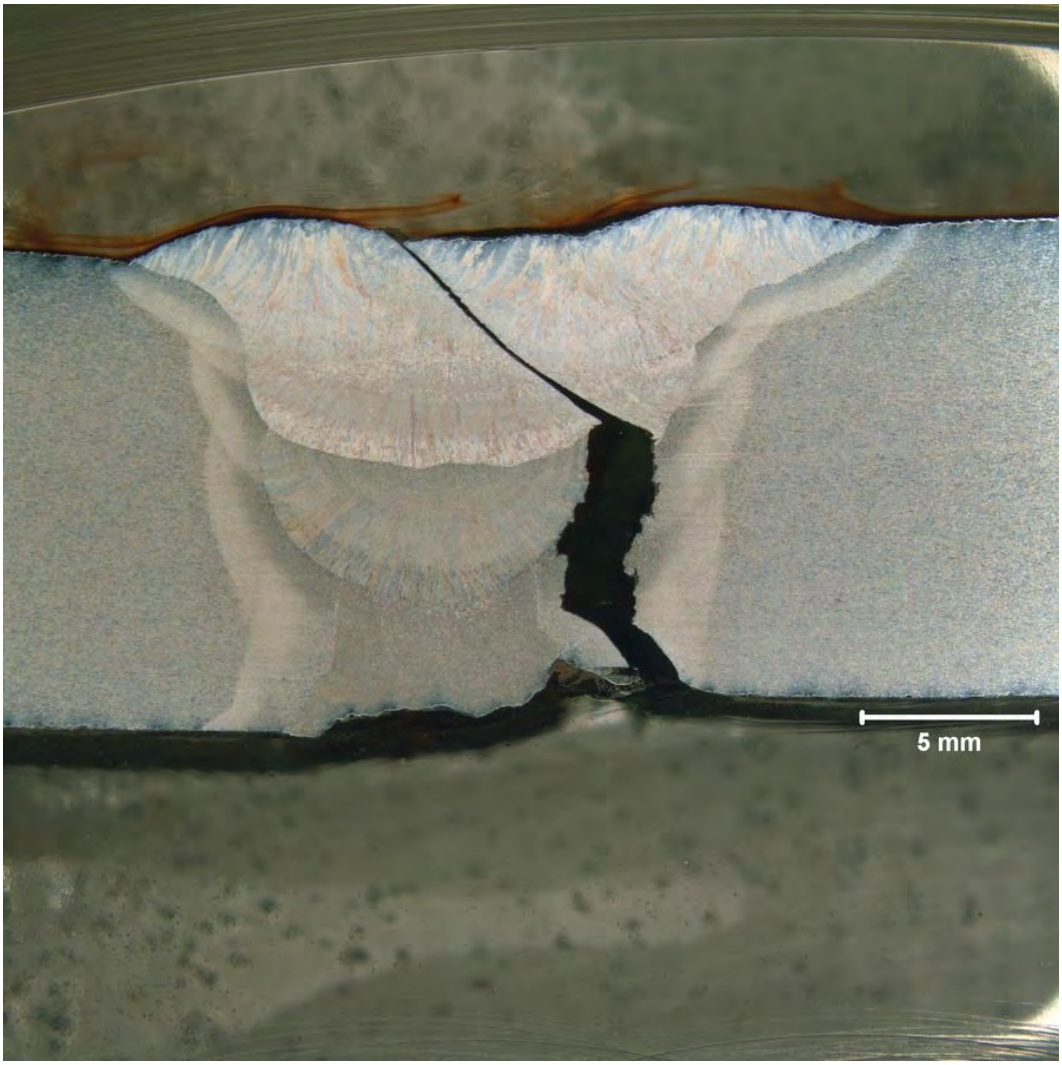


Figure 29. Representative Cross-Section from Sample M4

The sample shows grain elongation and an inclusion orientated parallel to the fracture surface which is consistent with ductile overload. There are also fissures in this sample that have the same morphology shown in M2 sample. A close-up of the M4 sample is provided in Figure 30.

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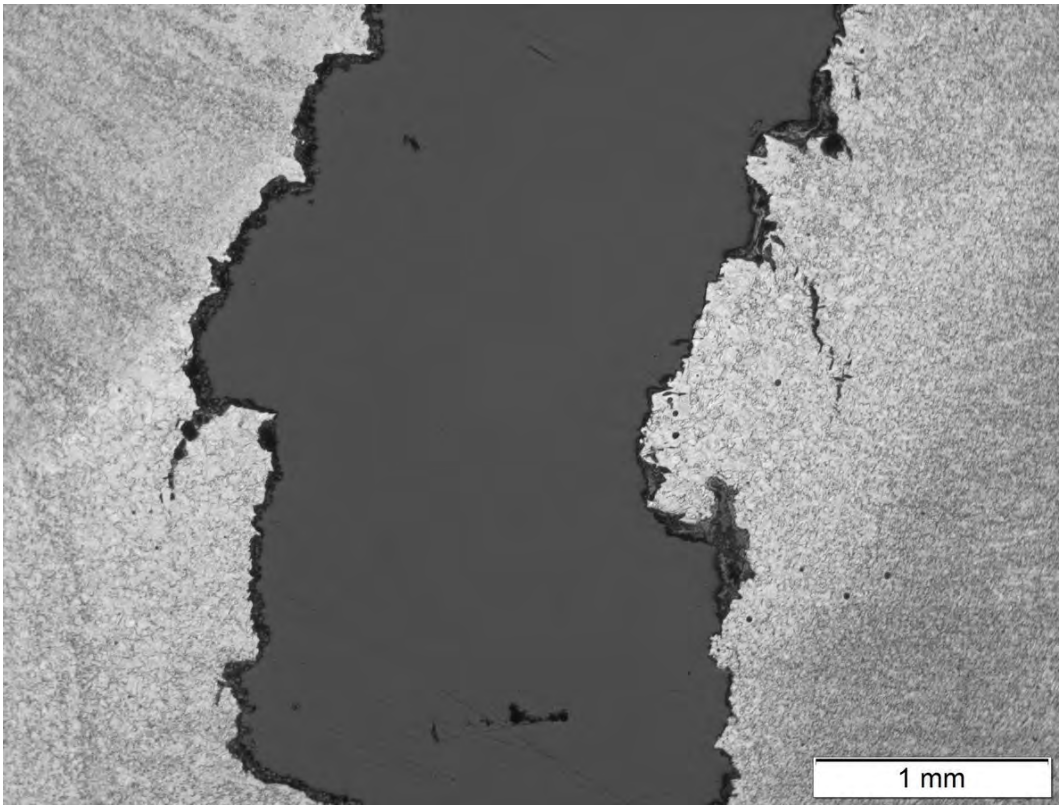


Figure 30. Close-Up of Sample M4

5.3.5 Metallurgical Sample 5

Sample 5 was removed from the failed GW at the 11:37 o'clock orientation (see Figure 31).

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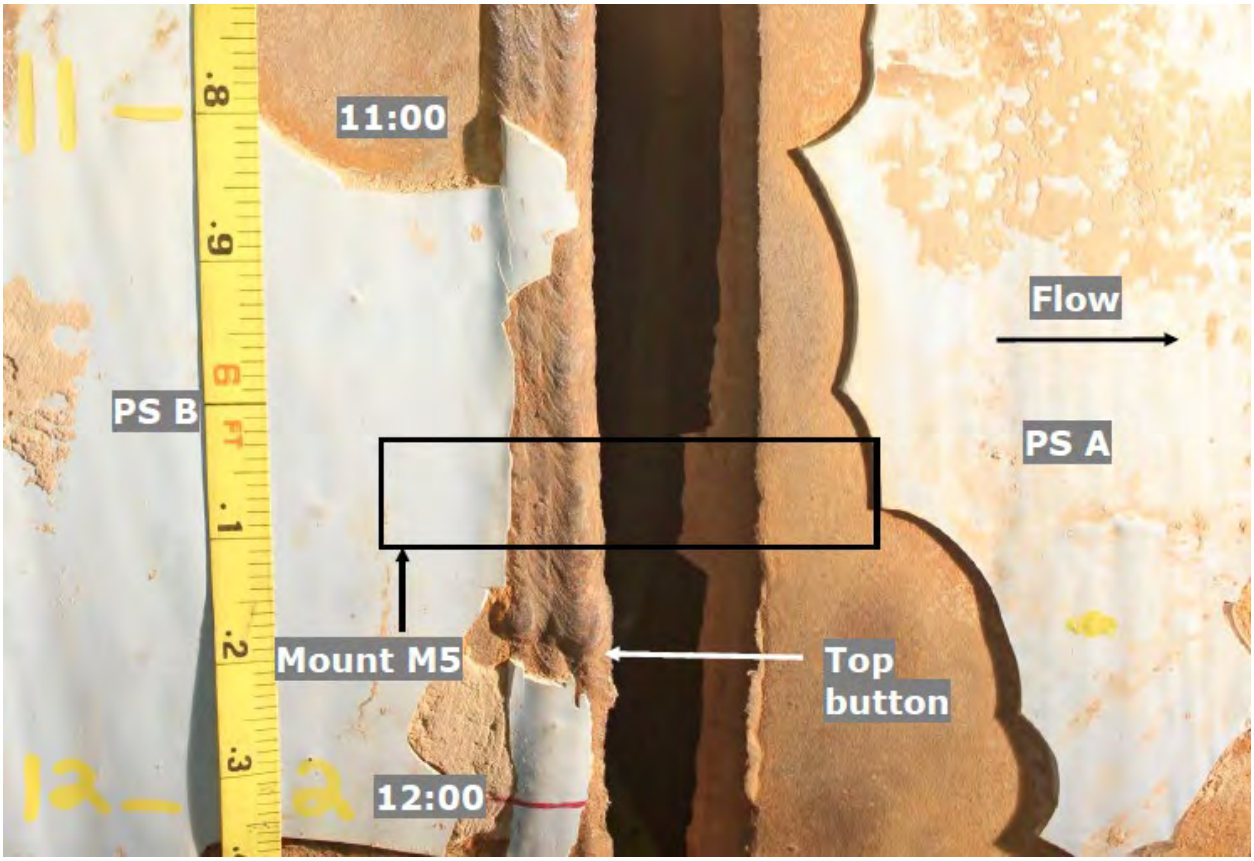


Figure 31. Overview of Mount M5

This sample has a smooth shear region on most of the fracture surface, located in both the weld metal and base metal. There is a shallow flaw between the weld metal and HAZ which is consistent with incomplete fusion. The high-low weld misalignment at this location was approximately 4.6% of the NWT. There is no evidence of crack extension at the flaw in this sample. A view of the cross section of sample M5 is provided in Figure 32.

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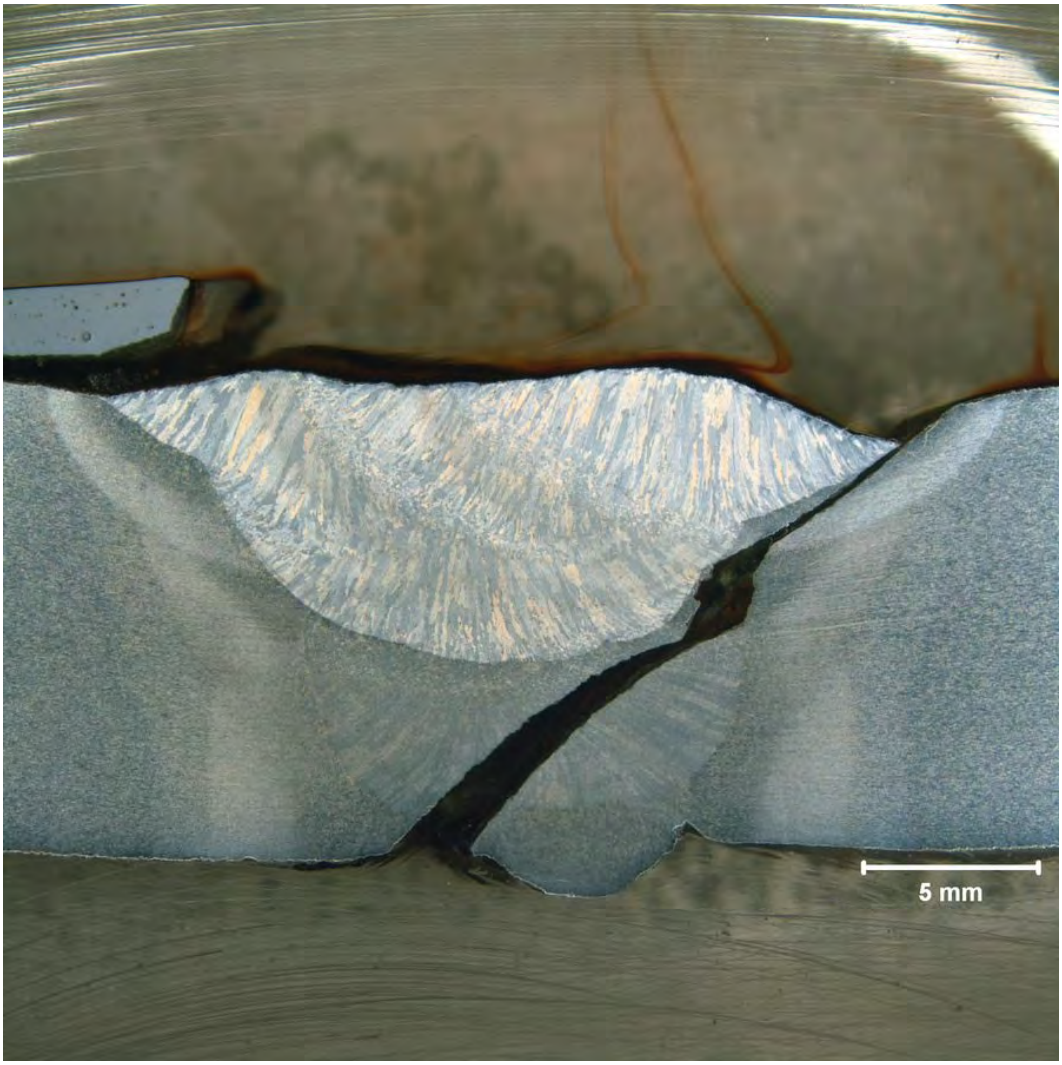


Figure 32. Representative Cross-Section from Sample M5

5.3.6 Metallurgical Sample MU1

Sample MU1 was removed from the intact girth weld. An overview of this sample is provided in Figure 33.

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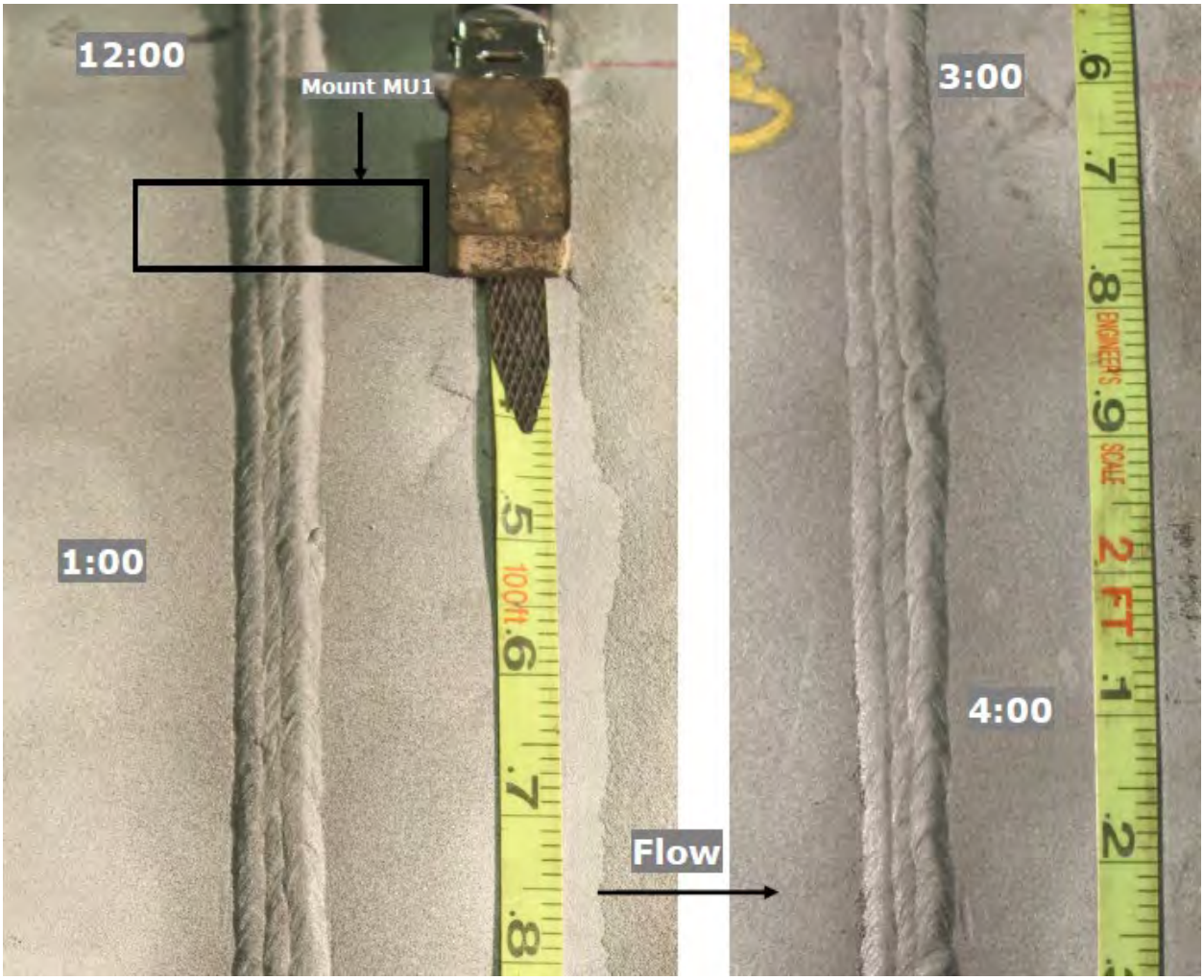


Figure 33. Overview of Mount MU1

This sample was removed from the intact GW at the 12:24 o'clock position. The morphology is similar to the previous mounts. The high-low weld misalignment at this location is approximately 4.6% of the NWT. The figure shows a shallow incomplete fusion flaw (1.9% of the NWT) between the weld metal and the HAZ. An image of the cross section of sample MU1 is provided in Figure 34.

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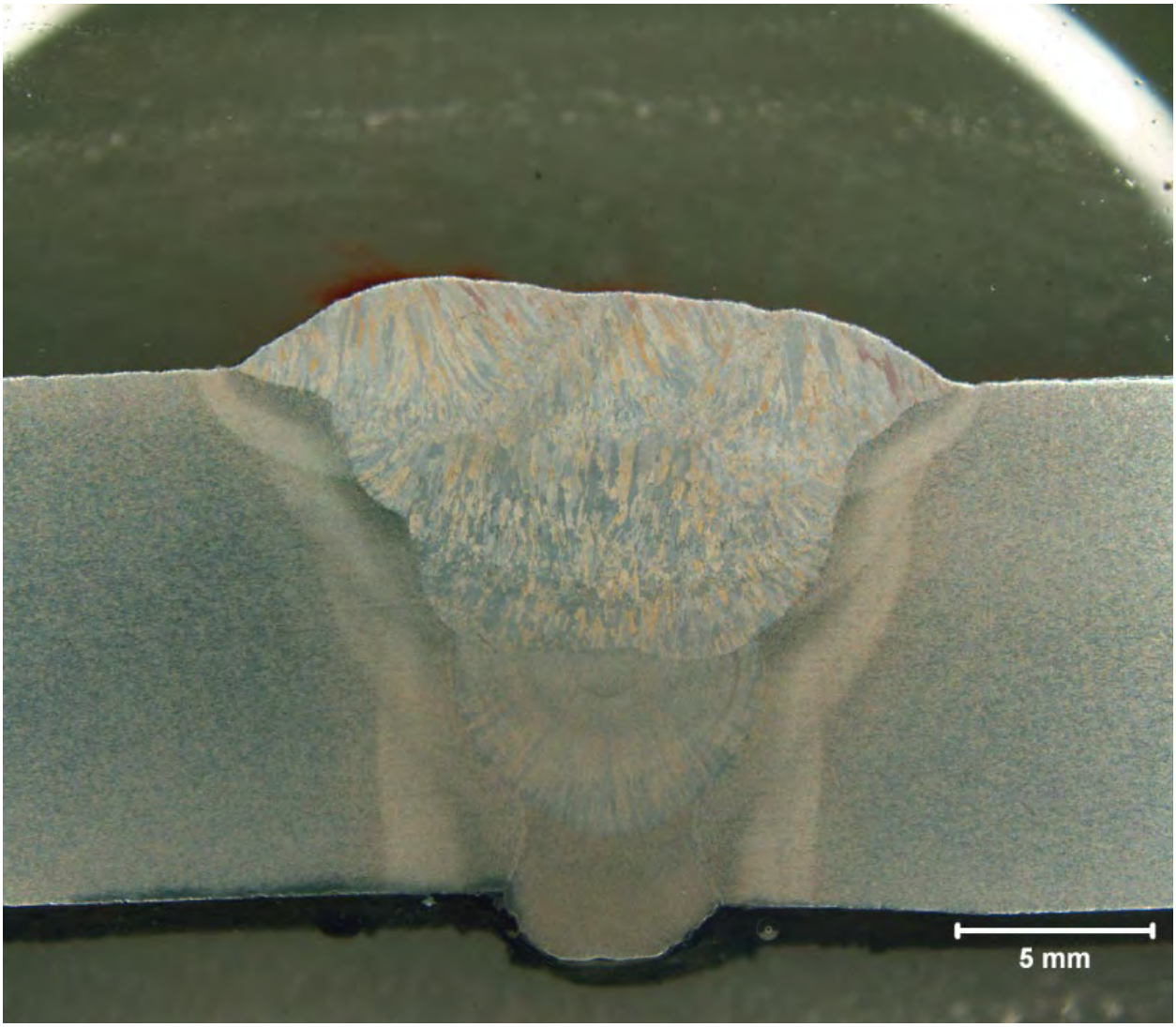


Figure 34. Cross Section of Mount MU1

A shallow flaw was identified between the weld metal and HAZ, with no evidence of cracking or extension of the flaw. A close up view of the flaw is provided in Figure 35.

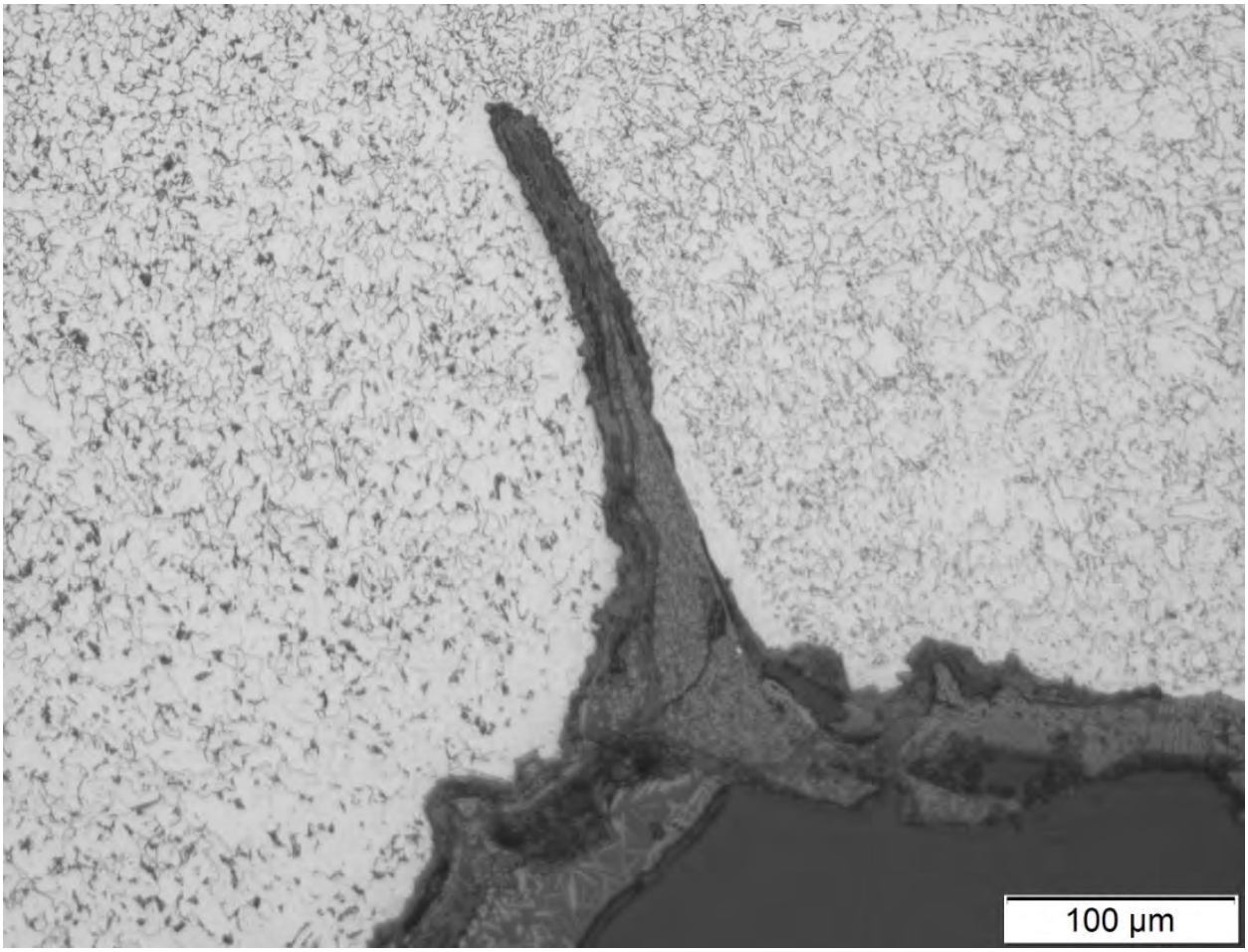


Figure 35. Close Up View of Sample MU1 Flaw

5.4 Scanning Electron Microscopy

As noted above, 4 samples were removed from PS A adjacent to the metallographic samples. No evidence of pre-existing flaws or fatigue were identified. SEM images (Figure 36, Figure 37, Figure 38) provide examples of dimples and mid-wall tears associated with ductile fracture, and cleavage facets associated with brittle fracture.

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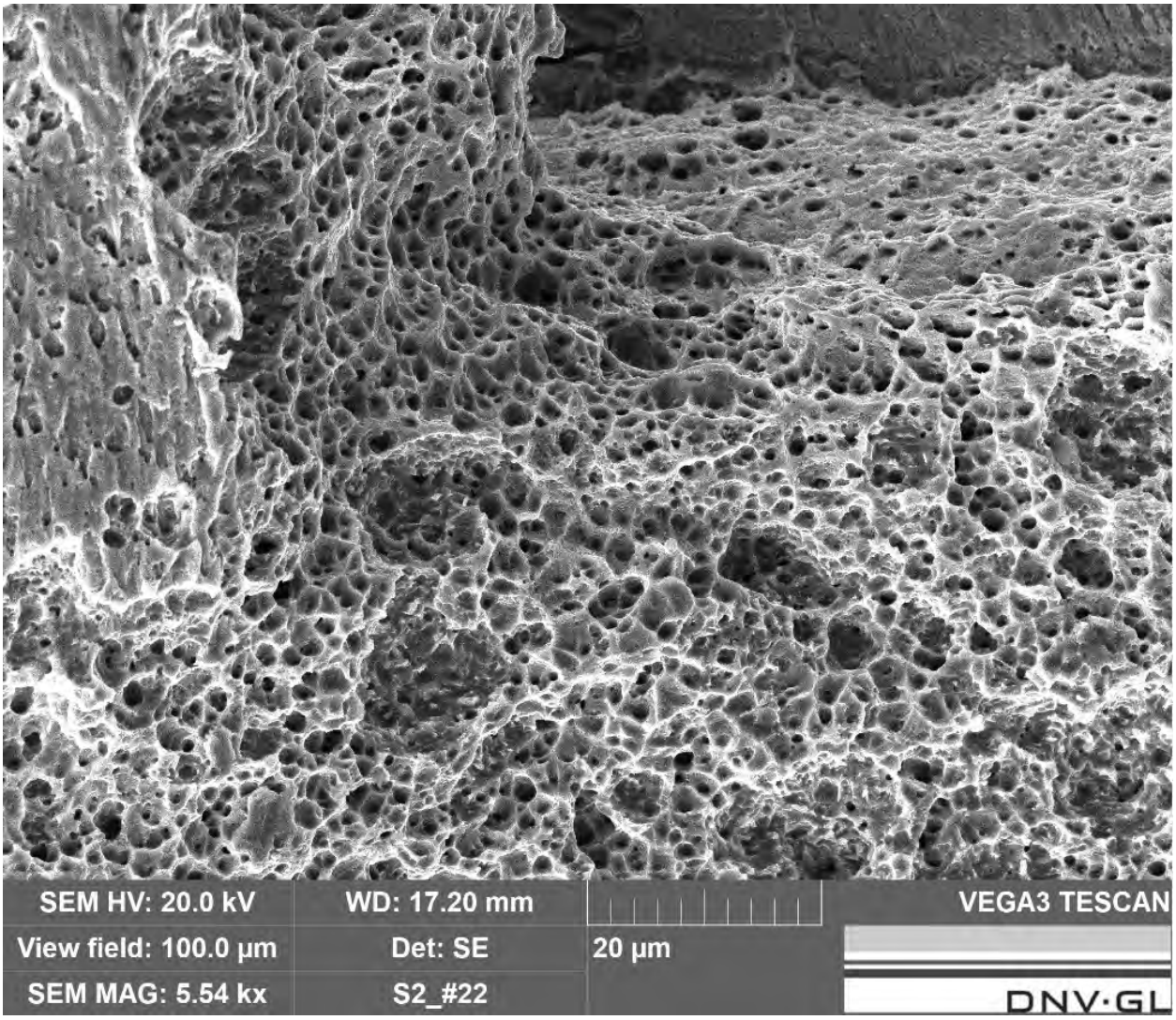


Figure 36. Sample S2 – Dimples Associated with Ductile Fracture

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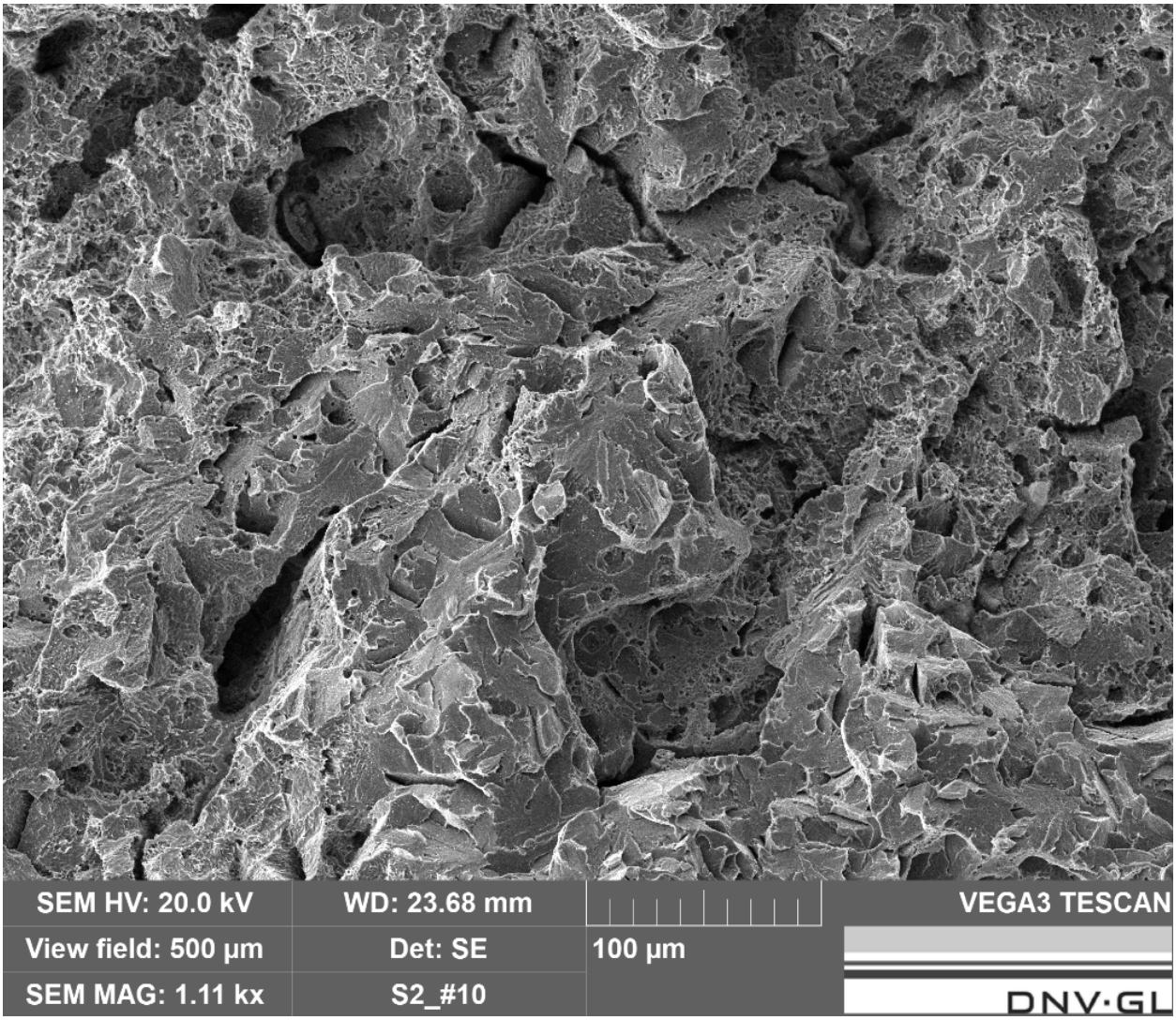


Figure 37. Sample S2 – Facets Associated with Brittle Fracture

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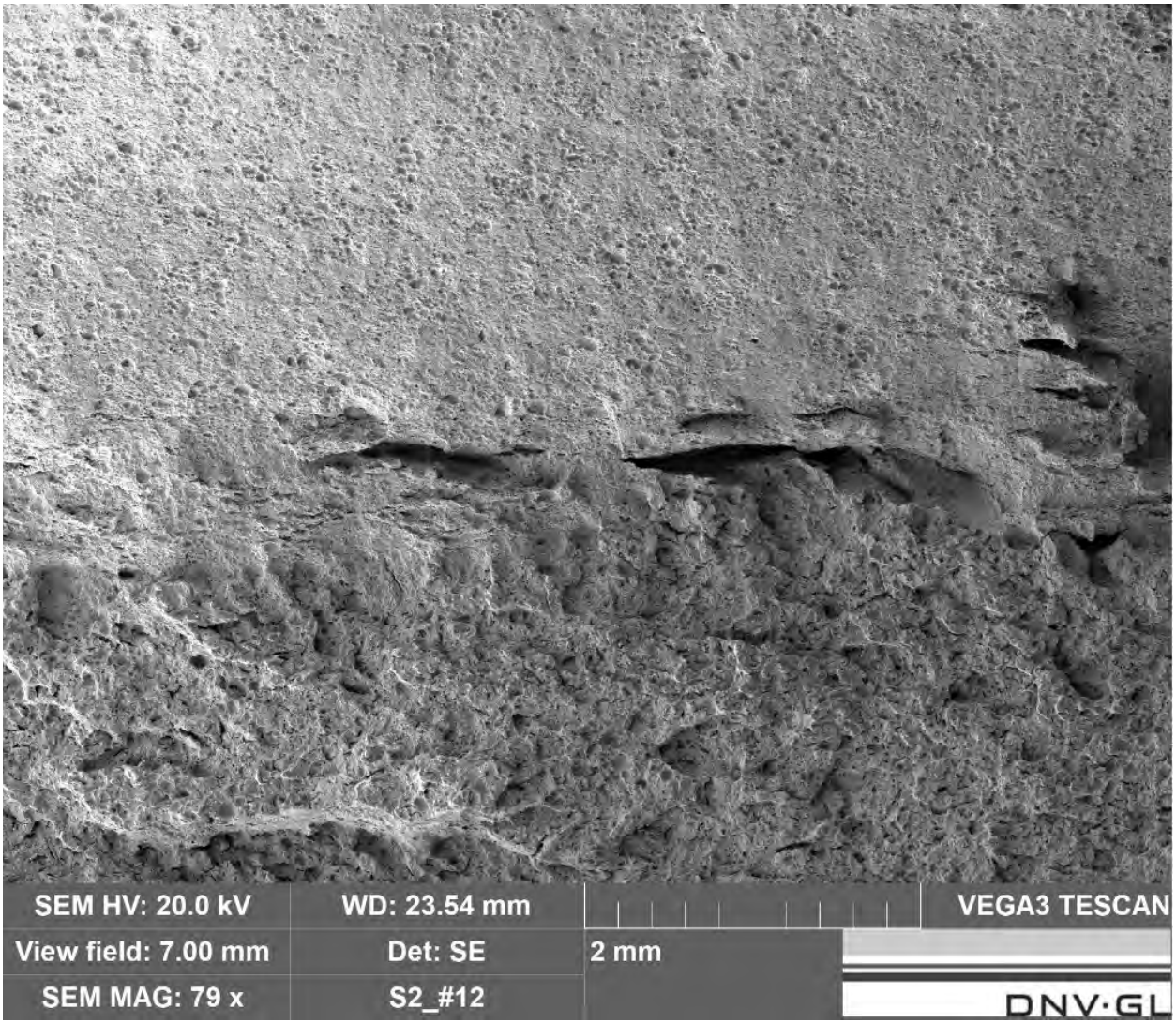


Figure 38. Sample S2 – Tears Mid-Wall (Smooth Region)

5.5 Hardness Testing

Vickers hardness testing was conducted on all six metallographic cross sections. No areas of unusually high hardness were identified. Hardness testing of the failed girth weld exhibit variability that is likely associated with cold work sustained during the failure. The hardness testing of the intact weld are the best representation of the base hardness of the welds preceding the failure. The results indicate a lower hardness of the weld metal compared to the pipe metal, which indicating that the weld metal is softer than the parent metal. Typically, the parent metal

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is harder than the weld metal. The axial tensile tests on the intact girth weld show similar failure to the actual fracture, further indicating that the lower hardness typical of the weld was the preferred location for the overload failure under applied axial stress. Hardness levels at varying points on sample M2 from the failed girth weld are shown in Figure 39.

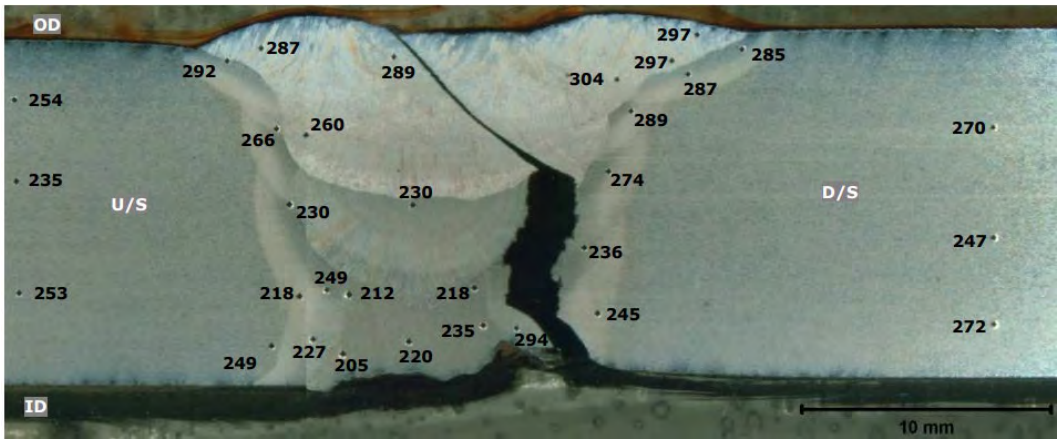


Figure 39: Light Photomicrograph of M2 Axial Cross-Section Showing Hardness Levels in HV

5.6 Mechanical Testing

A summary of mechanical testing results for the Delhi 24-inch pipeline samples is provided below. Additional detail is included in Appendix C.

5.6.1 Tensile Testing

Tensile testing of duplicate circumferential base metal specimens indicates the average yield strength (YS) and ultimate tensile strength (UTS) meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction. The average UTS of duplicate axial specimens taken from the intact girth weld was 103.3 ksi. Both specimens failed in the girth weld, similar to the in-service pipeline failure. The average axial YS and UTS value across the weld meets the tensile requirements for API 5L X80M PSL 2 line pipe at the time of construction.

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5.6.2 Charpy V-Notch Testing

The results of CVN testing of the base metal samples indicate impact values all exceeding the specified values for the specified minimum value for API 5L X80M PSL 2 line pipe at the time of construction. Test results of the girth weld samples taken from PS C indicate acceptable values, with the 85% Fracture Appearance Transition Temperature (FATT) 59.9ºF.

5.6.3 Chemical Analyses

The results of the chemical analysis indicate that the steels meet the compositional requirements of API 5L Grade X80M PSL 2 line pipe. The carbon equivalent (CE) values were calculated for the base metal samples PS A and PS C and are 0.17 and 0.16 respectively. These values compare favorably to the maximum allowable 0.25 according to API 5L specification at the time of construction.

6.0 CONCLUSIONS

The combined results of this investigation indicate that the root cause of the 24-inch Delhi pipeline failure was overload at a field girth weld due to axial stresses sufficient to cause an overload condition. Movement is considered to be a possible contributing factor. Based on the results of this investigation, we provide the following conclusions:

1. The brittle failure originated at a girth weld. The presence of soft regions with dimples (ductile mode) and cleavage facets (brittle mode) are characteristics typical of a failure from overload conditions.
2. The failure occurred due to axial stresses. There was no indication of a pre-existing defect and a specific failure initiation site was not apparent.
3. The weld metal for both the failed girth weld and the intact weld was found to have lower hardness values than the surrounding pipe materials indicating the weld metal was weaker than the pipe material and thus, more susceptible to overload under axial stress conditions. The findings do not suggest the failure resulted from a welding quality issue.

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4. There was no evidence of internal or external corrosion that may have contributed to the failure mode.
5. The mechanical and chemical testing results were in accordance with the requirements for API 5L X80M PSL 2 line pipe.
6. The microstructure of the pipe material U/S and D/S of the failed girth weld are consistent with modern X-80M PSL 2 line pipe steel.

7.0 APPENDICES

Appendix A – Denbury Yazoo County Pipe Sample Collection Protocol

Appendix B - Denbury Yazoo County Metallurgical Sampling & Testing Protocol

Appendix C - DNV-GL Metallurgical Analysis Report

Appendix D - Responses to Questions Provided by PHMSA 4/7/2021

Appendix E - Chain of Custody Documentation

Appendix F - Welding Procedure Development and Qualification for X80 Line Pipe

Appendix G - Welding Procedure Specification WPS 14 6/18/2008

Appendix H - Stress Analysis Report Denbury Delta Pipeline Repair 7/28/2021

Appendix A

Denbury Yazoo County Pipe Sample Collection Protocol

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Pipe Sample Collection Protocol

Denbury Yazoo County Pipeline

1. Each pipe sample location will be identified and documented according to Mears procedures.

2. The as-found condition of the site will be documented and photographed, and the areas previously identified will be excavated to uncover the pipeline.

3. Any welded sleeves or temporary repair clamps covering the area of interest are to be left in place for removal after delivery of the sample to the laboratory.

4. If any bolted connections are disconnected or removed, fasteners and gaskets will be marked for identification purposes, photographed and retained for further analysis (if applicable).

5. If the pipeline is encased at the area of interest:

    a. The exterior of the casing will be visually inspected, condition documented, and a section of the casing will be selected and marked for identification purposes.
    b. The identified casing section will then be removed in a manner that preserves the condition of the pipeline and casing in the area of interest to provide access for inspection of the pipeline in the area of interest.
    c. The interior surface of the casing will be visually inspected, documented and photographed.
    d. If applicable, samples of the casing or materials inside the casing will be selected and collected for detailed analysis.

6. The as-found condition of the carrier pipe will be documented and photographed. Labeling will include the 12:00 position of the pipe and direction of flow, prior to coating removal and pipe inspection.

7. Prior to disturbing or removing the pipe coating, samples of any liquids or solids deposits located between the carrier pipe and coating or adhered to the pipe surface located in the area of interest will be collected in duplicate. Liquid samples will be retrieved using a syringe. Solids samples will be collected using a wooden spatula/tongue depressor. All samples will be placed in sealed enclosures (test tubes or sample bags). Samples will then be labeled and photographed. Duplicate samples will be transferred to designated representatives of IPL or shall be retained for future transfer.

8. If no liquids are present, pH paper may be used to evaluate any moisture present on the pipe section.

9. The pipeline in the area of interest will then be evaluated to determine if pipe samples are required for further detailed analysis.

10. If temporary repairs are required at the area of interest in order to allow future removal of a pipe sample, the repair will be installed preserving the condition of the area of interest and will be left in place for removal after delivery to the laboratory.

11. Sample(s) to be removed for detailed analysis and testing from the pipe section cut out of the pipeline will be identified:

    a. The sample(s) will be marked for identification, including the 12:00 position of the pipe and direction of flow.
    b. The identified sample(s) will be photographed prior to removal from the pipeline.
    c. Coating removal and cuts will be made at least 12" from the identified defect/damage location, with care taken not to disturb the area of interest.
    d. If welded sleeves or temporary repair clamps cover the area of interest, cuts will be performed at least six inches from the edges of the sleeve or clamp.

12. After removal, the pipe sample(s) will be photographed prior to packaging for shipment:

    a. The pipe sample(s) will be wrapped in hydrophobic material like polyethylene to prevent contamination.
    b. The pipe sample(s) will then be crated for shipment, along with any other portable evidence identified for further testing.
    c. The pipe sample(s) will be immobilized within the container.

13. Transport documentation and chain of custody will then be initiated.

14. The pipe sample will then be shipped to DNV GL, Columbus, OH or Plain City, OH receiving yard.

Appendix B

Denbury Yazoo County Metallurgical Sampling & Testing Protocol

METALLURGICAL FAILURE INVESTIGATION PROTOCOL

Denbury Delhi 24 inch Transmission Pipeline

1. INTRODUCTION

The purpose of the failure analysis is to assign one or more probable causes to the failure. This failure analysis protocol specifically addresses the failure analysis of line pipe.

The protocol was written in accordance with the March 21, 2019 Metallurgical Laboratory Failure Examination Protocol by PHMSA.

2. VISUAL AND NONDESTRUCTIVE EXAMINATION

2.1 Open the crate to visually inspect the failed pipe sections. The crates should contain the failed pipe section, including one intact girth weld.

2.2 Photographically document each pipe section in the “as-received” condition before initiating the metallurgical evaluation.

2.3 Remove the protective wrapping from the failed pipe sections and perform visual examination of the external and internal pipe surfaces in the “as received” condition. Measure the length of the failed pipe sections and document the position and orientation of anomalies that may be present in the failed pipe sections. This step shall include:

- Fracture area and surface
- Seams
- Girth welds
- Coating condition
- Anomalies
- Manufacturing flaws and defects
- Presence of External or internal corrosion

2.4 Collect coating samples, solid and liquid samples (if present). All samples will be collected with companion samples or retained. If a sample is determined to be of insufficient volume for a companion sample to be collected, the sample will be retained for evaluation at a later date. Solid deposits and liquid samples, if present, from the internal and external pipe surfaces will be submitted for energy dispersive spectroscopy (EDS) elemental analysis, X-ray diffraction (XRD) and microbial tests. If not enough liquid is present for collection, consider using pH paper to characterize

pH. Use a soft clean/uncontaminated knife or spatula to collect samples and re-inspect the pipe section after collecting samples. Knives/Tools should be cleaned with alcohol wipes before each use. The films or deposits may be from the steel surface, coating surface, interior of a corrosion pit, or the backside of the coating. The color and type of sample should be recorded. Carefully transfer the sample to the test kit vial for testing and carefully follow the instruction given in the kit manual.

2.5 Carefully remove and retain samples of the coating around the suspected area of damage using a knife or similar instrument. Knives/Tools should be cleaned with alcohol wipes before each use. Avoid touching the soil, pipe surface deposits or product, or film with hands or tools other than those to be used in sample collection and/or provided with the test kits. Any liquid under the coating should be sampled if sufficient quantities are available. If insufficient quantities are found, the pH shall be tested with litmus paper.

2.6 After the coating sample is collected, visually inspect the internal and external surfaces of the failed section. Identify areas that may contain other types of anomalies such as cracking, stress corrosion cracking, or any other condition that could affect the long-term integrity of the pipeline. Clean and examine the external pipe surfaces adjacent to the failure using nondestructive testing techniques, such as magnetic particle inspection (MPI) such as wet fluorescent magnetic particle (WFMT). The surfaces of the pipe surrounding the corrosion or cracks must be clean, dry, and free of surface contaminants such as dirt, oil, grease, corrosion products and coating remnants.

2.7 The physical location of all samples that are removed from the pipe section for examination and metallurgical analysis will be documented such that all relevant features are visible (graphically and/or photographically). A pipe section schematic detailing the location and orientation of any samples will be prepared.

2.8 Determine the appropriate failure analysis processes to complete based on the initial observations and testing.

3. PHYSICAL MEASUREMENTS

3.1 Measure the diameter and wall thickness at the 12, 3, 6 and 9 o’clock orientations on undisturbed areas of the pipe.

3.2 Measure and record the length of each sample.

3.3 Examine the details of the failed area. Measure and record any additional defects identified.

3.4 Measure the diameter and wall thickness at selected locations of anomalies.

3.5 Verify roundness and geometry of pipe at the extremities and near the failed surface.

3.6 Measure the wall thickness around the failure and any damaged areas. Provide a schematic detailing the extent of the damage on the pipe surface and the pipe wall thickness on those areas. Supplement with photographic records. Supplement these measurements with laser scanning.

3.7 Determine and mark the locations of the long seam weld at each end of the sample.

3.8 Measure and record the size and location of anomalies and confirm the dimensions of the failed pipe section. Measure crack depths (if present) using direct exploration (grinding), shear wave ultrasonic testing, or other suitable method.

3.9 Measure the shortest axial distance from the failure to the nearest long seam weld (if applicable). Measure the shortest longitudinal distance from the failure to the nearest girth weld (if applicable).

4. CORROSION EXAMINATION

4.1 Examine the pipe external surface near the failure location to determine if anomalies exist.

4.2 Examine the pipe internal surface at the failure location to determine if anomalies exist.

4.3 If not already performed as described in Section 2, collect surface deposits and residues associated with the external pipe surface at the failure area and adjacent areas and analyze using MIC IV kits (or equivalent) and energy dispersive spectrometry (EDS) and microbial analysis. Knives/Tools should be cleaned with alcohol wipes before each use.

4.4 Photographically document the pipe internal surface conditions and any anomalies present.

4.5 Evaluate and document processes that potentially contributed to the failure to support selection of samples within the failed pipe section.

4.6 If internal anomalies are found, proceed with collection of surface deposits and residues associated with the failure area and analyze using MIC IV and MIC V kits (or equivalent) and energy dispersive spectrometry (EDS) and microbial analysis.

4.7 Determine specific locations of the failed pipe section for further investigation.

4.8 Cut and clean the selected locations for selection of initial metallographic sections, taking additional solids and liquid samples as necessary.

4.9 Perform hardness measurements in areas near the anomalies and also remote from the failure site.

4.10 Take initial metallographic sections at appropriate locations within the failure area.

4.11 Anomaly depths may be determined using pit depth gauge, ultrasonic thickness probe, profile gauges, 3D laser scanning, etc.

5. FRACTOGRAPHIC EXAMINATION

5.1 Visually examine the fracture surface in detail to identify specific characteristics, the nature of the original defect, and the failure initiation point (s). If it becomes necessary, a metallographic section will be made through the sample to open the failure for further examination.

5.2 Clean samples in an appropriate manner to remove loose rust, scale, etc. as necessary.

5.3 Remove selected fractographic samples as necessary for detailed microscopic examination using a scanning electron microscope equipped with EDS. Examine and document the fracture surface morphology.

5.4 Thoroughly document the location of the samples taken from the pipe section at or near the failure.

6. METALLOGRAPHIC EXAMINATION

6.1 Identify metallographic sample origin (sample identification, location, orientation, etc.), perform metallographic evaluation, and take representative photomicrographs.

6.2 Perform micro-hardness profiles at appropriate locations.

6.3 Document microstructural appearance of samples.

6.4 Document the extent of the wall loss, if any, of the cross section.

6.5 Based on the results of the visual, non-destructive, and metallographic examinations, the presence of corrosion will be documented, and the type and characteristics of any corrosion present should be evaluated.

NOTE:

- This protocol is subject to change.
- Additional tests may be added and/or changes made as necessary to accomplish the purpose of this failure analysis and complete this process.

Appendix C

DNV GL Metallurgical Analysis Report

DNV·GL

Draft Report

Metallurgical Analysis of 24-Inch Diameter Delhi Pipeline Failure (02/22/20)

Mears Group, Inc.
Plain City, Ohio

Report No.: O-AP-FINV / GTQU (10206282)
June 4, 2020



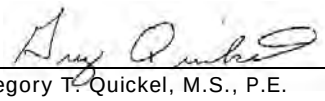
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Customer:	Mears Group, Inc.
Contact Person:	Aida Garrity
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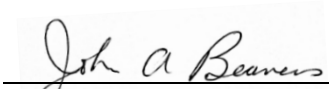
Please see Executive Summary.

Prepared by

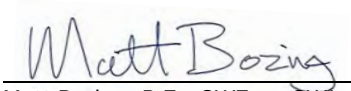


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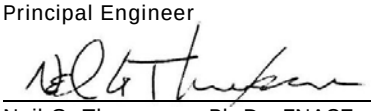
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Executive Summary

Mears Groups, Inc. (Mears) retained DNV GL USA, Inc. (*DNV·GL*) to perform a metallurgical analysis on a portion of the Delhi 24-inch diameter carbon dioxide (CO_2, dry) transmission pipeline, that failed at a girth weld while in service, resulting in full separation. The failure occurred on February 22, 2020 in Satartia, Mississippi at Stationing 348+26, 6.59 miles from the nearest upstream (U/S) pump station.

The segment of the pipeline that failed is comprised of 24-inch diameter by 0.540-inch wall, API 5L Grade X80M PSL 2 line pipe steel that contains a high frequency electric resistance welded (HF ERW) seam. The maximum allowable operating pressure (MAOP) is 2,160-psig, which corresponds to 59.6% of the specified minimum yield strength (SMYS). The pressure at the Tinsley Meter Station (Stationing 0+00) at the time of the failure was 1,336-psig (36.9% of SMYS). The pipeline normally operates between 1,200 and 1,450-psig (33.1 and 40.0% of SMYS, respectively).

The pipeline was installed in 2009 and is externally coated with a factory applied fusion bonded epoxy (FBE) and abrasion resistant overlay (ARO) coating. A liquid epoxy coating was applied to the pipeline at the girth welds in the field. Following construction, a hydrostatic pressure test was performed on January 14, 2009 to a minimum pressure at the dead weight gage of 2,908 psig (80.3% of SMYS). The pipeline has an impressed current cathodic protection (CP) system that was commissioned in 2009, directly following pipeline installation.

Three pipe sections (Pipe Sections [PSs] A, B, and C) were delivered to DNV GL for analysis. Pipe Section A was 5.99 feet long and contained the downstream (D/S) portion of the failed girth weld. Pipe Section B was 6.08 feet long and contained U/S portion of the failed girth weld. Pipe Section C was 8.00 feet long and contained an adjacent U/S intact girth weld. The objectives of the analysis were to determine the metallurgical cause of the failure and identify any contributing factors.

The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, due to axial stresses sufficient to produce overload failure. No pre-existing flaws were present on the fracture surface. A contributing factor to the failure was that the pipe steel was stronger than the girth weld.

The scope of the work consisted of:

- Visual inspection and photography
- Magnetic particle inspection
- Fractography
- Scanning electron microscopy
- Metallography
- Energy dispersive spectroscopy

- Hardness testing
- Mechanical testing
- Chemical analysis

The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, completely separating the girth weld. The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified. Microscopically, the fracture surface contained regions with dimples (ductile fracture) and cleavage facets (brittle fracture). The dimples were located where the fracture surface was at a shear angle and macroscopically smooth, and the cleavage facets were located where the fracture surface was perpendicular to the free surfaces and macroscopically rough. Both fractographic features are an indication of the overload nature on the fracture surface.

The failure occurred due to axial stresses sufficient to produce an overload failure. Supporting evidence for the presence of large axial stresses include 1) a relatively large opening between the failed ends and 2) cracked and missing epoxy coating U/S of the failed girth weld indicating a high strain prior/during fracture. A possible contributing factor to relatively large axial stresses includes stresses associated with movement.

No excessively high hardness areas were identified in the girth weld cross-sections. The weld metal of the intact girth weld had a lower hardness than the surrounding pipe material, indicating that the weld metal is weaker than the surrounding pipe material. This trend was somewhat followed for the failed girth weld, although cold work from the failure likely skewed some of the data. The softest regions in all the mounts was the weld metal root pass. The lower overall hardness values of the weld metal compared to the surrounding pipe material is consistent with the axial tensile results. The ultimate tensile strength for the girth weld of 103.3 ksi is less than the axial tensile strength of 109.7 ksi and 106 ksi for the joint's D/S and U/S, respectively, of the failed girth weld. The axial tensile tests across the intact GW failed in the GW, similar to the actual failure. Therefore, a contributing factor to the failure was that the pipe steel was stronger than the girth weld.

Below is a summary of additional conclusions:

- There was no evidence of notable internal or external corrosion.
- The tensile and toughness properties of the joint's U/S and D/S of the failed girth weld meet requirements for API 5L X80M PSL 2 line pipe at the time of construction.
- The chemical compositions of the joint's U/S and D/S of the failed girth weld meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.

- The microstructures of the joint's U/S and D/S of the failed girth are consistent with modern API 5L X80 line pipe steel.
- An analysis of the Charpy V-notch impact testing data for the intact girth weld indicates that the 85% fracture appearance transition temperature (FATT) is 59.9°F and upper shelf Charpy energy is 114 ft lbs.

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1.0 BACKGROUND

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2.0 TECHNICAL APPROACH

The procedures used in the analysis were in accordance with industry-accepted standards. Five of the general standards governing terminology, specific metallographic procedures, mechanical testing, and chemical analysis used are as follows:

- ASTM E7, “Standard Terminology Relating to Metallography.”
- ASTM E3, “Standard Methods of Preparation of Metallographic Specimens.”
- ASTM E8, “Test Methods for Tension Testing of Metallic Materials.”

- ASTM E23, “Standard Test Methods for Notched Bar Impact Testing of Metallic Materials.”
- ASTM A751, “Standard Test Methods, Practices, and Terminology for Chemical Analysis of Steel Products.”

The following steps were performed for the analysis. The pipe sections were removed from the wooden shipping crates and visually inspected and photographed. Wall thicknesses, outside diameters (ODs), and circumferences were measured at the field cut ends of the pipe sections. The external and internal surfaces of the pipe sections at the failed girth weld were cleaned with a Scotch-Brite™ pad, followed by photography of the surfaces. The fracture surfaces were then cleaned with a soft bristle brush, followed by photography at one hour o’clock increments. The external surface of PS C was grit blasted at the intact girth weld, followed by magnetic particle inspection (MPI) of the grit blasted surface. Samples were removed from PS A and C for mechanical testing and steel chemical analysis.

Axial (cross girth weld) cross-sections were removed from the failed girth weld (five total) and intact girth weld (one total) for metallographic analysis. The cross-sections were mounted, polished, and etched. Light photomicrographs were taken to document the morphology of any flaws and the microstructures of the pipe steel and welds. Hardness testing was performed on the six mounted cross-sections to document the hardness values at and away from the girth welds. Fracture surface samples (four total) were removed from PS A, cleaned in ENPREP® 214, examined optically at low magnification with a stereomicroscope, and imaged at high magnification in a scanning electron microscope (SEM) to document the fracture morphologies.

Magnetic particle inspection was performed on the internal surfaces of the intact and failed girth welds. Chemical analyses were performed on the steel samples removed from the joints U/S and D/S of the failed girth weld to determine the compositions. Tensile (duplicates) testing was performed on transverse and axial specimens removed from the joints U/S and D/S of the failed girth weld, and on axial (cross-girth weld) specimens removed from the intact girth weld, to document the tensile properties. Charpy V-notch (CVN, triplicates) testing was performed on transverse specimens removed from the joints U/S and D/S of the failed girth weld to document the base metal toughness. Charpy V-notch (CVN) impact testing (full curve, 10 specimens per curve) was performed on axial (cross-girth weld, heat affected zone [HAZ] notch) specimens removed from the intact girth weld and an upper shelf impact energy and 85% fracture appearance transition temperature (FATT) was determined.

Figure 1 is a schematic of PSs A, B, and C showing the locations of the girth welds and seam welds, and where samples for metallography (Mount M1, M2, M3, M4, M5, and MU1),

fractography (Sample S1, S2, S3, and S4), mechanical testing, and chemical analysis were removed.

3.0 RESULTS AND DISCUSSION

3.1 Optical Examination

Figure 2 is a photograph of the wooden shipping crate that contained PS A as received at DNV GL. The crate is approximately 10 feet long and was in good condition. Figure 3 is a photograph of PS A after removal from the wooden crate. The figure shows that the ends of the pipe were wrapped in clear plastic that was secured with duct tape. Foam insulation was secured to the U/S end of the pipe to cover the fracture surface of the failed girth weld. Figure 4 are photographs of PS A after removal of the clear plastic and foam insulation. Flow direction and o'clock orientation were marked (prior to shipment to DNV GL) on the pipe section. The pipe section is 5.99 feet long, contains a longitudinal seam weld at the 12:26 orientation, has portions of a field applied liquid epoxy coating (light blue appearance) at the girth weld, and portions of a factory applied FBE coating (reddish brown appearance) on the remainder of the pipe section. The figure shows a large portion of the coating is not present. The coating is not present between approximately 0 and 5.70 feet D/S of the girth weld, from the 8:00 to 4:00 orientations. Field personnel indicated that following failure the product flow was toward PS A, which may have contributed to the lack of coating. Additionally, the figure shows some residual soil is present on the pipe section.

Figure 5 is a photograph of the wooden shipping crate that contained PS B as received at DNV GL. The crate also is approximately 10 feet long and was in good condition. Figure 6 is a photograph of PS B after removal from the wooden crate. The figure shows that the ends of this pipe also were wrapped in clear plastic that was secured with duct tape. Foam insulation was secured to the D/S end of the pipe to cover the fracture surface of the failed girth weld. Figure 7 is a photograph of PS B after removal of the clear plastic and foam insulation. Flow direction and o'clock orientation were marked (prior to shipment to DNV GL) on the pipe section. The pipe section is 6.08 feet long, contains a longitudinal seam weld at the 10:37 orientation, has portions of a field applied liquid epoxy coating (light blue appearance) at the girth weld, and a factory applied FBE coating (reddish brown appearance) on the remainder of the pipe section. Some of the field applied coating was not present adjacent to the girth weld, for the entire circumference. Additionally, the figure shows some residual soil is present on the pipe section.

Figure 8 is a photograph of the wooden shipping crate that contained PS C. The crate also is approximately 10 feet long and was in good condition. Figure 9 is a photograph of PS C after removal from the wooden crate. The figure shows that the ends of the pipe also were wrapped in clear plastic that was secured with duct tape. Figure 10 is a photograph of PS C

after removal of the clear plastic. Flow direction and o'clock orientation were marked (prior to shipment to DNV GL) on the pipe section. The pipe section is 8.00 feet long and contains longitudinal seam welds at the 1:24 orientation (U/S joint) and at the 10:37 orientation (D/S joint). An intact girth weld, that is the girth weld just U/S of the failed girth weld, is indicated in the figure. A field applied liquid epoxy coating (light blue appearance) is located at the girth weld and a factory applied FBE coating (reddish brown appearance) on the remainder of the pipe section. The field and factory applied coatings were intact. Additionally, the figure shows some residual soil is present on the pipe section. There was no evidence of notable internal or external corrosion of the three pipe sections.

Figure 11 through Figure 14 are photographs of the external surface of PSs A and B adjacent to the fracture surfaces/failed girth weld. The figures are sequential photographs taken around the circumference of the girth weld and show the morphology of the weld pattern and where coating is present. The lack of coating adjacent to the girth weld on the PS B side (U/S of the failed girth weld) suggests that large strains were present prior to/during the failure. The figures shows that the fracture path traversed (crossed over) the weld at various locations. The external appearance of the weld ripple pattern is indicative of low hydrogen electrodes deposited in the vertical-down direction, with a triple pass wide weave cap pass. Even though downhill welding progression with low-hydrogen electrodes is not common in the pipeline industry, electrode manufactures do provide low-hydrogen electrodes specifically designed to weld down, which are classified as EXX45 type electrodes. The morphology of the weld ripple pattern also indicates that the top button (start of welding) is located near the marked 12:00 orientation; see Figure 14.

Figure 15 and Figure 16 contain photographs of the internal pipe surface adjacent to the fracture surface of PS B. Each photograph shows approximately 3 o'clock hours of the internal surface at the girth weld adjacent to the fracture surface. The figures show that the root pass is located on the PS A side of the failure opening between approximately the 6 and 9 o'clock orientations and a majority of the root pass is located on the PS B side of the failure opening elsewhere. The top button is indicated in Figure 16, near the marked 12:00 orientation.

Circumferences and ODs were measured at the four field cut ends of the pipe sections. Table 1 summarizes the results of the measurements. The ODs calculated from the circumference measurement were between 24.1 and 24.2 inches at the field cut ends. The diameters meet API 5L tolerance requirements for 24-inch diameter pipe. The ODs were measured with a tape measure from the 3 to 9 o'clock and 12 to 6 o'clock orientations to check for ovality. The ODs at the ends of PSs B and C, and both orientations, were 24.0 inches, indicating no measurable ovality. The ODs at the end of PSs A, and both orientations, were 24.1 inches, indicating no measurable ovality.

Wall thicknesses were measured at the 12, 3, 6, and 9 o'clock orientations at the four field cut ends. The external coating was ground prior to the measurements. The wall thickness values were between 0.530 and 0.540 inches, as shown in Table 2, and meet API 5L tolerance requirements for pipe with a nominal wall thickness (NWT) of 0.540 inches.

3.2 Magnetic Particle Inspection

The intact girth weld on PS C was grit blasted and MPI was performed. Figure 17 and Figure 18 contain photographs of the external surface at the girth weld following MPI. No crack-like indications were identified. A metallographic cross-section (Mount MU1) was removed from the 12:24 orientation. The weld ripple pattern of the weld is consistent with PS A and PS B and with the use of a low hydrogen electrode and a vertical-down progression. The top button (Figure 18) is just above (counter-clockwise of) the 12:00 orientation.

Note that MPI of the internal surface of the intact weld also was performed following mechanical testing, as was MPI of the internal surface of at the failed GW, following metallography. No crack-like indications were identified.

3.3 Fractography

3.3.1 Optical

Figure 19 is a photograph of the fracture surface and internal surface of PS A following cleaning with a soft bristle brush. Each o'clock hour is indicated and located at the twelve grey magnets. Figure 20 through Figure 31 are sequential photographs of the PS A side of the fracture surface of the failed girth weld, in 1 hour o'clock increments, starting at the 12:00 orientation. The fracture surface mainly consists of fairly smooth surfaces (*smooth regions*) at a shear (~45°) angle with respect to the free surfaces, and rougher surfaces (*rough* surfaces) that are perpendicular to the free surfaces. Some examples of the smooth surfaces are in Figure 21 through Figure 23, between the 1:00 and 3:45 orientations. The fracture surface between the 3:45 and 4:15 orientations contains smooth and rough regions. Some other examples of the rough regions are in Figure 29 through Figure 31, between the 9:15 and 12:00 orientations, where the rough regions are mainly ID surface breaking, with some midwall portions. The differences in these appearances is related to the fracture mode (ductile vs brittle), as described in Section 3.3.2, and both regions formed as a result of overload. There was no evidence of gross pre-existing flaws on the fracture surface that would have been rejected if detected by radiographic inspection. The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified.

3.3.2 Optical and Scanning Electron Microscopy

Four fracture surface samples (Samples S1, S2, S3, and S4) were removed from the PS A side of the failed girth weld, adjacent to the metallographic cross-sections. The results of examinations of Samples S2 and S3 are below.

Figure 32 is a light photomicrograph of the fracture surface of Sample S2, following cleaning in ENPREP® 214. Sample S2 was removed near the 4:00 orientation. The figure shows smooth regions (black dashed double arrows) adjacent to the OD and ID surfaces, and a rougher region (white double arrow) midwall. There is no evidence of any pre-existing (present prior to the failure) flaws on the facture surface. Figure 33 is an SEM image of Sample S2 adjacent to the ID surface. The figure shows a smooth region (adjacent to the ID surface) and a rough region of the fracture surface. Figure 34 is an SEM image of Sample S2 at the interface of a smooth and rough region. The black box in the figure is just below the interface and the figure shows dimples in the smooth region. Dimples indicate ductile (overload) fracture, which occurred during the failure. Figure 35 is a high magnification SEM image of Sample S2 in the smooth region. The figure clearly shows the dimples. Figure 36 and Figure 37 are SEM images of Sample S2 in a rough region. The fracture surface contains cleavage facets, which indicates brittle (overload) fracture, which occurred during the failure.

Figure 38 is an SEM image of Sample S2, midwall at a second interface of the smooth and rough regions. The figure shows what appear to be some tears in the smooth region, above the rough region. Figure 39 and Figure 40 are SEM images in the smooth region. The figures shows dimples, consistent with ductile (overload) fracture.

Figure 41 and Figure 42 are SEM images of Sample S2 in a smooth region adjacent to the OD surface. The figures show dimples, which is very clear in the high magnification SEM image. Again, the dimples indicate ductile (overload) fracture and are consistent with ductile fracture in the smooth region.

Figure 43 is a light photomicrograph of the fracture surface of Sample S3, following cleaning in ENPREP® 214. Sample S3 was removed near the 8:30 orientation. Figure 44 is an SEM image of Sample S3. The fracture surface is macroscopically smooth and at a shear angle to the free surfaces, and consists of mainly, if not entirely, smooth regions. Figure 45 is an SEM image of Sample S3 midwall. The figure shows small and larger dimples. Figure 46 is a high magnification SEM image of Sample S3 in the smooth region. The figure clearly shows the dimples.

Examination of Samples S1 and S4 showed similar fractographic features that formed as a result of overload failure. There was no evidence of obvious pre-existing flaws or fatigue growth on the fracture surfaces examined.

3.4 Metallography

Axial (cross girth weld) cross-sections were removed from the failed girth weld (five total) and the intact girth weld (one total) for metallographic analysis. Figure 47 is a photograph of the mounts that were removed from across the failed girth weld. The figure shows that Mounts M1 and M3 contain fracture paths at a shear angle, which is indicative of ductile overload failure. Mounts M2 and M4 (and a small portion of M5) contain regions where the fracture path is perpendicular to the free surface and regions of shear failure. The perpendicular portions are where the fracture surfaces are rough and the shear angle portions are where the fracture surfaces are smooth.

Figure 48 is a light photomicrograph of the axial metallographic cross-section (Mount M1), which was removed from the failed GW at the 1:35 o'clock orientation; refer to Figure 1 and Figure 11 for the location. The sequence of the welding is typical of a pipeline girth weld consisting of a root pass, a hot pass, several fill passes (depending on o'clock orientation), and cap passes. There is no evidence of excessive porosity or slag inclusions in the weld. The fracture path is at a shear angle and mainly located in the weld metal. The high-low weld misalignment at this location is approximately 0.023 inches (4.3% of NWT); note the misalignment is difficult to measure on the fracture cross-section and is an approximation.

Figure 49 is light photomicrograph of Mount M1 adjacent to the OD surface. The figure shows the fracture path is located in the HAZ, near the toe of the weld at the OD surface. Figure 50 is a light photomicrograph of Mount M1 adjacent to the fracture surface, near the OD surface. The figure shows inclusions aligned at an oblique angle with the fracture surface. The orientation of the inclusions is a result of cold work from the failure. Figure 51 is a high magnification light photomicrograph of Mount M1 adjacent to the fracture surface. The figure shows some grain elongation adjacent to the fracture surface and inclusions. The presence of the grain elongation from cold work and orientation of the inclusions is consistent with ductile overload. Figure 52 is a high magnification light photomicrograph of Mount M1 midwall adjacent to the fracture surface. The figure clearly shows the change in the grain orientation and thus more grain elongation adjacent to the fracture surface.

Figure 53 and Figure 54 are light photomicrographs showing the microstructures of the U/S and D/S Joints, respectively. The microstructures of the joints consist mainly of ferrite (white areas), which is consistent with modern X80 line pipe.

Figure 55 is a light photomicrograph of the axial metallographic cross-section (Mount M2), which was removed from the failed GW at the 3:55 o'clock orientation; refer to Figure 1 and Figure 12 for the location. The morphology of the weld similar to Mount M1. The high-low weld misalignment at this location is approximately 0.037 inches (6.9% of the NWT). The figure clearly illustrates the smooth and rough regions examined near SEM Sample S2, such

that the smooth regions are surface breaking and the rough region is midwall. The fracture path at this location is in both the weld metal and HAZ, such that smooth region near the OD surface is in the weld metal, and the rough region midwall and smooth region near the ID surface are in the HAZ. Fractography in the SEM demonstrated that the smooth region contains dimples and the rough region contains cleavage facets.

Figure 56 is a light photomicrograph of Mount M2 adjacent to the ID surface. The figure shows that the fracture surface is relatively smooth. Figure 57 is a high magnification light photomicrograph of Mount M2 adjacent to the ID surface. The figure shows grain elongation adjacent to the fracture surface. The presence of the grain elongation from cold work is consistent with ductile overload. Figure 58 is a light photomicrograph of Mount M2 midwall, in a rough region. The fracture surface is clearly rougher here than the previous figure, and the fracture path is mainly located in the HAZ, if not entirely. Figure 59 is a light photomicrograph of Mount M2 adjacent to the fracture, midwall. The figure shows some fissures. Figure 60 is a high magnification light photomicrograph of Mount M2 at fissures. The fissures are located where cleavage facets (brittle fracture) were present on the fracture surface. These fissures are commonly seen in girth weld overload failures, adjacent to fractures surfaces, or pipe (body or seam weld) failures that involve axially running fracture.

Figure 61 is a light photomicrograph of the axial metallographic cross-section (Mount M3), which was removed from the failed GW at the 8:35 o'clock orientation; refer to Figure 1 and Figure 13 for the location. The morphology of the weld is similar to Mounts M1 and M2. The fracture path is at a shear angle and mainly located in the weld metal. The high-low weld misalignment at this location is approximately 0.014 inches (2.6% of the NWT). The figure clearly illustrates the smooth region examined near SEM Sample S3.

Figure 62 is light photomicrograph of Mount M3 adjacent to the fracture surface, near the ID surface. The figure shows grain elongation adjacent to the fracture surface that is consistent with ductile overload.

Figure 63 is a light photomicrograph of the axial metallographic cross-section (Mount M4), which was removed from the failed GW at the 10:24 o'clock orientation; refer to Figure 1 and Figure 14 for the location. The morphology of the weld is similar to the previous mounts. The high-low weld misalignment at this location is minimal. The figure shows both a smooth shear angle region and a rough region oriented perpendicular to the free surfaces. The fracture path at this location is mainly in the HAZ.

Figure 64 is light photomicrograph of Mount M4 adjacent to the OD surface. The figure clearly shows the fracture path is located in the HAZ. Figure 65 is a high magnification light photomicrograph of Mount M4 adjacent to the OD surface. The figure shows grain

elongation, and an inclusion orientated parallel to the fracture surface, both observations consistent with ductile overload. Figure 66 is a light photomicrograph of Mount M4 midwall, mainly in a rough region. The figure shows some fissures. Figure 67 is a high magnification light photomicrograph of Mount M4 at some fissures. The fissure have the same morphology as shown in Mount M2. Figure 68 is a high magnification light photomicrograph of Mount M4 near the ID surface. The figure shows grain elongation adjacent to the fracture surface.

Figure 69 is a light photomicrograph of the axial metallographic cross-section (Mount M5), which was removed from the failed GW at the 11:37 o'clock orientation; refer to Figure 1 and Figure 14 for the location. The morphology of the weld is similar to the previous mounts. The high-low weld misalignment at this location is approximately 0.025 inches (4.6% of the NWT). The figure shows a smooth shear angle region for a majority of the fracture surface, and a rough region oriented perpendicular to the free surfaces midwall. The fracture path at this location is located in both the weld metal and base metal.

Figure 70 is a light photomicrograph of the axial metallographic cross-section (Mount MU1), which was removed from the intact GW at the 12:24 o'clock orientation; refer to Figure 1 and Figure 17 for the location. The morphology of the weld is similar to the previous mounts. The high-low weld misalignment at this location is approximately 0.011 inches (2.0% of the NWT). Figure 71 is a light photomicrograph of Mount MU1 adjacent to the ID surface. The figure shows a shallow (0.01 inches [1.9% of NWT] deep) flaw between the weld metal and HAZ. The location of the flaw is consistent with incomplete fusion (IF). Figure 72 is a high magnification light photomicrograph of Mount MU1 at the tip of the shallow IP flaw. The figure shows there is no evidence of crack extension at the flaw.

3.5 Hardness Testing

Vickers hardness testing was performed on all six mounts in the base metal, HAZ, and weld metal. A 1 kg load was used on Mounts M1, M4, and MU1 and approximately 1500 indents with approximately 0.5 mm spacing were performed. Figure 73, Figure 76, and Figure 78 are hardness map overlays showing the locations of the indents and color coded maps indicating the hardness values. The hardness values for the two mounts from the failed girth weld are between 208 and 317 HV, and the values for the mount from the intact girth weld are between 167 and 268 HV. The average hardness for Mount M1, M4, and MU1 are 266, 253, and 228 HV, respectively. There was a larger variation in the hardness values, and less of a consistent pattern of hardness values, for the mounts from the failed GW compared to the intact girth weld. Overall for the mounts from the failed girth weld, the weld metal in the root pass was the softest, the weld metal in the cap pass was higher than the fill passes, and the base metal was somewhere in between. The highest values for the

mounts from the failed girth weld was adjacent to the shear fracture surface, between midwall and the OD surface.

The hardness of the intact girth weld (Figure 78) is a better representation of the hardness of all the welds prior to the failure. For the intact girth weld, the values appeared to follow a more consistent pattern. Figure 78 clearly shows that the root pass of the weld metal is the softest and the surrounding base metal (adjacent to the HAZ) is harder than the weld metal. Hardness typically correlates with ultimate tensile strength (UTS) fairly well, thus the data indicates that the weld metal is weaker than the surrounding pipe material. The higher hardnesses measured in the failed welds, and the large variation and lack of a consistent pattern, is a byproduct of the cold work the material experienced during the failure.

A 10 kg load was used on Mounts M2, M3, and M5 (all from the failed girth weld) and indents were performed at approximately 20 to 30 locations. Figure 74, Figure 75, and Figure 77 are light photomicrographs of the mounts showing the indents and hardness values. The hardness values are between 205 and 304HV. The lowest values are at the ID weld metal (root pass, similar to the hardness maps), and the highest values are in the weld metal cap pass. The base metal is generally harder than the root and fill passes, and similar to or sometimes less than the cap pass.

Overall no areas of unusually high hardness area were found. The hardness results show that the softest region is located in the weld metal root pass, suggesting a lower grade electrode was used for the root pass compared to the other passes.

3.6 Mechanical Testing

3.6.1 Tensile Testing

The results of tensile testing of duplicate circumferential base metal specimens removed from PS A (Joint D/S of failed GW) are shown in Table 3. The average yield strength (YS) and ultimate tensile strength (UTS) of the circumferential specimens were 93.5 ksi and 112.4 ksi, respectively. The results of tensile testing of axial base metal specimens also are shown in the table and YS values for the axial specimens are quite a bit higher than those of the circumferential specimens (by 8 ksi). The YS and UTS of the circumferential base metal specimens meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.

The results of tensile testing of duplicate circumferential base metal specimens removed from PS C (Joint U/S of failed GW) are shown in Table 4. The average YS and UTS of the circumferential specimens were 91.0 ksi and 104.8 ksi, respectively, which is slightly less than the values for PS A. The results of tensile testing of axial base metal specimens also

are shown in the table and the YS values for the axial specimens also are higher than those of the circumferential specimens (by 6.7 ksi). The YS and UTS of the circumferential base metal specimens meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.

The average UTS of duplicate axial specimens removed across the intact girth weld was 103.3 ksi. Both cross-girth weld specimens failed in the girth weld, similar to the actual failure. YS values across the girth weld are not reliable and not specified in API 1104. The average UTS value across the weld meets the tensile requirements API 5L X80M PSL 2 line pipe at the time of construction. Note that the value of 103.3 ksi is less than the axial tensile strength of 109.7 ksi and 106 ksi for the joints D/S and U/S, respectively, of the failed girth weld.

3.6.2 CVN Testing of Base Metal Specimens

The results of CVN testing of triplicate transverse base metal specimens removed from PSs A (Joint D/S of failed GW) and C (Joint U/S of failed GW) are shown in Table 5. The specimens were tested at 32°F. The impact values are relatively high, i.e. full-size values all above 93 ft·lbs for PS A and above 148 ft·lbs for PS C. The shear % values are all 100% (indicating fully ductile behavior). The impact values all exceed the specified minimum value of 30 ft·lbs (at 32°F) for API 5L X80 PSL 2 line pipe, and the average of shear % values are greater than 85 %.

3.6.3 CVN Testing of Girth Weld Specimens

Table 6 shows the results of CVN testing for axial specimens removed from the intact girth weld (notch in the HAZ from PS C), while Figure 79 and Figure 80 show the Charpy percent shear and impact energy curves. An analysis of the data for the girth weld specimens indicates that the 85% FATT is 59.9°F and upper shelf Charpy energy is 114 ft lbs, as shown in Table 7. Both values are good for line pipe steel.

3.7 Chemical Analysis

The results of the chemical analyses conducted on steel samples removed from PSs A (Joint D/S of failed GW) and C (Joint U/S of failed GW) are summarized in Table 8. The results of the chemical analyses indicate that the steels meet the chemical composition requirements for API 5L Grade X80M PSL 2 line pipe steel at the time of construction. Carbon equivalent (CE) values were calculated for the base metal samples. The calculated CE_{Pcm} values for the PSs A and C are 0.17 and 0.16, respectively, compared to a maximum allowed CE_{Pcm} of 0.25 per the API 5L spec at the time of construction. These values for the joints are relatively low and indicate a very good resistance to HACC in the HAZ.

4.0 CONCLUSIONS

The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, completely separating the girth weld. The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified. Microscopically, the fracture surface contained regions with dimples (ductile fracture) and cleavage facets (brittle fracture). The dimples were located where the fracture surface was at a shear angle and macroscopically smooth, and the cleavage facets were located where the fracture surface was perpendicular to the free surfaces and macroscopically rough. Both fractographic features are an indication of the overload nature on the fracture surface.

The failure occurred due to axial stresses sufficient to produce an overload failure. Supporting evidence for the presence of large axial stresses include 1) a relatively large opening between the failed ends and 2) cracked and missing epoxy coating U/S of the failed girth weld indicating a high strain prior/during fracture. A possible contributing factor to relatively large axial stresses include stresses associated with movement.

No excessively high hardness areas were identified in the girth weld cross-sections. The weld metal of the intact girth weld had a lower hardness than the surrounding pipe material, indicating that the weld metal is weaker than the surrounding pipe material. This trend was somewhat followed for the failed girth weld, although cold work from the failure likely skewed some of the data. The softest regions in all the mounts was the weld metal root pass. The lower overall hardness values of the weld metal compared to the surrounding pipe material is consistent with the axial tensile results. The ultimate tensile strength for the girth weld of 103.3 ksi is less than the axial tensile strength of 109.7 ksi and 106 ksi for the joints D/S and U/S, respectively, of the failed girth weld. The axial tensile tests across the intact GW failed in the GW, similar to the actual failure. Therefore, a contributing factor to the failure was that the pipe steel was stronger than the girth weld.

Below is a summary of additional conclusions:

- There was no evidence of notable internal or external corrosion.
- The tensile and toughness properties of the joints U/S and D/S of the failed girth weld meet requirements for API 5L X80M PSL 2 line pipe at the time of construction.
- The chemical compositions of the joints U/S and D/S of the failed girth weld meet the requirements for API 5L X80M PSL 2 line pipe at the time of construction.
- The microstructures of the joints U/S and D/S of the failed girth are consistent with modern API 5L X80 line pipe steel.

- An analysis of the Charpy V-notch impact testing data for the intact girth weld indicates that the 85% FATT is 59.9°F and upper shelf Charpy energy is 114 ft lbs.

Table 1. Results of circumference and diameter measurements performed at the field cut ends of Pipe Sections (PS) A, B, and C.

Pipe Section	Pipe Section End	Circumference (feet)	Diameter (inches)		
			From Circumference Measurement	3 to 9 o'clock	6 to 12 o'clock
A	D/S	6.31	24.1	24.1	24.1
B	U/S	6.31	24.1	24.0	24.0
C	D/S	6.32	24.2	24.0	24.0
C	U/S	6.31	24.1	24.0	24.0

Table 2. Results of wall thickness measurements performed at the field cut ends of PS A, B, and C.

O'clock Orientation	Wall Thickness (inches)			
	PS A, D/S End	PS B, U/S End	PS C, D/S End	PS C, U/S End
12	0.539	0.536	0.537	0.531
3	0.533	0.538	0.536	0.530
6	0.536	0.535	0.534	0.530
9	0.533	0.540	0.537	0.530
Average	0.535	0.537	0.536	0.530

Table 3. Results of tensile tests performed on circumferential specimens from PS A (Joint D/S of failed GW) compared with requirements for API 5L X80M PSL 2 line pipe steel, and axial base metal specimens from Pipe Section A.

	Circumferential	API 5L X80M Line Pipe Steel [2]	Axial
Yield Strength, ksi [1]	93.5	80.5 – 102.3	101.5
Tensile Strength, ksi [1]	112.4	90.6 – 119.7	109.7
Elongation in 2 inches, % [1]	29.5	20.7 (min)	31.1
Reduction of Area, % [1]	61.6	–	67.1

1 – Average of duplicate tests.
2 – API 5L 44th Edition, October 1, 2007.

Table 4. Results of tensile tests performed on circumferential specimens from PS C (Joint U/S of failed GW) compared with requirements for API 5L X80M PSL 2 line pipe steel and axial base metal specimens and axial/cross-girth weld specimens from Pipe Section C.

	Circumferential	API 5L X80M Line Pipe Steel [2]	Axial	Cross Girth Weld
Yield Strength, ksi [1]	91.0	80.5 – 102.3	97.7	–
Tensile Strength, ksi [1]	104.8	90.6 – 119.7	106.0	103.3
Elongation in 2 inches, % [1]	29.0	20.7 (min)	31.8	–
Reduction of Area, % [1]	62.1	–	70.9	–

1 – Average of duplicate tests.
2 – API 5L 44th Edition, October 1, 2007.

Table 5. Results of Charpy V-notch impact tests for circumferential base metal specimens removed from the PS A (Joint D/S of failed GW) and PS C (Joint U/S of failed GW). Specimens were tested at 32F.

Sample ID	Sub Size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, mils
Pipe Section A				
PSA1	93	93	100	56
PSA2	109	109	100	71
PSA3	105	105	100	68
Avg.	102	102	100	65
Pipe Section C				
PSC1	164	164	100	71
PSC2	148	148	100	81
PSC3	155	155	100	73
Avg.	156	156	100	75
API 5L [1]	-	30	$\geq$ 85	-

1 – API 5L 44th Edition, October 1, 2007.

Table 6. Results of Charpy V-notch impact tests performed on axial/cross-girth weld (heat affected zone [HAZ] notch) specimens removed from PS C.

Sample ID	Temperature, °F	Sub Size Impact Energy, ft-lbs	Full Size Impact Energy, ft-lbs	Shear, %	Lateral Expansion, mils
1	-184	4	4	5	0
2	-112	7	7	16	6
3	-76	32	32	44	22
4	-40	59	59	51	41
5	32	69	69	69	48
6	73	116	116	97	81
7	104	117	117	87	65
8	140	122	122	100	86
9	176	95	95	92	64
10	194	118	118	100	87

Table 7. Results of analyses of Charpy V-notch impact energy and percent shear plots for axial/cross-girth weld (HAZ notch) specimens removed from PS C (Joint U/S of failed GW).

	Girth Weld
Upper Shelf Impact Energy (Full Size), Ft-lbs	114
85% FATT, °F	59.9

Table 8. Results of chemical analyses of base metal samples removed from PS A (Joint D/S of failed GW) and PS C (Joint U/S of failed GW), compared with composition requirements for API 5L X80M PSL 2 line pipe steel. The highlighted CE values are the ones that are applicable based on carbon wt%.

Element	Composition (Wt. %)		
	PS A (Joint D/S of failed GW)	PS C (Joint U/S of failed GW)	API 5L X80M [1] Req.
C (Carbon)	0.059	0.053	0.12 (max)
Mn (Manganese)	1.62	1.65	1.85 (max)
P (Phosphorus)	0.012	0.009	0.025 (max)
S (Sulfur)	0.003	0.005	0.015 (max)
Si (Silicon)	0.202	0.219	0.45 (max)
Cu (Copper)	0.016	0.023	≤ 0.50
Sn (Tin)	0.006	0.002	–
Ni (Nickel)	0.006	0.009	≤ 1.00
Cr (Chromium)	0.047	0.038	≤ 0.50
Mo (Molybdenum)	0.260	0.249	≤ 0.50
Al (Aluminum)	0.042	0.039	–
V (Vanadium)	0.006	0.007	–
Nb (Niobium)	0.082	0.081	–
Zr (Zirconium)	0.002	0.002	–
Ti (Titanium)	0.020	0.019	–
B (Boron)	0.0003	0.0003	–
Ca (Calcium)	0.0034	0.0025	–
Co (Cobalt)	0.002	0.004	–
Fe (Iron)	Balance	Balance	Balance
Nb + V + Ti	0.108	0.107	≤ 0.15
CE_{IIW} [2]	0.39	0.39	0.43 (max)
CE_{Pcm} [3]	0.17	0.16	0.25 (max)

1 – API 5L 44th Edition, October 1, 2007.

2 – $CE_{IIW} = C + Mn/6 + (Cu + Ni)/15 + (Cr + Mo + V)/5$

3 – $CE_{Pcm} = C + Si/30 + Mn/20 + Cu/20 + Ni/60 + Cr/20 + Mo/15 + V/10 + 5B$.

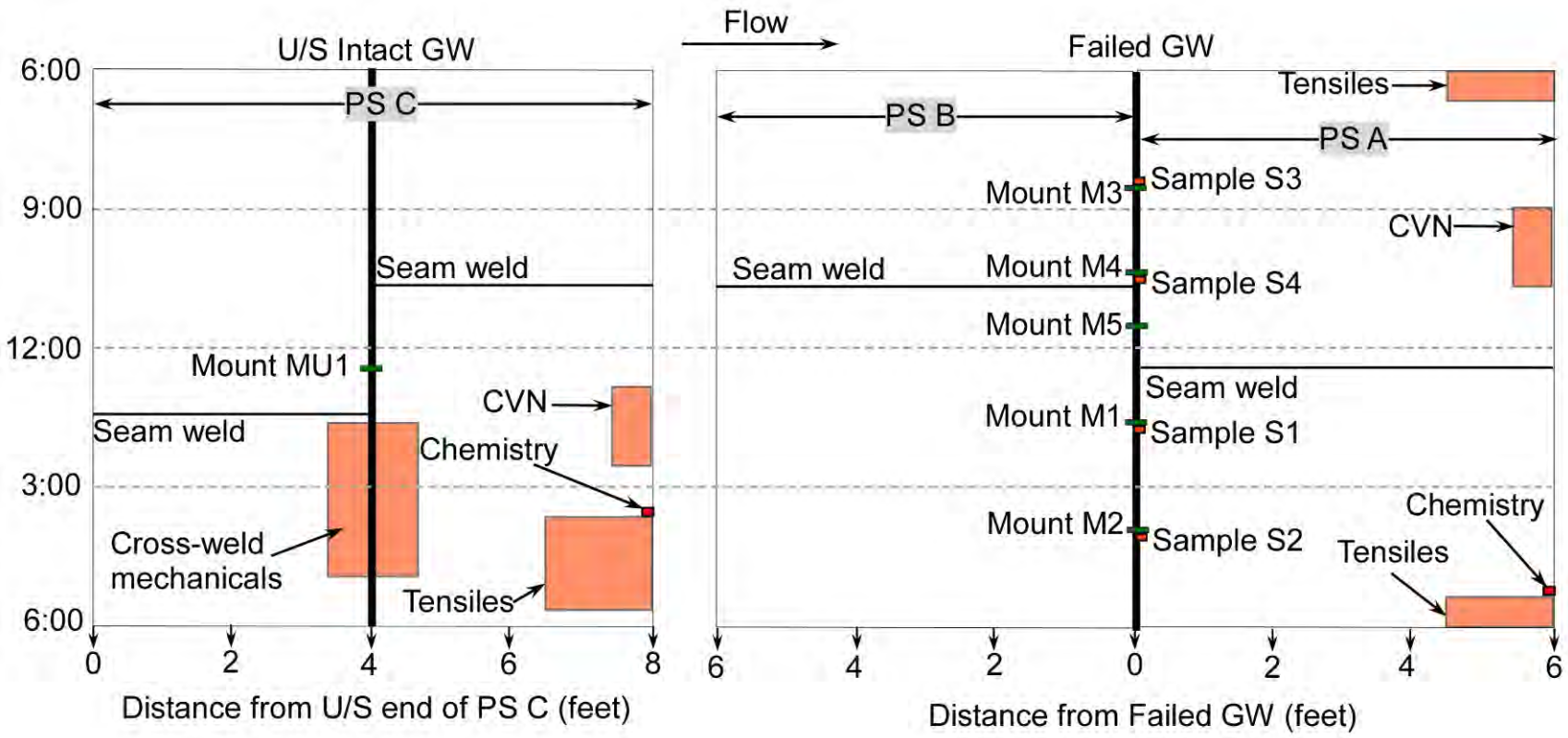


Figure 1. Schematic of Pipe Sections (PSs) A, B, and C showing the locations of the girth welds and seam welds, and where samples for metallography (Mounts M1, M2, M3, M4, M5, and MU1), fractography (Sample S1, S2, S3, and S4), mechanical testing (CVN, cross-weld mechanicals, and tensiles), and chemical analyses (chemistry) were removed.



Figure 2. Photograph of the wooden crate that contained PS A, as received at DNV GL.

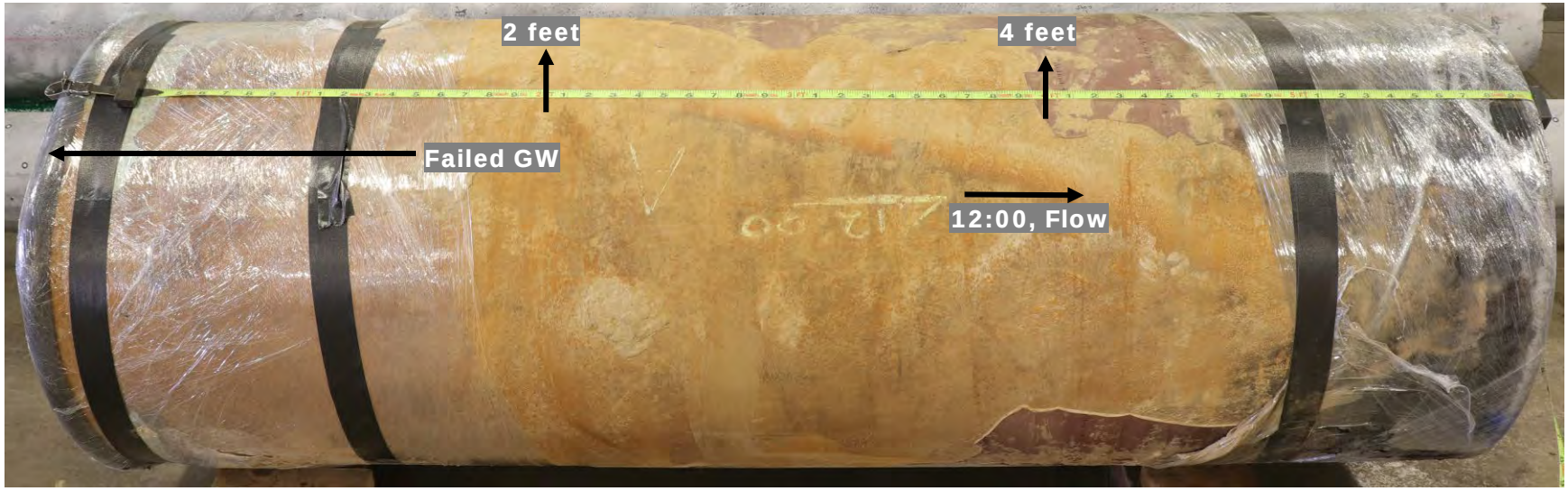


Figure 3. Photograph of PS A after removal from the wooden crate. The tape measure indicates the distance from the U/S end of PS A.

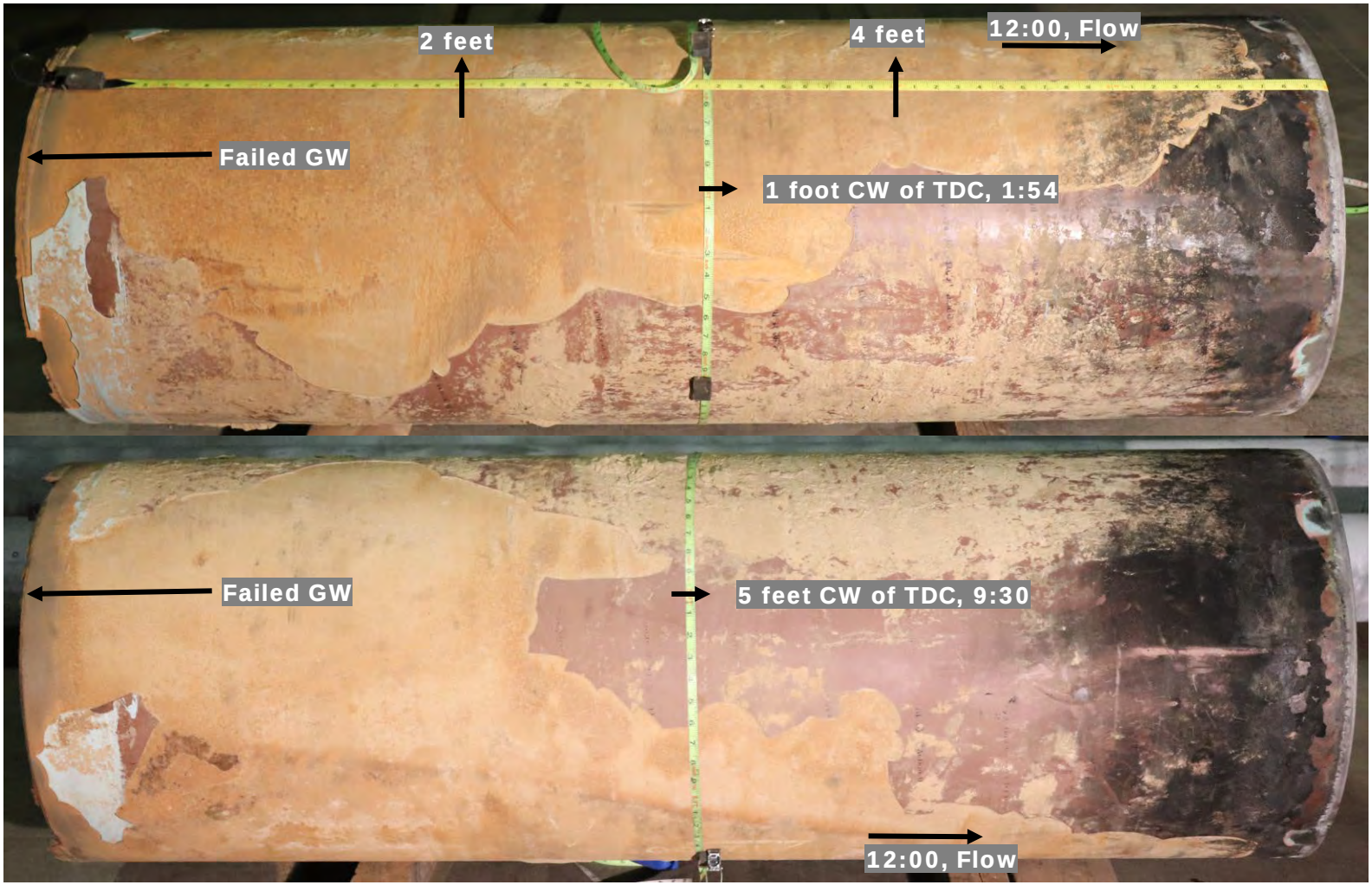


Figure 4. Photographs of PS A after removal of the protective wrappings. The horizontal tape measure indicates the distance from the U/S end of PS A, and circumferential tape measure indicates the distance clockwise (CW) of top-dead-center (TDC) looking downstream (D/S).



Figure 5. Photograph of the wooden crate that contained PS B, as received at DNV GL.

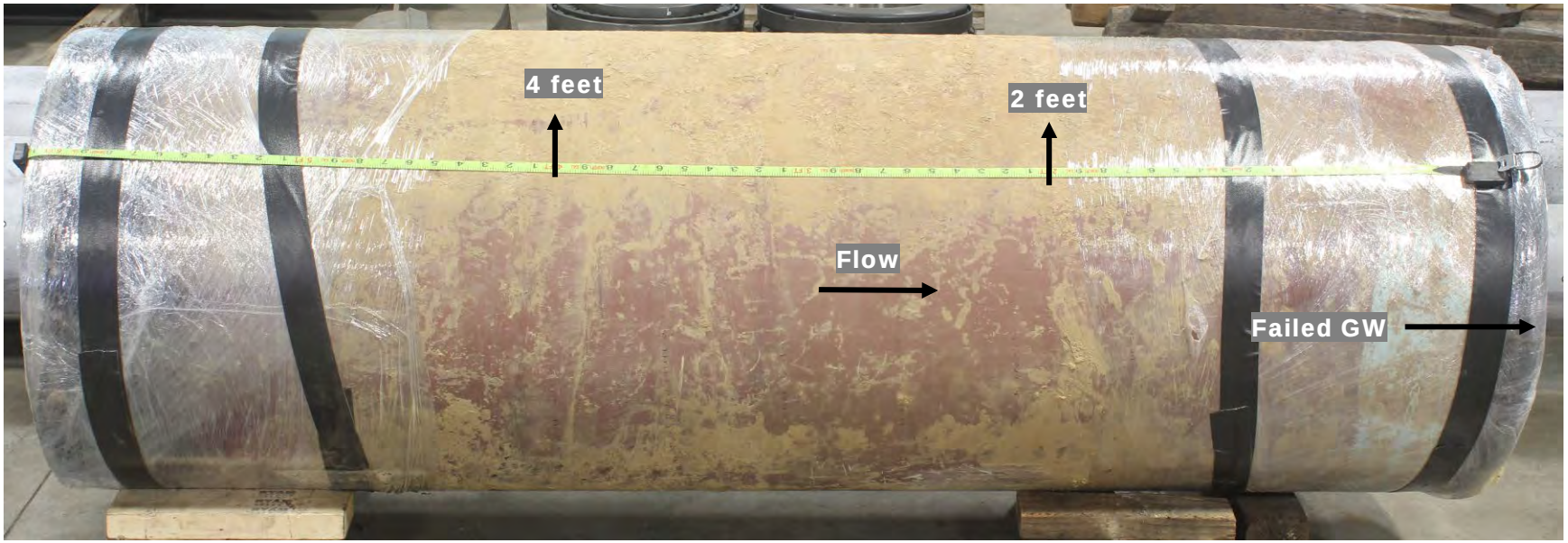


Figure 6. Photograph of PS B after removal from the wooden crate. The tape measure indicates the distance from the D/S end of PS B.



Figure 7. Photograph of PS B after removal of the protective wrappings. The tape measure indicates the distance from the D/S end of PS B.



Figure 8. Photograph of the wooden crate that contained PS C, as received at DNV GL.

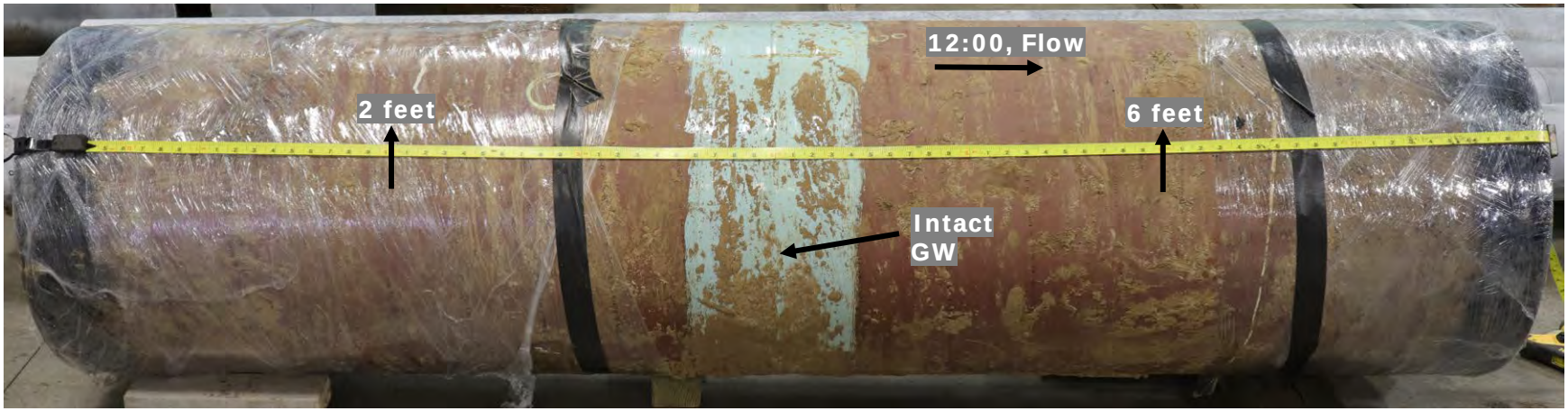


Figure 9. Photograph of PS C after removal from the wooden crate. The tape measure indicates the distance from the U/S end of PS C.

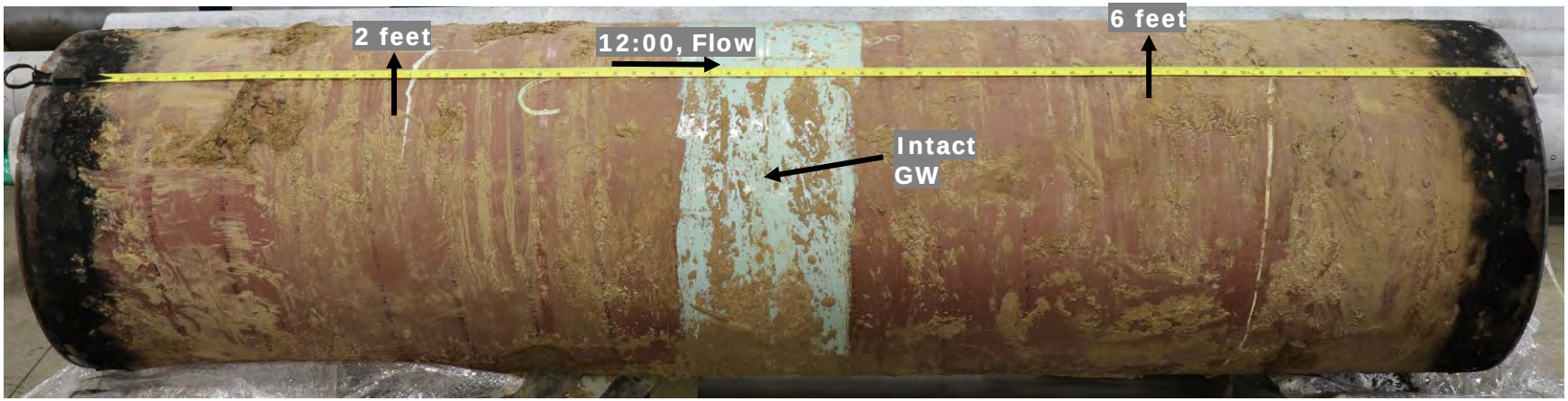


Figure 10. Photograph of PS C after removal of the protective wrappings. The tape measure indicates the distance from the U/S end of PS C.

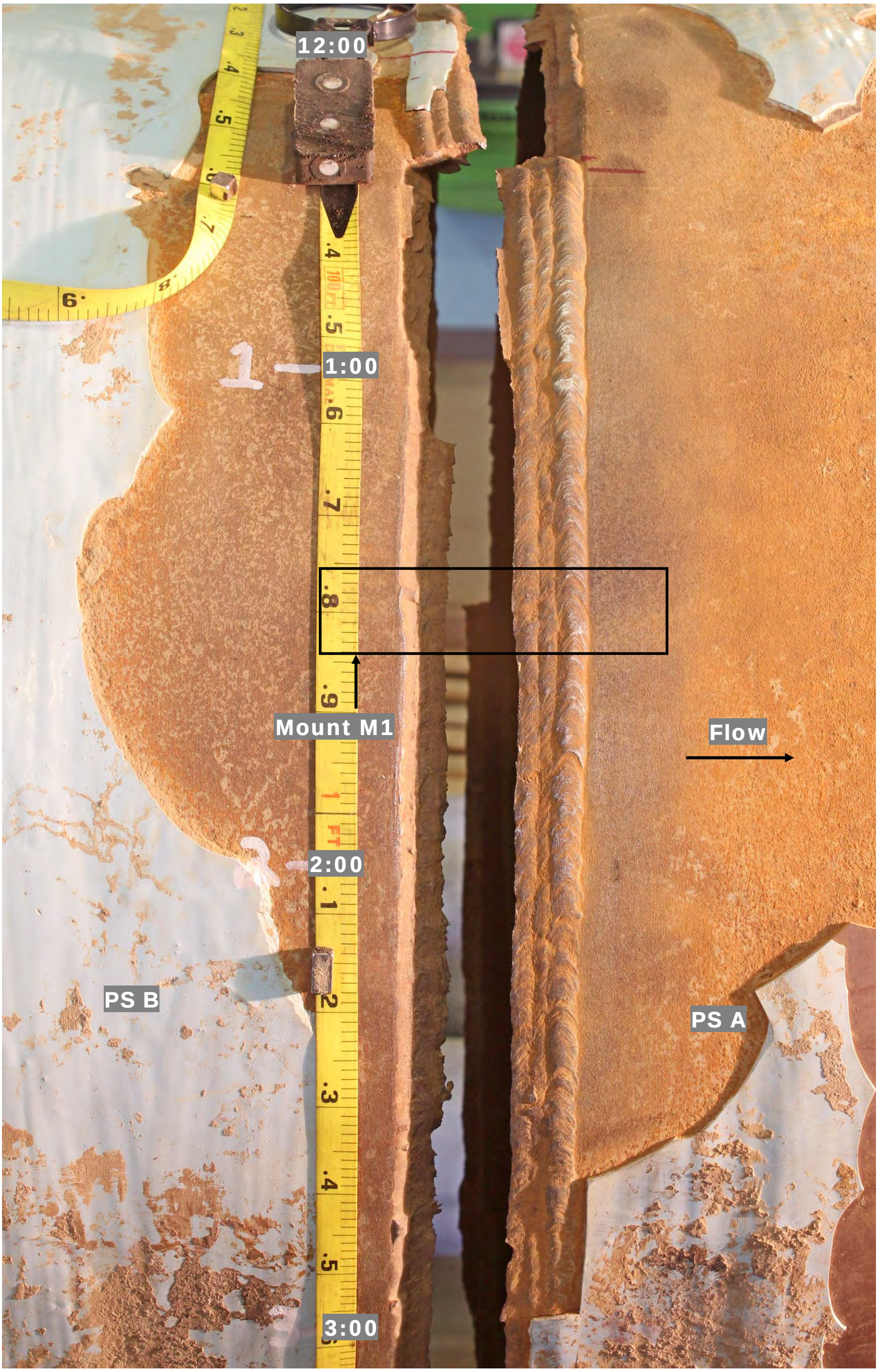


Figure 11. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 12 and 3 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

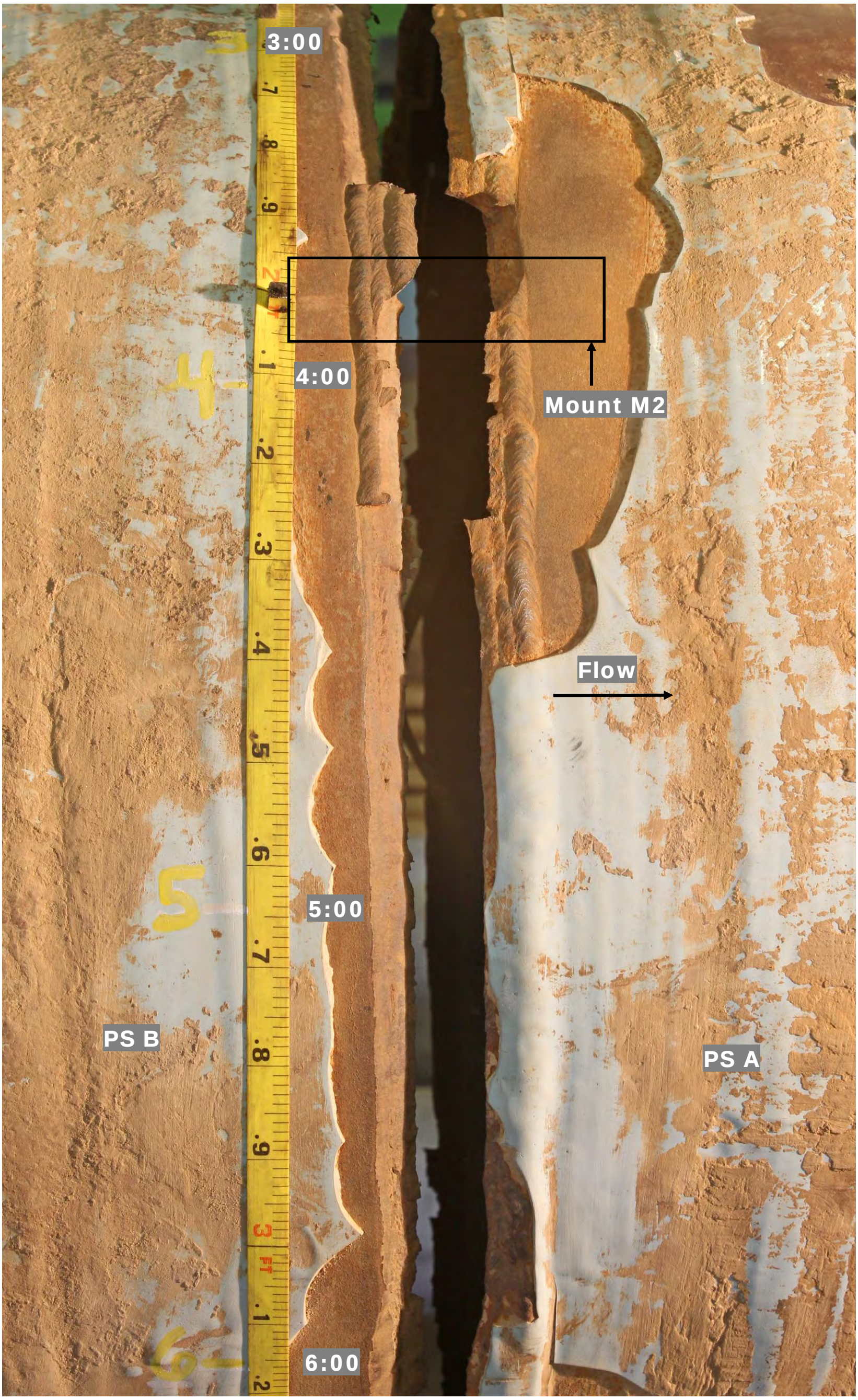


Figure 12. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 3 and 6 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

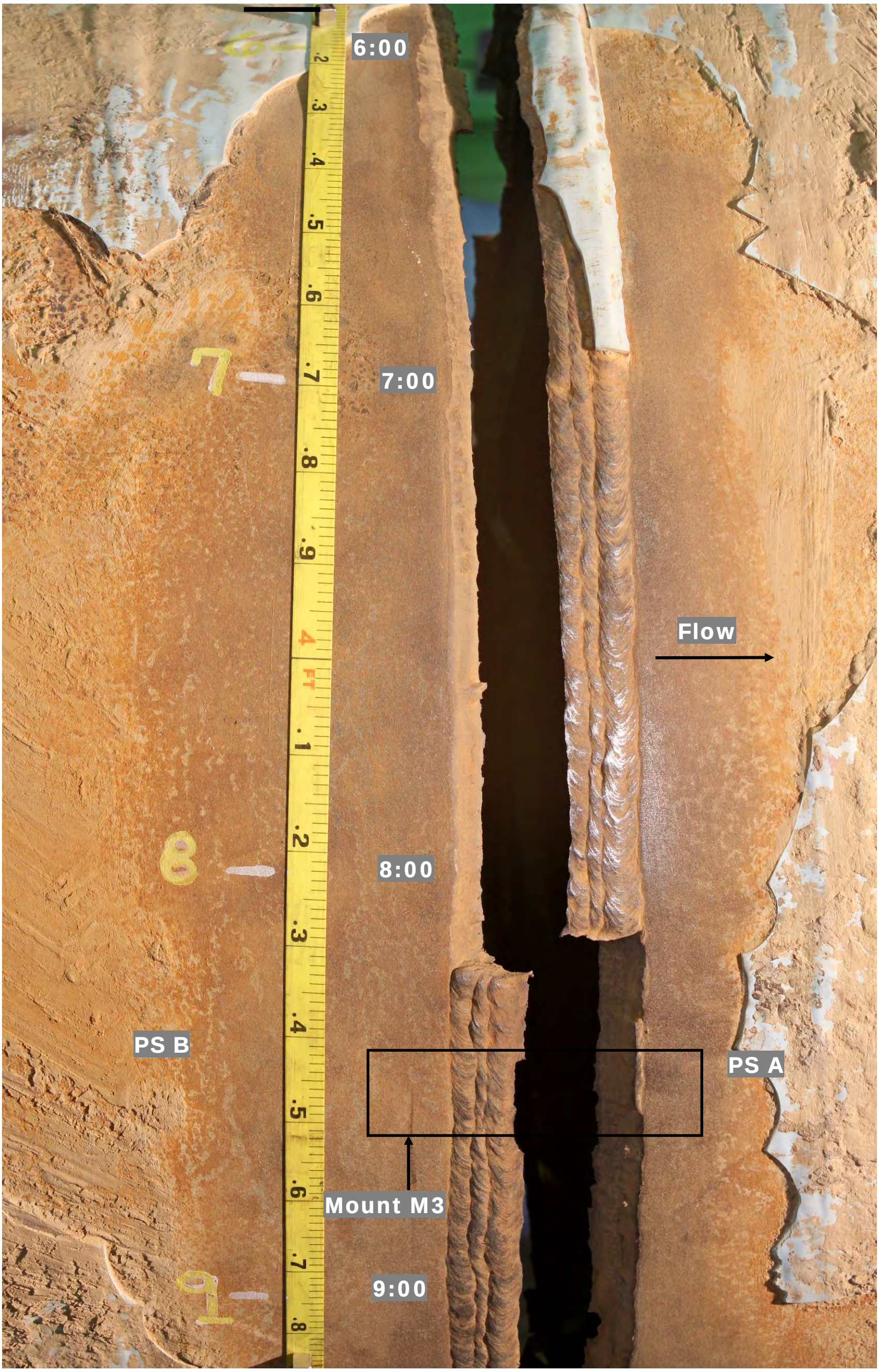


Figure 13. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 6 and 9 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

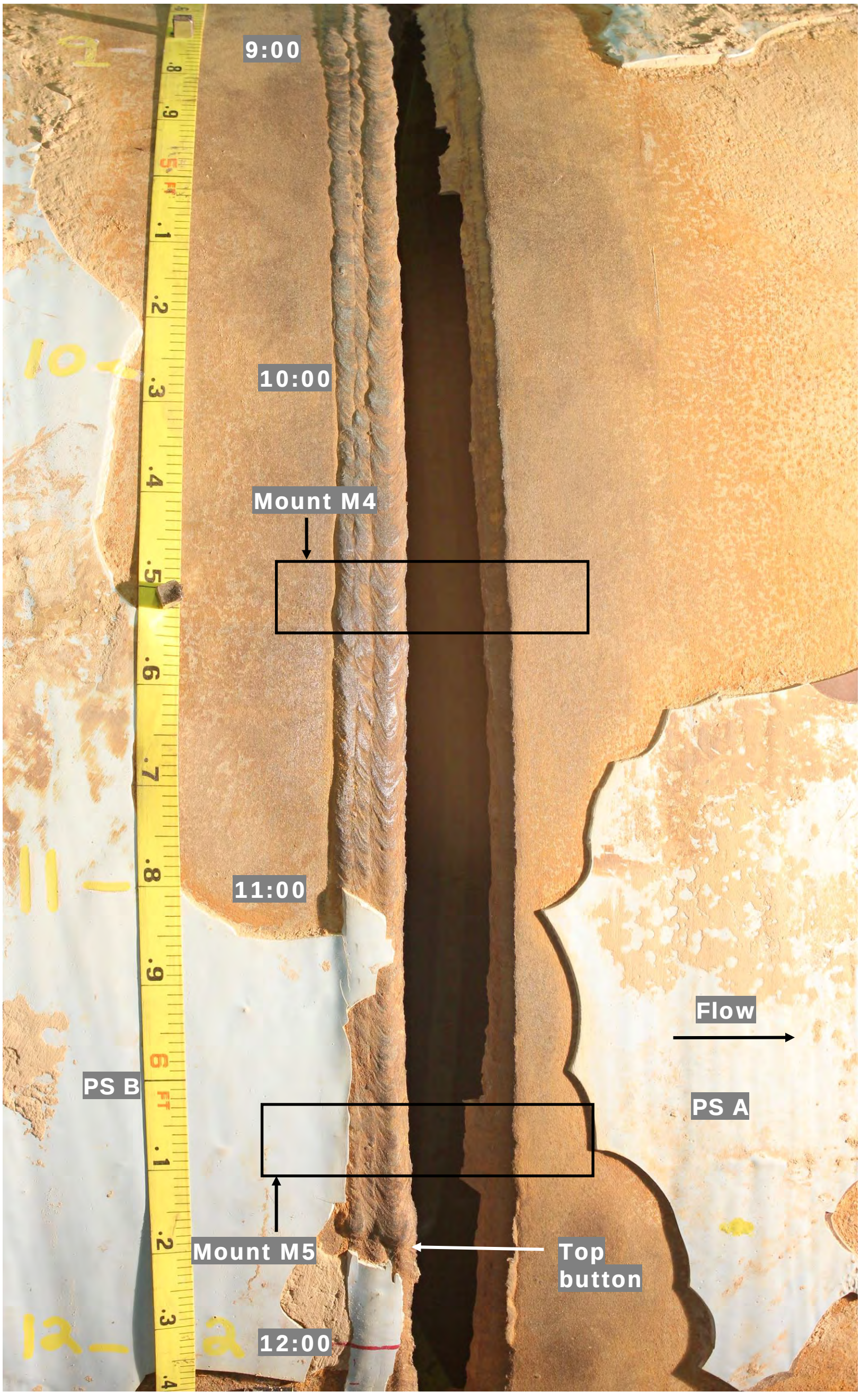


Figure 14. Photograph of the external of surfaces of PSs A and B adjacent to the fracture surfaces, between the 9 and 12 o'clock orientations, showing the failed girth weld and the morphology of the coating. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

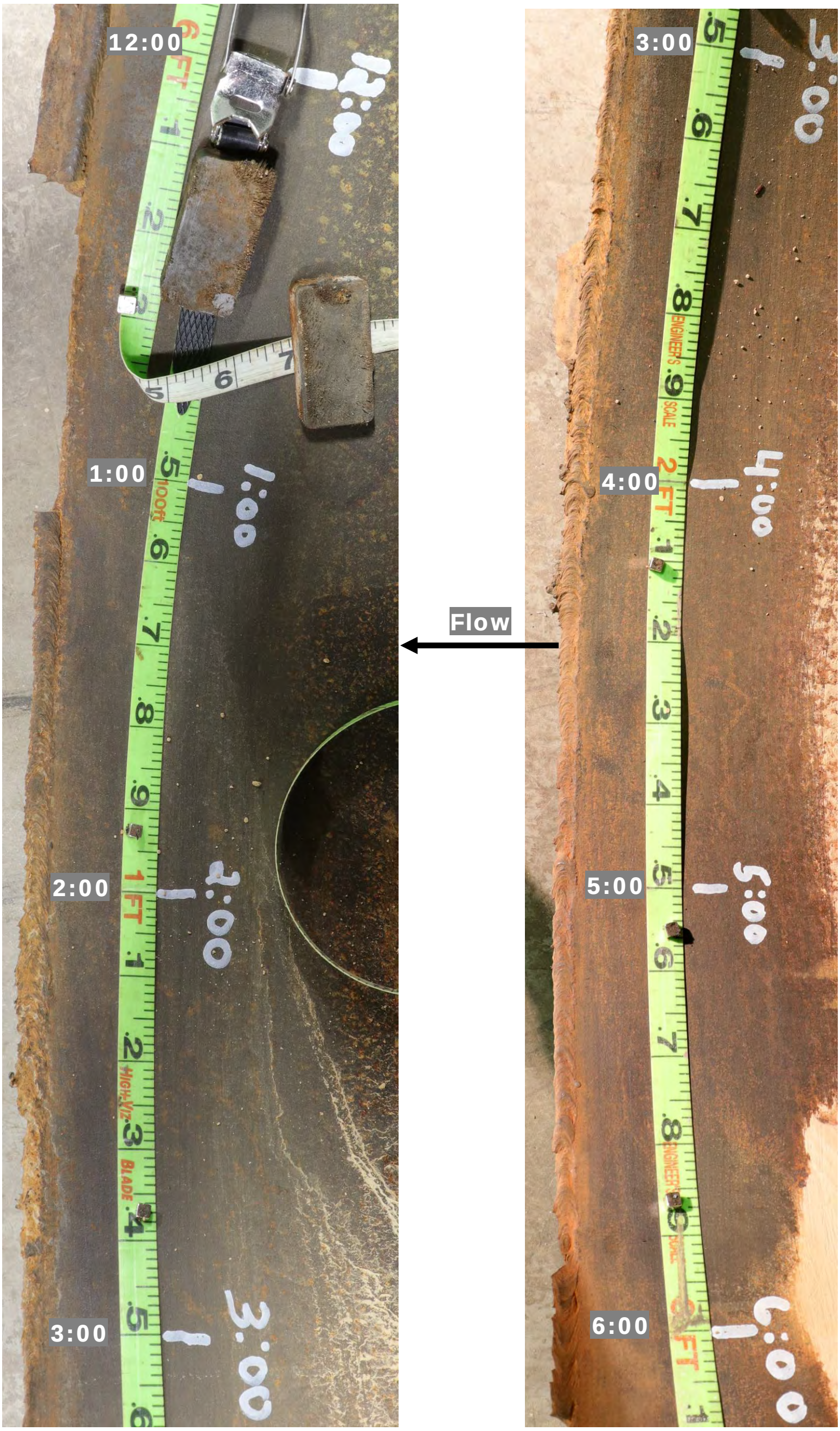


Figure 15. Photograph of the internal pipe surface adjacent to the fracture surface of PS B, between the 12 and 6 o'clock orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

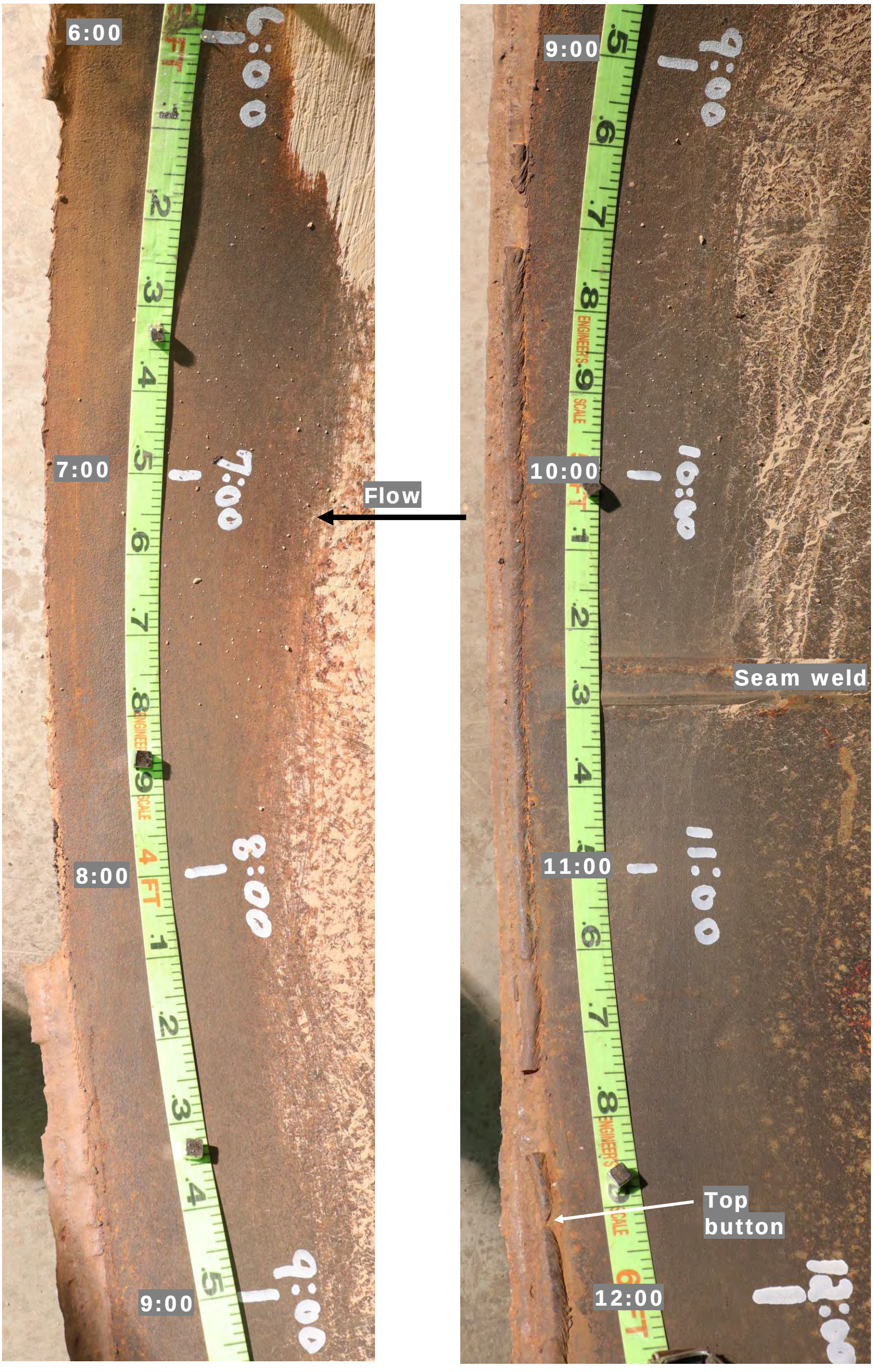


Figure 16. Photographs of the internal pipe surface adjacent to the fracture surface of PS B, between the 6 and 12 o'clock orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

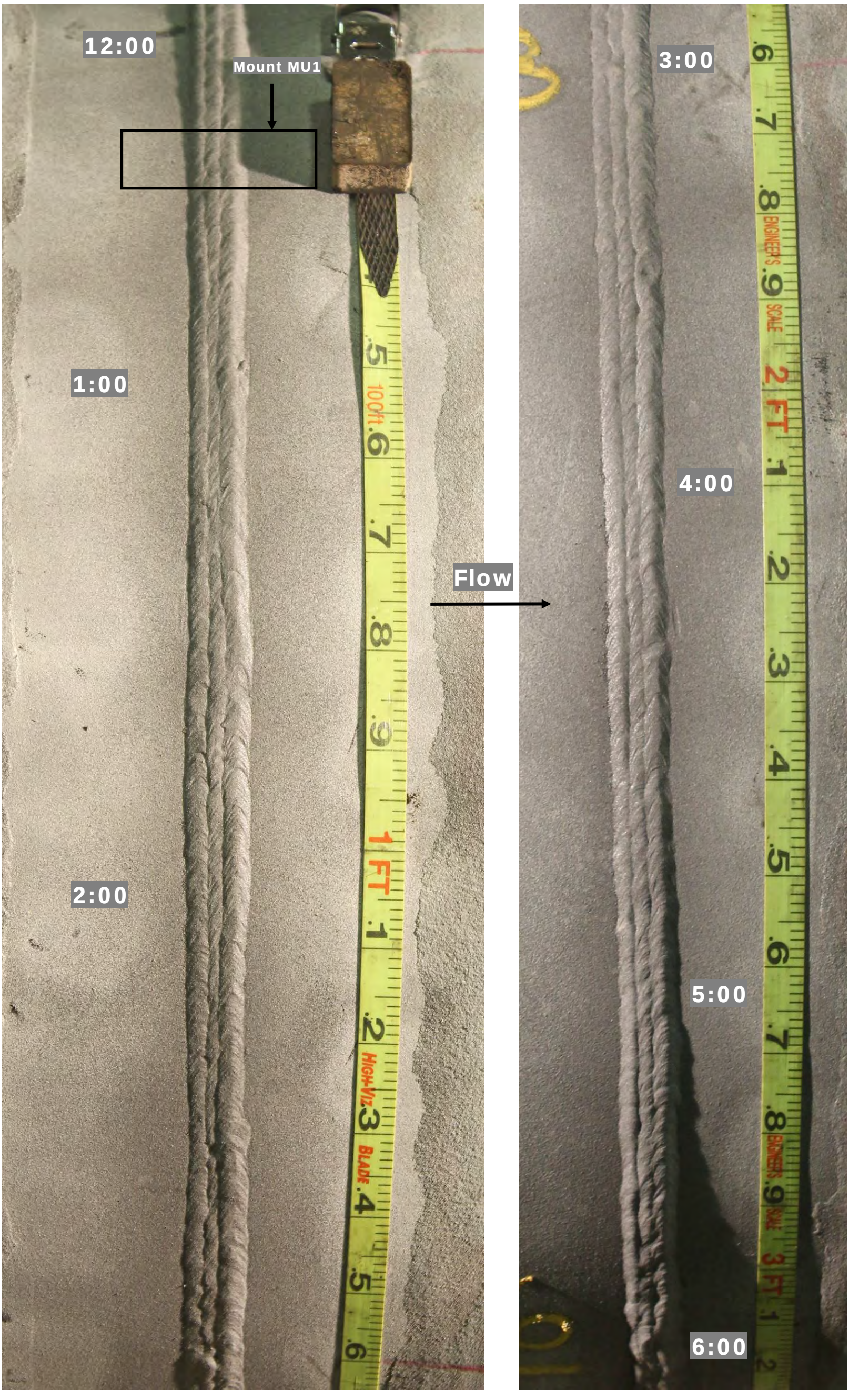


Figure 17. Photograph of the external pipe surface at the intact girth weld following grit blasting and MPI, between the 12:00 and 6:00 orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).

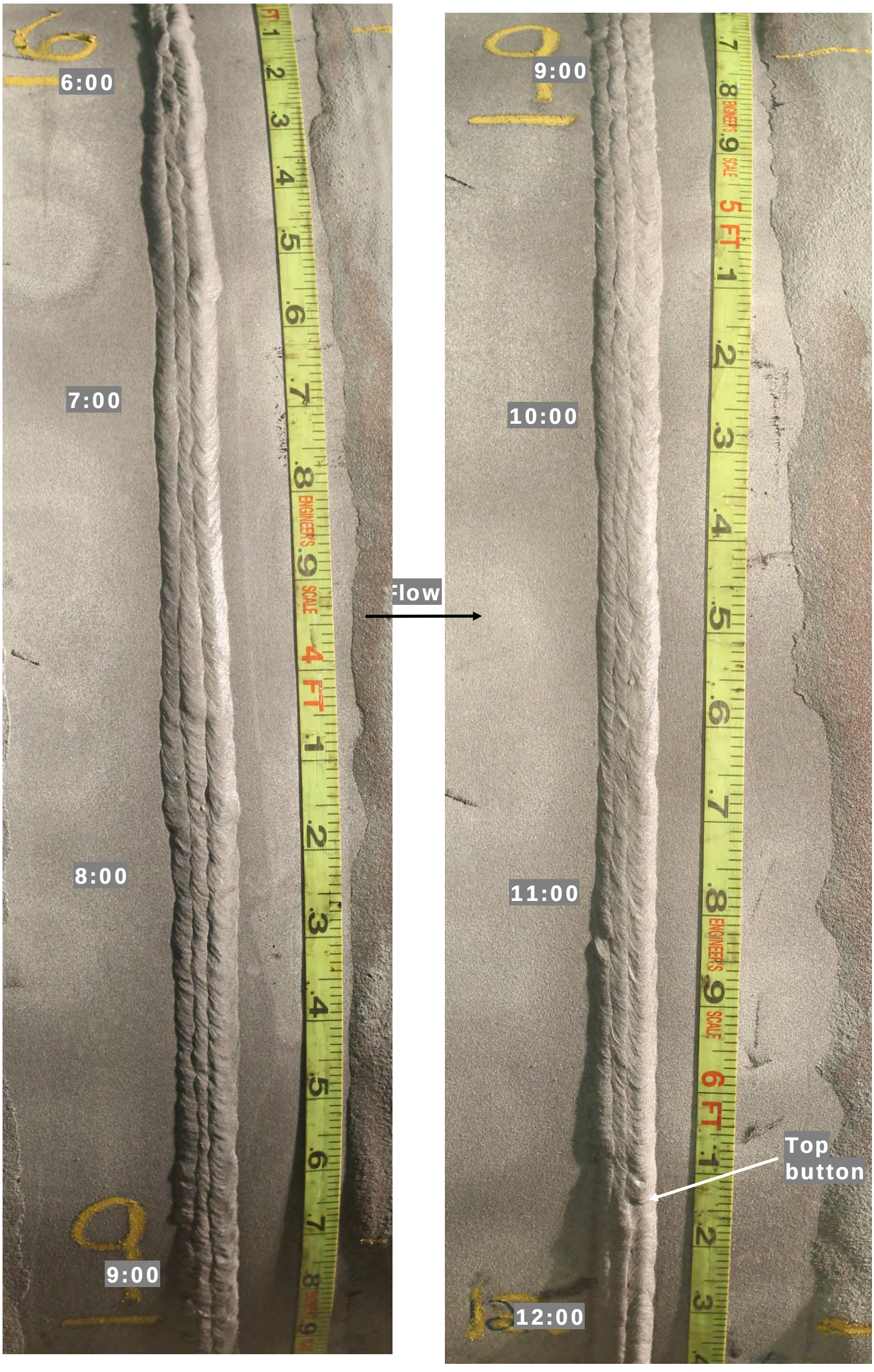


Figure 18. Photograph of the external pipe surface at the intact girth weld following grit blasting and MPI, between the 6:00 and 12:00 orientations. The tape measure indicates the approximate distance CW of TDC (looking D/S convention).



Figure 19. Photograph of the fracture surface and internal pipe surface of PS A. Flow direction is into the photograph. Labels on magnets indicate o'clock orientations.



Figure 20. Photograph of the fracture surface of PS A between the 12 and 1 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 21. Photograph of the fracture surface of PS A between the 1 and 2 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

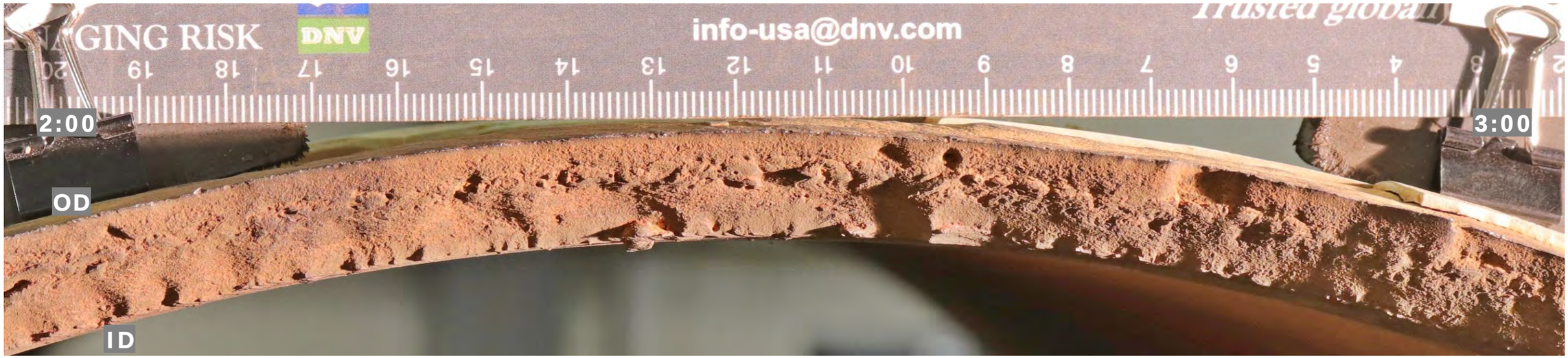


Figure 22. Photograph of the fracture surface of PS A between the 2 and 3 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 23. Photograph of the fracture surface of PS A between the 3 and 4 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

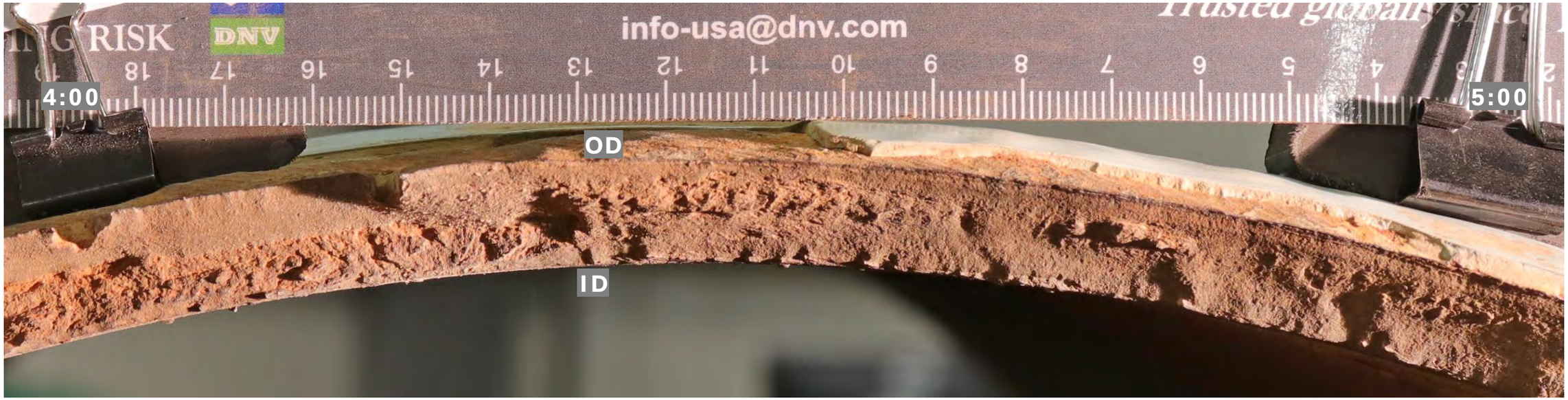


Figure 24. Photograph of the fracture surface of PS A between the 4 and 5 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 25. Photograph of the fracture surface of PS A between the 5 and 6 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 26. Photograph of the fracture surface of PS A between the 6 and 7 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 27. Photograph of the fracture surface of PS A between the 7 and 8 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 28. Photograph of the fracture surface of PS A between the 8 and 9 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 29. Photograph of the fracture surface of PS A between the 9 and 10 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.



Figure 30. Photograph of the fracture surface of PS A between the 10 and 11 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

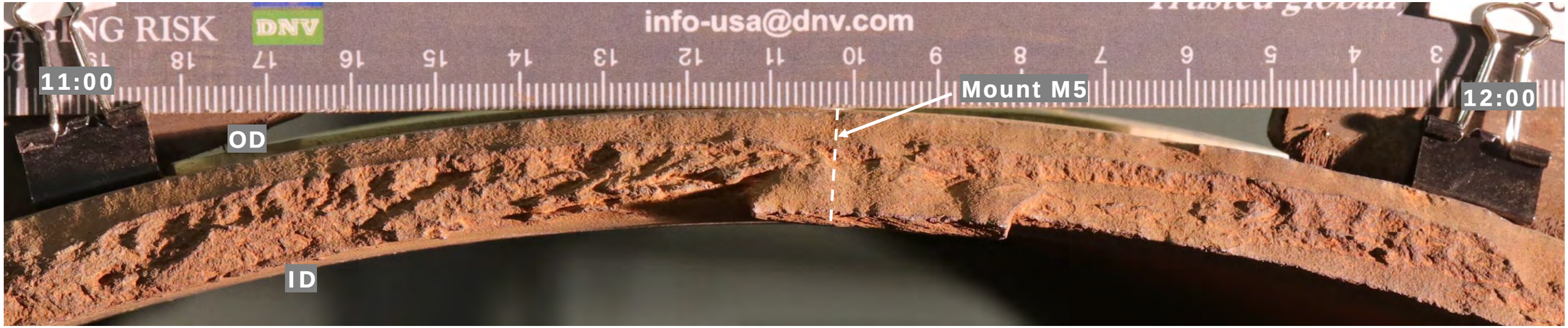


Figure 31. Photograph of the fracture surface of PS A between the 11 and 12 o'clock orientations. Units of ruler are in cm. Flow direction is into the photograph.

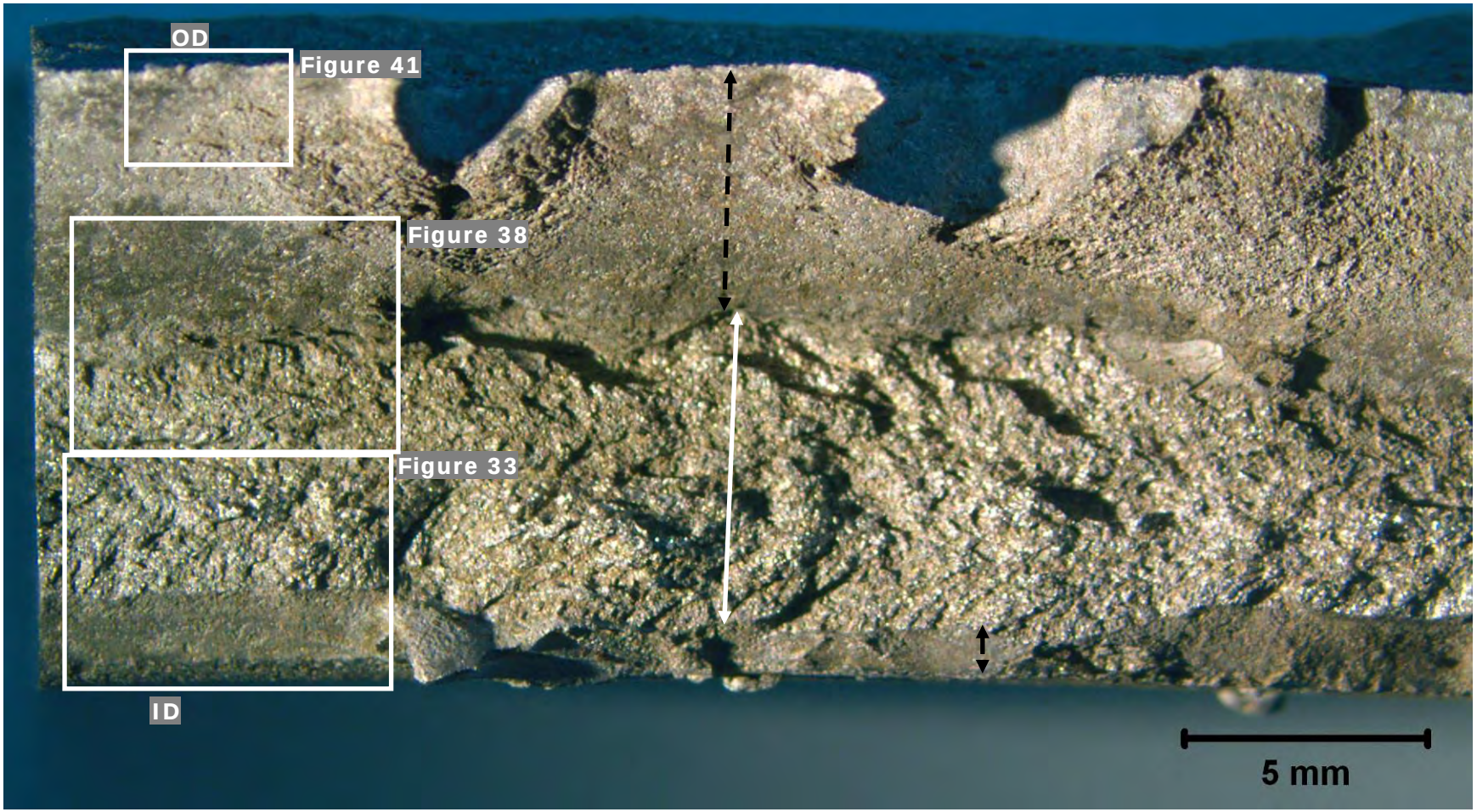


Figure 32. Light photomicrograph of the fracture surface of Sample S2, following cleaning in ENPREP® 214. The sample was removed near the 4:00 orientation from PSA; area indicated in Figure 23. The black, dashed double arrows indicate smooth regions and the white double arrow indicates a rough region.

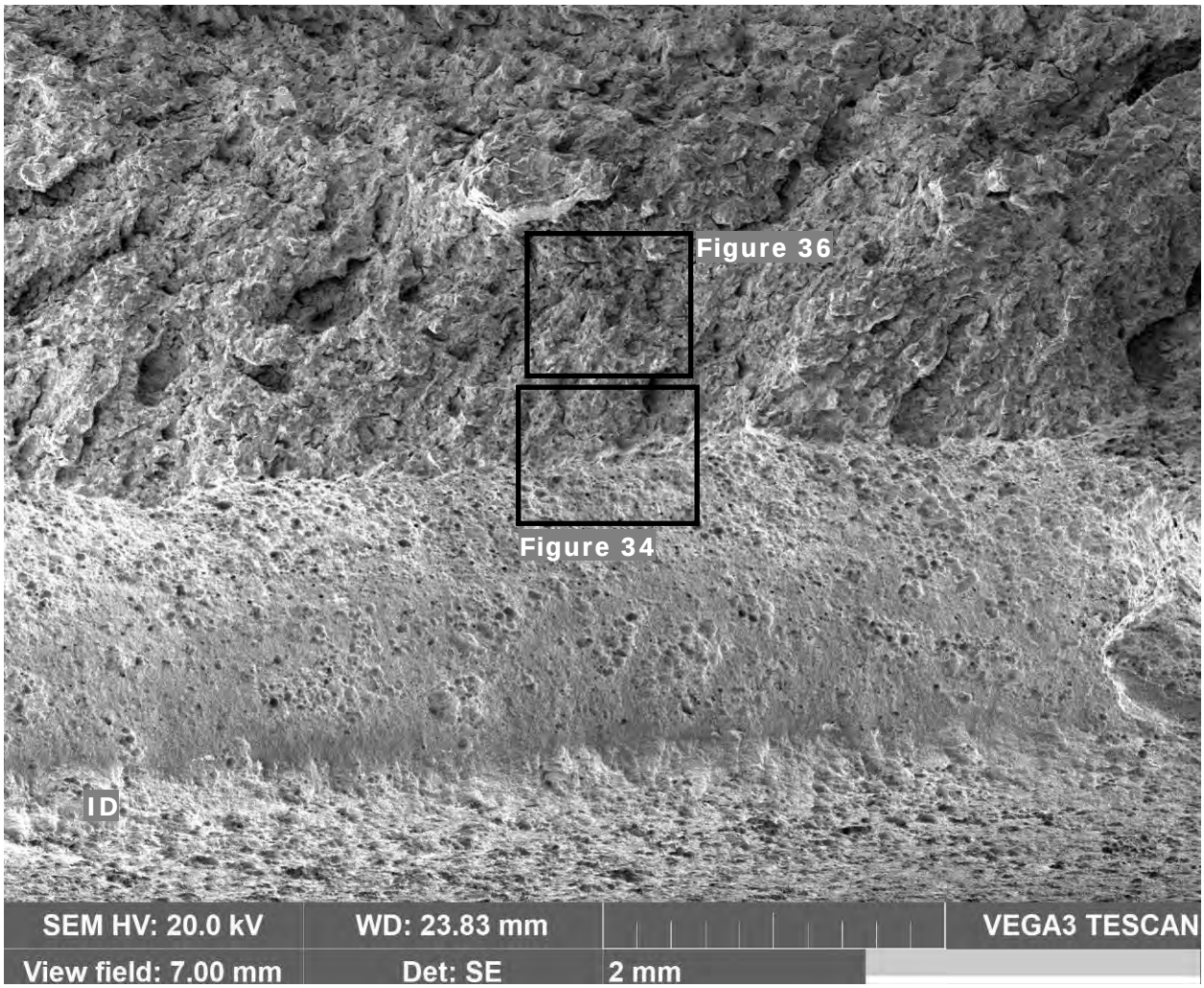


Figure 33. SEM image of Sample S2 adjacent to the ID surface; area indicated in Figure 32.

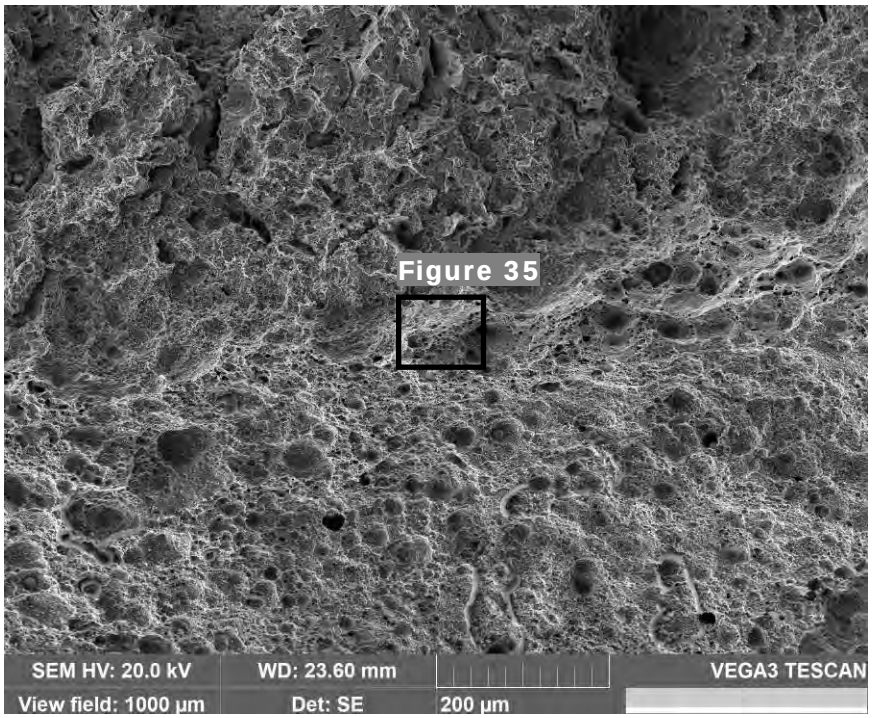


Figure 34. SEM image of Sample S2 at the interface of a macroscopically smooth and rough region; area indicated in Figure 33.

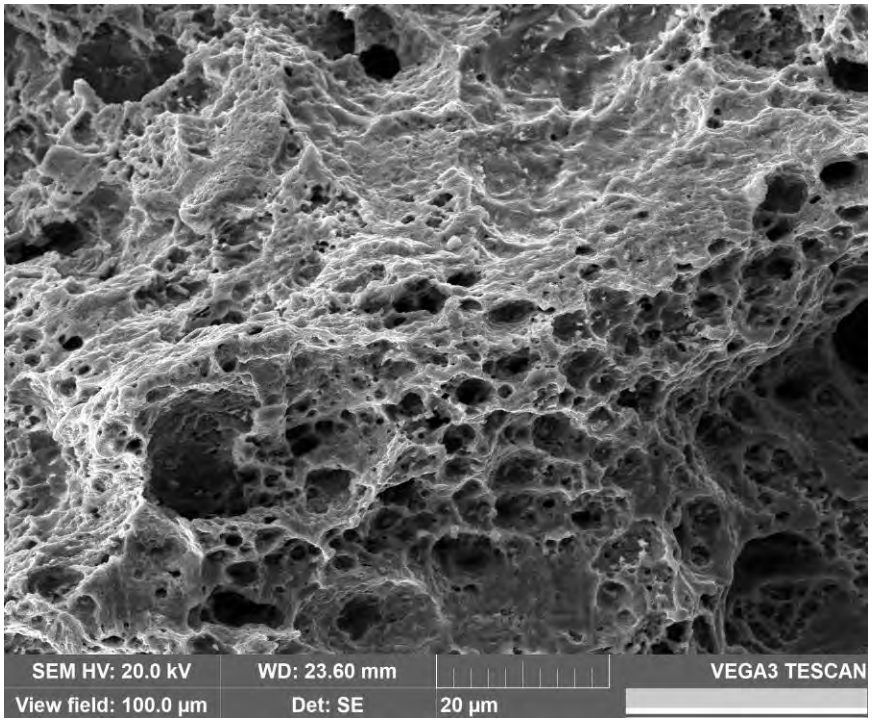


Figure 35. High magnification SEM image of Sample S2 in the macroscopically smooth region; area indicated in Figure 34.

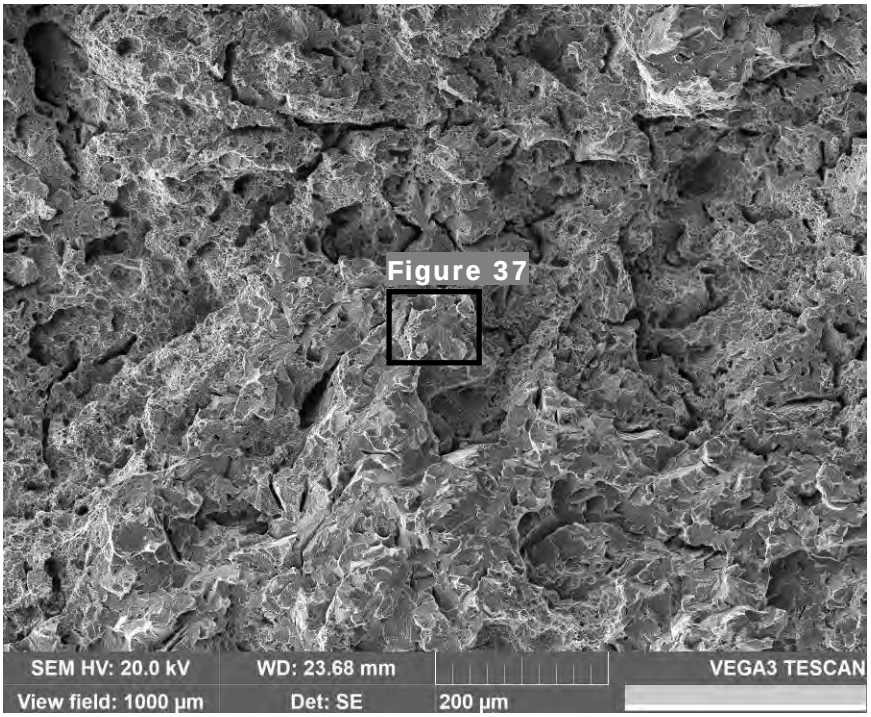


Figure 36. SEM image of Sample S2 in a macroscopically rough region; area indicated in Figure 33.

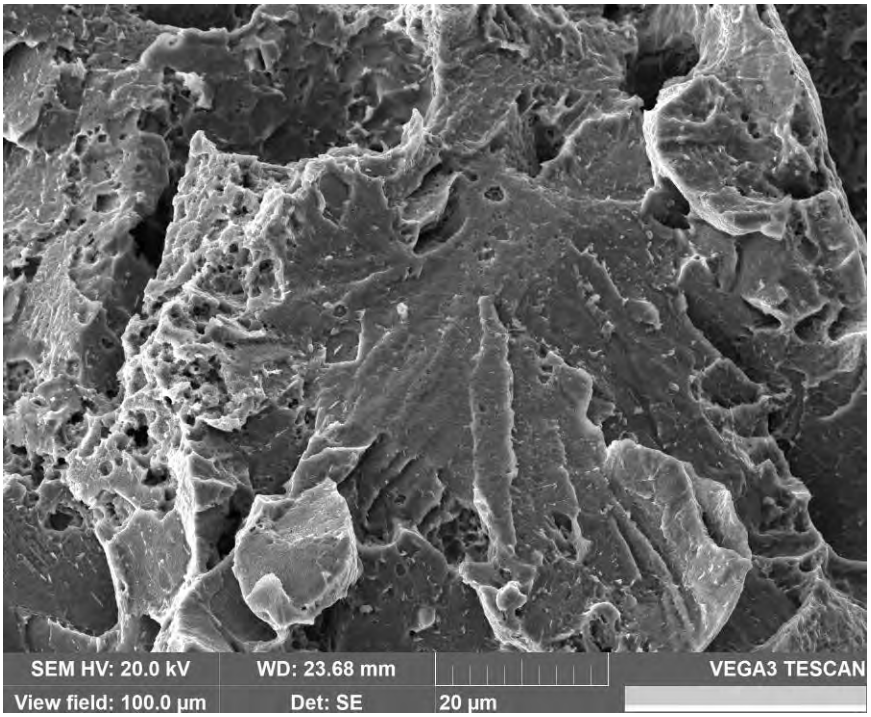


Figure 37. High magnification SEM image of Sample S2 in a macroscopically rough region; area indicated in Figure 36.

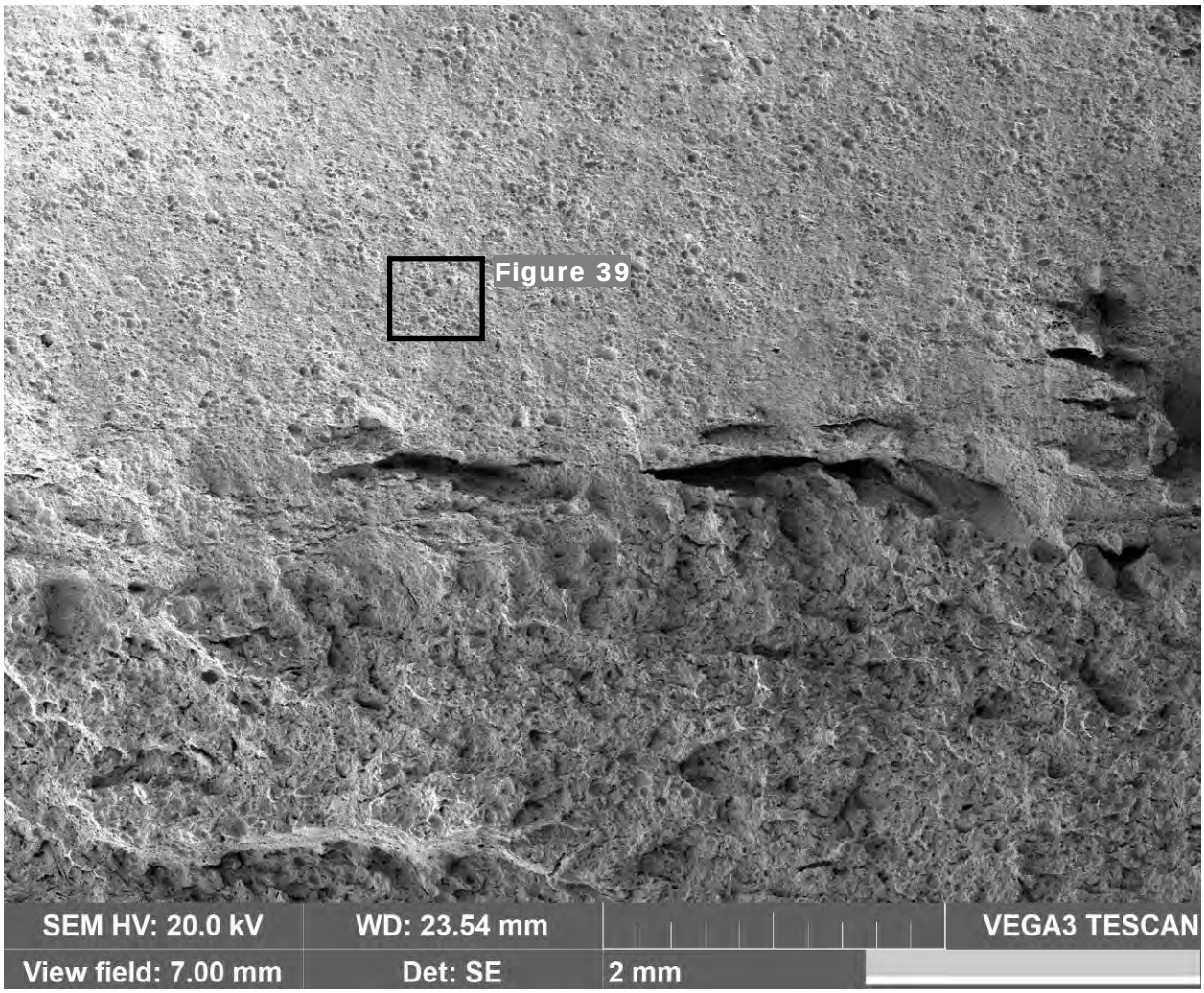


Figure 38. SEM image of Sample S2 midwall, showing macroscopically rough and smooth regions; area indicated in Figure 32.

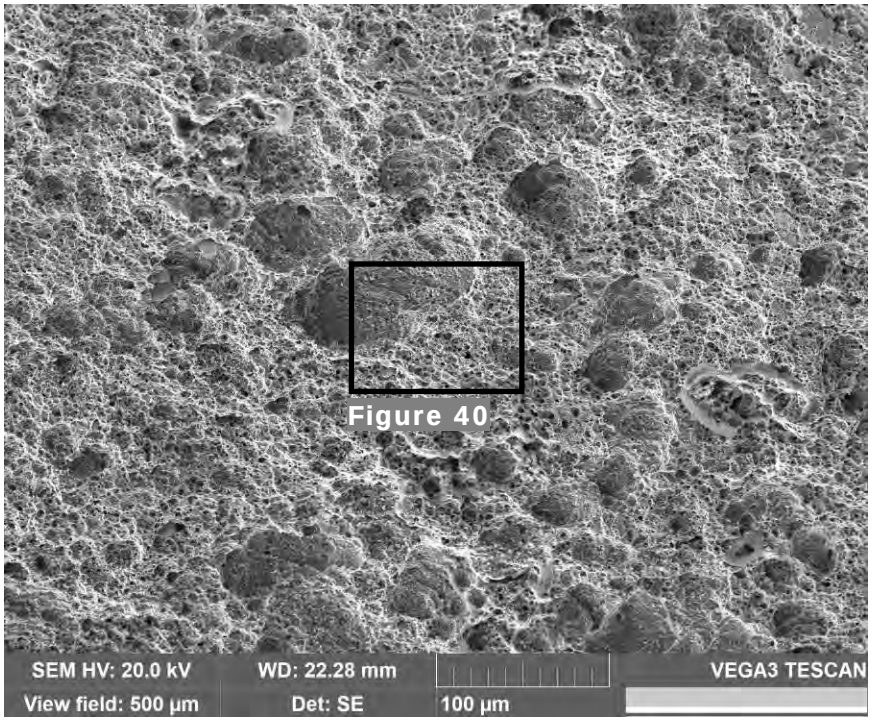


Figure 39. SEM image of Sample S2 in a macroscopically smooth region, near the OD surface; area indicated in Figure 38.

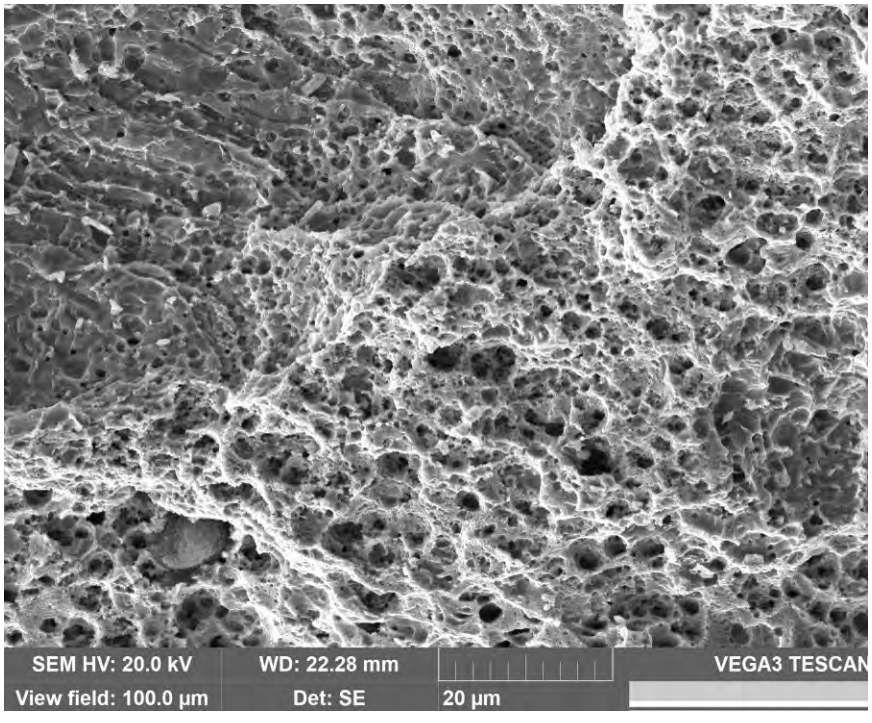


Figure 40. High magnification SEM image of Sample S2 in a macroscopically smooth region, near the OD surface; area indicated in Figure 39.

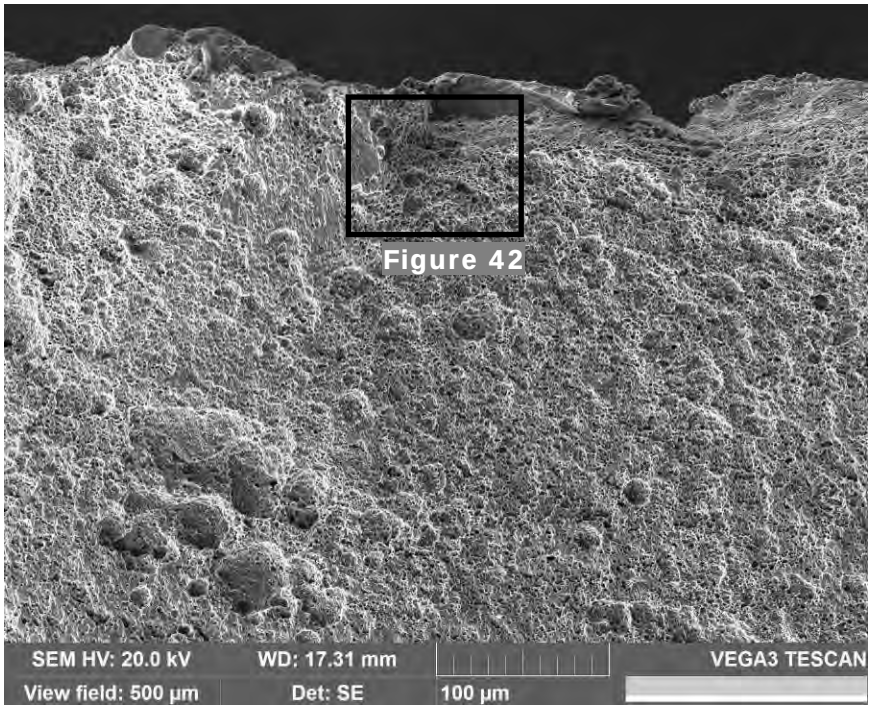


Figure 41. SEM image of Sample S2 adjacent to the OD surface; area indicated in Figure 32.

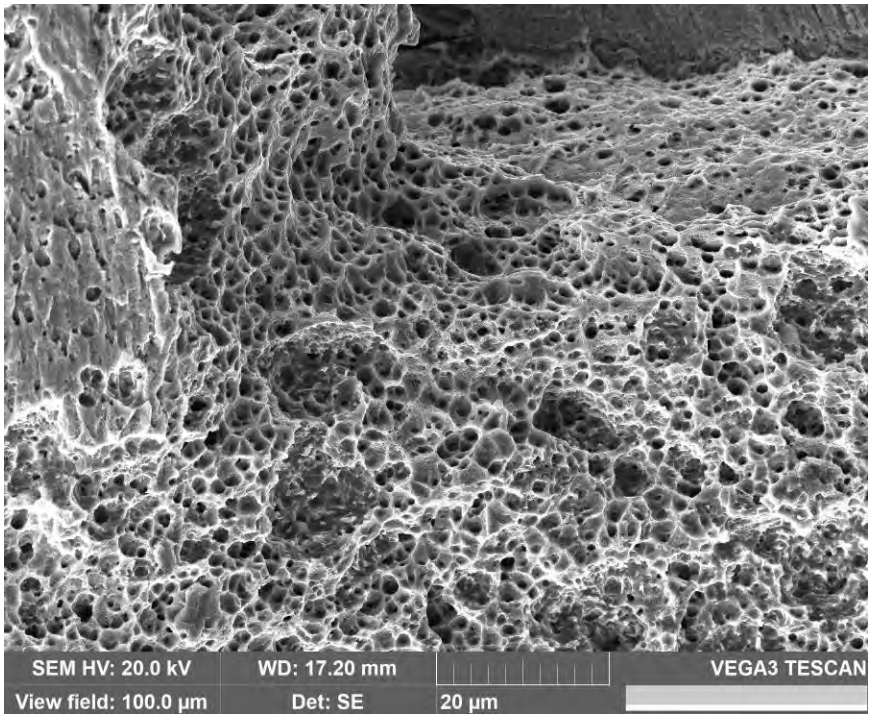


Figure 42. High magnification SEM image of Sample S2 adjacent to the OD surface; area indicated in Figure 41.

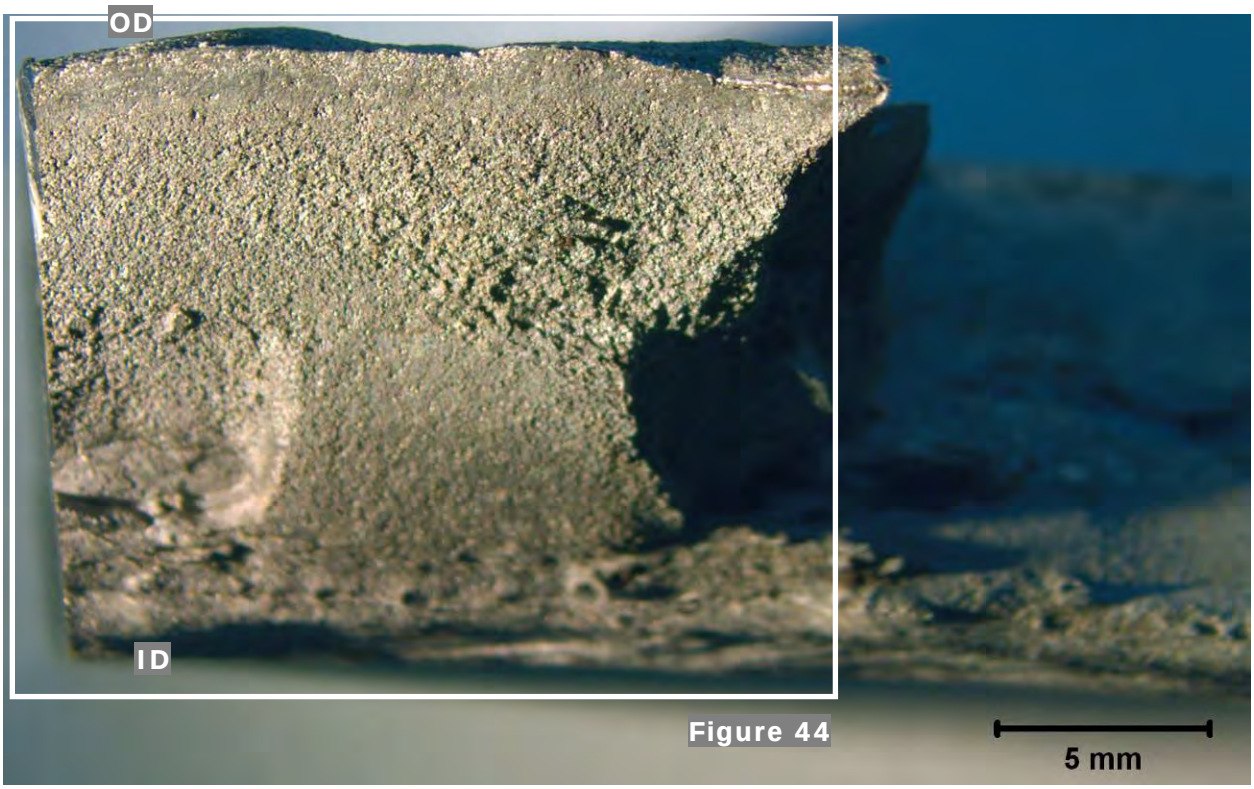


Figure 43. Light photomicrograph of the fracture surface of Sample S3, following cleaning in ENPREP® 214. The sample was removed near the 8:00 orientation; area indicated in Figure 28.

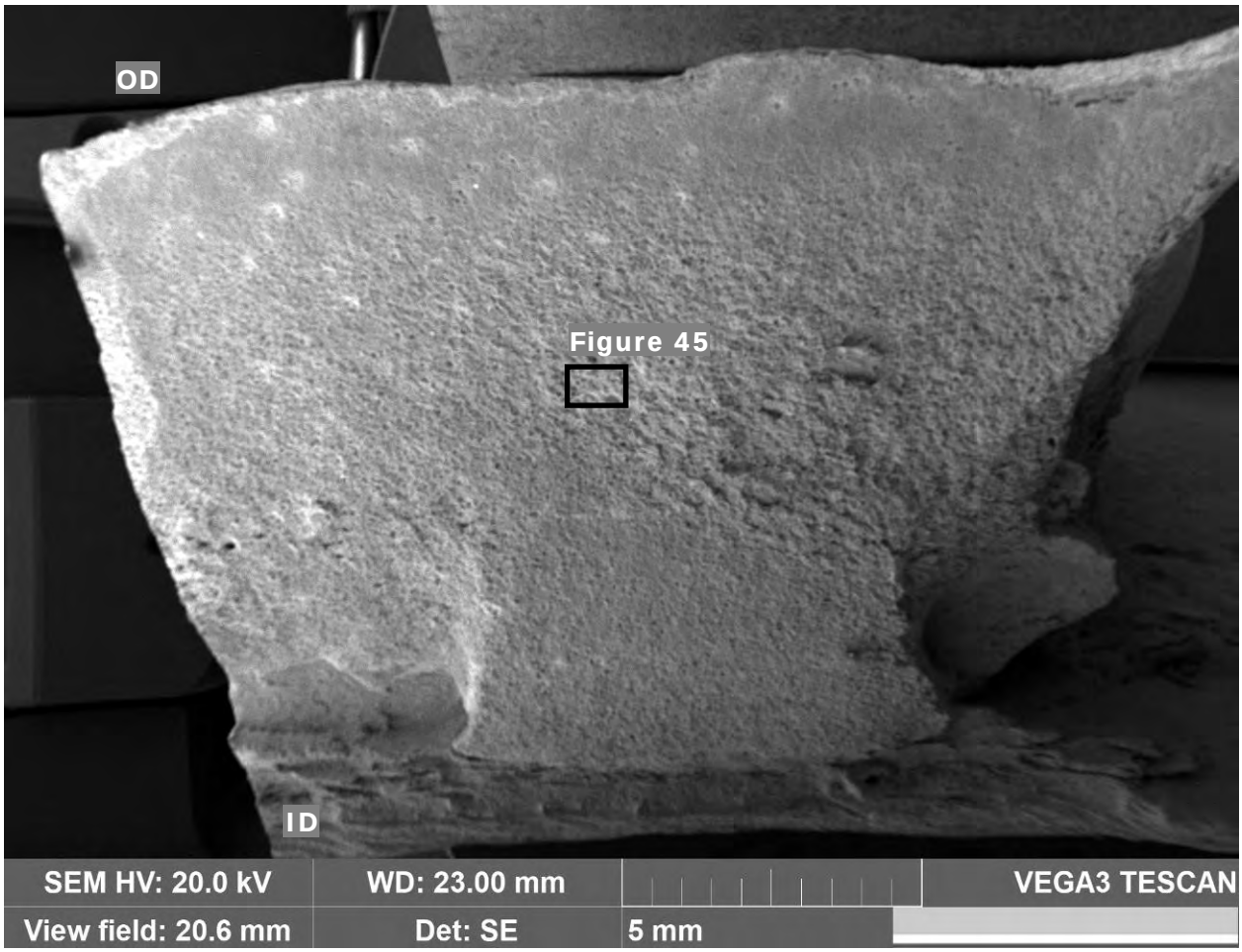


Figure 44. SEM image of Sample S3; area indicated in Figure 43.

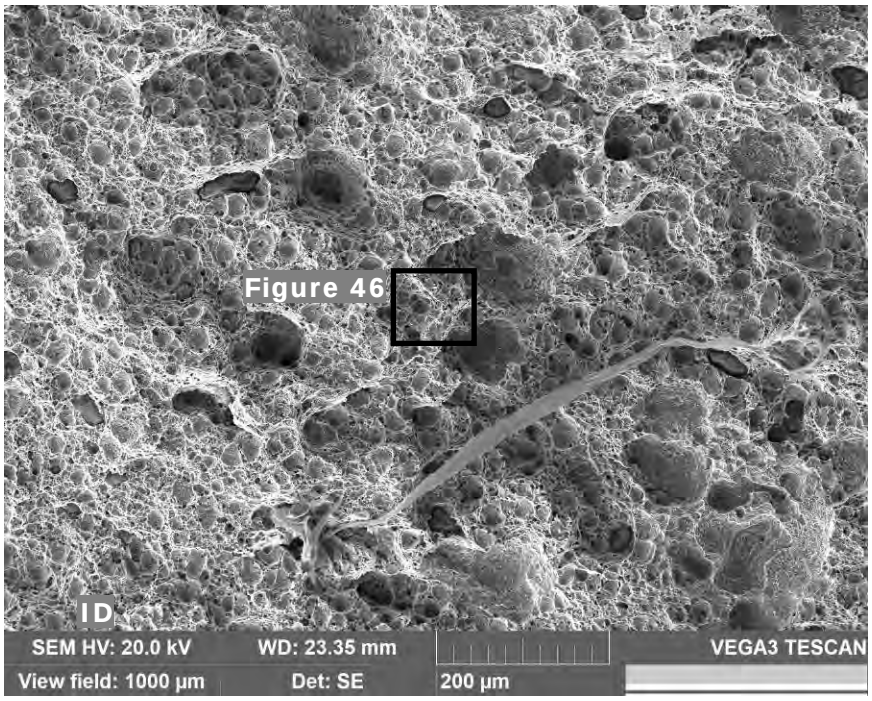


Figure 45. SEM image of Sample S3 midwall; area indicated in Figure 44.

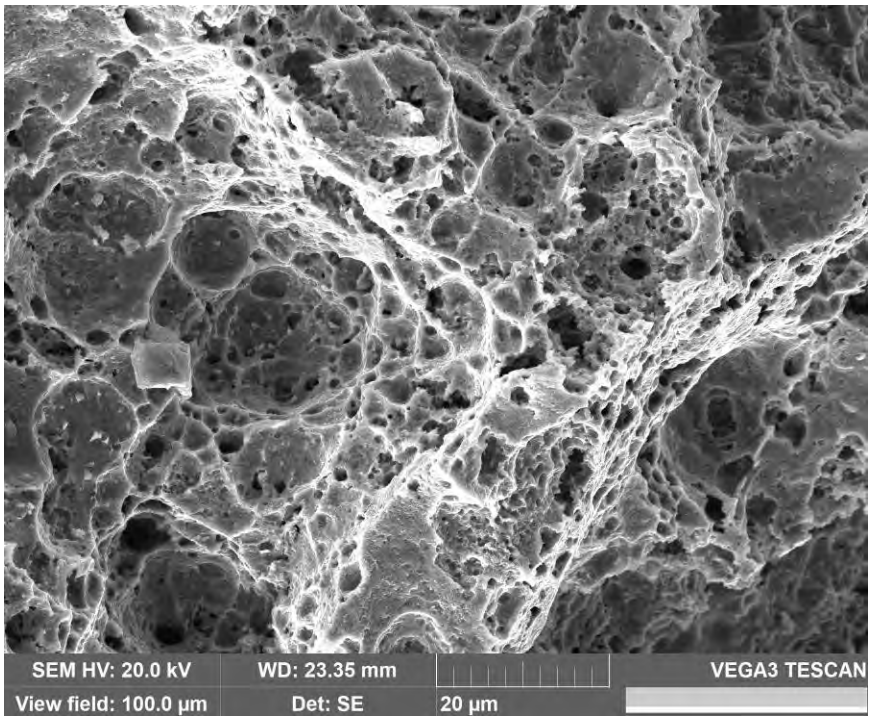


Figure 46. High magnification SEM image of Sample S3 midwall; area indicated in Figure 45.

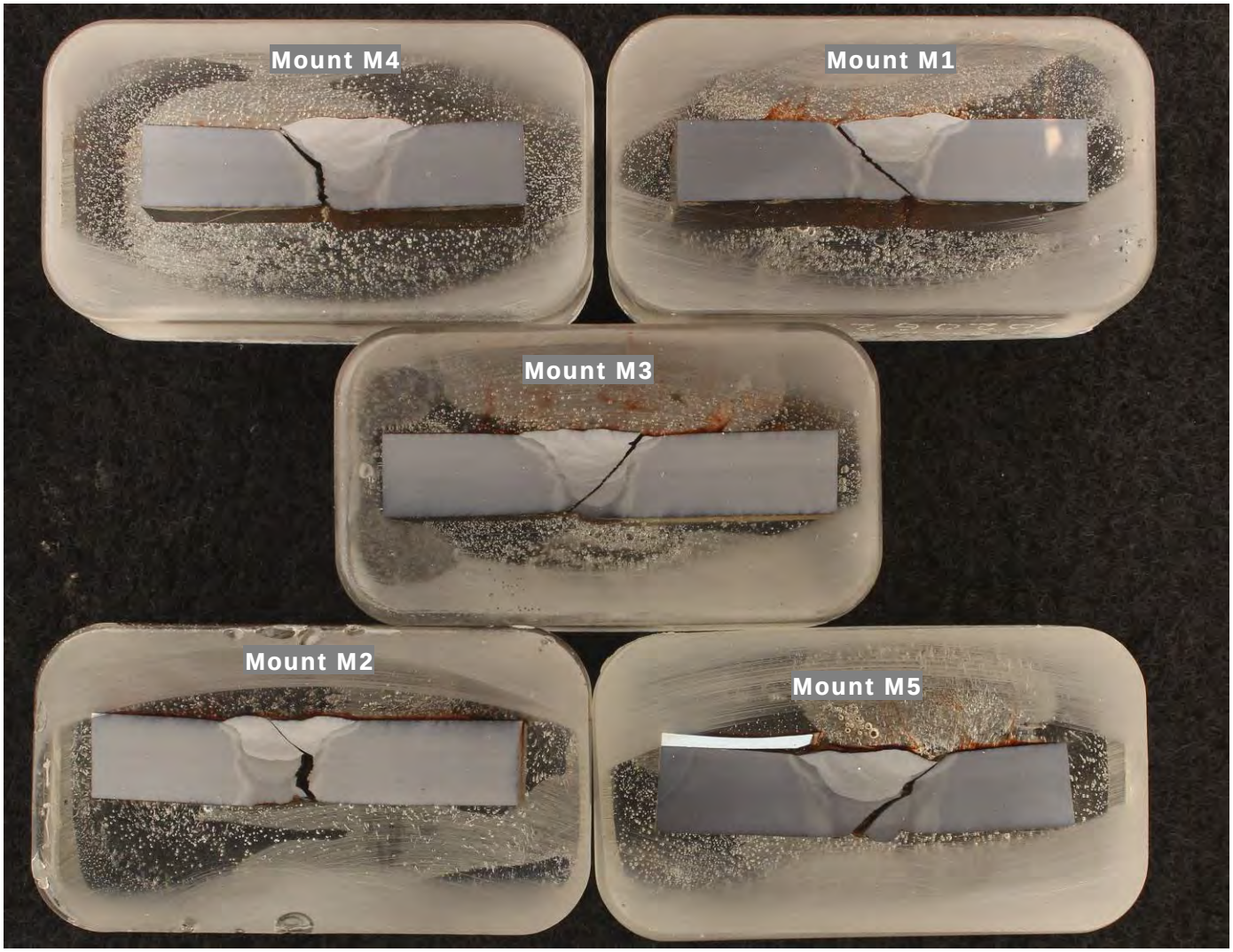


Figure 47. Photograph of the mounts (M1, M2, M3, M4, and M5) that were removed across the failure opening (2% Nital Etchant).

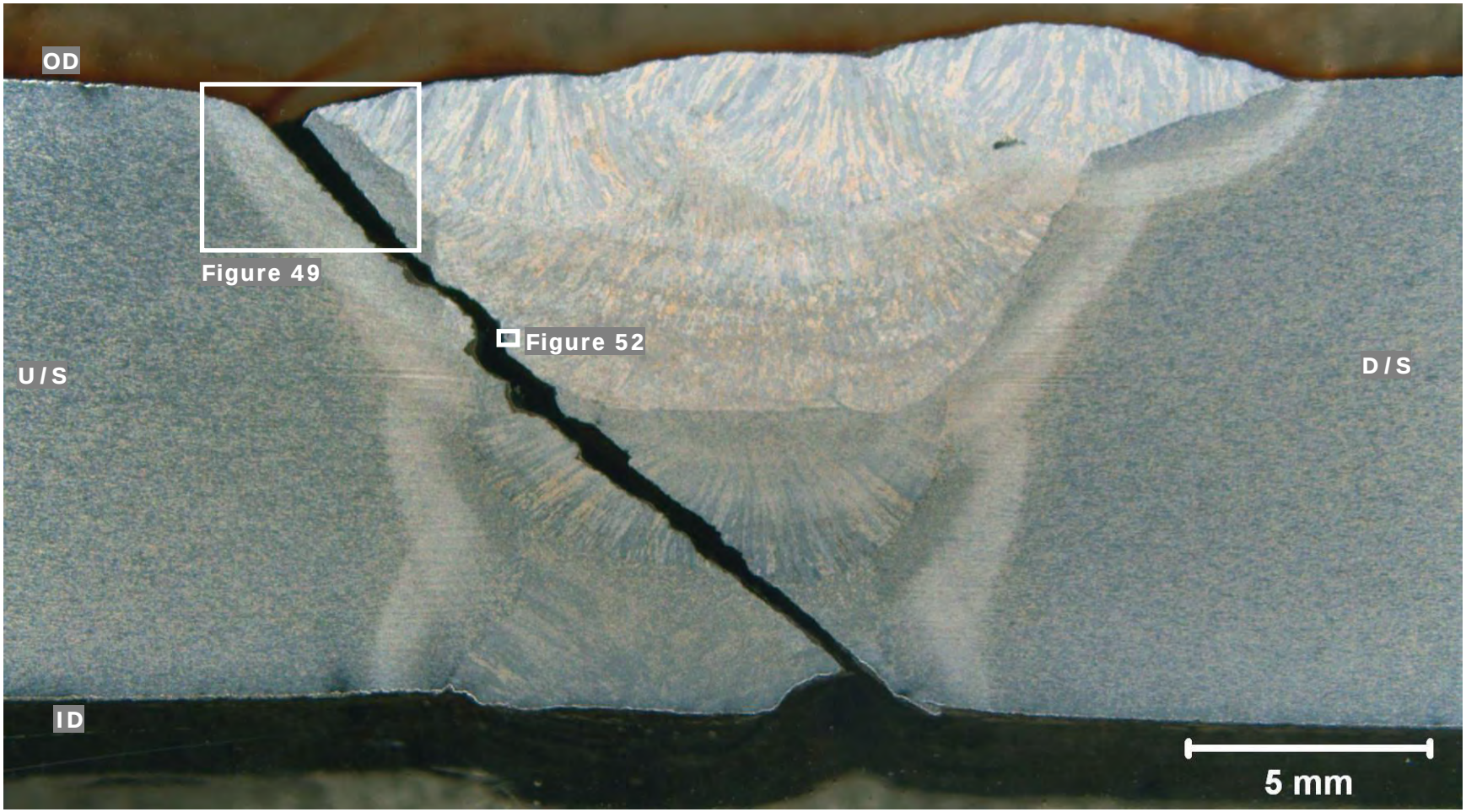


Figure 48. Light photomicrograph of Mount M1 (axial cross-section), which was removed from the failed GW at the 1:35 orientation; refer to Figure 1, Figure 11, and Figure 21 for location (2% Nital Etchant).

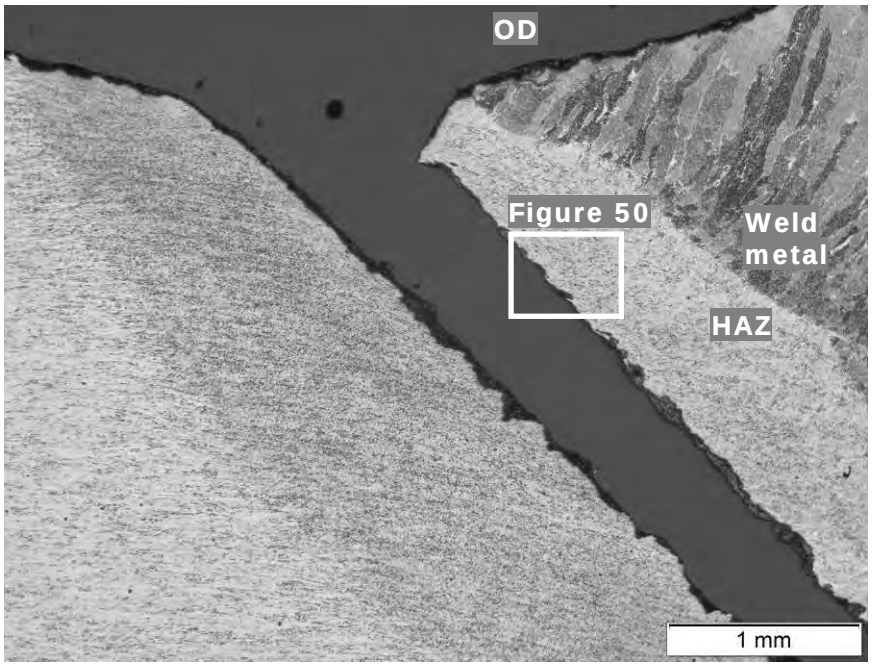


Figure 49. Light photomicrograph of Mount M1 adjacent to the OD surface (2% Nital Etchant); area indicated in Figure 48.

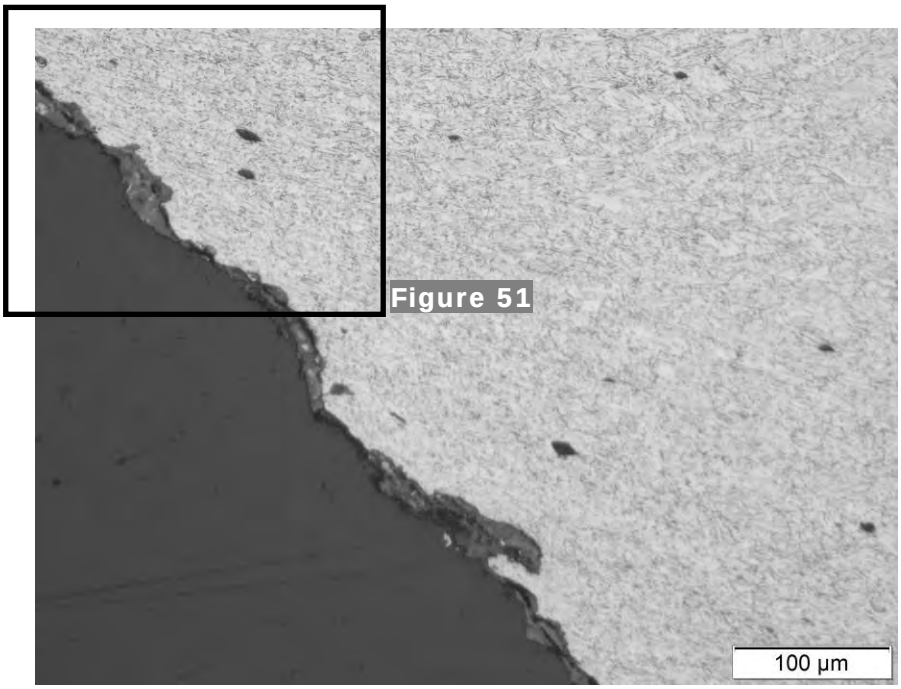


Figure 50. Light photomicrograph of Mount M1 showing inclusions in HAZ adjacent to the fracture surface; area indicated in Figure 49.

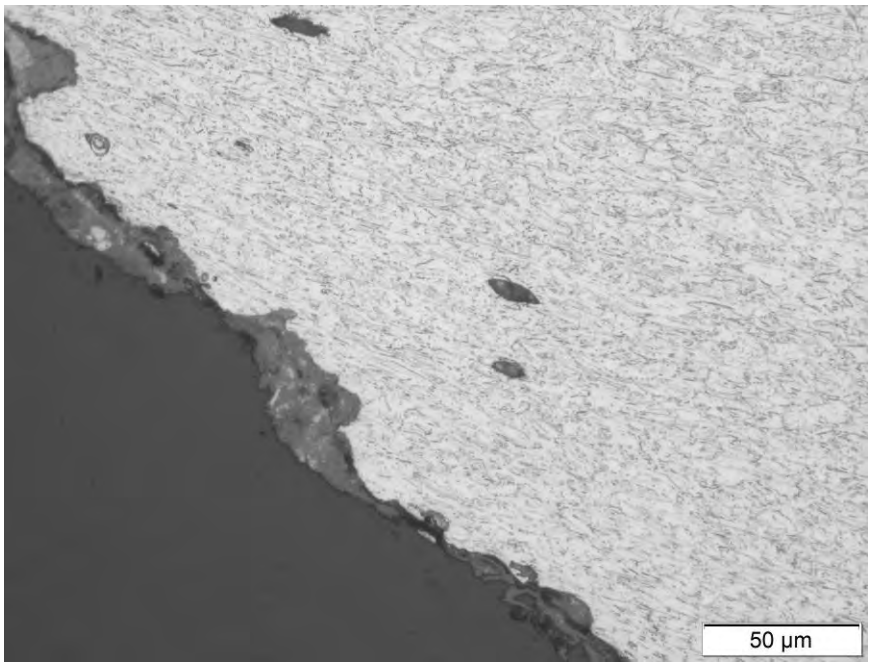


Figure 51. High magnification light photomicrograph of Mount M1 showing grain elongation adjacent to the fracture surface; area indicated in Figure 50.

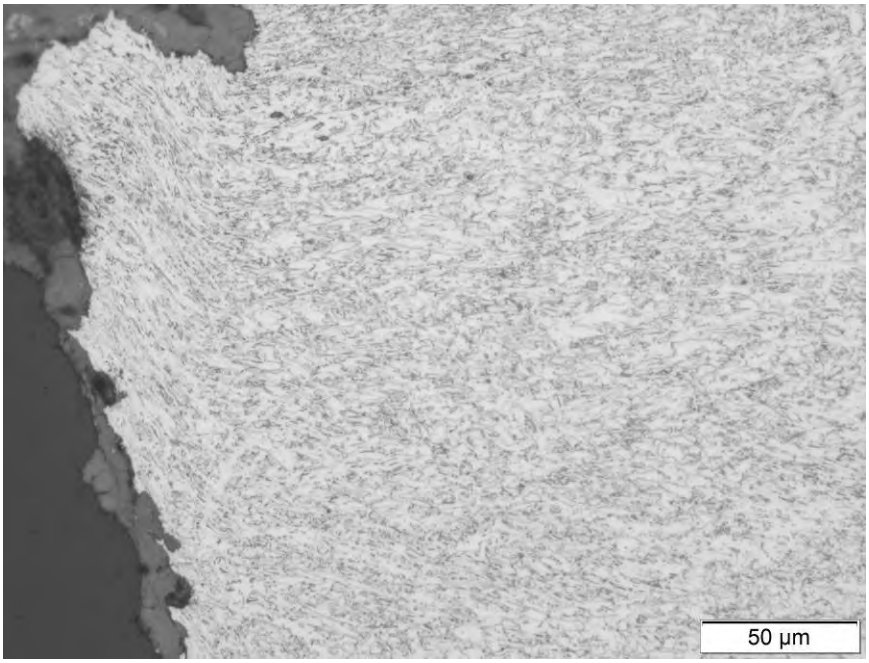


Figure 52. High magnification light photomicrograph of Mount M1 midwall adjacent to the fracture surface (2% Nital Etchant); area indicated in Figure 48.

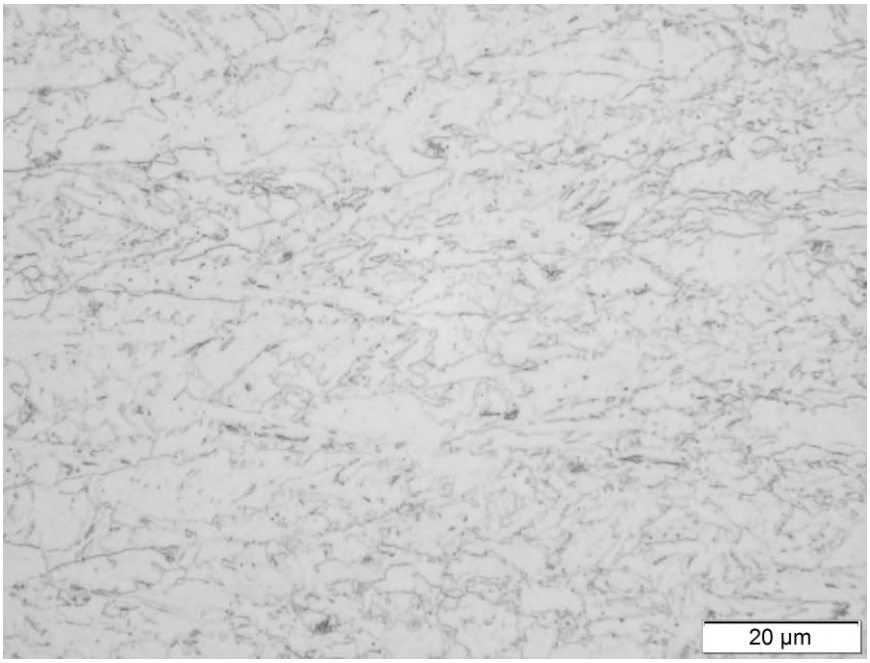


Figure 53. High magnification light photomicrograph of Mount M1 showing the typical base metal microstructure of the U/S Joint (PS B, 2% Nital Etchant).

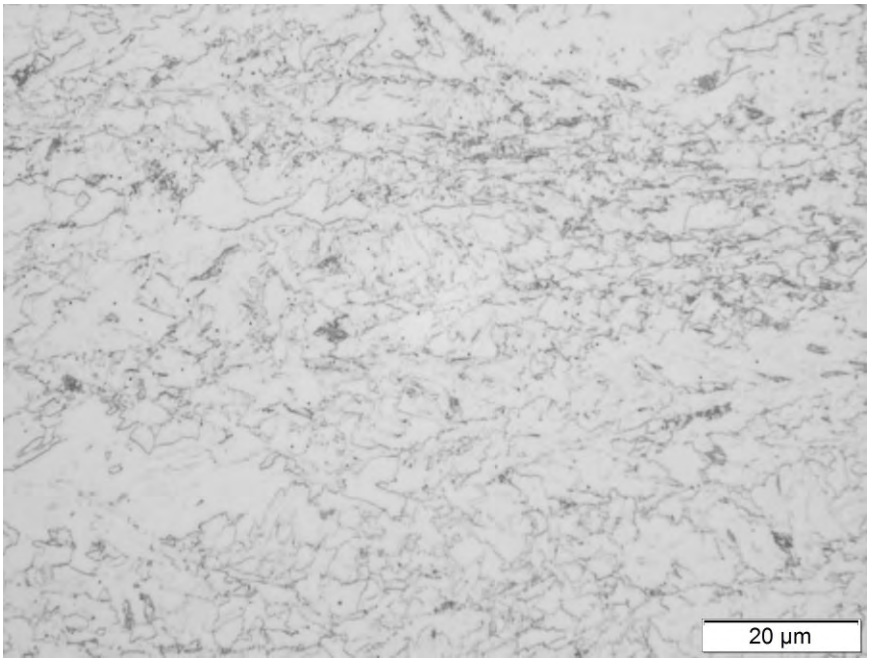


Figure 54. High magnification light photomicrograph of Mount M1 showing the typical base metal microstructure of the D/S Joint (PS A, 2% Nital Etchant).

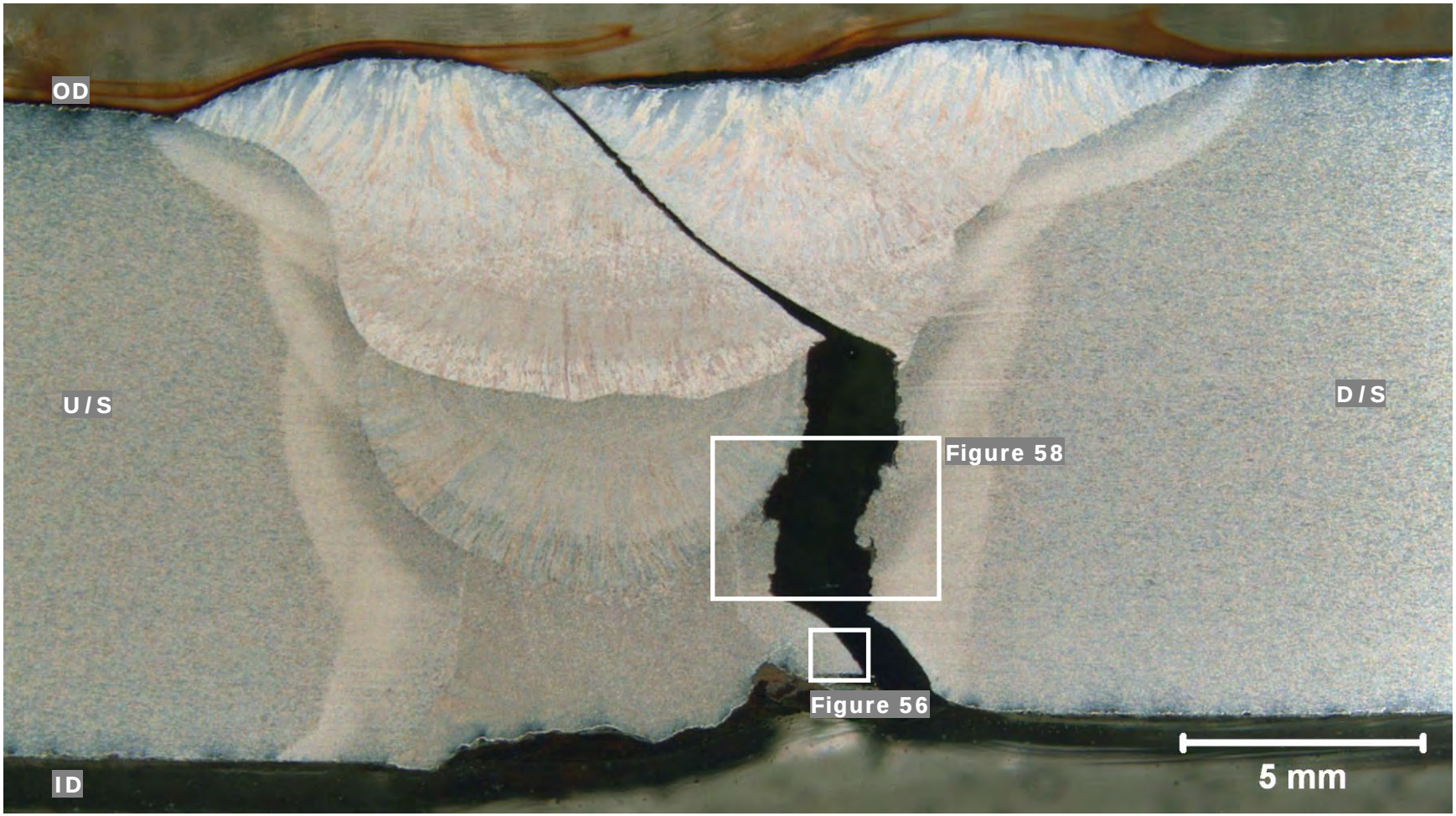


Figure 55. Light photomicrograph of Mount M2 (axial cross-section), which was removed from the GW at the 3:55 orientation; refer to Figure 1, Figure 12, and Figure 23 for location (2% Nital Etchant).

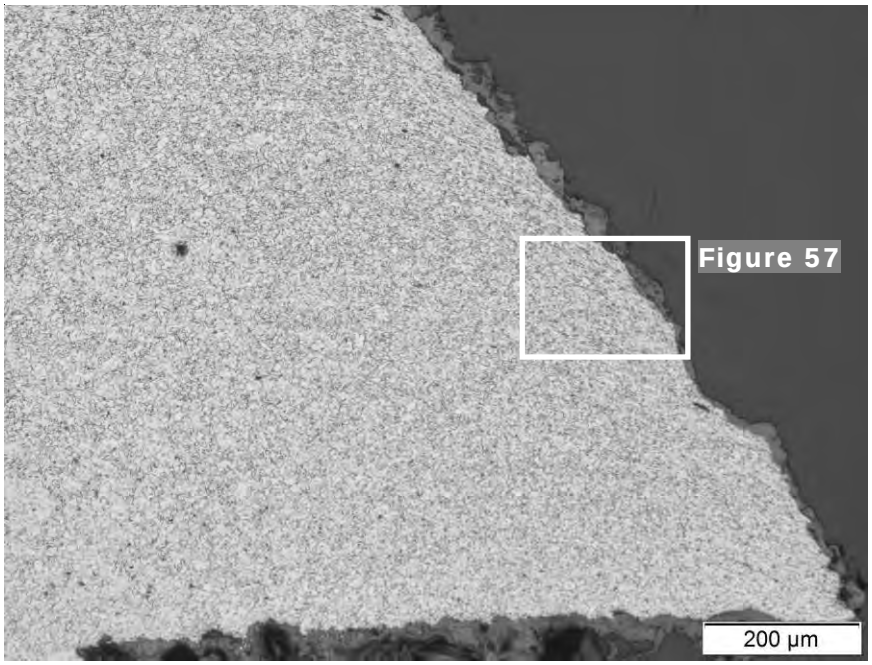


Figure 56. Light photomicrograph of Mount M2 adjacent to the ID surface (2% Nital Etchant); area indicated in Figure 55.

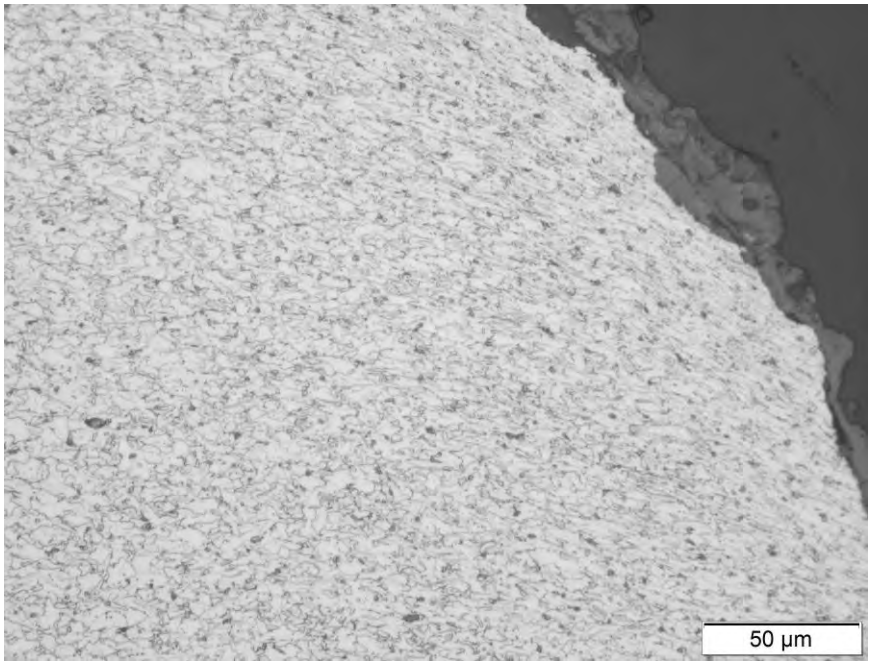


Figure 57. High magnification light photomicrograph of Mount M2 near the ID surface, adjacent to the fracture surface (2% Nital Etchant); area indicated in Figure 56.

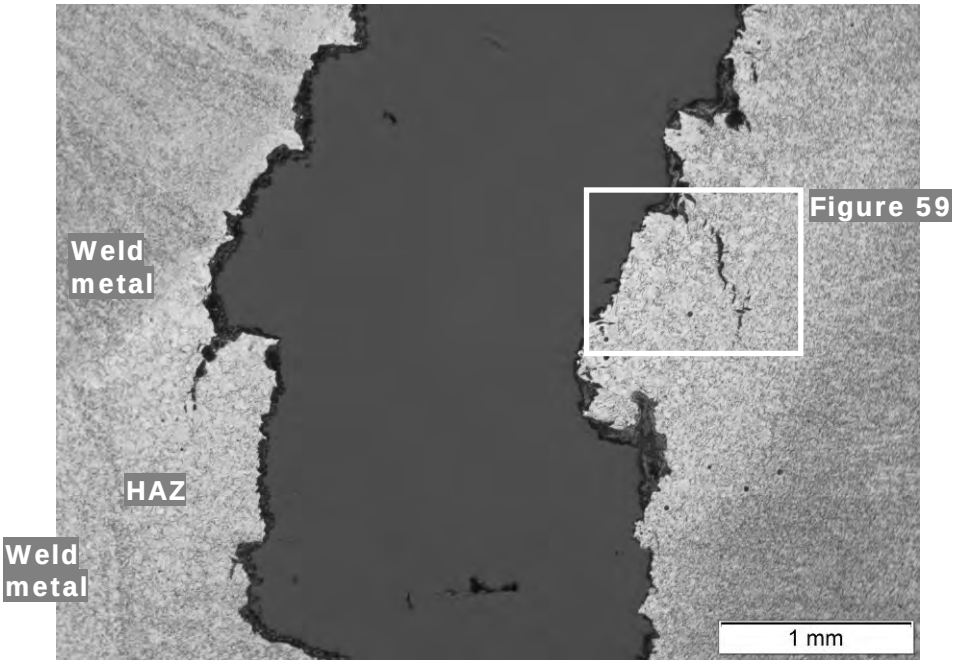


Figure 58. Light photomicrograph of Mount M2 midwall (2% Nital Etchant); area indicated in Figure 55.

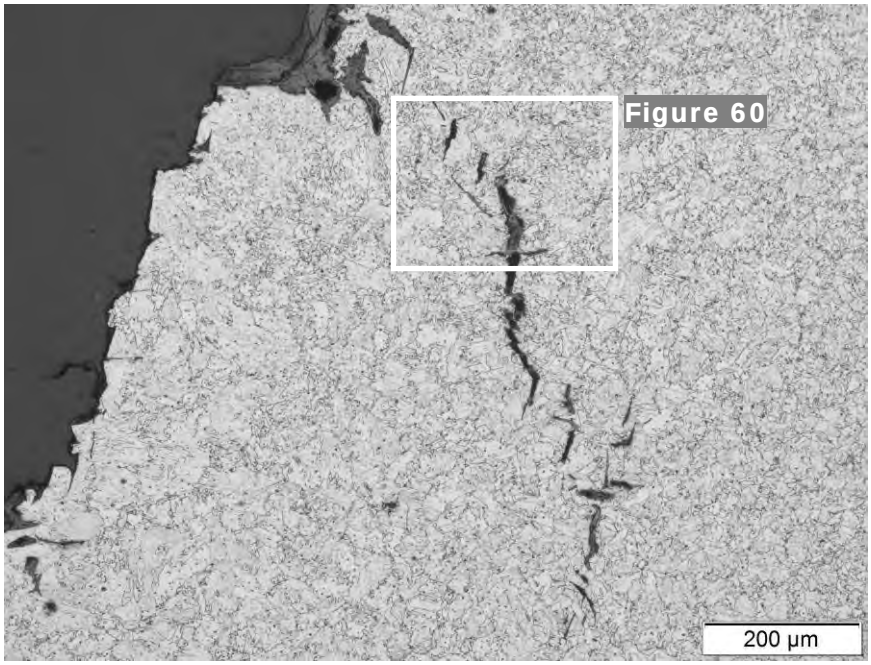


Figure 59. Light photomicrograph of Mount M2 adjacent to the fracture surface showing fissures (2% Nital Etchant); area indicated in Figure 58.

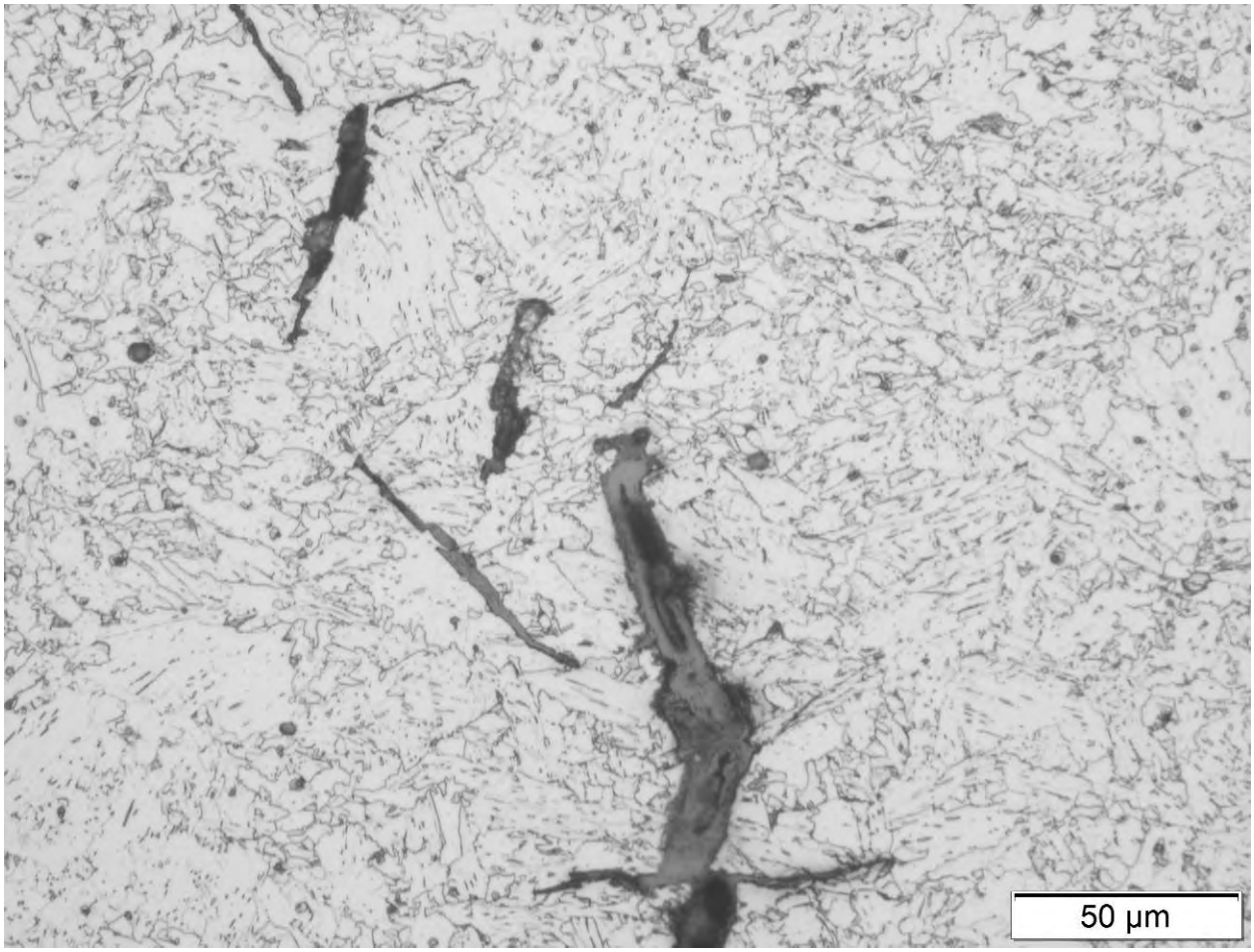


Figure 60. High magnification light photomicrograph of Mount M2 at fissures (2% Nital Etchant); area indicated in Figure 59.

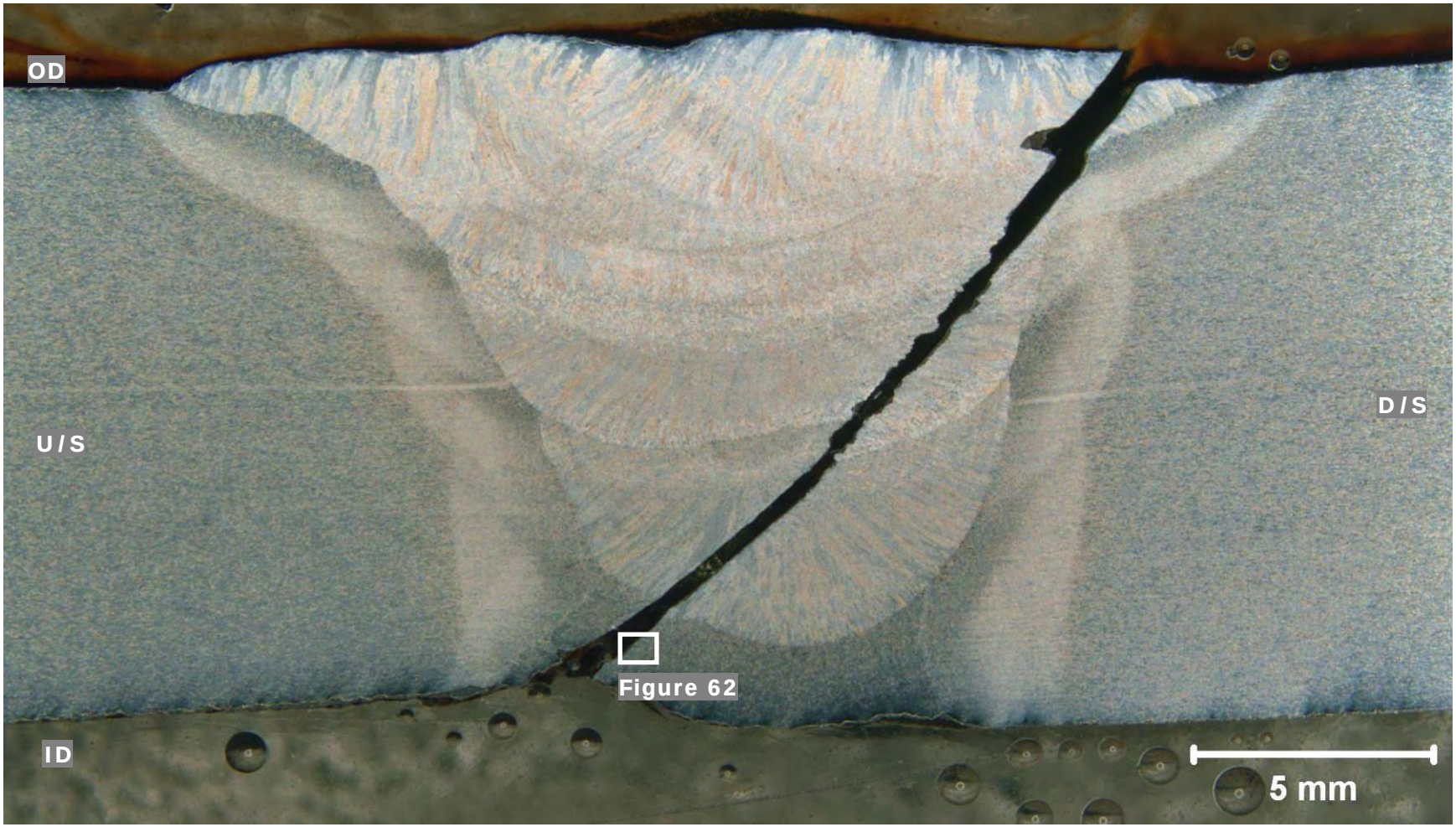


Figure 61. Light photomicrograph of Mount M3 (axial cross-section), which was removed from the GW at the 8:35 orientation; refer to Figure 1, Figure 13, and Figure 28 for location (2% Nital Etchant).

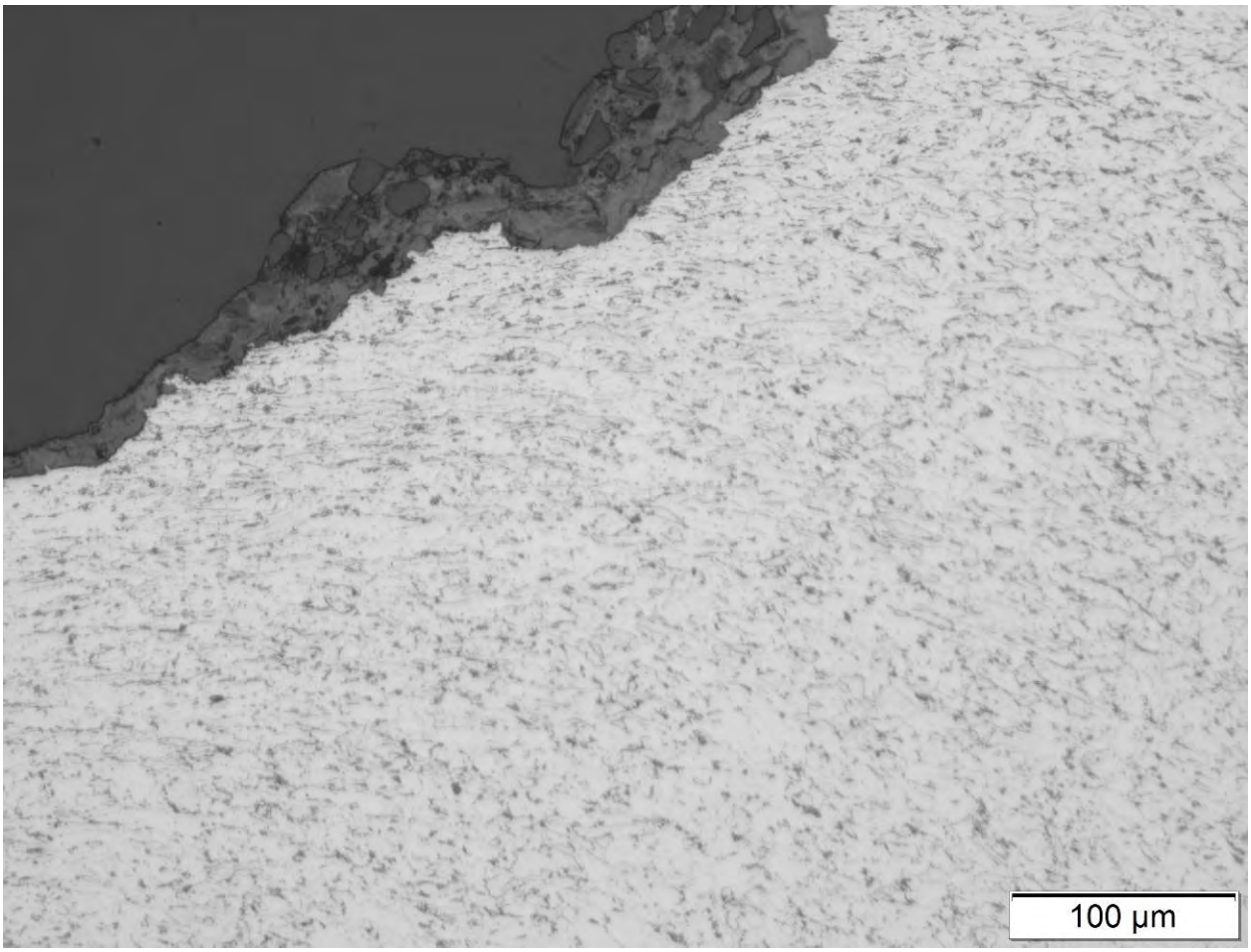


Figure 62. Light photomicrograph of Mount M3 adjacent to the fracture surface, near the ID surface (2% Nital Etchant); area indicated in Figure 61.

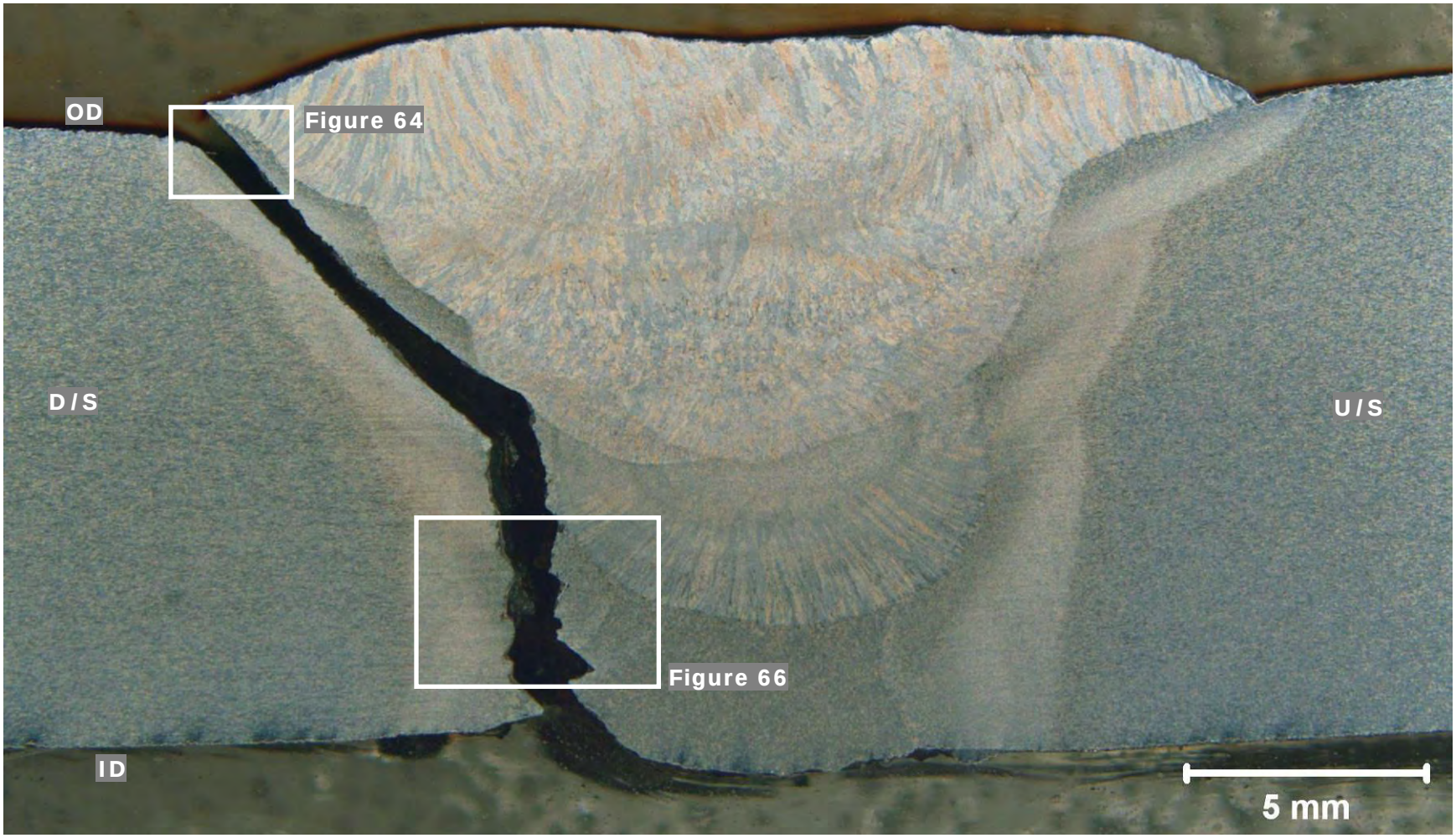


Figure 63. Light photomicrograph of Mount M4 (axial cross-section), which was removed from the GW at the 10:24 orientation; refer to Figure 1, Figure 14, and Figure 30 for location (2% Nital Etchant).

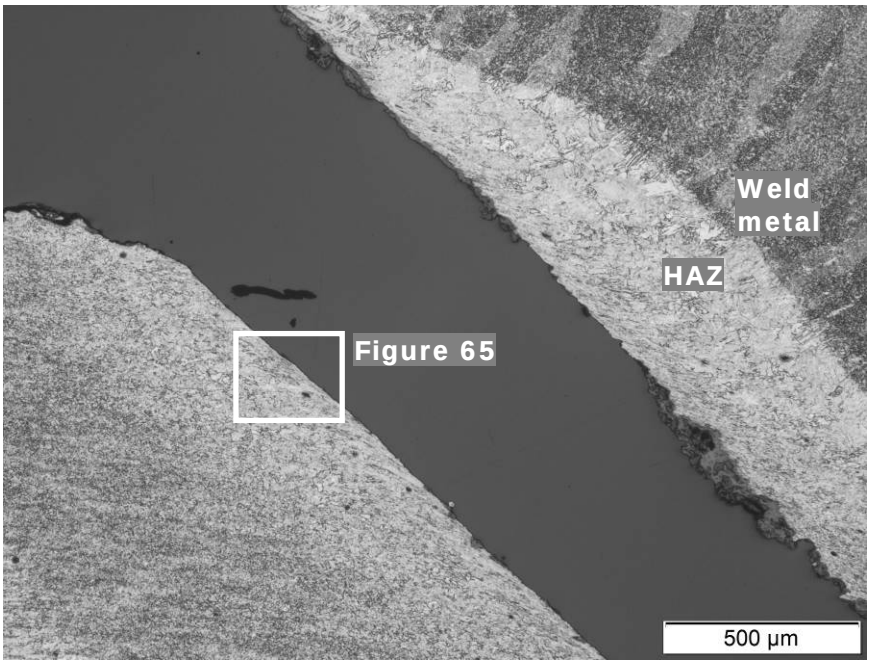


Figure 64. Light photomicrograph of Mount M4 near the OD surface (2% Nital Etchant); area indicated in Figure 63.

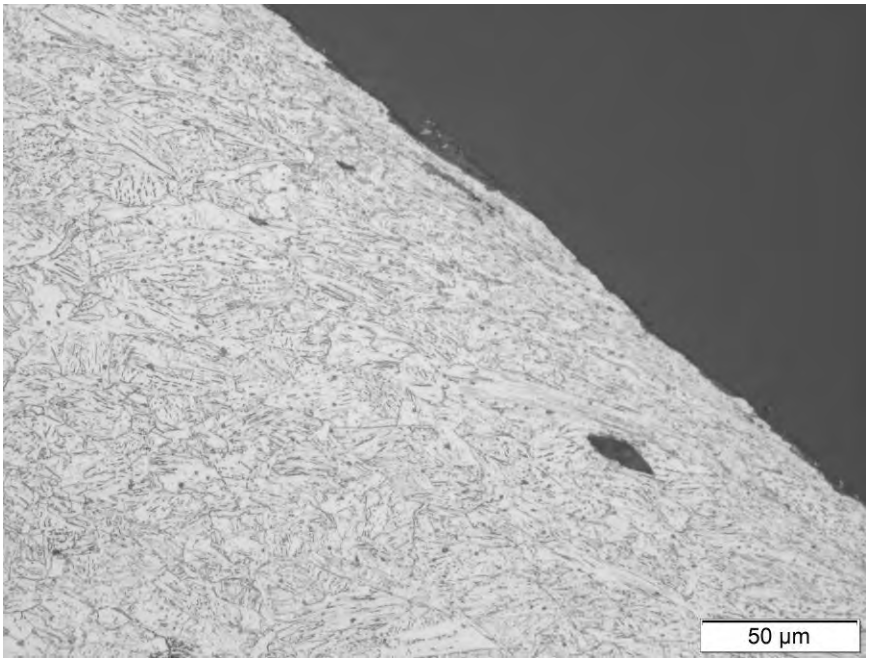


Figure 65. High magnification light photomicrograph of Mount M4 showing grain elongation adjacent to the fracture surface (2% Nital Etchant); area indicated in Figure 64.

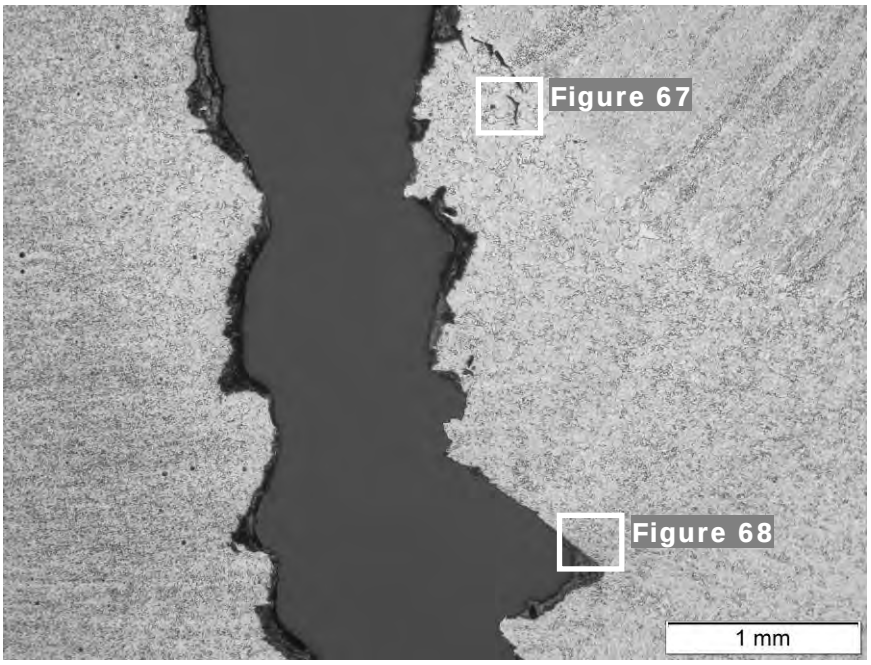


Figure 66. Light photomicrograph of Mount M4 near the ID surface (2% Nital Etchant); area indicated in Figure 63.

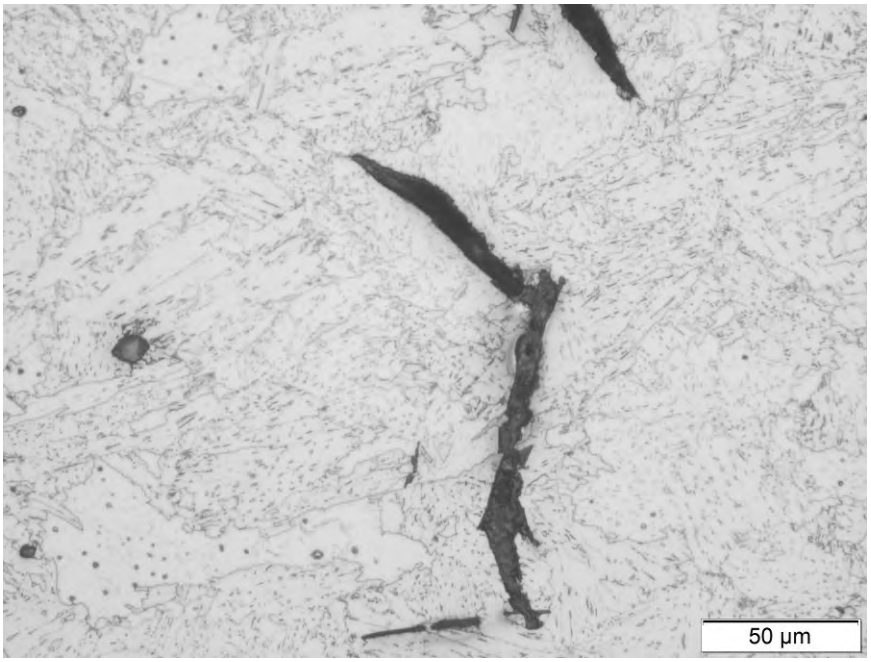


Figure 67. High magnification light photomicrograph of Mount M4 showing fissures (2% Nital Etchant); area indicated in Figure 66.

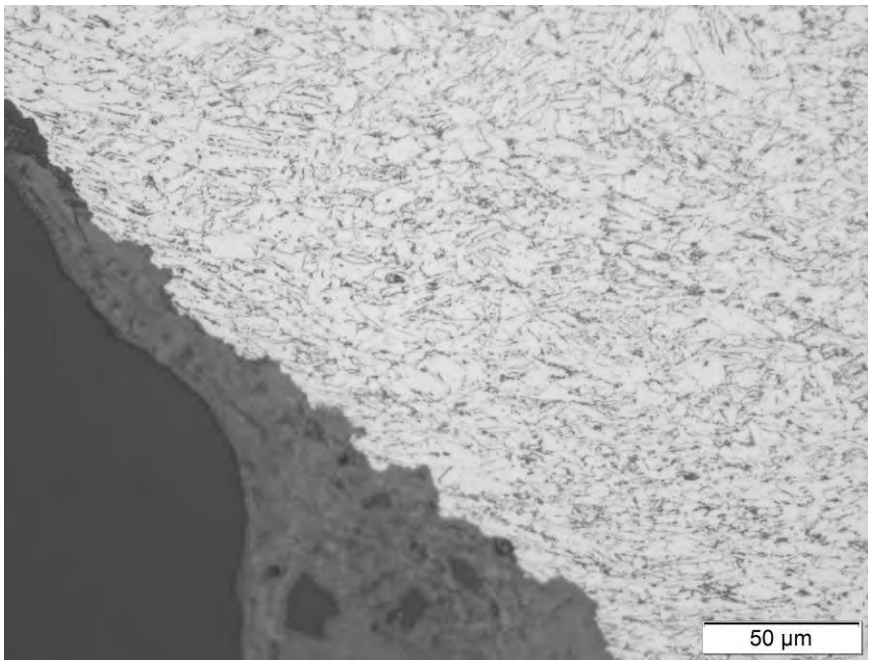


Figure 68. High magnification light photomicrograph of Mount M4 showing grain elongation adjacent to the fracture surface, near the ID surface (2% Nital Etchant); area indicated in Figure 66.



Figure 69. Light photomicrograph of Mount M5 (axial cross-section), which was removed from the GW at the 11:37 orientation; refer to Figure 1, Figure 14, and Figure 31 for location (2% Nital Etchant).

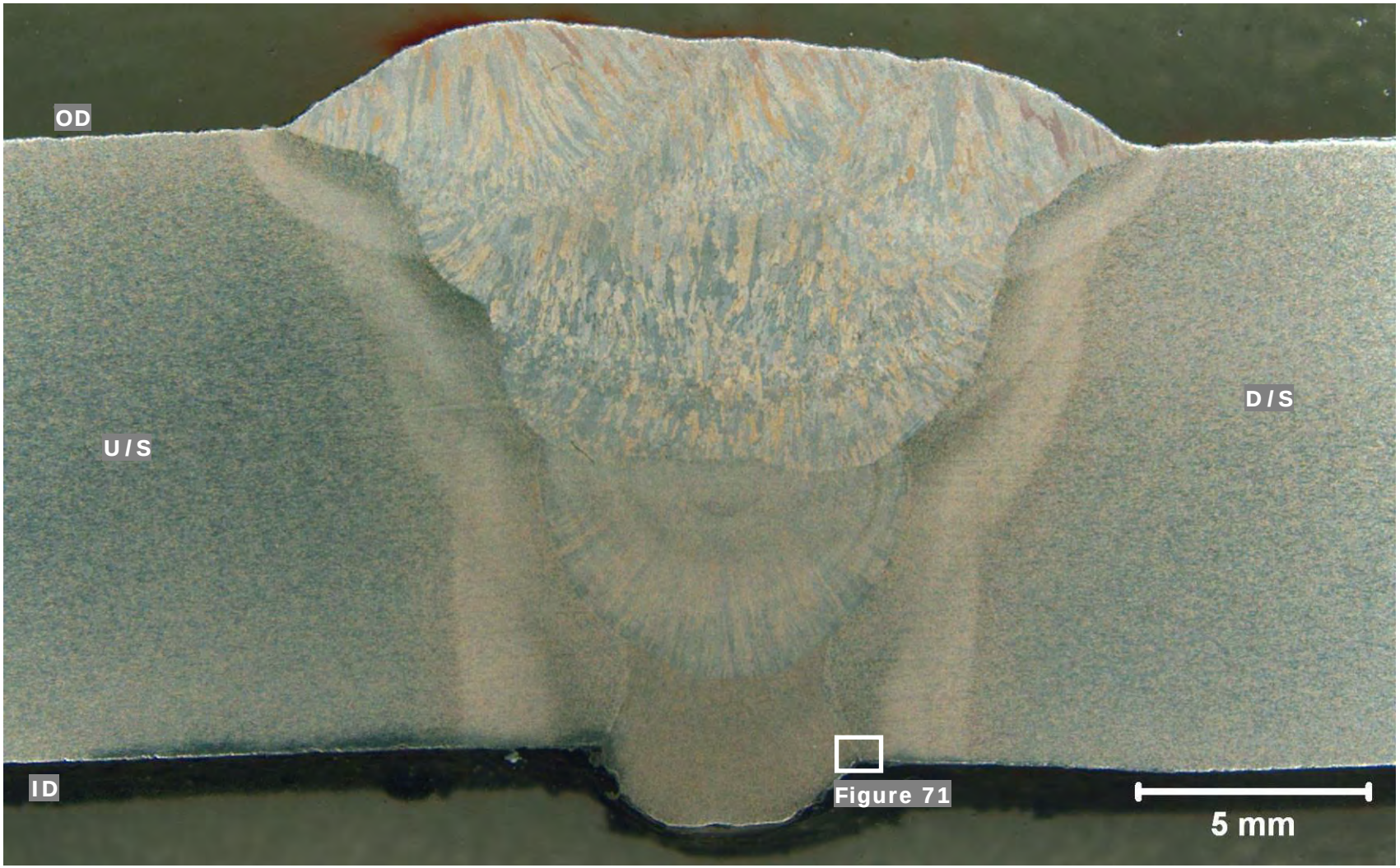


Figure 70. Light photomicrograph of Mount MU1 (axial cross-section), which was removed from the intact GW at the 12:27 orientation; refer to Figure 1 and Figure 17 for location (2% Nital Etchant).

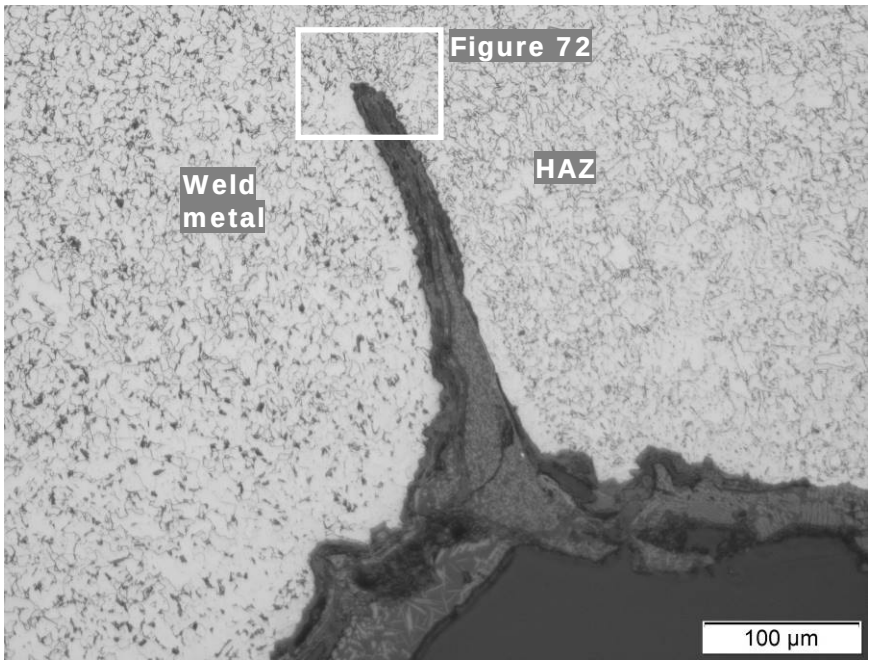


Figure 71. Light photomicrograph of Mount MU1 adjacent to the ID surface (2% Nital Etchant); area indicated in Figure 70.

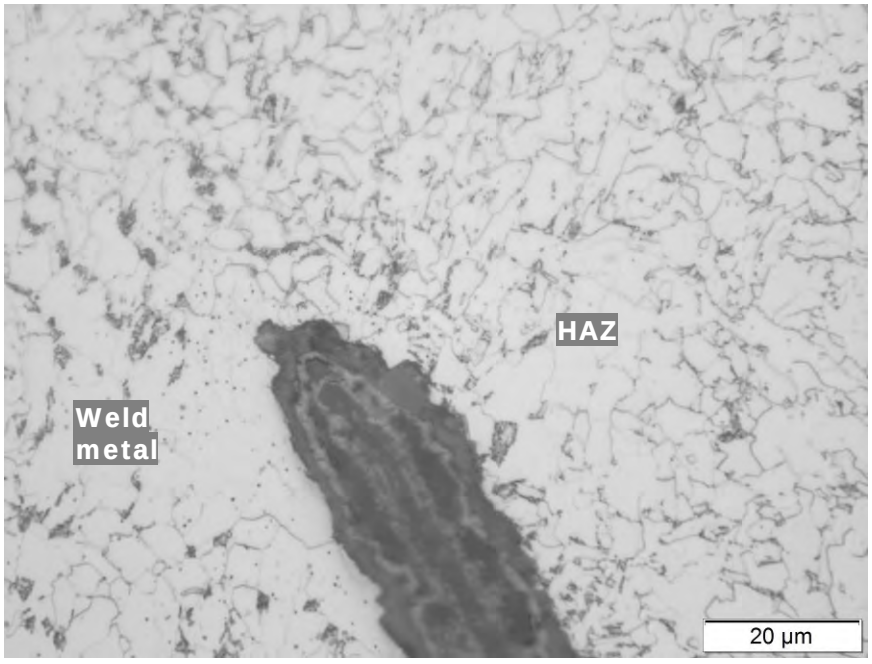


Figure 72. High magnification light photomicrograph of Mount MU1 at the tip of a shallow incomplete fusion (IF) flaw (2% Nital Etchant); area indicated in Figure 71.

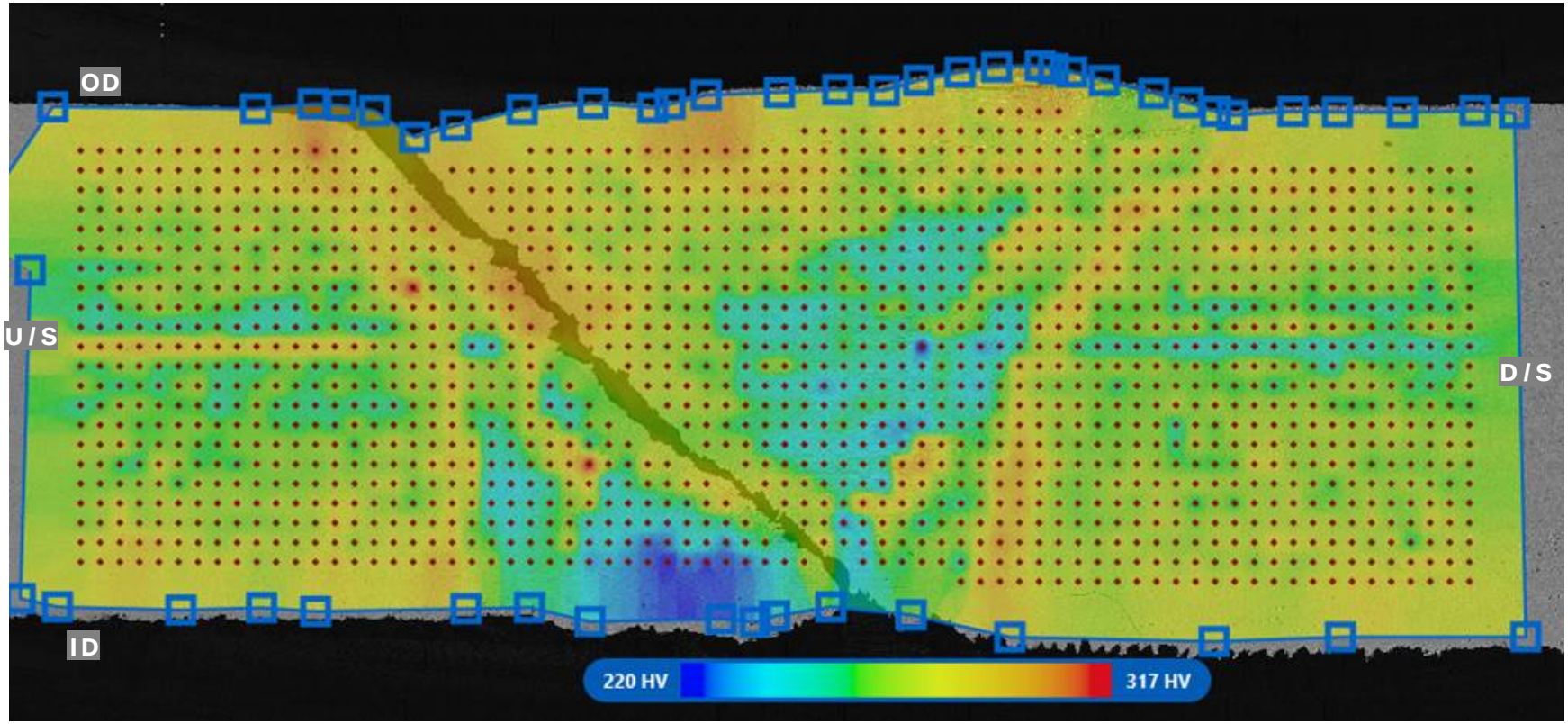


Figure 73. Hardness map overlay following hardness testing (Vickers 1 kg load) performed on Mount M1.

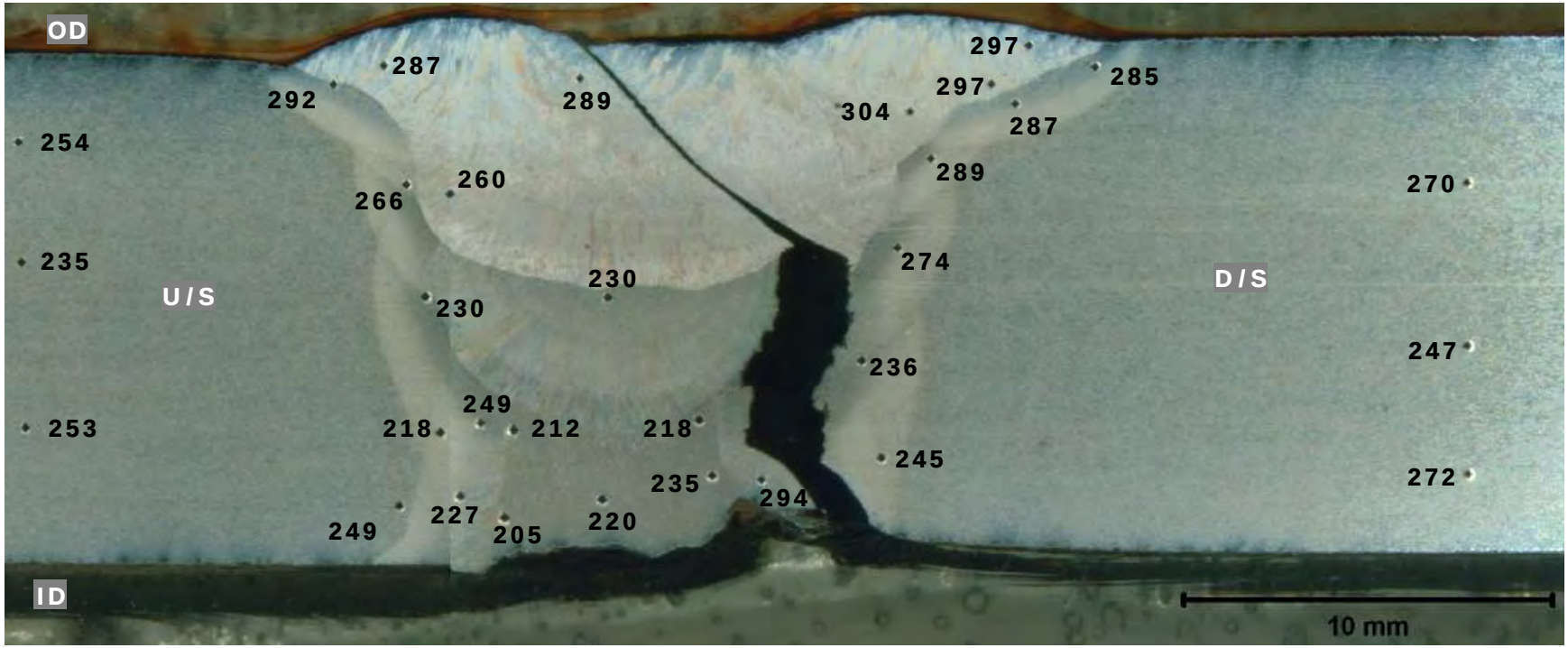


Figure 74. Light photomicrograph montage of Mount M2 (axial cross-section), showing the hardness indentations and the hardness values in HV (2% Nital Etchant).

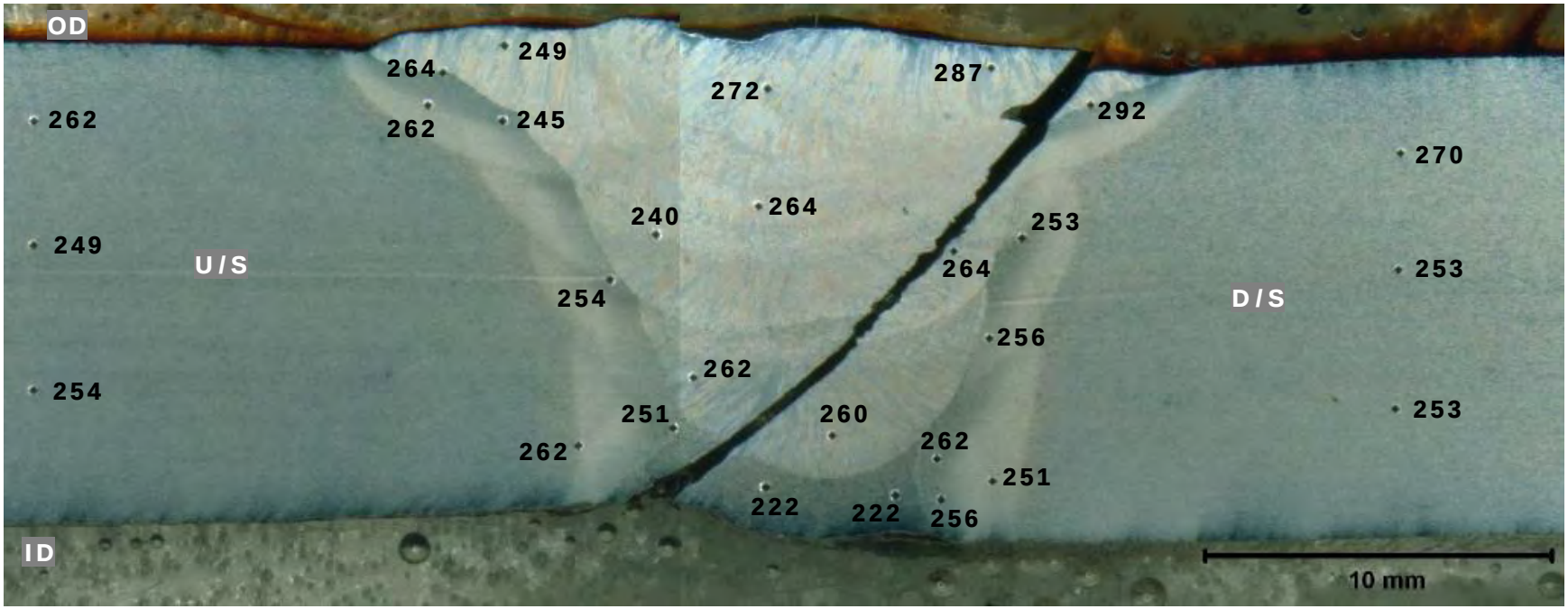


Figure 75. Light photomicrograph montage of Mount M3 (axial cross-section), showing the hardness indentations and the hardness values in HV (2% Nital Etchant).

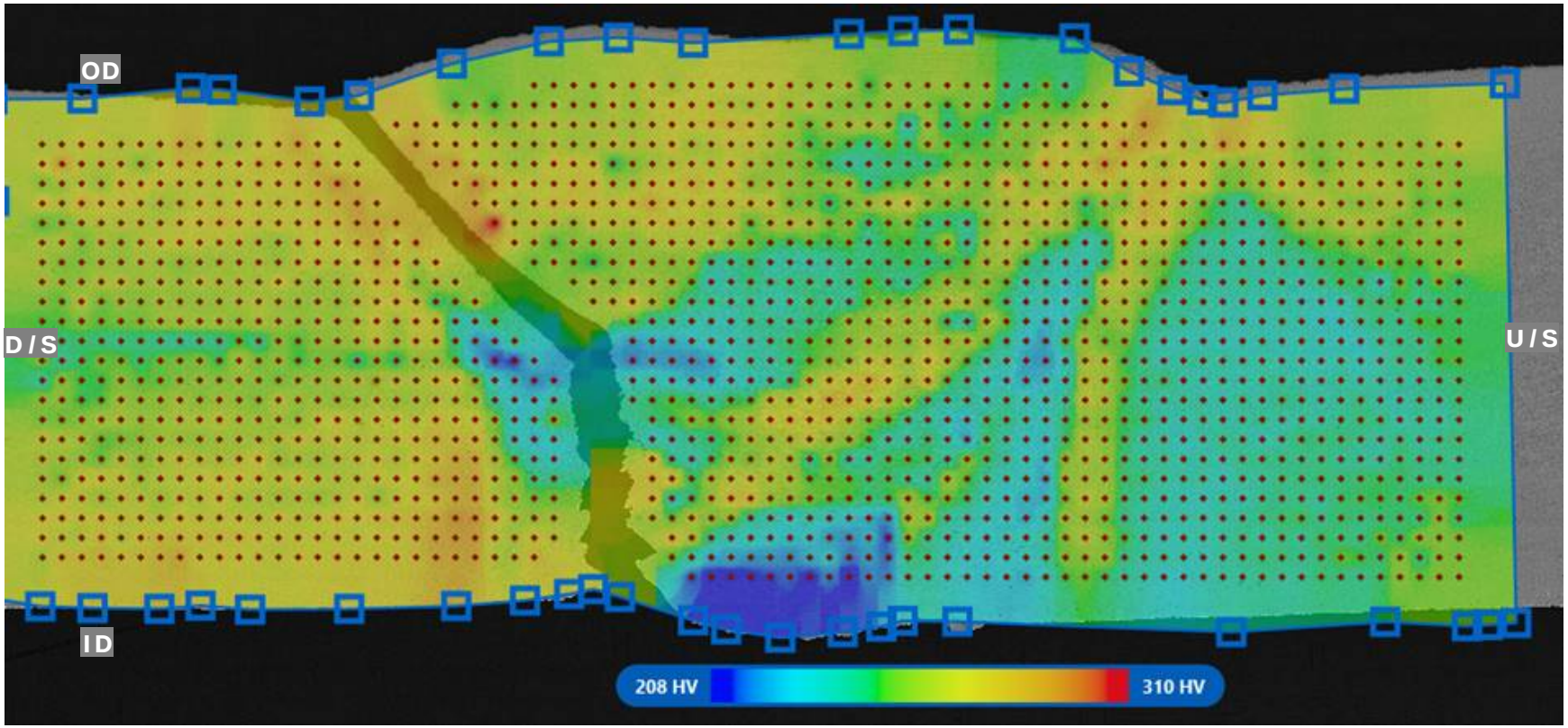


Figure 76. Hardness map overlay following hardness testing (Vickers 1 kg load) performed on Mount M4.

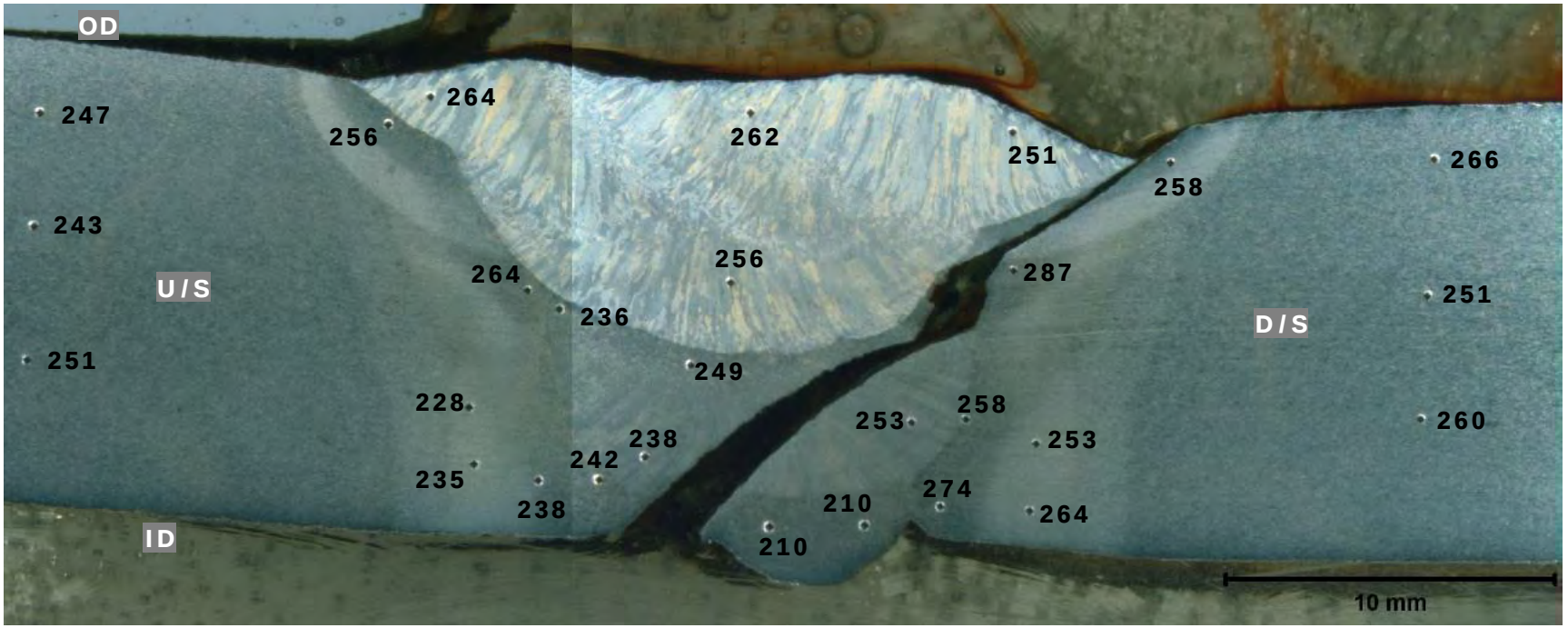


Figure 77. Light photomicrograph montage of Mount M5 (axial cross-section), showing the hardness indentations and the hardness values in HV (2% Nital Etchant).

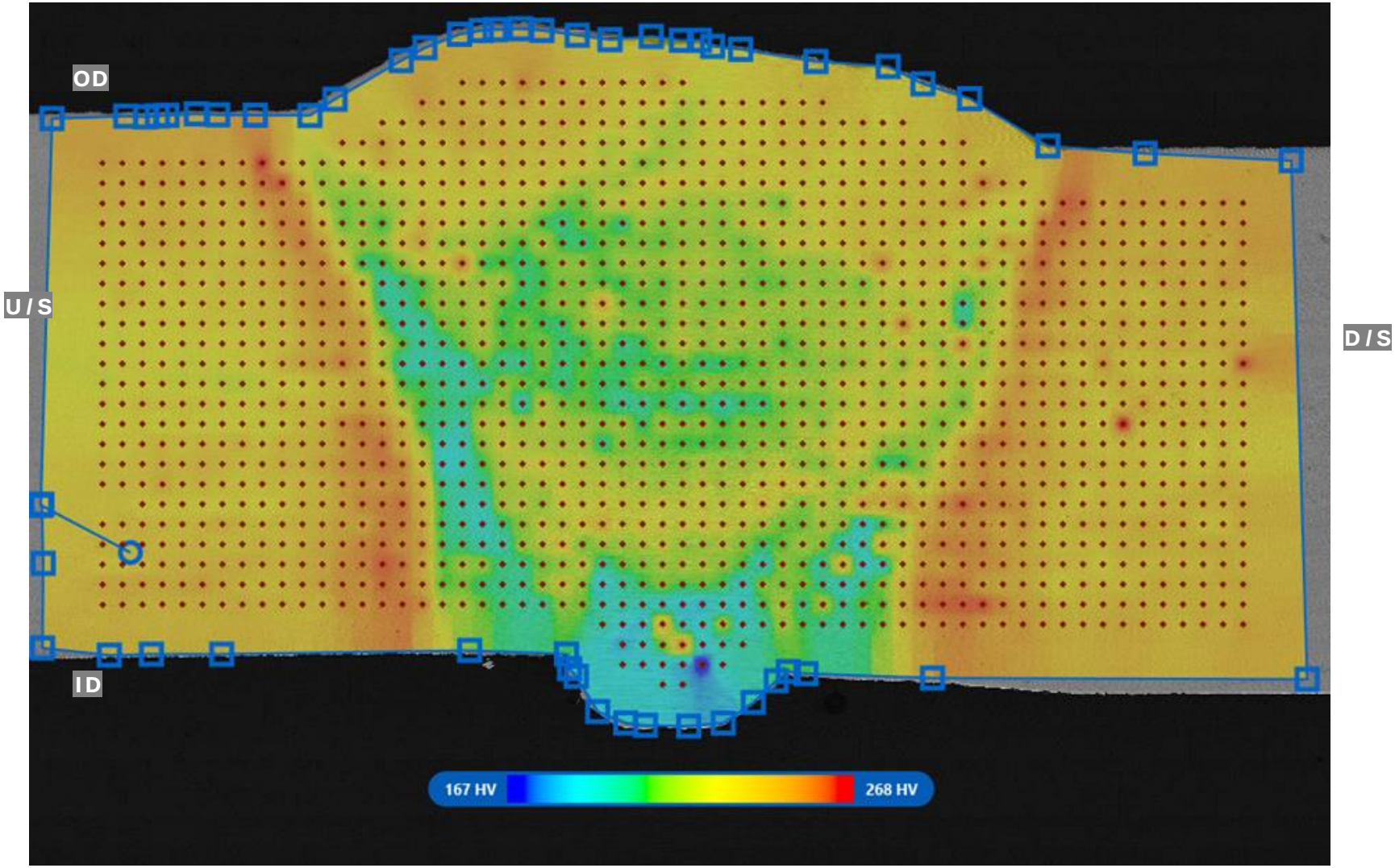


Figure 78. Hardness map overlay following hardness testing (Vickers 1 kg load) performed on Mount MU1.

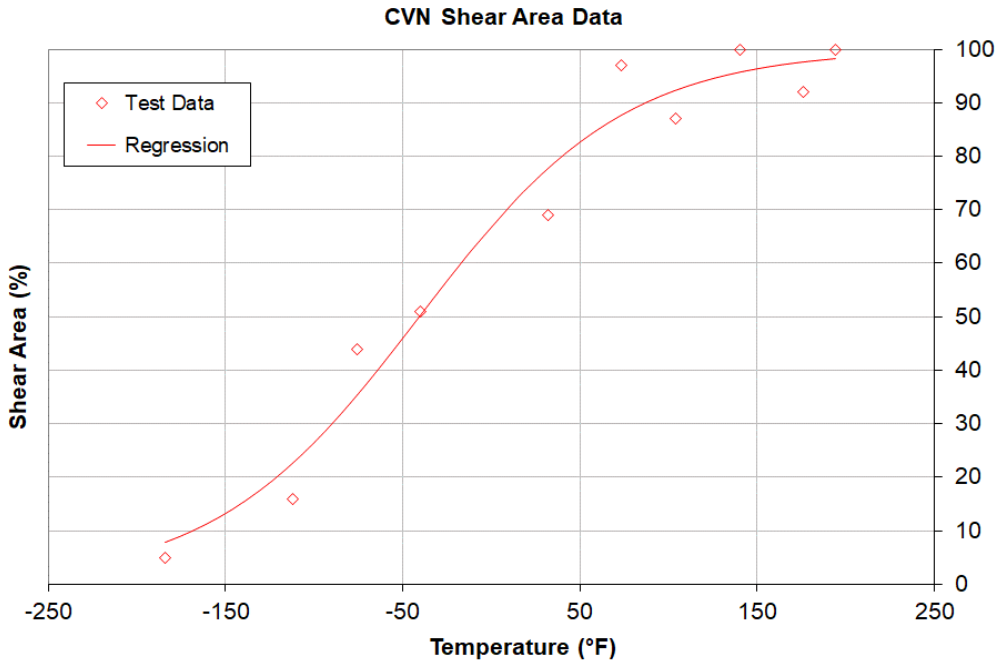


Figure 79. Percent shear from Charpy V-notch tests as a function of temperature for axial/cross-girth weld (HAZ notch) specimens removed from Pipe Section C.

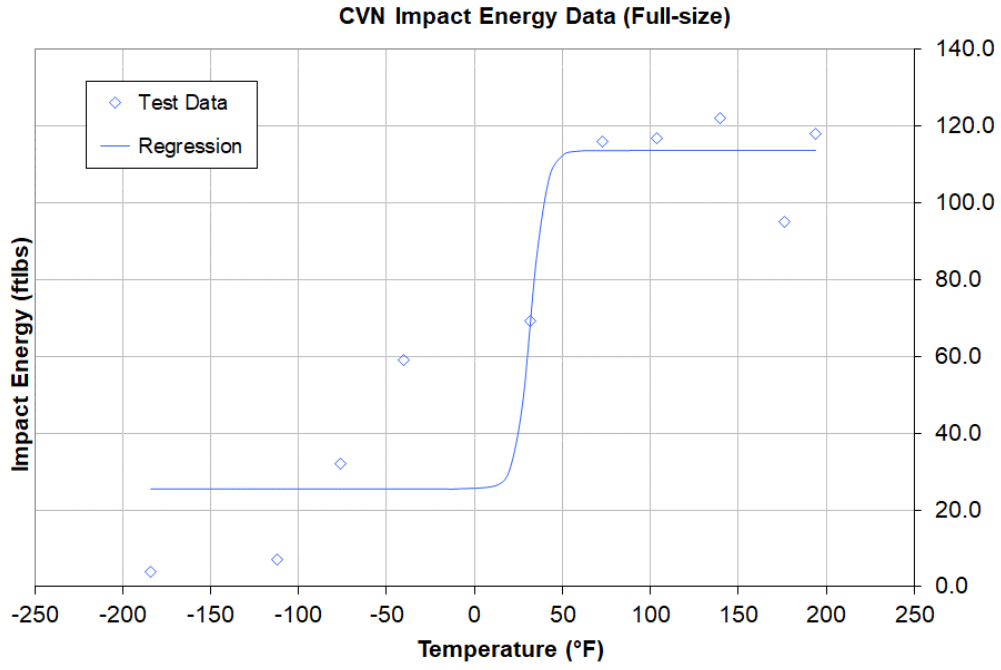


Figure 80. Charpy V-notch impact energy as a function of temperature for axial/cross-girth weld (HAZ notch) specimens removed from Pipe Section C.

ABOUT DNV GL

Driven by our purpose of safeguarding life, property, and the environment, DNV GL enables organizations to advance the safety and sustainability of their business. We provide classification and technical assurance along with software and independent expert advisory services to the maritime, oil and gas, and energy industries. We also provide certification services to customers across a wide range of industries. Operating in more than 100 countries, our professionals are dedicated to helping our customers make the world safer, smarter, and greener.

Appendix D

Responses to Questions Provided by PHMSA 4/7/2021

Questions and responses related to the Denbury Yazoo County RCA Final Report dated 8/7/2020:

1. **The metallurgy report does not reference chain-of-custody. Were chain-of-custody procedures used**

   Chain of custody procedures were used for collection and transport of the failed pipe section and samples. Copies of the chain-of-custody documentation have been provided to PHMSA and have been added to the appendices of this report.

2. **Copy and discussion of welding procedure used needed**

   A summary of the review of Denbury's welding procedure for the Delhi 24-inch Transmission Line utilized for original construction is provided below:

   Material: In this case the pipe material was high strength API 5L-X80-PSL2, 24-inch diameter, and 0.54-inch wall thickness.
   It is a requirement of the welding procedure that it produce a completed girth weld with similar strength properties of the pipe's base metal. This helps to ensure that the strains caused by loads imposed on the completed pipeline structure, do not concentrate in the vicinity of the weld. Another important aspect of the welding procedure is that it mitigates the risk of hydrogen embrittlement, which could lead to hydrogen cracking at the weld.

   There are 3 requirements for hydrogen cracking:
   a) Hydrogen in the weld,
   b) A crack susceptible microstructure, and
   c) Tensile stresses acting on the weld

   Weld Material: The Welding Procedure Specification WPS 14 indicates the use of the following electrodes:
   a) Root Bead: E6010
   b) Hot: E9010-G
   c) 1st Fill: E10045 P2 H4R
   d) Fill (s): E10045 P2 H4R
   e) Cap (s): E10045 P2 H4R

   Post Weld Heat Treatment: Not recommended

   Comments:

   1) Cellulosic-coated electrodes (AWS EXX10-type) contain moisture and organic compounds in the electrode coatings and result in a considerable amount of hydrogen in the weld. In the Denbury procedure electrode AWS E6010 and E9010-G were used for the root and hot pass in conjunction with low-hydrogen electrodes for the fill and cap passes. The Welding Procedure indicated that this is permissible because the heat from the fill and cap passes allows the hydrogen from the first 2 passes to diffuse out of the weld.

2) Electrode E10045 P2 H4R was used as a strength level low hydrogen downhill electrode. Only consumables with a maximum diffusible hydrogen content of 4ml/100g of deposited weld metal were selected for this case. “H” stands for hydrogen, the “4” stands for a maximum of 4ml of hydrogen per 100 grams of deposited weld metal, and “R” means the consumable is resistant to absorbing moisture from atmospheric conditions. During the qualification procedure, this electrode was found to be the most suitable electrode for this project. After the destructive testing, it was determined that the 100 ksi electrodes were a better match for use on this particular X80 line material which has a yield strength approaching 100 ksi.
3) Samples obtained during the failure analysis were evaluated using standard microscopy techniques including stereographic evaluations, microscopic evaluation, and scanning electron microscopy. Five axial and cross-sections were removed from the failed girth weld and one from an intact weld for metallographic analysis.

Actual findings during the failure analysis process:

a) There was no evidence of pre-existing manufacturing or welding flaws,
b) No indications of excessive porosity and/or inclusions,
c) Slight misalignment of high-low weld in the failed girth weld between 2.6% and 6.9% of the NWT,
d) Grain elongations due to the cold work that took place during the rupture process which is consistent with ductile overloading (see fig. 21 of the Mears report),
e) The sample obtained from the intact GW presented a similar morphology to the previous mounts. The high-low weld misalignment at this location was 4.6% of the NWT. The metallography of the section does not indicate a presence of a martensitic phase.
f) Hardness measurements were conducted on all metallographic cross sections. The values ranged between 205 and 304 HV. All the values were found to be in accordance with the applicable standards. Hardness testing of the failed weld presented variability that is likely associated with cold work sustained during the failure. The intact weld was the best representation of the base hardness of the pipe metal. The results indicate lower hardness of the weld metal compared to the pipe metal, which indicates that the weld metal is softer than the parent metal, however tests results were consistent with specifications for pipe of this vintage and yield strength in both the base metal and weld metal. Typically, the parent metal is harder than the weld metal. The axial tensile tests on the intact GW show similar failure to the actual failed pipe sample, further indicating that the lower hardness typical of the weld was the preferred location for the overload failure under applied axial stress. (See fig. 39 of the Mears report).
g) The mechanical testing indicated the average yield (YS) and ultimate tensile strength (UTS) meet the requirements for API X80M PSL 2 Line pipe. The average UTS of duplicate axial specimens taken from the intact girth weld was 103.3 ksi. The same applies to the Charpy V-Notch Testing.

Based upon review of the welding procedure, we conclude that:

1) The Welding Procedure Specification WPS 14 was appropriate to be use as a welding process for the material involved in this project.

2) The testing performed on the samples obtained during the failure investigation indicate that the welds showed that the microstructure and the mechanical properties of the base material and girth weld were in accordance with industry accepted standards.

3. **Report states on page iv: "The exact location of the initiation could not be determined due to a lack of chevrons on the fracture surfaces and the fact that no significant pre-existing (prior to failure) cracks were identified." "no significant" how was this determined?**

   The failure surfaces were inspected visually and optically for indications of surface oxides associated with development and deepening of cracks over an extended period. The lack of oxides precludes the possibility of pre-existing cracks and supports the determination that the failure occurred due to a sudden axial stress. In addition, the visual and optical inspections did not identify any marks or indications on the surface of the fracture that indicated an initiation point of the failure.

4. **The section on page 7 describes figures 53 and 54 and describes the area as "mainly ferrite". Specifically characterize the complete microstructure of the pipe and the weld metal.**

   Figures 53 and 54 of the DNV Metallurgical Analysis Report (Section 3.4) characterize the microstructure of the upstream and downstream pipe. Analysis of these photomicrographs indicate a significantly larger amount of ferrite than pearlite, which is consistent with the expected microstructure for pipe with the specified minimum yield strength and vintage of the Delhi 24-inch pipeline. Compared with photomicrographs of metal samples provided through industry literature, the microstructure of the 24-inch pipeline has a low carbon content, consistent with other X-80 pipelines. The microstructure of the failed girth shows similar characteristics (see Figure 62 of the DNV Metallurgical Analysis Report.

5. **Provide the hardness montage for MU1**.

   The hardness montage for mount MU1 is provided in Figure 78 of the DNV Metallurgical Analysis Report (Appendix C).

6. **Section 3.5 on hardness testing indicates various areas related to the weld area, include a discussion of the welding procedure utilized to produce the weld.**

   Discussion of the welding procedure is provided in the response to question #2 above.

7. **Typically, there is narrowing of a tensile specimen due to the area reduction during tensile overload. In this case was there a measurable necking down of the wall thickness adjacent to the fracture surface**

Evaluation of the metallurgical samples indicated slight reduction in wall thickness in each sample, ranging from 1.44% to 6.46%. Photos and measurements are provided in in figures 1 through 5 below:

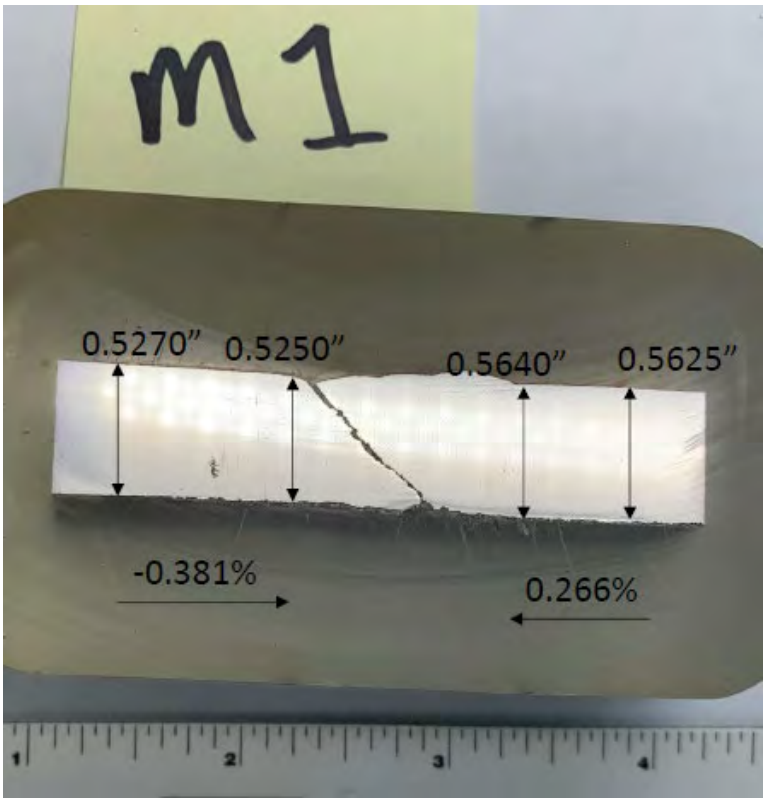


Figure 1: Cross-Sectional Measurements, Mount M1

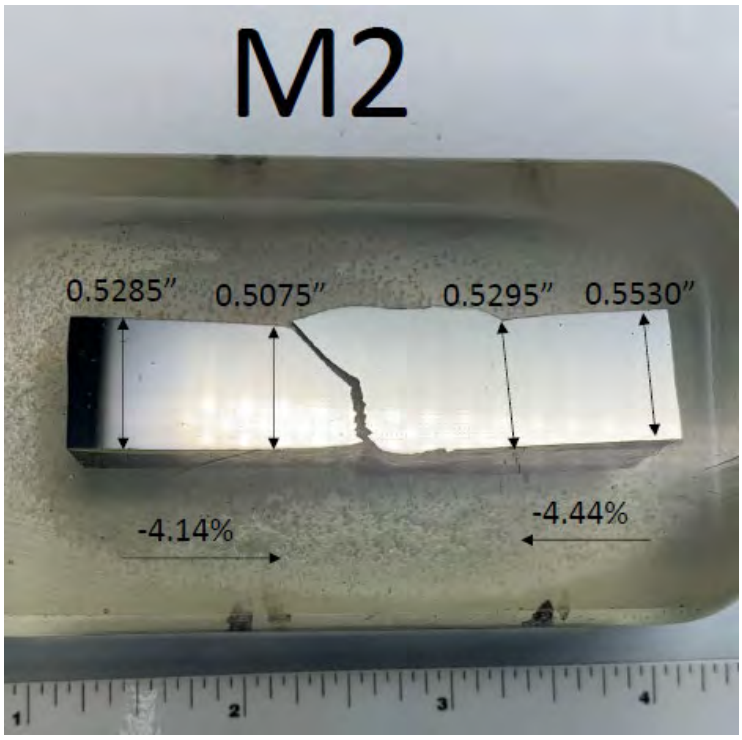


Figure 2: Cross-Sectional Measurements, Mount M2

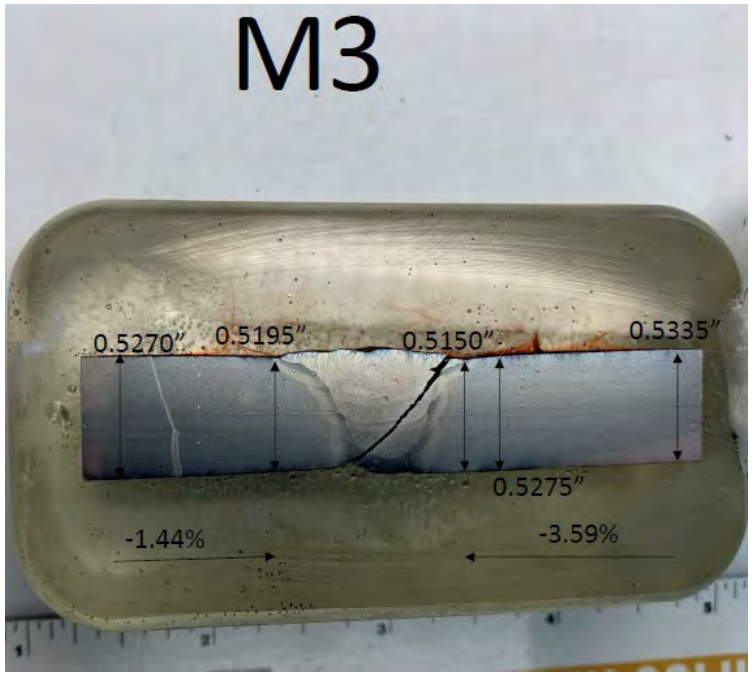


Figure 3: Cross-Sectional Measurements, Mount M3

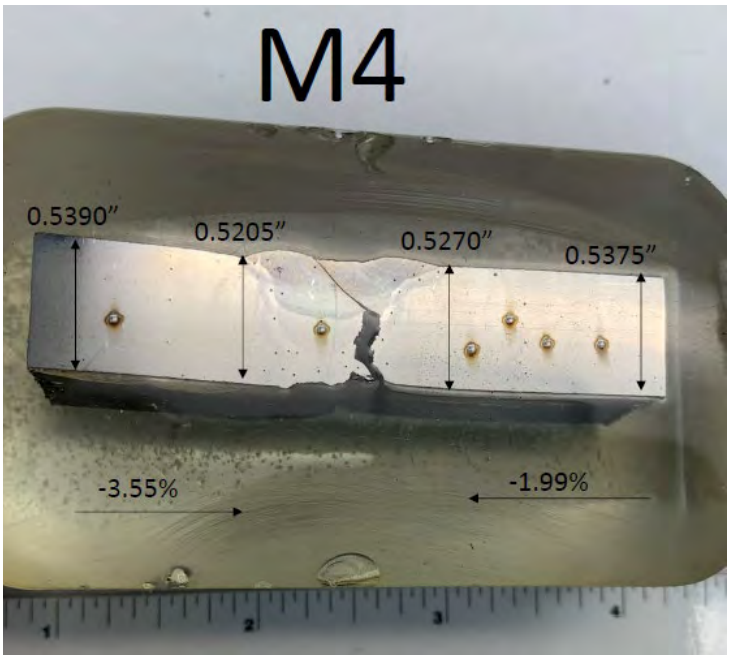


Figure 4: Cross-Sectional Measurements, Mount M4

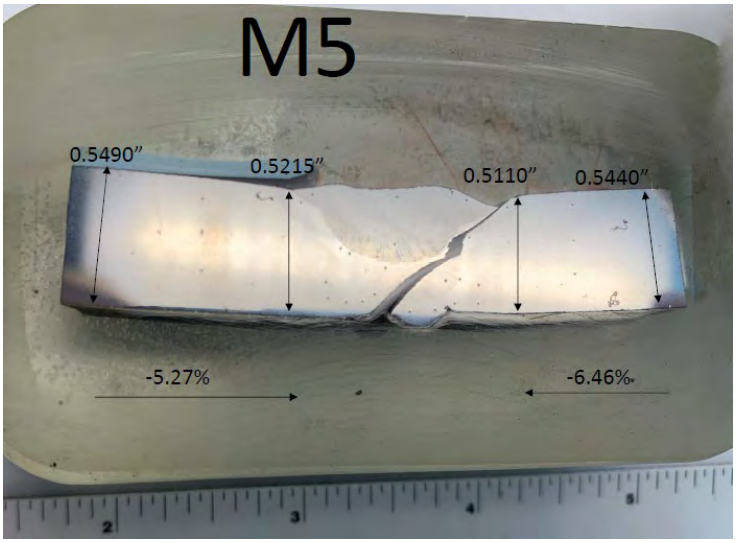


Figure 5: Cross-Sectional Measurements, Mount M5

These results are consistent with the characteristics of API X80M PSL 2 Line pipe.

8. Intact girth weld was tensile tested – compare and contrast fracture appearance of tested intact weld to failed girth weld

The average UTS of the axial specimens taken from the intact girth weld was 103.3 ksi, and both samples failed in the girth weld (DNV Metallurgical Analysis Report, section 3.6). While visual examination of the tensile sample fractures will confirm the location of each fracture, a comparison of the samples would only provide confirmation of the location of each fracture and not provide additional insight as to the reason for the failure, as the applied stresses would not be similar. The Pipeline Stress Analysis Report

provided by Mott MacDonald provides information related to the stress analysis associated with this failure.

9. Was leak before fracture mode of failure considered

Occurrence of a leak prior to the failure was considered, however the available information supports a rupture of the pipeline, including the following:

1) There was no indication of a pre-existing defect that would have contributed to a leak and a specific failure initiation site was not apparent.
2) Based upon a witnessed examination of the pipe, there was no evidence of internal or external corrosion that may have contributed to the failure mode.
3) No indication of a leak prior to the failure was identified in operating pressure trends.

10. Failure mode and influence of CO2 on ductile/brittle transition considering leak before rupture

Based upon the metallurgical examination, there is no evidence a leak occurred prior to the failure, therefore brittle failure mode is not feasible.

11. Chemistry of weld needed as this was a girth weld failure

Chemical analysis of the GW was not performed during the investigation. The mechanical testing results were within the accepted criteria during the preparation of the Welding Procedure Specification WPS 14. No additional testing of the chemistry of the girth weld was considered necessary based upon the results of the testing conducted.

12. Report states failure caused by large axial stress but fails to quantify strain

The Pipeline Stress Analysis Report provided by Mott MacDonald identified a stress ratio approximately 43% greater than allowable stresses per ASME B31.4 (2016).

13. Strain analysis would be an input for a geohazard management plan

The Pipeline Stress Analysis Report provided by Mott MacDonald provides information related to the strain analysis associated with this failure.

14. Brittle (cleavage facets) mode of failure noted, but no chevrons – significance

V-shaped chevron markings are characteristic of brittle fracture. These markings may indicate the origin of the fracture, however in this case no chevrons were identified.

15. Explanation of ductile/brittle appearance of the failed girth weld

As described in section 5.3 of the Mears report, the samples were evaluated utilizing standard microscopy techniques including stereographic evaluations, microscopic evaluation and scanning electron microscopy. Five (5) axial and cross-sections were removed from the failed girth weld and one (1) from the intact weld for metallographic analysis. Some of the samples contain fracture paths at a shear angle (fracture path through the smooth surfaces) and other show the fracture path perpendicular to the free surface and regions of shear failure (fracture surface is rough). The appearance of these surfaces further support the mode of failure as described in the executive summary of the DNV Metallurgical Analysis Report "The results of the metallurgical analysis indicate that the failure initiated at a field girth weld, due to axial stresses sufficient to produce overload failure. No pre-existing flaws were present on the fracture surface. A contributing factor was that the pipe steel was stronger than the girth weld."

16. Correlation of hardness areas and welding procedure

Hardness measurements were conducted on all metallographic cross sections. The values ranged between 205 and 304 HV. All the values were found to be in accordance with the applicable standards. Hardness testing of the failed weld presented variability that is likely associated with cold work sustained during the failure. The intact weld was the best representation of the base hardness of the pipe metal. The results indicate lower hardness of the weld metal compared to the pipe metal. Which indicates that the weld metal is softer than the parent metal, which was in accordance with the results of the welding qualification. Typically, the parent metal is harder than the weld metal. The axial tensile tests on the intact GW show similar failure to the actual fracture to the actual fracture, further indicating that the lower hardness typical of the weld was the preferred location for the overload failure under applied axial stress. (See fig. 39 of the Mears report).

17. How does the welding procedure tensile tests compare to the intact weld tensile tests

The mechanical testing indicated the average yield (YS) and ultimate tensile strength (UTS) meet the requirements for API X80M PSL 2 Line pipe. The average UTS of duplicate axial specimens taken from the intact girth weld was 103.3 ksi. The same applies to the Charpy V-Notch Testing (see section 5.6.2 of the Mears RCA Final Report).

The results of the Procedure Qualification Record (PQR 14a) indicated cross weld UTS of 115.6 ksi to 117.3 ksi. Per the Welding Procedure Development and Qualification for X80 Line Pipe, dated 8/13/2008, section 3.1, "After destructive testing it was determined that the 100 ksi electrodes were a better match for use on this particular X80 line pipe material, which has a yield strength approaching 100 ksi." Therefore test results from the mechanical testing of the intact girth weld are consistent with the pipeline's specifications.

Appendix E

Chain of Custody Documentation

mears
A QUANTA SERVICES COMPANY

STEP 2 – CHAIN OF CUSTODY

1. ORIGINATING LOCATION – Denbury Delhi 24 inch Transmission	
Contact Person: Seth Bayham	*Phone Number: (225) 202-1402*
Title: Corrosion Foreman	*Date: 3/10/2020*
Contact Address: 31589 Netterville Rd, Denham Springs, LA 70726	
Material Location, City, State: 688 MS 433, Sartitia, MS	
Signature: Seth Bayham	*Date:* 3/10/2020

2. AUTHORIZATION FOR RELEASE	
Authorized by: Seth Bayham	*Phone Number:* (225) 202-1402
Title: Corrosion Foreman	*Date:* 3-10-20
Department:	
Authorization provided (check one): _____ *by Telephone* ✓ *in Person* _____ *in Writing*	

SHIPPING INSTRUCTIONS

Samples should be shipped to DNV GL 9037 Heritage Drive, Plain City, OH 43064. Please contact Greg Quickel. Phone: (614) 378-4083.

3. ITEMS TRANSFERED	
Reference Number: Delhi 24-3 *Sample Identifier: Sample A* *Date Collected: 3/09/2020*	*Description: 24" diameter by 6' long pipe sample (D/S failure section)*
Reference Number: Delhi 24-4 *Sample Identifier: Sample B* *Date Collected: 3/09/2020*	*Description: 24" diameter by 6 ' long pipe sample (U/S failure section)*
Reference Number: Delhi 24-5 *Sample Identifier: Sample C* *Date Collected: 3/09/2020*	*Description: 24" diameter by 8' long pipe sample (U/S pipe section containing exemplar weld)*
Reference Number: *Sample Identifier:* *Date Collected:*	*Description:*
Reference Number: *Sample Identifier:* *Date Collected:*	*Description:*

CHAIN OF CUSTODY RECORD FOR SAMPLE A, B, C

☒ Received from Denbury Resources Date: 3/10/hr 1:30P Received by P. Jo. Reid
Reason for transfer

From: Company: Denbury Resources Signature
To: Company: Reid's Dozer service Signature P-JOE REID

Until the time you transferred custody of sample
To recipient listed above, has (have) this (these) item (s) left your custody, control at any time:
YES
NO

If YES, please explain:

Signature

CHAIN OF CUSTODY RECORD FOR SAMPLE A, B, C

□ Received from Reid's Dozer Service Date: 3/12 /hr 8:10 Received by Greg Quickle

Reason for transfer Testing at DNVGL

From: Company: Reid's Dozer Sevice Signature P-JOE REID
To: Company: DNV GL Signature Greg Quickel

Until the time you transferred custody of sample A, B, C
To recipient listed above, has (have) this (these) item (s) left your custody, control at any time:
YES
✓ NO

If YES, please explain:

Signature P-JOE REID

DNV GL USA, Inc.
Materials & Corrosion Technology Center
Incident Investigation
5777 Frantz Road
Dublin, OH 43017-1886
Tel: (614) 761-1214
Fax: (614) 761-1633
www.dnvgl.com

DNV·GL

CHAIN OF CUSTODY FORM

Project No.: 10206282 Sample: 24" @ Denbury

1. ORIGINATING LOCATION	
Contact Person: Greg Quickel	Phone No.: 614 378 4083
Title: Principal Eng	Date: 9/30/2020
Contact Address: See above	
Material Location, City, State:	
Signature: Greg Quickel	Date: 9/30/2020

Description of Evidence	Date Evidence Placed into Controlled Custody:
24" @ Denbury Failure	
Four pipe sections	
One box of samples (met/FS.)	Date Evidence Released from Controlled Custody: 9/30/2020
Two bags of soil from pipe	
Five steel coupons for mech testing	
Two bags of mech specimens	
	Release of Evidence Authorized by:
Received by:	

	Date	Time
Signature: Kurt Hahn Reason: TRANSFER	9/30/20	
Signature: _____ Reason: _____		
Signature: _____ Reason: _____		

Appendix F

Welding Procedure Development and Qualification for X80 Line Pipe

8/13/2008

FINAL REPORT

PROJECT CONSULTING SERVICES, INC.

WELDING PROCEDURE DEVELOPMENT AND QUALIFICATION FOR X80 LINE PIPE

PROJECT NO. 82681591
AUGUST 13, 2008

DET NORSKE VERITAS

FINAL REPORT

Date of Issue:
August 13, 2008

Project No.:
82681591

CC TECHNOLOGIES, INC.
Integrity & Materials

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Authored By:
Brad Etheridge
Engineer
Welding Technology

Reviewed By:
Bill Bruce
Director
Welding Technology

Approved By:
Patrick H. Vieth
Senior Vice President
Integrity & Materials

Client:
Project Consulting Services, Inc.

Summary:

CC Technologies, Inc. (CCT) was retained by Project Consulting Services, Inc. to develop and qualify welding procedures for 24 inch by 0.54 inch grade X80 line pipe. Several different production, repair, and in-service procedures were developed. These procedures were run at a Progressive Pipeline Inc. facility in Meridian, Missipppi under the supervision of a representative from CCT. The welds were sent to an independent laboratory for destructive testing. CCT then created welding procedure specifications and procedure qualification records for welds that passed all testing.

Project No:	Subject Group:	Date :	Number of Pages:
82681591	Welding Technology	August 13, 2008	6

Report Title:

Welding Procedure Development and Qualification for X80 Line Pipe

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Appendix A. Letter Report Pertaining to the Use of AWS E8010-G Electrodes for X80 Pipelines

Appendix B. Letter Report Pertaining to the Use of Cellulosic-Coated Electrodes for X80 Pipelines

FINAL REPORT

1. PROJECT SCOPE

CC Technologies, Inc. (CCT) was contracted by Project Consulting Services Inc. (PCS) to create and qualify welding procedure specifications (WPS) and procedure qualification records (PQR) for the construction of two 24-inch diameter x 0.54 inch wall thickness, API 5L-X80-PSL2 pipelines as per the requirements of the 19th and 20th editions of API 1104. A variety of procedure qualifications were performed so as to give PCS's client, Denbury Resources Inc. (DRI), options when selecting welding processes and consumables for construction. CCT was also asked to use their welding experience and expertise to identify the most appropriate welding procedures for the construction, maintenance, and repair of these pipelines. Procedure qualifications were performed using welding consumables and process that were suggested by PCS/DRI and using welding consumables and process that were determined by CCT to be acceptable alternatives to those suggested by PSC/DRI.

2. WORK PERFORMED

CCT attended a project kick off meeting in Birmingham, Alabama on April 2, 2008 at the PCS office. The goal of this meeting was to discuss what consumables to use for the construction of two new X80 pipelines that will operate in carbon dioxide service. When welding higher strength line pipe material such as X80, several concerns need to be addressed including weld strength level and the risk of weld metal hydrogen cracking.

In most welding applications, including pipeline girth welding, it is desirable for the weld to overmatch the strength of the base material. This ensures that the strains caused by loads imposed on the completed structure do not concentrate in the vicinity of the weld. Welds are more likely to contain discontinuities than base materials, so it is desirable to avoid the concentration of strains in the vicinity of welds. A letter report pertaining to the use of welding consumables and process that were suggested by DRI for construction of these pipelines, from the prospective of weld strength level, is shown in Appendix A.

There are three requirements for hydrogen cracking; hydrogen in the weld, a crack-susceptible weld microstructure, and tensile stresses acting on the weld. Cellulosic-coated electrodes (AWS EXX10-type) contain moisture and organic compounds in the electrode coatings and result in a considerable amount of hydrogen in the weld. Traditionally, heat-affected zone (HAZ) microstructures have been considered to be the most susceptible to hydrogen cracking. With the introduction of higher strength line pipe steels with good weldability, and the higher strength welding consumables required to weld them, weld metal microstructures are now as susceptible (if not more so) than HAZ microstructures. A letter report pertaining to the use of cellulosic-coated electrodes for construction of these pipelines, from the prospective of hydrogen cracking risk, is shown in Appendix B.

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CCT was asked to provide alternatives to traditional cellulosic-coated electrodes in the form of low-hydrogen consumables and processes. CCT provided several low-hydrogen alternatives to be qualified along with cellulosic-coated electrode procedures requested by DRI. These procedures were qualified, documented, and the completed WPS's and PQR's delivered to PCS.

The procedure qualifications were performed at a Progressive Pipeline Inc. facility in Meridian, Mississippi. A CCT employee was onsite during procedure qualification to provide support and record relevant welding parameters. The first round of welding procedure qualifications took place April 14 through 18, 2008. WPS 4 through WPS 11 (Table 1) were conducted during this first round of welding. A typical setup for these procedures is shown in Figure 1. A 2 foot long length of pipe was welded onto a longer piece of pipe using an external lineup clamp. The preheat was applied using propane with rosebud torches. These welds were inspected by radiography before being sent for destructive testing to prevent incurring the cost of performing destructive testing on welds that may contain unacceptable discontinuities. A second round of procedures was performed at the same location May 12 through 17, 2008. The procedures performed in May were WPS 14 through WPS 20 (Table 1) and included two in-service repair procedures for the installation of a tight fitting Type B repair sleeve, as shown in Figure 3.

3. RESULTS

3.1 Pipeline Girth Welding

A total of 12 procedures were qualified, a complete list of the procedures can be found in Table 1. The low-hydrogen procedures are WPS 7 through WPS 11 and WPS 17 through WPS 20. All of the other procedures involve the use of cellulosic-coated electrodes exclusively. Except for the in-service procedures (WPS 19 and 20), all of the procedures use cellulosic-coated electrodes for the root pass and the hot pass. For pipeline girth welding on thicker-wall X80 line pipe material, it is typically acceptable to use cellulosic-coated electrodes for the root and hot pass in conjunction with low-hydrogen consumables for the fill and cap passes. This is permissible because the heat from the fill and cap passes allows the hydrogen from the first two passes to diffuse out of the weld.

Three different types of low hydrogen consumables were used; low hydrogen down-hill stick electrodes (AWS EXX45-type), traditional up-hill low-hydrogen stick electrodes (AWS EXX18-type) and gas-shielded flux-cored arc welding wire (AWS E101T1-type). These consumables were used with the manual shielded metal arc welding (SMAW) process and the semi-automatic flux-core arc welding (FCAW) processes, respectively. Traditional vertical up low-hydrogen electrodes (E10018-G H4R) were used for a single repair procedure, WPS 11. Two different strength levels of the low hydrogen down-hill electrode (E9045 P2 H4R and E10045 P2 H4R) were used during the first set of welding trials. These strength levels represent the minimum ultimate tensile strength of the consumable. After destructive testing it was determined that the 100 ksi electrodes were a better match for use on this particular X80 line

pipe material, which has a yield strength approaching 100 ksi. During the second round of procedure qualifications the E10045 P2 H4R electrodes were the only low hydrogen down-hill electrodes used.

3.2 In-Service Welding

When qualifying welding procedures to be used on pipelines that are in-service, it is good practice to simulate in-service operating conditions. This is important because of the effect that the flowing contents in the pipeline has on the weld cooling rate. The flowing contents act as a heat sink when welding onto the carrier pipe, which causes the weld to solidify and cool extremely quickly. This in turn can promote the formation of crack-susceptible weld microstructures and cause large amounts of hydrogen to become trapped in the weld, if good low hydrogen welding techniques are not used. It is therefore critical to use welding processes and consumables that produce welds with a low amount of diffusible hydrogen.

For this reason, only consumables with a maximum diffusible hydrogen content of 4ml/100g of deposited weld metal were used. Notice the "H4R" designation at the end of the consumable specification in column 5 of Table 1. The "H" stands for hydrogen, the "4" stands for a maximum of 4 ml of hydrogen per 100 grams of deposited weld metal, and the "R" means the consumable is resistant to absorbing moisture from atmospheric conditions.

The setup used for the in-service welding procedure qualification can be seen in Figure 4. To create this testing rig, a section of pipe is enclosed by welding end caps to the open ends. A nozzle for an ordinary garden hose is installed on both ends of the vessel. This allows water from the faucet to flow through the pipe section while welding is performed. A valve was installed on the top of the pipe close to the end where the water exits to allow for air to be vented, ensuring the pipe is completely full of water. That end of the pipe was slightly elevated, which ensures that no air bubbles become trapped along the top of the pipe. Water flow was maintained during welding and continued until the welds cooled to room temperature.

3.3 Documentation

WPS and PQR combinations for each of the procedures that passed destructive testing were provided to PCS.

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Table 1. Qualified Welding Procedures Specifications.

Procedure	Type	Root Pass Consumable Specification	Hot Pass Consumable Specification	Fill and Cap Pass Consumable Specification
WPS 4	Production	E6010	E9010-G	E9010-G
WPS 7	Production	E6010	E9010-G	E9045 P2 H4R
WPS 8	Repair	E6010	E9010-G	E9045 P2 H4R
WPS 9	Production	E6010	E9010-G	E10045 P2 H4R
WPS 10	Repair	E6010	E9010-G	E10045 P2 H4R
WPS 11	Repair	E6010	E9010-G	E10018-G H4R
WPS 14	Production	E6010	E9010-G	E10045 P2 H4R
WPS 15	Repair	E6010	E9010-G	E10045 P2 H4R
WPS 16	Repair	E6010	E9010-G	E9010-G
WPS 17	Production	E6010	E9010-G	E101T1-GM-H8
*WPS 19	Sleeve	E10045 P2 H4R	E10045 P2 H4R	E10045 P2 H4R
*WPS 20	Sleeve	E101T1-GM-H4R	E101T1-GM-H4R	E101T1-GM-H4R

*In-service weld.

FINAL REPORT

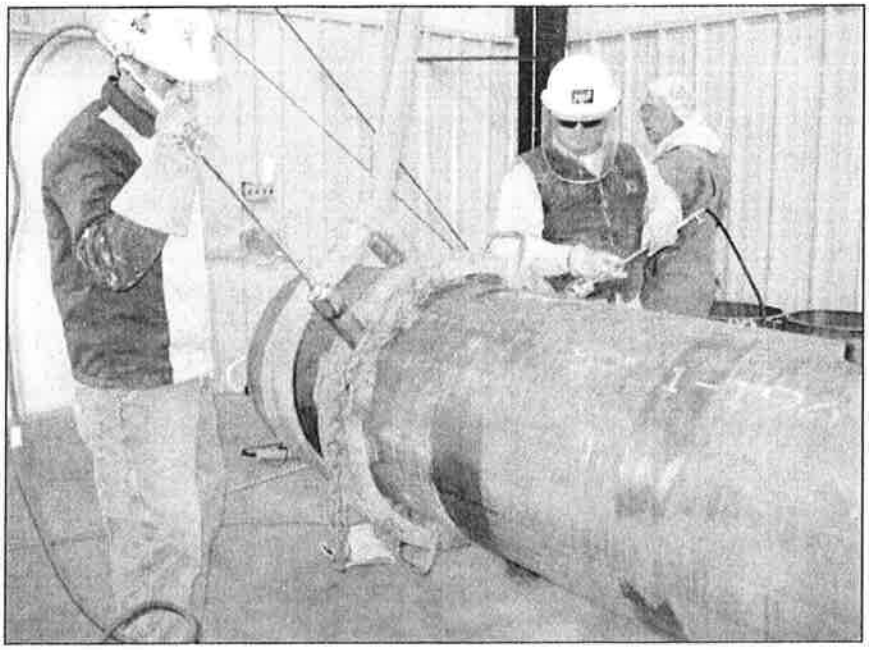


Figure 1. Typical setup for girth weld procedure qualification.



Figure 2. Typical completed girth weld coupon after cutting.

FINAL REPORT



Figure 3. In-service tight-fitting repair sleeve.

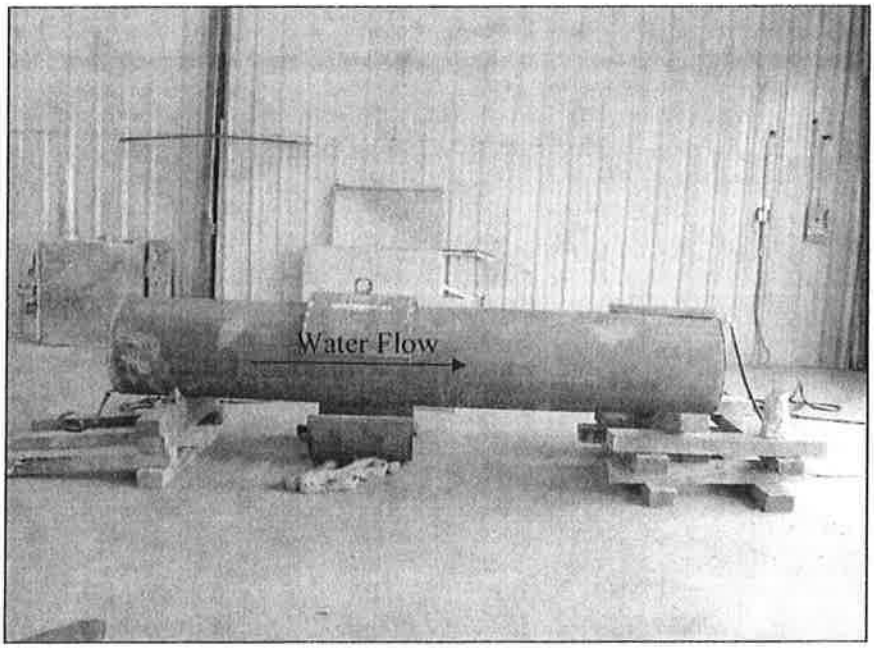
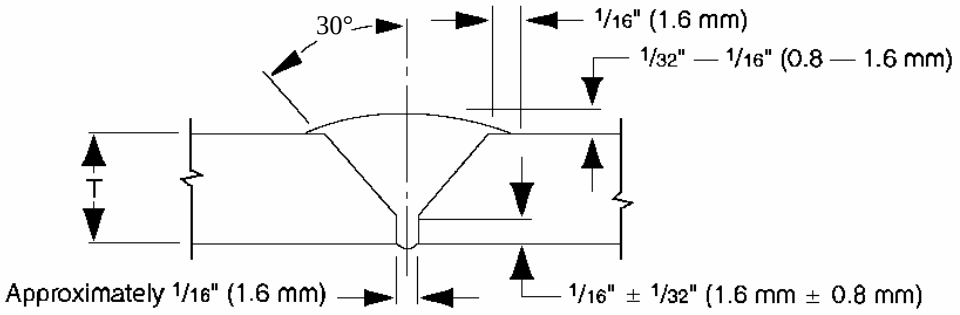
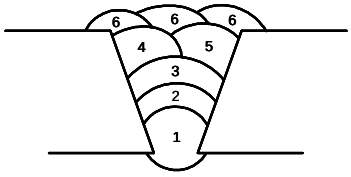


Figure 4. Setup for in-service welding procedure qualification.

Appendix G

Welding Procedure Specification WPS 14

6/18/2008

Scope of Procedure	This welding procedure specification details the procedure to be followed for the production of field butt welds in line pipe as required by the 19th and 20th editions of API 1104, Welding of Pipelines and Related Facilities			
Applicable Codes and Specifications	■ 19th & 20th Editions of API 1104 ☐ DOT 49 CFR Part 195 ☐ DOT 49 CFR Part 192	☐ ASME B 31.3 ☐ ASME B 31.4 ☐ ASME BPVC Section IX	☐ ASME B 31.8	
Supporting PQR	PQR: PQR-14a		Date Qualified: 5/14/08	
	Witnessed By: Brad Etheridge		Location: Meridian, Mississippi	
Materials	Grades Qualified	X80	PQR Material	API 5L – X80 - PSL2
	Qualified Diameter Range	All	Diameter of PQR	24 inches
	Qualified Wall Thickness Range	from 0.188" through 0.750"	Wall Thickness of PQR	0.54 inches
API 1104 Material Groupings Qualified	Diameter (inch)	☐ OD < 2.75 ☐ 2.75 < OD ≤ 12.750 ■ OD ≥ 12.750		
	Wall Thickness (inch)	☐ WT < 0.188 ■ 0.188 ≤ WT ≤ 0.750 ☐ WT > 0.750		
	SMYS (psi)	☐ ≤ 42,000 ☐ 42,000 < SMYS < 65,000 ■ ≥ 65,000		
Joint Design				
Position of Pipe Axis	■ Horizontal (1G or 5G) ☐ Vertical (2G) ☐ Inclined (6G)	■ Fixed ☐ Rolled	Generic Bead Sequence 	
Minimum Number of Welders	☐ One ■ Two ☐ Other			
Line Up Clamp	Type: External or Internal	A minimum of 50% the root bead must be completed before removal of the clamp.		
Preheating	Gas torch, electric induction coils, or any other company approved method. Verify temperature using company approved method	Preheat Temp. Min.	200℉	
		Interpass Temp. Max.	N/A	
		Interpass Temp. Min.	200℉	

Time Between Passes	Root and Hot	5 minutes	Hot and First Fill		24 hours
Cleaning	The use of both hand and power tools is acceptable. The base material should be free of scale or anything else that may impede welding before the start of any welding. Each pass should be thoroughly cleaned and free from slag and spatter before the next pass is made.				
Defect Removal	The only area that may be repaired is the weld cap. Other repairs are to be addressed by qualified repair welding procedures. Defects in the cap should be removed by grinding and welding shall follow the guidelines set forth in this procedure.				
Post Weld Heat Treatment	☐ Yes ■ No				

Welding Pass	Root Bead	Hot	1st Fill	Fill(s)	Cap(s)
Welding Process	SMAW	SMAW	SMAW	SMAW	SMAW
Manual or Automatic	Manual	Manual	Manual	Manual	Manual
Direction of Welding	Vert. Down	Vert. Down	Vert. Down	Vert. Down	Vert. Down
Shielding Gas	N/A	N/A	N/A	N/A	N/A
Flow Rate	N/A	N/A	N/A	N/A	N/A
Wire Feed Speed	N/A	N/A	N/A	N/A	N/A
Deposition Type	Stringer	Stringer/Weave	Weave	Weave	Weave
Technique	Backhand	Backhand	Backhand	Backhand	Backhand
Filler Manufacturer	Lincoln	Lincoln	Lincoln	Lincoln	Lincoln
Filler Trade Name	Fleetweld 5P+	Shield-Arc 90	LH-D100	LH-D100	LH-D100
AWS Group	1	2	3	3	3
AWS Specification	A5.1	A5.5	A5.5	A5.5	A5.5
AWS Classification	E6010	E9010-G	E10045 P2 H4R	E10045 P2 H4R	E10045 P2 H4R
Polarity	DCEP	DCEP	DCEP	DCEP	DCEP
Electrode Diameter(s)	1/8"* or 5/32"	5/32"	5/32"	5/32"	5/32"
Arc Voltage (V)	20 - 32	20 - 30	18 - 26	18 - 26	18 - 26
Current Range (Amp)	100 – 150* 110 - 170	110 - 170	150 - 230	150 - 230	150 - 230
Travel Speed Range (inch/min)	5 – 15	5 – 15	5 – 20	5 – 20	5 – 20

Minimum number of Passes	Wall Thickness Range (in)	Number of passes	Minimum does not include stripper passes or split caps.
	≤ 0.188	3	
	> 0.188 to 0.25	4	
	> 0.25 to 0.50	5	
	> 0.50 to 0.750	7	

Notes	Weave the hot pass as necessary to prevent wagon tracks. Stripper passes are optional. Either a two or three bead cap is acceptable.		
Submittal	Author: Brad Etheridge	Title: Welding Engineer	
	Company: CC Technologies Inc. A DNV Company		Date: 5/30/08

Owner Approvals	Title	Name	Signature	Date

Company Name: Progressive Pipeline	Date: 5/14/08	Notes: Welding machine used was a Lincoln Red-D-ARC, D300K 3+3 Diesel	
Project Number:	Location: Meridian, MS @ Progressive Pipeline facility		
PQR #: 14a	Inside/Outside: Inside, with open bay doors		
WPS #: 14	Temperature: 78 inside shop		
Coupon #:	Recorded by: Brad Etheridge		

#	Material	OD	WT	Length	Joint ID #	Heat #	Test Position	Horizontal	Time between root and hot			2:55
1	API 5L - X80 - PSL2	24	0.54	2 feet	L	8791-1940-06	Preheat Temp	200	Time between hot and first			
2	API 5L - X80 - PSL2	24	0.54	N/A	R	8791-1943-06	Clamp Type	EXT	Start	9:41 AM	Stop	11:00 PM

Filler Metal #	Manufacturer	Trade name	Classification	Specification	Diameter	Batch/Lot #	Welder Information	
1	Lincoln	Fleetweld 5P+	E6010		5/32	11558962	Side A Welder	Randall Nunez
2	Lincoln	Shield-Arc 90	E9010	G	5/32	11558966	Welder Stamp	
3	Lincoln	LH-D100	E10045	P2 H4R	5/32	Lot Q2 863C	Side B Welder	Ken Abernathy
4							Welder Stamp	

Notes: External linup clamp used to tack 2 foot coupon onto long joint. The short side of the coupon is "R" and the long side is "L". Pass 2 and 3 were split passes; they were placed side by si

Pass Type/ Number / Welder ID	Filler #	Process	Travel Direction	Amps	Volts	Distance (in)	Arc Time (Sec)	Travel Speed (IPM)	WFS (IPM)	Heat Input (KJ/in)	Oscillation		Method	Welding Gas		Interpass Temp
											Freq cycle/sec	Width ( )	Stringer or Weave	Type	Flow ( )	( )
Root A	1	SMAW	VD	116	22	6	33	10.91		13.7			S			
Root A	1	SMAW	VD	118	23	2.25	14	9.64		16.5			S			
Root A	1	SMAW	VD	107	24	8	45	10.67		14.1			S			
Root B	1	SMAW	VD	128	23	9	54	10.00		17.3			S			
Root B	1	SMAW	VD	137	24	2.5	16	9.38		21.0			S			
Hot A	2	SMAW	VD	141	29	8	32	15.00		16.0			S/W			
Hot B	2	SMAW	VD	138	30	6	36	10.00		24.3			S/W			
Hot B	2	SMAW	VD	136	30	6	36	10.00		24.1			S/W			
Fill 1-1 A	3	SMAW	VD	194	22	7	50	8.40		30.4			S/W			
Fill 1-2 A	3	SMAW	VD	218	21	8.5	46	11.09		24.8			S/W			
Fill 1 A	3	SMAW	VD	208	24	13	51	15.29		19.2			S/W			

Pass Type/ Number / Welder ID	Filler #	Process	Travel Direction	Amps	Volts	Distance (in)	Arc Time (Sec)	Travel Speed (IPM)	WFS (IPM)	Heat Input (KJ/in)	Oscillation		Method	Welding Gas		Interpass Temp
											Freq cycle/sec	Width ( )	Stringer or Weave	Type	Flow ( )	( )
Fill 1-1 B	3	SMAW	VD	198	20	6.5	48	8.13		28.4			S/W			
Fill 1-3 B	3	SMAW	VD	216	20	8.5	48	10.63		24.4			S/W			
Fill 2-1 A	3	SMAW	VD	199	22	8.5	48	10.63		24.1			S/W			
Fill 2-3 A	3	SMAW	VD	215	20	8	43	11.16		23.1			S/W			
Fill 2-1 B	3	SMAW	VD	205	21	8.75	55	9.55		26.4			S/W			
Fill 2-2 B	3	SMAW	VD	199	20	12	55	13.09		17.8			S/W			
Fill 3-1 A	3	SMAW	VD	197	22	8.5	51	10.00		25.4			S/W			
Fill 3-3 A	3	SMAW	VD	176	21	8	35	13.71		16.1			S/W			
Fill 3-1 B	3	SMAW	VD	196	20	7.5	49	9.18		25.6			S/W			
Fill 3 B	3	SMAW	VD	201	20	8.75	49	10.71		21.9			S/W			
Fill 4-1 A	3	SMAW	VD	195	20	8	46	10.43		22.4			S/W			
Fill 4-3 A	3	SMAW	VD	215	20	9	36	15.00		17.2			S/W			
Fill 4-1 B	3	SMAW	VD	184	21	8.5	45	11.33		20.4			S/W			
Fill 5-1 A	3	SMAW	VD	195	21	8	42	11.43		21.4			S/W			
Fill 5 A	3	SMAW	VD	212	20	9	34	15.88		16.0			S/W			
Fill 5-1 B	3	SMAW	VD	205	20	13.5	53	15.28		16.1			S/W			
Fill 5 B	3	SMAW	VD	198	20	9.5	49	11.63		20.4			S/W			
Cap 1 A	3	SMAW	VD	205	20	7	42	10.00		24.6			W			

Pass Type/ Number / Welder ID	Filler #	Process	Travel Direction	Amps	Volts	Distance (in)	Arc Time (Sec)	Travel Speed (IPM)	WFS (IPM)	Heat Input (KJ/in)	Oscillation		Method	Welding Gas		Interpass Temp
											Freq cycle/sec	Width ( )	Stringer or Weave	Type	Flow ( )	( )
Cap 1 A	3	SMAW	VD	208	20	9.5	58	9.83		24.8			W			
Cap 1 B	3	SMAW	VD	198	20	9	37	14.59		16.3			W			
Cap 1 B	3	SMAW	VD	214	20	8	33	14.55		17.6			W			
Cap 2 A	3	SMAW	VD	201	20	7.5	44	10.23		23.6			W			
Cap 2 B	3	SMAW	VD	207	20	10	46	13.04		19.0			W			
Cap 2 B	3	SMAW	VD	212	20	7	27	15.56		15.9			W			

Bodycote

Bodycote Testing Group, Houston North Laboratory, 9925 Regal Row, Houston, Texas, 77040
Tel: 281-848-0270, Fax: 281-848-0275

ACCREDITED CERTIFICATE 1283.01

CC Technologies, Inc.
5777 Frantz Road
Dublin, OH
43017-1386

REF No O802887 : Issue 1
Ord No 82681591

Date Tested 06/02/08
Date Reported 06/02/08

Attn: Brad Etheridge

Item - 24" OD x 1/2" Wall girth welded pipe sample
WPS 14

Specification - API 1104 & Client Requirement

Cross Weld Tensile - API 1104

	Dimensions [in]	Area [in^2]	UTL [lbs]	UTS [psi]	Fracture Location	Fracture Type
001:Cross Weld	0.9770x 0.5440	0.5315	61872.0	116400	Base	Ductile
002:Cross Weld	0.9720x 0.5400	0.5249	61559.0	117300	Base	Ductile
003:Cross Weld	0.9810x 0.5330	0.5229	60659.0	116000	Base	Ductile
004:Cross Weld	1.0170x 0.5400	0.5492	63462.0	115600	Base	Ductile

Item 01: Quad 1
Item 02: Quad 2
Item 03: Quad 3
Item 04: Quad 4

Charpy Test - ASTM E 23

	Position	Dimensions [mm]	Denomination	Test Temp [°F]	Energy Absorbed [ft.lbf]	Average [ft.lbf]	Comments
005:Weld Centre Line	N/A	10x10x2V	N/A	32.0	79, 69, 70	72.7	See Below
006:Weld Centre Line	N/A	10x10x2V	N/A	-50.0	45, 39, 29	37.7	See Below
007:Weld Centre Line	N/A	10x10x2V	N/A	-80.0	15, 31, 14	20.0	See Below

Item 05: Percent Shear: 85, 80, 75 / Mils Lat Exp: 58, 53, 46
Item 06: Percent Shear: 25, 35, 10 / Mils Lat Exp: 33, 25, 21
Item 07: Percent Shear: 10, 20, 10 / Mils Lat Exp: 12, 24, 14

Bend Test - API 1104

	Position	Dimension [in]	Bend Angle [°]	Former Dia	Result	Comments
008:Face Bend	Quad 1	.500	180	3.5"	Acceptable	Nil

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CC Technologies, Inc.
24" OD x 1/2" Wall girth welded pipe sample
WPS 14

REF No O802887 : Issue 1

Bend Test - API 1104

	Position	Dimension [in]	Bend Angle [°]	Former Dia	Result	Comments
009:Face Bend	Quad 2	.500	180	3.5"	Acceptable	Nil
010:Face Bend	Quad 3	.500	180	3.5"	Acceptable	Nil
011:Face Bend	Quad 4	.500	180	3.5"	Acceptable	Nil
012:Root Bend	Quad 1	.500	180	3.5"	Acceptable	Nil
013:Root Bend	Quad 2	.500	180	3.5"	Acceptable	Nil
014:Root Bend	Quad 3	.500	180	3.5"	Acceptable	Nil
015:Root Bend	Quad 4	.500	180	3.5"	Acceptable	Nil

Nick Break Test - API 1104

	Result	Comments
016:Weld	Unacceptable	Quad 1
017:Weld	Acceptable	Quad 2
018:Weld	Acceptable	Quad 3
019:Weld	Unacceptable	Quad 4

Approved By **Jim Blevins**

Jim Blevins
For and on authority of
Bodycote Testing Group

The failed two nick break tests were replaced by four acceptable retests of adjacent specimens. This is common practice in welding procedure qualification testing. The retest results can be found on the next page.

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Page 2 of 2

Bodycote MATERIALS TESTING
METAL TECHNOLOGY
Bodycote Testing Group, Houston North Laboratory, 9925 Regal Row, Houston, Texas, 77040
Tel: 281-848-0270, Fax: 281-848-0275

ACCREDITED CERTIFICATE 1283.01

Test Certificate

CC Technologies, Inc.
5777 Frantz Road
Dublin, OH
43017-1386

REF No O803170 : Issue 1
Ord No 82681591

Date Tested 06/09/08
Date Reported 06/09/08

Attn: Brad Etheridge

Item - 24" OD x 1/2" Wall girth welded pipe sample
WPS 14

Specification - API 1104 & Client Requirement

Nick Break Test - API 1104		
	Result	Comments
001:Weld	Acceptable	Quad 1
002:Weld	Acceptable	Quad 1
003:Weld	Acceptable	Quad 4
004:Weld	Acceptable	Quad 4

Certificate Comments

This is an electronic copy. See original certificate for photographs and figures where referenced.

Approved By Jim Blevins

Kevin J. Elliott
For and on authority of
Bodycote Testing Group

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Appendix H

Stress Analysis Report

Denbury Delta Pipeline Repair

7/28/2020

Denbury

MOTT MACDONALD

Document No. 20200724_MM_507102444_Pipeline Stress Analysis Report_EN_0015

PIPELINE STRESS ANALYSIS REPORT
DENBURY GULF COAST PIPELINES, LLC

DELHI PIPELINE REPAIR PROJECT

SATARTIA, MISSISSIPPI

Issue and Revision Record					
Rev	**Date**	**Originator**	**Checker**	**Approver**	**Description**
A	06/12/20	D. Dowling, PE	R. Sprague	R. Spence, PE	Draft
B	07/27/20	D. Dowling, PE	R. Sprague	R. Spence, PE	For Review
C	07/28/20	D. Dowling, PE	R. Sprague	R. Spence, PE	Final

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1 EXECUTIVE SUMMARY

Mott MacDonald (MM) has performed a stress analysis on the piping associated with the Delhi Pipeline incident/release on February 22, 2020. The piping was modeled using dimensions from Denbury supplied as-built records and Mott MacDonald survey data using AutoPIPE CONNECT Advanced Edition 12.02.00.14. The model was analyzed utilizing a combination of stress engineering methodologies and computational stress analysis.

Mott MacDonald performed a site-specific soil movement analysis that was used to establish soil loading on the pipeline for the stress analysis Utilizing guidance presented in the American Lifelines Alliance (guidance for the design of buried steel pipe July 2001) the Peak lateral earth pressure was calculated by utilizing Horizontal Bearing Capacity factors.

The mitigation procedure involved the identification and evaluation of critical areas against code allowable stress combinations. The results were compared using the stress ratio experienced by the component. A stress ratio greater than 1.0 represents components exhibiting stresses greater than the allowable stresses per ASME B31.4 (2016).

The following stress conditions were evaluated in the stress analysis:

- Load Cases
- Code Combinations
- Non-Code Combinations
- Thermal Analysis
- Soil Spring Analysis
- Soil Settlement Analysis
- Thermal Displacement

The geotechnical properties simulated within the models were reflective of the soil spring results presented in Section 7.2. Based on the models developed for this analysis, it is apparent that the soil movement present at the incident location was capable of exerting forces on the pipeline that exceed allowable limits. Mott MacDonald has reviewed the stress results with Denbury and developed solutions for the repair of the pipeline.

2 PROJECT DESCRIPTION

On February 22, 2020 the 24" CO2 Delhi Pipeline ruptured near a crossing of Mississippi Highway 433 approximately 1 (one) mile southeast of Satartia, MS. To help evaluate the cause of the release, Denbury contracted Mott MacDonald to gather information to support a thorough investigation. Mott MacDonald collected drone photogrammetry, terrestrial LIDAR and contracted PSI to perform a geotechnical investigation. Using this information Mott MacDonald performed a nodal evaluation using Bentley AutoPIPE CONNECT Advanced Edition Version 12.02.00.14 to determine stresses from external loading near the release of the Delhi Pipeline.

3 SCOPE

The stress model reflects the design of the project drawings and as-built information. The models were further analyzed using the various code and non-code guidelines listed in this section. These load combination guidelines can be generally categorized as follows:

- Hoop
- Sustained
- Occasional
- Expansion
- Combined Stress
- Unrestrained
- Support Loads

3.1 LOAD COMBINATIONS

Mott MacDonald analyzed the following code combinations as required by ASME B31.4. The loads are listed in Table 1 and 2 shown below. For allowable stress limits definition, see Appendix A.

Table 1 – Code Combinations

Case No.	Load Case Combinations	Category	Load Description
1	Max P	Hoop	Hoop Stress; ASME B31.4 Para. 402.3.5
2	GR + Max P	Sustained	Stress due to Sustained Loads; ASME B31.4 Para 402.6
3	Amb to T1	Expansion	Thermal stress range from restraint temp to the maximum temperature; ASME B31.4, Para. 402.5
7	Max Range	Expansion	Thermal stress range from the minimum temp to the maximum temperature (refer to all combinations); ASME B31.4, Para. 402.5
8	SUS + U1	Sustained	Stress due to Sustained Load and Soil Settlement; Sustained ASME B31.4, Para. 402.6

4 DESIGN INPUTS AND RESOURCES

The following resources and reports were utilized to provide design information and engineering inputs to various portions of the stress calculations and analysis:

Codes, Standards and Regulations - Applicable Federal, Provincial and Territorial Regulations, Codes and Bylaws – Latest Edition

1. ASME B31.4, Pipeline Transportation Systems for Liquids and Slurries
2. Federal Energy Regulatory Commission (FERC), Onshore Pipeline Regulations

External References

1. 49 CFR Part 195, Transportation of Hazardous Liquids by Pipeline
2. American Lifelines Alliance, Guidelines for the Design of Buried Steel Pipe, 2001
3. Peng, L.-C., & Peng, T.-L. (2009). Pipe Stress Engineering. New York, NY: The American Society of Mechanical Engineers.

The Project Data Sheet (Table 3) and additional variables (Table 4) defined below contain the design information and engineering inputs that were used for the stress calculations and analysis:

Table 3 – Project Data Sheet Variables

General Project Information			
Project Name:	Delhi Pipeline Repair Project	**Project No:**	507102444
Description:	Pipeline Repair Project		
Pipeline Data			
General Location	Satartia, MS		
MOP [psig]	2160		
Maximum Operating Temperature [˚F]	Maximum: +120˚F		
Pipe Data	API 5L 24" – 0.469" W.T., X80		
	API 5L 24" – 0.540" W.T., X80		
Pipeline Data			
Minimum Operational Design Temperature [˚F]	Above grade:	32˚F	
	Below grade:	70˚F	
Design Temperature [˚F]	Minimum:	-20˚F	
	Maximum:	120˚F	
Pipe Installation Temperature [˚F]*	60˚F		

* Based on average low temperature for this region during the month of construction.

5 ANALYSIS ASSUMPTION SUMMARY

The facility stress analysis was carried out using the following assumptions.

- Minimum Installation temperature of 60˚F.
- All welds connecting assembly piping are defect free
- Pipe is homogeneous and does not contain defects.
- Strains due to welding were ignored for this analysis.
- Bolt up strains are negligible.
- Small bore attachments do not govern the design.
- Dynamic Fluid loads were ignored for this analysis.
- Pressure and viscous drag effects were ignored for this analysis.
- All dynamic loads applied internally/externally were minimal.
- All material properties were assumed to be linear and elastic.
- Soil is represented by discrete linear elastic perfectly plastic springs.
- Welded branch connections consist of an ASME B31.4 listed fitting and is constructed with adequate strength.

6 PROJECT ANALYSIS

6.1 SOILS

Soil data used for the analysis was taken from soil bore samples provided by Intertek-PSI USA. For each USCS soil type, average values were developed for the peak and remolded undrained shear strengths and typical values were used for the soil densities. This data was applied to all below grade piping by centering the soil blocks at each of the shear vane locations. American Lifelines Alliance (ALA) soil spring calculations were generated manually using the ALA formulas at a depth appropriate for the location and spacing appropriate for the pipe size. The soil spring summary is included in Table 4.

Table 4 – Soil Spring Summary			
Stiff Clay – Under Road (SCUR)			
Total Unit Weight below pipe (lb/ft³)	**100**		
Dry Unit Weight above pipe (lb/ft³)	**97**		
Effective Unit Weight above pipe (lb/ft³)	**100**		
Soil Cohesion (psf)	**1000**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)
Trans. Horizontal	5780.82	13873.96	2.4
Longitudinal	14566.52	4369.96	0.3
Trans. Vertical Up	4166.67	20000	4.8
Trans. Vertical Dn	2643.55	12689.02	4.8
Soft Clay – Embankment (SOE)			
Total Unit Weight below pipe (lb/ft³)	**100**		
Dry Unit Weight above pipe (lb/ft³)	**97**		
Effective Unit Weight above pipe (lb/ft³)	**100**		
Soil Cohesion (psf)	**250**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)
Trans. Horizontal	920.34	3313.22	3.60
Longitudinal	3941.42	1576.57	0.40
Trans. Vertical Up	833.33	4000	4.80
Trans. Vertical Dn	871.78	4184.57	4.80
Soft Clay – Landside Edge (LSE)			
Total Unit Weight below pipe (lb/ft³)	**100**		
Dry Unit Weight above pipe (lb/ft³)	**97**		
Effective Unit Weight above pipe (lb/ft³)	**100**		
Soil Cohesion (psf)	**200**		
Friction Angle (deg)	**0**		
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)

Trans. Horizontal	657.98	2470.98	3.76
Longitudinal	3171.19	1268.48	0.40
Trans. Vertical Up	416.67	2000.00	4.8
Trans. Vertical Dn	639.78	3070.94	4.8
Stiff Clay – Outside Landslide (OLS)			
Total Unit Weight below pipe (lb/ft³)		**100**	
Dry Unit Weight above pipe (lb/ft³)		**97**	
Effective Unit Weight above pipe (lb/ft³)		**100**	
Soil Cohesion (psf)		**250**	
Friction Angle (deg)		**0**	
Direction Specific Soil Spring Values			
	K1 (lbf/in/ft)	P1 (lbf/ft)	Yield Disp. (in)
Trans. Horizontal	1072.47	3088.72	2.88
Longitudinal	3941.42	1576.57	0.40
Trans. Vertical Up	520.83	2500.00	4.80
Trans. Vertical Dn	746.79	3584.57	4.80

6.2 ENVIRONMENTAL LOADING

During the initial site visit, Mott MacDonald noticed evidence of soil movement along the ROW. The soil failure planes in the ROW extended approximately 900 ft at varying angles from 45˚ to 90˚. Figure 1 and Figure 2 below show 3D photogrammetry scans taken of the ROW and displays the long linear failures.



FIGURE 1: SOIL MOVEMENT PLAN VIEW



FIGURE 2: SOIL MOVEMENT ROW VIEW

The depth of the soil failures varied throughout the ROW, but as shown in Figure 3, the high level of detail captured with the 3D photogrammetry allowed for accurate measurements.

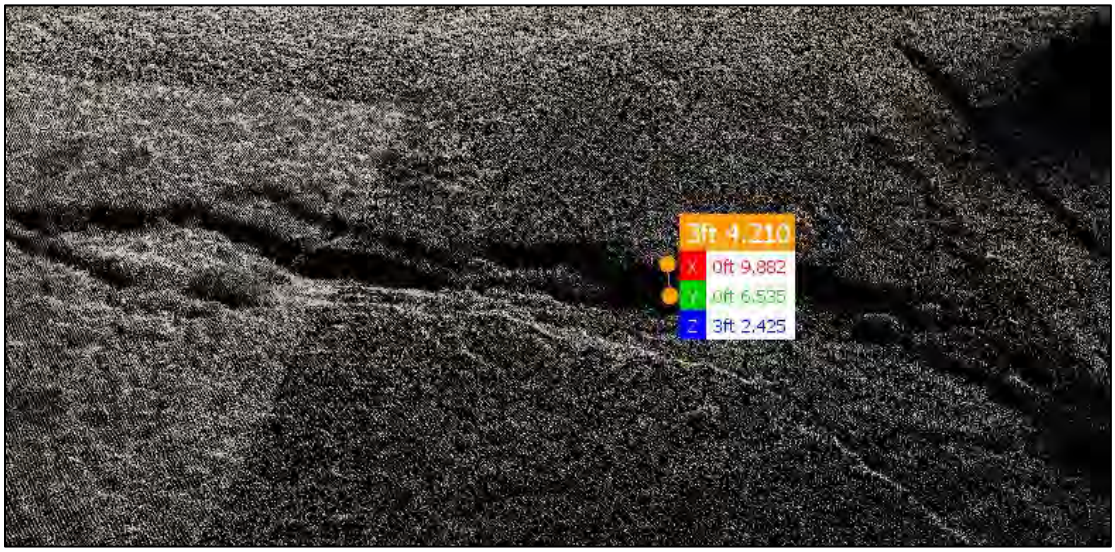


FIGURE 3: SOIL FAILURE DEPTH

To model the external force due to soil movement appropriately, Mott MacDonald's geotechnical team performed a soil movement analysis. Based upon information of the soil properties, pipeline burial depth and relative slope movement a calculation of the maximum earth pressure which could be applied to the pipe was developed. This value represents the maximum force per unit length which the soil could apply to the pipeline.

Note that this calculation method is applicable to small strain (pipe-soil localized strain) situations. Utilizing guidance presented in the American Lifelines Alliance

(guidance for the design of buried steel pipe July 2001) the Peak lateral earth pressure was calculated by utilizing Horizontal Bearing Capacity factors. This calculation resulted in a value of **2,800lb/ft** (force per foot length of pipe) being the maximum force the moving soil could apply to the pipeline at small strain. For this calculation, the following assumptions were made:

- Ground surface to spring line = 5ft
- Soil cohesion = 200 psf
- Soil angle of internal friction = zero
- Applied distributed load value = the maximum force per unit length of pipe that the soil could transmit to the pipe. This force may not have fully mobilized if pipe failed before sufficient earth strain occurred to reach this maximum force.
- Calculations follow American lifeline alliance, guideline for the design of buried steel pipe 2001 (B-2).

Utilizing the as-built data in conjunction with the photogrammetry, the Mott MacDonald team was able to provide varying environmental loading conditions for the pipeline. Table 6 below presents the soil classification (from geotechnical investigations performed by PSI), applied environmental loads and general soil description.

Table 6 – Environmental Loading

Station	Soil Classification	Applied Distributed Loads	General Description
361+00 -> 349+80	[A] Stiff Clay		Stronger soils restraining movements at boundary
349+80 -> 348+50	[B] Stiff Clay		Stronger soils with deep burial from highway embankment causing strong pipe restraint
348+50 -> 347+00	[C] Soft Clay		Softer soils down from highway embankment.
347+00 -> 346+50	[D] Soft Clay	2,800 lb/ft	Moving landslide body edge
346+50 -> 340+00	[E] Soft Clay [Horiz. Strength = 0]	2,800 lb/ft	Moving landslide body middle

340+00 -> 339+00	[D] Soft Clay	2,800 lb/ft	Moving landslide body edge
339+00 -> 338+50	[C] Soft Clay		Softer materials outside landslide body
339+00 -> 325+00	[A] Stiff Clay		Stronger soils restraining movements at boundary

The distributed loads were applied in the model based on understanding of the topography in the area as shown in the Figure 4 below.

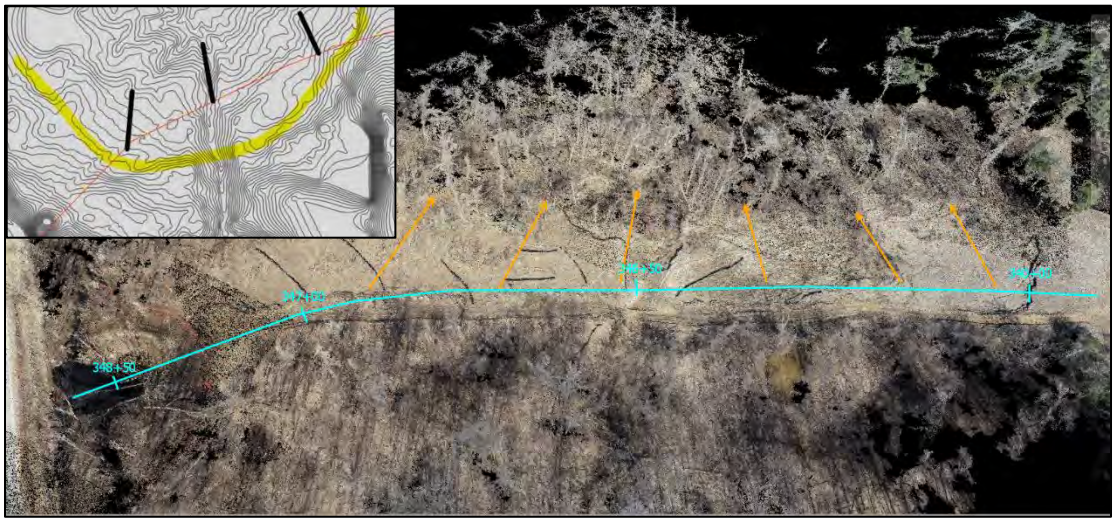


FIGURE 4: SOIL MOVEMENT DIRECTION

The external loads due to soil movement were applied per the list below.

- 347+00 -> 346+50 Azimuth 005 (5° east of north)
- 346+50 -> 340+00 Azimuth 350 (10° west of north)
- 340+00 -> 339+00 Azimuth 335 (25° west of north)

7 ANALYSIS RESULTS

7.1 PIPELINE ANALYSIS

The pipeline was modeled as per the above listed design information. Though not all of the model is shown the below Figure 5, Figure 6 and Figure 7 display the area of concern.

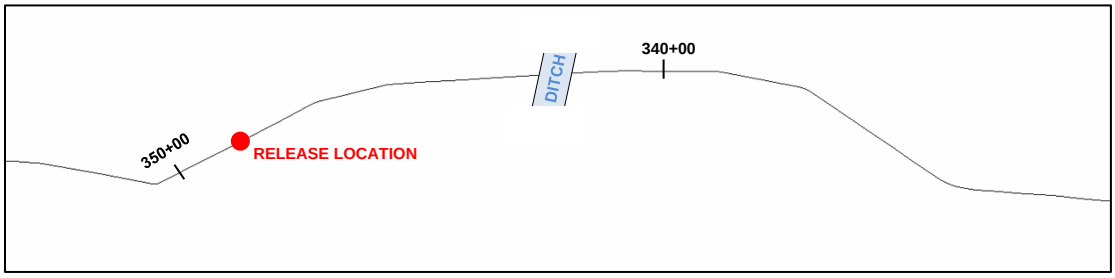


FIGURE 5: AUTOPIPE MODEL

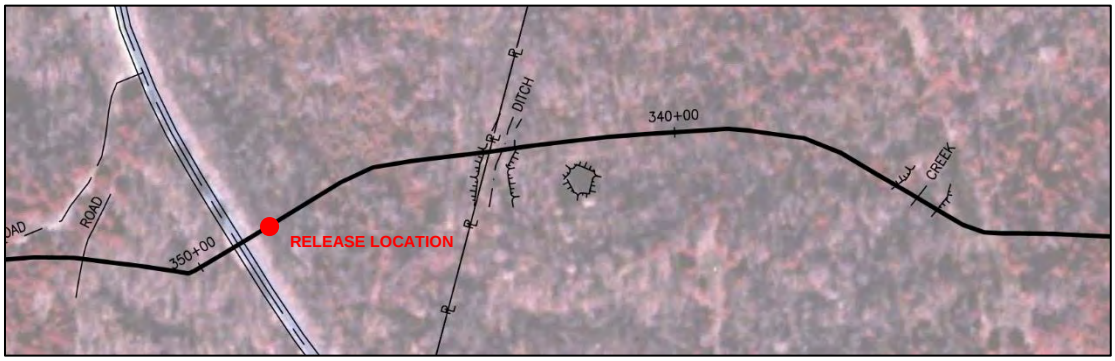


FIGURE 6: AS-BUILT ALIGNMENT SHEET

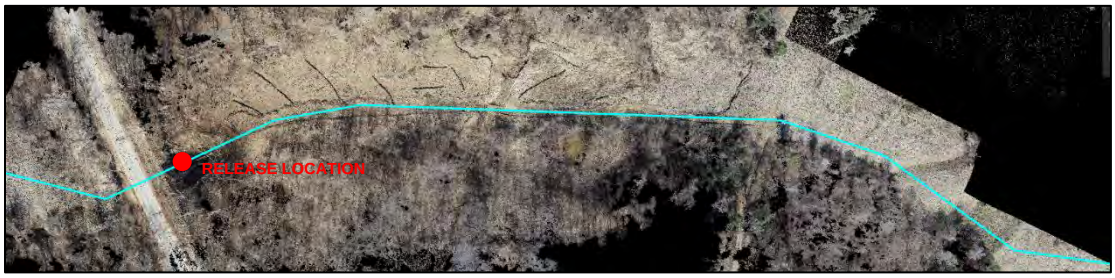


FIGURE 7: MODEL OVERVIEW

The road crossing utilized thicker pipe and was modeled as per the as-built alignment sheet, as shown in Figure 8.1.3.

- 24”–0.540 in – API 5LX–X80 – Cyan
- 24”–0.469 in – API 5LX–X80 – Red

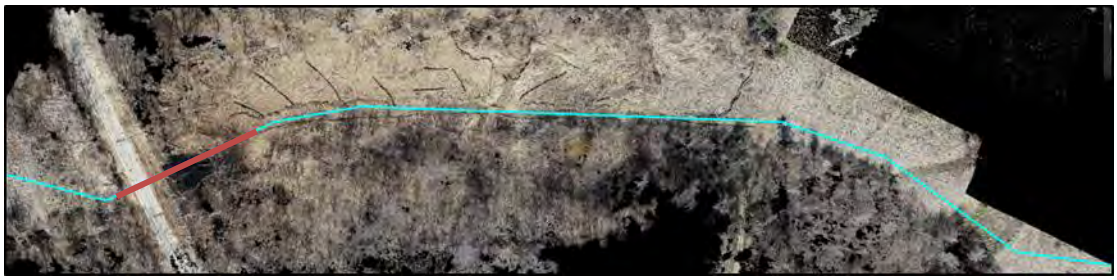


FIGURE 8: PIPE IDENTIFIER

Below shows the soil modeling based on the guidelines set forth in Section 7.1. The colors shown below denote the division in the soil as defined in Table 6.



FIGURE 9: SOIL IDENTIFIERS

The piping model was analyzed at low temperature limits defined by the project data sheet. At this location, the entire design was modelled at installation temperature, 60ºF. The effects of thermal expansion due to temperature within the pipeline as well as environmental changes are negligible.

The most significant stress values came from the external loading from soil movement. To establish a baseline, the stress team determined the maximum horizontal distributed load the pipe could withstand without rupture. Once the geotechnical team determined the estimated distributed loads, these numbers were compared. The comparison showed that the geotechnically determined loads exceeded the allowable horizontal distributed loads by more than 300 lbs/ft (2,800 lbs/ft vs. 2,475 lbs/ft).

As shown in Figure 10 below, the pipeline release location experienced excessive stress. The focal point of the stress at this location shows a maximum stress ratio of 1.43.

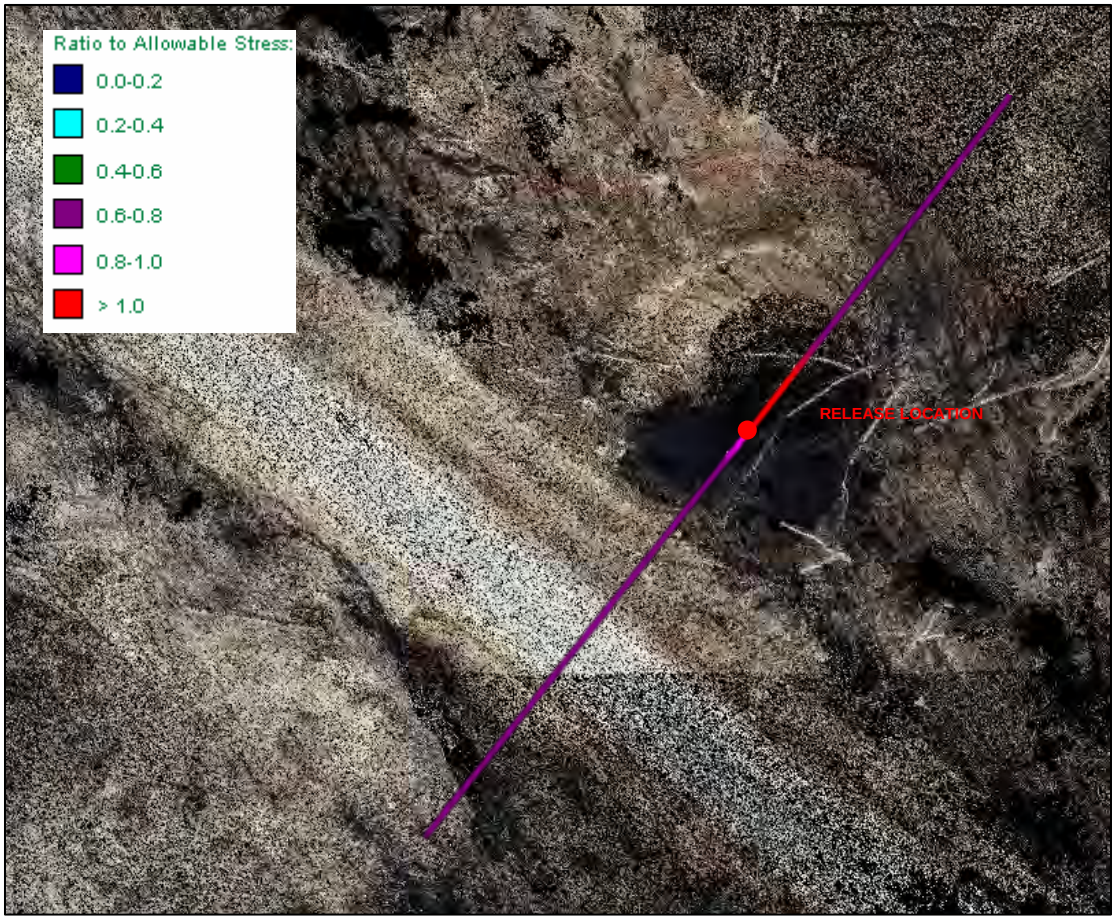


FIGURE 10: FAILURE LOCATION

At the release location, the pipe was calculated to have experienced load given in Table 7 below.

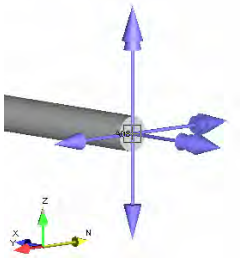


Table 7: Loads Experienced at Pipeline Release Location		
X-Direction	Y-Direction	Z-Direction
-848,020 lbf	7,229 lbf	-46483 lbf
-54,921 ft-lb	-706,996 ft-lb	36,274 ft-lb

Figure 11 below shows an exaggerated deflection curve of the pipeline.

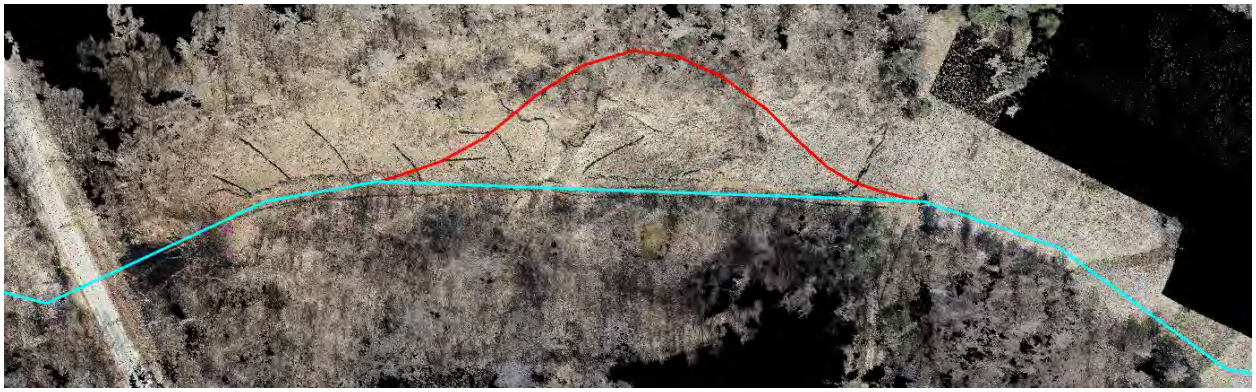


FIGURE 11: DEFLECTION CURVE

Mott MacDonald examined results as full design group to analyze the failure types and deflection curves. It was established that forces applied to the pipeline from the soil movement were significant enough to exceed the allowable stress limit of the Delhi Pipeline and likely was a contributing factor to the rupture.

8 CONCLUSION

Mott MacDonald performed a nodal analysis to analyze the Denbury Delhi Pipeline for stress concerns surrounding the rupture area. Key information (i.e. soil bores, topography, LIDAR scans) was gathered, interpreted and used in the evaluation.

The initial task performed by the stress team was to determine the maximum distributed load due to soil movement the pipeline could withstand under the given environmental conditions without exceeding the allowable stress. The results of this study found that at 2475 lb/ft certain areas began to exceed the allowable stress.

Utilizing the geotechnical investigation results and drone topography, the geotechnical team performed a soil movement analysis. The analysis concluded that the soil movement could project a load of 2800 lb/ft on the pipeline.

Under the provided 2800 lb/ft condition, the stress analysis showed the area of rupture on the Delhi Pipeline could have experienced stress ratios up to 1.43 or 43% greater than the allowable stresses under ASME B31.4 code.

The results of the analysis concluded that the soil movement found on the Delhi Pipeline Right-of-Way could induce axial stresses sufficient to cause an overload condition in the pipeline near the incident location.

9 RECOMMENDATION

Based on the results of the evaluation, Mott MacDonald recommends to stress relieve the pipeline by exposing approximately 135 feet of pipe near the opposing soil failure plane(at 339+00) then cut and replace a length of pipe.

The length of stress relieving area was determined by evaluating the over stressed model from the previous analysis. Using the deflection curve and stress ratio visuals in conjunction, the stress team identified a length of pipeline that exhibited a peak in stress values near the soil failure plane or at approximately 339+00.

On the upstream side of 339+00, the stress values decrease from 1.51 to 1.2 where they remained as it progressed upstream. These values are acceptable given these forces were due to axial stress and therefore were relieved when the pipeline failed.

The stress on the downstream side of 339+00 was caused by the restrained/unrestrained boundary condition created by the soil movement. This bending stress is the target of the relief exercise. The area shown in Figure 12 below, show a sharp rise in stress from a ratio of 0.70 to 1.51 in less than 50 ft. This boundary condition at the soil failure plane did not relieve after the pipeline failure and will have to be repaired.

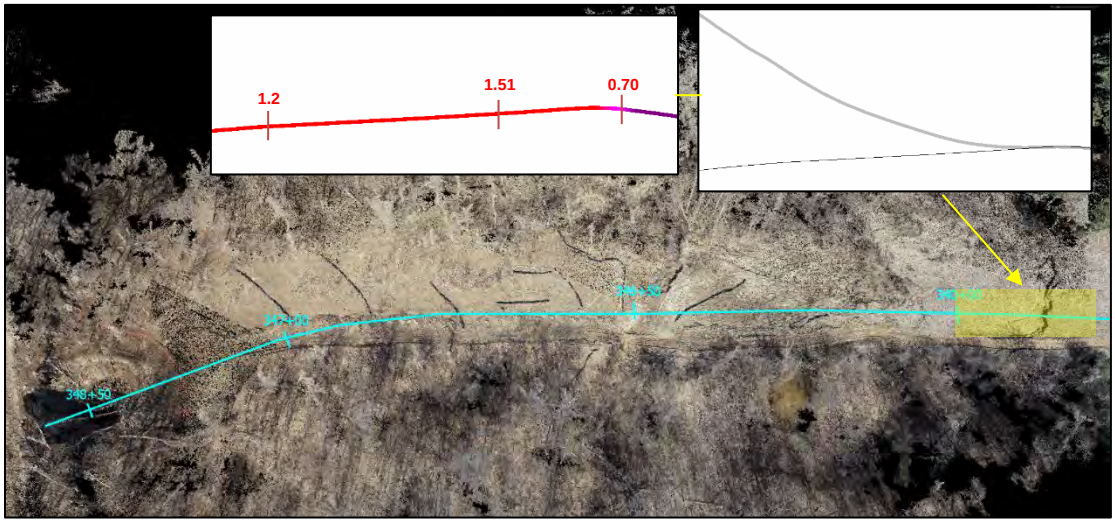


FIGURE 12: RECOMMENDED

Exposing at least 135 ft and removing and replacing as least a 10 ft section of pipe as recommended in the repair alleviates the overstressed boundary condition left by the soil movement and allows for safe transition between the two soil conditions. This recommendation is with the understanding that the remainder of the area of concern will be hydrotested as per ASME B31.4 to ensure the integrity of the pipe that experienced high tensile loads.

APPENDIX A: SUPPORTING INFORMATION

TEMPERATURE FOR SATARTIA, MS

History

September Data	Choose another month: September Submit		
Averages			
Average High Temperature	31 °C	Average Morning Relative Humidity	94%
Average Low Temperature	18 °C	Average Afternoon Relative Humidity	55%
Average Mean Temp	24 °C	Typical Sky Cover	CLR
Average Dew Point	19 °C	Average Precipitation (US Only)	91 mm
Average Windspeed	13 km/h	Average Snowfall (US Only)	0.00 cm
Average Wind Direction	SE		
Daily Counts			
Days With Precipitation	8	Days With Snow	0
Days With Thunderstorms	5	Days With Lows Below Freezing	0
Days With Fog	20	Days above 90° F (32.2° C)	12
Records			
Record High	40 °C	Record 24-hour Snowfall	0.00 cm
Record Low	2 °C	Record Monthly Rainfall	244 mm
Record Wind Speed	83 km/h	Record 24-hour Rainfall	117 mm
Record Monthly Snowfall	0.00 cm	Record Minimum Monthly Precipitation	15 mm

http://myforecast.co/bin/climate.m?city=21275&zip_code=39162&metric=true

ALLOWABLE STRESS LIMITS

HOOP STRESS

Hoop Stress (ASME B31.4 - 2016)

The hoop stress (Shoop) is calculated per A402.3.5

$$S_h = (P_i - P_e) \cdot \frac{D}{2t} \leq F_1 ST \quad (1)$$

$$\left[S_h = (P_i - P_e) \cdot \frac{D}{2000t}\right] \leq F_1 ST \quad (2)$$

$$S_h = (P_i - P_e) \cdot \frac{D-t}{2t} \leq F_1 ST \quad (3)$$

$$\left[S_h = (P_i - P_e) \cdot \frac{D-t}{2000t}\right] \leq F_1 ST \quad (4)$$

Where,

D is the nominal outside diameter of pipe, in. (mm)

F1 is the hoop stress design factor from Table A402.3.5-1

Pe is the external pressure, psi (kPa)

Pi is the internal pressure, psi (kPa)

S is the yield strength, psi (MPa)

Sh is the hoop stress, psi (MPa)

T is the temperature derating factor, found in the Results Model Options dialog

t is the nominal wall thickness, in. (mm)

Notes:
1. Equation 1 should be used if D/t is greater than or equal to 30. Equation 3 should be used if D/t is less than 30.
2. Equations 2 and 4 are the SI equivalents of equations 1 and 3, respectively.
3. In AutoPIPE, pressure data is gage pressure. In other words, $P_{AutoPIPE} = P_i - P_e$

SUSTAINED LOADS

Restrained

Calculations for restrained piping take into account flexibility and stress intensification factors of piping components. Longitudinal stress in restrained piping is calculated as:

$$S_L = S_E + \nu S_H \pm \frac{M}{Z} + \frac{F_a}{A}$$

Where sE is the restrained **thermal expansion stress**, sH is the **hoop stress** and A is the cross sectional area of steel.

When the "Use rest. long. code eq" option is not taken into account, AutoPIPE considers the actual restraint condition from supports and soil stiffness for longitudinal stress calculation.

$$S_L = MAX(\sigma_a + \sigma_b;\ \sigma_a - \sigma_b)$$

Where

$$\sigma_a = \frac{P_i D}{4t} - \frac{F_a}{A}$$

$$\sigma_b = \frac{\sqrt{M_i^2 + M_o^2}}{Z}$$

AutoPIPE reports sL and the allowable stress (0.90 Sy), where Sy is the specified minimum yield strength. If more than one operating load condition exists there may be more than one P value. Results are output for the operating load condition which produces the smallest margin (i.e., smallest value of 0.90· Sy, sL) at each point.

Note: AutoPIPE does not use the exact code equation for the longitudinal pressure stress. The code requires the use of vSH, whereas AutoPIPE uses PD/4t, which is approximately equal to 0.5SH.

THERMAL EXPANSION

Thermal Expansion Stress Range (ASME B31.4 - 2016)

Unrestrained

The stress due to defined thermal expansion ranges (sE) is calculated per the equation listed in para. 419.6.4(c) of the code, and as shown in Equation I.5-5:

$$S_E = \sqrt{S_b^2 + 4 \cdot S_t^2} \quad \text{(I.5 5)}$$

where:

$$S_b = \frac{\sqrt{(i \cdot M_{it})^2 + (i_o \cdot M_{ot})^2}}{Z_{cor}} \quad \text{(I.5 6)}$$

and:

$$S_t = \frac{M_{tt}}{2 \cdot Z_{cor}} \quad \text{(I.5 7)}$$

AutoPIPE reports sE, and the allowable stress (SA).

Restrained

The thermal expansion stress in restrained pipe is calculated as shown in Equation I.5-8:

$$S_E = E\alpha(T_1 - T_2) \quad \text{(I.5 8)}$$

Where E is the cold modulus of elasticity, a is coefficient of thermal expansion, in./in./F (mm/mm/C), T1 is the temperature of the pipe at installation or completion of final tie-in, F(C), and T2 is the operating temperature, F(C).

AutoPIPE reports sE and the allowable stress (0.90 Sy), where Sy is the specified minimum yield strength of the pipe material, in psi (MPa).

Appendix E CTEH Air Monitoring Summary Report

CTEH®

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DENBURY RESOURCES

AIR MONITORING REPORT

Satartia, Mississippi

Carbon Dioxide Pipeline Release

February 22-23, 2020

Project #112628

Report Submitted on June 05, 2020

1.0 INTRODUCTION

On February 22, 2020, CTEH®, LLC (CTEH) responded to a request from Denbury Resources (Denbury) to provide toxicology and air monitoring support following a carbon dioxide (CO_2) pipeline release near the town of Satartia, Mississippi. The village of Satartia was evacuated at approximately 2100 Central Standard Time (CST)[1] by local emergency management personnel and first responders. At 2230 on February 22, a CTEH consultant arrived onsite with air monitoring instrumentation and began monitoring areas in and around the village of Satartia for the presence of CO_2. As the potential for residual hydrogen sulfide (H_2S) resided in the line and complaints of an odor were received, monitoring was also conducted for the presence of H_2S. Additional CTEH personnel arrived and conducted air monitoring throughout the community. Once CO_2 levels returned to near ambient within the community, CTEH personnel conducted clearance monitoring within eighteen homes and three churches and their associated buildings. Denbury demobilized CTEH once ambient CO_2 concentrations within those structures were sustained below 5,000 parts per million (ppm) and residents had returned to their homes. This report summarizes data collected from February 22 through February 23.

2.0 METHODS

2.1 Handheld Real-Time Air Monitoring

Prior to CTEH's arrival, an air Sampling and Analysis Plan (SAP, Attachment A) was developed for worker monitoring, community monitoring, and site characterization. Based on site characteristics and associated scope of work, no worker monitoring or site characterization readings were recorded. In accordance with the SAP, CO_2, H_2S, and oxygen (O_2) concentrations were monitored using handheld real-time instrumentation throughout the community as well as within homes of residents who requested monitoring prior to re-occupancy. Monitoring was performed using RAE Systems by Honeywell MultiRAE Pro instruments. All instrumentation was calibrated prior to use.

Community monitoring was delineated into two subcategories: community real-time monitoring and indoor assessment real-time monitoring. Community real-time monitoring consisted of roaming handheld monitoring performed outdoors and downhill from the incident site, including checkpoints and church parking lots. Indoor assessments consisted of real-time monitoring within residences and church buildings potentially affected by the incident at the request of community members. If the initial indoor assessment resulted in CO_2 levels above the CTEH project-specific action level, another indoor assessment was performed after allowing the building to air out. For example, if real-time monitoring during the initial indoor assessment detected CO_2 levels above the CTEH project-specific action level, the windows and doors were opened and the occupant was advised not to re-enter until CO_2 concentrations returned to ambient levels, as determined by another indoor assessment. The ambient levels CO_2 in the non-industrial

[1] All other times referenced in the report will be CST unless otherwise delineated.

indoor environments may have a variety of sources, including human metabolism, and CO_2 levels can vary based on the number of people present, how long the area has been occupied, and the amount of outdoor fresh air entering the area.

2.2 Protective Action Criteria and CTEH Project-Specific Action Levels

The U.S. Department of Energy's Subcommittee on Consequence Assessment and Protective Actions (SCAPA) has established Protective Action Criteria (PACs) for over 3,300 chemicals for planning and response to uncontrolled releases of hazardous chemicals (DOE/SCAPA 2018). These criteria, combined with estimates of actual exposure, provide information necessary to evaluate chemical release events for the purpose of taking appropriate protective actions. During an emergency response, these criteria may be used to evaluate the severity of the event and to inform decisions regarding what protective actions may be taken. The PAC values for the chemicals of concern for this response are provided in Attachment B. The PAC-1, -2, and -3 for CO_2 are 30000, 40000, and 50000 ppm, respectively. For comparison, the American Conference of Governmental Industrial Hygienists (ACGIH) threshold limit values (TLVs) are also included in Attachment B. Although the TLVs are intended for occupational daily work shift exposures over an entire working lifetime, the literature regarding reviewed human studies involving CO_2 within the TLV documentation were referred to and will be discussed in Section 4.0. The current ACGIH TLV-Time Weighted Average (TLV-TWA) for CO_2 (5,000 ppm) is based on the lack of inhalation toxicity data in humans at this level and the ACGIH TLV-Short Term Exposure Limit (STEL) for CO_2 is 30,000 ppm. The TLV documentation cites data indicating elevated concentrations (above 50,000 ppm) of CO_2 can produce '*mild narcotic effects, stimulation of the respiratory center, and asphyxiation*', depending on exposure duration and conditions (ACGIH 2001). CTEH project-specific action levels for both monitoring plans were set at 5,000 ppm (sustained for 15 minutes) for CO_2 based on the ACGIH TLV-TWA (well below PAC-1 and ACGIH TLV-STEL), and the action level for H_2S was set at 1 ppm, which was also based on the ACGIH TLV-TWA.

In accordance with the SAP, CTEH project-specific action levels were used to provide information for assessing need to take corrective action to limit the potential of exposure. These values do not replace community exposure standards or guidelines but are intended to be a concentration limit that triggers a course of action to better address public safety.

3.0 RESULTS

Handheld real-time air monitoring results are summarized by subcategory in Tables 1 and 2: community real-time air monitoring and indoor assessment real-time air monitoring. Maps of the site location, community real-time monitoring locations, and indoor assessment real-time air monitoring locations are provided in Attachment C.

Table 1 Community Real-Time Air Monitoring Results

Analyte	Instrument	Number of Readings	Number of Detections	Concentration Range[1]
CO_2	MultiRAE Pro	108	108	100 – 26,000 ppm
H_2S	MultiRAE Pro	85	0	< 0.1 ppm
O_2	MultiRAE Pro	84	84	20.9 - 21.1 %

[1]A value preceded by the "<" symbol is considered below the instruments limit of detection and the value to the right is the instrument detection limit. ppm = parts per million.

Table 2 Indoor Assessment Real-Time Air Monitoring Results

Analyte	Instrument	Number of Readings	Number of Detections	Concentration Range[1]
CO_2	MultiRAE Pro	30	30	200 – 28,000 ppm
H_2S	MultiRAE Pro	18	0	< 0.1 ppm
O_2	MultiRAE Pro	8	8	20.9 %

[1]A value preceded by the "<" symbol is considered below the instruments limit of detection and the value to the right is the instrument detection limit. ppm = parts per million.

4.0 DISCUSSION

CTEH performed real-time air monitoring using handheld real-time instrumentation. Results of handheld real-time air monitoring are discussed below.

No H_2S detections were observed during handheld real-time air monitoring in the community or indoor assessment real-time monitoring. O_2 concentrations were not observed below 20.9%. Outdoor CO_2 concentrations ranged from 100 through 26,000 ppm in the community. Five detections of CO_2 exceeded 5,000 ppm. Residents of the community were already evacuated when these detections were observed.

After outdoor community CO_2 levels were sustained continually measured below 5,000 ppm, initial indoor assessment real-time monitoring was performed inside residences and church buildings potentially impacted by the incident, at owners'/occupants' request. During initial indoor assessment real-time monitoring, CO_2 concentrations ranged from 200 through 28,000 ppm, with six detections exceeding 5,000 ppm. In these instances, occupants of these structures were advised to open doors and windows and not to occupy those structures prior to re-assessment.

Indoor assessment real-time monitoring was performed for six structures to further assess homes and church buildings in which CO_2 concentrations above 5,000 ppm were observed during initial indoor assessment real-time monitoring. No readings of CO_2 greater than 3,500 ppm were recorded following any of these re-assessments.

While CTEH personnel were onsite, values of CO_2 were recorded up to 28,000 ppm. A notice issued by the Satartia Fire Department advising residents and members of the general public to evacuate the area was active during the period in which elevated CO_2 concentrations were observed. The ACGIH TLV documentation reports several effects resulting from inhalation of elevated CO_2 concentrations, including mild narcotic effects (30,000 ppm) and unconsciousness (> 50,000 ppm). Additional reports of human exposure to CO_2 indicate 20,000 ppm for several hours may cause transient effects, such as headaches, and exposure to up to 5,500 ppm for six hours may cause *no noticeable symptoms* (ACGIH 2001). To the best of CTEH's knowledge, including several interactions with community members during this response, there were no reports of hospitalization due to loss of consciousness within the community.

In conclusion, during the time period CTEH was present, the CO_2 concentrations observed were below the ACGIH TWA-STEL and PAC values and thus were not detected at levels that would be expected to cause anything other than transient effects, if any, or pose a chronic health risk to members of the community.

5.0 REFERENCES

ACGIH (2001) Carbon dioxide: TLV® Chemical Substances 7th Edition Documentation. Cincinnati, Ohio: American Conference of Governmental Industrial Hygienists.

ACGIH (2019) Guide to Occupational Exposure Values. Cincinnati, Ohio: American Conference of Governmental Industrial Hygienists.

DOE/SCAPA (2018) Protective Action Criteria (PAC): Chemicals with AEGLs, ERPGs, & TEELS: Rev. 29A. Washington, DC: U. S. Department of Energy. Available at:https://www.energy.gov/ehss/protective-action-criteria-pac-aegls-erpgs-teels-rev-29-chemicals-concern-may-2016.

Attachment A

Sampling and Analysis Plan

CTEH®
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Carbon Dioxide Pipeline Release

Satartia, MS

Air Sampling and Analysis Plan (SAP)

Version 1.0

Prepared on Behalf of:

Denbury Resources

Prepared By:

CTEH, LLC

5120 Northshore Drive

Little Rock, AR 72118

501-801-8500

February 22, 2020

	Name/Organization	Signature	Date Signed
Prepared by:	Pamella Tijerina, Ph.D.	PBT	02-22-2020
Reviewed by:	Eric Allaby		02-22-2020
Approved by:			
Approved by:			

Air Monitoring Strategy

CTEH® is focusing on the chemicals below chosen below because they are among the most important and readily monitored hazards of a carbon dioxide (CO_2) release. It is notable, however, that some chemicals may also be included within the SAP on the basis that some uncertainty exists during incidents and monitoring for these chemicals is necessary to ensure that a hazard does not exist. Monitoring for some chemicals or indicators of the presence of CO_2 may be conducted less frequently or even discontinued as product-specific information becomes available or as initial air monitoring results indicate that these chemicals and indicators do not pose a health concern.

The strategy is to utilize three broadly defined monitoring plans: **1)** Work Area Monitoring; **2)** Community Monitoring; and **3)** Site Assessment. Work Area monitoring will generally take place in those areas where workers are actively performing/supporting remediation operations. The readings will generally be taken at a height consistent with that of the workers breathing zone and in close proximity to workers without interfering or obstructing their remediation tasks. Community Monitoring may take place in those residential and/or commercial locations immediately surrounding the incident site, not necessarily currently occupied by members of the community. Unlike Work Area and Community monitoring, Site Assessment does not necessarily represent ambient air monitoring near breathing zone level. Site Assessment may involve a variety of different monitoring tasks intended to provide information that may help to delineate the nature and extent of the release (e.g. fence line monitoring, worst case determination, container head space, ground level, etc.).

Free-roaming handheld real-time air monitoring may be conducted in a variety of areas based on levels of activity, proximity to the release, and site conditions. Fixed-location handheld real-time locations may be established in the Community in order to provide concentration averages that may be observed and analyzed over time in distinct geographic locations in the community. AreaRAEs may be utilized to monitor the scene from remote location, if necessary.

CTEH® has the capabilities on site to collect ambient air samples, if necessary. These sampling methodologies may be utilized if the results from real-time air monitoring efforts indicate the potential for exposure above acceptable occupational or community exposure levels. CTEH® will discuss these methodologies with Denbury staff prior to implementation.

CTEH Site-Specific Action Levels

CTEH® site-specific action levels may be employed in all air monitoring plans to provide information for corrective action to limit potential exposures. These values do not replace occupational or community exposure standards or guidelines, but are intended to represent a concentration limit that triggers a course of action to better address worker and public safety. Action level exceedances will be communicated to Site Management and the CTEH Project Technical Director by the CTEH Project Manager (PM). Work practice may be assessed and then altered if necessary. Site-Specific Action Levels are not utilized for Site Assessment monitoring.

Plan 1: Work Area Monitoring

Objective: Report air levels before they reach those requiring respiratory protection

Analyte	Action Level	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
CO_2	5,000 ppm 15 min.	Egress & Notify PM	OSHA PEL & ACGIH TLV	MultiRAE Sensor	100 ppm	Measuring Range: 0 – 50,000 ppm	N/A
	30,000 ppm* 1 min.	Egress & Notify PM	ACGIH STEL				
O_2	< 20.3 %	Egress and Notify PM	ACGIH STEL for CO_2	MultiRAE Sensor	0.1 %	Range: 0 – 30 %	N/A
Hydrogen Sulfide	1 ppm	Egress and Notify PM	ACGIH TLV-TWA; Precautionary Monitoring to Rule Out	MultiRAE Sensor	0.1 ppm	Range: 0 – 100 ppm	N/A

* Note small margin between STEL and NIOSH IDLH (40,000 ppm)

Plan 2: Community Assessment

Objective: Report air levels before they reach those causing nuisance or health issues

Analyte	Action Level	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
CO_2	5,000 PPM* 15 min.	Notify PM	Warning prior to reaching PAC-1	MultiRAE Sensor	100 ppm	Measuring Range: 0 – 50,000 ppm	N/A
O_2	< 20.3 %	Notify PM	Precautionary	MultiRAE Sensor	0.1 %	Range: 0 – 30 %	N/A
Hydrogen Sulfide	Detection	Notify PM	Precautionary	MultiRAE Sensor	0.1 ppm	Range: 0 – 100 ppm	N/A

* Note: PAC-1 is 30,000 ppm, PAC-2 is 40,000 ppm, PAC-3 is 50,000 ppm

Plan 3: Site Assessment							
Objective: Characterize nature and extent of release							
Analyte	Action Level	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
CO_2	NA	Report reading to PM	NA	MultiRAE PID	0.1 ppm	Measuring range: 1 – 5,000 ppm	NA

All Plans (1-3): Flammability								
Analyte	Action Level	Corrected Value/ Instrument Reading	Action to be Taken	Basis	Instrument	Detection Limit	Notes	Correction Factor
LEL				CO_2 is non-flammable; Notify PM & PTD if LEL detected.				

General Information on Procedures (Assessment Techniques) Used

Procedure	Description
Real-Time Handheld Survey	CTEH staff members may utilize handheld instruments (e.g. MultiRAE Plus; ppbRAE, Gastec colorimetric detector tubes, etc.) to measure airborne chemical concentrations. CTEH will use these handheld instruments primarily to monitor the ambient air quality at breathing zone level. Additionally, measurements may be made at grade level, as well as in elevated workspaces, as indicated by chemical properties or site conditions. CTEH may also use these techniques to verify detections observed by the AreaRAE network.
Radio-Telemetering Network	CTEH may deploy a radio-telemetering network of AreaRAEs in locations where monitoring from a remote location would be beneficial. These instruments will relay readings back to a centralization location that is monitored by CTEH.
Fixed Real-Time Monitoring locations	Multiple Community locations may be identified and monitored at the same location approximately once per hour using handheld instruments. This allows the use of statistical analysis more effectively than with a random approach.

Quality Assurance/Quality Control Procedures

Method	Procedure
Real-Time	Real-time instruments may be calibrated in excess of the manufacturer's recommendations.

Method	Procedure
	At a minimum whenever indicated by site conditions or instrument readings. Co-located sampling for analytical analysis may be conducted, if necessary, to assess accuracy and precision in the field. Lot numbers and expiration dates may be recorded with use of Gastec colorimetric tubes.
Reporting	Daily data summaries may be provided for informational purposes using data that have not undergone complete QA/QC. Comprehensive reports of real-time and/or analytical data may be generated following QA/QC and may be delivered 60 days following receipt of validated results, if applicable.

Glossary

Term	Definition
Sustained	Instrument reading above the action level continuously for the listed time period.
Breathing zone	The area within an approximate 10-inch radius of an individual's nose and mouth.
Ambient Air	That portion of the atmosphere (indoor or outdoor) to which workers and the general public have access.

Attachment B

SCAPA PACs and ACGIH TLVs

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No.	Chemical Name	CASRN	PACs based on AEGLs, ERPGs, or TEELs			Units
			PAC-1	PAC-2	PAC-3	
570	Carbon dioxide	124-38-9	30,000	40,000	50,000	ppm
1426	Hydrogen sulfide	7783-06-4	0.51	27	50	ppm

Chemical Name	CASRN	ACGIH TLVs		Units
		TWA	STEL	
Carbon dioxide	124-38-9	5,000	30,000	ppm
Hydrogen sulfide	7783-06-4	1.0	5.0	ppm

Attachment C

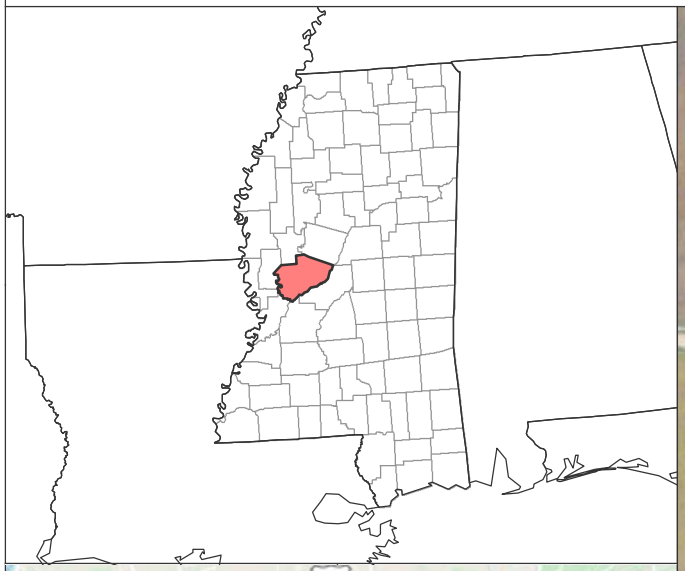
Site Maps

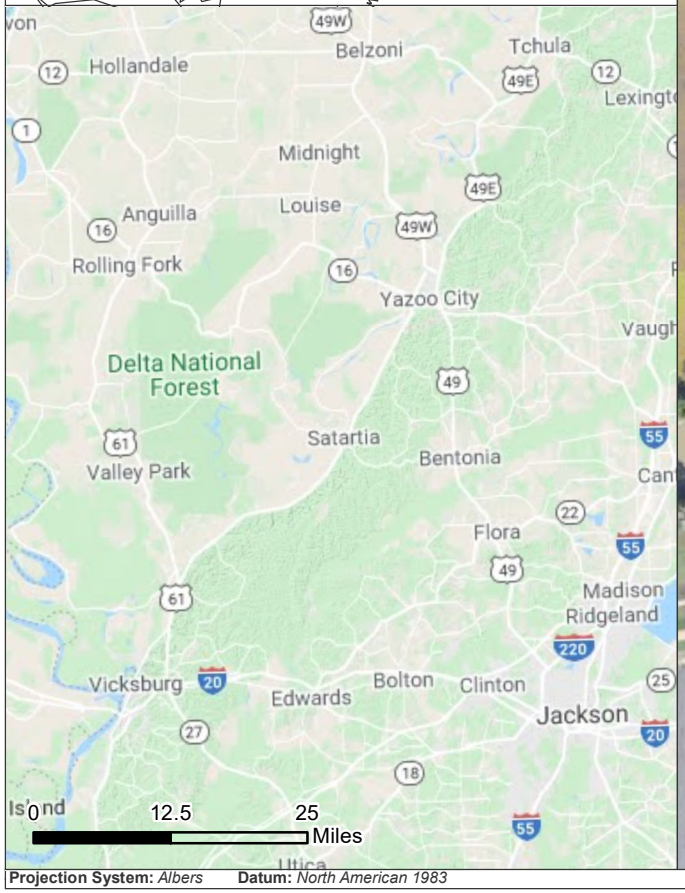
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Site Location

CO_2 Pipeline Release

Project: 112628
Client: Denbury
City: Satartia, MS
County: Yazoo







Projection System: *Albers* **Datum:** *North American 1983*

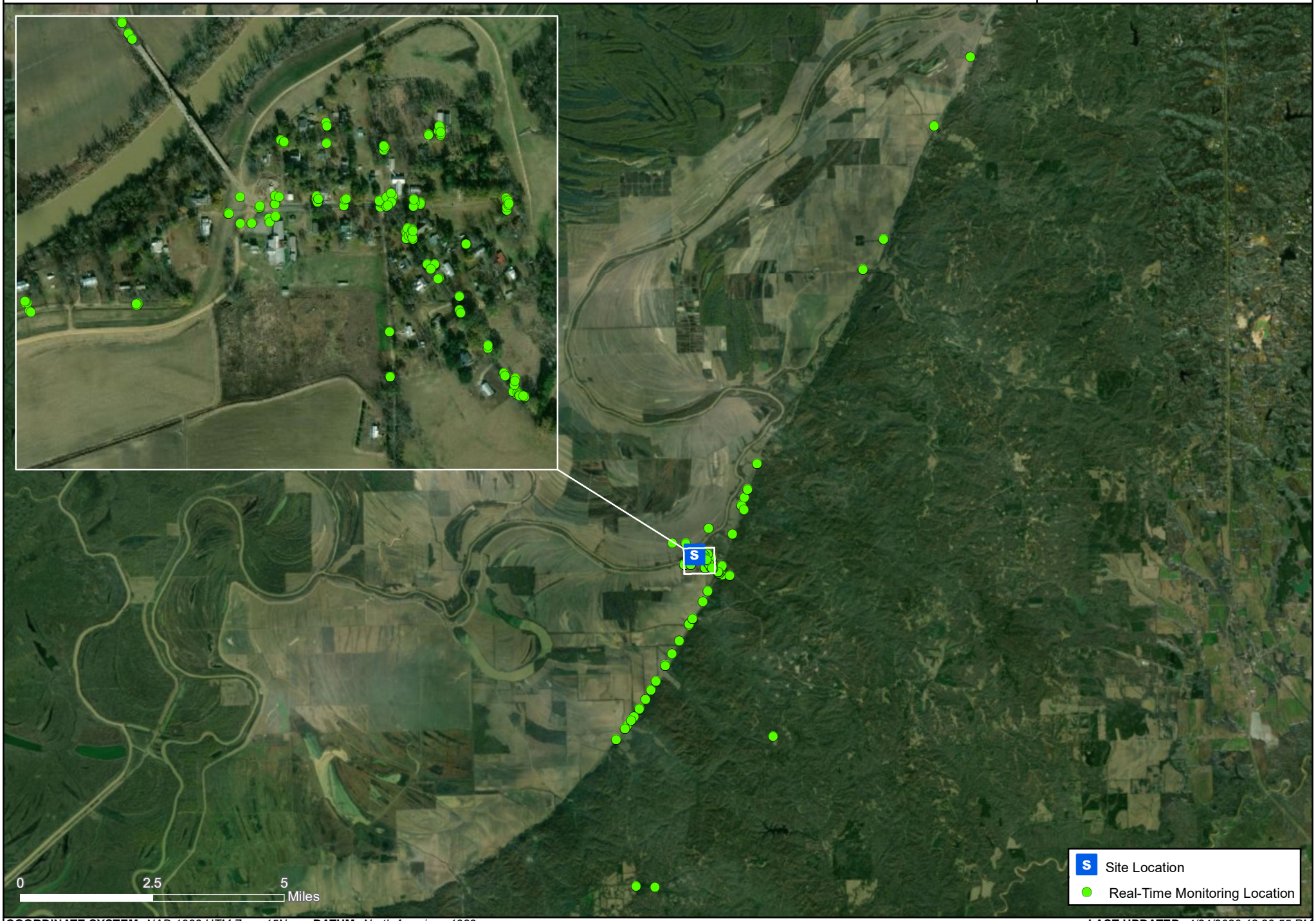
Document Name: 112628_site_location

Last Updated: *3/19/2020 1:44:18 PM*

Community Real-Time Air Monitoring Locations

CO_2 Pipeline Release | Satartia, MS | 2/22/2020 2230 - 2/23/2020 1134 CST

Project:112628
Client: Denbury
City: Satartia, MS
County: Yazoo



COORDINATE SYSTEM: *NAD 1983 UTM Zone 15N* **DATUM:** *North American 1983* **LAST UPDATED:** *4/24/2020 12:20:55 PM*

Indoor Assessment Real-Time Monitoring Locations

CO_2 Pipeline Release l Satartia, MS | 2/23/2020 0636 - 2/23/2020 1805 CST

Project:112628
Client: Denbury
City: Satartia, MS
County: Yazoo



COORDINATE SYSTEM: *NAD 1983 UTM Zone 15N* **DATUM:** *North American 1983* **LAST UPDATED:** *4/24/2020 12:10:31 PM*



Geologic Sequestration of Carbon Dioxide

Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance

Office of Water (4606M) EPA 816-R-13-005 May 2013

Disclaimer

The *Federal Requirements under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells* (75 FR 77230, December 10, 2010), known as the Class VI Rule, establishes a new class of injection well (Class VI).

The Safe Drinking Water Act (SDWA) provisions and U.S. Environmental Protection Agency (EPA) regulations cited in this document contain legally-binding requirements. In several chapters this guidance document makes suggestions and offers alternatives that go beyond the minimum requirements indicated by the Class VI Rule. This is intended to provide information and suggestions that may be helpful for implementation efforts. Such suggestions are prefaced by "may" or "should" and are to be considered advisory. They are not required elements of the rule. Therefore, this document does not substitute for those provisions or regulations, nor is it a regulation itself, so it does not impose legally-binding requirements on EPA, states, or the regulated community. The recommendations herein may not be applicable to each and every situation.

EPA and state decision makers retain the discretion to adopt approaches on a case-by-case basis that differ from this guidance where appropriate. Any decisions regarding a particular facility will be made based on the applicable statutes and regulations. Mention of trade names or commercial products does not constitute endorsement or recommendation for use. EPA is taking an adaptive rulemaking approach to regulating Class VI injection wells, and the agency will continue to evaluate ongoing research and demonstration projects and gather other relevant information as needed to refine the rule. Consequently, this guidance may change in the future without a formal notice and comment period.

While EPA has made every effort to ensure the accuracy of the discussion in this document, the obligations of the regulated community are determined by statutes, regulations or other legally binding requirements. In the event of a conflict between the discussion in this document and any statute or regulation, this document would not be controlling.

Note that this document only addresses issues covered by EPA's authorities under the SDWA. Other EPA authorities, such as Clean Air Act (CAA) requirements to report carbon dioxide injection activities under the Greenhouse Gas Mandatory Reporting Rule (GHG MRR), are not within the scope of this document.

Executive Summary

EPA's *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Sequestration Wells* has been codified in the U.S. Code of Federal Regulations (40 CFR 146.81 *et seq*.), and is referred to as the Class VI Rule. This rule establishes a new class of injection well (Class VI) and sets minimum federal technical criteria for Class VI injection wells for the purposes of protecting underground sources of drinking water (USDWs). This guidance is part of a series of technical guidance documents that EPA is developing to support owners or operators of Class VI wells and UIC Program permitting authorities in the implementation of the Class VI Rule. The Class VI Rule and related documents are available at http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm.

The Class VI Rule requires owners or operators of Class VI injection wells to delineate the area of review (AoR) for the proposed Class VI well, which is the region surrounding the proposed well where USDWs may be endangered by the injection activity [40 CFR 146.84]. The Class VI Rule requires that the AoR be delineated using computational modeling and the AoR must be reevaluated periodically during the lifetime of the geologic sequestration (GS) project [40 CFR 146.84]. Within the AoR, the owners or operators must identify all potential conduits for fluid movement out of the injection zone, including both geologic features and artificial penetrations [40 CFR 146.84(c)(1)(iii)]. The owner or operator must then evaluate those artificial penetrations that may penetrate the confining layer(s) of the injection project for the quality of casing and cementing, and in the case of abandoned wells, for the quality of plugging and abandonment, and perform corrective action on any identified artificial penetrations that could serve as a conduit for fluid movement [40 CFR 146.84(c)(2), 146.84(c)(3), and 146.84(d)]. The Class VI Rule allows, at the discretion of the UIC Program Director, the use of "phased" corrective action, where certain regions of the AoR are addressed prior to injection and other regions of the AoR are addressed during the injection phase of the project [40 CFR 146.84(b)(2)(iv)].

This guidance provides information regarding modeling requirements and recommendations for delineating the AoR, describes the circumstances under which the AoR is to be reevaluated, and describes how to perform an AoR reevaluation. In addition, the guidance presents information on how to identify, evaluate, and perform corrective action on artificial penetrations located within the AoR.

The introductory section reviews the definition of the AoR and regulations pertaining to AoR and corrective action in the Class VI Rule. Following that section:

- Section 2 addresses computational modeling of GS;
- Section 3 addresses AoR delineation using computational models;
- Section 4 addresses identification, evaluation, and performing corrective action on artificial penetrations within the AoR; and
- Section 5 addresses AoR reevaluation.

For each section, the guidance:

- Explains how to perform activities necessary to comply with AoR and corrective action requirements (e.g., performing computational modeling). Illustrative examples are provided in several cases;
- Provides references to comprehensive reference documents and the scientific literature for additional information; and
- Explains how to report to the UIC Program Director the results of activities related to AoR and corrective action.

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Acronyms and Abbreviations

AoR	Area of review
API	American Petroleum Institute
CAA	Clean Air Act
CFR	Code of Federal Regulations
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
GHG MRR	Greenhouse Gas Mandatory Reporting Rule
GPR	Ground penetrating radar
GS	Geologic sequestration
LBNL	Lawrence Berkeley National Laboratory
MAE	Mean-absolute error
mD	Millidarcies
ME	Mean error
MIT	Mechanical integrity test
MPa	Megapascals
PISC	Post-injection site care
RCSP	Regional Carbon Sequestration Partnership
RMSE	Root-mean squared error
SDWA	Safe Drinking Water Act
UIC	Underground Injection Control
USDW	Underground source of drinking water
USGS	United States Department of the Interior, United States Geological Survey

Definitions

Key to definition sources:

1: 40 CFR 146.81(d).
2: Definition drafted for the purposes of this document.
3: Class VI Rule Preamble.
4: 40 CFR 144.3.

Area of Review (AoR) means the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids, and is based on available site characterization, monitoring, and operational data as set forth in 40 CFR 146.84.[1]

Boundary condition parameters refers to the parameters that describe fluid flow rates and/or pressures at the edges of the model domain and in the location of injection/extraction wells.[2]

Capillary Pressure refers to the difference of pressures between two phases existing in a system of interconnecting pores or capillaries. The difference in pressure is due to the combination of surface tension and curvature in the capillaries.[2]

Computational code refers to a series of interrelated mathematical equations solved by computer to represent the behavior of a complex system. For the purposes of GS, computational models represent, at a minimum, the flow and transport of multiple fluids and components in varying phases through porous media. Computational codes offer the ability to predict fluid flow in the subsurface using scientifically accepted mathematical approximations and theory. The use of computational codes is necessary because the mathematical formulations describing fluid flow are complicated and in many cases, non-linear. Several codes have been specifically developed or tailored for injection activities similar to GS, and can be used for this purpose.[2]

Computational model means a mathematical representation of the injection project and relevant features, including injection wells, site geology, and fluids present. For a GS project, site specific geologic information is used as input to a computational code, creating a computational model that provides predictions of subsurface conditions, fluid flow, and carbon dioxide plume and pressure front movement at that site. The computational model includes all model input and predictions (i.e., outputs).[2]

Confining zone means a geologic formation, group of formations, or part of a formation stratigraphically overlying the injection zone(s) that acts as barrier to fluid movement. For Class VI wells operating under an injection depth waiver, confining zone means a geologic formation, group of formations, or part of a formation stratigraphically overlying and underlying the injection zone.[1]

Constitutive relationship typically means, empirically based approximations used to simplify the system and estimate unknowns in cases where the parameters of the governing equations are not readily available for use in the equation because necessary information is not typically measurable, and thus not directly input into the model. An example of a constitutive relationship is relative permeability-saturation functions. These functions estimate the relative permeability of a particular fluid in a porous media as a function of its saturation at a given location and time. This permeability is then used in the governing equation to predict flow.[2]

Equation of state refers to an equation that expresses the equilibrium phase relationship between pressure, volume and temperature for a particular chemical species.[2]

Geologic sequestration (GS) means the long-term containment of a gaseous, liquid or supercritical carbon dioxide stream in subsurface geologic formations. This term does not apply to carbon dioxide capture or transport.[1]

Geophysical surveys refers to the use of geophysical techniques (e.g., seismic, electrical, gravity, or electromagnetic surveys or well logging methods such as gamma ray and spontaneous potential) to characterize subsurface rock formations.[3]

Governing equation refers to the mathematical formulae that form the basis of the computational code are termed governing equations. For GS modeling, they govern the predicted behavior of fluids in the subsurface provided by the code. Governing equations are mathematical approximations for describing flow and transport of fluids and their components in the environment.[2]

Ground Penetrating Radar (GPR) refers to a geophysical method that utilizes microwave technology in order to characterize features found in the subsurface.[2]

Heterogeneity refers to the spatial variability in the geologic structure and/or physical properties of the site.[2]

Hysteresis means the phenomenon where the response of a system depends not only on the present stimulus, but also on the previous history of the medium. For example, in a GS project, relative permeability, capillary pressure, and residual trapping will depend upon the saturation history of the formation.[2]

Immiscible refers to the property wherein two or more liquids or phases do not readily dissolve in one another.[2]

Initial conditions refers to parameter values at the start of the model simulation.[2]

Intrinsic permeability refers to a parameter that describes properties of the subsurface that impact the rate of fluid flow. Larger intrinsic permeability values correspond to greater fluid flow rates. Intrinsic permeability has units of area (distance squared).[2]

Model calibration means adjusting model parameters in order to minimize the difference between model predictions and monitoring data at the site.[2]

Multiphase flow refers to flow in which two or more distinct phases are present (e.g., liquid, gas, supercritical fluid).[2]

Numerical Artifacts refers to model results that are created erroneously based on computational limitations of the model, which may result from improper model development.[2]

Parameter means a mathematical variable used in governing equations, equations of state, and constitutive relationships. Parameters describe properties of the fluids present, porous media, and fluid sources and sinks (e.g., injection well). Examples of model parameters include intrinsic permeability, fluid viscosity, and fluid injection rate.[2]

Relative permeability refers to a factor, between 0 and 1, that is multiplied by the intrinsic permeability of a formation to compute the effective permeability for a fluid in a particular pore space. When immiscible fluids (e.g., carbon dioxide, water) are present within the pore space of a formation, the ability for flow of those fluids is reduced, due to the blocking effect of the presence of the other fluid. This reduction is represented by relative permeability.[2]

Sensitivity Analyses refers to the study of how the output of a model varies based in changes to an input variable or model parameter over a specified range of values. The results of a sensitivity analysis determine the which input variable and model parameter variability have the greatest effect on the model results.[2]

Stochastic Methods means the use of probability statistical methods in development of one or more possible realizations of the spatial patterns of the value(s) of a given set of model parameters.[2]

Underground Injection Control Program refers to the program EPA, or an approved state, is authorized to implement under the Safe Drinking Water Act (SDWA) that is responsible for regulating the underground injection of fluids by wells injection. This includes setting the federal minimum requirements for construction, operation, permitting, and closure of underground injection wells.[2]

Underground Source of Drinking Water (USDW) means an aquifer or its portion which supplies any public water system; or which contains a sufficient quantity of ground water to supply a public water system; and currently supplies drinking water for human consumption; or contains fewer than 10,000 mg/l total dissolved solids; and which is not an exempted aquifer.[4]

Unit Conversions

Imperial/Non-Metric Unit	Metric Unit
1 Foot	0.3048 Meters
1 Mile	1.609 Kilometers
1 Pound per Square Inch (psi)	0.006895 Megapascals (MPa)
Temperature in Degrees Fahrenheit (ºF)	Temperature in Degrees Celsius = (ºF – 32) x 0.56
1 Pound (lb)	0.4536 Kilograms
1 Megatonne (Mt)	1 x 10^6 Tonnes
1 Metric Ton (tonne; t)	1,000 kg
1 Cubic Foot	0.0283 Cubic Meters

1. Introduction

Area of review (AoR) evaluations and corrective action are long-standing permit requirements of the Underground Injection Control (UIC) Program of the U.S. Environmental Protection Agency (EPA). The AoR refers to the delineated region surrounding the injection well(s) wherein the potential exists for underground sources of drinking water (USDWs) to be endangered by the leakage of injectate and/or formation fluids. Typically, for injection well classes other than Class VI, the AoR is defined either as a fixed radius around the injection well or by a relatively simple radial calculation. Owners or operators of injection wells are required to identify any potential conduits for fluid movement, including artificial penetrations (e.g., abandoned well bores) within the AoR, assess the integrity of any artificial penetrations, and perform corrective action where necessary to prevent fluid movement into a USDW [40 CFR 144.55, 146.84(d)].

The Class VI Rule introduces enhanced AoR and corrective action requirements for Class VI injection wells that are tailored to the unique circumstances of geologic sequestration (GS) of carbon dioxide projects [40 CFR 146.84]. The purpose of this guidance is to identify appropriate methods for delineating the AoR and performing corrective action for Class VI injection wells. The intended primary audiences of this guidance document are Class VI injection well owners or operators and their representatives conducting AoR delineation modeling or performing artificial penetration identification, assessment, and corrective action activities. The UIC Program staff who are responsible for reviewing and approving Class VI injection well permit applications and related reports concerning AoR delineation and corrective action are another intended audience of this guidance document.

This document is one of a series of technical guidance documents intended to provide information and possible approaches for addressing various aspects of permitting and operating a Class VI injection well. Three of these companion guidance documents focus on site characterization, well construction, and testing and monitoring:

- The *UIC Program Class VI Well Site Characterization Guidance*;
- The *UIC Program Class VI Well Construction Guidance*; and
- The *UIC Program Class VI Well Testing and Monitoring Guidance.*

These guidance documents are intended to complement each other and to assist owners or operators in preparing permit applications that satisfy the requirements of the Class VI Rule. Class VI injection well regulations are tailored to the characteristics of individual sites. For example, the required site characterization data collected will inform the model development for AoR delineation, and AoR models will be reevaluated, and perhaps change, based on the results of site testing and monitoring data (Figure 1-1). Cross-linkages between guidance documents are noted in the text where appropriate. Additional guidance on developing, presenting, and using the required Class VI project plan information as part of a Class VI injection well permit application is provided in the *UIC Program Class VI Well Project Plan Development Guidance*.

1.1. Overview of the Class VI Rule AoR and Corrective Action Requirements

The Class VI Rule defines the AoR as the region surrounding the GS project where USDWs may be endangered by the injection activity [40 CFR 146.84(a)]. The purpose of the AoR and corrective action requirements of the Class VI Rule is to ensure that the areas potentially impacted by a proposed GS operation are delineated, all wells that need corrective action receive it, and that this process is updated throughout the injection project. While the details of all of the requirements are presented in later sections of this guidance, the basic requirements that owners or operators of GS projects must meet include:

- Prepare, maintain, and comply with an AoR and Corrective Action Plan that includes all of the required elements of the plan [40 CFR 146.84(b)];
- Delineate the AoR using computational modeling and identify all wells that require corrective action [40 CFR 146.84(c)];
- Perform all required corrective action on wells in the AoR [40 CFR 146.84(d)];
- Reevaluate the AoR throughout the life of the project [40 CFR 146.84(e)];
- Ensure that the Emergency and Remedial Response Plan and financial responsibility demonstration account for the most recently approved AoR [40 CFR 146.84(f)]; and
- Retain modeling inputs and data used to support AoR reevaluations for 10 years [40 CFR 146.84(g)].

If a vertical leakage pathway out of the injection zone is present, USDWs in the vicinity of a proposed Class VI injection well may be endangered by (1) movement of carbon dioxide into the USDW, impairing drinking water quality through changes in pH, contamination by trace impurities in the injectate (e.g., mercury, hydrogen sulfide), and leaching of metals and/or organics; and (2) movement of non-potable water (e.g., brine) out of the injection formation into a USDW as caused by elevated formation pressures induced by injection. Therefore, the AoR encompasses the region overlying the separate-phase (e.g., supercritical, liquid, or gaseous) carbon dioxide plume and the region overlying the pressure front where fluid pressures are sufficient to force fluids into a USDW. While it may often be the case that the AoR will encompass the boundary of the GS project, within which all project activities will occur, the Class VI Rule does not require that the AoR and overall project boundary be equivalent in all cases.

The Class VI Rule requires that "the AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data" [40 CFR 146.84(a)]. As discussed below, GS computational modeling for Class VI injection wells is complex and requires advanced methods. Additionally, the AoR must be reevaluated at a minimum fixed frequency not to exceed five years, or when monitoring and operational conditions warrant [40 CFR 146.84(e)]. The purpose of Class VI well AoR reevaluations is to

ensure that site monitoring data are used to update modeling results, and that the AoR delineation reflects any changes in operational conditions. The general relationship between site characterization, modeling, and monitoring activities at a GS project is shown in Figure 1-1.

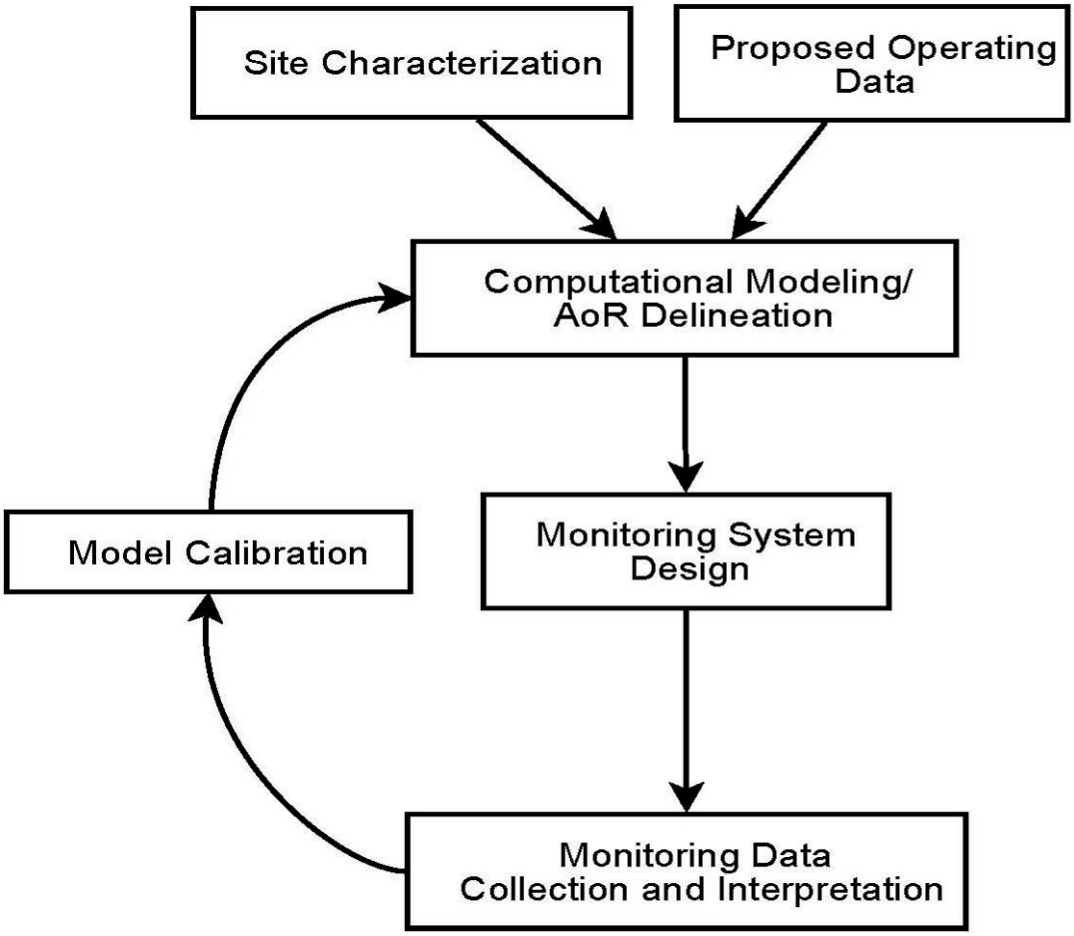


Figure 1-1: Flow Chart of Monitoring and Modeling at a GS Project.

An individual Class VI permit must be obtained separately for each injection well, as area permits are not allowed under the Class VI Rule [40 CFR 144.33]. However, EPA anticipates that, in many cases, multiple injection wells will be operated within a single GS project. If approved by the UIC Program Director, AoR delineation and corrective action activities may be performed collectively for all wells included within a single project. All required submittals (e.g., maps of the delineated the AoR and the AoR and Corrective Action Plan) must be submitted separately for each well, however, so that they may be incorporated into each well's Class VI permit. In all cases, EPA recommends that AoR delineation models account for all wells injecting into (including any injection wells associated with other UIC well classes or other Class VI operations) or pumping from the injection zone or any other zones that are hydraulically connected to the injection zone.

The corrective action requirements for Class VI wells are generally similar to those for other injection well classes. However, due to the potentially large AoR of GS projects, EPA has allowed the use of phased corrective action, if approved by the UIC Program Director [40 CFR 146.84(b)(2)(iv)]. If phased corrective action is approved by the UIC Program Director, owners or operators would be allowed to perform corrective action only on the subset of artificial penetrations located within the AoR prior to injection that are located in regions nearest the injection well(s). Corrective action would continue during injection in the remaining regions of the AoR prior to carbon dioxide migration or pressure elevation in that area. EPA encourages owners or operators to perform all necessary corrective action on deficient wells identified during the initial AoR delineation or AoR reevaluations before the end of the injection phase.

As a part of a Class VI permit application, the owner or operator must submit an AoR and Corrective Action Plan that describes the anticipated activities that will be performed to comply with these requirements [40 CFR 146.84(b)]. The AoR and Corrective Action Plan must be approved by the UIC Program Director prior to submittal of the initial AoR delineation and issuance of a permit [40 CFR 146.84(b)]. This plan will facilitate dialogue between the owners or operators and the UIC Program Director to ensure that the UIC Program Director understands and agrees early in the project lifetime with the methods necessary to delineate the AoR and complete all required corrective action. A Class VI AoR and Corrective Action Plan must include the following information [40 CFR 146.84(b)]:

1. The method for delineating the AoR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;
2. The minimum fixed frequency, at least once every five (5) years, that the owner or operator proposes to reevaluate the AoR;
3. The site- and project-specific monitoring and operational conditions that would warrant a reevaluation of the AoR prior to the next routinely scheduled reevaluation;
4. How specific monitoring and operational data (e.g., injection rate and pressure) will be used to inform an AoR reevaluation;

5. How corrective action will be conducted, including what corrective action will be performed prior to injection and what, if any, portions of the AoR will have corrective action addressed on a phased basis and how the phasing will be determined;
6. How corrective action will be adjusted if there are changes in the AoR; and
7. How site access will be guaranteed for future corrective action.

The requirements related to the AoR and Corrective Action Plan are discussed in depth in the *UIC Program Class VI Well Project Plan Development Guidance*.

1.2. Organization of this Guidance

This guidance document is organized to generally follow the sequence of AoR delineation and corrective action activities that an owner or operator will perform over the life of a proposed and later permitted Class VI injection project. These activities will generally proceed as described below.

Prior to the issuance of a permit for the construction of a new Class VI well (or the conversion of an existing well):

1. Collection of relevant site characterization and operational data [40 CFR 146.82(a)(3), 146.82(a)(5), 146.82(a)(6), and 146.83];

2. Determination of relevant operational data that will inform the AoR modeling [40 CFR 146.82(a)(7), and 146.82(a)(10)-(11)];

3. Development of an AoR and Corrective Action Plan [40 CFR 146.82(a)(13) and 146.84(b)];

4. Performing AoR modeling and delineation [40 CFR 146.82(a)(2)]; and

5. Identification and assessment of artificial penetrations within the AoR [40 CFR 146.82(a)(4)].

Prior to granting approval for injection:

6. Collection and/or updating of relevant site characterization and operational data that will inform AoR modeling [40 CFR 146.82(c)(2)-(5), 146.82(c)(7), and 146.83];

7. Identification of any needed updates to the AoR and Corrective Action Plan [40 CFR 146.82(c)(9)];

8. Finalizing AoR modeling and delineation [40 CFR 146.82(c)(1)]; and

9. Performing corrective action on those penetrations that may serve as a conduit for fluid movement [40 CFR 146.82(c)(6) and 146.84(d)].

During injection and post-injection site care (PISC):

10. Reevaluation of the AoR periodically, at least once every five (5) years [40 CFR 146.82(c)(9) and 146.84(e)], and updating the AoR and Corrective Action Plan; and

11. If phased corrective action is approved or when additional corrective action is warranted based on AoR reevaluations, performing corrective action [40 CFR 146.82(c)(6) and 146.84(d)].

Activities (1) through (5) must be performed prior to receiving approval to construct a Class VI injection well and activities (6) through (9) must be performed prior to receiving approval to inject carbon dioxide, and their results must be submitted to the UIC Program Director as part of the Class VI injection well permit application [40 CFR 146.82(a)]. The remaining activities will be performed after a permit application has been approved by the UIC Program Director and the Class VI injection well is actively operating.

This guidance document generally focuses on activities (4), (5), (8), (9), (10), and (11), as follows:

- Section 2 provides background on computational modeling of GS activities;
- Section 3 discusses performing computational modeling to delineate the AoR and comply with permit requirements (activities 4 and 8);
- Section 4 focuses on abandoned well identification, assessment, and corrective action on all artificial penetrations within the AoR (activities 5, 9, and 11); and
- Section 5 focuses on reevaluation of the AoR (activity 10).

Site characterization activities (activities 1 and 6) are discussed briefly in this guidance (Section 3.2), and are covered in more detail in the *UIC Program Class VI Well Site Characterization Guidance*. Preparation of the AoR and Corrective Action Plan (activity 3) and identification of any updates (activity 7) are also discussed briefly herein, and in more detail in the *UIC Program Class VI Well Project Plan Development Guidance*.

2. Computational Modeling for Geologic Sequestration

This section discusses the fundamentals of computational modeling for GS to provide the necessary background for owners or operators, and to assist in understanding and complying with the Class VI Rule. While computational modeling for GS may entail a vast amount of complex information, the purpose of this section is to provide a brief introduction to the modeling techniques and fundamentals that may be necessary or significant for satisfying the specific rule requirements. Following an introduction that explains the use of modeling in the context of meeting the requirements of the Class VI Rule:

- Section 2.1 discusses the processes that can be modeled;
- Section 2.2 presents a discussion of the parameters that are included in AoR models;
- Section 2.3 presents available computational approaches, including numerical, analytical, semi-analytical, and hybrid approaches;
- Section 2.4 discusses model uncertainty and sensitivity analyses;
- Section 2.5 discusses model calibration; and
- Section 2.6 provides an overview of existing codes used for development of GS models.

The AoR for a Class VI injection project must be delineated using a computational model that accounts for the physical and chemical properties of all phases of the injected carbon dioxide [40 CFR 146.84(a)]. A computational model is based on available data, and it is a mathematical representation of the GS project and relevant features, including injection wells, site geology, and fluids present. As described below, a site-specific computational *model* is designed by incorporating the GS site and operational characteristics into a computational *code*, which is a computer program that has been designed to simulate multiphase flow and other pertinent processes in geologic media based on scientific principles and accepted mathematical (i.e., governing) equations.

Computational codes that may be used for modeling of GS are necessarily more technically complex than commonly used ground water flow codes because GS modeling considers multiphase (e.g., gas, liquid, supercritical fluid) flow of several fluids (i.e., ground water, carbon dioxide, hydrocarbons), phase changes of carbon dioxide, heat flow, and significant pressure changes. Furthermore, in some cases models consider reactive transport (e.g., chemical reactions between constituents) and geomechanical processes (e.g., induced fault activation). As discussed below, the Class VI Rule requires that the AoR be delineated using models that include multiphase flow [40 CFR 146.84(a)], but not necessarily reactive transport or geomechanical processes. However, inclusion of these processes in the AoR delineation model may be important in some cases and may be required by the UIC Program Director.

Several codes are available that are capable for use in development of adequate models for delineation of the AoR at a GS site and for complying with Class VI injection well permit requirements (Section 2.6). Although available codes are sophisticated and based on the best-available scientific understanding, computational models are approximations and are never perfect representations of reality, and they cannot provide a completely accurate prediction of fluid movement at a GS site. Therefore, the characterization of model uncertainty, using sensitivity analyses, and conducting model calibrations are very important parts of many computational approaches.

Research studies have provided valuable information on the capabilities of available models, what information may be collected in order to properly inform model development, and how the model results may be presented. Importantly, the information and guidance provided here is based on currently available data, scientific research, and project experience. EPA recognizes that data collected from future GS projects may advance GS computational modeling and AoR delineation. EPA is committed to an adaptive approach for regulation of GS projects and may revisit aspects of Class VI federal regulations, and guidance, as new data becomes available.

There is a long history of simulating multiphase flow and transport in porous media using computational models. Comprehensive reviews of multiphase flow in porous media and modeling are provided elsewhere (e.g., Pinder and Gray, 2008; Miller et al., 1998; Gerritsen and Durlofsky, 2005; Finsterle, 2004). These models solve a series of governing equations to predict the composition and volumetric fraction of each phase state (e.g., liquid, gas, supercritical fluid) as a function of space and time for a particular set of circumstances. Governing equations are formulated to describe the flow and transport of several chemical species in several phases, in which interphase mass transfer may be important. Typically, flow equations are derived by substituting a multiphase form of Darcy's Law into continuum balance expressions.

The solution of the continuum balance equations requires that they be supplemented with closure relations that express unknowns in terms of accessible parameters. These include equations of state and constitutive relationships. Equations of state express the equilibrium phase relationship between pressure, volume, and temperature for a particular chemical. Accepted equations of state for carbon dioxide are presented in Figure 2-1, and are discussed in Section 2.2.4. Constitutive relationships are typically empirically based approximations used to simplify the system and estimate unknowns. Examples of constitutive relationships are saturation-relative permeability relationships, interphase mass transfer relations, and solution reaction relations.

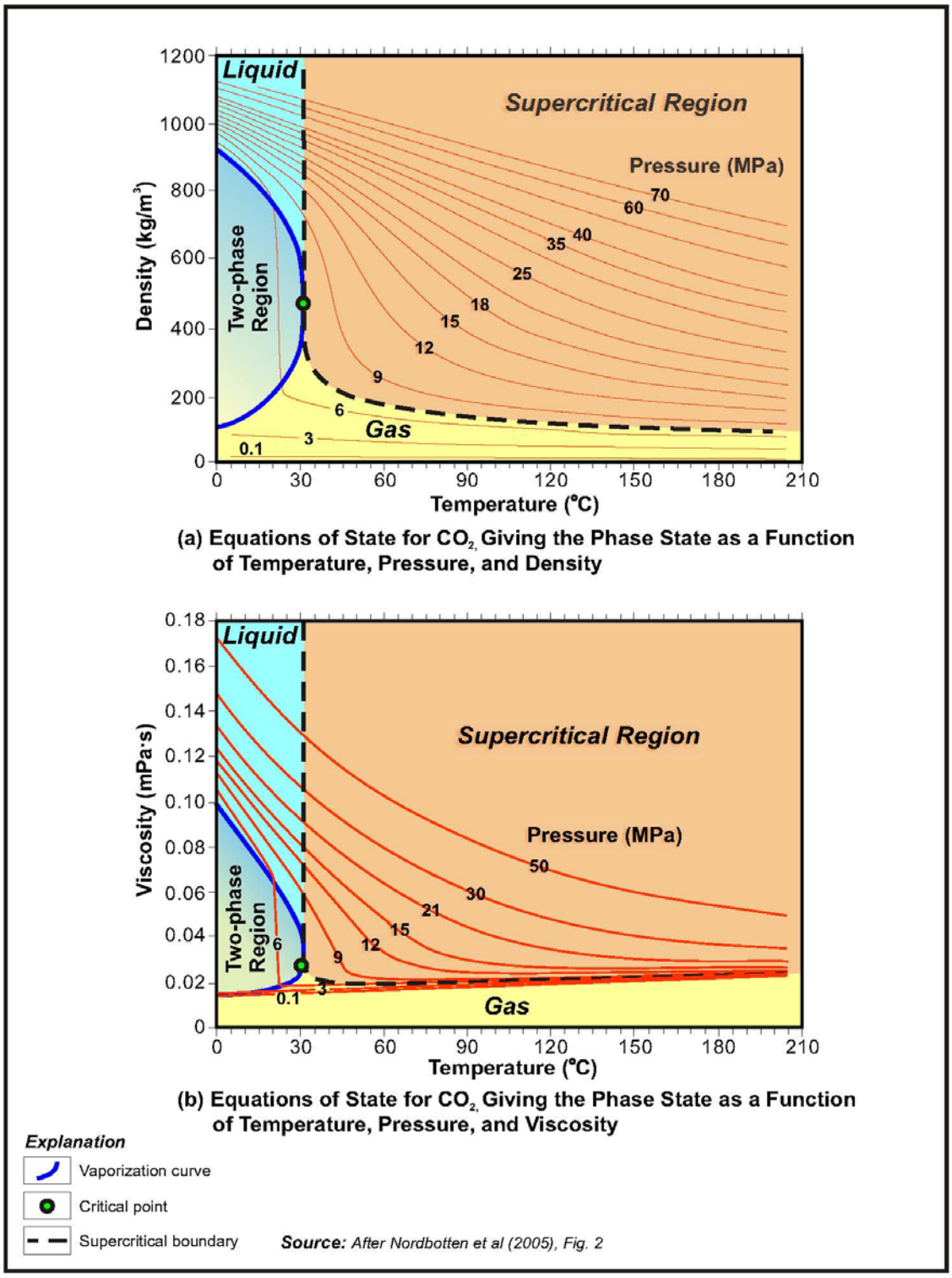


Figure 2-1: Equations of State for Carbon Dioxide.

2.1. Modeled Processes

Computational codes used for GS vary in complexity and may include routines for multiphase flow, reactive transport, and geomechanical processes. Traditionally, codes have been developed as separate entities to simulate these processes. Present-day simulators typically address and couple multiphase flow with geomechanical processes or geochemical processes. However, depending on site-specific characteristics, where the geochemical and geomechanical processes are significant, robust simulation of GS may require interactive coupling of all three processes. The Class VI Rule only requires that multiphase flow be included in computational modeling. However, the owner or operator, or the UIC Program Director, may determine that reactive transport and/or geomechanical modeling should also be included for a particular proposed project. For example, reactive transport could be relevant if permeability and/or porosity are predicted, based on previous testing, to change as a result of precipitation/dissolution reactions. Geomechanical processes could be relevant if previous testing has indicated that pressure and stress changes hydrogeologic properties and/or affects confining unit integrity.

Codes used to simulate multiphase flow generally incorporate some or all of the following processes: phase transition behavior of carbon dioxide (gas, liquid, supercritical fluid) and associated buoyancy; dissolution of carbon dioxide in brine and oil and associated increased density; dissolution of water in carbon dioxide; variable viscosity and density of brine and carbon dioxide phases; thermal effects such as cooling or freezing due to carbon dioxide expansion from supercritical and liquid phases; and reduced fluid permeability due to the presence of several immiscible fluids within a pore space.

Codes used to simulate reactive transport generally incorporate rate-limited intra-aqueous reactions, mineral dissolution and precipitation, changes in porosity and permeability due to these reactions, and multi-component gas mixtures. Reactive transport models can be used to determine the impact of carbon dioxide and its co-injectates (e.g., hydrogen sulfide, sulfur dioxide) on aquifer acidification, the concomitant mobilization of metals, and any mineral trapping of carbon dioxide (e.g., precipitation of carbonate minerals). Reactive transport models can also be used to assess corrosion of well construction materials as influenced by carbon dioxide.

The length scales associated with interfacial geochemistry are very small (e.g., micrometers to millimeters) compared to multiphase flow simulation (meters to kilometers). Small grid spacing around these regions may imply associated small time steps, so that the overall problem becomes computationally demanding when trying to couple these reactions to multiphase flow. Data related to geochemical rate parameters are generally lacking (e.g., Knauss et al., 2005; Xu et al., 2006), and have to be estimated for a wide range of possible environmental conditions and mineralogical interfaces. Several common codes that may be used for AoR delineation, such as ECLIPSE, normally do not include routines for reactive transport.

Geomechanical codes can be used to evaluate the effect of reservoir pressurization and buoyancy on the integrity of geologic confining units, reactivation of existing fractures and faults, and rock properties such as porosity and permeability. The amount and spatial distribution of pressure

buildup in a geologic formation will depend on the rate of injection, the permeability and thickness of the injection formation, the mechanistic properties of the rock matrix, the permeability of the confining units, and the presence or absence of permeability barriers, and boundary conditions of the system. Models used to simulate geomechanical processes generally incorporate effective stress/strain relationships, aperture stiffness and associated closing and widening, and variation in porosity and permeability. Geomechanical modeling may require simulation on both a large and small scale (individual fractures), which can be computationally challenging (i.e., require long model processing times on the order of days). When individual fractures are considered, the spatial grid resolution may need to be on the order of meters or less. Therefore, smaller-domain models may be necessary to investigate migration through individual fractures. Generally, simulation of flow through a fractured reservoir requires codes that have been designed for this purpose.

2.2. Model Parameters

A parameter is a variable in the governing equations of the model that may be of uniform value throughout the domain, or may vary in space and time. While maintaining salient features of the hydrogeologic system, some system aspects are often lumped together in simulation models and described by effective parameters that are estimated or averaged from several data sources. Relevant parameters for multiphase flow modeling of GS are summarized in Table 2-1, and include hydrogeologic characteristics, fluid properties, chemical properties, fluid injection and withdrawal rates, initial and boundary conditions, system orientation (e.g., model domain, grid cell size), and simulation control parameters. Initial conditions describe parameter values at the start of the model run. Boundary condition parameters describe conditions of the system (e.g., fluid flow rates and/or pressures) at the edges of the model domain and at the location of injection and/or extraction wells. While fluid injection and/or withdrawal rates and simulation control parameters are project specific, other particularly important site- and project-specific parameters for GS include formation intrinsic permeability, porosity, relative permeability, compressibility, fluid viscosity, and fluid density. These parameters are discussed in the following subsections.

Parameter values are to be based on site data to the extent possible. However, as discussed below, in cases where detailed site geologic characterization data are unavailable (i.e., if formation testing is not complete or core samples are not available), parameter values may be estimated from standard values or relationships in the scientific literature. Model calibration, which may occur during AoR reevaluation, consists of adjusting a subset of the estimated parameter values to minimize the difference between model simulations and observed monitoring data. Model parameters may also be adjusted based on newly acquired site characterization data. For example, data gathered during well logging may inform updates to parameter values. See the *UIC Program Class VI Well Site Characterization Guidance* for more information.

Table 2-1: Model Parameters for Multiphase Fluid Modeling of Geologic Sequestration.

Parameter	Description	Estimation Methods	Dimensions
Hydrogeologic Properties			
Intrinsic Permeability	Represents properties of the subsurface that impact the rate of fluid flow.	See the *UIC Program Class VI Well Site Characterization Guidance*, and Section 2.2.1 of this guidance	L^2
Porosity	The relative volume of void space within a formation. Controls the volume of carbon dioxide that may be stored.	See the *UIC Program Class VI Well Site Characterization Guidance*	Dimensionless
Capillary Pressure	The pressure difference across the interface of two immiscible fluids (e.g., carbon dioxide and water)	Calculated based on fluid saturations (see Section 2.2.2 of this guidance)	M/LT^2
Relative Permeability	Factor that determines the decrease in permeability for a fluid due to the presence of other immiscible fluids	Calculated based on fluid saturations (see Section 2.2.2 of this guidance)	Dimensionless
Fluid Pressure	Force acting on a unit area, measure of the potential energy per volume of fluid	See the *UIC Program Class VI Well Site Characterization Guidance*	M/LT^2
Temperature	Measure of the internal energy of a fluid	See the *UIC Program Class VI Well Site Characterization Guidance*	Temperature
Formation Compressibility	Measure of change in aquifer volume with a change in fluid pressure	See the *UIC Program Class VI Well Site Characterization Guidance*	LT^2/M
Water Saturation	The percent of system void space occupied by aqueous fluids	See the *UIC Program Class VI Well Site Characterization Guidance*	Dimensionless
Carbon Dioxide Saturation	The percent of system void space occupied by carbon dioxide	Calculated by the computational model	Dimensionless
Storativity	The volume of fluid released from storage per unit decline in head per unit area of the formation	See Standard References, e.g., Fetter, 2001	Dimensionless
Fluid Properties			
Viscosity	Measure of the internal resistance to flow	Calculated based on equations of state, also influenced by fluid composition (see Section 2.2.4 of this guidance)	M/LT

Parameter	Description	Estimation Methods	Dimensions
Density	The mass of a fluid per unit volume	Calculated based on equations of state, also influenced by fluid composition (see Section 2.2.4 of this guidance)	M/L^3
Composition	Molecular makeup, by volume or mass, of a fluid. Measurement of salinity, concentration of trace compounds	See the *UIC Program Class VI Well Site Characterization Guidance*	M/L^3
Fluid Compressibility	The change in volume of a fluid from a unit change in pressure	See Standard References, e.g., Perry and Green, 1984	LT^2/M
Chemical Properties			
Aqueous Diffusion Coefficient	The rate of chemical transport due to a concentration gradient	See Standard References, e.g., Tamimi et al., 1994	L^2/T
Aqueous Solubility	The maximum concentration of a chemical (e.g., carbon dioxide) dissolved in the aqueous phase	Salinity, temperature and pressure dependent (see Spycher et al., 2003; Spycher and Pruess, 2005)	M/L^3
Solubility in Carbon Dioxide	The maximum concentration of a chemical (e.g., water) dissolved in separate-phase carbon dioxide.	Temperature and pressure dependent (see Spycher et al., 2003; Spycher and Pruess, 2005)	M/L^3
Fluid injection and withdrawal rates			
Injection Rates	Injection rates at each well	Planned site operational data	L^3/T
Withdrawal Rates	Any fluid withdrawal rates within model domain	Measure rates for wells conducting pumping within the AoR	L^3/T
Boundary Conditions	Fluid pressures and/or flow rates at the edges of the model domain	Tested in conjunction with model extent, to ensure no artificial influence on model results	Varies
Fluid injection and withdrawal rates (Continued)			
Initial Conditions	Fluid pressures and/or flow rates within the domain at the beginning of the model run	Based on pre-injection site characterization data, see the *UIC Program Class VI Well Site Characterization Guidance*	Varies

Parameter	Description	Estimation Methods	Dimensions
System Orientation and Simulation Controls			
Model Extent (domain)	The lateral extent of the model in all directions	Tested in conjunction with boundary conditions, to ensure no artificial influence on model results	L
Number of Model Layers	Model vertical discretization	Based on conceptual site model of site stratigraphy, see the *UIC Program Class VI Well Site Characterization Guidance*	Dimensionless
Layer Thickness	Vertical extent of each model layer	See the *UIC Program Class VI Well Site Characterization Guidance*	L
Grid Cell Size	Lateral size of each model cell	May vary throughout domain, as dictated by conceptual model and computational necessities	L^2
Model Timeframe	The complete duration of the model run	Tested to ensure long enough to allow for pressure decline to pre-injection conditions	T
Time Step Size	The duration of each temporal interval during the model timeframe	Often controlled by code, tested to ensure small enough to not artificially influence results	T

L = Length; M = Mass; T = Time

2.2.1. Intrinsic Permeability

Intrinsic permeability is a property of the solid phase (i.e., porous medium) in the subsurface that impacts the rate of fluid flow. Larger intrinsic permeability values correspond to greater fluid flow rates. Intrinsic permeability has units of length squared and is often reported in the units of millidarcies (mD); one mD is equal to $9.9 \cdot 10^{-16}$ square meters (m^2). Typical permeability values for an injection zone at a GS project range from 1 to 10^2 mD (e.g., Sorensen et al., 2005; Fischer et al., 2005; MGSC, undated; ISGS, 2009). Typical permeability values for a confining unit (e.g., shale) range from 10^{-7} to 10^{-4} mD (e.g., Soeder, 1988).

Intrinsic permeability incorporates the effects of formation porosity, pore structure, such as pore-size distribution and connectivity, and the presence of fractures or faults. The spatially heterogeneous nature of subsurface materials results in a heterogeneous intrinsic permeability distribution in most formations. Additionally, intrinsic permeability is an anisotropic parameter, in that lateral intrinsic permeability is often significantly larger than vertical intrinsic permeability due to depositional layering. Anisotropy in intrinsic permeability, both vertical and horizontal, may also be an effective property of fractured rock media. Intrinsic permeability is typically estimated from a combination of hydrogeologic field tests (e.g., aquifer tests, pressure

fall-off tests), laboratory core analysis, and geophysical well logging. The *UIC Program Class VI Well Site Characterization Guidance* provides details regarding estimation of formation intrinsic permeability. Intrinsic permeability values are often adjusted during model calibration. See Box 2-1 for more information.

During the development of the computational model, the model developer determines how to estimate values of intrinsic permeability within the entire model domain based on results of site characterization activities at discrete locations. For modeling purposes, the simplest description of intrinsic permeability is a homogenous distribution, which incorporates a single value for the entire subsurface domain based on an average of available data. A model that assumes a homogeneous permeability distribution, however, will not account for heterogeneity (if it exists) that causes preferential flow paths or confining strata, or for the depth dependence of permeability in an updipping formation. Another option is to incorporate a layered distribution, which incorporates a single permeability value for each geologic stratum in the domain, and can be constructed by using geologic maps and cross-sections of the proposed project site.

Alternatively, geostatistical and stochastic methods are available to create a statistical ensemble of possible permeability distributions that incorporate both lateral and vertical heterogeneity based on available site characterization data. Spatial variability of permeability is thus described by a relatively small number of geostatistical parameters. Considering the large areas that are anticipated to be modeled for AoR delineations of proposed Class VI injection well project sites, techniques are among the best methods for incorporating realistic heterogeneity distributions into the computational model with limited data (see inset, Box 3-1).

Compared to homogeneous or layered permeability distributions, depending on the available data, intrinsic permeability fields developed with geostatistical techniques may provide a more realistic representation of conditions within the formation, and resulting models may better represent carbon dioxide migration through high-permeability channels. Commercial software packages are available for use in the development of heterogeneous intrinsic permeability distributions based on available site data (e.g., T-PROGS; Carle, 1999). See Doughty and Pruess (2004), Juanes et al. (2006), Obi and Blunt (2006), and Flett et al. (2007) for examples of the development of heterogeneous profiles based on geostatistical techniques. For more information regarding the use of geostatistical methods, see the *UIC Program Class VI Site Characterization Guidance*.

Several previous studies have evaluated the impact of permeability values on computational modeling results, through the use of parameter sensitivity analyses. Law and Bachu (1996) and Lindeburg (1997) demonstrated that for a homogeneous system, carbon dioxide mobility increases with increased formation permeability. Comparing homogeneous formations and those with layered heterogeneities, Lindeberg (1997) showed that the presence of thin shale layers increases sweep and thus carbon dioxide dissolution. For systems that are heterogeneous in three dimensions, Flett et al. (2007) illustrated that increased heterogeneity resulted in increased lateral migration and therefore dissolution. However, increasing heterogeneity also decreased the rate of residual phase trapping by delaying water imbibition into previously carbon dioxide-filled pore space. Overall, increased heterogeneity resulted in slower carbon dioxide migration and

decreased accumulation at the confining layer compared to a homogeneous case. Pruess (2008) showed that for discharge through a fault, decreased fault permeability resulted in delayed leakage to the surface and an increased maximum leakage rate.

Simulations by Zhou et al. (2008) indicate that patterns of formation pressure increase induced by carbon dioxide injection are sensitive to permeability. Larger formation permeability values resulted in less localized pressure increase surrounding the injection well. In addition, larger confining layer permeability resulted in less pressure buildup throughout the formation due to pressure dissipation and associated brine leakage.

2.2.2. Relative Permeability and Capillary Pressure

When immiscible fluids (e.g., carbon dioxide, water) are present within the pore spaces of a geologic formation, the ability for flow of one of those fluids is reduced, due to the blocking effect of the presence of the other fluid. Note that under any reservoir conditions, ground water and carbon dioxide will be immiscible, and ground water and hydrocarbons will be immiscible. Carbon dioxide and hydrocarbons, however, may be miscible or immiscible based on reservoir conditions. The relative permeability is a scaling factor that represents the reduction in the capacity for fluid flow due to the presence of other phases in porous media, with a value between 0 and 1. This value is multiplied by the intrinsic permeability of a geologic formation in order to compute the effective permeability for a fluid in a particular pore space. The relative permeability of a fluid is based on the properties and amounts of all fluids present within the system. The greater the amount of pore space occupied by a particular fluid or phase (measured as fluid saturation), the greater the relative permeability will be for that fluid. Because fluid saturations change over time and location, relative permeability values typically vary during model simulations.

The relative permeability for each fluid is typically calculated as a function of fluid saturations at each location and time within a model. This is achieved via a relative permeability-saturation function. The relative permeability-saturation function shape is based on properties of the porous media and fluids present at a particular site. Residual fluid saturation also impacts the shape of the relative permeability function, and describes the minimum fluid saturation within the porous medium following immiscible fluid displacement. An example relative permeability-saturation function is given in Figure 2-2. Note that this example function has been developed for a specific site (Doughty, 2007) and may not be applicable to other GS sites. Capillary pressure-saturation relationships (also known as characteristic curves) are also of importance because capillary pressure gradients provide a driving force for fluid movement under unsaturated conditions.

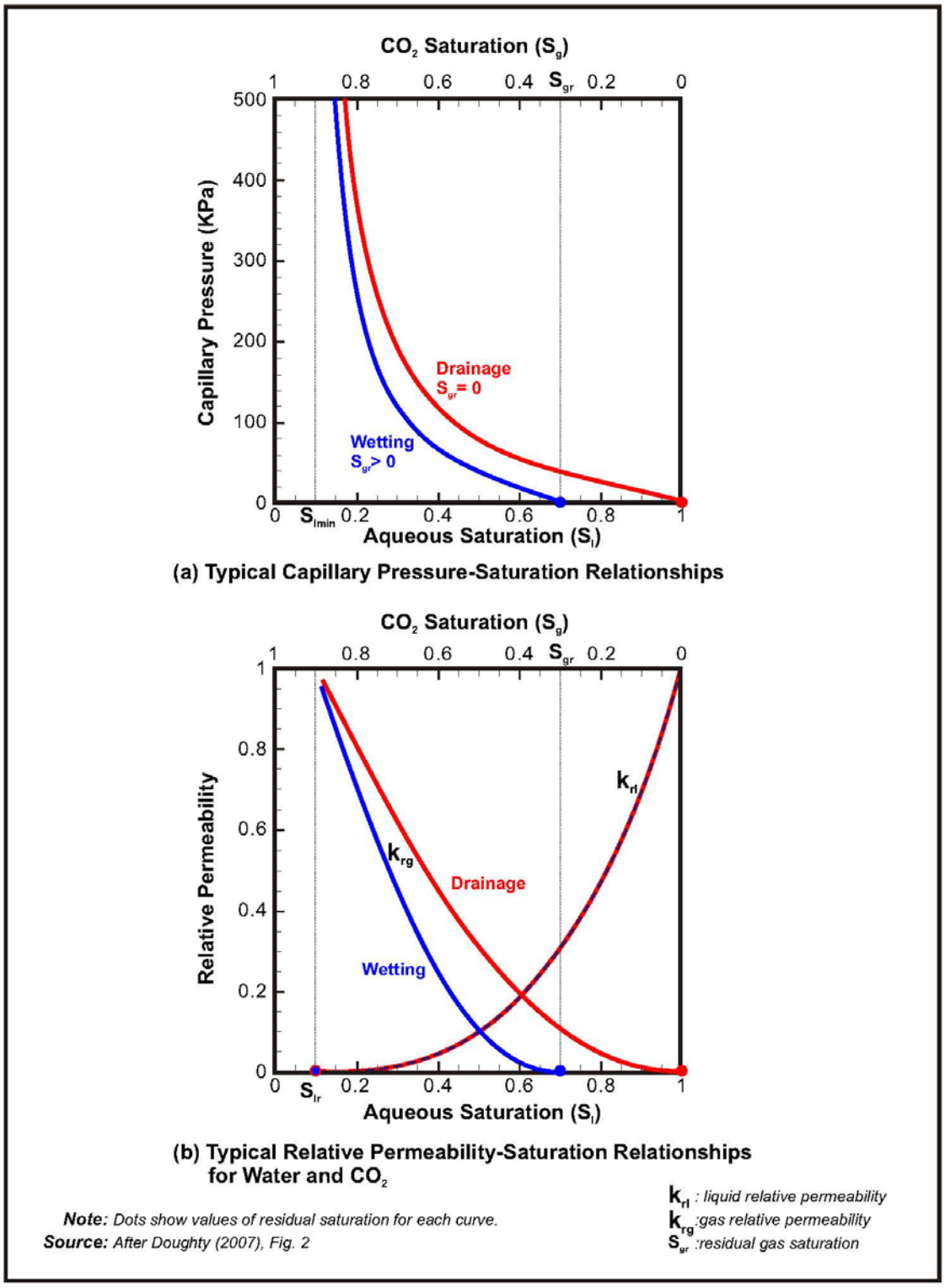


Figure 2-2: Example Relative Permeability-Saturation and Capillary Pressure-Saturation Relationships for Water and Carbon Dioxide.
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Previous research has shown that model predictions are very sensitive to the shape of the relative permeability-saturation functions used. The *UIC Program Class VI Well Site Characterization Guidance* provides details regarding measurement of relative permeability. Ideally, laboratory core-analysis techniques will be used for experimental measurement of the relative permeability-saturation and capillary pressure-saturation functions for a particular site at reservoir conditions, with carbon dioxide and representative native fluids (e.g., Perrin et al., 2008; Bachu and Bennion, 2008; Plug and Bruining, 2007). If this is not feasible, relative permeability-saturation relationships may be estimated from core analysis using other immiscible fluids (e.g., Doughty et al., 2007). Alternatively, previously reported functions may be used, such as those presented in Figure 2-2, if the experimental system was very similar to the site conditions for which the model will be applied. Relative permeability-saturation relationships are also commonly adjusted during model calibration.

Doughty and Pruess (2004) compared site-specific characteristic curves to "generic" curves at the Frio, TX GS pilot project site and found that the choice of characteristic curves had a significant impact on plume size, shape, and mobility. The authors point out that the differences in plume behavior for different sets of characteristic curves had important implications for operation and monitoring of the pilot test. Similarly, Doughty et al. (2007) found that model results were very sensitive to characteristic curve parameters. The authors constrained the value of characteristic curve parameters by calibration to monitoring data.

Pruess (2008) compared the effect of using three-phase characteristic curves developed for organic liquid-water-air systems (Stone, 1970) and simple linear characteristic curves. The choice of characteristic curves was found to have a significant impact on the observed leakage rate of carbon dioxide through a fault system. The linear characteristic curves resulted in simulated earlier leakage of carbon dioxide to the surface and lower leakage rates. Use of three-phase relationships resulted in small fluid permeability at intermediate saturations due to phase-interference effects.

The impact of using hysteretic versus non-hysteretic characteristic curves has also been compared. Hysteresis refers to the dependence of the shape of the characteristic curve on the history of fluid flow within the formation. For example, characteristic curves are often observed to have a different shape when non-wetting fluids (e.g., supercritical carbon dioxide) are displacing wetting fluids (e.g., formation water), than when wetting fluids are displacing non-wetting fluids. Juanes et al. (2006) showed that consideration of hysteresis and capillary trapping resulted in the carbon dioxide being spatially distributed over a larger area with less accumulation at the confining layer. Doughty (2007) found that results from simulations with non-hysteretic curves did a poor job of matching simulations with hysteretic curves in homogeneous and heterogeneous media. Relative to non-hysteretic cases, simulations including hysteresis exhibited a more mobile plume leading edge (where there is no water imbibition) and a slower trailing edge with a significant amount of residual trapping (due to water imbibition).

2.2.3. Injection Rate

The carbon dioxide injection rate at proposed Class VI injection wells is incorporated into the model by assigning the injection rate parameter at a constant or variable-rate boundary condition, or by defining various source terms for specific nodes that correspond to injection location. However, it is important to note that calculated pressure values where injection rates are applied may need to be monitored to identify flow-controlled or pressure-limited cases. Several researchers have reported that increasing the carbon dioxide injection rate results in increased migration rates (e.g., Law and Bachu, 1996; Saripalli and McGrail, 2002; Juanes et al., 2006). Juanes et al. (2006) considered capillary trapping in highly heterogeneous media, and found that increased injection rate resulted in more simulated residual trapping due to invasion of carbon dioxide into a wider range of pore sizes. Therefore, in the long term, increased injection rates actually decreased the final simulated extent of carbon dioxide migration, as more mass was immobilized through capillary forces. Pruess (2008) modeled leakage to the ground surface through a fault system, and simulations indicated that larger injection rates resulted in increased maximum surface discharge rates relative to injection rates.

2.2.4. Fluid Properties and Equations of State

The density, viscosity, and phase-state of the carbon dioxide injectate, ground water, and any other fluids that may be present (e.g., hydrocarbons), are important model input parameters. However, these properties change significantly across the temperature and pressure range that will be encountered at GS projects, and they are also affected by salinity. The equations of state describe these fluid properties and the existence of phases as a function of pressure and temperature; they are used by the model to calculate properties at conditions encountered in the simulation as they change with location and time. Graphs developed from accepted equations of state for carbon dioxide are depicted in Figure 2-1. Previous studies have shown that model results are sensitive to the equations of state used (Pruess et al., 2004; Han and McPherson, 2008).

The composition of the injectate will be reflected in several chemical and physical parameters assigned to the carbon dioxide fluid in the model simulations. Several studies have evaluated the impact of common carbon dioxide stream impurities hydrogen sulfide and sulfur dioxide on geochemical reactions and mineral trapping. Both Knauss et al. (2005) and Xu et al. (2007) showed that the addition of hydrogen sulfide had little impact, whereas the addition of sulfur dioxide resulted in a lower pH in the injection zone, less carbon-bearing mineral precipitation, and more formation-mineral dissolution.

2.2.5. Mass-Transfer Coefficients

Mass transfer coefficients describe the equilibrium concentration of chemical constituents (e.g., water, carbon dioxide) between separate phases. For example, the equilibrium aqueous concentration of carbon dioxide dissolved in ground water in contact with separate-phase (e.g., supercritical) carbon dioxide is described by a partitioning coefficient. Other mass-transfer

coefficients describe the distribution of constituents between the gaseous, aqueous, separate-phase carbon dioxide, and solid phases. For the case of reactive transport modeling, mass-transfer coefficients describe equilibrium concentration of constituents between mineral and dissolved phases. Similar to fluid properties, mass-transfer coefficients are in many cases temperature and pressure dependent. Mass-transfer coefficients may also be dependent on properties of the formation and fluids present, such as ground water salinity. Reference documents are available that provide many necessary mass-transfer coefficients (e.g., Green and Perry, 2008), and several commonly used codes include necessary mass-transfer coefficients (e.g., TOUGH2-ECO2N; Pruess and Spycher, 2007).

2.2.6. Mineral Precipitation Kinetic Parameters

Mineral precipitation is a subset of reactive transport problems and represents a trapping mechanism for carbon dioxide as well as a mechanism for permeability modification. As noted above, the Class VI Rule does not stipulate that reactive transport be considered in AoR delineation modeling. However, the owner or operator, or the UIC Program Director, may determine that reactive transport modeling should be considered for a particular project.

Studies accounting for mineral precipitation typically include precipitation kinetic (i.e., rate) parameters. Although precipitation rates have a large impact on mineral trapping, there is a great deal of uncertainty related to these parameters (Knauss et al., 2005; Xu et al., 2006). Furthermore, complex interrelationships exist between the rates of separate mineral species in a formation. For example, a sensitivity analysis for trapping through dawsonite [$NaAl(CO_3)(OH)_2$] precipitation showed that decreasing dawsonite kinetics resulted in increased formation of other trapping minerals calcite [$CaCO_3$] and magnesite [$MgCO_3$] (Knauss et al., 2005). Izgec et al. (2008) showed that changes in formation permeability resulting from mineralization reactions were very sensitive to kinetic rate parameters. Several modeling studies have indicated that geochemical equilibrium following injection may not occur for thousands of years (e.g., Xu et al., 2006; Gaus et al., 2005).

2.2.7. Model Orientation and Gridding Parameters

Numerical modeling requires the developer to define the spatial and temporal domains, grid spacing and gridding routine, and domain boundaries. These features of the model are typically designed with an effort to minimize computational demand and therefore processing time. However, there is potential for erroneous results based on grid features of the model (i.e., numerical artifacts), which can mask or enhance the effects of physical processes. A few studies have focused on evaluating the impacts of numerical artifacts for models of GS.

Doughty and Pruess (2004) tested the impact of varying grid cell sizes for a model of the Frio formation pilot GS project site in Texas. They found that the overall pattern of plume movement was similar for different grid sizes, but overly coarse grids were not able to simulate buoyancy-driven flow within individual sand channels. The authors also observed that the choice of grid block sizes and gridding routine could result in preferential flow in the grid axis direction and

numerical dispersion. Similarly, Juanes et al. (2006) observed that overly coarse grid block sizes that did not capture specific migration pathways overestimated carbon dioxide movement and the amount of capillary trapping. Doughty et al. (2007) note that higher-resolution models are needed for understanding of near well-bore effects. Yamamoto and Doughty (2009) demonstrate that grid refinement may have a substantial effect on overall simulated plume extent. Methods have been developed to establish numerical grids with high resolution in areas of interest (e.g., near well bores and fractures), and lower resolution in other areas, such as near the model area boundaries.

2.3. Computational Approaches

Computational codes consist of the set of interrelated mathematical equations (i.e., governing equations, constitutive relationships, and equations of state) that are solved simultaneously in order to predict fluid movement, pressure changes, and other changes, as a function of both location and time. These equations include complex partial differential equations that cannot be easily solved, and require complex estimation techniques. In most cases, numerical approximation methods, discussed below, will be needed to adequately represent the several physical processes necessary to delineate the AoR and comply with the Class VI Rule.

In certain circumstances, simpler analytic and semi-analytic approaches may be used to complement numerical efforts in delineating the AoR. As discussed below, analytic and semi-analytic approaches are not capable of representing several processes and features that are important for predictions of fluid movement, and they often assume simple geometry and homogeneity.

2.3.1. Numerical Approaches

Computational models used for practical applications typically consist of a numerical formulation of the governing equations applied over a spatially discretized model domain that defines the spatial extent and resolution of the problem (i.e., the model grid). This formulation is solved by a numerical method, such as finite element or finite difference approximation. The model grid is partitioned into grid cells, smaller spatial sub-units within the model. Fluid and heat flow is then solved between adjoining grid cells, while maintaining a mass and energy balance within the model. Phase changes, mass transfer, and chemical reactions can also be calculated for phases and constituents within a cell. Each cell can be assigned unique parameter values for physical properties (i.e., intrinsic permeability, porosity), allowing for three-dimensional, detailed representations of physical heterogeneity. Numerical models may be used for steady-state problems (in which injection and withdrawal rates are constant and the solution is obtained only for infinite time when system variables become constant and the solution becomes independent of the initial condition) and transient problems (in which injection and withdrawal rates may vary in time, and the solution is obtained at several discrete times during the model timeframe while the system variables exhibit change in time and depend upon the initial condition).

In addition to detailed geologic heterogeneity, numerical models are typically capable of representing density-driven fluid flow (e.g., the buoyancy of carbon dioxide) and the dissolution of carbon dioxide into ground water. Numerical models can also represent irreducible (i.e., residual) fluid saturations (i.e., the amount of fluid being "trapped" in geologic formation pore space even after another immiscible fluid has passed through that area), multiphase flow effects, and the concomitant reduced permeability.

The scale of spatial and temporal discretization of the model affects the accuracy of the solutions to these numerical formulations. Finer scales of time and space reduce numerical solution error. However, computational demand increases as the length scale (e.g., grid cell size) and time scale (e.g., time-step size) decrease, and as additional processes are simulated. Methods have been developed to mitigate increases in computational demand, while focusing on regions and times of interest, such as adaptive grid block size (i.e., mesh) refinement. Another possibility is the use of parallel computing, in which a single problem is broken up and distributed among many processors (e.g., Zhang et al., 2007).

2.3.2. Analytical, Semi-Analytical, and Hybrid Approaches

Analytical and semi-analytical models may be used to complement numerical modeling efforts in AoR delineation for Class VI wells. Compared to numerical models, analytical models have much lower computational requirements and therefore lower processing times. Analytical and semi-analytical codes may also be particularly useful for assessing the transport of carbon dioxide through abandoned well bores, which is difficult in numerical models due to the disparity in spatial scales. Analytical and semi-analytical models also may be used as screening tools to quickly assess potential storage sites, or as a relatively simple comparative check on numerical modeling results. Celia and Nordbotten (2009) suggest the use of hybrid numerical-analytical models for cases where a large-scale numerical model could be combined with local analytical models (e.g., describing wells), or the use of semi-analytical solutions where analytical solution is used in the spatial dimension and finite-stepping is used for temporal changes.

However, strictly analytical and semi-analytical models are not able to explicitly account for detailed physical and chemical characteristics of carbon dioxide injected as required under the Class VI Rule. They are also not able to simulate other important processes, such as capillary trapping, or account for varying injection rates or formation heterogeneity. The applicability of these models is limited to simplified cases where an exact function can be found to satisfy the governing equation and boundary and initial conditions. For example, in most cases, these models assume homogenous aquifers (i.e., no variability in physical structure, porosity, or intrinsic permeability). For most formations this is an unrealistic assumption, and it neglects preferential fluid movement through heterogeneous channels within geologic formations.

2.4. Model Uncertainty and Sensitivity Analyses

As discussed above, computational models are an approximate representation of reality, and thus predictions exhibit some degree of uncertainty. Model uncertainty is a result of the uncertainties

related to the underlying science of the governing equations and the uncertainty in the parameter values input to represent the actual system (USEPA, 2003). Uncertainty in governing equations and model framework may arise from incomplete scientific data or lack of knowledge, as well as the necessary simplifications that translate scientific concepts into mathematical equations. Parameter uncertainty results from poor data quality (e.g., measurement errors, analytical imprecision, limited sample size), lack of data, and the inherent variability in natural systems. Model predictions depend largely on the values input for a number of key parameters and thus may be significantly impacted by incomplete knowledge, or they may be process and scale dependent. The predictive accuracy of a model improves with improved data quality, increased data quantity, realistic assumptions that reflect observed conditions and scientific knowledge, and a modeling domain (extent and resolution) that sufficiently and accurately represents the GS project.

Significant uncertainty exists in modeling predictions of GS due to the difficulty in determining the geological formation structure and permeability field throughout the extensive area likely to be impacted by proposed large injection volumes, a relative lack of data on the behavior of supercritical carbon dioxide in the subsurface, the drastic changes in transport behavior of carbon dioxide caused by changes in pressure and/or temperature, and the buoyant nature of carbon dioxide relative to native formation ground water.

The impact of parameter uncertainty on modeling results can be characterized through a model sensitivity analysis, which consists of sequentially varying a single parameter in successive model simulations while keeping all other model features constant. Sensitivity analyses provide an indication of those modeling parameters that are most sensitive (i.e., that most impact predictions of carbon dioxide migration, trapping, and pressure changes), and provide guidance for what parameters to focus on during data collection, parameter estimation, and model calibration. Accepted guides to environmental modeling (e.g., NRC, 2007) recommend the use of sensitivity analyses in submission of modeling results. Parameters that are sensitive for a particular model will be based on case-specific circumstances, and will be identified via sensitivity analyses.

2.5. Model Calibration

Model calibration consists of using the computational model to simulate a past time period for which monitoring data are available and adjusting relevant model parameters to reduce differences between model results and the observed monitoring data. For example, during initial model development, in-situ pressure data of the injection zone may be available for comparison to model predictions of pre-injection fluid pressures. After the initiation of carbon dioxide injection, monitoring data may be available regarding changes in reservoir pressure and fluid properties that may be used to calibrate the model. It is generally understood that model calibration reduces model error in prediction of future conditions.

Examples of observed data that may be used for model calibration include carbon dioxide saturation values and fluid pressures. Model calibration involves adjustment of model parameters, termed “calibration parameters,” in order to minimize the difference between

simulated and observed data values. Calibration parameters for a particular model will be site specific, but they will commonly include intrinsic permeability and relative permeability-saturation function parameters. Calibration may involve incorporating additional heterogeneities or highly-permeable pathways. A case study of model calibration to monitoring data at an early GS research site, the Frio Brine Pilot in Texas, is provided in Box 2-1 of this guidance document.

Model calibration is never perfect, in that simulated and observed values for a computational model will not agree exactly. Calibration statistics are often used to characterize the error difference between model simulations and observed data values. The objective of model calibration is to minimize the value of the calibration statistics to the extent possible, using model parameters values consistent with site data or realistic estimates.

Common calibration statistics include the mean error (ME), mean-absolute error (MAE), and the root-mean squared error (RMSE). The ME is a simple average of the residual error between observed and simulated values and, therefore, positive values will offset negative values. The ME therefore provides an indication of the net bias (positive or negative) of the model simulated values. MAE is similar to the ME, with the important distinction that the sum of the absolute values of the residuals is calculated, thereby eliminating the offset that occurs by adding positive and negative values. The MAE, therefore, is always positive and represents the average difference between observed and simulated values. The RMSE is similar to the MAE, although negative values of the residual between observed and simulated values are eliminated by squaring the difference, and then the square root of the sum is determined prior to computing the average.

Model calibration may be conducted by use of computer programs designed for this purpose (i.e., automated calibration, see Finsterle, 2004), and/or adjusted manually based on best professional judgment. In practice, the automated programs can be cumbersome; therefore, manual parameter adjustment is a more standard practice in the calibration of complex models.

Box 2-1. Model Calibration Case Study: Frio Brine Pilot Project

Pilot projects of GS can provide valuable insight into modeling predictions and monitoring results comparison. The Frio Brine Pilot Project, in Dayton, TX, is an early experimental project conducted primarily by researchers at the Texas Bureau of Economic Geology and Lawrence Berkeley National Laboratory (LBNL). Two carbon dioxide injection and monitoring experiments (Frio I and Frio II) have been conducted at Frio, supplemented by numerical modeling. In this text box, separate-phase carbon dioxide data from monitoring wells, pressure monitoring data, and geophysical monitoring data are presented. These figures and discussion are taken from Doughty et al. (2007) and Ajo-Franklin et al. (2008).

A geologic schematic of the Frio pilot site is shown in Figure 2-3. For the Frio I pilot, 1,600 metric tons of carbon dioxide were injected over 10 days into a steeply dipping brine-saturated later at a depth of 1,500 m. For the Frio II pilot, approximately 350 metric tons of carbon dioxide was injected at a depth of 1,600 m. A number of pre-injection site characterization, and operational and post-injection monitoring activities were conducted along with both injections.

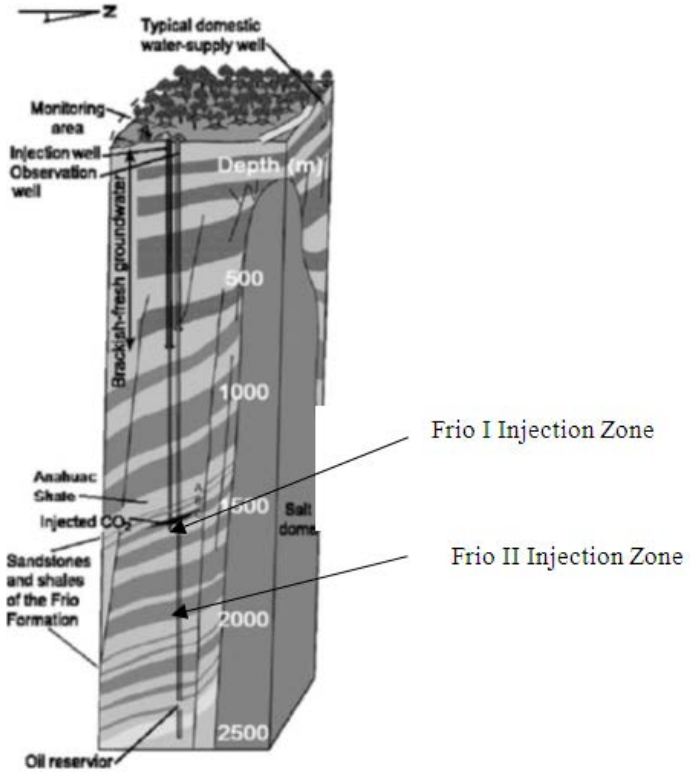


Figure 2-3: Geologic Schematic of Frio Brine Pilot Project. The arrow at top indicates the north direction.
From: Doughty et al. (2007).Reproduced with permission of Springer Science + Business Media.

For the Frio I pilot, a numerical model was calibrated by constraining the value of several parameters to a variety of monitoring data. Key calibration parameters were determined to be multi-phase flow parameters that describe the relative permeability-saturation relationship

Box 2-1. Model Calibration Case Study: Frio Brine Pilot Project, *continued*

(referred to in the study as the irreducible liquid saturation, S_{lr}) and the van-Genuchten (i.e., characteristic curve) parameter (m). The value of these parameters was constrained by several types of monitoring data (see Doughty et al., 2007). The researchers focused on calibration to the arrival time of carbon dioxide at the monitoring well, and pressure monitoring at the injection and monitoring wells. The arrival time of carbon dioxide at the injection well was determined based on a reduction of fluid density collected at the observation well using a U-tube sampling apparatus. The observed arrival time was compared to a series of model runs, varying S_{lr} and m (Figure 2-4). In addition, the observed pressure increase at both the monitoring and the injection wells were compared to model predictions (Figure 2-5). Based on these results, the value of the parameter S_{lr} was constrained to a range of 0.15 to 0.30, and the value of m was constrained to 0.9.

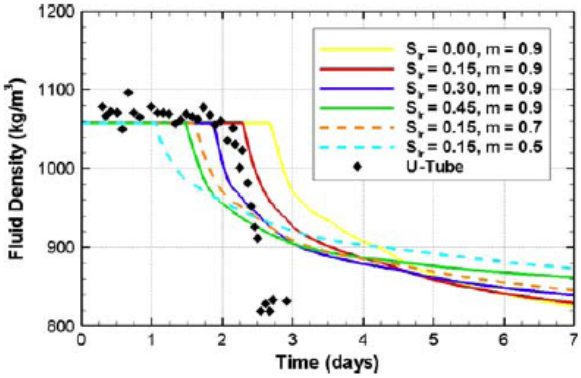


Figure 2-4: Observed and Modeled Carbon Dioxide Arrival at the Observation Well Based on Change in Fluid Density. From: Doughty et al. (2007). Reproduced with permission of Springer Science + Business Media.

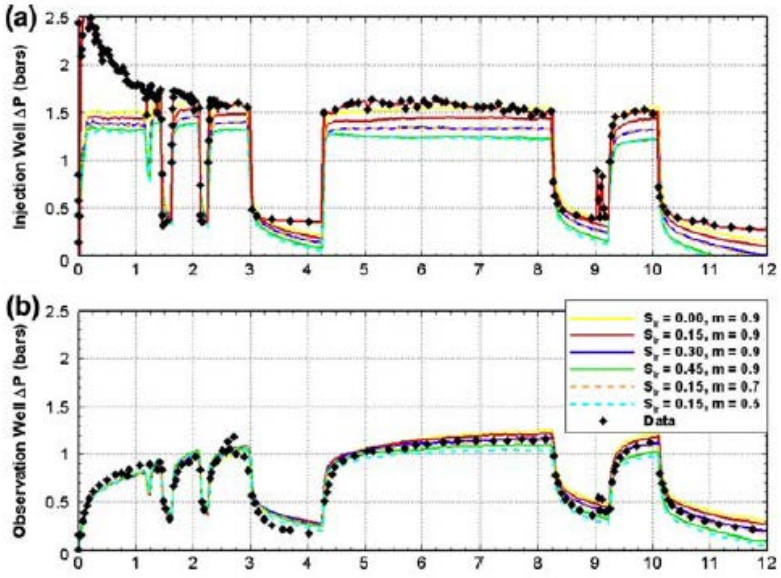
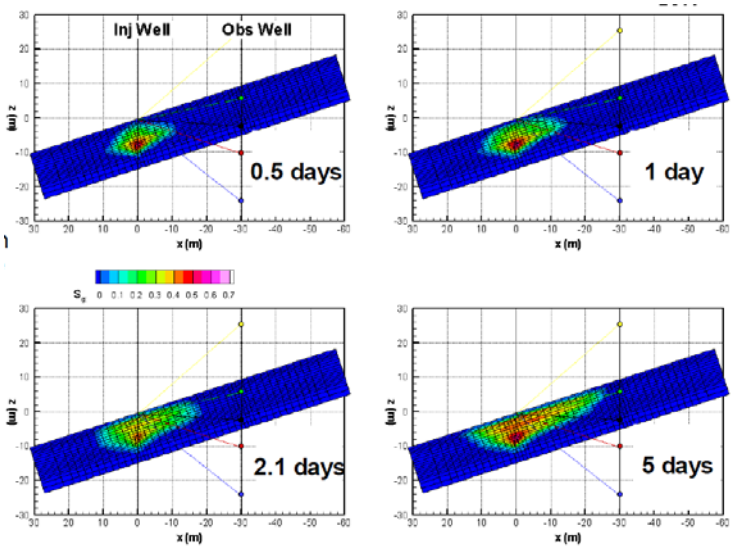


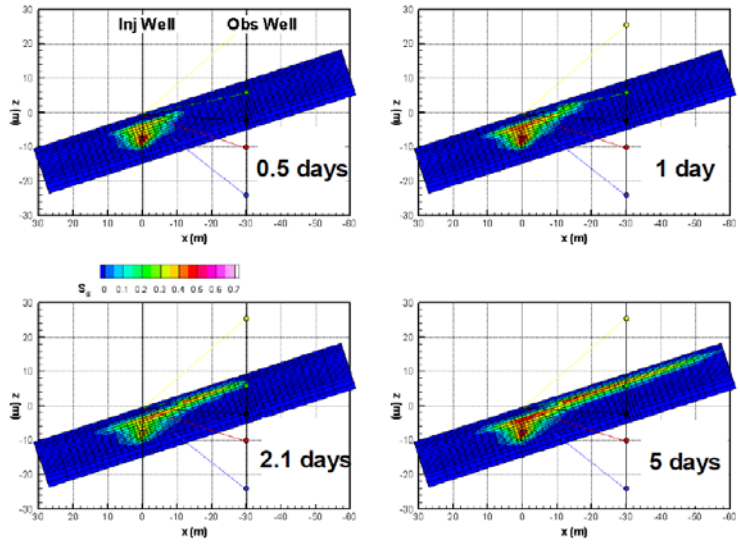
Figure 2-5: Observed and Modeled Pressure Increase at (a) the Injection Well and (b) the Monitoring Well (from Doughty et al., 2007). Reproduced with permission of Springer Science + Business Media.

Box 2-1. Model Calibration Case Study: Frio Brine Pilot Project, *continued*

Frio II used an initial numerical model to predict the evolution of the carbon dioxide plume over time. Observed seismic geophysical data of plume migration showed that a thin finger of carbon dioxide moved further up-dip than initially predicted by the model. The model was calibrated to the seismic monitoring results by, among other changes, increasing the value of the intrinsic permeability throughout the model, and increasing the thickness of a high-permeability channel at the confining zone-injection zone interface. The initial and data-calibrated model results are shown in Figure 2-6.



(a)



(b)

Figure 2-6: Comparison of (a) Initial and (b) Post-Calibration Model Predictions of Carbon Dioxide Plume Evolution. From: Ajo-Franklin et al. (2008).

2.6. Existing Codes used for Development of GS Models

A wide variety of modeling exercises have been reported in the peer-reviewed literature for GS and have been reviewed previously (Schnaar and Digiulio, 2009). Several computational codes have been developed for multiphase flow and transport problems, and a number of these codes are publicly or commercially available for the owners or operators of a GS project to use in AoR delineation modeling. Codes reported in the literature used for modeling of GS include petroleum reservoir codes (STARS, Law and Bachu, 1996; GEM, Kumar et al., 2004; ECLIPSE, Zhou et al., 2004; Juanes et al., 2006; CHEARS, Flett et al., 2007) and codes that have been developed at U.S. Department of Energy (DOE) national laboratories for a range of multiphase flow and transport problems (STOMP, CRUNCH, Knauss et al., 2005; TOUGH-series, Finsterle, 2004; Xu et al., 2006; Doughty and Pruess, 2004; Doughty, 2007). Additionally, DOE provides a summary of available models that have been used to model processes associated with injection for GS at the Regional Carbon Sequestration Partnership (RCSP) project sites. The document presents the types of data that are needed for various models and how to obtain such information (NETL, 2011). These codes vary not only in the physical processes considered, but also in numerical techniques such as the spatial discretization method, iteration approach, and gridding routines. The codes mentioned above are provided as examples that may be used for GS modeling, and the lists given are not meant to include all available codes, or to suggest preference for certain codes over others.

Codes used for modeling GS consider multiphase flow of carbon dioxide in supercritical, liquid, and gaseous phases including miscible and immiscible displacement, dissolution of carbon dioxide in ground water, density-driven flow, and flow of ground water as impacted by injection. Available codes may also be further categorized based on their ability to consider, or to be adjusted to consider, complex three-dimensionally heterogeneous formations, residual phase trapping and characteristic-curve hysteresis, mineral precipitation/dissolution reactions and subsequent mineral phase trapping and leaching of heavy metals, carbon dioxide sorption in coal-bed methane problems, and leakage through abandoned well bores. Models based on the TOUGH-series codes have been widely reported in the literature and are capable of considering three-dimensional heterogeneous formations, carbon dioxide dissolution, residual phase trapping and characteristic-curve hysteresis, coupled fluid flow and geomechanical processes, and mineral precipitation (e.g., Finsterle, 2004; Doughty, 2007; Xu et al., 2006; Rutqvist et al., 2008).

Several codes were compared for identical GS problems in an LBNL study (Pruess et al., 2004) in order to evaluate code comparability. Ten research groups representing six countries participated in the study. The codes evaluated included TOUGH-series codes (LBNL, CSIRO Petroleum, Industrial Research Limited), ECLIPSE 300 (Los Alamos National Laboratory), and STOMP (Pacific Northwest National Laboratory), among others. The problems considered varied in complexity and included mixture of gases in an open system, radial flow from an injection well, discharge along a fault zone, injection with mineral trapping, and injection with enhanced-oil recovery. For the most part, model results for the different codes were found to be in good agreement. Most discrepancies were traced to differences in the calculation of fluid properties (e.g., viscosity). These results emphasize the need for accurate descriptors of carbon dioxide transport properties and equations of state.

The use of proprietary codes (i.e., codes not available for free to the general public) may prevent full evaluation of model results (e.g., NRC, 2007). There are several aspects of a model that can be proprietary, and some may be more important than others for computational model evaluation. For example, use of a proprietary user interface with a publicly available code may not present a significant problem. Several popular codes in the petroleum-reservoir engineering discipline are proprietary (e.g., ECLIPSE). However, these codes have been used in peer-reviewed studies to model GS, and operators of particular GS sites may prefer to use these codes as they have previous experience with them. As discussed below, when using a proprietary model for AoR delineation, site operators of GS projects are encouraged to clearly disclose to the UIC Program Director the code assumptions and, if necessary, governing equations and equations of state with the permit application.

3. AoR Delineation Using Computational Models

Determination of the AoR for proposed Class VI wells will consist of data collection and compilation, development of the site computational model, delineation of the AoR based on model results, and submission of the model results and AoR delineation to the UIC Program Director with the Class VI permit application. The AoR and Corrective Action Plan must describe how the owner or operator plans to conduct these activities and is subject to UIC Program Director approval [40 CFR 146.84(b)].

The AoR delineation model must be submitted with the Class VI permit application—i.e., with the proposed AoR and Corrective Action Plan, as required at 40 CFR 146.82(a)(13)—and the modeled AoR will be finalized after all site data are collected and pre-injection testing is complete, per 40 CFR 146.82(c)(1). Therefore, the submittal, evaluation, and approval of the AoR, as part of the AoR and Corrective Action Plan, may be an iterative process, involving multiple drafts, until all the information required is submitted at the appropriate level of detail as determined by the UIC Program Director. See the *UIC Program Class VI Well Project Plan Development Guidance* for more information on the AoR and Corrective Action Plan. Also see the *UIC Program Class VI Implementation Manual* for additional information on how permitting authorities will review the information submitted by owners or operators.

This section describes the AoR delineation process and provides several quantitative examples revolving around a hypothetical GS site. EPA recommends that model development in all cases be conducted by a professional expert with the understanding of multiphase flow processes and experience with application of sophisticated computational models.

3.1. AoR Delineation Class VI Rule Requirements

The following Class VI Rule requirements pertain to AoR delineation:

- 40 CFR 146.84(a): The AoR is the region surrounding the GS project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.

- 40 CFR 146.84(c)(1): Owners or operators of Class VI wells must predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the UIC Program Director. The model must:

    (i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s), and any additional zones; and anticipated operating data,

including injection pressures, rates, and total volumes over the proposed life of the GS project;

(ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and

(iii) Consider potential migration through faults, fractures, and artificial penetrations.

3.2. Data Collection and Compilation

Computational modeling utilizes the required site characterization data for a proposed Class VI injection well site and applies scientifically accepted principles to estimate the carbon dioxide plume and pressure front migration. The extent to which site and operational conditions are realistically represented determines the validity of the resulting model predictions. Site characterization data inform model parameterization and the development of the model and, therefore, adequate data collection, analysis, and compilation are integral components of model development. Table 2-1 of this guidance provides a summary of important model parameters, many of which are determined based on site characterization data.

A variety of site characterization data are required to be collected for proposed GS projects [40 CFR 146.82 and 146.83]. These data are required to verify that the proposed injection zone at the characterized site has adequate injectivity to accept the injected carbon dioxide at the proposed rate and adequate volume to store the injectate over the lifetime of the project. Furthermore, site characterization data verify that suitable confining zone(s) are present to restrict the upwards movement of carbon dioxide. Additional features of the site, such as baseline geochemistry and pre-injection fluid pressures, inform the interpretation of future monitoring results and support reactive transport modeling if it is chosen to be used. As discussed below, much of the site characterization data collected at the proposed Class VI injection well site are also necessary to inform computational model development and AoR delineation. Site characterization requirements and methods are discussed in more detail in the *UIC Program Class VI Well Site Characterization Guidance*.

3.2.1. Site Hydrogeology

Regional and site-specific geology provide the foundations of the computational model used to delineate the AoR. This includes site stratigraphy, including formation elevation and thickness, as presented in cross sections and/or topographic maps. It is recommended that any data regarding structural geology (including folding, and fracture and fault systems) be identified and used when creating the computational model. For each geologic formation at the proposed injection site, hydrogeologic information, including initial fluid pressure, horizontal and vertical gradients, and ground water flow direction and velocity, should be considered. Other important characteristics include intrinsic permeability and porosity of all formations ranging from the uppermost USDW to beneath the injection zone. Where injection depth waiver applications are considered, EPA recommends that these parameters be determined for all formations down to and including the first USDW below the injection zone. See the *UIC Program Class VI Well Injection Depth Waivers Guidance* for additional information. EPA recommends that the

heterogeneity of these characteristics within each formation also be evaluated. Data regarding the heterogeneity of these parameters are of particular importance in representing the injection and confining zone(s). The Class VI Rule requires that AoR computational modeling take into account any geologic heterogeneities and other discontinuities [40 CFR 146.84(c)(1)(ii)].

Thorough characterization of multiphase flow parameters is also recommended to properly inform the computational modeling. These include parameters describing the capillary pressure-saturation and relative permeability-saturation relationships of each formation, with the injection and confining zones being of particular importance. See Figure 2-2 of this guidance for more information. EPA recommends that accepted formulations of these relationships be defined that are as specific to the site and fluids of interest (e.g., brine, carbon dioxide) as possible.

The quantity of data used to inform model development is recommended to be, at least, based on the Class VI Rule site characterization requirements, as discussed in the *UIC Program Class VI Well Site Characterization Guidance*. For pertinent data types, as discussed above, all data collected to comply with site characterization requirements may be considered in the AoR delineation. Furthermore, EPA recommends that any additional pertinent data available in the vicinity of the site, for example from the U.S. Geological Survey (USGS) or other sources, also be included in model development.

Additionally, EPA recommends that the lateral and vertical extents of all formations predicted to exhibit contact with supercritical carbon dioxide or elevated pressure over the lifetime of the proposed GS project be characterized for hydrogeologic properties. This may be an iterative process because initial model estimates of plume and pressure front migration may indicate further migration than previously assumed. In these cases, some additional site characterization in these regions may be requested by the UIC Program Director before a permit is approved.

EPA recommends that adequate data be collected to reasonably estimate site heterogeneity. Collection of sufficient data is always a challenge in geologic studies, and this is compounded by the large areas that may be impacted by GS projects. Use of geophysical site characterization techniques may reduce the burden of site characterization over large areas. See the *UIC Program Class VI Well Site Characterization Guidance* for more information on using geophysical methods to assist with collecting the required site characterization data for a Class VI injection well permit application.

3.2.2. Operational Data

The Class VI Rule requires that the AoR computational modeling for a Class VI injection well be based on existing or proposed operational data including injection pressures, rates, and total volumes over the lifetime of the GS project [40 CFR 146.84(c)(1)(i)]. EPA recommends that operational data also include the location and number of injection wells, and the injection well construction details (e.g., total depth, perforated interval). In the case of GS projects with multiple Class VI injection wells, it is important to note that each Class VI well is required to be permitted separately, as area permits are not allowed [40 CFR 144.33(a)(5)]. However, EPA strongly encourages potential Class VI injection well owners or operators to account for all

injection wells associated with the proposed project, or any other injection or extraction wells in the area, when developing the AoR model. EPA recommends that a single AoR delineation model be used for all Class VI injection wells for a single GS project, and that the model include the influences of all relevant wells. EPA also recommends that overlapping pressure perturbations be evaluated for a given basin or hydraulically connected formations to determine any combined risk to USDWs. The owner or operator may consult the UIC Program Director regarding any existing or planned projects in the vicinity of the proposed well.

3.3. Model Development

Once adequate data are collected, model development consists of the formation of a conceptual site model, design of the mathematical framework and grid, and parameterization (i.e., determination of input parameter values) (USEPA, 2003). The model is then executed to provide predictions of fluid movement and pressure perturbations during the lifetime of the project.

A Note Regarding Hypothetical Examples

Several informative boxes are included within this guidance that provide examples of the AoR delineation and reevaluation process based on a hypothetical site (Box 3-1, Box 3-2, Box 5-1, and Box 5-2). The hypothetical site presented is not intended to be representative of all GS projects. Assumptions and methods used in hypothetical examples may not be valid in all cases. A length scale has not been included on hypothetical site figures, such that an allowable size of the AoR, or distance between wells, is not unintentionally inferred from the figures.

3.3.1. Conceptual Model of the Proposed Injection Site

A conceptual site model is a schematic representation of the proposed GS project, including all major geologic elements present in the flow system and any relevant physical processes. In the delineation process, the conceptual model is translated mathematically into a numerical model to be solved for pressure and saturation. The conceptual site model is informed primarily by the collected site characterization data and the proposed operational conditions, such as well-field configuration and injection rates. EPA recommends that descriptions of the conceptual site model present a clear statement and description of each element of the site, as well as any assumptions and hypotheses related to the proposed injection site and the reasoning behind them (e.g., lab experiments, empirical data, or peer-reviewed literature). The conceptual site model also identifies the modeling region in three dimensions. Geologic stratigraphy, any other relevant geologic features, all physical processes that will impact migration of carbon dioxide and ground water, chemical species of interest, location of USDWs and potential conduits, conditions at site boundaries that may inform model boundary conditions, and areas of sparse site characterization data are also identified in the conceptual site model. See Box 3-1 for more information about the conceptual site model.

Box 3-1. Hypothetical Example of a Conceptual Site Model

A conceptual site model describes the general features of the anticipated Class VI project, using one or several schematics and diagrams. EPA recommends that schematics be used to show the general project orientation, both at the surface and at depth, important site features, and known processes that will impact plume and pressure front evolution at the site. Report text accompanying the conceptual site model schematic describes the relevant features at the site. A hypothetical example conceptual site model schematic is shown in Figure 3-1, and the example accompanying text is below.

For this hypothetical project, three injection wells are planned to inject a total of two million tons of carbon dioxide per year for 30 years. The source of carbon dioxide is a coal-fired power plant located approximately 200 miles to the north of the injection site. The injectate will be supplied via pipeline to the site, delivered to a surface facility, and then supplied separately to each of the injection wells. The injectate will be greater than 99% pure carbon dioxide at all times, containing trace amounts of sulfur dioxide and nitrogen oxides.

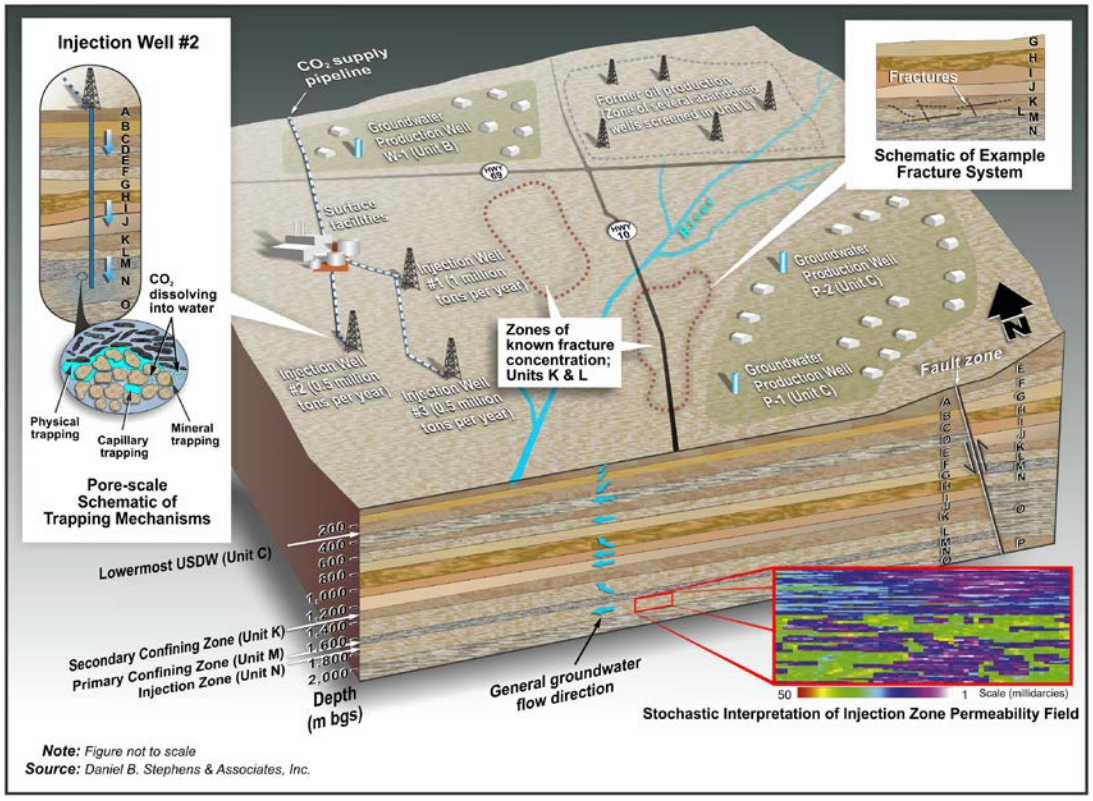


Figure 3-1: Hypothetical Conceptual Site Model for Geologic Sequestration.

Box 3-1. Hypothetical Example of a Conceptual Site Model, *continued*

Injection will occur into a saline formation (Unit N), with a measured salinity of 50,000 mg/L, at a depth of approximately 1,800 meters below ground surface. The formation dips slightly, and carbon dioxide and pressure front movement are expected to be generally greater in the up-dip direction. The permeability of the injection zone has been measured to range from 1 to 50 mD, with lower permeabilities generally at higher elevations and at the contact between the confining and injection zones.

A shale unit, at least 20 meters thick throughout the vicinity, serves as the primary confining unit (Unit M). The depth of the lowermost USDW (Unit C) varies somewhat throughout the vicinity, but it is generally from 200 to 500 meters below ground surface. Intervening layers of sand, shale, and clay units exist between the confining layer and lowermost USDW. A secondary confining zone (Unit K) has been identified.

The majority of carbon dioxide is expected to migrate upwards through the zones of higher permeability until encountering lower permeability zones within the injection zone, or the injection zone/confining zone contact, and be physically trapped. Capillary trapping, mineral trapping, and dissolution of carbon dioxide into ground water will also occur; however, at this point the rate and total amount expected to be sequestered via the different mechanisms has not been quantified. Currently, ground water in all subsurface formations flows generally to the west. It is expected that pressure increases within the injection zone induced by the project will cause ground water to generally flow radially away from the injection wells.

Two relevant geologic zones with a concentration of fractures are located in the vicinity of the project, as shown on Figure 3-1. Fractures exist primarily in Unit K, the secondary confining unit, but also are potentially identified in the primary confining zone, Unit M. Geologic studies of the fractures and preliminary modeling have indicated that due to the orientation and fracture widths, they will not serve as a leakage pathway during carbon dioxide injection. However, these two relevant geologic zones will likely be locations for enhanced monitoring during the lifetime of the project, based on consultation with the UIC Program Director.

A former oil and gas field is located to the northeast of the project. Further analysis, including modeling, is used to determine if carbon dioxide may migrate into this area. If migration is detected, enhanced corrective action and monitoring will occur within the area of the former oil and gas field in consultation with the UIC Program Director. A fault zone exists far to the east of the proposed site. Carbon dioxide is not expected to migrate as far as the fault zone. However, this feature may also be further evaluated over the course of project, along with the potential for brine migration through the fault zone as a result of pressure buildup in the formation.

3.3.2. Determination of Physical Processes to be Included in the Computational Model

Prior to developing the computational model for a proposed Class VI injection well AoR delineation, the owner or operator will need to determine what physical processes will be considered in the computational model. This determination is based on the most significant processes identified in the conceptual model, as well as those processes that can be realistically included in the computational model. At a minimum, the Class VI Rule requires that the model include multiphase flow of carbon dioxide and formation fluids [40 CFR 146.84(a) and (c)(1)]. Additional processes may be necessary for certain projects. For example, reactive transport could be relevant if permeability and/or porosity are predicted, based on previous testing, to change as a result of precipitation/dissolution reactions. In addition, geomechanical processes could be relevant if pressure and stress may change hydrogeologic properties. If the aqueous carbon dioxide plume is a potential risk factor, carbon dioxide dissolution into ground water may also be considered in the AoR delineation model.

For some model applications, including reactive transport and geomechanical processes may be impractical. Complications can arise from increases in computational demands (i.e., extremely long computer processing times), lack of meaningful data on mineral precipitation/dissolution kinetics, or the inability of preferred computational code. Furthermore, including these processes may be unnecessary in many cases because the impact on plume and pressure front migration may be relatively minor. The Class VI Rule does not require including reactive transport and geomechanical processes in the AoR delineation modeling. However, the UIC Program Director may request that the owner or operator include these additional processes in AoR delineation modeling in cases where doing so would improve the understanding of plume and pressure migration for the project.

3.3.3. Computational Model Design

After a conceptual site model has been developed, and the processes that will be considered have been determined, the next step is to develop the site computational model. This includes the determination of an appropriate computational code, and parameterization (i.e., populating the code with the selected site-specific parameters) in order to develop the model.

3.3.3.1. Computational Code Determination

To create the computational model, EPA recommends that a code be used that includes routines for the relevant physical processes at the site based on peer-reviewed theory and equations, including equations of state for carbon dioxide and other chemical species of interest. EPA recommends that the code also include accurate mass-transfer coefficients, including solubility of carbon dioxide, as a function of primary thermodynamic variables (e.g., temperature, pressure, phase saturations). If using an independently developed or untested code, EPA also recommends that the developer model test cases found in the literature to verify the accuracy of the model before submitting the Class VI injection well permit application to the UIC Program Director (e.g., see Pruess et al., 2004).

3.3.3.2. Model Spatial Extent, Discretization, and Boundary Conditions

The computational model will be designed by determining the spatial boundaries of the problem and spatial discretization. It is recommended that lateral grid spacing be fine enough to resolve heterogeneities, as discussed above (e.g., Doughty and Pruess, 2004). Vertically, the model is recommended to include the injection zone, with sufficient vertical resolution to properly account for buoyant plume migration, and a sufficient section of the primary confining zone to demonstrate to the satisfaction of the UIC Program Director that no leakage is expected to occur through the confining zone. In some cases, the UIC Program Director may require that additional zones be included in the computational model, such as overlying USDWs. Inclusion of additional zones may allow for estimation of vertical leakage rates and pressure changes above the primary confining zone, which may aid in performing risk assessments and designing the Class VI testing and monitoring program.

Boundary conditions are typically based on hydrogeologic conditions in locations corresponding to the edges of the model domain where the domain extends beyond the pressure front and/or plume. Model testing may be conducted to ensure that grid spacing, gridding routine, and boundary conditions do not result in numerical artifacts that impact the model results. If results of such testing indicate artificial impacts, then adjustment of the model may be necessary prior to running the model for a proposed Class VI injection well AoR delineation.

3.3.3.3. Model Timeframe

The Class VI Rule requires that the model used to delineate the AoR for a proposed Class VI injection well be run from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the UIC Program Director [40 CFR 146.84(c)(1)]. In order to meet these conditions, it may be necessary for the model simulation of the GS project to extend for several hundred or thousands of years (e.g., Flett et al., 2007).

3.3.3.4. Parameterization

Parameterization is the final step in the initial development of the computational model, and it consists of populating the computational code with the selected site-specific parameters. Key parameters include formation intrinsic permeability, porosity, phase-partitioning coefficients, and relative permeability-saturation parameters. Parameter values are based on the site-specific data as much as possible, but may also be based on values and relationships from the scientific literature. Geostatistical techniques can also be used to create a representation of realistic, three-dimensionally heterogeneous conditions in the subsurface. See Section 2.2 of this guidance for more information on model parameters. In some cases, a reasonable range of parameter values may be identified for the purposes of later sensitivity analyses.

3.3.4. Executing the Computational Model

The computational model is executed (i.e., solved) after parameterization, and this consists of using the code to calculate phase saturations and composition, fluid pressures, and other system aspects within the model domain for each point in time and space separated by specified intervals (i.e., time step, grid spacing). Model results are typically text files that contain modeled data for each grid cell, during each time step. In some cases, the model results will need to be post-processed following execution of the model before they can be easily visualized and interpreted. For example, model results may need to be transformed to produce site coordinates. Model results of particular interest for Class VI injection well AoR delineation include estimation of the extent of the separate-phase carbon dioxide plume migration and changes in fluid pressures within the injection zone over time. See Section 3.4 for more information on AoR delineation.

The use of an *a priori* AoR delineation based on computational modeling predictions highlights the need for uncertainty and sensitivity analyses for the initial prediction. Conservative predictions will be needed prior to the commencement of injection and the availability of any site-specific data on carbon dioxide migration paths and rates. EPA recommends conducting sensitivity analyses as the principal evaluation tool for characterizing the most and least important sources of error in computational models (USEPA, 2003). Based on these results, maximum-risk scenario simulations can be conducted considering plume extent and pressure perturbation predictions that account for uncertainties in the model.

3.4. AoR Delineation Based on Model Results

The planned or predicted AoR submitted with the permit application for a proposed Class VI injection well is required to be based on a delineation of the area where the GS project may cause endangerment of USDWs, which in turn is required to be based on the results of computational modeling [40 CFR 146.84(a) and 40 CFR 146.84(c)(1)]. The boundaries of the AoR are based on simulated predictions of the extent of the separate-phase (i.e., supercritical, liquid, or gaseous) plume and pressure front. As such, EPA recommends that the AoR encompass the maximum extent of the separate-phase plume or pressure front over the lifetime of the project and entire timeframe of the model simulations. The pressure front, as described below, is the extent of pressure increase of sufficient magnitude to force fluids from the injection zone into the formation matrix of a USDW.

In the case of GS projects with multiple Class VI injection wells, the owner or operator must apply for and obtain a Class VI injection well permit for each individual well [40 CFR 144.33(a)(5)]. However, as discussed previously, a single AoR modeling exercise may be conducted for all wells within a single project at the discretion of the UIC Program Director. In all cases, EPA recommends that the AoR delineation boundaries for the cumulative GS project be based on modeling that accounts for the anticipated injection rates from all planned Class VI injection wells.

Box 3-2 provides a hypothetical example of an AoR delineation based on computational modeling results, including the calculation of the threshold pressure that defines the pressure front. The determination of the pressure front in Box 3-2 (Step 2) is consistent with existing standard practices for other well classes of the UIC Program (e.g., Thornhill et al., 1982) and is applicable to any Class VI injection well for which, prior to injection, the injection zone is under-pressurized compared to the lowermost USDW (i.e., Method 1, Section 3.4.1). Determination of the pressure front is discussed in more detail in Section 3.4.1.

3.4.1. Determination of Threshold Pressure Front

The pressure front may be defined as the minimum pressure within the injection zone necessary to cause fluid flow from the injection zone into the formation matrix of the USDW through a hypothetical conduit (i.e., artificial penetration) that is perforated in both intervals. Several methods, as described below, are available to estimate the value of the pressure front, and are based on various assumptions. The owner or operator is encouraged to consult with the UIC Program Director to determine which method is appropriate for the proposed GS project. For instance, if an existing aquifer exemption is proposed to be expanded for a GS project, the pressure front may be determined based upon the pressure increase necessary for formation fluids to be displaced into portions of aquifer that are not exempted.

Method 1. Pressure front based on bringing injection zone and USDW to equivalent hydraulic heads (applicable to under-pressurized case only).

As stated by Thornhill et al. (1982), the pressure-front component of the AoR is "the area around an injection well where, during injection, the [hydraulic] head of the formation fluid in the injection zone is equal to or greater than the [hydraulic] head of USDWs." Defined this way, the pressure-front ($P_{i,f}$) may be calculated by the following equation:

$$P_{i,f} = P_u + \rho_i g \cdot (z_u - z_i) \qquad \text{[Eq-1]}$$

where P_u is the initial fluid pressure in the USDW, ρ_i is the injection-zone fluid density, g is the acceleration due to gravity, z_u is the representative elevation of the USDW, and z_i is the representative elevation of the injection zone. Similarly, the increase in pressure that may be sustained in the injection zone ($\Delta P_{i,f}$) is given by:

$$\Delta P_{if} = P_u + \rho_i g \cdot (z_u - z_i) - P_i \qquad \text{[Eq-2]}$$

where P_i is the initial pressure in the injection zone. Eq-1 and Eq-2 are subject to the assumption that the hypothetical open borehole is perforated exclusively within the injection zone and USDW.

A positive value of $\Delta P_{i,f}$ (Eq-2) corresponds to an injection reservoir that is under-pressurized relative to the USDW and can accommodate an increase in pressure equal to $\Delta P_{i,f}$ prior to potential fluid migration into the drinking water reservoir. A $\Delta P_{i,f}$ value of zero corresponds to the hydrostatic case, and a negative value of $\Delta P_{i,f}$ relates to a situation where the injection zone is

already over-pressurized and thus subject to potential fluid leakage from the injection reservoir to the drinking water aquifer even prior to the planned GS project. Eq-1 and Eq-2 are only applicable for calculating the allowable pressure increase for the under-pressurized case (i.e., positive value of $\Delta P_{i,f}$). Alternative methods may be applicable for the hydrostatic case or over-pressurized cases (see below).

EPA recommends that Eq-1 and Eq-2 be applied using values of pressure and fluid density (i.e., P_u, P_i, and ρ_i) based on direct measurement of fluid properties in the direct vicinity of the proposed project (i.e., see the *UIC Program Class VI Well Site Characterization Guidance*). Notably, the results of Eq-1 and Eq-2 are sensitive to the injection-zone fluid density (ρ_i), which is influenced by the pressure, temperature, and salinity of the injection zone. Salinity, pressure, and temperature tend to increase with depth below the ground surface. If site-specific fluid density values at reservoir conditions are not available, injection zone fluid density may be estimated based on measured salinity, temperature, and pressure. Figure 3-2 presents fluid density as a function of depth below ground surface for several different salinities, based on the method of Peng and Robinson (1976).

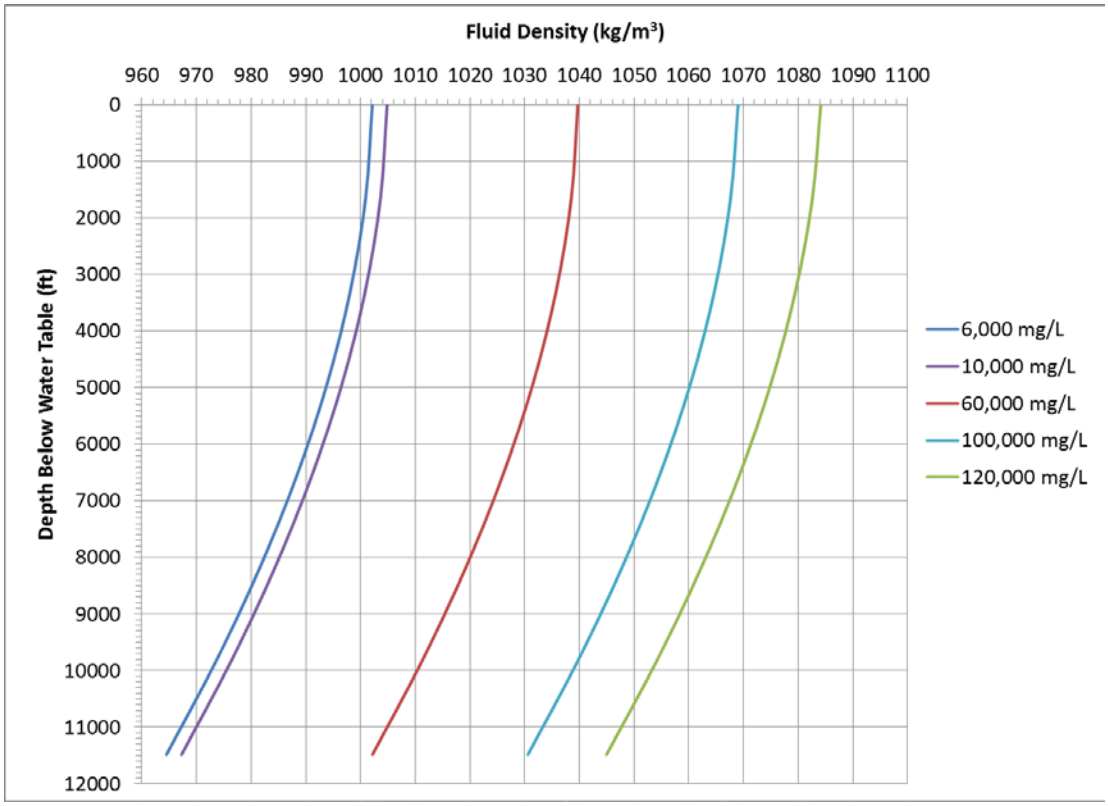


Figure 3-2: Fluid Density Functions for Varying Salinities.

Note also that, in using this method, $P_{i,f}$ is a function of the fluid density of the injection zone, the elevation of both formations, and the fluid pressure within the USDW. To the extent that these parameters vary spatially in the vicinity of the project, the value of $P_{i,f}$ may also vary throughout the region of the AoR.

Method 2. Pressure front based on displacing fluid initially present in the borehole (applicable to hydrostatic case only).

Under hydrostatic conditions, a pressure increase within the injection zone may be allowable due to the fact that water entering a hypothetical borehole from the injection zone will be more dense than the fluid initially present in that borehole. Fluid from the injection zone will displace the fluid in the borehole, which will flow into the USDW. However, below a calculated threshold pressure, a new pressure equilibrium will be established, and fluid from the injection zone will not intrude into the USDW.

As given by Nicot et al. (2008) and Bandilla et al. (2012), assuming (1) hydrostatic conditions and (2) initially linearly varying densities in the borehole and constant density once the injection-zone fluid is lifted to the top of the borehole (i.e., uniform density approach), the threshold pressure increase (ΔP_c) may be calculated:

$$\Delta P_c = \frac{1}{2} \cdot g \cdot \xi \cdot (z_u - z_i)^2 \qquad \text{[Eq-3]}$$

where ξ is a linear coefficient defined by:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \qquad \text{[Eq-4]}$$

and where ρ_u is the fluid density of the USDW.

Nicot et al. (2008) also present a solution subject to the assumption of linearly varying densities in the borehole both initially and when the injection zone fluid is lifted to the top of the borehole (i.e., equilibrium approach), rather than the uniform density approach (assumption #2) used to derive Eq-3 (see Nicot, 2008 and Bandilla, 2012). Birkholzer et al. (2011) state that the value of ΔP_c calculated using the uniform density approach (Eq-3) may be less precise than the equilibrium approach, but it is easier to apply and also more conservative for protection of the USDW.

At pressure increase less than ΔP_c, the fluid originally present in the borehole will leak into the USDW. This fluid leakage from the borehole may be acceptable and not cause degradation of water quality within the USDW, as the volume of water in the borehole may be minor and quickly diluted by water in the surrounding aquifer.

Calculation of the allowable threshold pressure increase using these methods (Eq-3 and Eq-4) is applicable only to the hydrostatic case. In some instances, site-specific fluid pressure and density measurements may not be available at the time of preparing the permit application and initial AoR delineation in order to evaluate if the injection reservoir is over- or under-pressurized. If warranted by previous site knowledge (i.e., no previous large-scale fluid withdrawal or injection from the injection zone), it may be acceptable to initially assume hydrostatic conditions. The owner or operator may choose to use these methods (Eq-3 and Eq-4) for an initial estimate of the

threshold pressure allowable for delineation of the AoR. However, once site-specific data are available for the proposed injection zone following construction of injection or monitoring wells, EPA recommends reevaluation of the hydrostatic assumption. If the reservoir is under-pressurized, the allowable threshold pressure increase may be greater than calculated using Eq-3 (see Method 1, above). However, if the injection reservoir is actually over-pressurized, the allowable pressure increase will be less than calculated using Eq-3.

Methods for over-pressurized cases.

In some instances, the desired injection zone may already be over-pressurized relative to the USDW prior to the injection project (i.e., $\Delta P_{i,f}$ value is negative using Eq-2). In this situation, fluid leakage would occur from the injection zone to the USDW through a borehole perforated within both zones even prior to commencing injection. Additional pressure increase within the injection zone owing to the injection associated with the GS project may increase fluid leakage rates. Determination of the allowable pressure increase to be used in AoR delineation for the over-pressurized case may require more sophisticated methods than the analytical equations described above for Methods 1 and 2.

Possible methods to estimate an acceptable pressure increase for over-pressurized reservoirs include:

1. Using similar methods as described in Nicot et al. (2008), some over-pressurization within the injection zone may be allowable without causing sustained fluid leakage, owing to the density differential between the injection zone and USDW. If the value of ΔP_c using Eq-3 is greater than the absolute value of $\Delta P_{i,f}$ using Eq-2, the difference in magnitude between the two may be used as an estimate of the allowable pressure increase, subject to the assumptions used to derive Eq-3 (see Method 2, above). To date, peer-reviewed research papers on this topic have developed analytical solutions only for the hydrostatic case. Future publications may address the initially over-pressurized case and, if so, these methods may be used to calculate an allowable pressure increase in an over-pressurized reservoir.

2. A multiphase numerical model may be designed to model leakage through a single well bore, or through multiple well bores in the formation (see e.g., Birkholzer et al., 2011). Additional pressure increases up to a certain point within an already over-pressurized injection zone may not cause an appreciable increase in fluid leakage rates through a hypothetical borehole. A sensitivity analysis may be conducted to bound the modeled leakage rates.

3. In conjunction with item #2 above, numerical or analytic ground water modeling may be conducted for the USDW to estimate how additional fluid leakage caused by the injection project is diluted within the USDW and attenuated. Dilution of fluid leakage from a borehole is impacted by the natural background flow rate of water within the USDW, which is turn a function of the hydraulic gradient, aquifer thickness, and hydraulic conductivity. An additional pressure increase may be allowable if it can be demonstrated

to the UIC Program Director that negligible degradation of the USDW would result from increased fluid leakage rates.

Box 3-2. Hypothetical Example of an AoR Delineation

The AoR is based on the results of computational modeling and encompasses the predicted maximum extent of the separate-phase plume or pressure front over the lifetime of the project. The pressure front is defined as the pressure, within the injection zone, great enough to force fluids from within the injection zone through a hypothetical open conduit into any overlying USDW. This box provides a hypothetical example of an AoR delineation using a stepwise approach. The example scenario is based on the conceptual site model described above (see Box 3-1). First, the threshold pressure that defines the pressure front is determined. Next, maps showing the maximum extent of the plume and pressure front are overlaid and the AoR is delineated.

Step 1. Determine the Pressure Front

A cross-sectional schematic of the hypothetical scenario is shown in Figure 3-3, which also presents values for fluid density, and pressure (units of megapascals, MPa, equal to $1 \cdot 10^6$ Pa) for each formation.

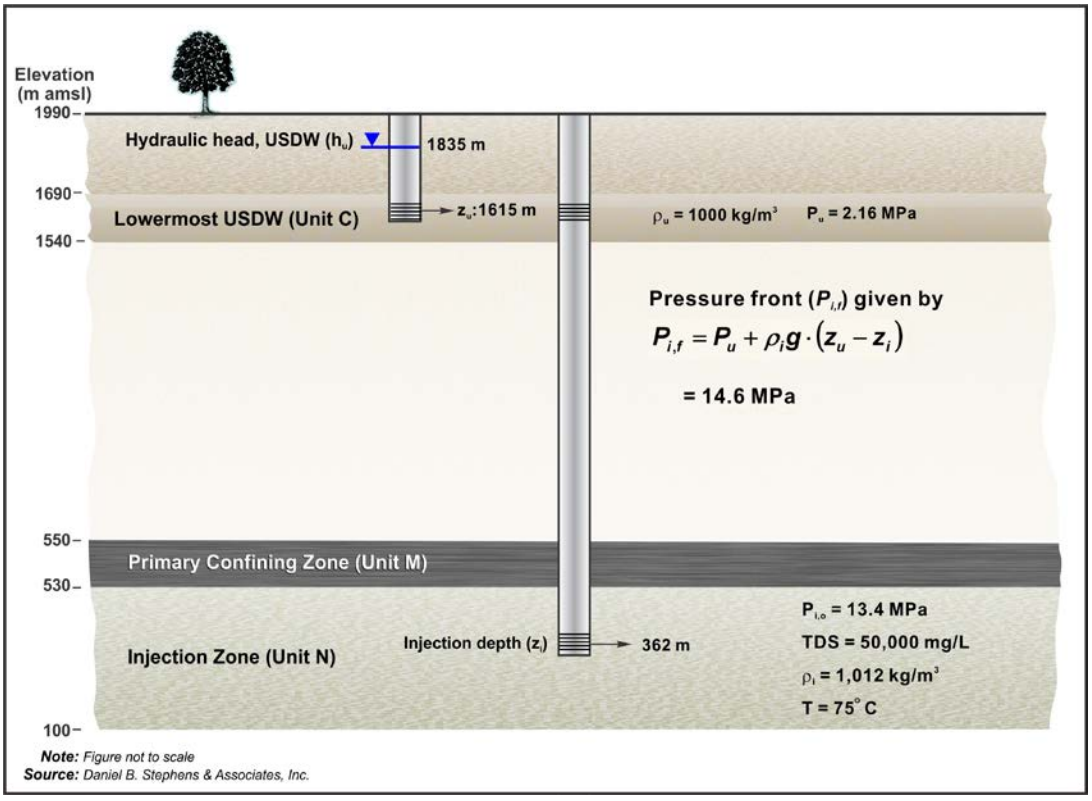


Figure 3-3: Hypothetical Geologic Sequestration Site: Cross Sectional Schematic and Calculations.

Box 3-2. Hypothetical Example of an AoR Delineation, *continued*

The methodology used here is consistent with the determination of the pressure front for other well classes within the UIC Program (e.g., USEPA, 2002). As explained above, in Section 3.4 of this guidance, this methodology is applicable to any proposed Class VI injection well for which, prior to injection, the injection zone is not over-pressurized compared to the lowermost USDW (i.e., the injection zone has a lower or equal hydraulic head as compared to the lowermost USDW).

The pressure front is determined by calculating the minimum pressure within the injection zone ($P_{i,f}$) necessary to cause fluid flow from the injection zone into the formation matrix of the USDW through a hypothetical conduit (i.e., artificial penetration) that is perforated in both intervals. $P_{i,f}$ is calculated using Eq-1 (Section 3.4.1). In this example, $P_{i,f}$ is 14.6 MPa.

Step 2. Inspect Model Results to Determine the Maximum Extent of the Pressure Front (P_f)

The computational model will provide a prediction of the pressures within the injection zone over time. For the purpose of AoR delineation, EPA recommends using the pressure distribution corresponding to the time of maximum lateral extent of the pressure front ($P_{i,f}$). This will likely correspond to a time of maximum injection rates during the operational phase of the project or to the end of a long injection period.

EPA recommends contouring these predictions of pressure increase and providing the predictions on a base map of the proposed project area (Figure 3-4). In this recommended contour map, EPA also recommends highlighting the pressure equivalent to $P_{i,f}$. In the hypothetical example provided here, the region encompassed by $P_{i,f}$ includes the three planned Class VI injection well locations and a significant distance surrounding the area of the proposed injection wells.

Box 3-2. Hypothetical Example of an AoR Delineation, *continued*

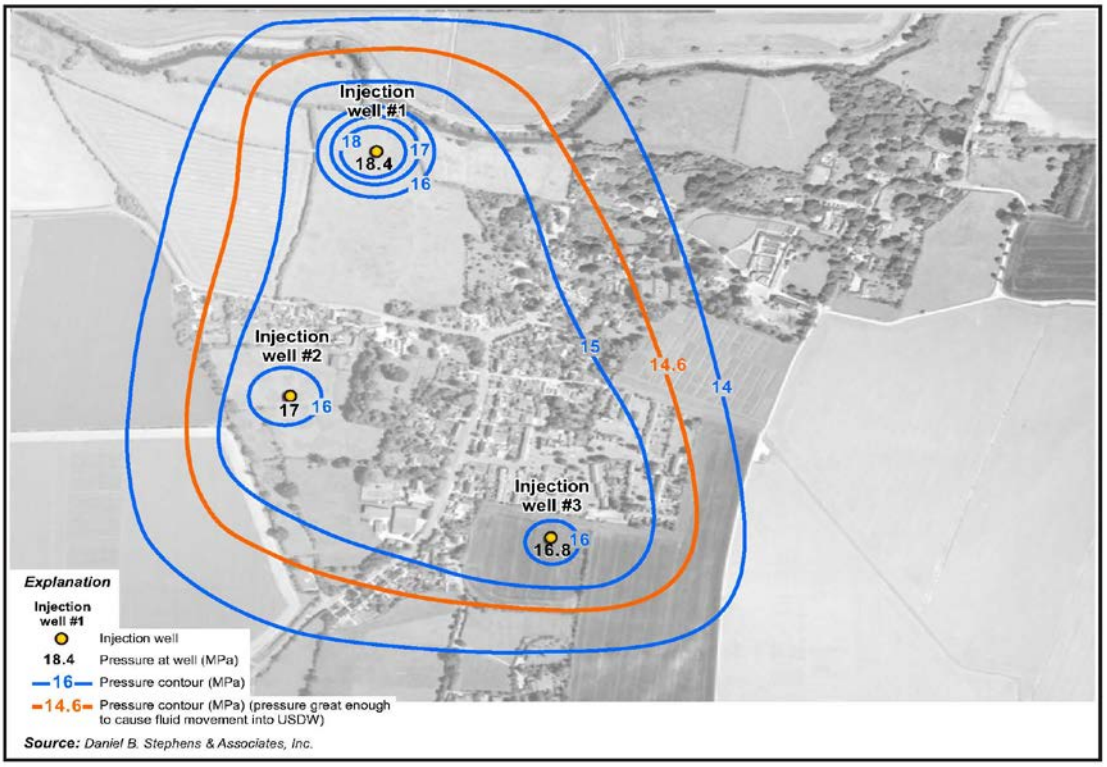


Figure 3-4: Hypothetical Geologic Sequestration Site: Model Predicted Maximum Pressure Within the Injection Zone.

Step 3. Inspect Model Results to Determine the Maximum Extent of the Separate-Phase Plume

The computational model will also provide a prediction of the extent of the separate-phase plume as it evolves over time. EPA recommends that these data be also contoured and provided on a base map (Figure 3-5). In the example provided here, the maximum extent of the supercritical plume, as predicted by the model, exists at 50 years after carbon dioxide injection commences.

Box 3-2. Hypothetical Example of an AoR Delineation, *continued*

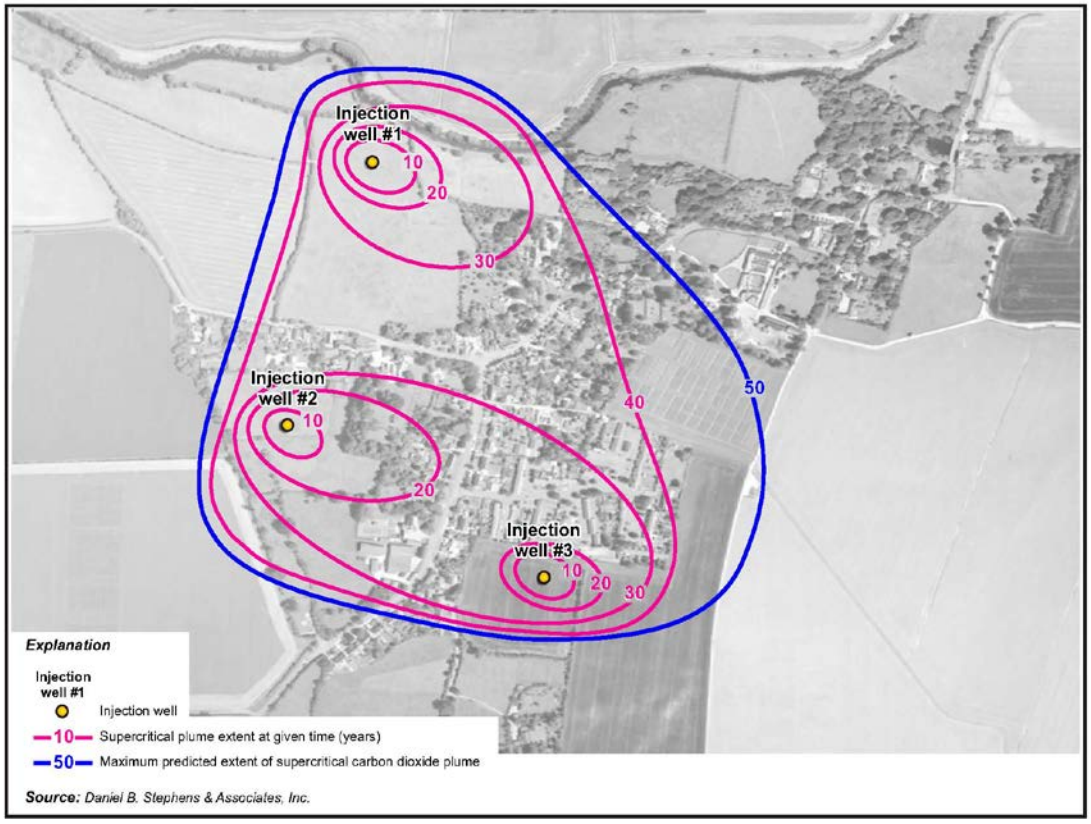


Figure 3-5: Hypothetical Geologic Sequestration Site: Model Predicted Extent of Supercritical Carbon Dioxide Plume Over Time.

Step 4. Delineate the AoR

Lastly, the maximum extent of the separate-phase plume and pressure front is compared and overlaid on the base map (see Figure 3-6). The AoR is delineated by drawing the contour line that encompasses the maximum extent of the separate-phase plume or pressure front (Figure 3-6).

Box 3-2. Hypothetical Example of an AoR Delineation, *continued*

It is important to note that the region encompassed by the pressure front will not in all cases be larger in all directions than the extent of the separate-phase plume. This is because the pressure front does not include all areas exhibiting any increase in pressure, only pressure great enough to cause fluid movement into a USDW. Therefore, pressure differentials may still exist outside of the pressure front, and separate-phase fluids may migrate beyond the extent of the pressure front. For this reason, it is necessary to calculate the extent of both the plume and pressure front to delineate the AoR for a proposed Class VI injection well and to submit these separate delineation results to the UIC Program Director with the permit application.

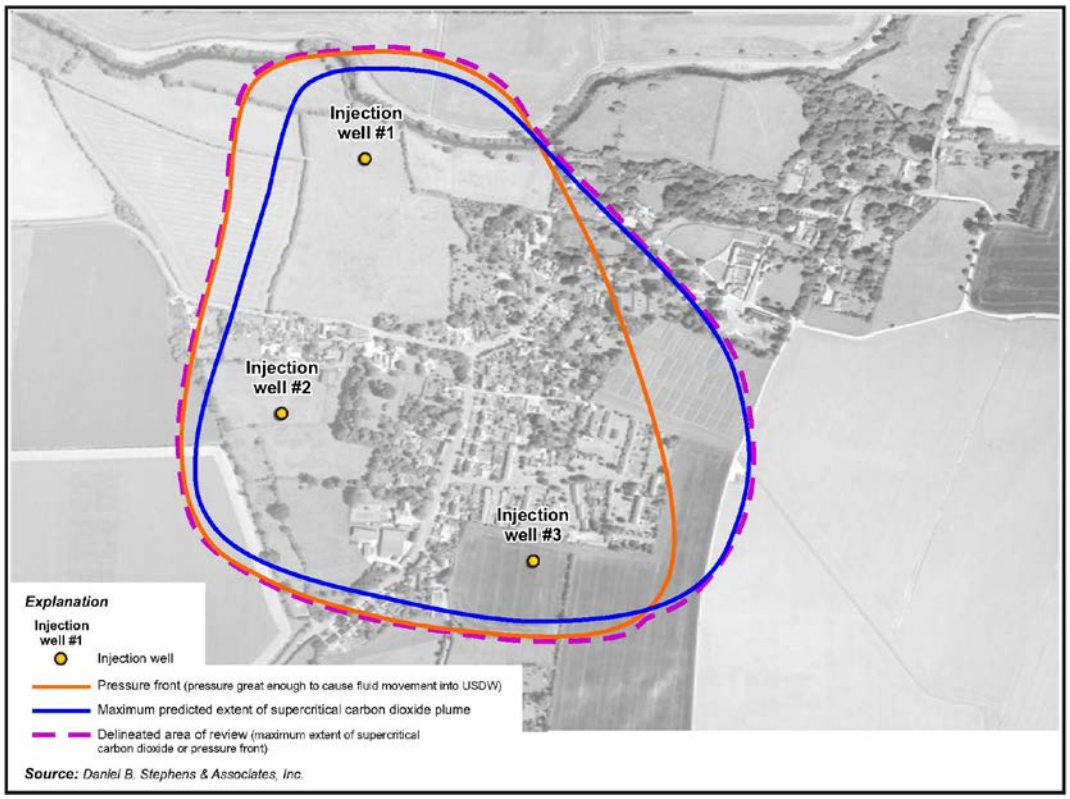


Figure 3-6: Hypothetical Geologic Sequestration Site: Initial Area of Review Based on Model Results.

3.5. Reporting AoR Delineation Results to the UIC Program Director

The owner or operator is required to submit the AoR and Corrective Action Plan with the initial permit application [40 CFR 146.82(a)(13)]. Information pertaining to how this plan should be submitted is provided in the *UIC Program Class VI Well Project Plan Development Guidance*. The final delineated AoR based on computational modeling is submitted to the UIC Program Director prior to receiving authorization to inject [40 CFR 146.82(c)(1)].

EPA recommends that this permit application submittal include all necessary information for the UIC Program Director to evaluate the AoR delineation results and replicate the computational modeling exercise if he or she elects to do so, as well as all model input and output data and files. This may include providing inputs for the UIC Program Director to use in their verification modeling effort. The owner or operator and the UIC Program Director should discuss the specific needs as the permit application is submitted. For additional information on submitting information to support Class VI permit applications, please see the *UIC Program Class VI Well Recordkeeping, Reporting, and Data Management Guidance for Owners and Operators.*

EPA recommends that the permit application submittal include the following in support of the AoR delineation:

- The conceptual site model and all supporting data on which the model is based, including the description of geologic stratigraphy and any relevant geologic features. See Box 3-1 of this guidance document for more information;
- Attributes of the code used to create the computational model, including the code name, name of developing organization, a full accounting of or reference to the model governing equations, scientific basis, and any simplifying assumptions;
- A description of the model domain, i.e., the model's lateral and vertical extents, geologic layer thickness, and grid cell sizes, as presented on maps and cross-sections;
- An accounting of all equations of state used for all fluids modeled (e.g. ground water, carbon dioxide);
- Any constitutive relationships, such as relative-permeability saturation relationships, and how they were determined;
- Values of all model parameters, as detailed in Table 2-1 of this guidance document, throughout the entire model domain, as a function of time if necessary, including initial conditions and boundary conditions, and a description of how model parameters were determined based on site characterization data. This information may be submitted in tabular or graphical/map formats;
- If required by the UIC Program Director, the owner or operator must also include raw model input and output files [40 CFR 146.82(a)(21)]. These files may be useful in model

verification, or if the UIC Program Director wishes to run alternative simulations/scenarios with the model;

- Model results, including predictions of carbon dioxide and pressure-front migration over the lifetime of the project. EPA recommends that the model results be presented in the form of contour maps, cross sections, and/or graphs showing plume and pressure front migration as a function of time, and that the permit application submittal include the outcome of parameter sensitivity analyses;

- A description of pressure front calculation and delineation of the AoR; and

- If required by the UIC Program Director, the relevant qualifications and professional experience of any individuals and/or consulting firms responsible for model development, AoR delineation, and reevaluation, including examples of previous multiphase modeling studies conducted.

4. Identifying Artificial Penetrations and Performing Corrective Action

The purpose of AoR delineation for a proposed GS project is to determine the area where any geologic features or artificial penetrations (e.g., wells) may become conduits for fluid movement out of the injection zone, or additional zones, and potentially cause endangerment to a USDW. Artificial penetrations include any man-made structures, such as wells or mines, which provide a flow path out of the injection zone. The Class VI Rule requires that the owner or operator prepare, maintain, and implement a AoR and Corrective Action Plan that includes a description of how corrective action will be performed on any artificial penetrations through the confining zone and whether such action will be phased [40 CFR 146.84(b)(2)(iv)].

This section discusses the identification and evaluation of artificial penetrations and the performance of required corrective action (if necessary). Monitoring activities necessary for detection of fluid leakage into USDWs are discussed in the *UIC Program Class VI Well Testing and Monitoring Guidance*.

4.1. Rule Requirements

The following rule requirements pertain to corrective action within the AoR:

- 40 CFR 146.84(c)(2): Using methods approved by the UIC Program Director, identify all penetrations, including active and abandoned wells and underground mines, in the AoR that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/ or completion, and any additional information the UIC Program Director may require;

- 40 CFR 146.84(c)(3): Determine which abandoned wells in the AoR have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream;

- 40 CFR 146.84(d): Perform corrective action on all wells in the AoR that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate;

- 40 CFR 146.84(e)(2): During the AoR reevaluation process, identify all wells in the reevaluated AoR that require corrective action in the same manner specified in 40 CFR 146.84(c);

- 40 CFR 146.84(e)(3): Perform corrective action on wells requiring corrective action in the reevaluated AoR in the same manner specified in 40 CFR 146.84(d);

- 40 CFR 146.84(e)(4): Revise the AoR and Corrective Action Plan as necessary whenever the AoR is reevaluated.

4.2. Identifying Artificial Penetrations within the AoR

The Class VI Rule requires potential Class VI injection well owners or operators to identify all artificial penetrations located within the delineated AoR, including active and abandoned wells and underground mines, that may penetrate the confining zone, and provide a description of each well's type, construction, date drilled, location, depth, and if applicable, the record of plugging and/or completion, and any additional information the UIC Program Director may require [40 CFR 146.84(c)(2)]. If the identified abandoned wells have been improperly plugged or not plugged at all, such penetrations can provide unimpeded flow conduits out of the injection zone. As such, they must be properly plugged in order to prevent endangerment of USDWs [40 CFR 146.84(d)].

A variety of types of abandoned wells may exist within the delineated AoR of a proposed GS project, including wells constructed prior to federal or state regulation (i.e., in the late 1800s or early 1900s) and any recently decommissioned wells. Wells constructed during early oil exploration, including cable-tool drilled wells, pose the largest risk because these wells may be relatively deep and often consist of an open (i.e., non-cased) well bore over much of their length. These older wells may also not have been documented in state or local records.

Historically, wells no longer in use may not have been plugged and abandoned by today's common standards. Prior to the early 1900s, there were no regulations concerning well abandonment and it is unlikely that those wells were abandoned properly. Even in states regulating well abandonment, it is likely that any wells abandoned before 1952 may have inadequate plugs (Ide et al., 2006). In 1952, the American Petroleum Institute (API) published its standards for cements for oil and gas wells. Prior to that, cement often lacked sufficient additives to achieve the proper cement setting in the conditions experienced in oil and gas wells. As a result, the plugs in many of these older wells failed to set properly and may have experienced channeling and/or cement failure because of fluid intrusion into the improperly set cement. The potential also exists for more recently constructed wells to have been decommissioned improperly. For example, owners or operators may have gone bankrupt and failed to plug their wells or used substandard materials.

Depending on site conditions and corrosion, "properly" plugged wells may also contain zones (i.e., annular spaces) that could serve as a conduit for fluid movement. In other cases, the well plugs may have degraded over time because of a poor cement job and/or corrosive conditions. Even properly plugged wells may have been plugged with types of cement that could degrade when in contact with a carbon dioxide plume. See the *UIC Program Class VI Well Construction Guidance* for information on compatibility of different materials with a carbon dioxide stream.

Detecting abandoned wells can be very challenging in certain locations because of the variety of wells that may exist. In addition, steel casings, the primary detectable portion of the well, were often removed from abandoned wells for recycling and use during World War II (Gochioco and Ruev, 2006). These challenges are compounded by the potentially large AoR delineation determined for a proposed Class VI injection project, and therefore the greater surface area that will have to be evaluated for the presence of artificial penetrations. However, as discussed

below, several methods and sources of information are available to identify those artificial penetrations in a relatively efficient manner. The primary stages of an abandoned well investigation within the AoR include historical research, site reconnaissance, review of aerial and satellite imagery, and one or more geophysical surveys. The reader is referred to additional standard references regarding identification of artificial penetrations for further information (Jordan and Hare, 2002; Frischknecht et al., 1985; ASTM, 2005).

4.2.1. Historical Research

Most deep wells that may penetrate the primary confining zone of a proposed GS project site are related to oil and gas exploration and production. Deep well drilling for oil and gas exploration dates back to the 1870s. State and local databases of well exploration may include locations of abandoned wells, and EPA recommends conducting a records review as the first step in abandoned well identification within the delineated AoR for a proposed Class VI injection well. In addition, state and local records will provide information on the time period and types of exploration that have been conducted in an area, and they may also provide information on typical completion and abandonment methods in a given field. This records search will provide a list of known abandoned wells, and it may inform additional stages of abandoned well identification.

State well databases will, in most cases, provide valuable information for assistance with the identification of abandoned wells. Prior to well construction, a government permitting authority requires owners or operators to seek a permit to drill from a specific agency, such as a state natural resources agency, environmental quality agency, or geological survey. Most states maintain records of drilled wells, including location, construction, operating, and plugging information. Although these records can take many forms, many states now have comprehensive databases of these well records that have been digitized and made available online. However, when conducting this historical records search, owners or operators of proposed Class VI injection wells should be aware that older well records may not have been entered into databases. In some cases, the records from different time periods may be filed in separate locations or on separate types of media.

For example, the Wyoming Oil and Gas Conservation Commission maintains a digital database, accessible online, of wells within the state. (See http://wogcc.state.wy.us for more information on this database.) Basic information is available to the public regarding each well, including geophysical survey results where available. The database can be searched by location, well name, and well number, among other fields. The state also has a "well book" available online, which contains records of older wells not entered in the database.

In addition, county records, including survey maps, ownership records, and chain-of-title and property lease history, maintained by local tax assessors and county clerks, list abandoned wells in many cases. Such records may also indicate land use and indicate areas and timeframes in which drilling activities likely occurred. Private data compilation services often maintain detailed databases for the purpose of oil and gas exploration, including information regarding well locations, plugging, and abandonment. Often these services will maintain maps of known well

locations. While these maps can be out of date, most private services have been known to update their database for a fee.

4.2.2. Site Reconnaissance

Site reconnaissance includes interviewing local residents and property owners, as well as conducting a physical search for features indicative of abandoned wells. Initial site reconnaissance may be informed by the historical database research. For example, the records search may indicate that, with a great deal of confidence, certain regions of the AoR have never been subject to oil and gas exploration, deep well injection, or any other activity that may result in deep well penetration. In this case, the owners or operators may choose to exclude those areas from any additional well identification efforts.

Local residents that may be well informed regarding abandoned wells include oilfield workers and service company employees, including consultants, and property and drilling-rights ownership brokers. Such informed residents may be able to provide information on the areas and timeframes where past drilling occurred. They may also be able to give additional details in response to specific questions and provide information on locations, completion methods, and plugging of wells.

Surface features that may be indicative of abandoned wells include abandoned well derricks, access roads, brine pits, or vegetation stress associated with brine leakage. Detection of these features at a site indicates the possible likelihood of one or more wells in the area. EPA recommends that, because the AoR is likely to cover a large area, a surface review for such features is most effectively supplemented by use of aerial surveys or photos.

4.2.3. Aerial and Satellite Imagery Review

EPA recommends that historical aerial photographs and satellite imagery be used in the identification of abandoned wells. Aerial photographic surveys, taken from airplanes, were conducted beginning in the 1930s and are available from a variety of governmental and private information services. All historical aerial photos within the AoR are recommended to be reviewed for evidence of past drilling activity. Surface features that provide a "signature" of drilling activity include drill derricks, rig platforms, brine pits, power sources, and access roads.

Depending on the resolution of the image, satellite (i.e., remote sensing) images may be used to detect wellheads, derricks, and surface features indicative of abandoned wells. These include spatial patterns indicative of a well site, brine pits, modified topography, and vegetation stress associated with brine leakage.

4.2.4. Geophysical Surveys

Geophysical surveys, including magnetic, ground penetrating radar (GPR), and electromagnetic methods, can be used in the detection of abandoned wells. EPA recommends conducting geophysical surveys throughout regions of the AoR that may have been subject to oil and gas

exploration, deep well injection, or any other activity that may result in deep well penetration. Geophysical methods will supplement other identification methods, discussed above. Geophysical methods can help to pinpoint locations of known wells where surface evidence of the well has been removed or can help to identify abandoned wells that are undocumented. The type(s) of geophysical surveys conducted at a proposed Class VI injection well site are based on known site subsurface and surface conditions. In general, at least two different types of geophysical surveys are recommended in order to parse data background noise and to inform the interpretation of survey results. As discussed below, ground or aerial (e.g., aeromagnetic) surveys may be conducted, depending on the size of the area of interest.

4.2.4.1. Magnetic Methods

The magnetic method is one of the oldest and most well developed geophysical techniques, and it is the standard method used for abandoned well detection. Magnetic surveys measure a component of the magnetic field near the land surface. Any anomalies in the magnetic field are caused by subsurface features, which could include abandoned well bores with iron or steel casings. Anomalies associated with well casings are typically distinguishable from the background magnetic field.

Magnetic surveys are applicable to abandoned wells with iron or steel casings or to wellheads in areas with relatively low background magnetic signatures. Areas with significant cultural development on the surface or in the shallow subsurface may have high interferences. Airborne magnetic surveys can detect most wells constructed with approximately 200 feet or more of at least 8-inch casing, and in some cases, very large cavities (Frischknecht et al., 1985). However, open well bores, non-steel casings, or severely corroded casings cannot typically be detected with a magnetic survey.

Ground or aerial (i.e., aeromagnetic) surveys may be conducted, depending on the size of the area of interest. Aeromagnetic surveys will likely be more practical for most GS projects due to the anticipated size of the delineated AoR, as they can collect large amounts of data in a relatively short amount of time. Both ground and aerial surveys are conducted along straight-line transects. EPA recommends that that ground survey transect spacing be no larger than 20–30 feet, and aerial survey transect spacing be no larger than 50–100 feet (Jordan and Hare, 2002).

Magnetic surveys may be conducted to measure the total magnetic field, or the vertical or horizontal field gradients. For the purpose of locating abandoned well bores, the total magnetic field measurement type is recommended. During these surveys, EPA recommends that the operator periodically return to a common point to ensure instrument repeatability, continuously measure diurnal variation in the magnetic field, and avoid high magnetic gradients. Data processing of magnetic surveys includes incorporation of spatial positioning data, correction for diurnal variation, and data filtering.

Figure 4-1 compares aeromagnetic survey results for the Coon Creek oil field in Oklahoma to abandoned wells identified from aerial imagery (USGS, 1995). As shown in the figure, magnetic anomalies associated with well casings are typically apparent. However, this figure also reveals

some of the typical challenges that may be faced by owners or operators in abandoned well bore identification. One challenge is that, due to the presence of other buried infrastructure (e.g., pipes), certain regions exhibit larger magnetic field values even if wells are not present. Additionally, some wells may not be identified in the aeromagnetic survey, most likely because of well casing removals. These challenges demonstrate the benefits of using multiple survey techniques in order to properly identify abandoned wells.

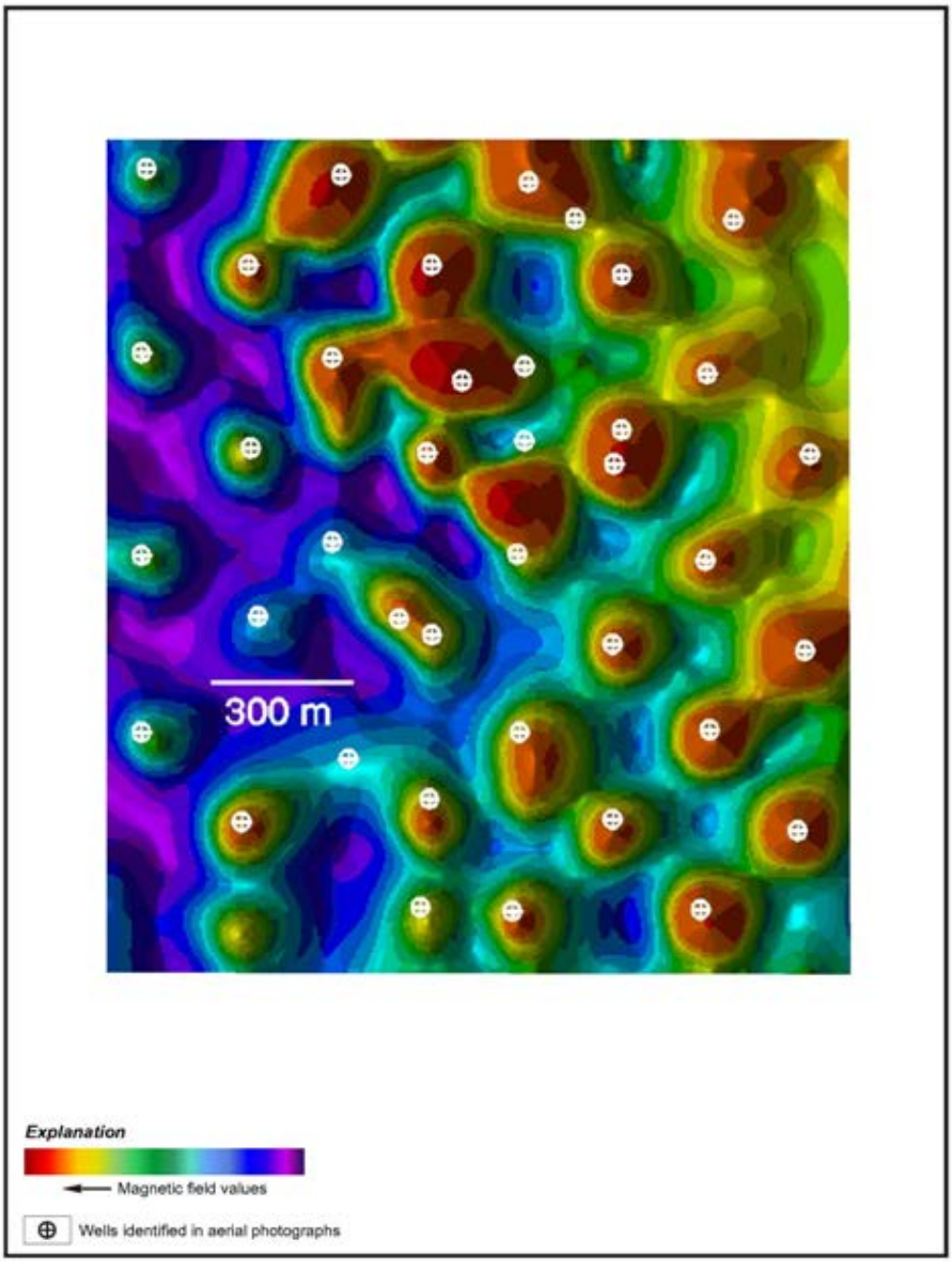


Figure 4-1: Total Field Aeromagnetic Map, Cook Creek Oil Field, Arcadia, Oklahoma.
From: USGS (1995).

4.2.4.3. Electromagnetic Methods

Electromagnetic methods used for abandoned well bore detection include frequency-domain and time-domain electromagnetic surveys. These surveys consist of an electromagnetic transmitter that establishes an electromagnetic field measured by a receiver. Similar to magnetic surveys, electromagnetic surveys are non-invasive, as both the transmitter and receiver are positioned above the ground surface. Both surface and aerial electromagnetic surveys are possible. The depth at which these instruments are able to detect objects depends on the size and geometry of the sensor, the size and conductivity of the target, and the potential interference from other sources, such as fences and pipelines. Generally, object detection at depths ranging from a few meters to several hundred meters is possible. Larger and more complex arrays are required at greater depths. Aerial surveys are not likely able to detect small objects, such as well casings, but may detect brine plumes, which may indicate the presence of abandoned wells (Jordan and Hare, 2002).

Abandoned well bore detection using electromagnetic methods is based on the larger conductivity of steel casings and other well materials compared to surrounding soils and geologic formations. These methods may detect anomalous fluids associated with leakage from an abandoned well. Frequency-domain electromagnetic methods can measure current induced in the subsurface by the electromagnetic field established by the transmitter. Induced current establishes a secondary electromagnetic field detected by the receiver. The magnitude of the induced current is a function of subsurface conditions, including conductivity. Time-domain electromagnetic methods measure the decay of the secondary magnetic field created by the induced current, and they can be especially useful for detection of brine leakage.

4.2.4.4. Ground Penetrating Radar

GPR may be used in abandoned well bore detection and in finding other artificial penetrations. Unlike other geophysical methods, GPR does not rely on the presence of a steel or iron well bore, so it may be able to detect open boreholes and non-metallic materials. GPR uses high frequency radio waves to measure the transmission of electromagnetic energy. The investigation depth possible depends on the frequency of the radio waves and the conductivity of the ground. The greater the depth, the less resolution the instrument will have. For small objects, such as well casings, depths are limited to a few meters (Jordan and Hare, 2002). This depth limitation may lessen the value of GPR in areas with large topographical changes. GPR is also slower than magnetic or electromagnetic methods. GPR is likely not as practical to use throughout the delineated AoR as an initial larger scale survey method because the distance between transect lines for sufficient resolution is too small. Instead, EPA recommends using GPR to determine the exact location of abandoned well bores within a given area that have already been identified by earlier, larger scale surveys.

4.3. Assessing Identified Abandoned Wells

After all artificial penetrations within the AoR that may penetrate the confining zone have been identified, the owners or operators of a proposed Class VI injection well must evaluate the

potential for each artificial penetration to serve as a conduit for fluid movement. In particular, owners or operators must establish which abandoned wells in the AoR, if any, have not been plugged in a manner that would prevent the movement of carbon dioxide or other fluids that may endanger USDWs [40 CFR 146.84(c)(3)]. To prevent fluid movement, abandoned wells should include a cement plug through the primary confining zone, and/or across the injection zone/confining zone contact, with sufficient integrity to contain separate-phase carbon dioxide and elevated pressures. The type of plugging that is sufficient to contain carbon dioxide and formation fluids from the injection zone will be site specific and should be reviewed with the UIC Program Director. In the absence of an adequate plug across the confining zone, cross-migration may occur where fluids enter a permeable zone below the lowermost USDW and then migrate upward from that zone. See Figure 4-2 for more information. EPA recommends cement surface plugs (typically required by well abandonment regulations), and the UIC Program Director may require additional plugs based on site-specific circumstances.

Evaluation of the wells in the AoR requires a two-step approach. The first step is to review whatever records are available, as outlined in Section 4.3.1, for information relevant to proper plugging. The second step is to perform physical tests on wells that are suspect or for which no records are available.

4.3.1. Abandoned Well Plugging Records Review

A records review can aid in reducing the number of identified wells that may need to be evaluated by future field testing. Records of wells that have been recently abandoned, have no mentions of any difficulties experienced during the abandonment procedure, are cased holes, and have plugs and cement situated to isolate the injection zone from other fluid containing zones may be used to justify reduction in the number of follow-up field investigations. If records are incomplete or indicate that the well has not been plugged or was inadequately plugged, follow-up field investigations should be performed. Identified undocumented wells will have no records and will require field investigation in order to determine the quality of plugging, as required in the Class VI Rule [40 CFR 146.84(c)(3)]. The owner or operator may also choose to plug any questionably abandoned wells rather than go through the expense of evaluating the plugs.

There are many elements in existing reports that can help in determining the adequacy of abandonment procedures for identified wells located within the AoR. Some key elements to review include, but are not limited to:

- Well depth and completion;
- Well abandonment date;
- Open hole or cased hole;
- Location of plugs;
- Casing and cementing records;
- Records of mechanical integrity tests (MITs) or logs performed; and
- Well deviation.

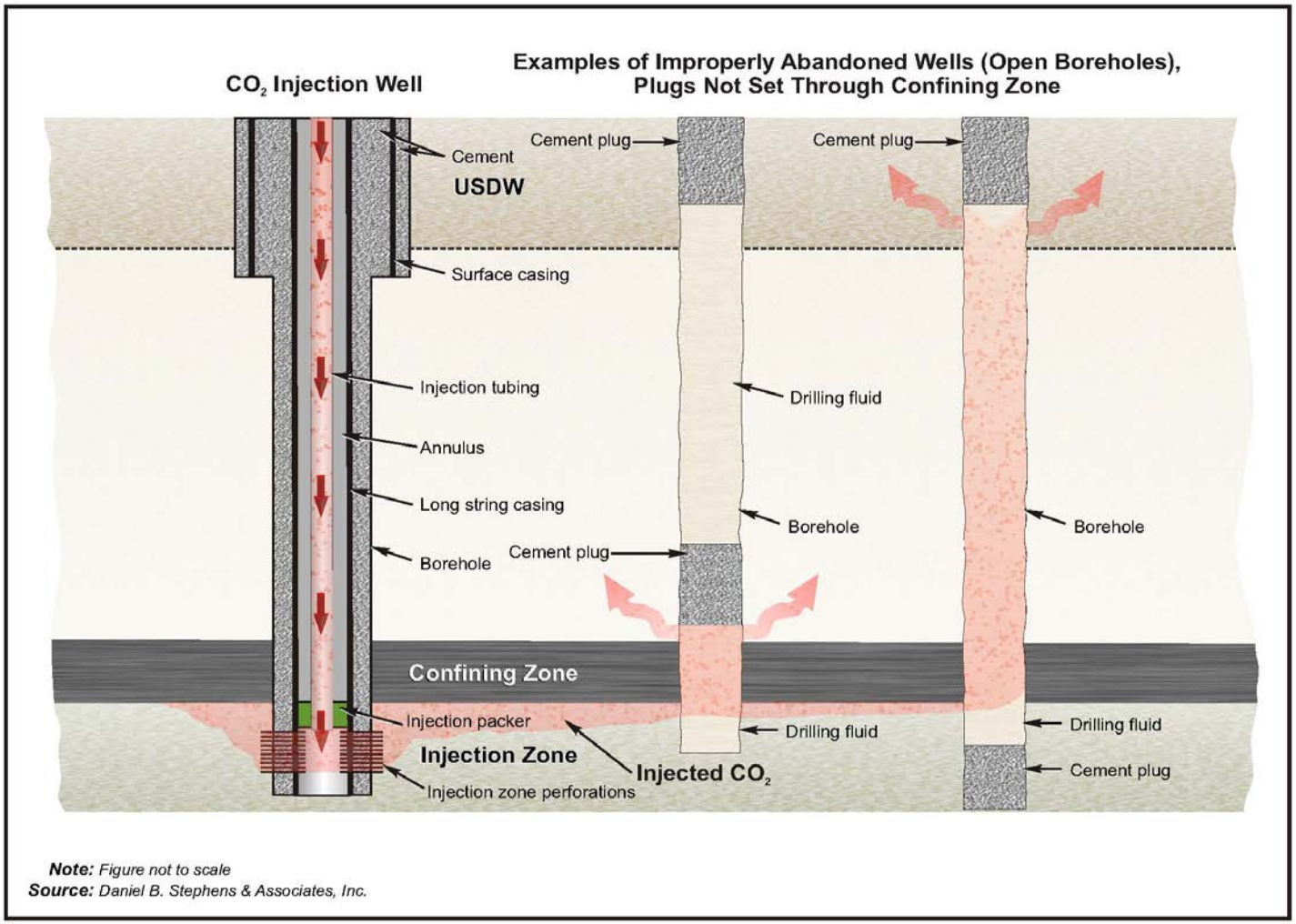


Figure 4-2: Examples of Carbon Dioxide Leakage Through Improperly Abandoned Wells.

The well completion depth is important in determining if the identified abandoned well may penetrate the proposed confining zone(s). If the well completion depth is above the confining zone(s), no further action would likely need to be taken. The date of abandonment may also provide information as to the adequacy of the abandonment procedure. Whether the well was abandoned with casing or as an open hole is an important consideration in determining the likelihood that the well might act as a conduit for fluid movement. Open holes are susceptible to cross-migration between aquifers. If the hole is open and there is not a proper plug located at a depth corresponding to the primary confining zone, fluids may migrate out of the injection zone and into a USDW. For cased holes, EPA recommends that integrity of the casing be evaluated.

The location and type of plugs are also important factors, especially in open-hole wells. The plug locations must be reviewed in order to determine the quality of plugging, as required in the Class VI Rule [40 CFR 146.84(c)(3)]. For example, EPA recommends that the injection zone be isolated from all other formations with plugs. This may be especially important if a well was completed in a formation deeper than the proposed injection zone. EPA recommends that any length of the well in the proposed injection zone be properly isolated by means of plugs and casing. Mechanical plugs and cemented casing are not sufficient for the long-term isolation of carbon dioxide, as eventually the metal is likely to corrode and the plug will fail (Randhol et al., 2007). Therefore, cement plugs are considered superior to mechanical plugs for preventing the movement of fluids into or between USDWs. EPA recommends that cement plugs be located across the bottom of any casings, at the base of the lowermost USDW, and that plugging fluid (i.e., composition, specific gravity) characteristics be considered, as drilling fluid of sufficient weight may resist displacement by the injectate or mobilized fluids.

The integrity of any existing casing and cement must be determined in order to assess the quality of well construction and plugging, as required in the Class VI Rule [40 CFR 146.84(c)(3)]. EPA recommends reviewing the casing and cement quality through the proposed injection zone in order to ensure that they are appropriate for contact with carbon dioxide, as well as reviewing any additional well records that may indicate unusual conditions experienced during casing and cementing. Events such as a loss of circulation, well bore stability problems, lack of the use of centralizers, and/or improper removal of drilling mud before cementing can all lead to premature cement or casing failure. Reviewing load calculations, if available, and comparing them to actual events recorded in the drilling log may give the owners or operators an indication of an under-designed casing that may be susceptible to failure. For example, if the casing had a low axial loading stress and stuck pipe was experienced during casing placement, it is possible that the casing may have experienced damage. The materials used for the well casing and cement must also be assessed to see if they are compatible with carbon dioxide, in order to comply with Class VI Rule requirements [40 CFR 146.84(c)(3)]. See the *UIC Program Class VI Well Construction Guidance* for more information on compatibility of different materials with a carbon dioxide stream.

Any tests performed on the well prior to its abandonment can also be useful information. An MIT such as a pressure test, noise log, temperature log, or cement evaluation log can provide information on any known or suspected leaks. If leaks were encountered, EPA recommends determining if the source of the leak was found and repaired. If the leaks were not sealed,

corrective action would be required to be taken to plug the leaks as discussed below [40 CFR 146.84(d)]. Drilling records can yield clues as to areas that might be susceptible to failure. Mud logs and open-hole caliper logs can show areas of weak formations. Weak formations are susceptible to well bore instability and subsequent cement failure. Cement evaluation logs and temperature logs taken at the time of completion can also give an idea of the condition of the cement, although degradation is always possible after well completion. Any corrosion logs will help provide information on the condition of the casing. Results from mechanical caliper logs, electromagnetic thickness logs, or down-hole video can show the casing condition when the well was abandoned. For more information regarding these logs and tests, see the *UIC Program Class VI Well Testing and Monitoring Guidance*.

Evaluation of well records for deviation during drilling may also identify wells more likely to be in need of corrective action, as deviated wells are far more likely to fail than wells with no deviation (Watson, 2009). Events such as well bore collapse during drilling or conditions that placed unusual loads on the casing may also indicate a higher chance of failed well bore integrity. EPA recommends that the design casing load also be checked to ensure adequacy for the actual loads faced by the well.

4.3.2. Abandoned Well Field Testing

After all the available records have been reviewed, any wells located within the AoR that cannot be proven to have plugs adequate to prevent migration of carbon dioxide or formation fluids out of the injection zone must be evaluated by field tests in order to determine the quality of plugging, as required in the Class VI Rule [40 CFR 146.84(c)(3)]. Evaluation and corrective action for wells which the plume is not expected to reach in the near future may be phased. If the owner or operator chooses and the UIC Program Director agrees, the evaluation may be omitted and the wells re-plugged. If the integrity of the bottom plug or cement is in question, and records cannot prove that the plugging is adequate, EPA recommends that the surface plug and possibly additional plugs down-hole be drilled out and tests conducted to determine the adequacy of abandonment. There are numerous field tests available to evaluate the integrity of abandoned wells. Several of these tests are discussed in detail in the *UIC Program Class VI Well Testing and Monitoring Guidance*. Additionally, the owner or operator must demonstrate guaranteed site access to wells potentially needing corrective action in the future [40 CFR 146.84(b)(iv)]. The owner or operator is encouraged to consult the UIC Program Director regarding any difficulties in gaining site access in order to evaluate and perform corrective action on any identified improperly plugged abandoned wells.

EPA recommends that both the casing and the cement plugs be evaluated. Casing failure is most common at joints and in weak formations where instability around the well bore can lead to failed cement and to casing buckling. Weak formations are also common areas for cement failure, as are high pressure formations, due to fluid intrusion. Tools used to evaluate the cement and casing include, but are not limited to:

- Multi-finger caliper log;
- Sonic scanner;

- Ultrasonic imaging tool;
- Cement evaluation log;
- Radioactive tracer;
- Cased hole dynamic tester;
- Modular sidewall coring tool; and
- Cased hole fluid test.

Multi-finger caliper logs measure the radius of the borehole in a non-destructive way. They can give a 360-degree picture of the inside of the casing and identify any defects caused by corrosion, erosion, or other events (e.g., dropped tools).

A sonic scanner sends out sound waves and measures the returned waves in receivers. The log provides information on the quality of the casing-cement bond and the cement-formation bond. The sonic scanner averages the results for the entire radius and therefore cannot provide three-dimensional pictures of the cement bond, or determine the reasons for a poor quality cement bond. An ultrasonic imaging tool is another non-destructive tool that uses ultrasonic transmitters and receivers to determine information about the casing and cement. The ultrasonic imaging tool can return 360-degree information on casing thickness, cement thickness, and cement bond. More information on these tools can be found in Duguid and Crow (2007) and Close et al. (2009).

A cement evaluation log is another tool used and log results include information on both the cement and the bond quality. This log provides results that are averaged over the circumference of the well, and testing is typically conducted in combination with an ultrasonic imaging tool to provide more complete information on the three-dimensional picture of the well. In some cases, the cement hardens while the well casing is under pressure and, when pressure is released, microannuli can form between the casing and cement. If unconnected to other cracks, these microannuli cannot transmit fluid, but they will appear in logging results as a potential poor bond. This artifact can be evaluated by performing the cement evaluation log under pressure (Randhol et al., 2007). Radioactive tracers also can be used to detect leaks in casing and cement and fluid leaking along channels in the well bore. Radioactive tracers are injected down the well, and gamma detectors are used to detect any fluid flow.

Cased-hole dynamic testers measure mobility or porosity. They can be used to determine the porosity of the cement. They are semi-destructive tests as they do create a small hole in the casing and cement; however, the hole is patched after the test is run. The instrument works well in highly permeable formations or in cement, while performance in lower porosity formations is still under investigation.

Modular sidewall coring tools take small cores of the casing and cement for analysis in the laboratory. Laboratory analyses can include scanning electron microscopy, X-ray diffraction, and measurements of permeability and density. This is a more destructive test that leaves approximately 1-inch diameter holes in the side of the well, which is then patched with a remedial cement squeeze after testing is completed. Cased-hole fluid testers can be run with the

cased-hole mobility tool, using optical instruments to determine what fluids are present in the formation outside the well bore.

In general, EPA recommends that these tests be run sequentially, from the simplest and least destructive tests to the more complicated and destructive tests. This way, if a flaw is found with a simpler test that determines that the well should be plugged or otherwise remediated, the more expensive and destructive tests may be avoided. The typical order of running the tests is caliper log, sonic and ultrasonic tools, cased-hole mobility and fluid tests, and then sidewall cores (Duguid and Crow, 2007). This set of tools can be used to determine the quality of the casing and cement; if flaws such as degraded cement porosity, casing corrosion, microannuli in the cement, channels between the cement and casing or cement and formation, or missing cement are found, the Class VI Rule requires that corrective action be performed on the well [40 CFR 146.84(d)]. A brief summary of the main methods for evaluating cement and casing condition along with major benefits and disadvantages are included in Table 4-1 below.

Table 4-1: Tools for Assessment of the Integrity of Abandoned Wells.

Tool	Target	Advantages	Disadvantages
Multifinger calipers	Casing	Non-destructive, relatively simple	Only examines interior, only detects casing damage
Sonic Logs	Cement	Non-destructive, yields information on cement bond	Results averaged over well circumference, can't indicate reasons for poor quality bond
Ultrasonic Logs	Casing, Cement	Non-destructive, can detect flaws in casing and cement, provides three-dimensional images	Sensitive to well fluids
Cement evaluation log	Cement	Non-destructive, yields information on quality of cement bond	Results averaged over well circumference
Tracers	Leak detection	Can pinpoint routes of leaks, channeling	Radioactive tracers require special handling and may have negative public perception
Dynamic Cased Hole Tester	Cement	Can determine porosity of cement	Semi-destructive, untested in low porosity conditions
Sidewall coring	Cement	Can give detailed analysis of cement condition	Destructive

4.4. Performing Corrective Action on Wells Within the AoR

The Class VI Rule requires that owners or operators of Class VI injection wells perform corrective action on all artificial penetrations in the AoR that may penetrate the confining zone and are determined to have been plugged and abandoned in a manner such that they could serve

as a conduit for fluid movement and endanger USDWs [40 CFR 146.84(d)]. In performing corrective action, owners or operators must use methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate [40 CFR 146.84(d)]. Figure 4-3 presents a decision tree that illustrates how the various evaluation tools can be used together to evaluate abandoned wells in an efficient and logical manner.

As described above, the Class VI Rule allows owners or operators to perform corrective action on a phased basis, if approved by the UIC Program Director. If a phased approach is approved for performing corrective action for a GS project, EPA recommends that all required corrective action on wells identified as deficient during the permit application process (or AoR reevaluations) receive corrective action prior to the end of the injection phase.

It is possible that some corrective action may be performed during the post-injection phase. For example, if the plume and pressure front movement were to deviate from predictions, this may necessitate corrective action for newly identified artificial penetration during the post-injection phase.

Performing corrective action on improperly abandoned wells is intended to prevent the movement of carbon dioxide or other mobilized fluids into or between USDWs. Acceptable forms of corrective action include well plugging and/or remedial cementing of the improperly abandoned well. In addition to corrective action, EPA recommends performing enhanced monitoring in the vicinity of improperly abandoned wells, including ground water monitoring and using indirect geophysical techniques for obtaining monitoring results. Appropriate monitoring for Class VI injection wells is discussed in the *UIC Program Class VI Well Testing and Monitoring Guidance*.

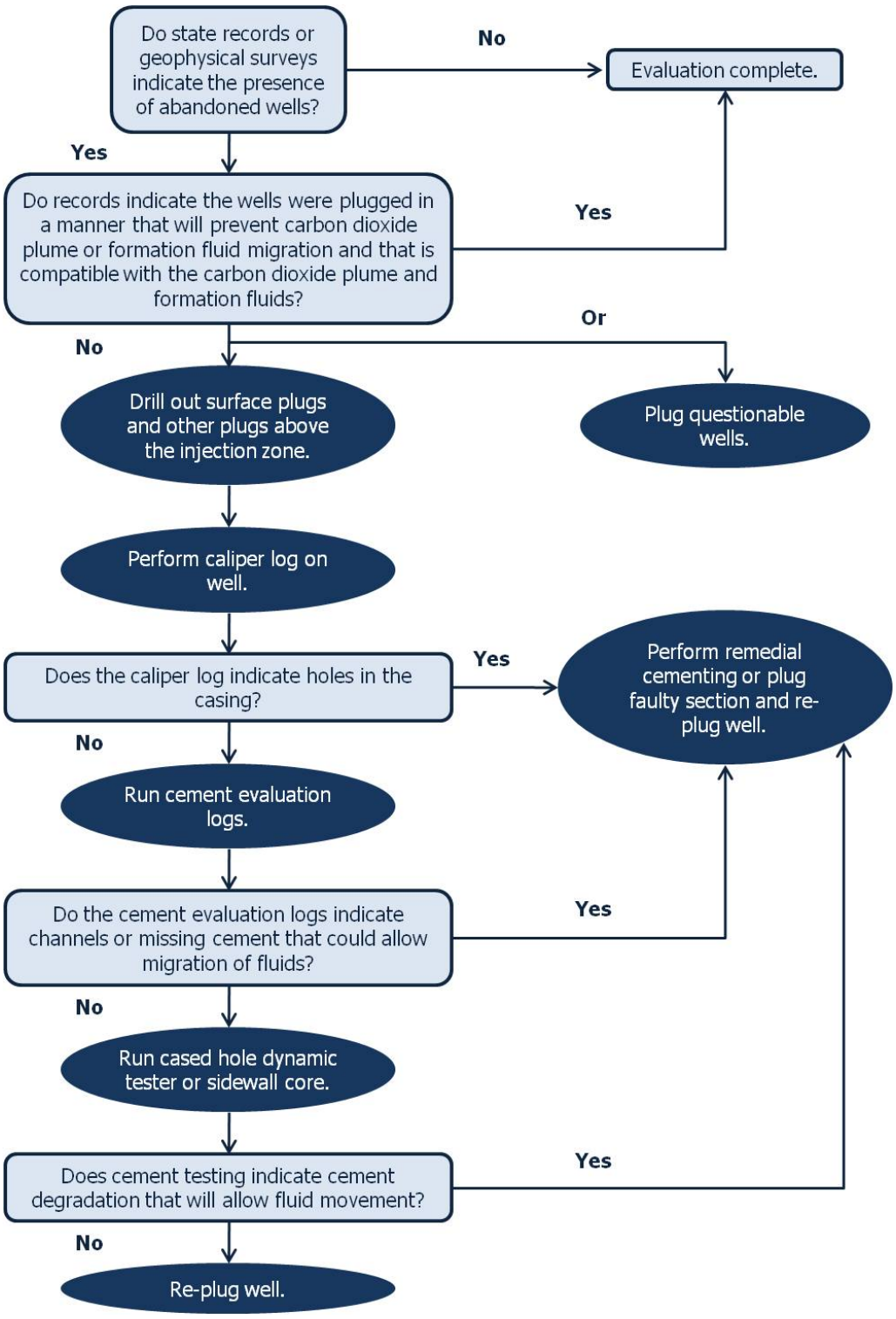


Figure 4-3: Well Evaluation Decision Tree.

4.4.1. Plugging of Wells within the AoR

Plugging of Class VI injection wells at the cessation of the injection phase of the project is discussed in detail in the *UIC Program Guidance on Class VI Well Plugging, Post-Injection Site Care, and Site Closure*. This section focuses on the plugging of improperly abandoned wells within the AoR prior to the commencement of injection. However, because similarities exist in plugging techniques for abandoned wells and former injection wells, the reader should refer to the *UIC Program Guidance on Class VI Well Plugging, Post-Injection Site Care, and Site Closure* for further detail regarding well plugging techniques for Class VI injection wells.

A well requires plugging if records indicate that an abandoned well was not plugged, was plugged and abandoned improperly, or has not been plugged in a manner that prevents movement of carbon dioxide or other fluids that may endanger USDWs [40 CFR 146.84(c) and (d)]. In addition, where records indicate that a well plug does not exist at a depth corresponding to the primary confining layer of the GS project, EPA recommends that the well have an additional plug set at this depth to meet the requirements of the Class VI Rule. Where records indicate that there are no well plugs below USDWs or other permeable formations that may exhibit cross flow of mobilized fluids, additional plugs may be required by the UIC Program Director for proper corrective action in these zones. Also, in wells that were plugged but the evaluation techniques discussed in Section 4.3 of this guidance document reveal cracks, channels, or annuli in the plug that would allow fluid migration, EPA recommends drilling out and replacing the plug. In addition, if the plug material may corrode in a carbon-dioxide rich environment, EPA recommends replacing it. For wells where casing exists at depths corresponding to the injection and/or confining zone and the annular space may serve as a conduit for fluid movement if not properly cemented, remedial cementing may be necessary or the casing may need to be removed and replaced with a cement plug. See Section 4.4.2 of this guidance document for more information on remedial cementing.

For the plugging of improperly abandoned wells within the AoR, EPA recommends that a plug be set at a depth interval corresponding to the primary confining zone overlying the injection zone of the Class VI injection well. In the absence of an adequate plug across the confining zone, cross-migration may occur wherein fluids enter a permeable zone below the lowermost USDW and then migrate upward from that zone. See Figure 4-2 of this guidance document for more information. However, in order to supplement the confining-zone plug, ideal additional plugging zones include the bottom of any casings and across any USDWs. A surface plug would also typically be required by local well abandonment regulations to ensure that there is no risk of anyone physically falling into the well bore.

To provide the best possible barrier to carbon dioxide migration out of the injection zone, EPA recommends that corrective action be conducted in a manner to provide multiple barriers to carbon dioxide migration and avoid underground cross-flow. Materials that are compatible with the carbon dioxide must be used where appropriate [40 CFR 146.84(d)]. Material compatibility with carbon dioxide is discussed further in the *UIC Program Class VI Well Construction Guidance*.

4.4.2. Remedial Cementing

Properly cementing improperly abandoned wells located within the delineated AoR between any existing well casing and the geologic formation, especially through the injection zone, provides an important fluid migration barrier. EPA recommends performing remedial cementing in order to meet the corrective action requirements of the Class VI Rule if a well has been properly plugged but the records, or any testing such as that described in Section 4.3 of this guidance, indicate that the cement surrounding the well bore has failed or has cracks, channels, or annuli that could allow migration of carbon dioxide. Key areas on which to focus remedial cementing include depths corresponding to the injection zone and through any other permeable zones.

Remedial cementing is performed through squeeze cementing, where the cement is emplaced into the affected area. For more information on cement squeezes, refer to Reynolds and Kiker (2003). Increased pressure on the cement forces water out of the cement slurry leaving behind the partially dehydrated cement. Cement squeezes can either be low pressure or high pressure. Low pressure squeezes are used to set a small amount of cement in a given area and operate at a pressure lower than the fracture pressure of the formation. Higher pressure squeezes are used when channels or disconnected microannuli are to be cemented. The higher pressure squeezes may fracture the formation and then allow the cement to flow into disconnected channels.

Cement squeezes can be performed using either a packer or a bradenhead squeeze. The methods differ in how the treated section is isolated from the rest of the well. In the packer squeeze, packers isolate the area to be treated, and a bridge plug isolates the area below the area to be cemented, while a modified packer with a bypass valve isolates the area above the treated area. Cement retainers are used if significant back pressure is expected. A bradenhead squeeze only isolates the area below the area to be cemented. It is typically used only if the casing above the treated area is strong enough to withstand the squeeze pressure. In cement squeezes, either drillable packers or retrievable packers can be used. Drillable packers allow less freedom in placement but better control of the cement. They are preferred if high pressures are maintained on the cement after the squeeze.

Cements used in squeeze cementing can vary depending on the nature of the defect. The Class VI Rule requires that all materials used for cementing of abandoned wells be compatible with the carbon dioxide stream, where appropriate [40 CFR 146.84(d)]. Traditional cements may be supplemented with or replaced by materials such as polymer gels and acrylic grouts. Acrylic grouts can be used for small casing leaks or cases where pressure leak off is detected. High concentration low molecular weight polymers can be used for small to moderate leaks. High molecular weight polymers are typically used for channeling and lost circulation applications. Cement or cement/polymer blends are typically used for severe leaks (Randhol et al., 2007).

4.5. Reporting Well Identification, Assessment, and Corrective Action to the UIC Program Director

As discussed in the *UIC Program Class VI Well Project Plan Development Guidance*, the AoR and Corrective Action Plan, submitted with the initial stage of the permit application, must

indicate what well identification and assessments will be used and how corrective action will be conducted [40 CFR 146.84(b)(2)(iv)]. The plan is a condition of the permit and is subject to UIC Program Director approval [40 CFR 146.84(b)].

Owners or operators seeking a Class VI injection well permit are required to report the following information regarding abandoned wells within the AoR that may penetrate the primary confining zone: the well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information required by the UIC Program Director [40 CFR 146.82(a)(4)]. This information may be found in acceptable public and private databases, where available. See Section 4.2.1 for more information. In cases where available records do not provide the necessary information or indicate that the well was plugged improperly, in a questionable manner, or with materials inappropriate for contact with carbon dioxide, then site investigations must be performed to establish the condition of the well, as discussed previously [40 CFR 146.84(c)(3)].

The UIC Program Director will review the submitted well information to ensure completeness and may consult with officials at oil and gas or water agencies to ensure that the well search was thorough. The UIC Program Director will also review well completion records to determine those wells that may penetrate the primary confining zone and will likely compare this list to wells scheduled for corrective action and submitted with the Class VI injection well permit application. For those identified abandoned wells that have been determined by the owner or operator to not require corrective action, the UIC Program Director will likely review the records of plugging and any field testing conducted, to verify that the well does not require corrective action. If information on the depth or condition of the plug(s) is missing, the UIC Program Director may request additional tests or require the well to be re-plugged.

Reports of any tests done on abandoned wells must be submitted to the UIC Program Director with the permit application along with a list of wells for which corrective action will be conducted, as part of the AoR and Corrective Action Plan required at 40 CFR 146.84(b). Before receiving authorization to inject, the owner or operator must submit a report on the status of corrective action [40 CFR 146.82(c)(6)], indicating the number, type, and location of the plugs. EPA recommends that owners or operators also submit any records of remedial cementing with the Class VI injection well permit application, along with cement logs showing the methods used and the results of the remedial cementing. Testing and remedial cementing records for wells which are part of a planned later stage of corrective action may be submitted after that phase is completed.

5. AoR Reevaluation

The Class VI Rule requires owners or operators of permitted Class VI injection wells to reevaluate the AoR delineation on a regular basis, at a frequency of at least once every five (5) years [40 CFR 146.84(e)]. The purpose of AoR reevaluation is to ensure that the initial model predictions are adequate for predicting the extent of the separate-phase carbon dioxide plume and pressure front. To this end, AoR reevaluation consists of a comparison of modeling predictions and the required site monitoring data [40 CFR 146.90] and a revision of the model used to delineate the AoR when necessary. Because Class VI injection well permits are granted for the lifetime of the project, AoR reevaluation is the primary opportunity for the owner or operator and the UIC Program Director to assess the project's operation and take additional appropriate actions, if necessary, to protect USDWs. If a revision of the AoR delineation is necessary, a revision of the AoR and Corrective Action Plan is also required [40 CFR 146.84(e)(4)], along with other related project plans that may be dependent on the extent of the delineated AoR, including the Testing and Monitoring Plan [40 CFR 146.90(j)]. It is important to note that a change in the AoR and/or the AoR and Corrective Action Plan after the permit is issued may constitute a modification of the Class VI permit, and would be subject to public notice [40 CFR 144.39(a)(5)(i)].

Reevaluations of the AoR must continue throughout the life of the GS project, including the post-injection phase [40 CFR 146.84(e)]. It is likely that, following cessation of injection, the area of increased pressure will reduce in size as pressures dissipate; therefore, EPA expects that the reviews will entail an examination of monitoring data and confirmation and communication to the UIC Program Director that no modifications to the AoR or amendments to any plans are needed. However, this step is necessary to ensure that USDWs are not endangered and that all of the plans in force (including the PISC and Site Closure Plan and the Emergency and Remedial Response Plan) remain protective of USDWs.

5.1. Class VI Rule Requirements Related to AoR Reevaluation

The following Class VI Rule requirements pertain to reevaluation of the AoR:

- 40 CFR 146.84(e): At the minimum fixed frequency, not to exceed five years, as specified in the AoR and Corrective Action Plan, or when monitoring and operational conditions warrant, owners or operators must:

  (1) Reevaluate the AoR in the same manner specified in 40 CFR 146.84(c)(1);

  (2) Identify all wells in the reevaluated AoR that require corrective action in the same manner specified in 40 CFR 146.84(c);

  (3) Perform corrective action on wells requiring corrective action in the reevaluated AoR in the same manner specified in 40 CFR 146.84(d); and

  (4) Submit an amended AoR and Corrective Action Plan or demonstrate to the UIC Program Director through monitoring data and modeling results that no amendment to the AoR and Corrective Action Plan is needed. Any amendments

to the AoR and Corrective Action Plan must be approved by the UIC Program Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate.

5.2. Conditions Warranting an AoR Reevaluation

AoR reevaluation is required at a minimum fixed frequency of at least once every five years, or when monitoring and operational conditions warrant [40 CFR 146.84(e)]. EPA recommends that monitoring and operational conditions that may warrant a reevaluation of the AoR include:

- Significant changes in site operations that may alter model predictions and the AoR delineation;
- Monitoring results for the injected carbon dioxide plume and/or the associated pressure front that differ significantly from model predictions; or
- New site characterization data obtained that may significantly change model predictions and the delineated AoR.

Any site-specific criteria that will trigger an AoR reevaluation for a particular project must be included in the AoR and Corrective Action Plan [40 CFR 146.84(b)(2)(ii)].

5.2.1. Minimum Fixed Frequency

As stated above, the owners or operators of permitted Class VI injection wells must reevaluate the AoR delineation at least once every five years [40 CFR 146.84(e)]. The planned fixed frequency for reevaluation must be included in the AoR and Corrective Action Plan [40 CFR 146.84(b)(2)(i)]. The AoR may need to be reevaluated more frequently than the previously scheduled timeframe based on other factors. In these cases, the schedule for AoR reevaluation may be updated appropriately. At no time may AoR reevaluation occur less than once every five years [40 CFR 146.84(e)].

5.2.2. Significant Changes in Operations

Significant changes in operation of the GS project and/or individual Class VI injection wells mandate an AoR reevaluation [40 CFR 146.84(e)]. The UIC Program Director may require an AoR reevaluation prior to approving any operational changes. If allowed by the UIC Program Director, operational changes may occur prior to reevaluation of the AoR. In these cases, EPA recommends that the AoR reevaluation be submitted to the UIC Program Director within an agreed-upon timeframe of instituting such changes, as described in the AoR and Corrective Action Plan.

EPA recommends that proposed operational changes warranting an AoR reevaluation may include, but are not limited to, a change in the location or number of Class VI injection wells injecting into the same injection zone and/or a change in carbon dioxide injection rates, volumes, or pressures outside of the limits of the original permit and AoR delineation. Additional

operational changes that may warrant an AoR reevaluation, if required by the UIC Program Director, include a change in the composition of the injectate or changes in fluid production rates from the injection or overlying zones. Based on the discretion of the UIC Program Director, short-term routine operational changes (e.g., temporary well shut-ins) may not warrant reevaluation of the AoR.

In addition, the owner or operator may choose to perform an AoR reevaluation based on other operational changes, with the approval of the UIC Program Director. Specific operational triggers for an AoR reevaluation for a particular Class VI injection well must be included in the AoR and Corrective Action Plan submitted with the permit application for that particular injection well [40 CFR 146.84(b)(2)(ii)]. Operational changes that trigger a reevaluation may be associated with the GS project under which the permitted Class VI injection well operates or with separate projects that inject carbon dioxide into the same injection formation.

5.2.3. Results from Site Monitoring that Differ From Model Predictions

EPA recommends that collection of any monitoring data (required under 40 CFR 146.90) that indicate carbon dioxide and/or pressure front migration significantly different than that predicted by the current AoR delineation model warrant an AoR reevaluation. Specific criteria for differences in monitoring data and model predictions that may trigger an AoR reevaluation for a particular project must be included in the AoR and Corrective Action Plan [40 CFR 146.84(b)(2)(ii)]. In such cases, when monitoring data and modeling predictions differ, the owner or operator is encouraged to notify the UIC Program Director and submit an AoR reevaluation within timeframes that have been established in the AoR and Corrective Action Plan. Methods for monitoring the evolution of the carbon dioxide plume and associated pressure front are discussed in more detail in the *UIC Program Class VI Well Testing and Monitoring Guidance.* An example of evaluation of monitoring results during AoR reevaluation is provided in Box 5-1.

The owner or operator is required to perform monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure [40 CFR 146.90(g)]. Pressure monitoring is required using direct methods (e.g., pressure transducers) within the injection zone, and indirect methods for plume tracking are also required unless the UIC Program Director determines, based on site-specific geology, that such methods are not appropriate [40 CFR 146.90(g)(1) and (2)]. Additionally, the owner or operator is required to perform periodic monitoring of ground water quality and geochemical changes above the primary confining zone that may be a result of carbon dioxide movement through the confining zone [40 CFR 146.90(d)]. On a site-specific basis, the UIC Program Director may require additional geochemical monitoring within the injection zone as a component of carbon dioxide plume tracking [40 CFR 146.90(i)].

EPA recommends that pressure measurements indicative of pressure-front migration further than that predicted by the current computational model warrant an AoR reevaluation. In practice, this would be indicated by an observed increase in pressure at monitoring wells greater than predicted by the computational model. In some cases, pressure measurements may fluctuate, and

short-term temporary pressure increases (e.g., spikes) may not warrant an AoR reevaluation. EPA recommends that the specific pressure monitoring results that would trigger an AoR reevaluation be included in the AoR and Corrective Action Plan. For example, the owner or operator may specify the magnitude and duration of increased pressure that would trigger an AoR reevaluation for each monitoring well.

Results of carbon dioxide plume and pressure-front tracking using indirect methods, such as periodic geophysical surveys, may also be used for comparison to model predictions. Geophysical survey results provide information over relatively large areas, as opposed to "point" measurements provided by monitoring wells. Geophysical survey results are intended to provide an estimate of the extent of the separate-phase carbon dioxide plume and, in some cases, pressure changes. EPA anticipates that results of indirect monitoring that indicate carbon dioxide migration (1) outside of the boundaries of the current AoR delineation, or (2) at rates significantly greater than current model estimates would also warrant an AoR reevaluation.

EPA also recommends performing an AoR reevaluation if the results of the ground water geochemical sampling indicate separate-phase (i.e., supercritical, liquid, or gaseous) carbon dioxide migration outside of the boundaries of the current AoR delineation, or at rates significantly greater than predicted by the computational model. The presence of separate-phase carbon dioxide in the sampled fluids above the confining zone is evidence of carbon dioxide/fluid migration out of the injection zone and is cause to notify the UIC Program Director pursuant to 40 CFR 146.91(c)(1). In addition, elevated carbon dioxide aqueous concentrations may indicate the presence of separate-phase carbon dioxide in the immediate vicinity of the monitoring well.

5.2.4. Ongoing Site Characterization

Site characterization is not a one-time exercise at GS project sites. As additional site characterization data are collected via geophysical surveys, the drilling of new injection or monitoring wells, or from other sources, the data must be subsequently incorporated into the existing computational model used for AoR delineation [40 CFR 146.84(c)(1) and (e)(1)]. Types of data that may be incorporated into a reevaluation include newly identified potential conduits for fluid movement, updated information regarding injection or confining zone extent and thickness, or further characterization of formation heterogeneity. The UIC Program Director may also require an AoR reevaluation based on any newly available site characterization data that may impact current modeling predictions.

5.3. Performing an AoR Reevaluation

The first step in performing an AoR reevaluation for a Class VI injection well is a comparison of the available monitoring data and the model predictions. If Class VI owners or operators believe that monitoring and modeling data are consistent and that revision of the model is not necessary, they must demonstrate this to the UIC Program Director in lieu of revising the computational model [40 CFR 146.84(e)(4)]. However, if monitoring data and modeling predictions differ significantly, then the Class VI owner or operator must submit an amended AoR and Corrective

Action Plan and revise both the computational model and the AoR delineation results [40 CFR 146.84(e)(1) and (4)].

Box 5-1. Hypothetical Example of an AoR Reevaluation

An AoR reevaluation consists of comparing monitoring results of plume and pressure-front movement to model predictions. In this hypothetical example, a continuation of the scenario presented earlier in Boxes 3-1 and 3-2, the AoR reevaluation required after 20 years of injection is illustrated below. In this example, the previously required AoR reevaluations at 5, 10, and 15 years did not result in any AoR delineation modifications.

Comparison of Plume Monitoring Data

In this hypothetical scenario, monitoring data are available from eight monitoring wells screened within the injection zone and from an indirect geophysical monitoring technique. Monitoring well data are used to assess the potential presence of separate-phase carbon dioxide at each location. The data indicate that separate-phase carbon dioxide is present at one of the monitoring wells. These data are compared to initial model predictions of plume evolution for 20 years after the commencement of injection (Figure 5-1). Carbon dioxide is detected at MW-6, outside of the areas predicted by the model to exhibit carbon dioxide.

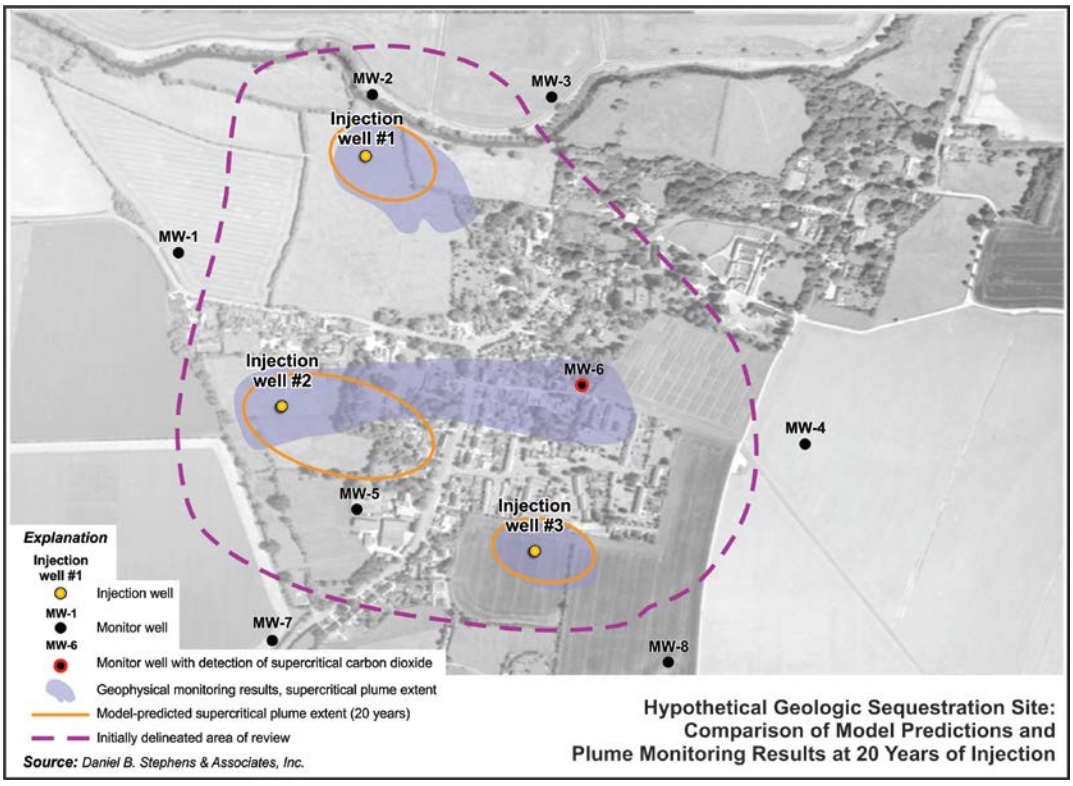


Figure 5-1: Hypothetical Geologic Sequestration Site: Comparison of Model Predictions and Plume Monitoring Results at 20 Years of Injection.

Box 5-1. Hypothetical Example of an AoR Reevaluation, *continued*

Compared to monitoring well data, geophysical data provide a larger-area estimate of the extent of separate-phase carbon dioxide. The geophysical and monitoring-well data are consistent in their general evaluation of where separate-phase carbon dioxide is present. Geophysical data and model results are generally consistent for the plume emanating from Injection Well #3, and inconsistent for Injection Wells #1 and #2. The carbon dioxide plume may have migrated differently than originally predicted for several reasons, as discussed below.

Comparison of Pressure Monitoring Data

Bottom-hole pressure data are collected at all of the eight monitoring wells. This example focuses on data collected at three of the wells, MW-1, MW-2, and MW-6. For actual projects, EPA recommends that data from all monitoring wells be considered. Graphs of pressure monitoring data over the first 20 years of the project, compared to modeling results, are presented in Figure 5-2.

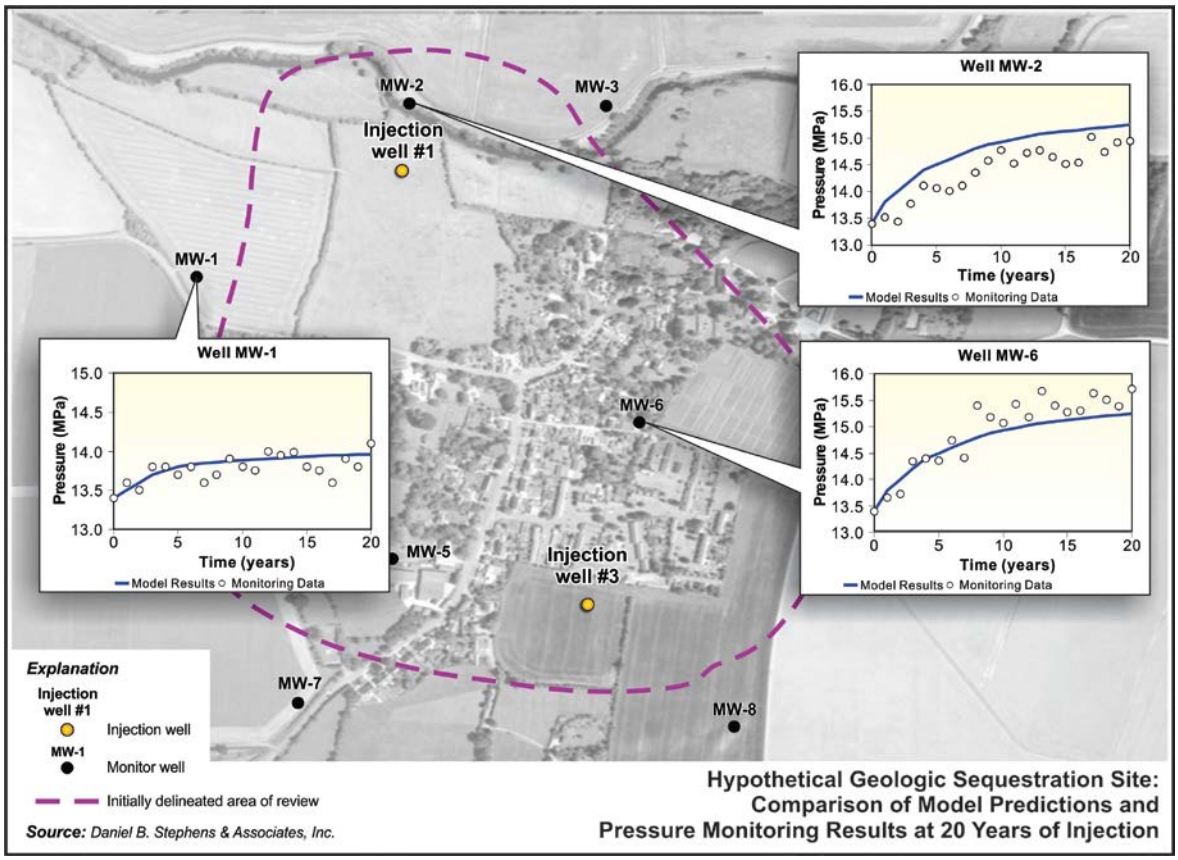


Figure 5-2: Hypothetical Geologic Sequestration Site: Comparison of Model Predictions and Pressure Monitoring Results at 20 Years of Injection.

Box 5-1. Hypothetical Example of an AoR Reevaluation, *continued*

Pressure monitoring data are consistent with modeling predictions on the western edge of the project (MW-1). The general scatter in the monitoring data are expected, and there is no significant bias (i.e., less than, greater than) in comparing the monitoring data and modeling results. Data from the northern portion of the project (MW-2) indicate that actual pressure increases in the injection zone are lower than model predictions. This area has exhibited less of a pressure perturbation caused by injection than originally predicted. In contrast, data from the eastern portion of the site (MW-6) indicate that there has been a larger pressure increase than originally predicted. These data are generally consistent with the plume migration data, presented above, which showed that the plume has migrated further east than originally predicted.

Outcome of Monitoring Data and Model Comparison

This comparison indicates that, after 20 years of injection, modeling results and monitoring data compare favorably in some regions of the site. However, the plume and pressure front appear to have migrated further to the east than initially predicted. This disparity may be due to several factors. Examples include the presence of a high-permeability pathway within the injection zone that had not been fully characterized during initial site characterization, or the dip angle at the injection zone/confining zone interface being larger than originally assumed. Based on this comparison, the operator of the project site, in consultation with the UIC Program Director, decided to calibrate the AoR model and re-delineate the AoR. See Box 5-2 for more information.

5.3.1. Demonstrating Adequate Existing AoR Delineation

An AoR reevaluation does not necessarily need to result in revisions or updates to the site computational model. If the owner or operator determines that no changes are necessary, the required reevaluation may consist of demonstrating this to the UIC Program Director [40 CFR 146.84(e)(4)]. EPA recommends that demonstrating the adequacy of the current AoR delineation includes verification that existing operational and site characterization data have been incorporated into the model and that existing monitoring data agree with the modeled predictions.

EPA recommends that the Class VI injection well owners or operators submit any new operational, monitoring, or site characterization data that have been received since the last AoR reevaluation to the UIC Program Director. EPA also recommends that details regarding how this information has been incorporated into the site computational model be presented, as newly received operational or site characterization data may impact model input parameter values.

Integral to demonstrating that the current AoR delineation is adequate is the comparison of monitoring data and model predictions. EPA recommends that this comparison take the form of graphics and informative maps showing the general agreement between monitoring results and model predictions, and that all available monitoring data be considered, including fluid geochemistry monitoring, pressure monitoring, and geophysical surveys.

5.3.2. Modifying the Existing AoR Delineation

Any significant differences between operational monitoring results and the existing model predictions that are the basis for the AoR delineation, for example as discussed in Section 5.2.3 of this guidance document, warrant a modification to the existing AoR delineation [40 CFR 146.84(e)]. The steps in revision of the AoR delineation include adjusting the site conceptual model, model calibration (i.e., adjusting model parameters), and presentation of adjusted model results and the newly delineated AoR to the UIC Program Director.

EPA recommends that the site conceptual model be revised based on new site characterization, operational, and, in some cases, monitoring data. The new conceptual site model schematic may be provided to the UIC Program Director along with the AoR reevaluation information, with any changes highlighted. Examples of changes to the conceptual model include new injection wells, newly elucidated geologic features (e.g., stratigraphic layers), or a revised permeability field.

Following revision of the site conceptual model, revision of the existing AoR delineation may require model calibration in order to minimize the differences between monitoring data and model simulations (see Section 2.5 of this guidance). EPA recommends that the relative error difference between monitoring data and model predictions be quantified via the use of calibration statistics (e.g., ME, MAE, RMSE). To the extent possible, the value of the calibration statistics should be minimized during model calibration. The value of the model calibration statistics also informs the expected uncertainty and error in model predictions of future

conditions. Following model calibration, the AoR delineation may be revised using methods described in Section 3.4 of this guidance.

In reporting an AoR computational model and delineation revision, EPA recommends that all model attributes, as given in Section 3.5 of this guidance document, be re-submitted to the UIC Program Director. In addition, EPA recommends that the model calibration process and final AoR delineation results be presented in detail as part of the submission with:

- Adjusted input parameter values listed;
- Graphs comparing observed and modeled values of carbon dioxide migration and fluid pressure;
- Model results showing carbon dioxide and pressure front migration over time included; and
- The value of the model calibration statistics.

The newly delineated AoR may be presented on maps which would highlight similarities and differences in comparison with previous AoR delineations. See Box 5-2, below, for an example of a hypothetical AoR reevaluation.

If a revision of the AoR delineation is necessary, an amendment to the AoR and Corrective Action Plan is also required, along with possible amendments to other related project plans [40 CFR 146.84(e)(4) and (f)]. EPA recommends that the amended AoR and Corrective Action Plan explain any differences in corrective action activities that result from AoR revision, including a demonstration of adequate surface access rights in order to perform the required corrective action activities. See Section 4 for more information on performing corrective action. Furthermore, in some cases, GS project attributes that are outside the scope of the Class VI Rule and the UIC Program, such as pore-space ownership rights, may be related to the size of the AoR. In these cases, the owners or operators are encouraged to consult with the UIC Program Director, or another applicable regulatory agency, following a revision of the AoR in order to proceed.

Box 5-2. Hypothetical Example of a Presentation of the Revised AoR

After the site computational model has been revised through model calibration to monitoring data, and/or updating with new operational or site characterization parameters, the AoR must be re-delineated [40 CFR 146.84(e)]. See Box 3-2 for more information on AoR delineation; the same general methods should be used during the reevaluation. Once the AoR has been revised, it may be presented on a site base map in comparison to the former AoR delineation (Figure 5-3).

In this hypothetical example, the AoR reevaluation has resulted in an AoR delineation that extends generally farther toward the east than previously. This is consistent with the monitoring data (Box 5-1) indicating further plume and pressure front migration toward the east. The model was revised to match monitoring data by adjusting intrinsic permeability values within the injection zone and the dip angle at the injection/confining zone interface.

The region newly identified as located within the delineated AoR (between the purple and blue contour lines) must be subjected to the artificial penetration identification, assessment, and corrective action procedures as discussed in Section 4 of this guidance document [40 CFR 146.84(e)(2) and (3)]. Furthermore, the revision of the AoR requires revisions to the AoR and Corrective Action Plan and other project plans, as discussed in the *UIC Program Class VI Well Project Plan Development Guidance*. Changes to the AoR and Corrective Action Plan may demonstrate a need to secure new surface access rights for the newly included area. The owner or operator may also contact the applicable regulatory agency for other project attributes (e.g., new pore space ownership rights) that are outside the scope of the Class VI Rule and the UIC Program.

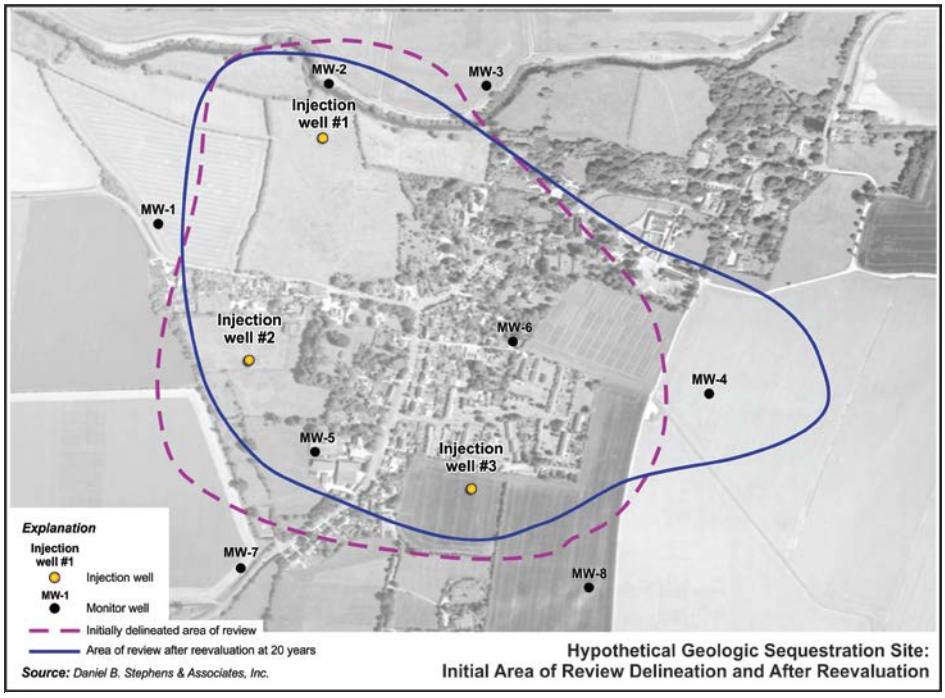


Figure 5-3: Hypothetical Geologic Sequestration Site: Initial AoR Delineation and Delineation after Reevaluation.

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U.S. ENVIRONMENTAL PROTECTION AGENCY

UNDERGROUND INJECTION CONTROL PERMIT

DRAFT PERMIT

CLASS VI INJECTION WELL

Permit Number: R9UIC-CA6-FY22-1.1

Well Name: 373-35R

Issued to:

Carbon TerraVault JV Storage Company Sub 1, LLC

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 9
75 Hawthorne St.
San Francisco, CA 94105-3901

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT: CLASS VI

Permit Number: R9UIC-CA6-FY22-1.1
Facility Name: CTV 1: Elk Hills 26R

Pursuant to the Safe Drinking Water Act and Underground Injection Control regulations of the U.S. Environmental Protection Agency codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 124, 144, 146, and 147,

Carbon TerraVault JV Storage Company Sub 1, LLC of Tupman, CA

hereinafter, the permittee, is hereby authorized to construct and operate a Class VI injection well located in the State of California, Kern County, T 30 S, R 23 E of Mount Diablo Base Meridian, Section 35, 35° 16' 34.5276" N, 119° 28' 24.1836" W, as part of the Elk Hills 26R Carbon Dioxide Storage Project. The well will inject a carbon dioxide stream (carbon dioxide is also called CO_2 in the attachments to this permit) sourced initially from the proposed Lone Cypress hydrogen plant, pre-combustion gas treatment, and the proposed Avnos Direct Air Capture facility (see Attachment B). All three initial carbon dioxide sources are to be located within the Elk Hills oil field. The permittee may request to inject carbon dioxide from additional emission sources in the future, subject to review and approval by EPA, as described in Section N of this permit. The permittee stated in their application that potential future sources of carbon dioxide may include: post combustion capture from the Elk Hills power plant, renewable fuel plants, post combustion capture from steam generators, other power plants, and industrial sources. The carbon dioxide stream, as characterized in the permit application and the administrative record, shall be a liquid, supercritical fluid, or gas. Injection is authorized into the Monterey Formation at a depth of approximately 6,000 feet below ground surface upon the express condition that the permittee meet the restrictions set forth herein. The designated confining zone for this injection is the Reef Ridge Shale Formation.

Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, directs federal agencies, to the greatest extent practical and permitted by law, to identify and address, as appropriate, disproportionate, and adverse human health or environmental impacts on people of color and low-income populations. See Exec. Order No. 12898, 59 Fed. Reg. 7629 (Feb. 11, 1994). Recently, Executive Order 14096, *Revitalizing Our Nation's Commitment to Environmental Justice for All*, supplemented this direction. See Exec. Order No. 14096, 88 Fed. Reg. 25251 (Apr. 21, 2023). As part of the decision-making process for this permit, EPA considered these executive orders and EPA's Environmental Justice Guidance for UIC Class VI Permitting and Primacy (Aug. 17, 2023). EPA's evaluation and consideration of environmental justice for this permit is described in EPA's Fact Sheet.

This permit is for the construction and operation of one Class VI injection well (well name 373-35R); three other wells at the Elk Hills 26R Carbon Dioxide Storage Project are authorized under separate Class VI permits (Permit Nos. R9UIC-CA6-FY22-1.2, R9UIC-CA6-FY22-1.3 and R9UIC-CA6-FY22-1.4). Injection shall not commence until the operator has received written authorization from the Director of the Water Division of EPA Region 9, in accordance with Section S of this permit.

All references to Title 40 of the Code of Federal Regulations are to all regulations that are in effect on the date that this permit is effective. The following attachments are incorporated into this permit as enforceable conditions:

- A: Summary of Operating Requirements;
- B: Area of Review and Corrective Action Plan;
- C: Testing and Monitoring Plan;
- D: Well Plugging Plan;
- E: Post-injection Site Care and Site Closure Plan;
- F: Emergency and Remedial Response Plan;
- G: Construction Details;
- H: Financial Assurance Demonstration; and
- I: Stimulation Program.

This permit shall become effective on [Insert date], and shall remain in full force and effect during the operating life of the well and the post-injection site care period until site closure is authorized and completed, unless this permit is revoked and reissued, terminated, or modified pursuant to 40 CFR 144.39, 144.40, or 144.41. This permit shall also remain in effect upon delegation of primary enforcement responsibility of the UIC program for Class VI wells to the State of California until such time as the State issues its own permit to the permittee or the State chooses to adopt this permit as a State permit. The permit will expire in one year, if the permittee fails to commence construction on the well, unless a written request in electronic format for an extension of this one-year period has been approved by the Director. The permittee may request an expiration date sooner than the one-year period, provided no construction on the well has commenced. At least every five years from the effective date specified above, the permittee must re-evaluate the Area of Review and comply with 40 CFR 146.84(e). If results from the re-evaluated Area of Review are different from what is predicted in Attachment B of this permit, EPA may require the permittee to update the permit and the attachments.

Signed and Dated: _____

DRAFT

_____

[Insert Name of signing official]
[Insert Title, Office/Division]

PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is authorized to engage in underground injection in accordance with the conditions of this permit. Notwithstanding any other provisions of this permit, the permittee authorized by this permit shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus or formation fluids into underground sources of drinking water (USDWs) or any unauthorized zones. The objective of this permit is to prevent the movement of fluids into or between USDWs or into any unauthorized zones consistent with the requirements at 40 CFR 146.86(a). Any underground injection activity not specifically authorized in this permit is prohibited. For purposes of enforcement, compliance with this permit during its term constitutes compliance with Part C of the Safe Drinking Water Act (SDWA). Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA or any other common or statutory law other than Part C of the SDWA.

Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local laws or regulations. Nothing in this permit, nor compliance with its terms, shall be construed to relieve the permittee of any duties under applicable State or local laws or regulations that are not preempted or superseded by the Federal SDWA Underground Injection Control (UIC) program.

B. PERMIT ACTIONS

1. **Modification, Revocation and Reissuance, and Termination –** The Director of the Water Division of Region 9 of the U.S. Environmental Protection Agency (EPA), hereinafter, the Director, may, for cause or upon request from any interested person, including the permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR 124.5, 144.12, 146.86(a), 144.39, and 144.40. The permit is also subject to minor modifications for cause as specified in 40 CFR 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

2. **Minor Modifications –** Upon the consent of the permittee, the Director may modify this permit to make the corrections or allowances for minor changes in the permitted activity as listed in 40 CFR 144.41. Any permit modification not processed as a minor modification under 40 CFR 144.41 must be made for cause, and with part 124 draft permit and public notice as required in 40 CFR 144.39.

3. **Transfer of Permits** – This permit is not transferable to any person except in accordance with 40 CFR 144.38(a) and Section O(6)(b) of this permit.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR part 2 (Public Information) and 40 CFR 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential business information by the submitter. Any such claim must be asserted at the time of submission by clearly identifying each page with the words "confidential business information" on every page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2.

E. DEFINITION

All terms used in this permit shall have the meaning set forth in the SDWA and Underground Injection Control regulations specified at 40 CFR parts 124, 144, 146, and 147. Unless specifically stated otherwise, all references to "days" in this permit should be interpreted as calendar days.

F. DUTIES AND REQUIREMENTS

1. **Duty to Comply** – The permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application.

2. **Duty to Reapply** – If the permittee wishes to continue an activity regulated by this permit after the expiration or termination of this permit, the permittee must apply for and obtain a new permit.

3. **Penalties for Violations of Permit Conditions** – Any person who violates a permit requirement is subject to civil penalties and other enforcement action under the SDWA. Any person who willfully violates permit conditions may be subject to criminal prosecution under the SDWA and other applicable statutes and regulations.

4. **Need to Halt or Reduce Activity Not a Defense –** It shall not be a defense for the permittee in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

5. **Duty to Mitigate** – The permittee shall take all timely and reasonable steps necessary to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

6. **Proper Operation and Maintenance** – The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control and related appurtenances which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes, among other things, effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

7. **Duty to Provide Information** – The permittee shall furnish to the Director in an electronic format, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit or the UIC regulations. The permittee shall also furnish to the Director, upon request within a time specified, electronic copies of records required to be kept by this permit.

8. **Inspection and Entry** – The permittee shall allow the Director or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

   (a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where electronic or non-electronic records are kept under the conditions of this permit;

   (b) Have access to and copy, at reasonable times, any electronic or non-electronic records that are kept under the conditions of this permit;

   (c) Inspect, at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

   (d) Sample or monitor, at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location, including facilities, equipment or operations regulated or required under this permit.

9. **Signatory Requirements** – All reports or other information, required to be submitted by this permit or requested by the Director shall be signed and certified in accordance with 40 CFR 144.32.

G. AREA OF REVIEW AND CORRECTIVE ACTION

1. The Area of Review (AoR) is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data. The permittee shall maintain and comply with the approved Area of Review and Corrective Action Plan (Attachment B of this permit) which is an enforceable condition of this permit and shall meet the requirements of 40 CFR 146.84.

2. As delineated in Attachment B, 157 wellbores within the AoR require plugging because the wellbores penetrate the injection zone or confining layer and will not be used for injection or monitoring within the 26R storage project. The wells are required to be properly plugged and abandoned prior to authorization of carbon dioxide injection.

3. At least sixty (60) days prior to commencing corrective action, the permittee shall submit procedures for performing corrective action on the identified deficient wells within the AoR and not commence any corrective action until the procedures are approved by the Director.

   (a) As corrective action activities are completed, the permittee shall provide periodic updates, including plugging reports, to the Director.

   (b) Corrective action on all deficient wells in the AoR must be complete, and approved in writing by EPA, before the permittee may commence injection pursuant to Section Q(3) of this permit.

4. At a fixed frequency of every five years, or more frequently when monitoring and operational conditions warrant, the permittee must reevaluate the area of review and perform any necessary corrective action in the manner specified in 40 CFR 146.84. The first reevaluation shall be completed no later than 5 years from the effective date of this permit unless the Director requests an earlier reevaluation. After conducting an AoR reevaluation, the permittee shall update the Area of Review and Corrective Action Plan or demonstrate to the Director that no update is needed.

5. Following each AoR reevaluation, the permittee shall submit the resultant information (i.e., the completed reevaluation analysis, along with either a revised AoR and Corrective Action Plan or a demonstration that the reevaluation analysis determined no revised Plan is needed) in an electronic format to the Director for review and approval. If a revised AoR and Corrective Action Plan is submitted and approved by the Director, the revised Plan becomes an enforceable condition of this permit.

6. To ensure permit activities do not increase environmental impacts, resource needs, and public health risks in already overburdened communities, along with the submittal of a

revised AoR and Corrective Action Plan, the permittee shall submit an updated EJScreen analysis that incorporates the revised AoR boundary.

H. FINANCIAL RESPONSIBILITY

1. **Financial Responsibility** – The permittee shall maintain financial responsibility and resources to meet the requirements of 40 CFR 146.85 and the conditions of this permit. Financial responsibility shall be maintained through all phases of the project. The permittee must maintain financial responsibility until site closure is authorized from the director as described in Section Q of this permit. Compliance with the financial responsibility requirements, including the applicable duration, described in this permit shall not relieve the permittee from complying with any other applicable Federal, State, and local financial responsibility requirements that are not preempted or superseded by the Federal SDWA UIC program.

   The financial instrument(s) must be sufficient to cover the cost of:

   (a) Corrective action (that meets the requirements of 40 CFR 146.84);

   (b) Injection well plugging (that meets the requirements of 40 CFR 146.92);

   (c) Post injection site care and site closure (that meets the requirements of 40 CFR (146.93) and;

   (d) Emergency and remedial response (that meets the requirements of 40 CFR 146.94).

   The permittee submitted a letter of credit, with a standby trust agreement, to cover financial assurance for items 1(a), (b), and (c) and submitted a certificate of insurance with details about a third-party insurance policy it will secure to cover financial assurance for 1(d). The EPA-approved financial assurance mechanisms are found in Attachment H and in the administrative record of this permit.

   The total initial cost estimates for these activities to be covered by the approved financial assurance mechanisms is $33,672,785. This amount covers all four Class VI injection well permits for the Elk Hills 26R CO_2 Storage Project.

2. **Cost Estimate Updates** – During the active life of the geologic sequestration project, the permittee must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) and provide this adjustment to the Director in an electronic format. The permittee must also provide to the Director written updates in an electronic format of adjustments to the cost estimate within 60 days of any amendments to the Project Plans included as Attachments B – F of this permit, which address items (a) through (d) in Section H(1) of this permit.

3. **Notification** –

(a) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the permittee, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase.

(b) Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the permittee has submitted a justification for the reduced cost estimate and received written approval from the Director. For requested reductions in the face amount of a financial instrument, the Director may provide notice to the public of the proposed reduction, prior to finalizing approval of the reduction.

(c) The permittee must notify the Director by certified mail and in an electronic format of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging, post-injection site care and site closure, and any applicable ongoing actions under Corrective Action or Emergency and Remedial Response.

(i) If the permittee or the third-party provider of a financial responsibility instrument is going through a bankruptcy, the permittee must notify the Director by certified mail and in an electronic format of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the permittee as debtor, within 10 days after commencement of the proceeding.

(ii) A permittee who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy.

4. **Establishing Other Coverage** – The permittee must establish other financial assurance or liability coverage acceptable to the Director, within 60 days of the occurrence of the events in Section H(2) or H(3) of this permit.

I. CONSTRUCTION

1. **Siting** – The permittee has demonstrated to the satisfaction of the Director that the well is in an area with suitable geology in accordance with the requirements at 40 CFR 146.83.

2. **Casing and Cementing** – Casing and cement or other materials used in the construction of the well must have sufficient structural strength for the life of the geologic sequestration project. All well materials must be compatible with all fluids with which the materials may

be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must prevent the movement of fluids into or between USDWs for the expected life of the well in accordance with 40 CFR 146.86. The casing and cement used in the construction of this well are shown in Attachment G of this permit and in the administrative record for this permit. Any change must be submitted in an electronic format for approval by the Director before installation.

3. **Tubing and Packer Specifications** – Tubing and packer materials used in the construction of the well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The permittee shall inject only through tubing with a packer set within the long string casing at a point within or below the confining zone immediately above the injection zone. The tubing and packer used in the well are represented in engineering drawings contained in Attachment G of this permit. Any change must be submitted in an electronic format for approval by the Director before installation.

J. PRE-INJECTION TESTING

1. Prior to the Director authorizing injection, the permittee shall perform all pre-injection logging, sampling, and testing specified at 40 CFR 146.87. This testing shall provide data sufficient to address the pre-operational testing objectives identified in Attachment G of this permit, including:

   (a) Logs, surveys, and tests to determine or verify the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in all relevant geologic formations. These tests shall include:

      (i) Deviation checks that meet the requirements of 40 CFR 146.87(a)(1);

      (ii) Logs and tests before and upon installation of the surface casing that meet the requirements of 40 CFR 146.87(a)(2);

      (iii) Logs and tests before and upon installation of the long-string casing that meet the requirements of 40 CFR 146.87(a)(3);

      (iv) Tests to demonstrate internal and external mechanical integrity that meet the requirements of 40 CFR 146.87(a)(4); and

      (v) Any alternative methods that are required by or approved by the Director pursuant to 40 CFR 146.87(a)(5).

   (b) Whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone that meet the requirements of 40 CFR 146.87(b);

(c) Records of the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone that meet the requirements of 40 CFR 146.87(c);

(d) Tests to provide information about the injection and confining zones, including calculated fracture pressure and the physical and chemical characteristics of the injection and confining zones and the formation fluids in the injection zone that meet the requirements of 40 CFR 146.87(d); and

(e) Tests to verify hydrogeologic characteristics of the injection zone that meet the requirements of 40 CFR 146.87(e), including:

(i) A pressure fall-off test; and

(ii) A pumping test or injectivity tests.

2. The permittee shall submit to the Director for approval in an electronic format a schedule for logging and testing activities 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test. The permittee must provide the Director or their representative with the opportunity to witness all logging, sampling, and testing required under this Section.

K. OPERATIONS

1. **Injection Fluids/Carbon Dioxide Sources –** The permittee will capture carbon dioxide from multiple sources during the life of the permit for injection into the Class VI well. Three initial sources of carbon dioxide are approved sources for injection: the proposed Lone Cypress hydrogen plant, pre-combustion gas treatment, and the proposed Avnos Direct Air Capture facility (see Attachment B). The permittee may propose additional sources of carbon dioxide for injection, subject to review and approval by EPA, as described in Section N of this permit.

2. **Injection Pressure Limitation** – The permittee must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case shall injection pressure initiate fractures or propagate existing fractures in the confining zone or cause the movement of injection or formation fluids into a USDW. The maximum injection pressure limit is listed in Attachment A.

3. **Stimulation Program** – Pursuant to requirements at 40 CFR 146.82(a)(9), all stimulation programs proposed by the permittee must be approved by the Director as a permit modification and incorporated into Attachment I of this permit.

4. **Additional Injection Limitation** – No injectate other than that which has been analyzed and approved by the Director under this permit in accordance with Section N of this permit shall be injected except fluids used for rework, and well tests as approved by the Director.

5. **Annulus Fluid** – The permittee must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director.

6. **Annulus/Tubing Pressure Differential** – Except during workovers or times of annulus maintenance, the permittee must maintain on the annulus a pressure that exceeds the operating injection pressure as specified in Attachment A of this permit, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.

7. **Automatic Alarms and Automatic Shut-off System** –

   (a) The permittee must:

      (i) Install, continuously operate, and maintain an automatic alarm and an automatic shut-off system or, at the discretion of the Director, down-hole shut-off systems, or other mechanical devices that provide equivalent protection; and

      (ii) Successfully demonstrate the functionality of the alarm system and shut-off system prior to the Director authorizing injection, and at a minimum of once every twelfth month after the last approved demonstration.

      (iii) Establish well-specific thresholds for activating the shut-off system and submit a revised Attachment A to the Director prior to the Director authorizing injection.

   (b) Testing under this Section must involve subjecting the system to simulated failure conditions and must be witnessed by the Director or his or her representative unless the Director authorizes an unwitnessed test in advance. The permittee must provide notice in an electronic format 30 days prior to running the test and must provide the Director or their representative the opportunity to attend. The test must be documented using either a mechanical or digital device which records the value of the parameter of interest, or by a service company job record. A final report including any additional interpretation necessary for evaluation of the testing must be submitted in an electronic format within the time period specified in Section O(4) of this permit.

8. **Precautions to Prevent Well Blowouts** – At all times, the permittee shall maintain on the well a pressure which will prevent the return of the injection fluid to the surface. The well bore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient or a plug shall be installed which can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. The permittee shall

follow procedures such as those below to assure that a backflow or blowout does not occur:

(a) Limit the temperature and/or corrosivity of the injectate; and

(b) Develop procedures necessary to assure that pressure imbalances do not occur.

9. **Circumstances Under Which Injection Must Cease** –

Injection shall cease when any of the following circumstances arise:

(a) Failure of the well to pass a mechanical integrity test;

(b) A loss of mechanical integrity during operation;

(c) The automatic alarm or automatic shut-off system is triggered;

(d) A significant unexpected change in the annulus or injection pressure;

(e) The Director determines that the well lacks mechanical integrity; or

(f) The permittee is unable to maintain compliance with any permit condition or regulatory requirement and the Director determines that injection should cease.

10. **Approaches for Ceasing Injection** –

(a) The permittee must shut-in the well by gradual reduction in the injection pressure as outlined in Attachment A of this permit; or

(b) The permittee must immediately cease injection and shut-in the well as outlined in the Emergency and Remedial Response Plan (Attachment F of this permit).

L. MECHANICAL INTEGRITY

1. **Standards** – Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the injection well must have and maintain mechanical integrity consistent with 40 CFR 146.89. To meet these requirements, mechanical integrity tests/demonstrations must be witnessed by the Director or an authorized representative of the Director unless prior approval has been granted by the Director to run an un-witnessed test. To conduct testing without an EPA representative, the following procedures must be followed.

(a) The permittee must submit prior notification in an electronic format within the time period specified in Section L(3) of this permit and if EPA informs the permittee that no

EPA representative is available this must be documented in the approved plan and testing report. The permittee must receive permission from the Director to proceed;

(b) The test must be performed in accordance with the Testing and Monitoring Plan (Attachment C of this permit) and documented using either a mechanical or digital device that records the value of the parameter of interest; and

(c) A final report including any additional interpretation necessary for evaluation of the testing must be submitted in an electronic format within the time period specified in Section O(4) of this permit.

2. **Mechanical Integrity Testing** – The permittee shall conduct a casing inspection log and mechanical integrity testing as follows:

(a) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate internal mechanical integrity pursuant to 40 CFR 146.87(a)(4):

(i) A pressure test with liquid or gas; and

(ii) A casing inspection log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(b) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.87(a)(4):

(i) A tracer survey such as an oxygen activation log; or

(ii) A temperature or noise log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(c) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the permittee must continuously monitor injection pressure, injection rate, injection volumes, pressure on the annulus between tubing and long string casing, and annulus fluid volume as specified in 40 CFR 146.88(e) and 146.89(b).

(d) At least once per year, the permittee must perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.89(c):

(i) An Administrator-approved tracer survey such as an oxygen-activation log; or

(ii) A temperature or noise log. The Director may require such tests whenever the well is worked over; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(e) After any workover that may compromise the internal mechanical integrity of the well, the well shall be tested by means of a pressure test approved by the Director and the well must pass the test to demonstrate mechanical integrity.

(f) Prior to plugging the well, the permittee shall demonstrate external mechanical integrity as described in the Injection Well Plugging Plan and that meets the requirements of 40 CFR 146.92(a).

(g) The Director may require the use of any other tests to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator pursuant to requirements at 40 CFR 146.89(e).

3. **Prior Notice and Reporting** –

(a) The permittee shall notify the Director in an electronic format of his or her intent to demonstrate mechanical integrity at least 30 days prior to such demonstration. At the discretion of the Director, a shorter time period may be allowed.

(b) Reports of mechanical integrity demonstrations which include logs must include an interpretation of results by a knowledgeable log analyst. The permittee shall report in an electronic format the results of a mechanical integrity demonstration within the time period specified in Section O(4) of this permit.

4. **Gauge and Meter Calibration** – The permittee shall calibrate all gauges used in mechanical integrity demonstrations and other required monitoring to an accuracy of not less than 0.5 percent of full scale, within one year prior to each required test. The date of the most recent calibration shall be noted on or near the gauge or meter. A copy of the calibration certificate shall be submitted to the Director in an electronic format with the report of the test. Pressure gauge resolution shall be no greater than five psi. Certain mechanical integrity and other testing may require greater accuracy and shall be identified in the procedure submitted to the Director prior to the test.

5. **Loss of Mechanical Integrity** –

(a) If the permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, or fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity as defined by 40 CFR 146.89(a)(1) or (2) is suspected during operation (such as a significant unexpected change in the annulus or injection pressure), the permittee must:

(i) Cease injection in accordance with Sections K(8) and K(9)(a) or (b), and Attachments A or F of this permit;

(ii) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone. If there is evidence of USDW endangerment, implement the Emergency and Remedial Response Plan (Attachment F of this permit);

(iii) Follow the reporting requirements as directed in Section O of this permit;

(iv) Restore and demonstrate mechanical integrity to the satisfaction of the Director and receive written approval from the Director prior to resuming injection; and

(v) After receiving written approval to resume injection, notify the Director in an electronic format when injection is expected to resume.

(b) If a shutdown (*i.e.,* down-hole or at the surface) is triggered, the permittee must immediately investigate and identify as expeditiously as possible the cause of the shutdown. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required indicates that the well may be lacking mechanical integrity, the permittee must take the actions listed above in Section L(5)(a)(i) through (v).

(c) If the well loses mechanical integrity prior to the next scheduled test date, then the well must either be plugged or repaired and retested within 30 days of losing mechanical integrity. The permittee shall not resume injection until mechanical integrity is demonstrated and the Director gives written approval to recommence injection in cases where the well has lost mechanical integrity.

6. **Mechanical Integrity Testing on Request From Director** – The permittee shall demonstrate mechanical integrity at any time upon written notice from the Director.

M. TESTING AND MONITORING

1. **Testing and Monitoring Plan** –

(a) The permittee shall maintain and comply with the approved Testing and Monitoring Plan (Attachment C of this permit) and with the requirements at 40 CFR 144.51(j), 146.88(e), and 146.90. The Testing and Monitoring Plan is an enforceable condition of this permit. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. Procedures for all testing and monitoring under this permit must be submitted to the Director in an electronic format for approval at least 30 days prior to the test. In performing all testing and monitoring under this permit, the permittee must follow the procedures approved by the Director.

If the permittee is unable to follow the EPA-approved procedures, then, the permittee must contact the Director at least 30 days prior to testing to discuss options, if any are feasible. When the test report is submitted, a full explanation must be provided as to why any approved procedures were not followed. If the approved procedures were not followed, EPA may take an appropriate action, including but not limited to, requiring the permittee to re-run the test.

(b) The permittee must update the Testing and Monitoring Plan as required at 40 CFR 146.90 (j) to incorporate monitoring and operational data and in response to AoR reevaluations required under Section G(2) of this permit or demonstrate to the Director that no update is needed. The amended Testing and Monitoring Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation, following any significant changes to the facility such as addition of monitoring wells or newly permitted injection wells within the AoR, or when required by the Director.

(c) Following each update of the Testing and Monitoring Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and approval of the results. Once approved by the Director, the revised Testing and Monitoring Plan will become an enforceable condition of this permit.

2. **Carbon Dioxide Stream Analysis** – The permittee shall analyze the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics, as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(a).

3. **Continuous Monitoring** – The permittee shall maintain continuous monitoring devices and use them to monitor injection pressure, flow rate, volume, the pressure on the annulus between the tubing and the long string of casing, annulus fluid level, and temperature. This monitoring shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(b). The permittee shall maintain for EPA's inspection at the facility an appropriately scaled, continuous record of these monitoring results as well as original files of any digitally recorded information pertaining to these operations.

4. **Corrosion Monitoring** – The permittee shall perform corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion on a quarterly basis using the procedures described in the Testing and Monitoring Plan and in accordance with 40 CFR 146.90(c) to ensure that the well components meet the minimum standards for material strength and performance set forth in 40 CFR 146.86(b).

5. **Ground Water Quality Monitoring** – The permittee shall monitor ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones. This monitoring shall be performed for the parameters identified in the Testing and Monitoring Plan at the

locations and depths, and at frequencies described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(d).

6. **External Mechanical Integrity Testing** – The permittee shall demonstrate external mechanical integrity as described in the Testing and Monitoring Plan and Section L of this permit to meet the requirements of 40 CFR 146.90(e).

7. **Pressure Fall-Off Test** – The permittee shall conduct a pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information. The test shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(f).

8. **Plume and Pressure Front Tracking** –The permittee shall track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) as described in the Testing and Monitoring Plan.

   (a) The permittee shall use direct methods to track the position of the carbon dioxide plume and the pressure front in the injection zone as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(1).

   (b) The permittee shall use indirect methods to track the position of the carbon dioxide plume and pressure front as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(2).

   (c) If any indirect monitoring performed under Section M(8)(b) of this Permit detects increased pressure above the confining zone or other unanticipated results, the permittee shall increase the frequency of geochemical sampling under Section M(8)(a) to monthly sampling.

   (d) If data collection performed under Section M(8)(a) and M(8)(b) of this permit detects increased pressure above the confining zone or other unanticipated results the Director may require installation of additional monitoring wells.

9. **Surface Air and/or Soil Gas Monitoring** –

   (a) The permittee shall conduct any surface air monitoring or soil gas monitoring required by the Director to detect movement of carbon dioxide that could endanger a USDW or public health at the frequency and locations described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(h).

   (b) Any surface air monitoring or soil gas monitoring described in the Testing and Monitoring Plan of this Permit must not conflict with air monitoring requirements set forth by other Federal, State, or local agencies for the project, including monitoring to comply with the approved Monitoring, Reporting, and Verification (MRV) plan under 40 CFR part 98, Subpart RR, monitoring required for California's Low-Carbon Fuel Standard

program compliance, and monitoring required by Kern County pursuant to a Conditional Use Permit (CUP) and environmental impact report (EIR) for the project.

10. **Leak Detection Monitoring** -

(a) The permittee shall conduct any leak detection monitoring at the wellhead required by the Director to ensure injection well integrity and detect movement of carbon dioxide that could endanger a USDW or public health at the frequency and locations described in the Testing and Monitoring Plan.

(b) Any leak detection monitoring described in the Testing and Monitoring Plan of this Permit should be consistent with EPA's document "Leak Detection and Repair – A Best Practices Guide" (October 2007), and must not conflict with leak detection monitoring requirements set forth by other Federal, State, or local agencies for the project, including monitoring to comply with the approved Monitoring, Reporting and Verification (MRV) plan under 40 CFR part 98, subpart RR, monitoring required for California's Low-Carbon Fuel Standard program compliance, and monitoring required by Kern County pursuant to a Conditional Use Permit (CUP) and environmental impact report (EIR) for the project.

11. **Additional Monitoring** – If required by the Director as provided in 40 CFR 146.90(i), the permittee shall perform any additional monitoring determined to be necessary to support, upgrade, and improve computational modeling of the AoR evaluation required under 40 CFR 146.84(c) and to determine compliance with standards under 40 CFR 144.12 or 40 CFR 146.86(a). This monitoring shall be performed as described in a modification to the Testing and Monitoring Plan.

N. INJECTION OF CARBON DIOXIDE FROM ADDITIONAL SOURCES

1. The permittee must receive written approval from the Director before injecting carbon dioxide from a source that is not fully described in Attachment B of this permit. Carbon dioxide from additional sources will not be approved if the Director determines that the carbon dioxide stream from the proposed additional source is incompatible, or will adversely interact, with the injection well material, injection formation, or confining zone.

2. Proposed additional sources of carbon dioxide will be evaluated by EPA to determine if the additional source is approvable, and if so, whether its addition requires a major permit modification or a minor permit modification.

(a) Conditions that will result in a major permit modification include, but are not limited to, if the proposed additional source of carbon dioxide meets any of the following:

i. The addition of the proposed carbon dioxide source would increase the injection volume or injection pressure above the amount authorized in this permit; or

ii. The proposed additional carbon dioxide source is determined to have a chemical composition outside of the range of injectate compositions listed in Attachment B of this permit, or

iii. The addition of the proposed carbon dioxide source would interfere with the operation of the facility or its ability to meet conditions described in the permit; or

iv. The addition of the proposed carbon dioxide source would result in a material and substantial alteration or addition to the permitted Class VI injection activity which justifies the application of permit conditions that are different or absent in the existing permit; or

v. The Director determines that addition of the proposed carbon dioxide source does not meet criteria for a minor permit modification.

3. In proposing an additional source of carbon dioxide for the Director's approval, the permittee shall provide the Director with the following information:

   (a) The analytical parameters of the proposed additional carbon dioxide stream from the proposed source as described in the Testing and Monitoring Plan of this permit;

   (b) A description of the industry in which the proposed additional carbon dioxide stream will be produced from;

   (c) The name and address of the proposed additional carbon dioxide source;

   (d) An evaluation of the impact the proposed carbon dioxide source (the creation, capture, and transportation of carbon dioxide) will have on criteria pollutant and hazardous air pollutant emissions in the area; and

   (e) An assessment of the compatibility of the carbon dioxide stream with subsurface fluids and minerals, and assurance that the construction materials of the injection wells and other wells that may encounter the injected plume are still compatible (e.g., will not corrode over time due to the chemical interactions).

4. All proposed additional sources of carbon dioxide will require pre-approval by Kern County Planning and Natural Resources Department, and any necessary mitigation measures pursuant to an approved Conditional Use Permit and Environmental Impact Report.

5. The public shall be notified within 30 days when a proposed additional carbon dioxide source is submitted to EPA for review.

6. The public shall be notified 30 days before the injection of an EPA-approved additional

carbon dioxide stream is injected.

O. REPORTING AND RECORDKEEPING

1. **Electronic Reporting** – Electronic reports, submittals, notifications, and records made and maintained by the permittee under this permit must be in an electronic format approved by EPA. The permittee shall electronically submit all required reports to the Director at:

   https://epa.velo.pnnl.gov/operators

2. **Semi-Annual Reports** – The permittee shall submit semi-annual reports containing:

   (a) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;

   (b) Monthly average, maximum, and minimum values for injection pressure, flow rate and daily volume, temperature, and annular pressure;

   (c) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;

   (d) A description of any event which triggers the shut-off systems required in Section K(6) of this permit pursuant to 40 CFR 146.88(e), and the response taken;

   (e) The monthly volume or mass of the carbon dioxide stream injected over the reporting period and the volume or mass injected cumulatively over the life of the project;

   (f) Monthly annulus fluid volume added or produced; and

   (g) Results of the continuous monitoring required in Section M(3), including:

      (i) A tabulation of: (1) daily maximum injection pressure; (2) daily minimum annulus pressure; (3) daily minimum value of the difference between simultaneous measurements of annulus and injection pressure; (4) daily volume; (5) daily maximum flow rate; and (6) average annulus tank fluid level; and

      (ii) Graph(s) of the continuous monitoring as required in Section M(3) of this permit, or of daily average values of these parameters. The injection pressure, injection volume and flow rate, annulus fluid level, annulus pressure, and temperature shall be submitted on one or more graphs, using contrasting symbols or colors, or in another manner approved by the Director; and

   (h) Results of any additional monitoring identified in the Testing and Monitoring Plan and described in Section M of this permit.

3. **<u>24-Hour Reporting</u>** –

(a) The permittee shall report to the Director any permit noncompliance which may endanger human health or the environment or any events that require implementation of actions in the Emergency and Remedial Response Plan (Attachment F of this permit). Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such verbal reports shall include, but not be limited to, the following information:

(i) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW, or any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW;

(ii) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;

(iii) Any triggering of the shut-off system required in Section K(6) of this permit (i.e., down-hole or at the surface);

(iv) Any failure to maintain mechanical integrity;

(v) Pursuant to compliance with the requirement at 40 CFR 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere; and

(vi) Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F of this permit).

(b) A written submission shall be provided to the Director in an electronic format within five days of the time the permittee becomes aware of the circumstances described in Section O(3)(a) of this permit. The submission shall contain: a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F of this permit); and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance.

4. **<u>Reports on Well Tests and Workovers</u>** – The permittee shall report, within 30 days, the results of:

(a) Periodic tests of mechanical integrity;

(b) Any well workover, including stimulation;

(c) Any other test of the injection well conducted by the permittee if required by the Director; and

(d) Any test of any monitoring well required by this permit.

5. **Advance Notice Reporting** –

(a) **Well Tests** – The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned workover, stimulation, or other well test.

(b) **Planned Changes** – The permittee shall give written notice to the Director in an electronic format, as soon as possible, of any planned physical alterations or additions to the permitted injection facility other than minor repair/replacement or maintenance activities. An analysis of any new injection fluid and, as specified in Section N of this Permit, an analysis of any additional source of carbon dioxide, shall be submitted to the Director for review and written approval at least 60 days prior to injection; this approval may result in a permit modification.

(c) **Anticipated Noncompliance** – The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

6. **Additional Reports** –

(a) **Compliance Schedules** – Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted in an electronic format by the permittee no later than 30 days following each schedule date.

(b) **Transfer of Permits** – This permit is not transferable to any person except after notice is sent to the Director in an electronic format at least 30 days prior to transfer and the requirements of 40 CFR 144.38(a) have been met. Pursuant to requirements at 40 CFR 144.38(a), the Director will require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

(c) **Other Noncompliance** – The permittee shall report in an electronic format all other instances of noncompliance not otherwise reported with the next monitoring report. The reports shall contain the information listed in Section O(3)(b) of this permit.

(d) **Other Information** – When the permittee becomes aware of failure to submit any relevant facts in the permit application or that incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such

facts or corrected information in an electronic format within 10 days in accordance with 40 CFR 144.51(l)(8).

(e) **Report on Permit Review** – Within 30 days from the effective date of this permit, the permittee shall certify to the Director in an electronic format that he or she has read and is personally familiar with all terms and conditions of this permit.

7. Records –

(a) The permittee shall retain records and all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit (including records from pre-injection, active injection, and post-injection phases) for a period of at least 10 years from collection.

(b) The permittee shall maintain records of all data required to complete the permit application form for this permit and any supplemental information (e.g., modeling inputs for AoR delineations and reevaluations, plan modifications) submitted under 40 CFR 144.27, 144.31, 144.39, and 144.41 for a period of at least 10 years after site closure.

(c) The permittee shall retain records concerning the nature and composition of all injected fluids until 10 years after site closure.

(d) The retention periods specified in Section O(7)(a) through (c) of this permit may be extended by request of the Director at any time. The permittee shall continue to retain records after the retention period specified in Section O(7)(a) through (c) of this permit or any requested extension thereof expires unless the permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

(e) Records of monitoring information shall include:

(i) The date, exact place, and time of sampling or measurements;

(ii) The name(s) of the individual(s) who performed the sampling or measurements;

(iii) A precise description of both sampling methodology and the handling of samples;

(iv) The date(s) analyses were performed;

(v) The name(s) of the individual(s) who performed the analyses;

(vi) The analytical techniques or methods used; and

(vii) The results of such analyses.

P. PUBLIC AVAILABILITY OF MONITORING AND COMPLIANCE DATA

1. The permittee shall develop and maintain a publicly accessible website with all available monitoring data collected under this Permit. The website must be accessible to persons with disabilities and compliant with Section 508, and it shall include:

   (a) Semi-annual monitoring reports and data;

   (b) An executive summary (in both English and Spanish) that interprets the Semi-annual monitoring reports and data;

   (c) Real-time display of data collected for any Surface Air/Soil Gas Monitoring required under Section M(9) and Leak Detection Monitoring required under Section M(10) of this Permit; and

   (d) Notification of any permit non-compliance on a quarterly basis, including the steps taken to resolve the non-compliance, and any actions taken to prevent a re-occurrence of the non-compliance.

Q. WELL PLUGGING, POST-INJECTION SITE CARE, AND SITE CLOSURE

1. **Well Plugging Plan** – The permittee shall maintain and comply with the approved Well Plugging Plan (Attachment D of this permit) which is an enforceable condition of this permit and shall meet the requirements of 40 CFR 146.92.

2. **Revision of Well Plugging Plan** – If the permittee finds it necessary to change the Well Plugging Plan (Attachment D of this permit), a revised plan shall be submitted in an electronic format to the Director for written approval. Any amendments to the Well Plugging Plan must be approved by the Director, must be incorporated into the permit and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41.

3. **Notice of Plugging and Abandonment** – The permittee must notify the Director in writing in an electronic format pursuant to 40 CFR 146.92(c), at least 60 days before plugging, conversion or abandonment of a well. At the discretion of the Director, a shorter notice period may be allowed.

4. **Plugging and Abandonment Approval and Report** –

   (a) The permittee must receive written approval of the Director before plugging the well and shall plug and abandon the well in accordance with 40 CFR 146.92, as provided in the Well Plugging Plan (Attachment D of this permit).

   (b) Within 60 days after plugging, the permittee must submit in an electronic format a plugging report to the Director. The report must be certified as accurate by the

permittee and by the person who performed the plugging operation (if other than the permittee.) The permittee shall retain the well plugging report in an electronic format for 10 years following site closure. The report must include:

(i) A statement that the well was plugged in accordance with the Well Plugging Plan previously approved by the Director (Attachment D of this permit); or

(ii) If the actual plugging differed from the approved plan, a statement describing the actual plugging and an updated plan specifying the differences from the plan previously submitted and explaining why the Director should approve such deviation. If the Director determines that a deviation from the plan incorporated in this permit may endanger USDWs, the permittee shall re-plug the well as required by the Director.

5. **Temporary Abandonment** – If the permittee ceases injection into the well for more than 24 consecutive months, the well is considered to be in a temporarily abandoned status, and the permittee shall plug and abandon the well in accordance with the approved Well Plugging Plan, 40 CFR 144.52 (a)(6), and 40 CFR 146.92, or make a demonstration of non-endangerment of this well while it is in temporary abandonment status. During any periods of temporary abandonment or disuse, the well will be tested to ensure that it maintains mechanical integrity, according to the requirements and frequency specified in Section L(2) of this permit. The permittee shall continue to comply with the conditions of this permit, including all monitoring and reporting requirements according to the frequencies outlined in the permit.

6. **Post-Injection Site Care and Site Closure Plan** –

(a) The permittee shall maintain and comply with the Post-Injection Site Care and Site Closure Plan (Attachment E of this permit), which meets the requirements of 40 CFR 146.93 and is an enforceable condition of this permit. The permittee shall:

(i) Upon cessation of injection, either submit in an electronic format for the Director's approval an amended Post-Injection Site Care and Site Closure Plan or demonstrate through monitoring data and modeling results that no amendment to the plan is needed.

(ii) At any time during the life of the project, the permittee may modify and resubmit in an electronic format the Post-Injection Site Care and Site Closure Plan for the Director's approval. The permittee may, as part of such modifications to the Plan, request a modification to the post-injection site care timeframe that includes documentation of the information at 40 CFR 146.93(c)(1).

(b) The permittee shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs

are not being endangered, as specified in the Post-Injection Site Care and Site Closure Plan and in 40 CFR 146.90, and 40 CFR 146.93, including:

(i) Ground water quality monitoring;

(ii) Tracking the position of the carbon dioxide plume and pressure front including direct pressure monitoring and geochemical plume monitoring and the use of indirect methods;

(iii) Any other required monitoring, e.g., soil gas and/or surface air monitoring described in the Post-Injection Site Care and Site Closure Plan;

(iv) The permittee shall submit in an electronic format the results of all monitoring performed according to the schedule identified in the Post-Injection Site Care and Site Closure Plan; and

(v) The permittee shall continue to conduct post-injection site monitoring for at least 50 years or for the duration of any alternative timeframe approved pursuant to 40 CFR 146.93(c) and the Post-Injection Site Care and Site Closure Plan.

(c) The post-injection monitoring must continue until the project no longer poses an endangerment to USDWs and the demonstration pursuant to 40 CFR 146.93(b)(2) and as described in Section Q(6)(d) of this permit is approved by the Director.

(d) Prior to authorization for site closure, the permittee shall submit to the Director for review and approval, in an electronic format, a demonstration, based on information collected pursuant to Section Q(5)(b) of this permit, that the carbon dioxide plume and the associated pressure front do not pose an endangerment to USDWs and that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs, as required under 40 CFR 146.93(b)(3). The Director reserves the right to amend the post-injection site monitoring requirements (including extending the monitoring period) if the carbon dioxide plume and the associated pressure front have not stabilized or there is a concern that USDWs are being endangered.

(e) The permittee shall notify the Director in an electronic format at least 120 days before site closure. At this time, if any changes to the approved Post-Injection Site Care and Site Closure Plan in Attachment E of this permit are proposed, the permittee shall submit a revised plan.

(f) After the Director has authorized site closure, the permittee shall plug all monitoring wells as specified in Attachment E of this permit – the Post-Injection Site Care and Site Closure Plan – in a manner which will not allow movement of injection or formation fluids that endangers a USDW. The permittee shall also restore the site to its pre-injection condition.

(g) The permittee shall submit a site closure report in an electronic format to the Director within 90 days of site closure. The report must include the information specified at 40 CFR 146.93(f).

(h) The permittee shall record a notation on the deed to the facility property or any other document that is normally examined during a title search that will in perpetuity provide any potential purchaser of the property the following information:

(i) The fact that land has been used to sequester carbon dioxide;

(ii) The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and

(iii) The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.

(i) The permittee shall retain for 10 years following site closure an electronic copy of the site closure report, records collected during the post-injection site care period, and any other records required under 40 CFR 146.91(f)(4). The permittee shall deliver the records in an electronic format to the Director at the conclusion of the retention period.

R. EMERGENCY AND REMEDIAL RESPONSE

1. The Emergency and Remedial Response Plan describes actions the permittee must take to address movement of the injection or formation fluids, including surface leaks of carbon dioxide or other contaminants, that may cause an endangerment to a USDW or public health during construction, operation, and post-injection site care periods. The permittee shall maintain and comply with the approved Emergency and Remedial Response Plan (Attachment F of this permit), which is an enforceable condition of this permit, and with 40 CFR 146.94.

   Prior to the Director authorizing injection, the permittee shall revise the Emergency and Remedial Response Plan to include a description and documentation of the contracts the permittee holds with service providers, including any contracts or access agreements with local emergency response authorities, to perform the actions outlined in the Emergency and Remedial Response Plan, and shall confirm that any required payments were made to Kern County Planning and Natural Resources Department, as required by the approved Conditional Use Permits, for transfer to the Kern County Fire Department for equipment and training specific to the detection and control of emergency situations caused by the release of carbon dioxide.

2. If the permittee obtains evidence that the injected carbon dioxide or associated pressure front may cause endangerment to a USDW or public health, the permittee must:

   (a) Cease injection in accordance with Sections K(8) and K(9)(a) or (b), and Attachments A or F of this permit;

   (b) Take all steps reasonably necessary to identify and characterize any release;

   (c) Notify the Director within 24 hours; and

   (d) Implement the Emergency and Remedial Response Plan (Attachment F of this permit) approved by the Director.

3. At least every five years, or more frequently when monitoring and operational conditions warrant, the permittee shall review and update the Emergency and Remedial Response Plan as required at 40 CFR 146.94(d) or demonstrate to the Director that no update is needed. The amended Emergency and Remedial Response Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation, following any significant changes to the facility such as addition of injection wells, or when required by the Director.

4. Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and confirmation of the results. Once approved by the Director, the revised Emergency and Remedial Response Plan will become an enforceable condition of this permit.

S. COMMENCING INJECTION

The permittee may not commence injection until:

1. Results of the formation testing and logging program and a demonstration that all pre-operational testing objectives have been met as specified in Section J of this permit and in 40 CFR 146.87 are submitted to the Director in an electronic format and subsequently reviewed and approved by the Director;

2. Mechanical integrity of the well has been demonstrated in accordance with 40 CFR 146.89(a)(1) and (2), and in accordance with Section L(1) through (3) of this permit;

3. The completion of corrective action required by the Area of Review and Corrective Action Plan found in Attachment B of this permit in accordance with 40 CFR 146.84;

4. All requirements at 40 CFR 146.82(c) have been met, including but not limited to reviewing and updating of the Area of Review and Corrective Action, Testing and Monitoring, Well

Plugging, Post-Injection Site Care and Site Closure, and Emergency and Remedial Response plans to incorporate final site characterization information, final delineation of the AoR, and the results of pre-injection testing, and information has been submitted in an electronic format, reviewed and approved by the Director;

5. The permittee has submitted the results of an analysis of the physical and chemical characteristic of the carbon dioxide stream for all analytical parameters identified in the Testing and Monitoring Plan (Attachment C of this Permit).

6. Construction is complete and the permittee has submitted to the Director in an electronic format a notice that completed construction is in compliance with 40 CFR 146.86 and Section I of this permit;

7. The Director has inspected or otherwise reviewed the injection well and all submitted information and finds it is in compliance with the conditions of this permit;

8. The Director has approved demonstration of the alarm system and shut-off system under Section K(6) of this permit;

9. The Permittee has revised the Emergency and Remedial Response Plan to include a description and documentation of the contracts the permittee holds with service providers in order to perform the actions outlined in the Emergency and Remedial Response Plan;

10. The Director has approved the publicly accessible website required under Section P of this permit; and

11. The Director has given written authorization to commence injection.

ATTACHMENTS

These attachments include, but are not limited to, permit conditions and plans concerning operating procedures, monitoring and reporting, as required by 40 CFR parts 144 and 146. The permittee shall comply with these conditions and adhere to these plans as approved by the Director, as follows:

A. SUMMARY OF OPERATING REQUIREMENTS

B. AREA OF REVIEW AND CORRECTIVE ACTION PLAN

C. TESTING AND MONITORING PLAN

D. WELL PLUGGING PLAN

E. POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

F. EMERGENCY AND REMEDIAL RESPONSE PLAN

G. CONSTRUCTION DETAILS

H. FINANCIAL ASSURANCE DEMONSTRATION

I. STIMULATION PROGRAM

SUMMARY OF REQUIREMENTS

CLASS VI OPERATING AND REPORTING CONDITIONS

Elk Hills 26R Storage Project

Facility Information

Facility name: Elk Hills 26R Storage Project
373-35R

Well location: Elk Hills Oil Field, Kern County, CA
35°16'34.5276"N / 6121906
119°28'24.1836"W / 2290081

Table 1. Injection Well Operating Conditions

PARAMETER/CONDITION	LIMITATION or PERMITTED VALUE
Maximum Injection Pressure - Surface	1992 psi
Maximum Injection Pressure - Bottomhole	4294 psi
Annulus Pressure	3621 psi
Annulus Pressure/Tubing Differential	550 psi
Maximum CO_2 Injection Rate	25 mmscfpd

There will be continuous monitoring of injection pressure, rate and annulus pressure for the injector, as described in the well Construction, Operation and Plugging details (COP) document for 373-35R.

The maximum injection pressure, which serves to prevent confining-formation fracturing, was determined: using the fracture gradient of 0.701psi/ft obtained from Fracture stimulation data obtained from well 388-26R in the 26R reservoir multiplied by 0.9, per 40 CFR 146.88(a).

Routine Shutdown Procedure

For injection shutdowns occurring under routine conditions (e.g., for well workovers), the permittee will reduce CO_2 injection at a rate of 165 tons per day over a 6 day period to ensure protection of health, safety, and the environment. This procedure applies to routine shutdowns and to “gradual shutdowns” described in the Emergency and Remedial Response plan. (Procedures that address immediately shutting in the well are in the Emergency and Remedial Response Plan of this permit.)

Table 2. Class VI Injection Well Reporting Requirements

ACTIVITY	REPORTING REQUIREMENTS
CO_2 stream characterization	Semi-annually
Injection pressure, injection rate, injection volume, pressure on the annulus, and annulus fluid level	Semi-annually
Corrosion monitoring	Semi-annually
External MITs	Within 30 days of completion of test
Pressure fall-off testing	In the next semi-annual report

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

Table 3. Class VI Project Reporting Requirements

ACTIVITY	REPORTING REQUIREMENTS
Groundwater quality monitoring	Semi-annually
Plume and pressure front tracking	In the next semi-annual report
Monitoring well MITs	Within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Facility Information

Facility name: Elk Hills 26R Storage Project

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment B - AoR_CA	1	01/11/21
Attachment B - AoR_CA	2	05/31/22
Attachment B - AoR_CA	3	12/21/22
Attachment B - AoR_CA	4	05/14/2023
Attachment B – AoR_CA	5	6/23/2023

Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase

- Liquid and gas relative permeability
- Capillary pressure data
- Current saturation, pressure, and temperature estimates

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the Elk Hills 26R project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of CO_2 in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual oil in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.
2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).
3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

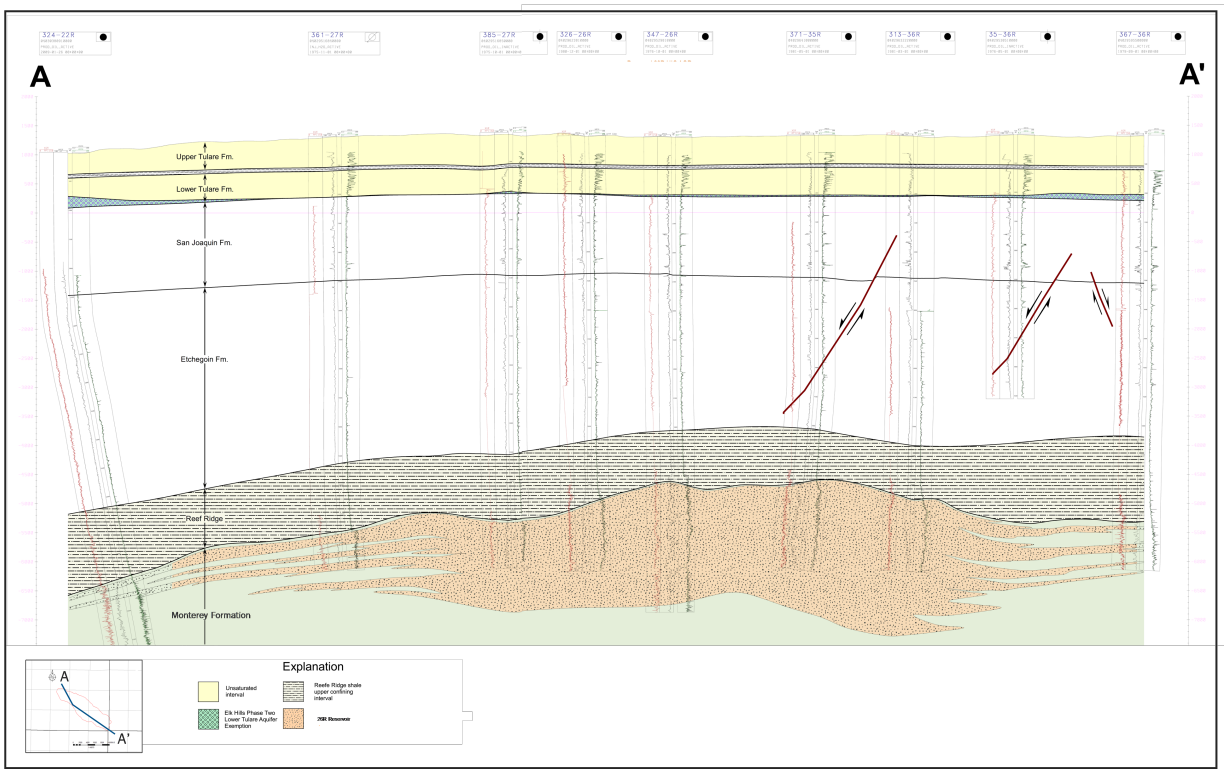
1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al
2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

Site Geology and Hydrology

The 31S field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation 26R sands, present in the southwestern portion of the field pinch out on top of the structure and along strike (Figure 1).

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation 26R, but for all Monterey accumulations in the greater Elk Hills area.

Figure 1: Cross-section A-A' showing lateral Monterey Formation 26R sand pinch-out.



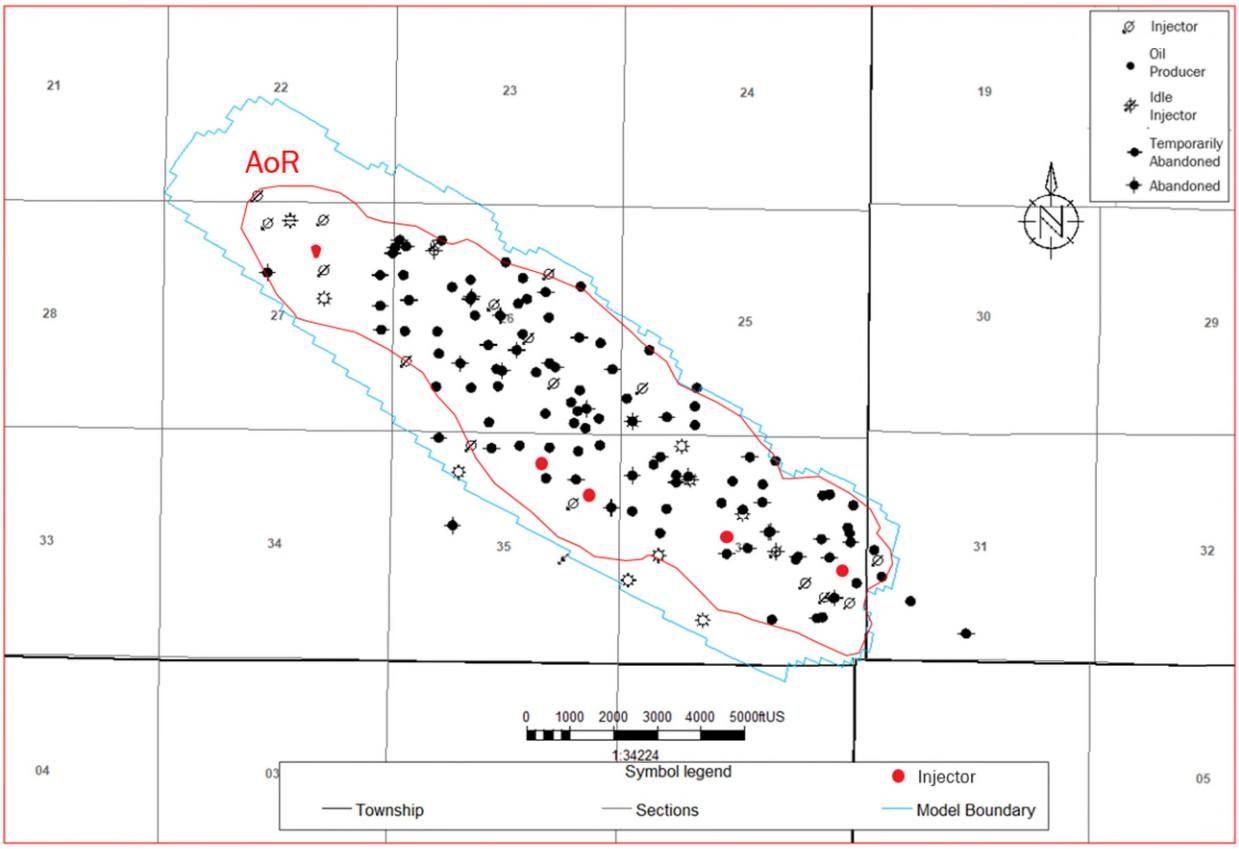
The Elk Hills 26R Class VI injection wells will target injection in the Monterey Formation 26R sands. The Monterey Formation 26R oil and gas reservoir was discovered in the 1940's and has been developed with primary production and pressure maintenance (Table 1: Production and Injection volumes). Starting in the year 1998, pressure maintenance ceased, and the gas cap reservoir was "blown-down", depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 150-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

Table 1: Production and injection volumes for the Monterey Formation 26R reservoir.

Process	Phase	Volume
Production	Oil	222 million barrels
	Gas	1,244 billion cubic feet
	Water	81 million barrels
Injection	Water	114 million barrels
	Gas	841 billion cubic feet

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir, and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

Figure 2: Location of wells with open-hole log data used to develop the static model and computational model boundary.



Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2. The lateral dimensions and vertical thickness of the geomodel were chosen to capture the maximum extent of the mapped 26R reservoir. Well logs from the wells shown in Figure 2 were used to map the extent and delineate the edges of the reservoir where the reservoir sands pinchout or transition to shale. The total grid dimensions were chosen to adequately capture the reservoir properties and heterogeneity, while at the same time maintaining computational efficiency.

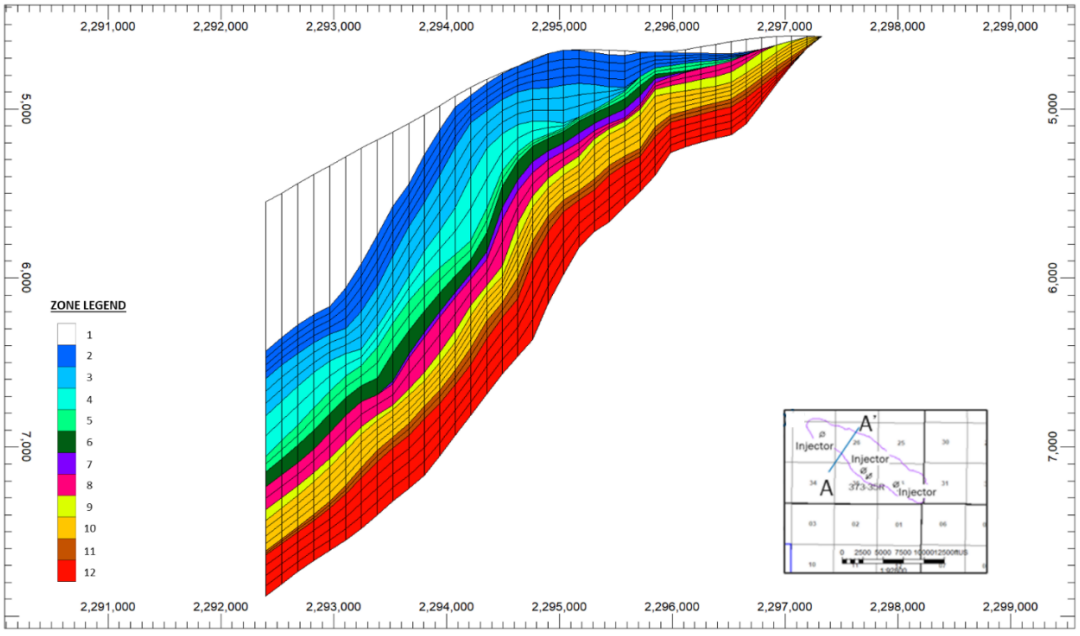
Table 2. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD 83		
Coordinate System Units	Feet		
Zone	CA83-VF		
FIPSZONE	0405	**ADSZONE**	3376
Coordinate of X min	6113669.29	**Coordinate of X max**	6130553.74
Coordinate of Y min	2286478.43	**Coordinate of Y max**	2299980.65
Elevation of bottom of domain	-6651.18	**Elevation of bottom of domain**	-3544.42

The geo-cellular grid is uniformly spaced throughout the 3.7 square mile model area (Figure 2) at 190 feet by 150 feet. The model is oriented at 18 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were selected to define plume extent and edges of the Monterey Formation 26R reservoir.

The reservoir has been separated into 12 zones and 27 layers (Figure 3) respectively and an average grid cell height of 117 feet. Each of the 12 zones is a mappable sand and were modeled separately to ensure stationarity of the geostatistical model. With a data driven geostatistical model, the model can discretize the reservoir into multiple zones. Grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing CO_2 movement. Well data that defines the stratigraphy also defines the structure of the 26R storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

Figure 3: Static model layering of the Monterey Formation 26R reservoir showing the 12 zones, and the 27 layers. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale laterally.



Porosity and Permeability

Figure 2 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Figure 4A shows how the log derived porosity compares to the upscaled model (synthetic) porosity for 363-27R (track five with log derived in black and the Upscaled model / synthetic porosity in blue). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 4B) that is dependent on porosity and clay volume.

Figure 4A: Log derived and Model Upscaled (Synthetic porosity) for 363-27R (track five with log derived in black and the Upscaled model synthetic in blue).

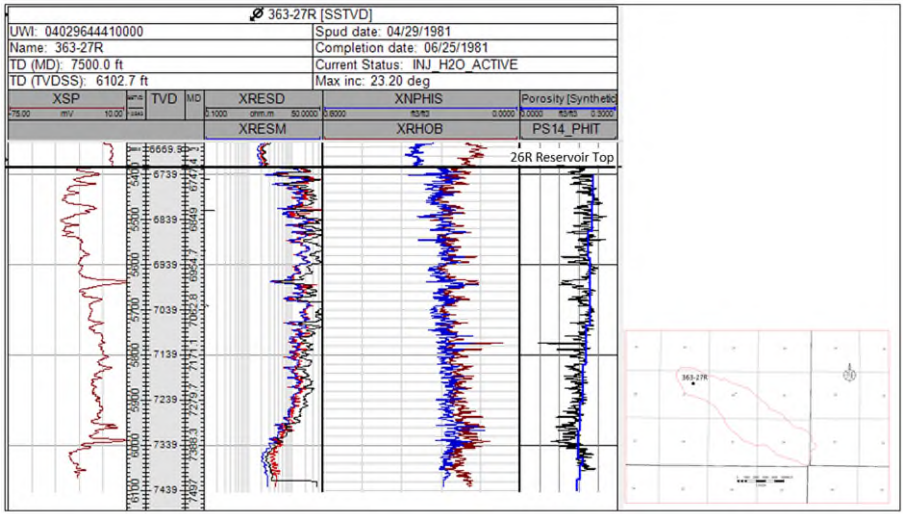


Figure 5B: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.

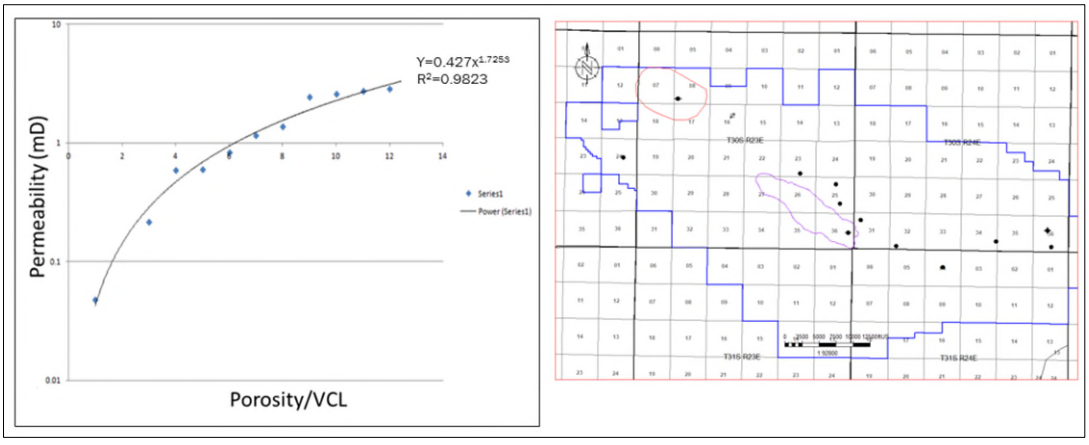


Figure 6: Monterey Formation 26R sands porosity and permeability distribution in the static model.

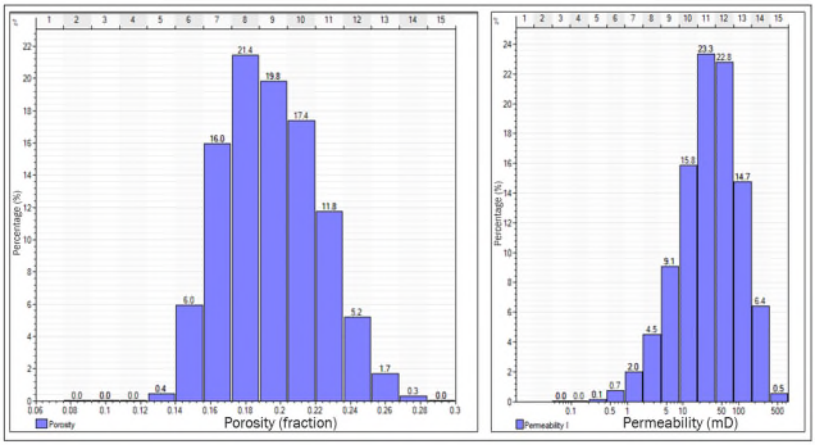
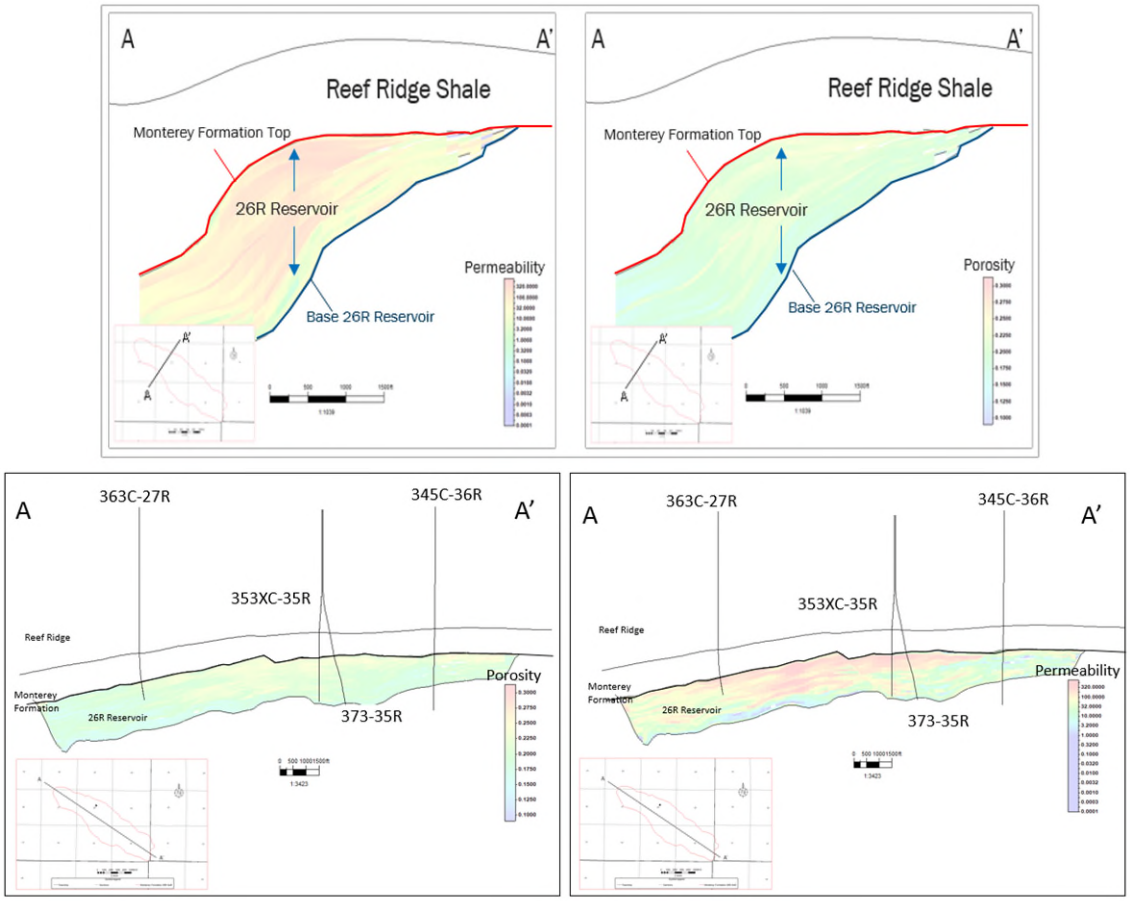


Figure 5 shows porosity and permeability histograms for the Monterey Formation 26R sands in the static model. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 6 shows the permeability and porosity distribution in cross-section A-A'.

Figure 7: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



A variable permeability anisotropy was included in the model, with a Vertical permeability (kv) to horizontal permeability (kh) ratio which ranged from 0.0001 to 1, with a log mean of value of 0.01. The permeability anisotropy was arrived at by upscaling log derived permeability, and then distributing the upscaled log data across the model domain. The log data was upscaled using an arithmetic mean to represent the horizontal permeability, and a harmonic mean to represent the vertical permeability.

Constitutive Relationships and Other Rock Properties

The Monterey Formation 26R reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

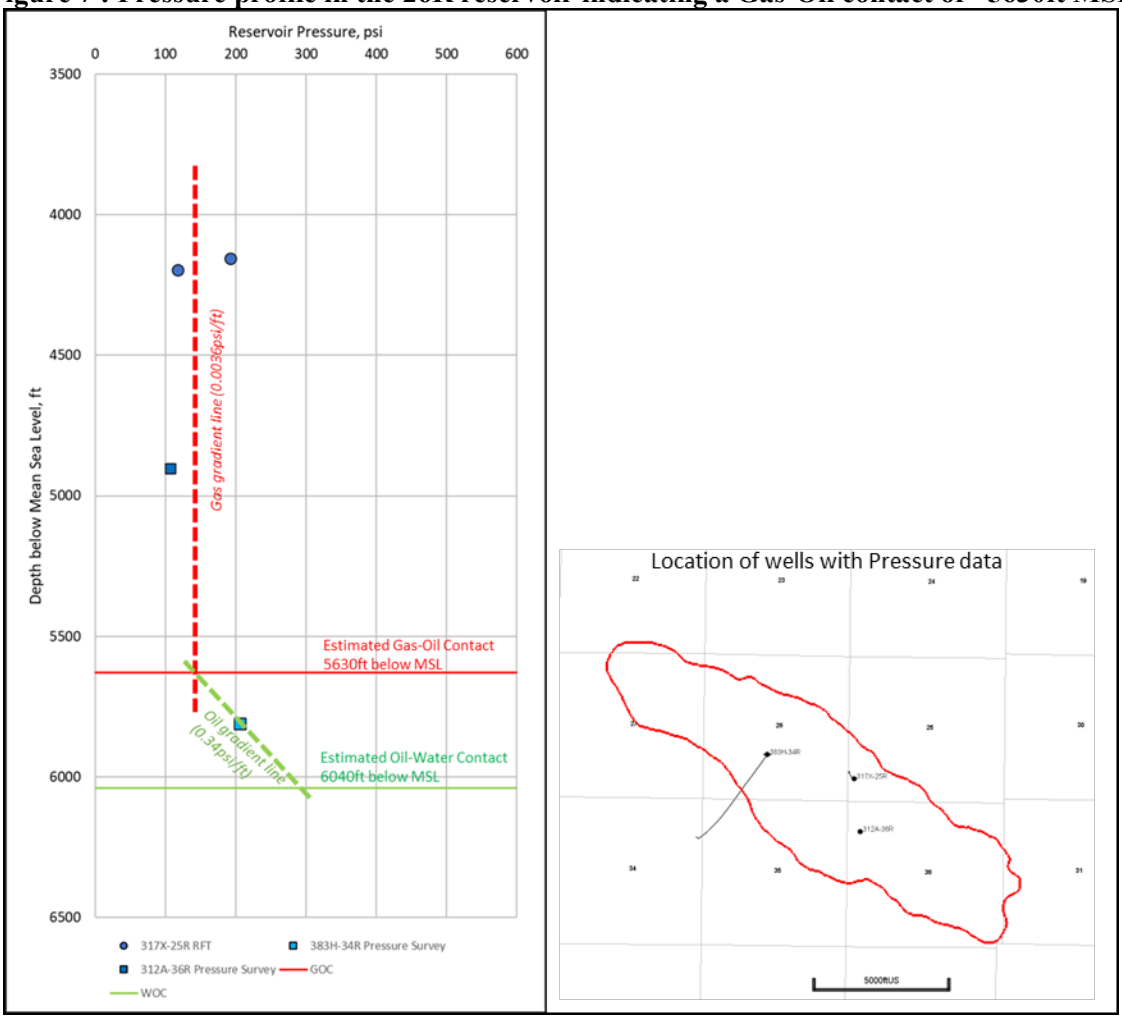
The saturations for the Gas, Oil and Water in the Gas Cap and Oil Band portions of the reservoir were determined using a Material Balance approach. The Pore Volume, discovery fluid contacts, pressure history, cumulative production and injection data for the reservoir, and the PVT properties of the fluids were used to estimate a current average oil, water, and gas saturation for the hydrocarbon portion of the 26R reservoir. These average saturations and estimates of remaining oil in place were used to iterate to a current oil-water and gas-oil contact in the computational model and the CMG GEM simulation model was initialized using the relative permeability curves, capillary pressure curves and current estimate of reservoir pressure.

The most recent data used to help validate the estimated gas-oil contact was pressure data gathered between 2006-2015. The pressure profile from this data was used to help estimate a gas contact of ~5630ft below MSL, using a gas gradient (0.0036psi/ft) and an oil gradient of 0.34psi/ft (see Figure 7). As there has not been evidence of an active aquifer following the blow down of the reservoir, the water contact is estimated to be at or near the original contact of ~6040ft below MSL, which was determined based on well logs obtained during the initial characterization of the reservoir in the 1950's.

Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs, pressure data, material balance and production analysis.

	Gas Cap	Oil Band	Water Zone
Contact (depth sub-sea)	Gas - Oil <5,630	Oil - Water 5630-6,040	> 6,040
Saturation (fraction)	Oil: 15% Water: 33.7% Gas: 51.3%	Oil: 37.1% Water: 25% Gas: 0%	Water: 100%

Figure 7 : Pressure profile in the 26R reservoir indicating a Gas-Oil contact of ~5630ft MSL



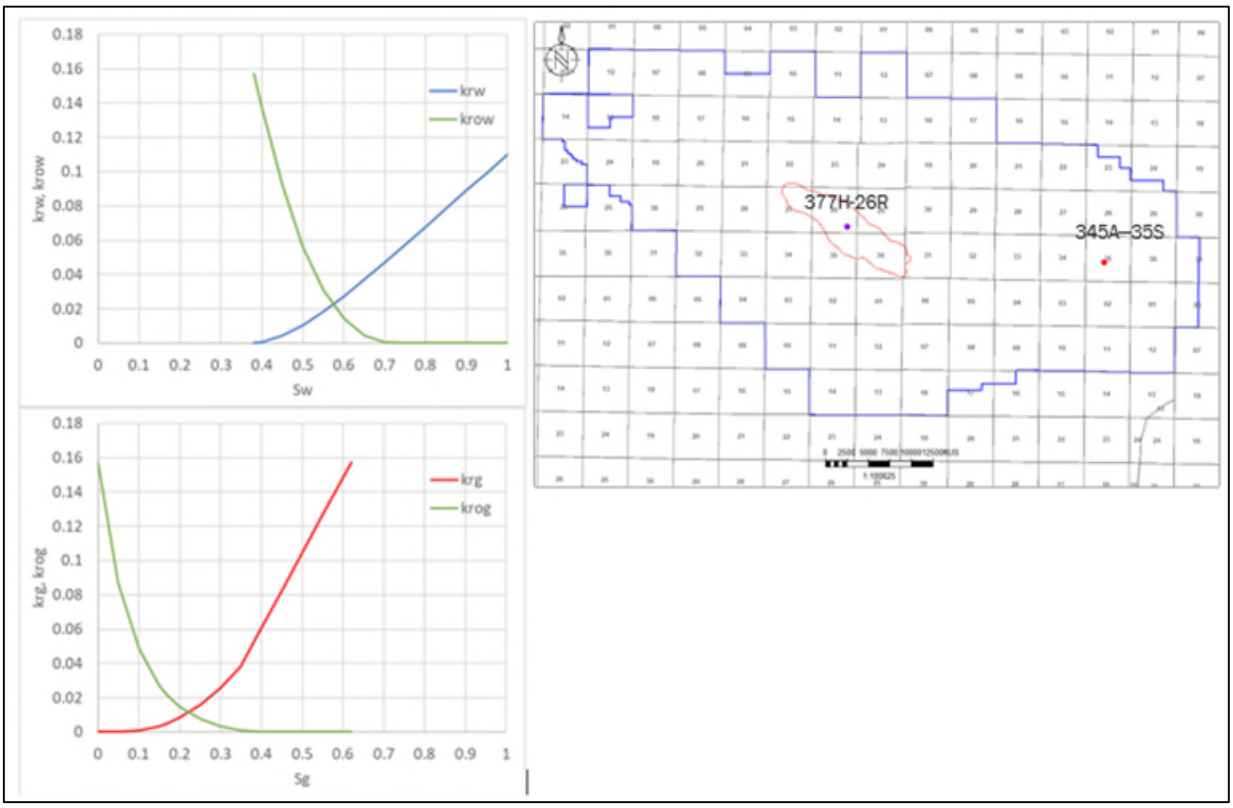
With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving krw, krow, krg, and krog as a function of saturation.

Where,
krg – relative permeability of Gas in a Gas–Oil system
krog – relative permeability of Oil in a Gas–Oil system
krow – relative permeability of Oil in an Oil-Water system
krw – relative permeability of Water in an Oil-Water system

Data acquired from Special Core Analyses (SCAL) determines these relationships. The geomodel modelled two rock types – sand and shale, but for the simulation a single sand rock type was modeled with the shale facies cells being treated as inactive cells. Core obtained from well 377H-26R in the 26R reservoir and equivalent Monterey Formation sandstone from well 345A-35S in the Elk Hills reservoir were used to generate the relative permeability relationships for the sand

facies. The data was normalized with respect to air permeability using end point scaling and a single Corey relative permeability fit was generated. Figure 8 shows the relative permeability curves used in the computational modeling and Figure 9 shows the relative permeability data from wells 377H-26R and 345A-35S in tabular form.

Figure 8: Relative permeability curves for krg-krog and krw-krow used in the computational model study and wells locations for data used to develop the curves.



The functional form of the relative permeability curves are -
krw = krwiro * ((Sw - Swcrit)/(1.0 - Swcrit - Soirw))^{Nw}
krow= krocw * ((So - Sorw)/(1.0 - Swcon - Sorw))^{Now}
krog=krogcg*((Sl - Sorg - Swcon)/(1.0 - Sgcon - Sorg - Swcon))^{Nog}
krg =krgcl *((Sg - Sgcrit)/(1.0 - Sgcrit - Soirg - Swcon))^{Ng}

With the parameters for the curve being -
Swcon - Endpoint Saturation: Connate Water = 0.38
Swcrit - Endpoint Saturation: Critical Water = 0.38
Soirw - Endpoint Saturation: Irreducible Oil for Water-Oil = 0.2
Sorw - Endpoint Saturation: Residual Oil for Water-Oil = 0.22
Soirg - Endpoint Saturation: Irreducible Oil for Gas-Liquid = 0.21
Sorg - Endpoint Saturation: Residual Oil for Gas-Liquid = 0.22
Sgcon - Endpoint Saturation: Connate Gas = 0
Sgcrit - Endpoint Saturation: Critical Gas = 0.05
krocw - Kro at Connate Water = 1

krwiro - Krw at Irreducible Oil = 0.43
krgcl - Krg at Connate Liquid = 0.4
krogcg - Krog at Connate Gas = 1
Nw = 1.3
Now = 3
Nog = 3.8
Ng = 2.5

The end point relative permeabilities of the curves were then scaled by a factor of 0.1547 using Oil to Air permeability ratio from well 345A-35S, so that the curves would be in reference to air permeability, which was used in the simulation model.

Figure 9: Monterey formation relative permeability data from wells 345A-35S and 377H-26R

Well: 345A-35S						
Sample Depth, feet:	7161.80					
Permeability to Air, md:		99.1				
Porosity, fraction:		0.221				
Initial Water Saturation, fraction:		0.380				
Effective Oil Permeability at Swi, md:		15.6				
Oil to Air Permeability ratio		0.1574				
* Relative to the effective permeability to oil at initial water saturation						
Water Displacing Oil				Gas Displacing Oil		
Sw	Relative Permeability to Water	Relative Permeability to Oil		Sg	Relative Permeability to Gas	Relative Permeability to Oil
0.380	0.000	1.000		0.000	-	1.000
0.436	0.026	0.662		0.184	0.002	0.109
0.460	0.053	0.525		0.198	0.005	0.093
0.510	0.108	0.324		0.226	0.014	0.069
0.557	0.176	0.176		0.269	0.040	0.040
0.645	0.328	0.033		0.334	0.106	0.010
0.803	0.615	-		0.405	0.195	-

Well: 377H-26R						
Sample Depth, feet :		5972.8		6015.9		
Permeability to Air, md :		100.0		286		
Porosity, fraction :		0.186		0.213		
Initial Water saturation, fraction		0.234		0.219		
* Relative to the effective permeability to oil at initial water saturation						
Water Displacing Oil				Gas Displacing Oil		
Sw	Relative Permeability to Water	Relative Permeability to Oil		Sg	Relative Permeability to Gas	Relative Permeability to Oil
0.234	0.000	1.000		0.000	0.000	1.000
0.286	0.034	0.851		0.133	0.011	0.332
0.313	0.045	0.764		0.162	0.017	0.252
0.377	0.069	0.541		0.198	0.029	0.170
0.461	0.098	0.292		0.226	0.041	0.131
0.523	0.121	0.147		0.259	0.059	0.091
0.568	0.141	0.070		0.285	0.082	0.070
0.590	0.152	0.040		0.309	0.101	0.051
0.606	0.163	0.025		0.342	0.134	0.035
0.620	0.168	0.018		0.369	0.175	0.022
0.644	0.182	0.009		0.394	0.221	0.015
0.649	0.187	0.006		0.411	0.249	0.011
0.667	0.195	0.003		0.432	0.279	0.007
0.685	0.205	0.001		0.486	0.406	
0.694	0.213					

Mineralization

Based on previous studies on reactive transport modeling and geochemical reactions in CCS applications have shown that the amount of CO2 predicted to be trapped by mineralization reactions is extremely small over a 100 year post injection time frame (IPCC, 2005: IPCC Special report on Carbon Dioxide Capture and Storage) for sandstone reservoirs. In addition, due to the fairly low salinity of the Formation water, stable mineralogy and minor expected on the AoR, reactive transport was not included as a part of the compositional simulation modeling at this time for computational efficiency.

Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation 26R reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

2. Performance data from operating the Monterey Formation 26R oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 10) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 10) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

    iii. Pressure in the reservoir is at 150 - 300 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

3. The 26R reservoir pinches out in the updip and lateral portions of the reservoir, and transitions to shale as shown in Figure 1.

Pressure data obtained while drilling wells in the AoR shows the pressure isolation of the 26R reservoir from the overlying Etchegoin Formation and the Lower Monterey Formation. Figure 11 shows the pressure data obtained for the formations, and location of these wells within the AoR.

Additional pressure data will be gathered and provided to the EPA during the pre-operational testing phase when all production operations in the reservoir have ceased, to confirm the historical understanding.

Figure 10: Monterey Formation 26R production and injection data.

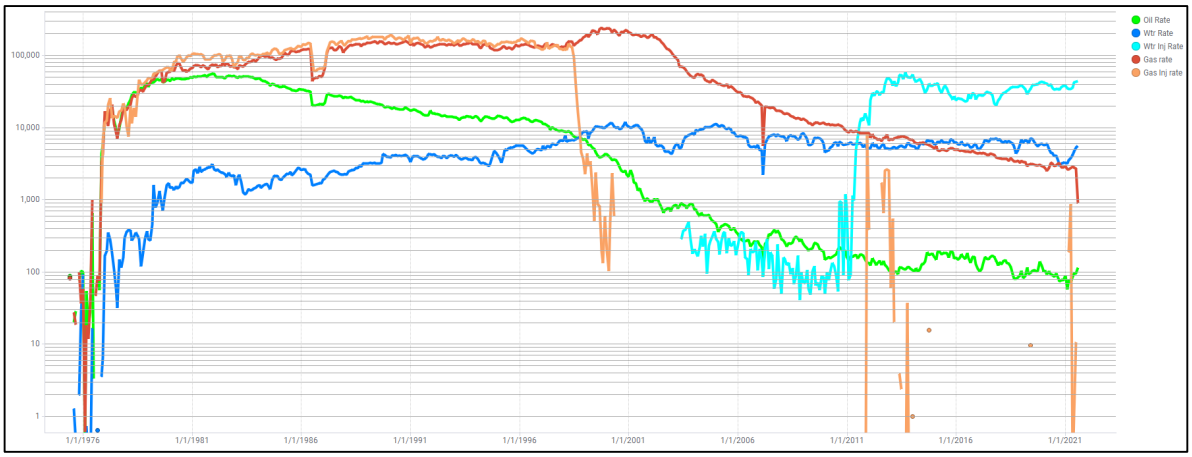
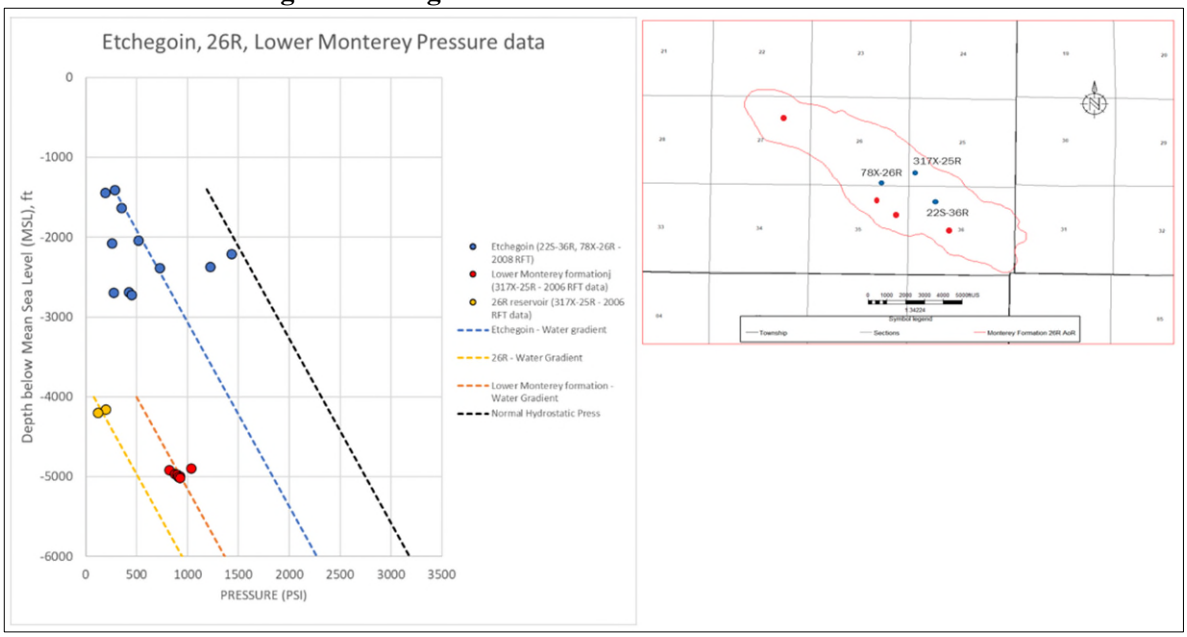


Figure 11: Etchegoin Formation, 26R Reservoir and Lower Monterey Formation repeat formation tester (RFT) pressure data in the AoR shows pressure isolation between the different formations. Data was obtained during the drilling of wells between 2006-2008.



Initial Conditions

Initial model conditions (start of CO_2 injection) of the Monterey Formation 26R reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4. Depths in the Table 4 are depths below Mean Sea Level (MSL), which is used as the reference elevation.

Table 4. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft, below Mean Sea Level)	Data Source
Temperature	210	Fahrenheit	5,630	Fluid Analysis
Formation pressure	150	Pounds per square inch	5,630	Pressure Test
Fluid density	61	Pounds per cubic foot	5,630	Water analysis
Salinity	25,000	Parts per million		Water analysis

Operational Information

Details on the injection operation are presented in Table 5.

Table 5. Operating details.

Operating Information	Injection Well 1 373-35R	Injection Well 2 345C-36R	Injection Well 3 353XC-35R	Injection Well 4 363C-27R
Location (global coordinates)	35.1634 N 119.2824W	35.2743 N 119.4577 W	35.3768 N 119.4732 W	35.2779 N 119.4535 W
Model coordinates (ft) X Y	 6121906 2290081	 6126556 2289316	 6121940 2290248	 6117204 2295938
No. of perforated intervals	13	25	11	12
Perforated interval (ft TVD / MD) Top Bottom	 6807 / 7086 7109 / 7426	 6097 / 6101 7710 / 7720	 6625 / 6810 8373 / 8545	 6698 / 6731 8124 / 8216
Production Casing diameter (in.)	4.5”	4.5”	4.5”	4.5”
Planned injection period Start End	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051
Injection duration (years)	27	27	27	27
Injection rate (t/day)*	993	993	993	993

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

Fracture Pressure and Fracture Gradient

A fracture gradient of 0.701 psi/ft is expected for the 26R reservoir. This is based on fracture stimulation performed on well 388-26R in the 26R reservoir.

CTV will ensure that the injection pressure is below 90% of the fracture pressure as calculated at the top perforation for each injector. The maximum allowable subsurface wellbore injection pressure for the 4 injectors in the project is shown below in Table 6.

Table 6. Injection pressure details.

Injection Pressure Details	Injection Well 1 373-35R	Injection Well 2 345C-36R	Injection Well 3 353XC-35R	Injection Well 4 363C-27R
Fracture Gradient (psi/ft)	0.701	0.701	0.701	0.701
Maximum allowable downhole injection pressure (90% of fracture pressure), psi	4294	3847	4180	4226
Elevation corresponding to maximum allowable bottomhole pressure (ft, TVD / MD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Elevation of top of the perforated interval (ft, TVD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Planned bottom hole injection pressure at top of perforations (psi)	4060	3555	3787	3558
Planned bottom hole injection gradient at top of perforations (psi/ft)	0.596	0.583	0.572	0.531

Proposed Carbon Dioxide Stream

CTV is planning to construct a carbon capture and sequestration "hub" project (*i.e.*, a project that collects carbon dioxide (CO_2) from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC permitted injection well(s)). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The anthropogenic CO_2 will be sourced from:

- Initial onsite emissions:
    - Lone Cypress blue hydrogen plant, up to 200,000 tonnes per annum
    - Elk Hills field gas treatment (pre-combustion for Elk Hills Power Plant), up to 200,000 tonnes per annum
    - Avnos Direct Air Capture (DAC), up to 1,500 tonnes per annum
- Future emission Sources:
    - CalCapture Elk Hills 550 MW natural gas power plant (post combustion), renewable fuel plants, steam generators post combustion and other power plants / industrial sources in the area

CTV expects the CO_2 stream to be sampled at the transfer point from the source and analyzed according to the analytical methods described in the QASP document and the Attachment C – Testing and Monitoring plan document. Should the injectate not meet the minimum requirements, it will be rejected.

The anticipated injection temperature at the wellhead is 90 – 130° F.

For the purposes of Geochemical modeling, CO2 Plume modeling, and Well design, two major types of Injectate compositions were considered based on the source.

- Injectate 1: is a potential injectate stream composition from a Direct Air Capture (DAC) or a Pre-Combustion source (such as the Lone Cypress blue hydrogen facility) or a Post-Combustion source (such as a gas fired power plant or steam generator) where N2 will likely be the major impurity.
- Injectate 2: is a potential injectate stream composition from a Biofuel Capture source (such as a Biodiesel plant) or an Oil & Gas Refinery or Natural Gas processing facilities (such as CO2 capture from the feed gas to the Elk Hills Power plan stated above) where light end Hydrocarbons (Methane, Ethane) will be the major impurity.

Design studies for CO2 capture at the planned Lone Cypress facility and design studies for CO2 capture from feed gas to the Elk Hills power plant were incorporated into the two injectate compositions shown in Table 7, in addition to preliminary injectate specifications provided by other potential sources and from literature studies.

Table 7 : Injectate compositions

Component	Injectate 1	Injectate 2
	Mass%	**Mass%**
CO2	99.213%	99.884%
H2	0.051%	0.006%
N2	0.643%	0.001%
H2O	0.021%	0.000%
CO	0.029%	0.001%
Ar	0.031%	0.000%
O2	0.004%	0.000%
SO2+SO3	0.003%	0.000%
H2S	0.001%	0.014%
CH4	0.004%	0.039%
NOx	0.002%	0.000%
NH3	0.000%	0.000%
C2H6	0.000%	0.053%
Ethylene	0.000%	0.002%
Total	**100.00%**	**100.00%**

For geochemical and plume modeling scenarios, these injectate compositions were simplified to a 4-component system, shown in Table 8. The 4 component simplified compositions cover 99.9% by mass of Injectate 1 & 2 and cover particular impurities of concern (H2S and SO2). The estimated properties of the injectates at downhole conditions are specified in Table 9

Table 8: Simplified 4 component composition for Injectate 1 and Injectate 2

Injectate 1	
Component	**mass%**
CO2	99.213%
N2	0.643%
SO2+SO3	0.003%
H2S	0.001%

Injectate 2	
Component	**mass%**
CO2	99.884%
CH4	0.039%
C2H6	0.053%
H2S	0.014%

No corrosion is expected in the absence of free phase water provided that the entrained water is kept in solution with the CO_2. This will be ensured by maintaining a water specification limit <25 lb/mmscf for the injectates, and this specification will be a condition of custody transfer at the capture facility. For transport through pipelines, which typically use standard alloy pipeline materials, this specification is critical to the mechanical integrity of the pipeline network, and out of specification product will be immediately rejected. Therefore, all product transported through pipeline to the injection wellhead is expected to be dry phase CO_2 with no free phase water present.

Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. CRA tubing will be used in the injection wells to mitigate any potential corrosion impact should free-phase water from the reservoir become present in the wellbore, such as during shut-in events when formation liquids, if present, could backflow into the wellbore. CTV may further optimize the maximum water content specification prior to injection based on technical analysis.

Injectate will be sampled and analyzed as part of the pre-operational testing, to confirm that it is consistent with the well design, Plume modeling and Geochemical modeling assumptions.

Computational Modeling Results

Predictions of System Behavior

The base simulation case was run for a 127 year period, covering 27 years of injection and 100 years of post injection. The simulated injection storage capacity is 38MMT taking the reservoir from current reservoir conditions to initial discovery pressure of 3,250 psi. A 100% CO2 injectate stream was assumed for the base case simulation studies. Additionally, scenarios were also run for the two injectates (Injectate 1 and Injectate 2) detailed in the "Proposed Carbon Dioxide Stream" section. Minimal difference in results was seen between the cases. Table 9 summarizes the expected CO2 injectate properties at reservoir conditions over the life of the project.

Table 9: CO2 injectate properties at reservoir conditions

Injectate property	100% CO2	Injectate 1	Injectate 2
Viscosity, cp	0.019-0.044	0.019-0.043	0.019-0.045
Density, kg/m3	16.6-544.8	16.5-543.5	1.035-545.8
Salinity, ppm	NA	NA	NA
Compressibility factor, Z	0.97-0.59	0.97-0.59	0.97-0.59

The following maps (Figure 12) and cross-sections (Figure 13) show the computational modeling results and development of the CO_2 plume at multiple time-steps. For all layers in the model and at all time-steps, the plume stays within the AoR. The CO2 plume grows rapidly within the first 15 years of injection with majority of the CO2 going into the higher quality upper portion of the 26R reservoir and being controlled by the structure of the reservoir and the closed updip boundary. Thereafter, the CO_2 injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the CO_2 injectate remains as super-critical CO_2.

The CO2 plume reaches its maximum vertical and lateral extent 20 years after the end of injection. The vertical and lateral extent of the CO2 plume predicted by the model aligns well with estimated discovery Oil-Water contacts of the reservoir and the vertical and lateral extent of the reservoir. The extent of the CO2 plume is slightly deeper than discovery fluid contacts in a few areas of the model likely due to gas override during injection and dissolution of the CO2 into the aqueous and oleic phases at the edge of the plume. The CO2 plume is largely stabilized 20 years after the end of injection, with little to no movement of the supercritical phase CO2 seen past this date.

The pressure front (defining as >10psi change from pressure at start of injection) in the reservoir reaches the vertical and areal boundaries of the model 6 years after the start of injection. The pressure in the reservoir reaches its peak at the end of injection. The reservoir pressure stabilizes fairly immediately in the reservoir with end of injection, and < 5psi/year change is expected in the first year after the end of injection. Figure 14 shows the average pore volume pressure vs time.

Figure 12A: Plan view showing the CO2 plume development through time. Plume is at its greatest extent at 20 years post injection.

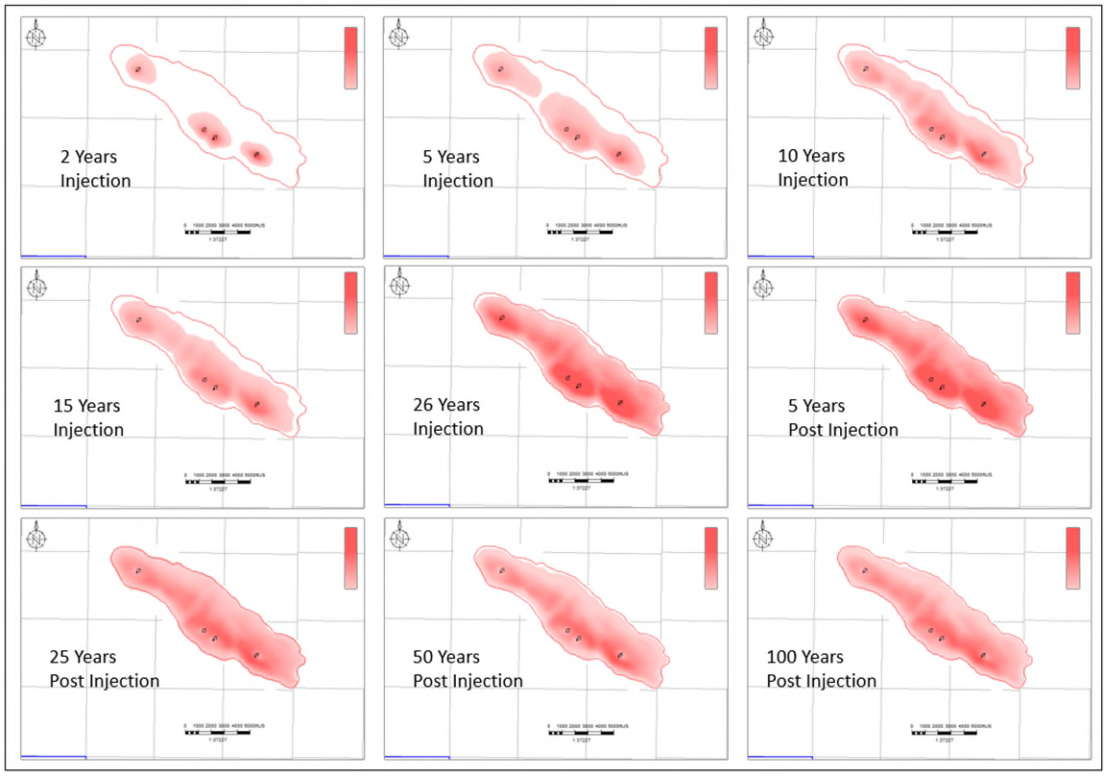


Figure 12B: Plan view showing the gas extent through time. Maps scaled so as to present Gas saturation over a nomial baseline

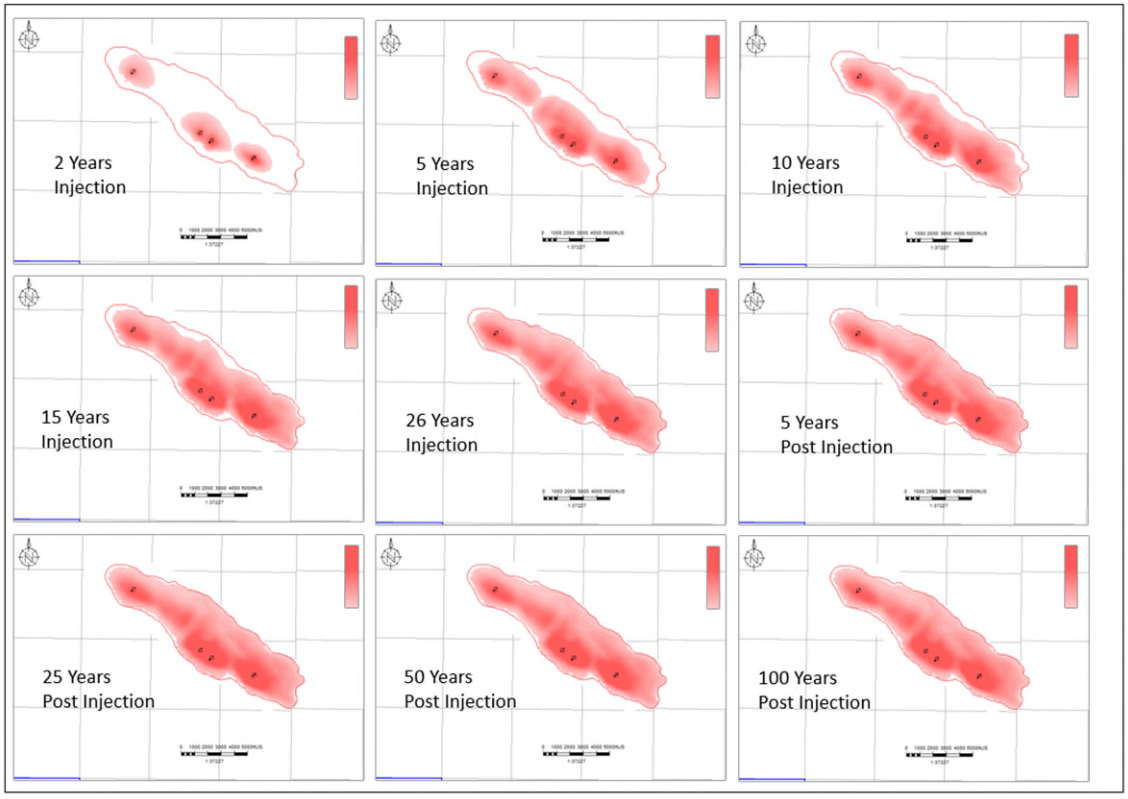


Figure 13A Cross-sections showing the CO2 plume development through varying times during the project.

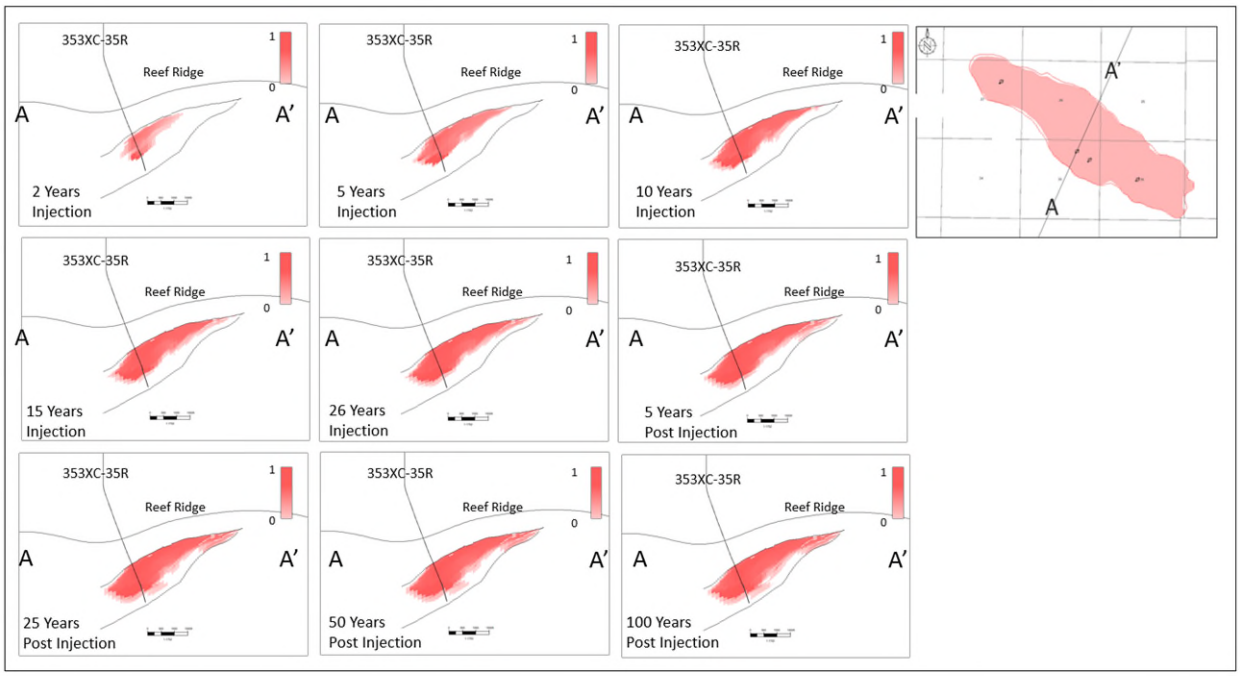


Figure 13B: Cross-sections showing the gas extent through varying times during the project. Maps scaled so as to present Gas saturation over a nomial baseline

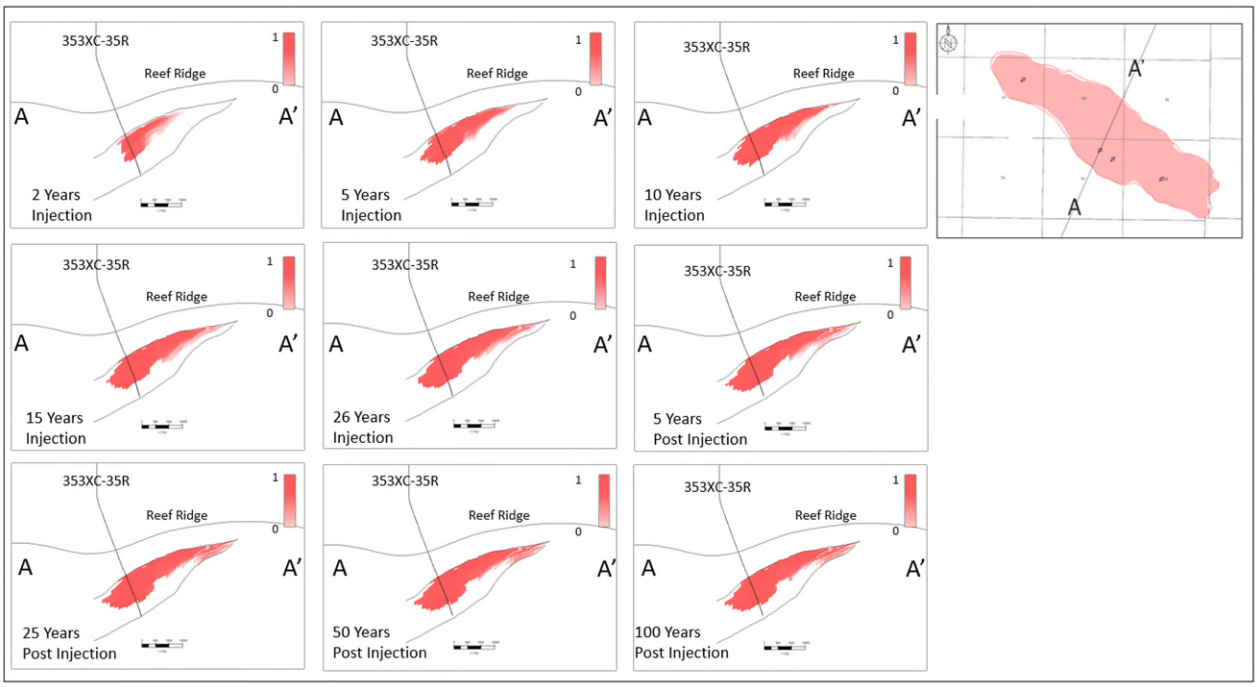
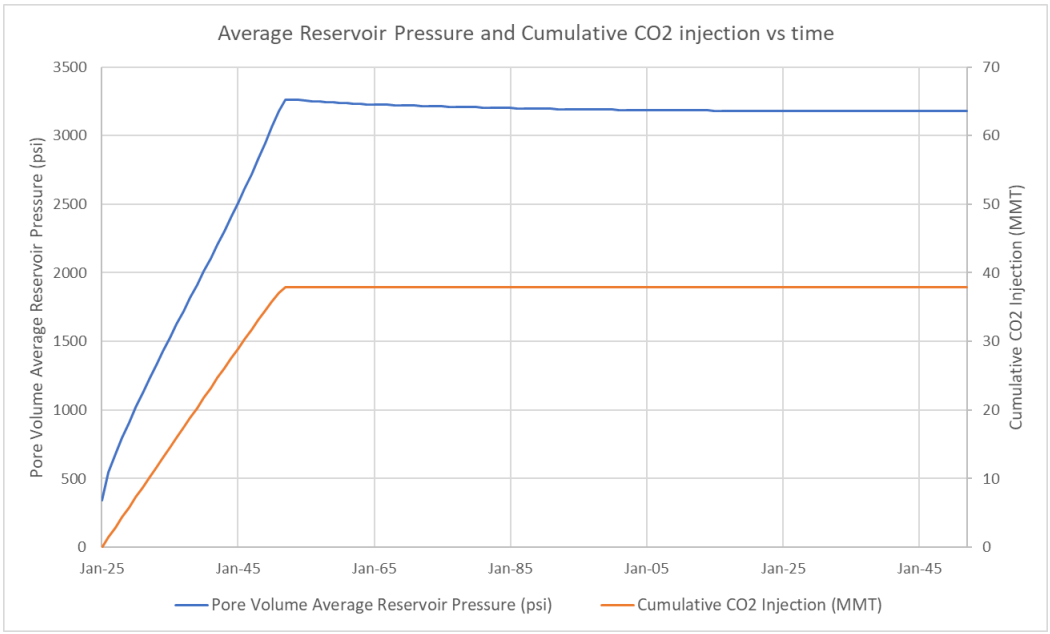
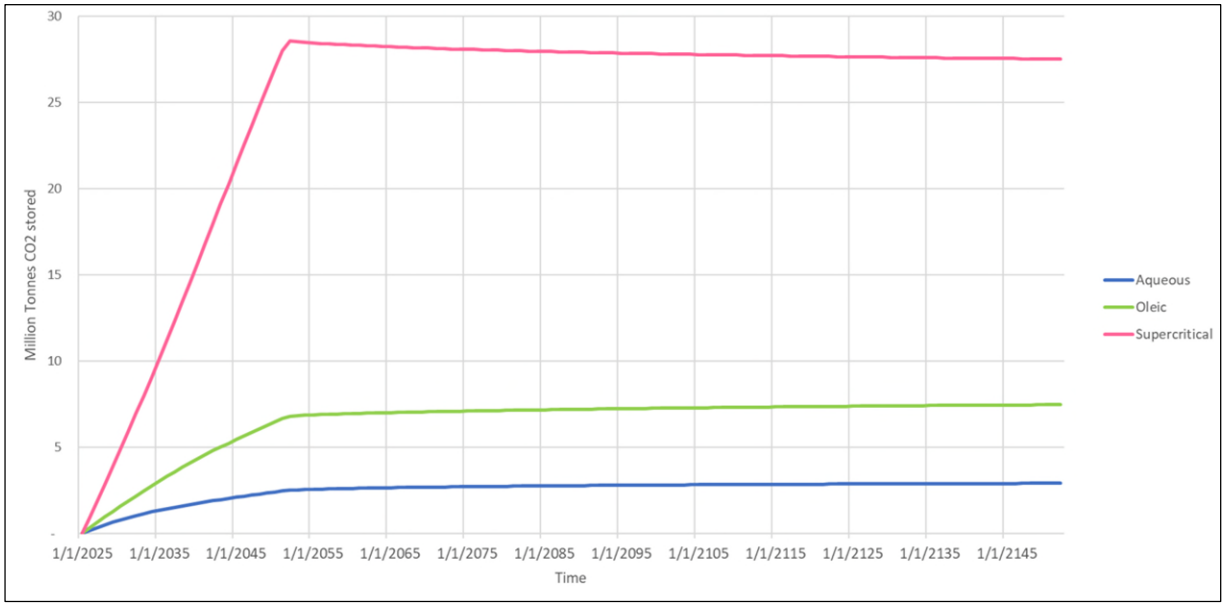


Figure 14: Average Reservoir pressure and cumulative CO2 injection versus time plot



CO_2 injected into the Monterey Formation 26R reservoir will be soluble in both water and oil. Due to remaining saturation of oil and water in the depleted reservoir, total dissolved CO_2 in oil and water is 20% and 8% of the CO_2 injected respectively. The remaining will be stored as super-critical CO_2. Figure 15 shows the cumulative storage for each of the mechanisms.

Figure 15: Storage mechanism through time for the 26R reservoir.



CO_2 Injectate Composition effect on Plume and AoR modeling

The Plume model developed in the Computer Modeling Group (CMG) GEM software was run for the two simplified injectate compositions, and their results were also compared against a 100% CO2 injectate case. The cumulative volume of injectate for all 3 cases was the same.

The CO2 plume for Injectate 1 and Injectate 2 (detailed in the "Proposed Carbon Dioxide stream" section in this document) is consistent with the plume outline for 100% CO2 injectate (Figure 16), which was defined by a 0.03 global CO2 mole fraction for all 3 cases. The 100 year post end of injection plumes for the 3 cases are shown below in Figure 16. The wells that fall within the CO2 plume are the same for all 3 cases.

Additionally, the average Pore Volume pressure was plotted for the 3 cases and there was minimal difference seen between the cases, as shown in Figure 17.

In summary, there is minimal effect of the minor components on the CO2 plume shape and the AoR boundary, for the proposed injectate compositions. As such, CTV's Plume and AoR modeling for Corrective Action assessment is adequate. CTV will confirm that the properties of the injectate are consistent with the model inputs at pre-operational injectate sampling. In addition, the AoR will be reviewed as per the Reevaluation Schedule and Criteria section.

Figure 16: CO2 plume outlines for Injectate 1 (Light Blue), Injectate 2 (Green) and 100% CO2 Cases (Red). Larger Red outline is the model boundary. There are Minimal difference in AoR boundaries between the 3 cases

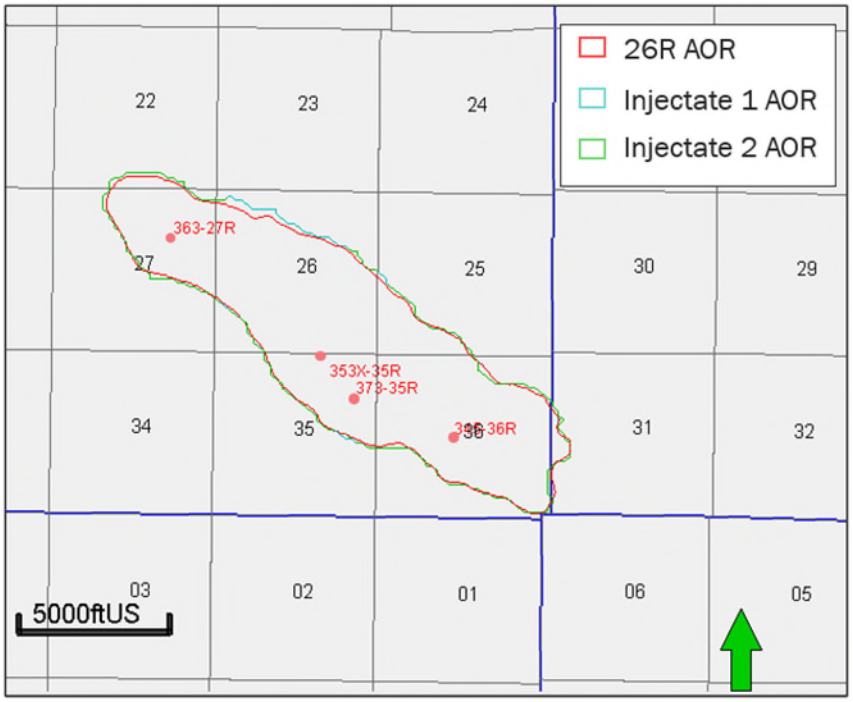
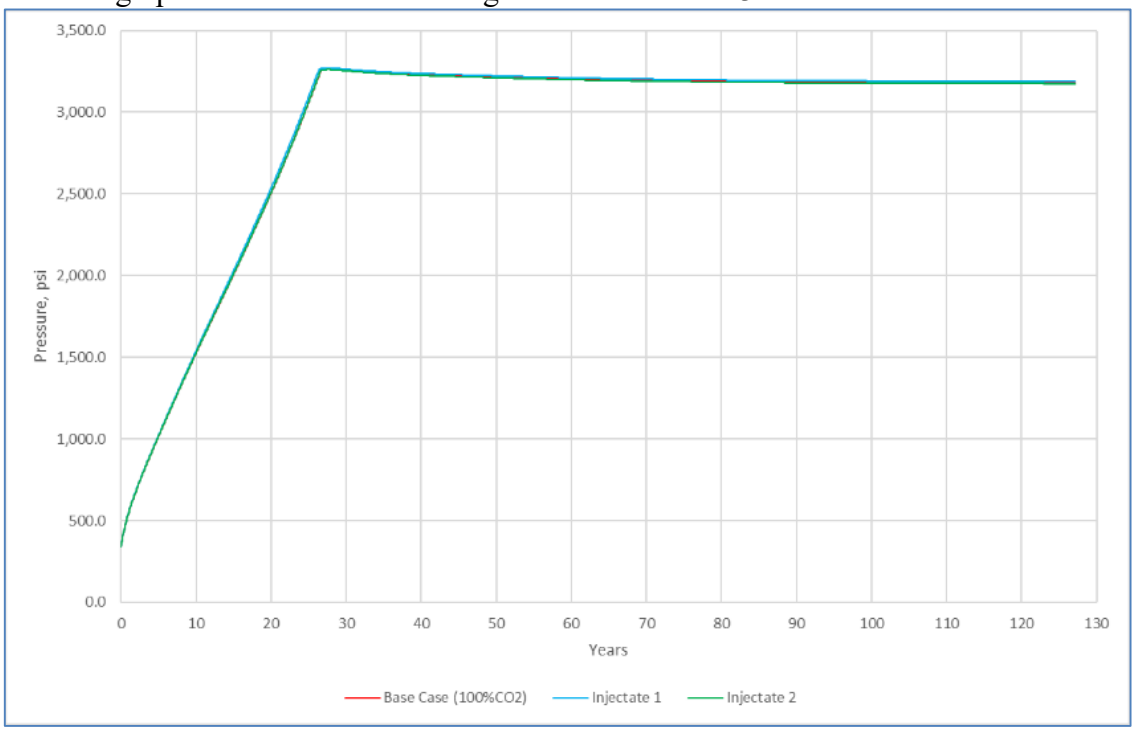


Figure 17: Average reservoir pressure vs time for Injectate 1 (Light blue), Injectate 2 (Green) and base 100% CO2 (Red) cases. Minimal difference in pressure trends between the 3 cases as shown in the graph with the trends tracking each other for the 3 cases.



Model Calibration, Sensitivies and Validation

Previous operators injected 1,244 billion cubic feet of gas into the Monterey Formation 26R reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

The simulation model was run for different initial reservoir pressure and saturation cases to determine the sensitivity of the storage volume and plume extent to these variables. Due to ongoing water injection in the 26R reservoir, sensitivities were run to test the effect of higher reservoir pressure and higher water saturation in the Oil band and Gas cap to see if there would be significant impacts to the storage volume and AoR boundaries.

Sensitivities were also run varying major geomodel inputs into the simulation model (Porosity, Permeability, NTG) and varying the Grid XY dimensions, cell thickness, local grid refinement around injectors, and temperature effects to see if there was a significant change to the storage amount and AoR boundary. Although there was some effect to the total CO2 storage for the different cases, there was minimal change to the maximum extent of the CO2 plume. The porosity, permeability and NTG uncertainty were further modeled stochastically to understand their effect and is discussed in the next section.

- Cell thickness sensitivity case was run by reducing the cell thickness in the overall grid to an average of 18ft. The results of this finer cell thickness model, compared favorably to the Base case model with a < 2% increase in predicted CO2 storage capacity and minimal change to the plume extent.

- The local grid refinement case was run with a finer grid spacing in the 5Acre region around the injector location, with the X-Y grid dimensions reduced to 19ft by 15ft in that region. The results of this case also compared favorably against the base case, with the predicted maximum bottom hole pressure at the injector locations being within 0.5% of the Base Case.

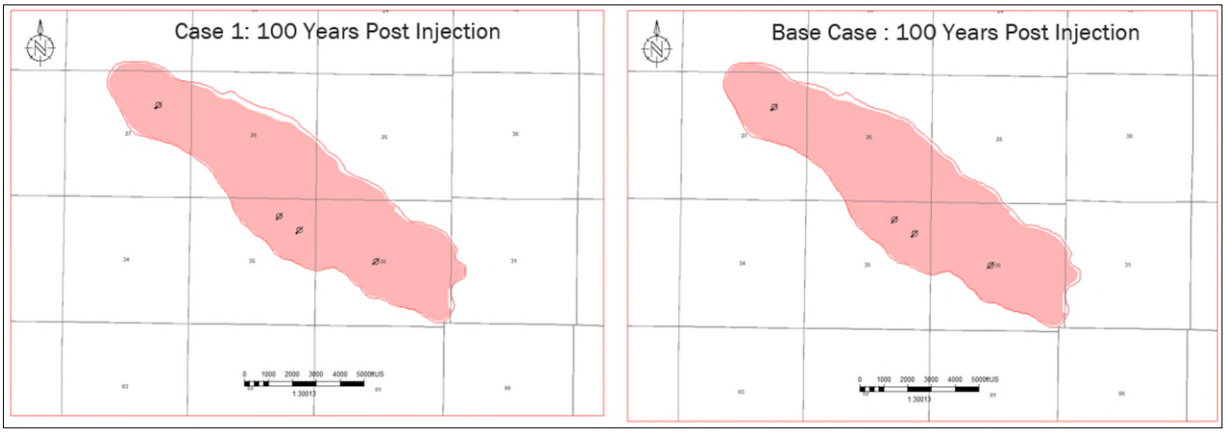
- The Base case model was initialized using a uniform average temperature of 210° F (based on idle well temperature surveys run on wells in the area between 2008 – 2014) and with no thermal effect modeling in the reservoir. A sensitivity case was run using GEM's thermal option to model heat balance and gauge if modeling temperature change in the reservoir with CO2 injection was necessary. The results indicated minimal effect on the system behavior with < 2% change in CO2 storage capacity, and < 2% deviation in reservoir pressure trends.

Table 10 summarizes the sensitivity cases run and their effect on storage volume and the AoR boundary. Figure 18 compares the CO2 plume extent for Case 1 against the Base Case.

Table 10: Summary of sensitivity cases

Case #	Sensitivity Case	Storage Volume effect	AoR boundary effect
1	Pressure : Gas cap pressure increased to 300psi	Decreased volume	Minimal effect to AoR
2	Pressure : Gas cap pressure increased to 500psi	Decreased volume	Minimal effect to AoR
3	Saturation: Higher water saturation in Oil band and Gas cap	Decreased volume	Minimal effect to AoR
4	Porosity: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
5	Porosity: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
6	Permeability: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
7	Permeability: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
8	NTG: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
9	Grid Dimensions: reduced grid XY dimensions to 95 ft x 75ft	No effect	Minimal effect to AoR
10	Cell Thickness: Reduced average cell thickness in Gas cap to 18ft	Increased volume	Minimal effect to AoR
11	Local grid refinement around Injectors: reduced grid X-Y dimension to 19ft x 15ft in 5Acre area around injectors	No effect	Minimal effect to AoR
12	Temperature effect: model was run with GEM's thermal option	Minimal change	Minimal effect to AoR

Figure 18: CO2 plume extent for layer 2 comparing Base Case against Pressure and Saturation sensitivity cases.



These scenarios demonstrated that the AoR, as defined by the maximum extent of CO_2 injectate, is consistent. This provides confidence that the corrective action well review and potential impact is conservative.

Stochastic analysis of effect of Reservoir parameters

A stochastic analysis was carried out using the reservoir parameters – Porosity, permeability, Net to Gross (NTG) ratio and kv-kh ratio. An upper and lower bound of the grid property was entered (directly or using multipliers), along with a distribution (see Table 11) in CMG's CMOST module to generate a set of 50 cases using the Latin Hypercube sampling method. All cases were run with the same bottom hole pressure control on the injectors, and with the same condition of ceasing injection once the reservoir had been brought back up to initial conditions. Although the stochastic analysis showed a range of storage capacity, the P50 estimate was 37MMT, with a P10 of 30MMT and a P90 of 44MMT.

Table 11: Parameters and distributions used for Stochastic analysis

Parameters	Parameter/ Multiplier	Parameter / Multiplier range	Distribution type	Description
Porosity	Multiplier	0.78 - 1.22	Normal distribution	Multiplier range used to have grid mean value range of 0.14 - 0.22
Permeability	Multiplier	0.3 - 3	Log Normal distribution	Multiplier range used to have grid mean value range of ~15 - 150md
Net to Gross ratio (NTG)	Multiplier	0.9 - 1.1	Uniform distribution	A uniform distribution uncertainty of +-10% applied
kv-kh ratio	Parameter	0.001 - 0.2	Log Normal distribution	A kv-kh ratio of 0.001 to 0.2 applied over the entire grid

AoR Delineation

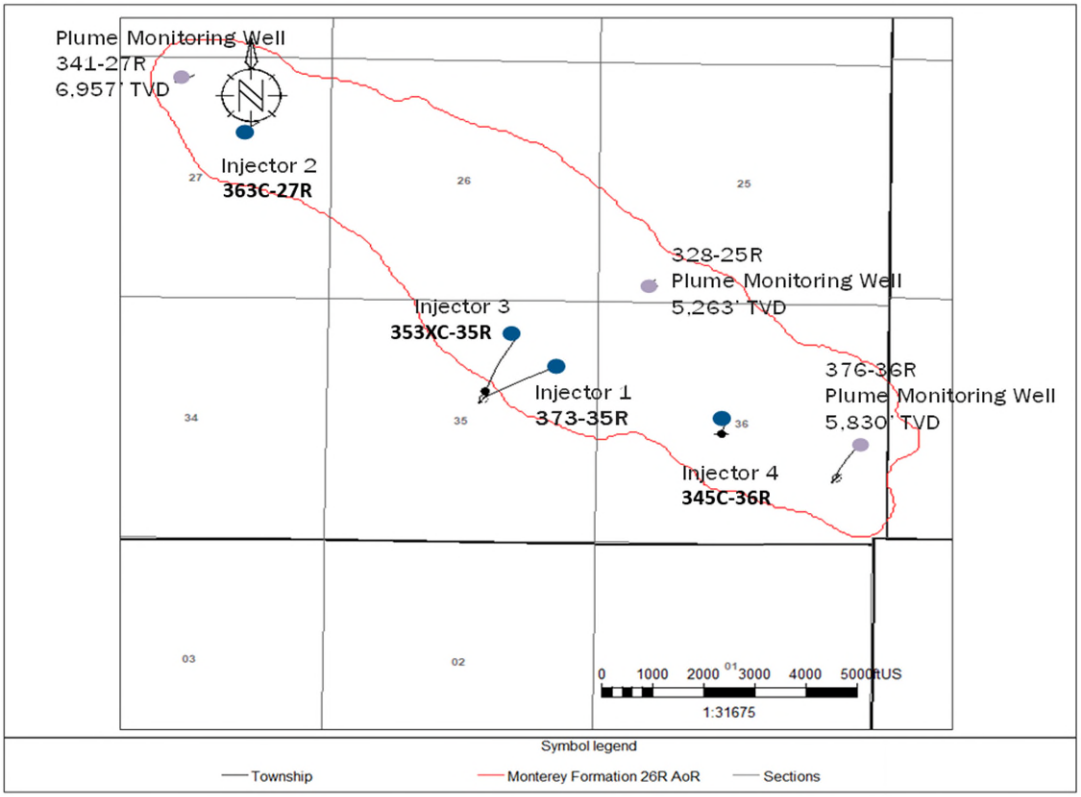
The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. A Global Mole Fraction cut off of 0.03 was used to delineate the plume boundary. In the AoR scenario, CO_2 was injected into the depleted Monterey Formation 26R reservoir until the reservoir pressure reached the discovery pressure of 3,250 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.
Figure 19 shows the AoR, injectors and offset monitoring wells. All wells that are currently operating in the 26R reservoir will cease operations, and wells not associated with the project will be abandoned prior to injection so as to eliminate interference with the AoR delineation and re-establish the confining layer. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

Figure 19: Map showing the location of injection wells and plume monitoring wells.



Corrective Action

The review of all wells within the AoR to determine the need for corrective action is a requirement of 40 CFR 146.84(c).

Tabulation of Wells within the AoR

Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation 26R reservoir was discovered in the 1940's and subsequent development drilling began around 1950. As such, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the over 70-year development history of the reservoir that includes injection of water and gas.

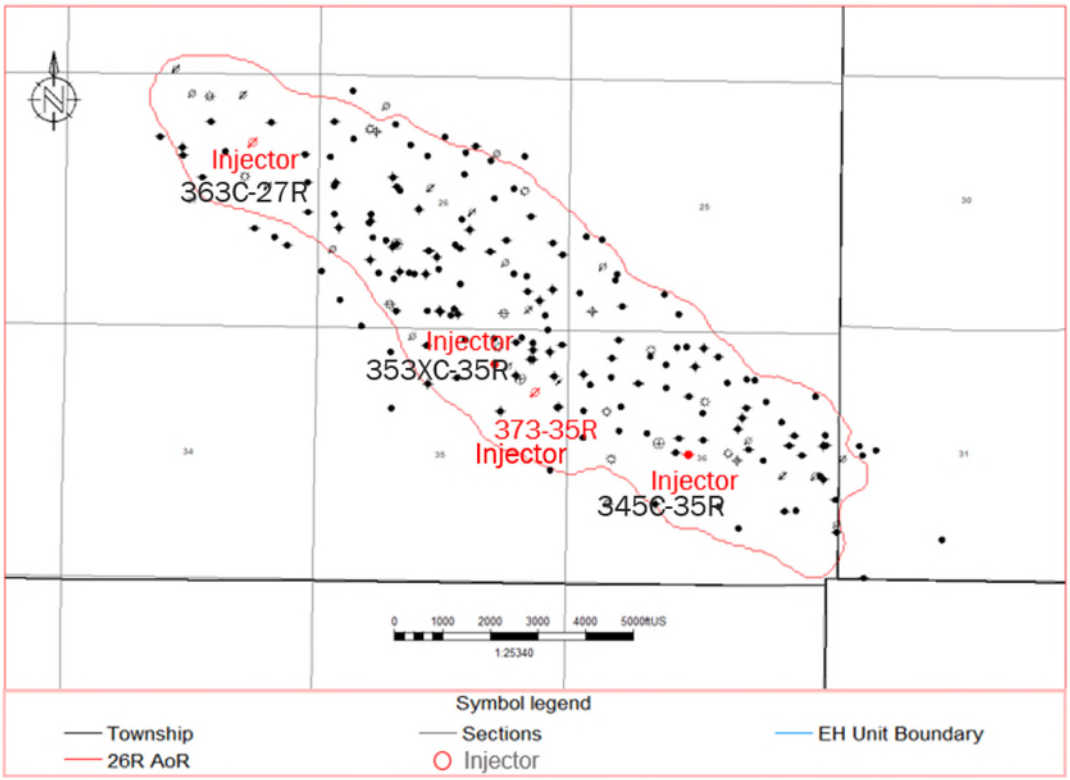
CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Table 12 is a summary of the AoR wells by type. Figure 20 displays the AoR wells' surface locations in map view. *Appendix: Well Table with Corrective Action Assessment* lists the wells individually and provides a description of each well's type, construction, date drilled,

location, depth, and record of plugging and/or completion, as required in 40 CFR 146.84 (c)(2). Additionally the table identifies pre-operational requirements and the corrective action assessment for each wellbore.

Table 12: Wellbores in the AoR by Well Type

Well Type	Count
Oil & Gas Producing Wells	145
Class II Injection/Disposal Wells	22
Pressure Observation wells	2
Plugged back	35
Total	**204**

Figure 20: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation 26R sequestration reservoir reviewed for corrective action.



Corrective Action Assessment Methodology

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q4 2021, and the results of the review are incorporated into the assessment.

The corrective action assessment includes the generation and detailed review of wellbore/casing diagrams for each well in the AoR. The results of the assessment are included in the *Appendix: Well Table with Corrective Action Assessment*. Information used in the review includes depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of Cement (TOC) determination supports the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface.

A well in the AoR is a penetration of the Monterey Formation and/or Reef Ridge Shale that may have multiple wellbores resulting from sidetracking the well. CTV tracks wells at the "wellhead" level using API-10 and at the "wellbore" level using API-12 such that a single well may have multiple wellbores, and each wellbore may or may not penetrate the AoR. The assessment of all penetrations was conducted by evaluating all wellbores, and the summary data provided refers to wellbore penetrations.

Protection of USDW

The Upper Tulare is an unsaturated zone, and the Lower Tulare is an exempt aquifer. There is no USDW in the AoR.

Wells Penetrating the Confining Zone

Of the 204 wellbores penetrating the Reef Ridge formation (Table 13), zero wells have been permanently abandoned to surface. Three wells will be repurposed as CCS monitoring wells, and one well, 373-35R, will be repurposed as a CO_2 injector. Of the remaining, 157 wellbores require plugging because the wellbores penetrate the injection zone and/or confining layer and will not be used for injection or monitoring within the 26R storage project. The wells are not known to be deficient and are not known to require corrective action. The wells will be abandoned prior to CO_2 injection under the asset retirement obligation plan (ARO) to reduce abandonment liability at Elk Hills. 35 wellbores have been plugged back for sidetrack, and as such have the API-12 status of P&A while API-10 status is either Active or Inactive, depending on the status of the current wellbore.

Table 13: Wellbores to be abandoned prior to injection

Wellbores Penetrating Reef Ridge Formation	Wellbores Requiring Corrective Action	P&A Wells Requiring Corrective Action	Wellbores Requiring Pre-Operational Abandonment
204	0	0	157

Monterey Formation 26R Isolation

CTV can demonstrate that the USDW (not present in AoR) is protected and that, with well abandonment prior to injection and implementation of a robust ongoing monitoring program, the CO_2 injected will be confined to the Monterey Formation 26R reservoir.

Plan for Site Access

CTV owns the mineral and pore space for the Monterey Formation 26R reservoir and surface access rights have been guaranteed for the duration of the project.

Corrective Action Schedule

All wellbores within the AoR will, if necessary, be pressure tested, abandoned, re-abandoned, monitored and/or have a technical demonstration of adequate zonal confinement prior to the commencement of CO_2 injection or based on an agreed upon phased schedule after CO_2 injection commences, if conditions allow. Additional evaluation during pre-operational testing will inform the suitability and isolation of wells proposed for use in the project as injectors and monitoring wells. Diagnostics may also be performed, if necessary, to complement abandonment operations. Although no wellbores have been identified for corrective action and no corrective action schedule is required, if additional evaluation efforts result in the identification of wellbores that require corrective action, CTV will notify the EPA and communicate a corrective action plan and schedule.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

4. A review of the full suite of water quality data collected from monitoring wells in addition to CO2 content/saturation (to evaluate the potential for unanticipated reactions between the injected fluid and the rock formation).

5. Review and submission of any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.

6. Reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation). A report describing the comparison of the modeling results will be provided to the EPA with a discussion on whether the results are consistent.

7. Description of the specific actions that will be taken if there are discrepancies between monitoring data and prior modeling results (e.g., remodel the AoR, update all project plans, perform additional corrective action if needed, and submit the results to EPA).

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Changes in pressure or injection rate that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

2. Difference between the computation modeling and observed plume development:

    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation reservoir that are not related to well integrity.

b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results with a deviation greater than +-10% from the Base Case.

c. Any other activity prompting a model recalibration.

3. Seismic monitoring anomalies within two miles of the injection well that are indicative of:

    a. The presence of faults near the confining zone that indicates propagation into the confining zone.

    b. Events reasonably associated with CO_2 injection that are greater than M3.5.

2. Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.

3. Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).

4. Initiation of competing injection projects within the same injection formation within a 1-mile radius of the injection well (including when additional CTV injection wells come online);

5. A significant change in injection operations, as measured by wellhead monitoring;

6. Significant land-use changes that would impact site access; and

7. Any other activity prompting a model recalibration.

CTV will discuss any such events with the UIC Program Director as soon as possible to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan within six months of the triggering event.

ATTACHMENT C: TESTING AND MONITORING PLAN - 373-35R
40 CFR 146.90

Elk Hills 26R Storage Project

Facility Information

Facility Name: Elk Hills 26R Storage Project
373-35R

Facility Contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Comments
Attachment C – TM 373-35R	1	09/30/2023	
Attachment C – TM 373-35R	2	12/05/2023	Addition of air monitoring.

The Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills 26R storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the CO_2 within the storage zone, supporting AoR re-evaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

Quality Assurance Procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the Appendix to this Testing and Monitoring Plan.

Reporting Procedures

CTV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

CTV will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a). Samples will be collected and analyzed quarterly, starting three months after the date of authorization of injection and every three months thereafter.

The anthropogenic CO_2 will be sourced from:

- Initial onsite emissions:
    - Lone Cypress blue hydrogen plant, up to 200,000 tonnes per annum
    - Elk Hills field gas treatment (pre-combustion for Elk Hills Power Plant), up to 200,000 tonnes per annum
    - Avnos Direct Air Capture (DAC), up to 1,500 tonnes per annum
- Future emission Sources:
    - CalCapture Elk Hills 550 MW natural gas power plant (post combustion), renewable fuel plants, steam generators post combustion and other power plants / industrial sources in the area.

CO_2 injectate from these sources has been incorporated into Table 1 for injectate sampling. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

Sampling Location and Frequency

CO_2 injectate samples will be taken for each injection source and between the final compression stage and the wellhead. Sampling will take place three months after the commencement of injection and every three months thereafter. Sampling process will follow the procedures below.

CTV will increase the frequency and collect additional samples if the following occurs:

1. Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source; and
2. Facility or injector downtime is greater than thirty days.

Analytical Parameters

CTV will analyze the water content and injectate the constituents identified in Table 1 using the methods listed. An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 1. Summary of analytical parameters for CO_2 stream.

Parameter	Analytical Method(s)
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD
Carbon Monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)
Total Hydrocarbons	ISBT 10.0 THA (FID)
Ammonia	ISBT 6.0 (DT)
Ethanol	ISBT 11.0 (GC/FID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Methane, Ethane, Ethylene	ISBT 10.1 (FID)
Hydrogen Sulfide and Sulfur Dioxide	ISBT 14.0 (GC/SCD)
CO_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
δ13C	Isotope ratio mass spectrometry
Water Vapor	ISBT 3.0

Sampling Methods

Stream sampling will occur for each required CO2 analysis and in the last compressor station prior to being sent to the injector. A sampling station will be installed to facilitate collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a full-service laboratory in Bakersfield, 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 4.

Zalco has a chain of custody procedure that includes the following.

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

For each required CO_2 analysis, CTV will report the time each sample was taken, a tabulation of all CO_2 stream analyses (including any quality assurance/quality control samples), an interpretation of the results, any identified changes and explanation of any data gaps.

Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

CTV will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring Devices, Location, and Frequency

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table. Depths of downhole continuous monitoring equipment are specified for each well and labeled in the Appendix_26R - Injection & Monitoring Well Schematics document.

Monitoring for the parameters, except for annulus fluid volume, will be continuous with a 10 second sampling and 30 second recording frequency for both active and shut-in periods. This will be adequate to monitor for changes in the wellbore and the reservoir.

Table 2. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface Downhole 345C-36R: 5690'(MD) 353X-35R: 6390' (MD) 363-27R: 6290' (MD) 373-35R: 7010' (MD)	10 seconds	30 seconds

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection rate	Flowmeter	Surface	10 seconds	30 seconds
Injection volume	Calculated	Surface	10 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	10 seconds	30 seconds
Annulus fluid volume		Surface	4 hours	24 hours
Temperature	Temperature Gauge	Surface Downhole 345C-36R: 5690'(MD) 353XC-35R: 6390' (MD) 363C-27R: 6290' (MD) 373-35R: 7010' (MD)	10 seconds	30 seconds
Temperature	DTS	Along wellbore to packer	10 seconds	30 seconds

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Injection Rate and Pressure Monitoring

Injection pressure, temperature and flow rate will be continuously monitored and recorded by the Elk Hills Central Command Facility (CCF). The injection pressure will be measured and recorded using pressure gauges at surface and downhole. The injectate temperature will be measured with a temperature gauge at the surface. The injection rate will be measured with a Coriolis flowmeter. The meter will be calibrated annually for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent. Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable bottomhole injection pressure. Pressure and temperature gauges will be calibrated annually. Table 6 of the QASP provides operating range and precision specifications.

Calculation of Injection Volume and Mass

The volume and mass of CO_2 injected into the Monterey Formation 26R will be calculated from the injection flow rate and CO_2 density. Density of CO_2 injected into the Monterey Formation 26R will be calculated using PVTP, a fluid thermodynamics package, developed by Petroleum Experts Ltd. PVTP is an industry standard software package that has been used extensively in CO_2 EOR applications to accurately model and match CO_2 PVT properties over a wide range of temperatures and pressures.

Annular Pressure Monitoring

Annulus pressure is monitored continuously to ensure integrity of the downhole packer, tubing, and casing. CTV will monitor the casing-tubing pressure continuously (every 10 seconds) using an electronic pressure gauge. The annulus will be filled with a non-corrosive brine with corrosion inhibitor. The casing-tubing annulus pressure for injection wells 373-35R, 345C-36R, 353XC-35R, 363C-27R will be maintained with at least 100psi at surface, as stated in the injection well operating procedure documents. Monitoring wells will be operated with 100 psi positive annular pressure at surface.

Failure to maintain >100 psi consistently could be an indication of internal or external mechanical integrity failure, provided that thermal (such as material contraction due to cooling) and pressure (such as ballooning due to increasing tubing pressure) transient effects of normal operational changes are properly diagnosed as acceptable deviations. CTV will notify EPA if (1) pressure decreases to 0 psig and cannot be explained by operational conditions, or (2) pressure drops below 100 psi threshold and cannot be maintained or stabilized after three attempts. Additionally, CTV will notify EPA if pressure increases above 1000 psi and cannot be explained by operational conditions.

Corrosion Monitoring 40 CFR 146.90(c)

CTV will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description below.

Monitoring Location and Frequency

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. The corrosion coupons will be installed in the pipeline that feeds CO_2 injectate to the injectors.

Sample Description

Samples of the materials used in the construction of the pipeline, injection wells, and monitoring wells that are directly in contact with CO_2 injectate will be monitored for corrosion. Corrosion coupons of the representative materials shown in Table 3 will be weighed, measured, and photographed prior to installation directly upstream of the wellhead. For well 373-35R, the wellbore materials exposed and in direct contact with injected CO_2 include the N-80 grade long string casing below the packer and the CRA tubing. These casing materials will be included in the corrosion coupon monitoring and are presently included in Table 3. General construction materials for pipeline, tubing and wellhead are shown in Table 3. Materials of construction will be reaffirmed after well and pipeline construction and prior to injection, as part of pre-operational testing. Subsequently, corrosion coupons consistent with final well construction materials will be used for corrosion monitoring.

Table 3. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Casing	N-80 steel (373-35R injection well) K-55 steel (341-27R, 328-25R monitoring wells) Chrome alloy consistent with final well construction for new drill wells
Tubing	Chrome alloy consistent with final well construction
Packer	Chrome alloy consistent with final well construction
Wellhead	Chrome alloy consistent with final well construction

Sample Handling and Measurement

Upon collection, the coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The samples will be handled and assessed in accordance with NACE TM0169/G31 and/or EPA 1110A SW846. Monitoring results will be documented and submitted to the EPA as per 40 CFR 146.91 (a)(7). Table 5 of the QASP document provides detection limit/range and precision.

A detected corrosion rate of greater than 0.3 mils/year will initiate consultation with the EPA. In addition, a casing inspection log may be run to assess the thickness and condition of the casing if the corrosion rate exceeds 0.3 mils/year. CTV will continually update the corrosion monitoring plan as data is acquired.

Above Confining Zone Monitoring

CTV will monitor water quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). The Etchegoin and Tulare Formations are permeable reservoirs above the confining zone.

Etchegoin Formation Monitoring

The Etchegoin Formation is between the Reef Ridge confining zone and the Upper Tulare USDW and will dissipate CO_2 injectate that may migrate upward from the injection zone. The Etchegoin Formation is continuous across the AoR and will be monitored continuously for pressure and temperature changes. Figure 1 shows the location of 355X-26R and the shallow groundwater monitoring well. The well is suitable and appropriate to adequately monitor for pressure and temperature changes within the first porous and continuous sand above the sequestration zone. This sand is present from 4,063’ – 4,087’ MD in 355X-26R.

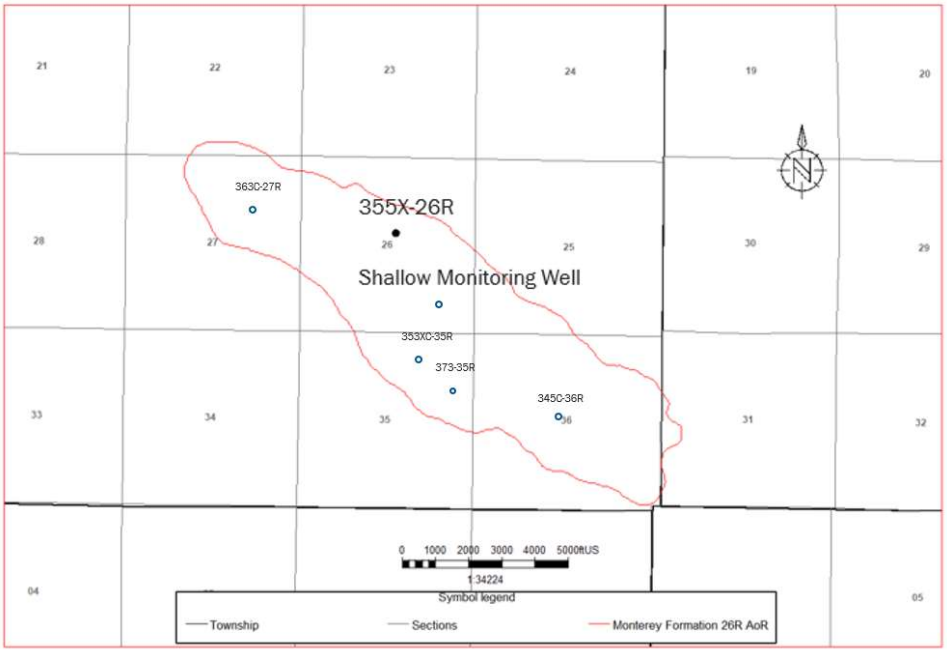


Figure 1: Above confining zone monitoring wells.

The effect of potential leakage from the Monterey Formation to the Etchegoin Formation is an increase in reservoir pressure and decrease in temperature of the Etchegoin. Additionally, potential leakage will create compositional changes detectable with fluid sampling and geochemical monitoring. Pre-injection geochemical composition will be established from baseline water analysis acquired within the Etchegoin Formation during pre-operational testing.

Tulare Formation Monitoring

Monitoring in the Upper Tulare will include pressure, temperature, and fluid sampling. Leakage to the Tulare Formation would increase the reservoir pressure and change the composition of the formation water (increased CO_2 concentration). The Upper Tulare is unsaturated in the AoR. The Upper Tulare Formation will be monitored between 400' – 450' MD in the shallow monitoring well that will be drilled specifically for this project.

Pre-injection geochemical composition will be established from baseline water analysis acquired within the Tulare Formation during pre-operational testing. Subsequent results will be compared against these baseline results for significant changes or anomalies. pH will be monitored as a key indicator of CO_2 presence.

Additional groundwater monitoring wells will be drilled to assess and monitor the Upper Tulare USDW if the following occurs:

1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation 26R CO_2 injection.

2. Upper Tulare Formation pressure or composition changes due to Monterey Formation 26R CO_2 injection.

Monitoring Methods, Location, and Frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well with respect to the AoR. The wells are located within the Elk Hills Oil Field, and CTV owns the surface and mineral rights.

Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	Shallow Water Monitoring Well	Pump	–400’ - 450' MD/VD	Quarterly
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’ - 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’ - 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	400' - 500' MD/VD in each well	Continuous
Etchegoin	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Quarterly
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' 4788' - 4811' 4205' - 4226' (all MD/VD)	Continuous

Analytical Parameters

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 5. Summary of analytical and field parameters for water samples from the USDW monitoring well and the Etchegoin monitoring well.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)
Dissolved CO_2	Coulometric titration, ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Sampling Methods

Samples will be collected using the following procedures:

1. Depth and elevation measurements for water level taken.
2. Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
3. Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
4. Samples preserved and sent to lab as per chain of custody procedure.
5. Closure of well.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by Zalco, a full-service state certified laboratory in Bakersfield, approximately 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3. Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

Internal Mechanical Integrity Testing

A Class VI well has mechanical integrity if there is no significant leak in the casing, tubing, or packer. CTV will conduct an initial annulus pressure test on all injection wells and on monitoring wells that penetrate the confining zone and are configured with tubing and a packer. Additionally, any time the packer is replaced or reset, a SAPT will be performed. The injection and monitoring wells will be configured with continuous recording devices to monitor the pressure on the annulus between the tubing and the casing, and annulus fluid volumes will be measured and recorded. These actions satisfy the requirements of 40 CFR 146.88(e)(1) and 40 CFR 146.89(b).

Standard Annular Pressure Testing (SAPT)

Pascal's Law states that any pressure applied to a fluid filling a closed vessel will be transmitted undiminished, throughout the vessel. This is the basis for the SAPT as the primary means to determine if a well's casing, tubing, packer, and wellhead (the annulus system) are liquid tight. Because the annulus system is not an isolated system, the measured pressure applied may not be constant throughout time. The temperatures along the wellbore must change as injection rates and temperatures change because of heat exchange between injectate and the surrounding formations. When the well is shut in, the wellbore may cool or become warmer as the well materials are subjected to the natural geothermal temperatures, which will result in expansion or contraction of liquid in the annulus. Because liquids are effectively incompressible, annular pressure is expected to fluctuate due to changes in the tubing such as contraction, elongation, and ballooning during transient injection or shut-in periods.

The procedure for conducting SAPT is as follows:

1. CTV will notify the Director to provide the opportunity to witness the testing.

2. Completely fill the tubing/casing annulus with packer fluid consisting of weighted brine and appropriate additives such as corrosion inhibitors, oxygen scavengers, and biocide. The volume to fill should be measured and recorded. The annulus liquid should be temperature stabilized prior to conducting the test.

3. The annulus will be pressurized to a surface pressure which exceeds the maximum injection pressure by at least 100 psi unless an alternate pressure is approved by the EPA Director.

4. Following pressurization, the annular system will be isolated from the source of pressure by a closed valve, or it will be disconnected entirely.

5. The isolation will be maintained for no less than one hour. During this time, pressure measurements will be recorded in at least one-minute intervals.

6. After the SAPT is concluded, the valve to the annulus should be opened to bleed down the pressure. The liquid returns from the annulus should be measured and recorded.

Monitoring wells that do not have a specified maximum tubing pressure will be tested to 1000 psi initially. As reservoir pressure increases during injection and tubing pressure is continuously monitored, SAPT test pressure will be reconsidered. When tubing pressure approaches 100 psi less than the initial SAPT test pressure, i.e. 900 psi, the SAPT will need to be performed again unless an alternative method or test pressure is approved by the EPA Director. Table 6 provides information on the frequency and test pressures for injection and monitoring wells within the project.

Table 6. Internal MIT requirements

Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)	Maximum Injection Pressure (psi)	Test Pressure (psi)
Standard Annular Pressure Test (SAPT)	373-35R[1]	Casing/tubing annulus from surface to packer	Once, upon initial installation	Any time packer is replaced or reset	Not Applicable	1992	2092
	345C-36R[1]					1888	1988
	363C-27R[1]					2020	2120
	353XC-35R[1]					1997	2097
	355X-26R[2]				Any time packer is replaced or reset	--	1000
	341-27R[3] 328-25R[3] 376-36R[3]					--	1000

Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)	Maximum Injection Pressure (psi)	Test Pressure (psi)	
Annular Pressure	373-35R[1] 345C-36R[1] 353XC-35R[1] 363C-27R[1]	Wellhead	Continuous	Continuous	Not Applicable	--		-
	355X-26R[2] 341-27R[3] 328-25R[3] 376-36R[3]				Continuous			-

[1] *CO2 injection well*
[2] *Above Zone monitoring well*
[3] *Injection Zone monitoring well*

The interpretation of the SAPT will compare the pressure change during the test once the initial pressure has stabilized. If the change (gain or loss) in pressure is less than 3% of the test pressure, the well has demonstrated mechanical integrity, pursuant to 40 CFR 146.8(a)(1). If the change in pressure (gain or loss) exceed 3% of the test pressure, the well has failed to demonstrate mechanical integrity.

CTV will utilize an EPA-approved Annular Pressure Test form to record the results of the SAPT if the test is not witnessed by the EPA. If the test indicates the well has demonstrated mechanical integrity, the test form and raw pressure data (original chart recordings or a digitized log of pressure and time) will be provided to the EPA. If the test indicates a failure of mechanical integrity in an injection well, the well will be shut in, no injection will occur, and the EPA Director will be notified within 24 hours.

Continuous Monitoring of Annular Pressure

Injection and monitoring wells will record continuous annular pressure such that internal MIT can be confirmed in real-time based on the interpretation of this data. CTV will identify and investigate pressure deviations that do not align with changes to operating conditions or temperature effects due to seasonal variation. In the event of a casing leak into a permeable zone, the pressure will normally fall. In the event of a tubing or packer leak, the annulus pressure will track injection pressure, although the pressures are not likely to be equal due to friction and density differences.

This data will be provided in the semi-annual report to demonstrate ongoing internal mechanical integrity.

External Mechanical Integrity Testing

CTV will conduct mechanical integrity testing on each injection well at least once per year to demonstrate external mechanical integrity using an approved test method per 146.89(c). CTV will, at a minimum, perform a temperature log on the injection wells.

Testing Methods

Table 7 shows testing methods that may be utilized for MIT on injection and monitoring wells associated with this project. CTV will utilize an approved MIT technique, such as temperature logging with wireline, oxygen-activation logging, or noise logging on CO_2 injection wells as the primary method. While DTS may not be considered an approved temperature logging method for injection well MIT, CTV may seek Director approval in the future prior to using this method. If CTV elects to conduct an alternate MIT, notification including a description of the proposed testing method and procedure will be sent to the EPA for approval.

Since temperature decay logs require injection to cool the wellbore and near wellbore region prior to logging, monitoring wells cannot be tested for external MIT without approval to inject fluid. Additionally, injecting fluid such as H_2O or CO_2 for the purpose of testing may be undesirable for other reasons. Therefore, MIT on monitoring wells will not be conducted using temperature decay logging. Instead, another approved method under 40 CFR 146.89(c) may be utilized, or DTS may be proposed for EPA Director approval for monitoring well MIT.

Table 7. External Mechanical Integrity Testing Methods

Test Description	Location
Temperature Decay Log	Along wellbore using wireline well log
Distributed Temperature Log (DTS)	Along wellbore using fiber optic sensing (DTS), continuous
Oxygen Activation Log (OA)	Along wellbore using wireline well log
Noise Log	Along wellbore using wireline well log

Description of Temperature Logging with Wireline

EPA has specific requirements that must be satisfied for a temperature log to be considered valid for MIT as specified by 40 CFR 146.89(c). CTV will utilize the following procedures and comply with EPA guidance to ensure testing requirements are achieved.

1. Stabilize injection for 24 hours prior to running the temperature log.

2. Run an initial temperature survey logging down from at least 200 feet above the base of the Reef Ridge Shale to the deepest point reachable in the well, while injecting at a rate that allows for safe operations. The temperature sensor should be located as close to the bottom of the tool string as possible. The optimal wireline speed is 30 ft/min, and the acceptable range is between 20 and 50 feet per minute.

3. Shut in the injection to the well and run multiple temperature surveys with 4 hours between runs. The minimum shut-in time following the initial temperature log is 12 hours total, and the superimposed logging passes should be at least 4 hours after the injection pass.

4. Assess the time lapse temperature profiles against the baseline injection survey to identify temperature anomalies that may indicate a failure of well integrity. Evaluate the data to determine if additional passes are needed for interpretation. If CO_2 migration is interpreted in the topmost section of the logging pass such that the top of the migration pathway cannot be identified, additional logging runs over a shallower interval will be required to find the top of migration.

5. Both the printed or digital log and the raw data for at least two logging runs should be provided to the EPA. The printed or digital log should have the following:

    a. The heading must be complete and include all pertinent information to identify the well, well location, date of the survey, etc.

    b. Vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs.

    c. Horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.

    d. The right-hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.

    e. The left-hand track must contain a casing collar log, a legible lithology log such as spontaneous potential (SP) or gamma ray, and identification of the base of USDW, if present.

Description of Temperature Logging using Distributed Temperature Sensing (DTS)

DTS is a fiber optic continuous temperature monitoring system that will be installed in injection and monitoring wells to measure wellbore temperature in real time from the annulus along the length of the tubing. Like a temperature log, the DTS temperature data can be used to assess the internal and external mechanical integrity of injection and monitoring wells. Successful comparisons of DTS temperature logs to wireline temperature logs have been well documented and validate the use of DTS as a temperature log for mechanical integrity testing. By continuously monitoring DTS data, this testing method provides an early detection of temperature changes through the capability to continuously monitor MIT in Realtime, making this technology potentially superior to wireline temperature logging.

The impact to health, safety, and environment of DTS temperature logging is significantly improved in comparison to wireline temperature logging operations. Because the DTS system is installed at the time of well construction or workover, no crew is required to be present at the

wellsite. The following procedure can be performed to acquire a temperature log using DTS for mechanical integrity analysis for an injector:

1. Establish baseline temperature profile that defines the natural gradient along the well prior to injecting.

2. During injection, record the temperature profile for 6 hours prior to shutting in the well.

3. Stop injection and record the temperature for sufficient time to allow cooling.

4. Start injection and record the temperature profile for 6 hours.

5. Compare the baseline analysis to the time-lapse data for assessment of temperature anomalies that may indicate a well failure.

Description of Passive Temperature Logging using DTS

DTS can be used for passive external mechanical integrity monitoring on monitoring wells. This solution has advantages compared to wireline temperature logging on monitoring wells in liquid-depleted reservoirs. DTS will be installed on the tubing string from surface to the packer on the injection wells, the injection zone monitoring wells, and the above zone monitoring well. DTS will detect temperature changes along the wellbore if external mechanical integrity is compromised.

On injection wells, temperature changes associated with external fluid migration will be masked due to the dominating impact of injectate temperature on the wellbore materials. However, during shut-in periods immediately following sustained injection, when warm back can be observed along the length of the DTS fiber, migration pathways of fluids at non-geothermal temperature gradients can be identified. Additionally, lack of deviation from temperature reversion to the geothermal gradient is a demonstration of external mechanical integrity. It is appropriate for the DTS fiber to monitor temperature throughout and above the confining layer, and the configuration of DTS fiber as described above, from surface to the top of the packer, is sufficient to monitor injection wells for external MIT above the injection zone.

On the injection zone monitoring wells, the DTS string will monitor the confining layer and all above layers in real-time. If dense phase CO_2 were to breach the injection zone and migrate upward, the warmer CO_2 would cause a discernible temperature anomaly. If the CO_2 were to change phase to gas phase, a cooling effect would be observed. The high frequency and volume of data is superior to wireline temperature logging, significantly enhancing diagnosis capability and reaction time. DTS is not required to be deployed through the injection zone to assess external MIT within and above the confining layer.

Description of Noise Logging

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. Noise logging may be carried out while injection is

occurring. If ambient noise is greater than 10 mv, injection will be halted. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Run a noise survey from top of Tulare to the deepest point reachable in the Monterey Formation while injecting at a rate that allows for safe operations.

3. Make noise measurements at intervals of 100 feet to create a log on a coarse grid.

4. If any anomalies are evident on the coarse log, construct a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.

5. Make noise measurements at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing:

   a. The base of the lowermost bleed-off zone above the injection interval and

   b. The base of the lowermost USDW.

6. Additional measurements may be made to pinpoint depths at which noise is produced

Description of Oxygen Activation Logging

To ensure the mechanical integrity of the casing, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. OA logging may be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Conduct a baseline Gamma Ray (GR) log and Casing Collar Locator (CCL) log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool. Gamma Ray Log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.

3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches and less than 13- 3/8 inches.

4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.

5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a "no vertical flow behind the casing" section of the well to ensure accurate, repeatable tool response and for measuring background counts.

6. Take, at a minimum, a 15-minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 feet above the injection interval so that turbulence does not affect the readings.

7. Take, at a minimum, a 15-minute stationary reading at a location approximately midway between the base of the lowermost USDW and the confining interval located immediately above the injection interval.

8. Take, at a minimum, a 15-minute stationary reading adjacent to the top of the confining zone.

9. Take, at a minimum, a 15-minute stationary reading at the base of the lowermost USDW.

10. If flow is indicated by the OA log at a location, move up hole or downhole as necessary at no more than 50-foot intervals and take stationary readings to determine the area of fluid migration.

Pressure Fall-Off Testing

Pressure falloff tests are used to measure formation properties in the vicinity of the injection well, and the intent of periodic testing is to monitor for any changes in the near-wellbore environment that may impact injectivity or increase pressure. CTV will perform pressure fall-off tests on each injector during the injection phase every five years as described below to meet the requirements of 40 CFR 146.90(f). CTV will refer to EPA Region 9 UIC Pressure Falloff Requirements for planning and conducting the testing as well as preparing and submitting the monitoring report.

Testing Details

The following procedure will be followed:

1. Injection rate will be held constant for at least one week prior to shut in. The injection pressure will be high enough to produce a pressure decrease upon shut in that will result in valid test data for derivative analysis. The maximum operating pressure will not be exceeded.

2. The injection well will be equipped with surface and downhole pressure and temperature gauges. Bottomhole gauges will have surface readout capabilities and will be the primary source of pressure data for analysis because these gauges will be least affected by wellbore fluid effects. Prior to and throughout the shut-in period, the gauges will collect pressure data in 10 second intervals, which is sufficient and appropriate for pressure-transient analysis. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

3. The injection well will be shut in at the wellhead to minimize wellbore storage effects from compressible fluids. The injection rate of the offset injector will be held constant during the test. Accurate records of offset wells completed within the same zone will be maintained and considered in the interpretation.

4. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage. This desired radial flow regime is identified by a zero slope of the pressure derivative through pressure transient analysis. The data can be analyzed in real time because of the surface readout capabilities of the pressure gauges and can therefore ensure a complete and adequate test before restarting injection.

5. Interference testing may be conducted at the conclusion of the falloff test to demonstrate communication between the wells. The injection rate of the offset injector would be increased or decreased multiple times to create pressure pulses that can be observed by the shut in well.

6. The interpretation of the pressure transient dataset will be performed by a trained engineering professional using proven industry standard methodologies. Anomalies that are identified from the interpretation will be investigated.

7. A report containing the pressure fall-off data and interpretation of the reservoir pressure will be submitted to the EPA in the next semi-annual report. The report will follow the guidance of the EPA Region 9 UIC Pressure Falloff Testing Requirements document.

Carbon Dioxide Plume and Pressure Front Tracking

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

Plume Monitoring Location and Frequency

Figure 2 shows the location of the wells that will monitor the CO_2 plume directly in the targeted 26R reservoir. These wells will actively monitor the development of the CO_2 plume upon the initiation of injection. If the plume development is not consistent with computation modeling results, CTV will assess whether additional monitoring of the plume is necessary. Determination for plume monitoring changes will be made in consultation with the UIC Program Director and would trigger an AoR reevaluation, per the AoR and Corrective Action Plan.

Based on the Base case model, the CO2 plume is expected to arrive at the monitoring well locations at approximately the – 7th year of injection for 376-25R, 8th year of injection for 328-25R and the 9th year of injection for 341-27R.

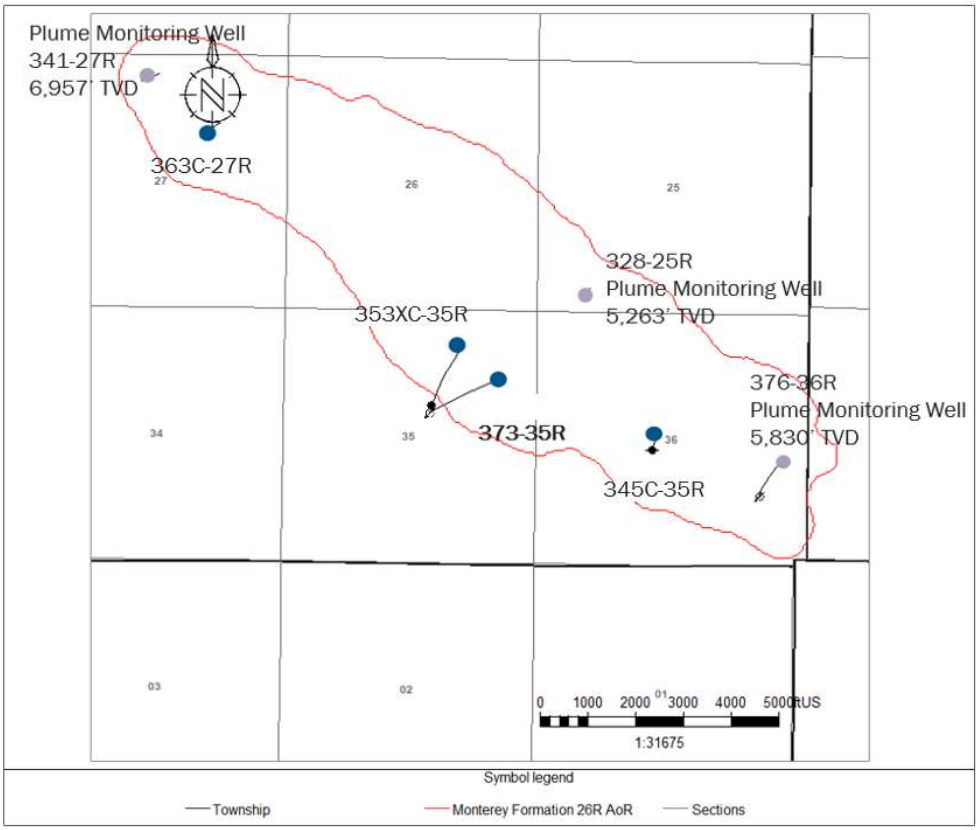


Figure 2: Monterey Formation 26R sequestration reservoir monitoring wells, with true vertical depth in feet of the monitoring interval.

Table 8 presents the methods that CTV will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 9. Detection limits, precisions, and quality control requirements for these methods are presented in Table 3 of the QASP.

Table 8. Plume Monitoring Activities

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Formation 26R	Fluid Sampling	341-27R	6981' - 7237' MD	Once	Quarterly	Annual
		Pressure		6910' MD	Baseline	Continuous	Continuous
		Temperature		6910' MD	Baseline	Continuous	Continuous
		Fluid Sampling	328-25R	5268' - 5800' MD	Once	Quarterly	Annual

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)
	Monterey Formation 26R	Pressure		5188' MD	Baseline	Continuous	Continuous
		Temperature		5188' MD	Baseline	Continuous	Continuous
	Monterey Formation 26R	Fluid Sampling	376-36R	5832' - 6815' MD	Once	Quarterly	Annual
		Pressure		5760' MD	Baseline	Continuous	Continuous
		Temperature		5760' MD	Baseline	Continuous	Continuous
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	341-27R	6981' - 7237' MD	Baseline	Every year from start of injection	Every 5 years
			328-25R	5268' - 5800' MD			
			376-36R	5832' - 6815' MD			

Table 9. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510

Parameters	Analytical Methods
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Plume Monitoring Details

Fluid sampling, pressure monitoring, and temperature monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but more importantly, the CO_2 content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in Table 9.

The DTS from the monitoring wells will provide continuous temperature from packer to surface.

As discussed in the AoR and Corrective Action Plan, 72% of the post-shut-in injected CO_2 will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and formation fluid density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand CO_2 saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every year during the injection phase.

CTV does not plan to conduct VSP monitoring for the depleted 26R oil and gas reservoir. The resolution for the CO2 plume using VSP will be limited due to noise and limited density contrast between the reservoir before and after CO2 injection. Seismic monitoring works especially well in thick, brine filled formations and may not be appropriate for depleted gas reservoirs (page 106 Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance). In addition, the unsaturated Tulare Formation and depleted gas San Joaquin Formation will limit VSP seismic wave responses.

Pressure Front Monitoring Location and Frequency

The aerial extent of plume development in the Monterey Formation 26R reservoir will reach the reservoir boundaries early in the injection phase. Because the reservoir is pressure-depleted, injected CO_2 will quickly fill the available pore space. Table 8 indicates that pressure front monitoring will coincide with direct monitoring of the CO_2 plume using the monitoring wells identified and will support CO_2 plume model and AoR model validation. Monitoring well locations with respect to plume development through time are shown in Figure 3.

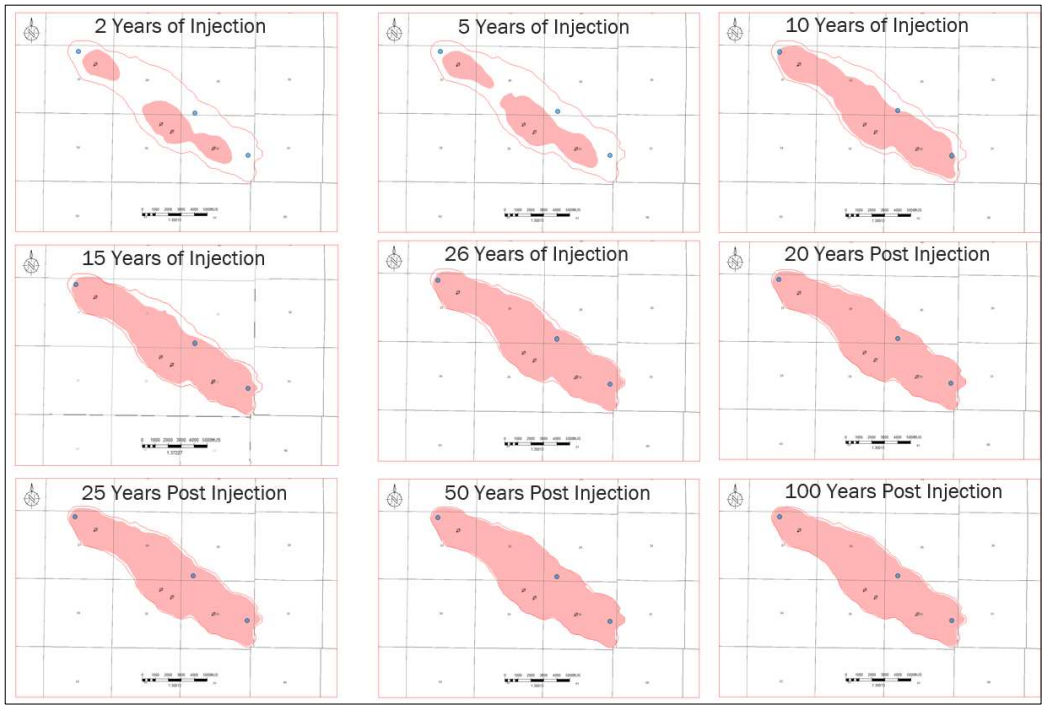


Figure 3: Monitoring well location with maps showing plume development through time from computational modeling.

Monitoring well 328-25R pressure development based on computational modeling is shown in Figure 4. The average pore volume reservoir pressure stabilizes 1 year after the end of injection. This is due to the majority of CO_2 that remains super-critical and low quantity of CO_2 that will be soluble in either the oil or water phases. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

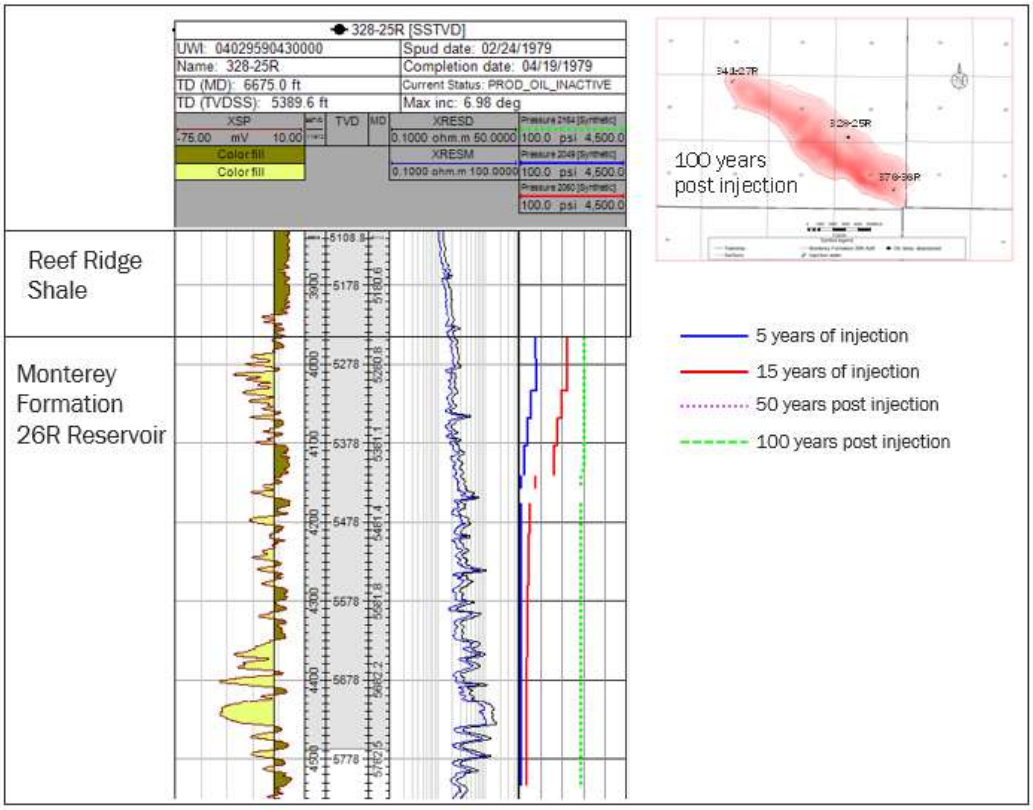


Figure 4: Monitoring well 328-25R showing the pressure increase through time from the computational modeling results.

Pressure Front Monitoring Details

Direct pressure monitoring of the plume will be achieved through installation of pressure and temperature gauges in monitoring wells 341-27R, 328-25R and 376-36R. The depleted Monterey Formation 26R oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 5 shows the pressure in the reservoir post-injection. CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies.

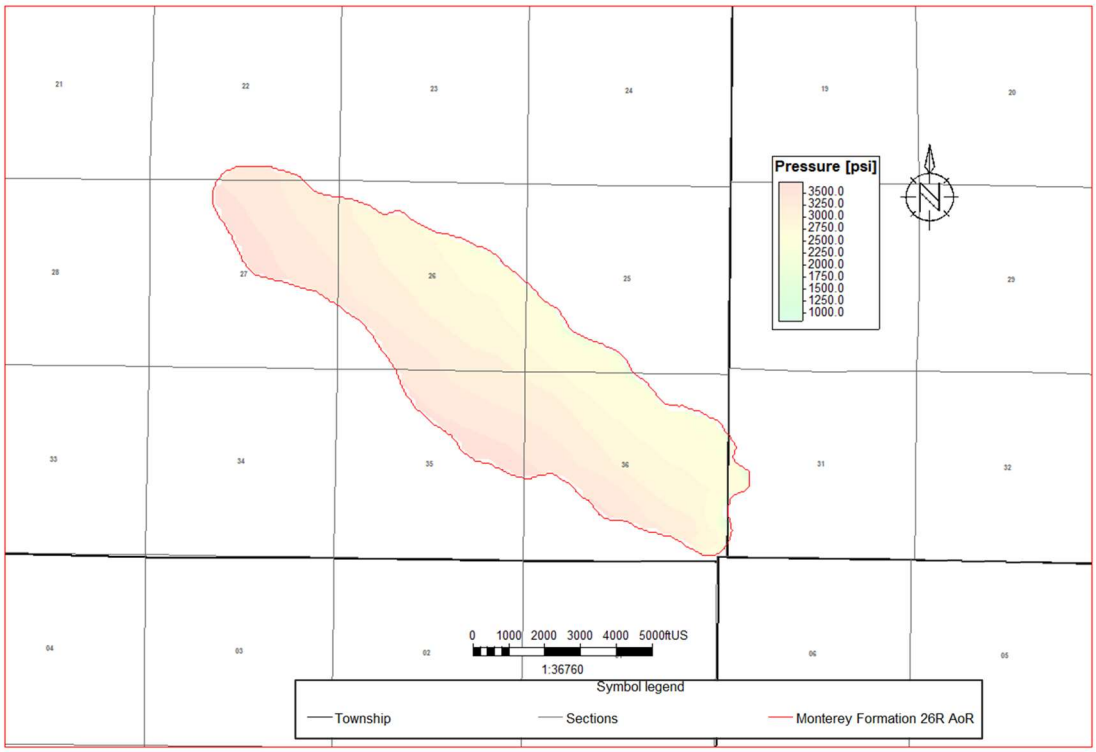


Figure 5: Monterey Formation 26R pressure 50 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.

The modeled pressure increases at monitoring well 328-25R are shown in Figure 4. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

Table 10 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ. Downhole gauge specifications are provided in Table 8 of the QASP document.

Table 10. Pressure-front monitoring activities.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)]	Monterey Fm 26R	Pressure	341-27R	6981' - 7237' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
DIRECT MONITORING	Monterey Fm 26R	Pressure	328-25R	5268' - 5800' MD	Baseline	Continuous
		Temperature			Baseline	Continuous

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
	Monterey Fm 26R	Pressure	376-36R	5832' - 6815' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
Other Plume / Pressure-Front Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Baseline	Continuous

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole seismometers in the Elk Hills Oil Field. This network will be implemented to monitor seismic activity near the project site. Direct pressure monitoring of the storage reservoir will be used in conjunction with the passive seismic monitoring to demonstrate that there are no seismic events affecting CO_2 containment.

Specifications of the network are as follows:

- 7 sensor locations (borehole and near surface) with high-sensitivity 3-component geophones (Figure 6)
- Borehole sensors have been deployed (depths shown in Figure 6) to ensure a good quality signal and to minimize noise. A velocity model will be derived from vertical seismic profiles (VSPs), sonic well logs, and check shots.
- The system will be designed with capability of detecting and locating events >M_w 0.0

Baseline Analysis:

The monitoring network has been installed to collect seismicity data to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

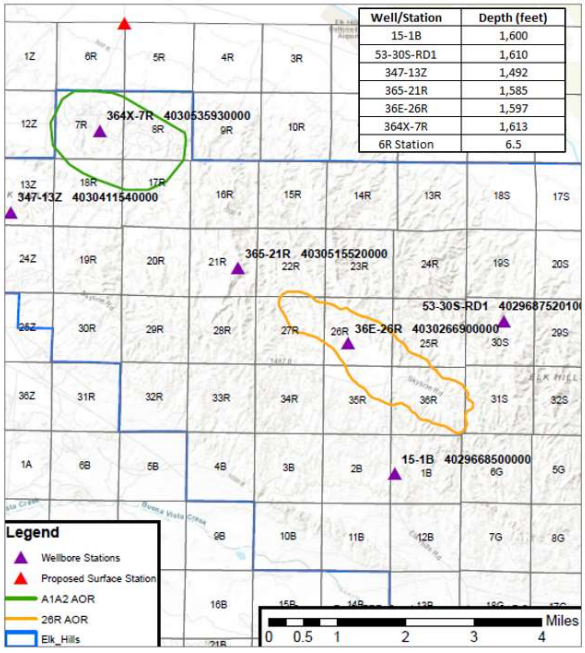


Figure 6: Elk Hills seismic monitoring network station location and depth of geophone sensors.

Monitoring Analysis:

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed continuously.

- Waveform data to be transmitted near real-time via cellular modem or other wireless means and archived in a database

- Event notifications to be automatically sent to required personnel to ensure compliance with CTV's Emergency and Remedial Response Plan

Additionally, CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network. The EPA Director will be notified of seismic activity as per the Emergency and Remedial Response Plan.

Surface Air Monitoring

Surface air monitoring, including broad aerial monitoring and targeted monitoring at wells and pipelines will be conducted.

Continuous Monitoring of AOR

Broad aerial surface air monitoring will be conducted with eddy covariance towers. Eddy covariance towers are a widely used micrometeorological technique for direct high-speed

measurements of the transport of gases, are a recommended component of CCS project surface air monitoring.

Each eddy covariance tower will consist of a solar-powered 3-dimensional sonic anemometer and open-path gas analyzer installed on a stationary tower and will be installed downwind of the prevailing wind direction from potential gas sources. Annual average prevailing wind direction in the vicinity is from the northwest. Proposed tower locations are displayed on Figure 7. Locations were chosen to be downwind (southeast) of the injection wells and surface expression of the simulated CO_2 plumes, to be in locally high topographic locations given the hilly terrain in the project vicinity, and in a location with access for equipment installation and servicing.

Monitoring equipment will be installed at a height of approximately 5 meters (33 feet). In general, the upwind distance represented by the tower height can be determined by the 1:100 rule; in this case with a 5-meter tower height the majority of measured flux will come from an oval-shaped area from near the tower to 500 meters (1,640 feet) upwind.

Gas emission rate is calculated from air density, vertical wind speed, and dry CO_2 mole fraction. Air density fluctuation is assumed to be negligible, wind speed will be measured with the sonic anemometer and CO_2 mole fraction with the gas analyzer. The sonic anemometer will be Campbell Scientific CSAT3 or equivalent, and CO_2 gas analyzer will be LI-COR Biosciences LI-7500A or equivalent. The gas analyzer will be positioned at or slightly below the sonic anemometer level, with a separation distance less than 20 centimeters. Vibration will be minimized by the use of several guy wires attached at the middle of the tower.

Manual cleaning of the gas analyzer will be performed on an as-needed basis when anomalous readings or excessive zero-drift in the data is observed. Factory calibration is assumed to be stable for at least several years and will be checked once per every six months as a precaution.

Data processing will be conducted and will be presented as hourly-averaged CO_2 concentrations and gas emission rates. Detection of anomalous and increasing CO_2 concentrations will lead to eddy covariance tower equipment testing and CARB consultation.

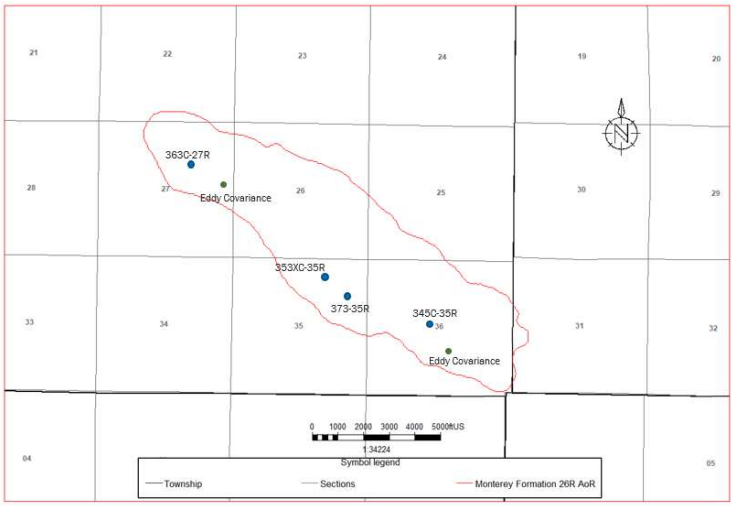


Figure 7: Location of Eddy Covariance monitoring.

Continuous Equipment Monitoring

Surface components of the injection system, including the flowlines and wellheads, will be monitored using equipment that will monitor for elevated CO_2. This leak detection equipment will be integrated with automated warning systems that notify the control center at the central facility, giving the operator the ability to remotely close the valves in the event of an anomalous reading. The central facility uses a SCADA software system to implement operational control decisions on a real-time basis throughout the project to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Monitoring Summary

This proposed monitoring program meets the goals of 40 CFR 146.90(g) by capturing continuous direct measurements of pressure and temperature in the storage reservoir (in-zone), Etchegoin (above zone) and USDW across key points of the AOR, in addition to frequent fluid samples and PNL to track the progress and confinement of the CO_2 plume. This data will also calibrate the dynamic model to predict plume front movement and pressure increase. In addition, the high resolution seismic monitoring network will provide a wide area measurement to indirectly monitor for pressure increase in-zone and above, that can be used in conjunction with the data from the monitoring wells to confirm confinement.

Direct:

The three in-zone monitoring wells are located close to the edges of the AOR, up-dip of the injectors, and thus in the flow direction of the less buoyant injected CO_2. The wells will be continuously measuring pressure and temperature at these locations. The continuous signals of pressure change in the reservoir will be used to update and calibrate the dynamic model and identify any major deviations from the predicted behavior of the reservoir. The continuous temperature measurements will provide data for the arrival of CO_2 at these locations.

In addition to the USDW and Etchegoin monitoring wells, the in-zone monitoring wells will provide confirmation of the confinement of CO_2 to the injection zone by also continuously measuring temperature changes in the Etchegoin and USDW (via DTS). Periodic fluid sampling at these locations will confirm the continuous pressure and temperature data, by providing measurements of CO_2 concentration in the reservoir that can further calibrate the dynamic model. Thus, the direct measurements for the injection zone through these wells will provide adequate special coverage of the development of the plume and pressure front, which can also improve the accuracy of the dynamic model predictions.

The two centrally located monitoring wells in the Etchegoin formation and USDW will continuously measure pressure and temperature in their respective zones, thus providing continuous direct measurements to assess the confinement of the injected CO_2. In addition, the continuous temperature measurements at these two locations, combined with the temperature measurement covering the Etchegoin and USDW at the three in-zone monitoring wells will provide adequate spatial coverage across the AOR to evaluate confinement of CO_2 in the storage reservoir.

Indirect:

PNL at the three in-zone monitoring wells will provide indirect measurement of gas saturation and CO_2 concentration in the injection zone, which will track the progress and confinement of the plume and further calibrate the dynamic model.

The seismic monitoring network will provide an indirect measurement of the pressure increase in the injection zone, the Etchegoin and the USDW. The seismic monitoring network will be sufficient to resolve events greater than 0 magnitude, with a 1,000 ft vertical resolution at the injection depths and above, giving us the ability to differentiate between events in the injection zone versus events in the shallower Etchegoin or USDW. This provides an indirect way to monitor for pressure increases in-zone or above zone via seismic events that could be triggered from pressure changes due to CO_2 injection or fluid migration.

Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan

WELL PLUGGING PLAN

Elk Hills 26R Storage Project

Injection Well 373-35R

Facility Information

Facility Name: Elk Hills 26R Storage Project
373-35R

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – CoP Details_373-35R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – CoP Details_373-35R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – CoP Details_373-35R_V3	3	01/11/23	Revisions made based on questions received from the EPA 01/06/23
Attachment G – CoP Details_373-35R_V4	4	05/14/2023	Revisions made based on questions received from the EPA 03/2023
Attachment D – Well Plugging Plan_373-35R_V5	5	11/29/2023	Separating Construction and Plugging Plans into Separate Attachments

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

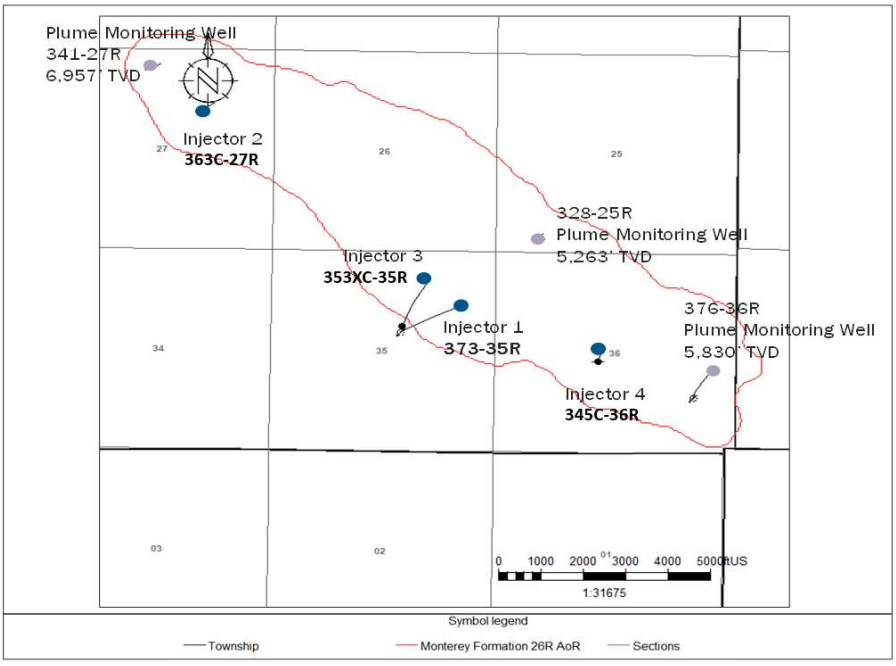


Figure 1: Map showing the location of injection wells and monitoring wells.

Injection well 373-35R is an existing well approved for water injection as part of a UIC approval for pressure maintenance. The well has cumulative injection of 4.7 million barrels of water. As part of the UIC approval, California Resources Corporation (CRC) has conducted mechanical integrity (MIT) and standard annular pressure (SAPT) tests to ensure internal and external mechanical integrity.

Figure 2 and *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Planned Tests or Measures to Determine Bottomhole Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottomhole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The planned external MIT method will be a temperature log or other approved external MIT (Table 1) and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Table 1: External Mechanical Integrity Testing Methods

Test Description	Location
Temperature Decay Log	Along wellbore using wireline well log
Distributed Temperature Log (DTS)	Along wellbore using fiber optic sensing (DTS), continuous
Oxygen Activation Log (OA)	Along wellbore using wireline well log
Noise Log	Along wellbore using wireline well log

Information on Plugs

CTV will use the materials and methods noted in Table 2 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well

plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 2, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures. Note that ground level corresponds to 14' MD due to the depth reference to the kelly bushing 14' above ground level during drilling.

Table 2: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	6.276	6.366	6.366	6.276
Depth to bottom of tubing or drill pipe (ft)	7,871	2,529	1,097	39
Sacks of cement to be used (each plug)	201	25	25	5
Slurry volume to be pumped (bbl)	41.17	5.12	5.12	1.02
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	6,799	2,404	972	14
Bottom of plug (ft)	7,871	2,529	1,097	39
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or Coiled-Tubing Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. Wellbore Bullheading will be conducted at appropriate rates so as to ensure no fracturing of the surrounding formation occurs and the cement plugs are not compromised in any way. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

9. Once the fourth cement plug is placed at surface, casing will be cut 5' below ground level. A metal cap will be welded onto the top of the cut casing, stamped with the well name and API. Surface location will then be backfilled and restored to pre-operation conditions.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

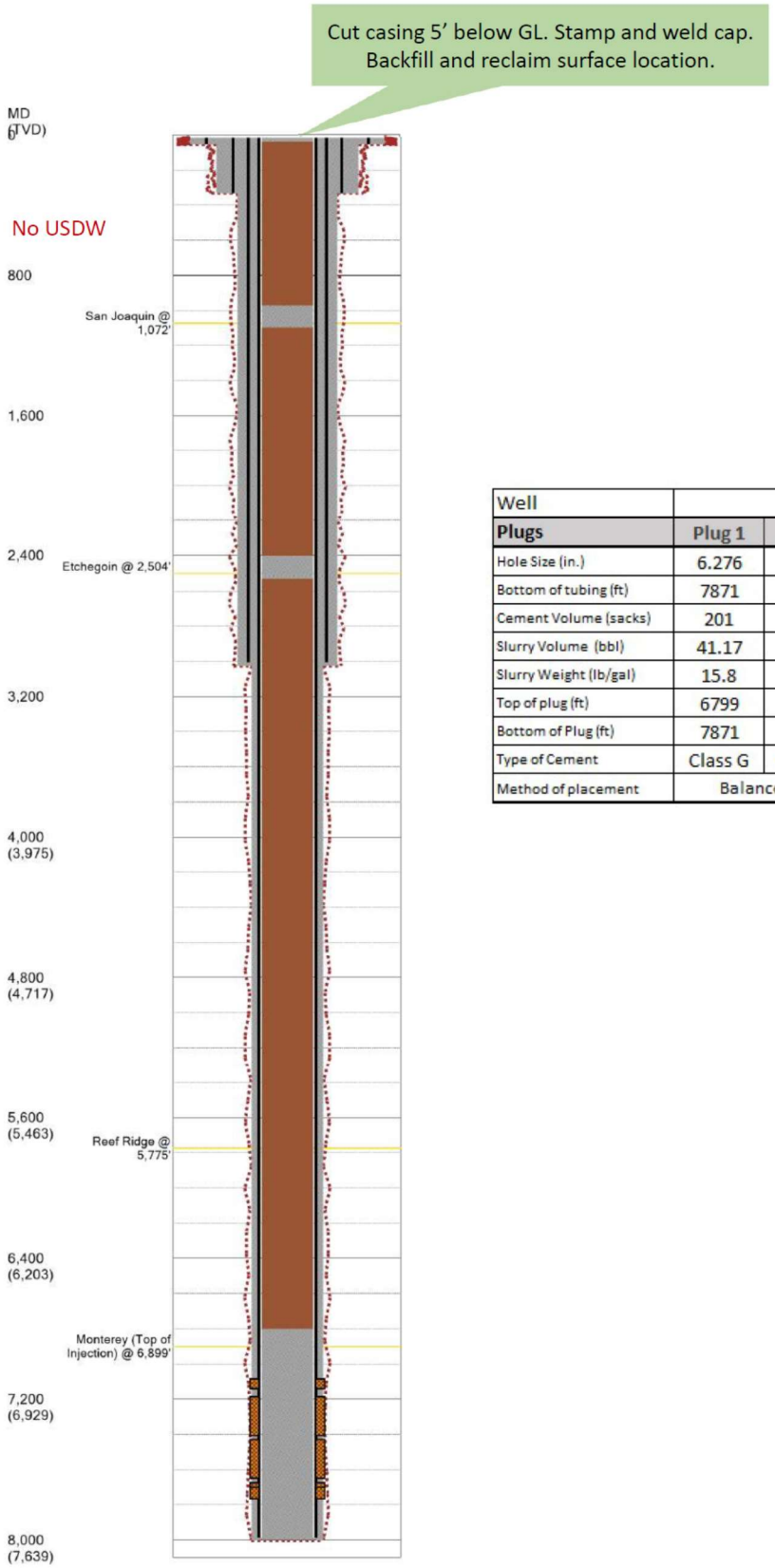
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has <10,000 mg/L TDS):

    - If there is cement behind the casing across the base of USDW (if present), a 100-foot cement plug shall be placed inside the casing across the interface.

    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

    - In 26R, this interval would be located at the top of the San Joaquin formation.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.



Well	373-35R			
Plugs	**Plug 1**	**Plug 2**	**Plug 3**	**Plug 4**
Hole Size (in.)	6.276	6.366	6.366	6.276
Bottom of tubing (ft)	7871	2529	1097	39
Cement Volume (sacks)	201	25	25	5
Slurry Volume (bbl)	41.17	5.12	5.12	1.02
Slurry Weight (lb/gal)	15.8	15.8	15.8	15.8
Top of plug (ft)	6799	2404	972	14
Bottom of Plug (ft)	7871	2529	1097	39
Type of Cement	Class G	Class G	Class G	Class G
Method of placement	Balanced Plug, Retainer, or CT Plug			

Figure 2: Injection Well 373-35R, Abandonment Schematic

ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

CTV I Elk Hills 26R Project

Facility Information

Facility name: Elk Hills 26R Storage Project

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment E -PISC_SC	1	01/11/21
Attachment E -PISC_SC V2	2	05/31/22
Attachment E -PISC_SC V3	3	12/21/22

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault 1 LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

Based on the modeling of the pressure front as part of the AoR delineation, pressure at the injection well is expected to stabilize within one year after injection ceases. Injection limits will be based

on the fracture pressure of the Monterey Formation 26R reservoir and final pressure post injection will target the initial reservoir pressure at the time of discovery. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the AoR and Corrective Action Plan.

Discussion

The Monterey Formation 26R reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. This operating strategy was developed to minimize the potential for induced seismicity and to ensure confinement of the injectate.

The maximum pressure differential between the injection wellbore and the depleted Monterey Formation 26R storage reservoir exists prior to the commencement of CO_2 injection. Through time, the injection pressure differential will shrink, until at the time of project abandonment when the reservoir pressure will be at the initial conditions of the reservoir. Figure 1 shows the pressure of the Monterey Formation 26R reservoir through time from computational modeling.

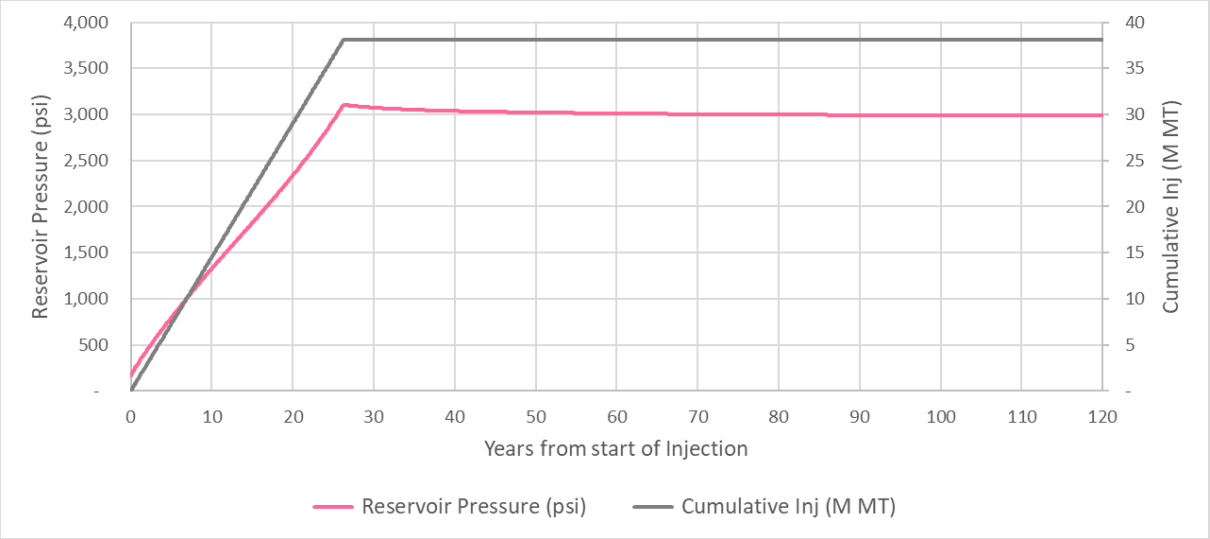


Figure 1: Reservoir pressure and Cumulative injection.

Pressure after 50 and 100 years post-injection are the same in monitoring well 328-25R (Figure 2) indicating plume stabilization. The low water saturation within the Monterey Formation 26R storage reservoir results in 72% of the CO_2 injectate remaining super-critical, minimizing the quantity of CO_2 dissolving in formation water through time.

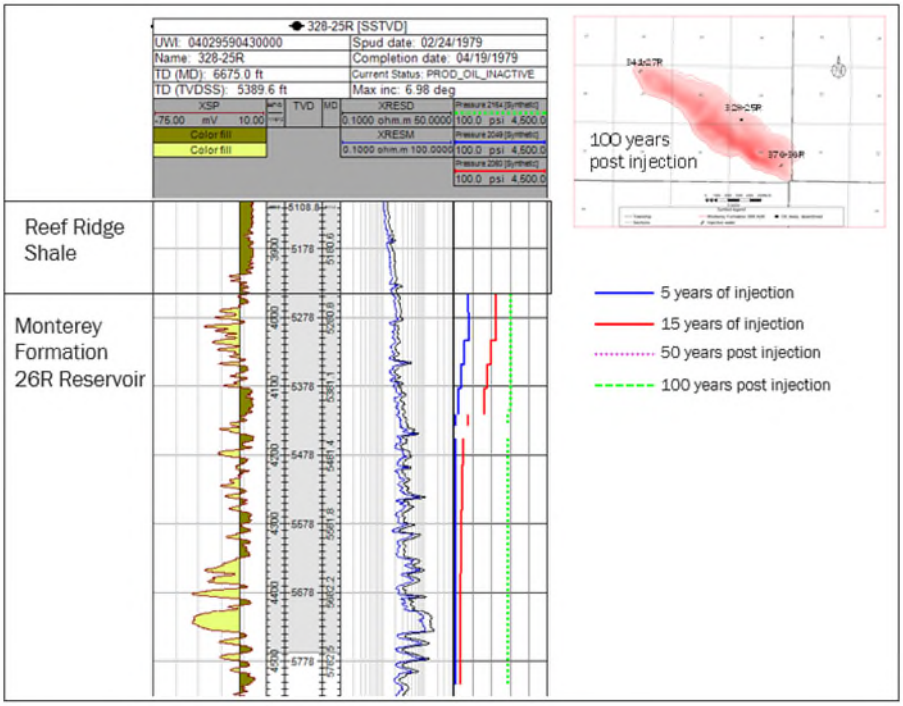


Figure 2: Pressure at the 328-25R monitoring well. Pressure after 50 and 100 years post-injection are the same indicating plume stabilization.

Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 3 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

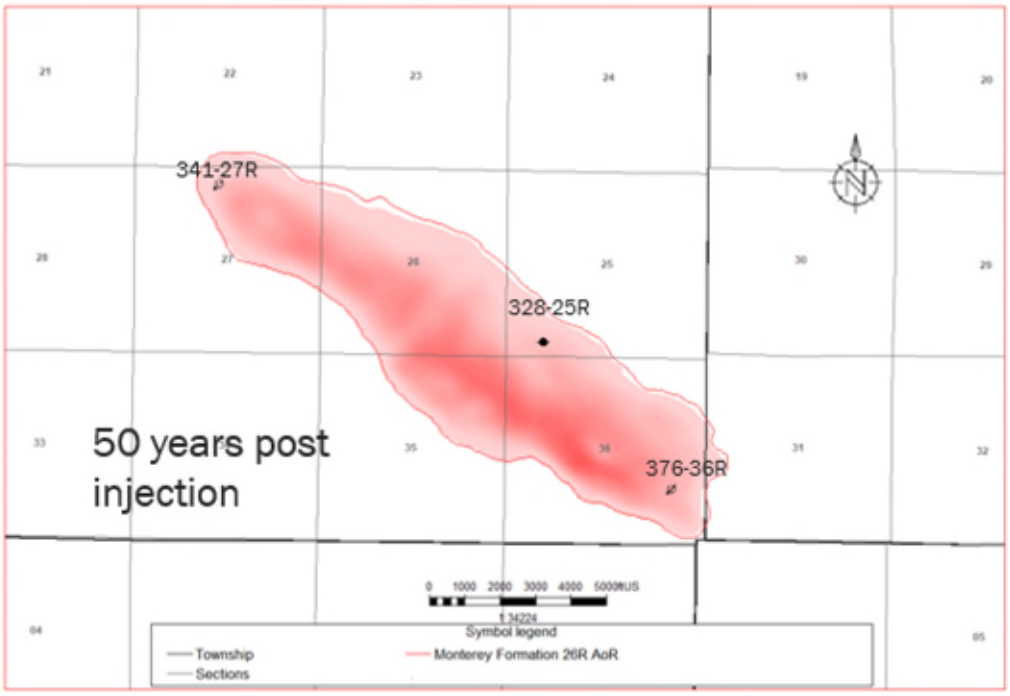


Figure 3: Map of the predicted extent of the CO_2 plume post-injection after 50 years with plume monitoring well locations . The pressure of the 26R reservoir will be at or beneath the initial pressure at the time of discovery.

Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include pressure monitoring and fluid composition monitoring in the storage reservoir and reservoirs above the injection zone. Post-injection monitoring, as described in the following sections, will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days of the anniversary date of final injection, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

The Testing and Monitoring Plan describes the monitoring strategies within the injection zone, above the injection zone, and within the USDW-containing reservoir. In addition to monitoring the zones above the injection zone for stabilized pressure and absence of CO2, the injection zone will be monitored for pressure stabilization as the best method to confirm confinement within the storage reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.

The Quality Assurance and Surveillance Plan (QASP) for all testing and monitoring activities during the injection and post-injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Throughout the AoR there is no USDW groundwater but a zone of unsaturated sands in the Upper Tulare. A shallow groundwater monitoring well will continuously assess reservoir pressure. Groundwater samples will be analyzed annually for indicators of CO_2 movement into the formation.

CTV own the mineral rights for the Monterey Formation 26R reservoir. Surface access is guaranteed for the life of the project as CTV is a wholly owned subsidiary of California Resources Corporation, owner of the surface rights.

Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ. Figure 4 shows the monitoring well locations. Table 3 shows the sampling and recording frequencies for continuous pressure monitoring in the shallow monitoring well. The pressures of these reservoirs may be affected by regional water recharge, injection, or withdrawal. For the Tulare Formation monitoring, CTV will compare these results to other groundwater monitoring wells in the Elk Hills Oil Field.

Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Post-Injection)
Tulare	Fluid Sampling	Shallow Water Monitoring Well	Pump	400’- 450' MD/VD	Annual
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’- 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’- 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	800' - 1100' MD/VD in each well	Continuous
Etchegoin	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Annual
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' MD/VD 4788' - 4811' MD/VD 4205' - 4226' MD/VD	Continuous

Table 2. Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn and T1)	ICP-MS EPA Method 6020
Cations (Ca, FE, K, Mg, Na, Si)	ICP-OEC EPA Method 6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300.0
Dissolved CO2	Coulometric Titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
Alkalinity	Method 2320B
δ13C	Isotope ratio mass spectrometry
pH	EPA 150.1
Total Dissolved Solids (TDS)	Gravimetry; Method 2540 C
Specific Conductance (field)	APHA 2510
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

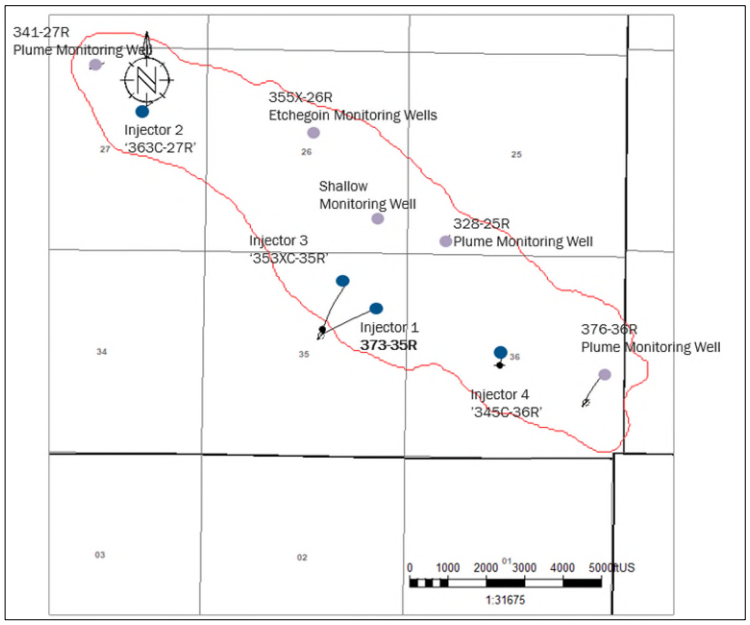


Figure 4: Map showing AoR and well locations for monitoring.

Table 3. Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
During active injection	Pressure Gauge	Shallow Monitoring Well	5 hours	5 hours
Post injection	Pressure Gauge	Shallow Monitoring Well	12 hours	12 hours

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the associated increase in pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the CO_2 plume, including the activities, locations, and frequencies CTV will employ. The parameters to be analyzed as part of fluid sampling in the Monterey Formation 26R (and associated analytical methods) are presented in Table 2.

Table 4. Post-injection phase plume monitoring.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Post-Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm 26R	Fluid Sampling	341-27R	6981' - 7237' MD	Annual
		Pressure		6910' MD	Continuous
		Temperature		6910' MD	Continuous
	Monterey Fm 26R	Fluid Sampling	328-25R	5268' - 5800' MD	Annual
		Pressure		5188' MD	Continuous
		Temperature		5188' MD	Continuous
	Monterey Fm 26R	Fluid Sampling	376-36R	5832' - 6815' MD	Annual

		Pressure		5760' MD	Continuous
		Temperature		5760' MD	Continuous
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	341-27R	6981' - 7237' MD	Every 5 years
			328-25R	5268' - 5800' MD	
			376-36R	5832' - 6815' MD	

Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn and T1)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na and Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300.0
Dissolved CO2	Coulometric Titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
Alkalinity	Method 2320B
δ13C	Isotope ratio mass spectrometry
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Total Dissolved Solids (TDS)	Gravimetry; Method 2540 C
Specific Conductance (field)	APHA 2510
pH (field)	EPA 150.1
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Fluid sampling will be performed as described in B.1. of the QASP. Sample handling and custody will be performed as described in B.3. of the QASP. Quality Control will be ensured using the methods described in B.5. of the QASP.

CTV will employ indirect and direct methods to monitor the pressure front. Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies. Direct monitoring will include pressure gauges to monitor the pressure of the CO_2 plume in the three Monterey Formation 26R monitoring wells. Additionally, seismic monitoring via installed surface and shallow borehole seismometers well will be utilized to detect micro-seismic events. Figures 4 and 5 show the location of the monitoring wells and the predicted extent of the CO_2 plume in map view and cross-section.

Table 6. Post-injection phase pressure-front monitoring.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Post-Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm 26R	Pressure	341-27R	6981' - 7237' MD	Continuous
		Temperature			Continuous
	Monterey Fm 26R	Pressure	328-25R	5268' - 5800' MD	Continuous
		Temperature			Continuous
	Monterey Fm 26R	Pressure	376-36R	5832' - 6815' MD	Continuous
		Temperature			Continuous
Pressure-Front Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Continuous

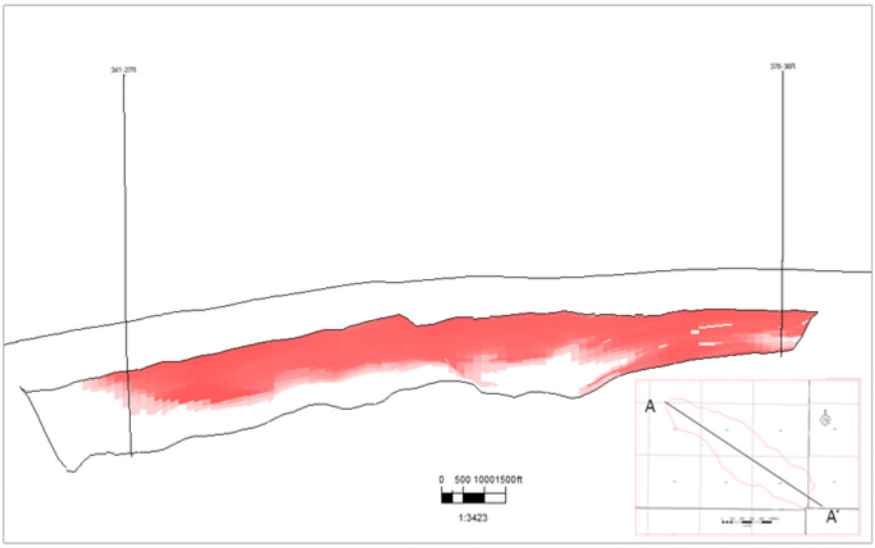


Figure 5: Cross-section showing plume CO2 plume 100 years post injection and 341-27R and 376-36R monitoring wells for post-injection monitoring.

Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period; i.e. well-based monitoring data, sample analysis, and the results from updated site models.

Non-Endangerment Demonstration Criteria [40 CFR 143.93(b)(2) or (3)]

Prior to authorization of site closure, CTV will submit a demonstration of non-endangerment of USDWs to the Director.

CTV will provide a report to the Director that demonstrated USDW non-endangerment based on the evaluation of site monitoring data. The report will detail how the non-endangerment determination is based on site-specific conditions, supported with the computational model. All relevant monitoring data and interpretations will be provided.

Summary of Monitoring Data

A summary of the site monitoring data, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project. Data submission will be in a format acceptable to the Director and will include:

1. A narrative that explains the monitoring activities,

2. Dates of all monitoring events,

3. Changes to the monitoring program over time,

4. An explanation of all monitoring information that has existed at the site,

5. Explanation of how the monitoring data from injection and PISC has varied from the baseline data during site characterization, and

6. Summary of any emergencies that occurred during the injection and post-injection phases of the project. Included will be a description of how any issues have been resolved and that there is no endangerment to the USDW.

Evaluation of the CO2 Plume and the AoR

Computational modeling results calibrated with monitoring data (e.g., pressure) will be used to support that the plume has stabilized and that the pressure change is negligible (less than 10 psi per year) and poses no risk for potential vertical migration. Computational modeling results calibrated with monitoring data from storage reservoir, USDW and above zone will be used to demonstrate:

1. the lack of CO2 leakage over the project timeframe,

2. the accuracy of the model to predict and represent the storage reservoir, and

3. the computational model adequately defined the AoR.

Evaluation of Reservoir Pressure

Monitoring data will be reviewed to ensure that the CO2 plume has stabilized post-injection and that the reservoir pressure change is negligible (less than 10 psi per year). This demonstration will be supported by the computational model that has been calibrated with the most recent monitoring data. The plume is trapped by structure and pinch-out of the reservoir sands. Plume migration is minimal, as such pressure stabilization will be used for non-endangerment assessment.

Evaluation of Potential Conduits for Fluid Movement

Wells that require corrective action will be reviewed and assessed prior to PISC and Site Closure, this includes monitoring wells, injection wells and other wells that penetrate within the AoR and the confining layer. Final demonstration will be made that natural and artificial conduits will not allow fluid migration from the storage reservoir.

Evaluation of Seismicity Monitoring

Demonstration will be made that the plume has stabilized and the pressure change is negligible (less than 10 psi per year), minimizing the risk for induced seismicity after site closure. Final review will be made with the seismicity monitoring to demonstrate seal integrity and that there is no further endangerment of to the USDW

Site Closure Plan [40 CFR 146.93(e)]

CTV will conduct site closure activities to meet the requirements of 40 CFR 146.93(e), with notification to the permitting agencies at least 120 days prior to its intent to close the site. Upon approval of the permitting agencies, CTV will plug the injection and monitoring wells, restore the site, and submit a site closure plan to the EPA. A site closure report will be prepared and submitted within 90 days following site closure supported by the following.

1. Verification of injector and monitoring well plugging,

2. Notifications to state and local authorities as per 40 CFR 146.93 (f)(2)

3. Composition and volume of the injected CO2, and

4. Post-injection monitoring records

CTV will record a notation to the property's deed that will indicate:

1. The property was used for CO2 sequestration, the period of injection and the volume of CO2 injected,

2. The formation that the fluid was injected, and

3. The name of the local agency to which a plat of survey with injection well locations was submitted.

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

CTV I: Elk Hills 26R Project

Facility Information

Facility name: CTV I: Elk Hills 26R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment F -ERR Plan	1	01/11/21
Attachment F -ERR Plan	2	05/31/22
Attachment F -ERR Plan	3	12/10/22

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault I LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

The Emergency and Remedial Response Plan would be implemented in response to events that could be detected in the course of monitoring pursuant to the Testing and Monitoring Plan, including exceedances of Actionable Testing limits described in the QASP (Table 7: Actionable Testing and Monitoring Outputs).

If CTV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.

3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in the individual Well Construction, Operating and Plugging details (COP) documents) is appropriate.

Local Resources and Infrastructure

Resources in the vicinity of the CTV I Elk Hills 26R Project that may be affected as a result of an emergency event at the project site include:

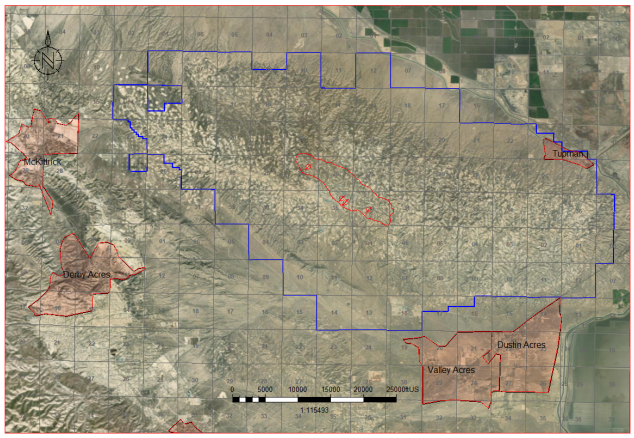
1. Elk Hills oil and gas production resources not associated with the CTV I Elk Hills 26R Project. These oil and gas operations are operated by California Resources Corporation (CRC) an owner of the CTV I Elk Hills 26R Project.
2. Upper Tulare USDW overlying the CO_2 plume. The USDW is not being utilized in the AoR and CTV does not expect usage in the foreseeable future.
3. The nearest census designated area is Valley Acres, 3.6 miles from the AoR. The population was 527 at the 2010 U.S. Census.

Infrastructure in the vicinity of the CTV I Elk Hills 26R Project that that may be affected as a result of an emergency at the project site include:

1. Elk Hills infrastructure owned and operated by CRC that is associated with oil and gas operations.

Resources and infrastructure addressed in this plan are shown in Figure 1.

Figure 1: Map of the site resources and infrastructure. The project is located 3.36 miles from the census designated area of Valley Acres.



Potential Risk Scenarios

The following events related to the CTV I Elk Hills 26R Project that could potentially result in an emergency response:

- Well integrity failure
- Injection well or monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- Potential Brine or CO2 Leakage to a USDW;
- A natural disaster (e.g. tornado, lightning strike); or
- Induced or natural seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

Well Integrity Failure

Integrity loss at the injection well and/or verification well may endanger USDWs. Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).

Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
    - Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

Severity: Low to moderate, dependent on the magnitude of the event.

Timing of event: Injection/Post-Injection

Avoidance measures: Well maintenance, monitoring and control of injection flow and pressure.

Detection methods: Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual (CO_2 at surface).

Potential response actions:

- Notify the plant superintendent and project manager.
- Limit access to wellhead to authorized personnel only.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (loss or increase of pressure or fluid volumes and/or loss of mechanical integrity during testing and maintenance):
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Communicate with CTV personnel and local authorities to initiate evacuation plans, as necessary.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
    - If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
    - Preform a well log/MIT to detect CO2 movement outside of the casing.
    - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).
- For a Minor emergency (downhole and surface sensor/monitoring equipment failure):
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.

- Shut-in injection well and vent CO_2 from surface facilities.
- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
- Perform a well log/MIT to detect CO2 movement outside of the casing.
- Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Injection Well or Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Severity: Low

Timing of event: Injection

Avoidance measures: Well maintenance, and careful monitoring and control of injection flow and pressure.

Detection methods: Anomalies in monitoring data, and visual failure of equipment.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (failure of sensors that will require shutdown of well to repair, requires extended repair time (>48 hours) and/or well intervention to remediate):
    - Contact security to restrict access to the Elk Hills 26R Storage site.

- Communicate with CTV personnel and local authorities to isolate the area and initiate evacuation plans, as necessary.
- Initiate shutdown plan.
- Shut-in injection well and vent CO_2 from surface facilities.
- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
- Verify whether contamination has occurred via handheld CO_2 monitors.
- Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.

- For a Minor emergency (sensor or monitoring failure that does not require shutdown of the well to repair):
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan and refer to Major or Serious emergency guidelines.
  - Evaluate the cause of failure, and mitigate if necessary (i.e., repair equipment).
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response Personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) movement out of the injection zone or CO_2 leakage into a USDW. This may be identified through elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO2 leakage into a USDW. For example, a pressure increase of 50 PSI (not tied to seasonal changes) or a pH of 1.

Severity: Serious

Timing of event: Injection

Avoidance measures: CTV will operate the project to ensure containment of CO_2. Contamination to USDWs will be avoided by:

1. Ensuring injection well integrity through well maintenance and mechanical integrity testing
2. Maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer.
3. Reviewing monitoring well data to understand plume extent.
4. Monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

Detection methods: Pressure or water composition change in Etchegoin Formation or USDW monitoring well. Detection limits are 0.001 PSI for the pressure gauge and 0.2 for pH.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Shut-in all injection wells and vent CO_2 from surface facilities.
    - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
        - Remediate unacceptable impacts to the affected USDW.
    - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
    - Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to aerate CO_2-laden water).
    - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.
    - If there is a well integrity issue perform MITs, refer to the Mechanical Integrity Failure scenario.

- If the leak poses a risk to air quality a perimeter will be established vi hand-held air monitoring devices.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, groundwater remediation equipment, cement or casing and air and water testing equipment.

Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. Natural disasters (e.g. tornado or lightning strike) may disturb surface and/or subsurface facilities.

Severity: Minor to catastrophic

Timing of event: Pre-injection, injection, and/or post injection phases.

Avoidance measures: N/A

Detection methods: N/A

Potential response actions:

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
  - Initiate shutdown plan.
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Shut-in all injection wells and vent CO_2 from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - If contamination has occurred refer to the Potential Brine or CO_2 Leakage to USDW scenario.
  - Communicate with CTV personnel and local authorities to initiate evacuation procedures (if necessary).
  - If there is a well integrity issue for the injector or monitoring well, refer to the Mechanical Integrity Failure scenario.

- Perform MITs on the injection wells to identify if a loss of external mechanical integrity occurred.
- If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

- For a Minor emergency:
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan.
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Shut-in all injection wells and vent CO_2 from surface facilities. Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Induced or Natural Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a two-mile radius of the injection wells.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the Elk Hills 26R site for seismic activity. In addition to the CTV seismic monitoring, the Southern California Earthquake Data Center has deployed a network to monitor natural seismicity in the area.

Severity: Minor to Major

Timing of event: Injection / post injection

Avoidance measures: N/A

Detection methods: The seismic monitoring network.

Potential response Actions:

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table 2. Seismic monitoring system, for seismic events > M1.5 with an epicenter within a two-mile radius of the injection well.

Operating State	Threshold Condition[1,2]	Response Action[3]
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels. 2. Document the event in semiannual reports to the EPA.
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the injection wells if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 5. Document the event in semiannual reports to the EPA.
Orange	Seismic event greater than M1.5 and local observation or felt report Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the injection wells if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 5. Report findings to the UIC Program Director and perform corrective actions. 6. Document the event in semiannual reports to the EPA

[1] Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition[1,2]	Response Action[3]
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate gradual shutdown of the injection wells if it is determined appropriate. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 9. If USDW contamination is detected or endangerment, or CO2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and perform corrective actions. 12. Document the event in semiannual reports to the EPA.
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4]	1. Initiate shutdown plan for all injection wells. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

Operating State	Threshold Condition[1,2]	Response Action[3]
	Or Seismic event >M3.5	4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 8. Determine if leaks to ground water or surface water occurred. 9. If USDW contamination or endangerment is detected, or CO_2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and perform corrective actions. 12. Document the event in semiannual reports to the EPA.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Ken Haney (661- 763-6101)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director (24 hour contact)

Bill Blair (562-743-8336)

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	**Phone Number**
Local police	9-1-1 (Emergency) 661-861-3110 (Non-emergency)
California Governor's Office of Emergency Services (Cal OES)	(916) 845-8506
UIC Program Director (EPA Region 9)	David Albright (albright.david@epa.gov)
EPA National Response Center (24 hours)	800-424-8802
Kern County Fire Department	9-1-1 (Emergency) 661-324-6551 (Non-emergency)
California Air Resources Board (CARB)	800-242-4450
Poison Control Center	800-342-9293
California Office of Emergency Services (24 hours)	800-852-7550
State Water Quality Control Board (Central Valley)	916-255-3000
Kern Medical	661-326-2000

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

Emergency Communications Plan

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For

responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within 30 days, or other time prescribed by the EPA director, following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

Staff Training and Exercise Procedures

All CTV staff and contractors operating at the CO_2 sequestration facilities, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

CO_2 Facilities Training

Onsite and classroom training for facility and infrastructure security, maintenance, and operations.

CO_2 Safety Training

Carbon dioxide detection equipment: Operation and maintenance of personal monitors, portable multi-gas monitors and stationary monitors throughout the facility.

Carbon Dioxide Hazards: Accidental exposure, adverse health effects, workplace exposure limits and first aid.

Emergency Response: Training in the event of CO2 leakage and exercise and drills simulating potential emergency situations.

WELL CONSTRUCTION PLAN

Elk Hills 26R Storage Project

Injection Well 373-35R

Facility Information

Facility Name: Elk Hills 26R Storage Project
373-35R

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – CoP Details_373-35R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – CoP Details_373-35R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – CoP Details_373-35R_V3	3	01/11/23	Revisions made based on questions received from the EPA 01/06/23
Attachment G – CoP Details_373-35R_V4	4	05/14/2023	Revisions made based on questions received from the EPA 03/2023
Attachment G – CoP Details_373-35R_V5	5	11/29/2023	Separating Construction and Plugging Plans into Separate Attachments

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

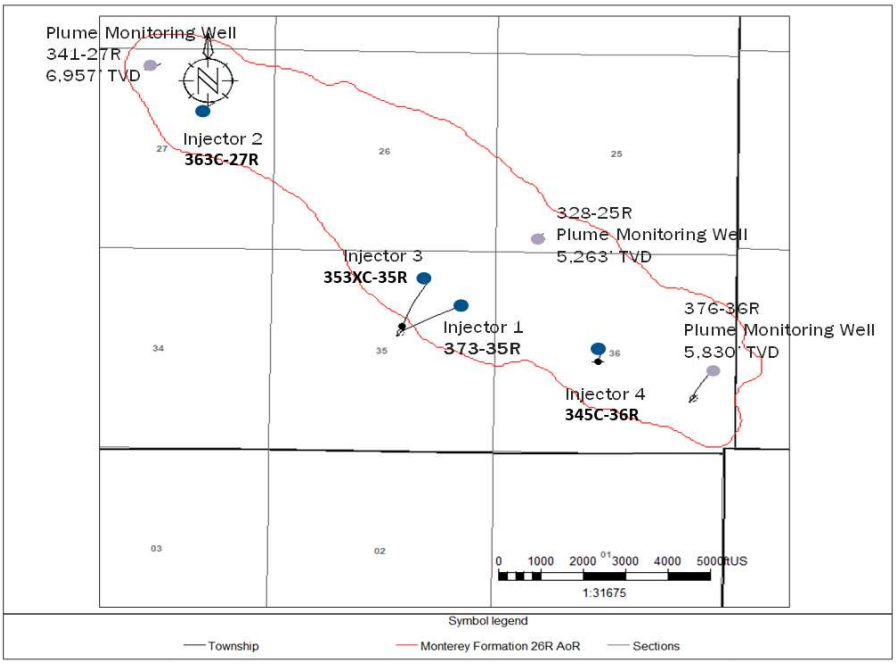


Figure 1: Map showing the location of injection wells and monitoring wells.

Injection well 373-35R is an existing well approved for water injection as part of a UIC approval for pressure maintenance. The well has cumulative injection of 4.7 million barrels of water. As part of the UIC approval, California Resources Corporation (CRC) has conducted mechanical integrity (MIT) and standard annular pressure (SAPT) tests to ensure internal and external mechanical integrity.

Figure 7 and *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Construction Details [40 CFR 146.82(a)(12)]

Injectate Migration Prevention

373-35R was drilled in 1982, at which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the shallow formations, and allow for monitoring, as described by the following:

1. Well design exceeds criteria of all anticipated load cases including safety factors.
2. Although no USDW is present, multiple cemented casing strings protect potential shallow USDW-bearing zones from contacting fluids within the production casing.
3. All casing strings were cemented in place using industry-proven recommended practices for slurry design and placement, and each casing string was cemented to surface.
4. Cement bond log (CBL) indicates presence of cement in the production casing annulus well above the Reef Ridge Shale confining layer and consistent with cementing operations results. Cement is present throughout the entire CBL logging interval within the Monterey and Reef Ridge formations (from base of 7" casing to ~6600 feet).
5. Upper completion design (injection tubulars, packer, and wellhead) enables monitoring devices to be installed downhole, cased hole logs to be acquired, and Mechanical Integrity Testing (MIT) to be conducted.
6. Realtime surface monitoring equipment with alarms and remote connectivity to a centralized facility provides continual awareness to potential anomalous injection conditions.
7. Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment.

Materials

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion:

- Tubing – corrosion-resistant alloy (CRA) consistent with accepted industry practices for corrosion mitigation based on a mixture of formation fluids and injectates.

- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on a mixture of formation fluids and injectates.
- Packer – corrosion resistant alloy material or coating and hardened rubber elastomer element material.
- Casing – the standard N-80 and K-55 casing which is currently installed will be demonstrated to be compatible with the CO_2 injectate through corrosion coupon monitoring as discussed in the Testing and Monitoring document.
- Cement- portland cement has been used extensively in enhanced oil recovery (EOR) producers for decades. Data acquired from existing wells supports that the cement is compatible with CO_2 when good cement bond between formation and casing exists within the Injection and Confining Zones.

Standards

Well materials follow the following standards:

1. API Spec 5CT / ISO 11960 – Specification for Casing and Tubing
2. API Spec 5CRA / ISO 13680 – Specification for Corrosion-Resistant Alloy Seamless Tubes for use as Casing, Tubing, and Coupling Stock
3. API Spec 10A / ISO 10426-1 – Cements and Materials for Cementing
4. API Spec 11D1 / ISO 14310 – Downhole Equipment – Packers and Bridge Plugs
5. API Spec 6A / ISO 10423 – Specification for Wellhead and Tree Equipment

Casing

The Monterey Formation temperature in 26R is approximately 210 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet industry standards. Temperature differences between the CO_2 injectate and reservoir will not affect well integrity. The casing will not experience loads from CO_2 injection beyond the designed capability of the well including safety factors. Subsidence has not been observed historically in the areas around the injection wells because of hydrocarbon production, and shallow compression is not anticipated as a concern for casing or cement integrity.

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure specified in the Operational Procedures section. Casing corrosion logging data to be collected during pre-operational testing will be used to ensure the current condition of the casing will withstand CO_2 injection load cases expected with the project.

Table 1: Casing Specifications for the 373-35R injector

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14 – 54	20.000	19.124	94	--	--	2.62	--	--
Surface	14 – 331	13.375	12.715	48	H-40	Short	2.62	1,730	740
Intermediate	14 – 3,006	9.625	8.835	40	K-55	Long	2.62	3,950	2,570
Long-string	14 – 79 79 – 5,028 5,028 – 6,618 6,618 – 7,988	7.000	6.276 6.366 6.276 6.276	26 23 26 26	N-80 K-55 K-55 N-80	Long	2.62	7,240 4,360 4,980 7,240	5,410 3,270 4,320 5,410

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

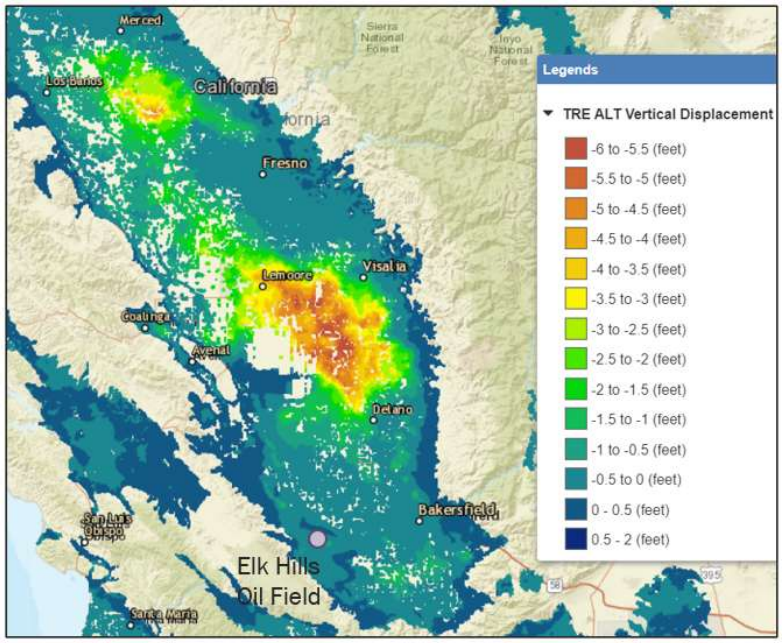


Figure 2: Subsidence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Cement

Class G portland cement has been used to cement the well. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2. The 13-3/8" casing string was cemented with returns to surface. The 9-5/8" casing string was cemented with returns to surface. The 7" casing string was cemented in place with Class G portland cement followed with cemented to surface by annular top squeeze. Subsequently, a CBL was run from 6600' – 7900' and indicates annular isolation throughout and above the Monterey and Reef Ridge formations.

Protection of USDW

No USDW is present within the AoR. However, if USDW is discovered within the AoR in the future, the USDW and all strata overlying the injection zone will be protected by the following:

1. Surface casing is set and cemented to surface within the potential USDW interval, providing multiple protective barriers to ensure protection of the potential USDW above the casing point.
2. The intermediate casing string is set across the base of the potential USDW, and annular cement isolates the potential USDW from the injection string by providing multiple protective barriers to ensure protection of potential USDW.
3. The cement bond log on the 7" casing string indicates annular cement within and above the injection and confining zones, providing adequate isolation of the potential USDW from CO_2 injectate.
4. SAPT tests pressure the well annulus to demonstrate isolation of primary and secondary barriers for the protection of potential USDW. All SAPT's demonstrate that the production casing, tubing, packer, and wellhead have mechanical integrity. Casing/tubing annulus pressure tests to 500 psi for 30 minutes have been acquired through time. SAPT will be acquired before the start of injection and every five years thereafter.
5. If mechanical integrity issues are indicated through monitoring during injection, CTV will perform diagnostics and remediate as necessary.

Tubing and Packer

Table 2 provides injection tubing specifications as the well will be configured at the time of injection and supports the requirements of 40 CFR 146.86(c). The tubing and packer that are currently installed will be removed prior to injection. A suitable corrosion-resistant alloy will be installed once the CO_2 stream impurities and impurity concentrations have been determined. The grade identified in Table 2 is anticipated to be acceptable.

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 2. Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection Tubing	7,050	4.50	4.000	11.6	L-80 CRA	Premium	7,780	6,350

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 3 provides specifications of a sealbore packer suitable to use in this application. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel. The proposed packer setting depth is within a cemented interval of the 7" casing string.

Table 3. Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	7,020	30.3	26-32	5.875	4.000

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rates, injection pressure, and annular pressure monitoring and alarms. The

Operating Procedures plan detail the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The EPA Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design 373-35R with a surface shut-off valve at the wellhead and not a down-hole device.

Logging and Testing

The following data have been acquired during the initial well construction or during subsequent operations. Data required pursuant to 40 CFR 146.87 that is not presented and has not been acquired will be addressed in the Pre-Operational Testing plan document.

Deviation Checks During Drilling

Deviation checks were acquired during drilling at varying frequency from ~3,181' feet measured depth (MD) to bottom hole at 8,001 feet MD (Table 4).

Table 4: Deviation checks during drilling for the 373-35R well.

MD	INC	AZI	TVD		MD	INC	AZI	TVD
3,181.00	0.25	250.85	3,180.90		5,344.00	21.5	61.85	5,225.10
3,255.00	2	42.85	3,254.90		5,413.00	21	62.85	5,289.40
3,286.00	3.25	49.85	3,285.90		5,502.00	21.75	61.85	5,372.20
3,349.00	6	52.85	3,348.70		5,660.00	21.5	61.85	5,519.10
3,412.00	9.25	60.85	3,411.10		5,816.00	21.5	62.85	5,664.30
3,442.00	10.75	58.85	3,440.70		5,940.00	21.75	62.85	5,779.50
3,515.00	13.25	55.85	3,512.10		6,056.00	21.25	73.85	5,887.50
3,577.00	14.75	55.85	3,572.20		6,088.00	22	77.85	5,917.30
3,672.00	15.75	59.85	3,663.90		6,163.00	23.75	81.85	5,986.40
3,766.00	17.5	59.85	3,754.00		6,322.00	24	78.85	6,131.80
3,860.00	19	61.85	3,843.20		6,479.00	24	76.85	6,275.20
3,955.00	20.5	63.85	3,932.60		6,542.00	23.75	74.85	6,332.80
4,019.00	21.75	64.85	3,992.30		6,668.00	24.25	72.85	6,447.90
4,152.00	22.25	63.85	4,115.60		6,795.00	24.75	69.85	6,563.50
4,308.00	21.75	64.85	4,260.30		6,859.00	24.75	65.85	6,621.60
4,498.00	21.75	63.85	4,436.80		6,922.00	25	65.85	6,678.80
4,656.00	21.75	62.85	4,583.50		7,016.00	25.75	59.85	6,763.70
4,807.00	21.25	62.85	4,724.00		7,126.00	26.75	55.85	6,862.40
4,996.00	21	62.85	4,900.30		7,265.00	26.5	53.85	6,986.60
5,123.00	20.75	61.85	5,019.00		8,001.00	28.25	50.85	7,640.20
5,246.00	21.25	60.85	5,133.80					

Open Hole Log Analysis

Open-hole wireline log data was acquired prior to installation of 7" casing long string. Figure 3 provides the results of these measurements that include spontaneous potential, natural gamma ray, and borehole caliper in track 1 (leftmost), resistivity in track 2 (second from left), neutron porosity and bulk density in track 3, permeability in track 4, porosity in track 5, and lithology in track 6 (right most).

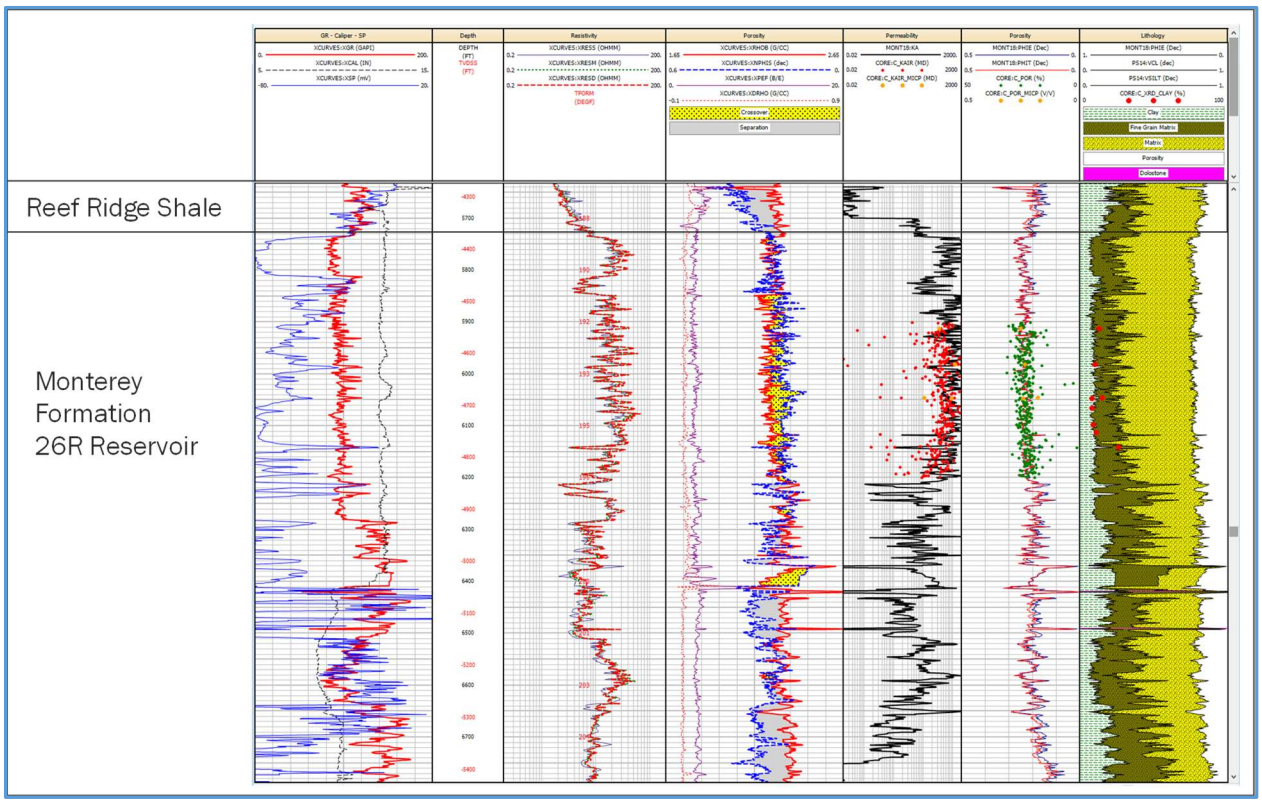


Figure 3: Open-hole well logs for 373-35R before installation of long string.

Cement Evaluation

The cement bond log amplitude and variable density log (VDL) show isolation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 4). Late VDL arrivals show the presence of cement throughout the interval and bond from cement to formation. The CBL acquired at the time of construction was not logged across the entire 7" casing interval. The top of cement was not observed deeper than 6600', the top of the cement bond logging interval. The Pre-Operational Testing plan document specifies additional cement evaluation logging to be performed across the entire 7" casing string during pre-operational testing.

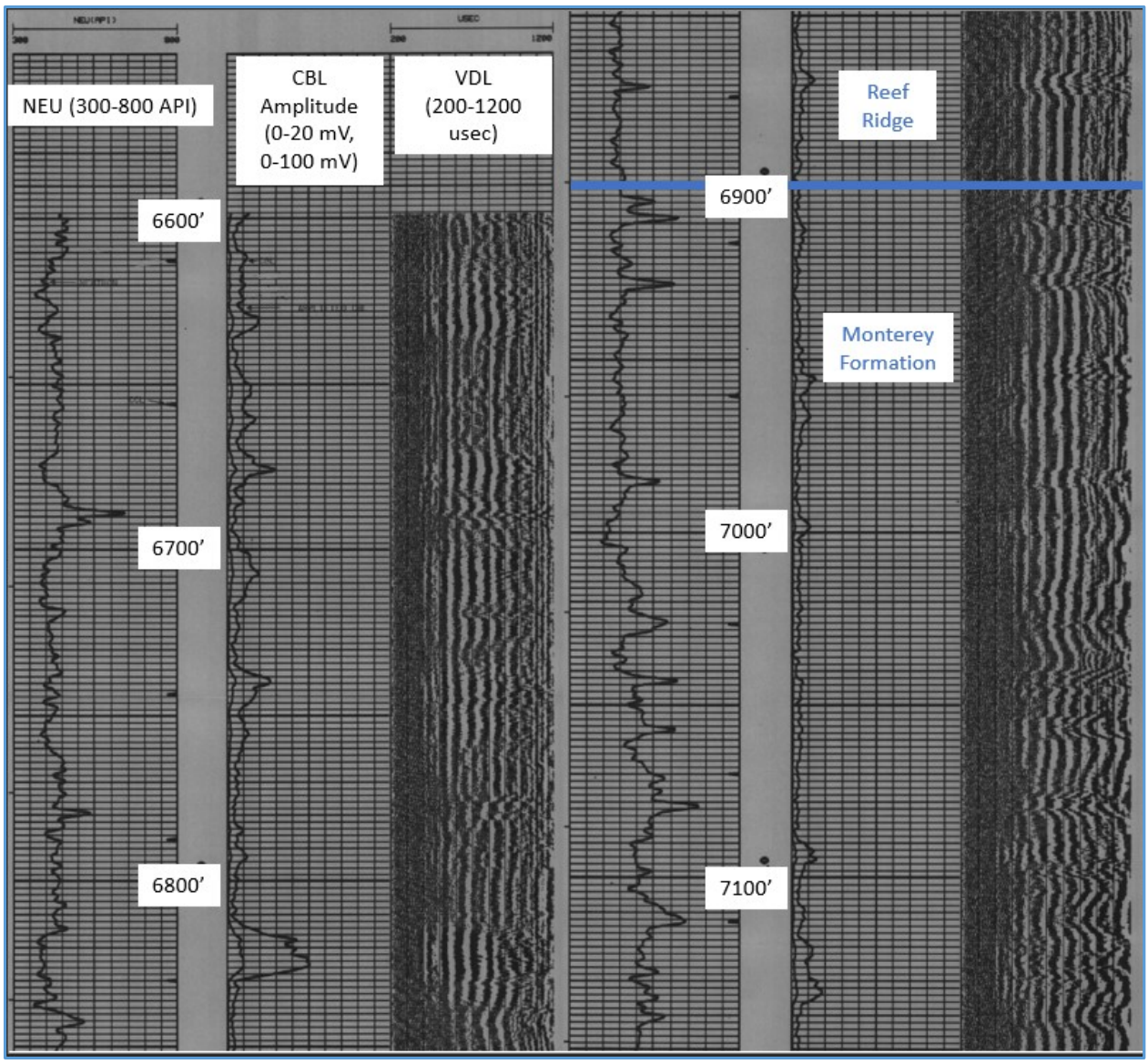


Figure 4: Cement bond log example for 373-35R, after installation of long string casing. The Monterey Formation 26R top is at 6,900 feet.

MIT – Internal: Standard Annular Pressure Test (SAPT)

The most recent standard annular pressure test, dated August 10th, 2020, is displayed in Figure 5. It demonstrates that the annulus can hold pressure more than 500 psi without gain or loss for 30 minutes indicating mechanical integrity of the tubing, casing, and packer as the well is currently configured. SAPT will be conducted again during installation of CRA tubing string prior to injection, and this procedure will be addressed in the Pre-Operational Testing plan document.

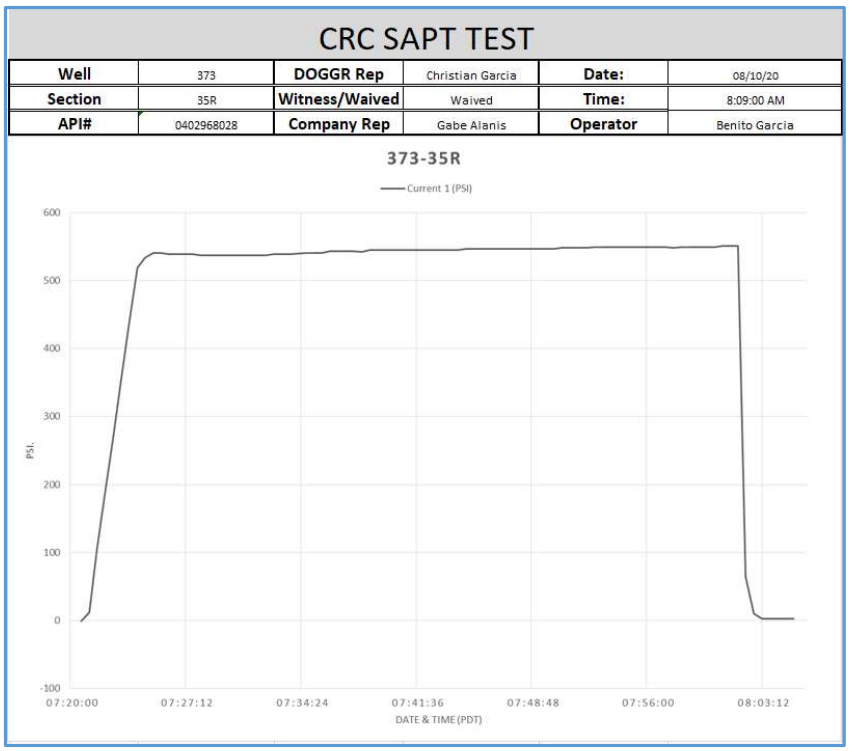


Figure 5: SAPT for 373-35R showing mechanical integrity of the tubing, casing, and packer.

MIT – External: Tracer Survey and Temperature Log

The tracer survey in Figure 6 was acquired on February 26th, 2020. The survey utilizes radioactive tracer to determine injection zone conformance. The interpreted log below indicates valid tubing integrity and no migration of injectate around the top perforation at 7086' or at the packer at 7050'. The analysis indicates that all injection fluid is entering perforations below ~7450'. The temperature profile in green confirms the results.

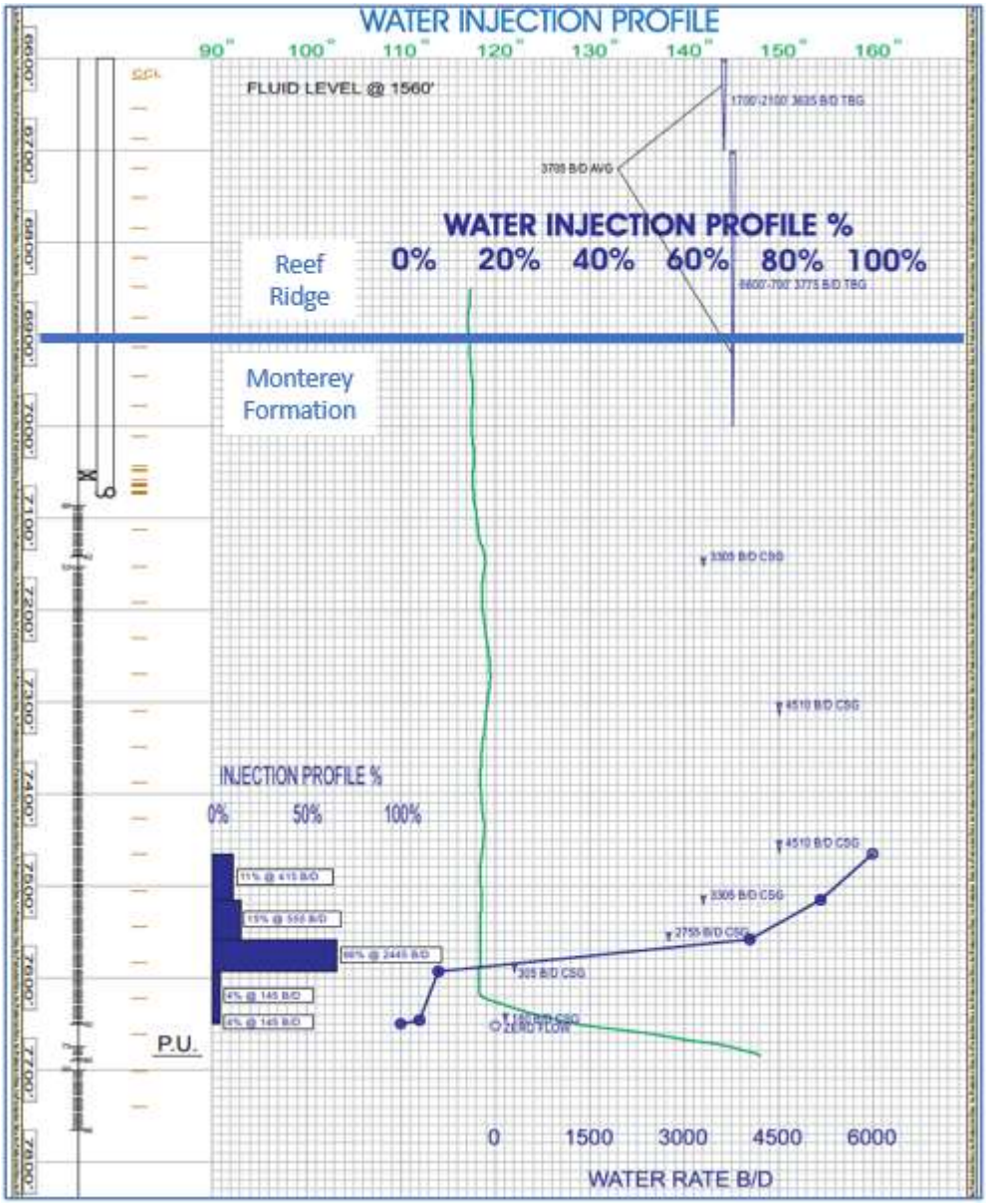


Figure 6: Radioactive tracer and temperature survey for well 373-35R showing mechanical integrity of the tubing and isolation of the perforation by the packer.

Planned Well Retrofitting

Prior to first injection, the existing wellbore will be reconfigured for injection through the following procedure:

1. Install and test Blowout Prevention Equipment (BOPE)
2. Pull existing injection tubing and packer
3. Clean out well to Plugback Measure Depth (PBMD)
4. Acquire remaining pre-operational phase data per Att G and T&M docs

5. Install CCS injection tubing, packer, injection tree, and all monitoring equipment per T&M, well schematics.
6. Perform Standard Annular Pressure Test (SAPT) per T&M procedure
7. Perform injectivity test and pressure falloff test
8. Suspend well temporarily for CCS project startup

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the reviews. This information is summarized below (along with the planned tests that will address each data need that was described in the initial permit application materials submitted in November 2021) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c) and 146.87.

Regional Geology and Geologic Structure

• Perform pressure build-up testing (anticipated testing method: pressure build-up test).

• Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

• Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

• Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

• Determine if there are any heterogeneities within the Monterey 26R injection zone that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; planned and completed core, log, and seismic analysis).

CO2 Stream Compatibility with Subsurface Fluids and Minerals

• Confirm the composition and water content of the CO2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses, benchtop studies).

• Confirm that the properties of the CO2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).

• Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of the geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

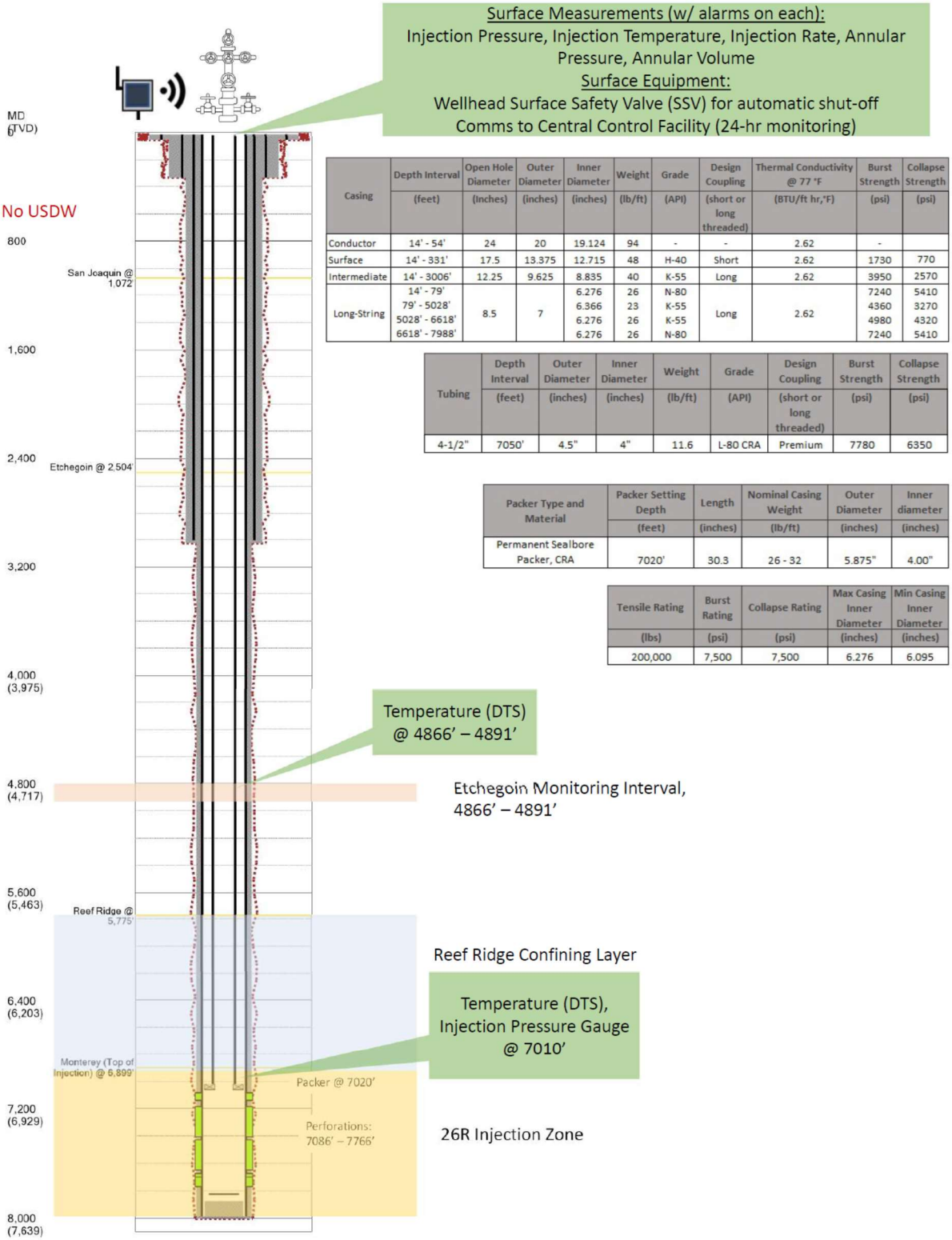
• Collect baseline pressure data in the Etchegoin Formation to support upward confinement between the Monterey and shallower formations (anticipated testing method: pressure build-up test).

• Determine the porosity and permeability of the Reef Ridge Shale at the location of each of the 26R project wells (anticipated testing methods: core and log data during well drilling).

• Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

• Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).



Casing	Depth Interval (feet)	Open Hole Diameter (inches)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)	Thermal Conductivity @ 77 °F (BTU/ft hr,°F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14' - 54'	24	20	19.124	94	-	-	2.62	-	
Surface	14' - 331'	17.5	13.375	12.715	48	H-40	Short	2.62	1730	770
Intermediate	14' - 3006'	12.25	9.625	8.835	40	K-55	Long	2.62	3950	2570
Long-String	14' - 79' 79' - 5028' 5028' - 6618' 6618' - 7988'	8.5	7	6.276 6.366 6.276 6.276	26 23 26 26	N-80 K-55 K-55 N-80	Long	2.62	7240 4360 4980 7240	5410 3270 4320 5410

Tubing	Depth Interval (feet)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)	Burst Strength (psi)	Collapse Strength (psi)
4-1/2"	7050'	4.5"	4"	11.6	L-80 CRA	Premium	7780	6350

Packer Type and Material	Packer Setting Depth (feet)	Length (inches)	Nominal Casing Weight (lb/ft)	Outer Diameter (inches)	Inner diameter (inches)
Permanent Sealbore Packer, CRA	7020'	30.3	26 - 32	5.875"	4.00"

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max Casing Inner Diameter (inches)	Min Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Figure 7: Injection Well 373-35R, CO_2 Injection Schematic

ATTACHMENT H: FINANCIAL ASSURANCE DEMONSTRATION
40 CFR 146.85

CTV I: Elk Hills 26R Project

Document Version History

Version	Revision Date	File Name	Description of Change
1	9/29/2023	Att H_Financial Responsibility_26R	Compilation of financial responsibility documents in one attachment

Facility Information

Facility name: CTV I: Elk Hills 26R

Facility contact: Travis Hurst / Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Financial Instruments

Carbon TerraVault (CTV) is providing financial responsibility information pursuant to 40 CFR 146.85. CTV is using the following financial instruments:

- Letter of Credit to cover the costs of corrective action, injection well plugging, post-injection site care, and site closure.
- Certificate of Insurance to cover costs of emergency and remedial response

The estimated costs of each of these activities, as provided by CTV, are presented in Table 1.

CTV has provided financial assurance for Emergency and Remedial Response by procuring an environmental insurance policy. If needed the limits will be re-determined by a reasonable estimate of the cost of these activities prior to the commencement of injection operations. The Elk Hills 26R project environmental insurance policy covers all emergency and remedial response activities arising from the assets. The selected insurance carrier has issued a financial assurance certificate in compliance with state and federal regulations that is provided below.

Table 1. Cost Estimates for Activities to be Covered by Financial Responsibility.

Activity	Instrument	Total Cost ($)
Corrective Action	Letter of Credit	111,320
Plugging Injection Wells	Letter of Credit	1,197,840
Post-Injection Site Care	Letter of Credit	6,790,750
Site Closure	Letter of Credit	994,750
Emergency and Remedial Response	Certificate of Insurance	24,578,125

The following supporting information is provided below to satisfy Financial Responsibility requirements:

- Daniel B. Stephens & Associates, Inc. (DBS&A) third party cost estimate
- Deutsche Bank AG Irrevocable Standby Letter of Credit
- Irrevocable Standby Letter of Credit Notification Letter
- Bank of New York Mellon Standby Trust
- Letter of Credit Cost Estimate and Funding Value Summary
- Ascot Certificate of Insurance
- Insurance Endorsement
- Financial Strength Demonstration

DBS&A THIRD PARTY COST ESTIMATE

CLASS VI FINANCIAL RESPONSIBILITY DEMONSTRATION

COST ESTIMATE

CTV I 26R

Carbon TerraVault (CTV) had the following cost estimate prepared by third party contractor, Daniel B. Stephens & Associates, Inc., completed on 9/5/2023.

Table 1. Financial Responsibility Cost Summary

Activity	Estimated Cost	Reference
Corrective Action	$ 111,320	Table 2
Injection Well Abandonment	$ 1,197,840	Table 3
Post-Injection Site Care	$ 6,790,750	Table 4
Site Closure	$ 994,750	Table 5
Emergency and Remedial Response	$ 24,578,125	Table 6
Total	**$**	**33,672,785**

All values in 2022 dollars

Table 2. Costs, Corrective Action Total

Activity	Unit		Unit Cost	Total	Reference
Revise Numerical Model	400	hrs	$ 220	$ 88,000	-
Review CalGEM Well Database	40	hrs	$ 220	$ 8,800	-
Plug Deficient Wells	0	wells	-	$ -	A
Project Management	1	each		$ 14,520	B
			Total	**$ 111,320**	

Notes

A: Per Attachment B, as required wells will be abandoned prior to injection as part of asset retirement obligations

B: 15% of project costs

Table 3. Costs, Injection Well Abandonment

Location	Unit Cost		Depth (ft)	Cost	Reference
Injector 4 345C-36R	30	$/ft	8,680	$ 260,400	A
Injector 1 373-35R	30	$/ft	8,680	$ 260,400	A
Injector 3 353XC-35R	30	$/ft	8,680	$ 260,400	A
Injector 2 363C-27R	30	$/ft	8,680	$ 260,400	A
Documentation, project management	1	each	-	$ 156,240	B
			TOTAL	**$ 1,197,840**	

Notes

A: Abandonment costs from Driltek, 2021; well construction from Attachment G 'Injection Well 1 353XC-35R', Table

B: 15% of project costs

Table 4. Post Injection Site Care Costs

Activity	Unit		Events, 50 years	Unit Cost	Total	Reference
USDW geochemical monitoring/fluid sampling	1	well	50	$ 6,000	$ 300,000	A
Above Confining zone geochemical, pressure monitoring	1	well	50	$ 5,600	$ 280,000	A
Injection zone geochemical, pressure monitoring	3	well	50	$ 5,600	$ 840,000	A
Monitoring well O&M, Above confining zone	1	well	3	$ 30,000	$ 90,000	B
Injection zone monitoring well O&M	3	wells	10	$ 84,000	$ 2,520,000	-
Indirect Plume Monitoring (Pulsed neutron)	1	survey	10	$ 37,500	$ 375,000	C
Mechanical Integrity Test, Injection zone	3	well	10	$ 50,000	$ 1,500,000	B
Reporting/Project Management	1	each	-	$ 885,750	$ 885,750	D
				Total	**$**	**6,790,750**

Notes:

A: Assumes 1 geochemical monitoring event per year per well and continuous pressure monitoring with automated gage; shallow groundwater well have a higher testing cost than the other monitoring wells due to the potential time required to obtain a stabilized sample from a reservoir with low water deliverability.

B: Patrick Engineering, 2013; assumes $2,000 base cost + $4.25/ft (+12%)

C: Zaluski et al., 2016; assumes 8 well survey (inflation adjusted); technology and frequency from PISC plan Table 4

D: 15% of project costs

Assumes:

1 USDW Monitoring Well (exempt or unsaturated)

1 Above Confining Zone Monitoring Well

3 Injection Zone Monitoring Wells

4 Injection wells

Table 5. Costs, Site Closure

Activity	Unit		Unit Cost	Total	Reference
Non-endangerment report	1	each	$ 45,000	$ 45,000	-
Injection zone monitoring well plugging	3	wells	$ 200,000	$ 600,000	A
Above-confining zone monitoring well plugging	1	wells	$ 170,000	$ 170,000	A
USDW Monitoring well plugging	1	well	$ 50,000	$ 50,000	
Plugging documentation, project management	1	each		$ 129,750	B
			Total	**$**	**994,750**

Notes
A: Abandonment costs from Driltek, 2021
B: 15% of project costs

Assumes:
1 USDW Monitoring Well (exempt or unsaturated)
1 Above Confining Zone Monitoring Well
3 Injection Zone Monitoring Wells
4 injection wells

Table 6. Emergency Response

Groundwater Contamination Causal Investigation

Activity	Unit		Unit Cost	Total	Reference
Planning/permitting	1	each	$ 1,381,875	$ 1,381,875	B
Monitoring wells, depth 1,000 ft	5	well	$ 385,000	$ 1,925,000	A
Monitoring wells, depth 5,000 ft	3	well	$ 1,925,000	$ 5,775,000	A
Abandoned well investigation	51	well	$ 27,500	$ 1,402,500	D
Former Injection Well Investigation	4	well	$ 27,500	$ 110,000	-
Reporting/Project Management	1	each	$ 921,250	$ 921,250	C
Total				**$**	**11,515,625**

Groundwater Contamination Remediation

Activity	Unit		Unit Cost	Total	Reference
Planning/permitting	1	each	$ 1,567,500	$ 1,567,500	B
Pumping well, depth 1,000 ft	4	well	$ 350,000	$ 1,400,000	A
Pumping well, depth 5,000 ft	4	well	$ 1,925,000	$ 7,700,000	A
Groundwater extraction	1	year	$ 300,000	$ 300,000	-
Above-ground CO_2 removal (aeration)	1	unit	$ 150,000	$ 150,000	-
Former injection well repair	4	well	$ 225,000	$ 900,000	-
Reporting/Project Management	1	each	$ 1,045,000	$ 1,045,000	C
Total				**$**	**13,062,500**

Total, Causal Investigation and Remediation	**$**	**24,578,125**

Notes

A: Assumes $385/ft for permitting, installation, field oversight, logging drilling, and waste

B: 15% of project costs

C: 10% of project costs separate from Planning/permitting

D: Assumes 25% of wellbores penetrating Reef Ridge Formation, Attachment B Table 9

References

Driltek, 2021: Personal communication with Driltek regarding well abandonment costs, California

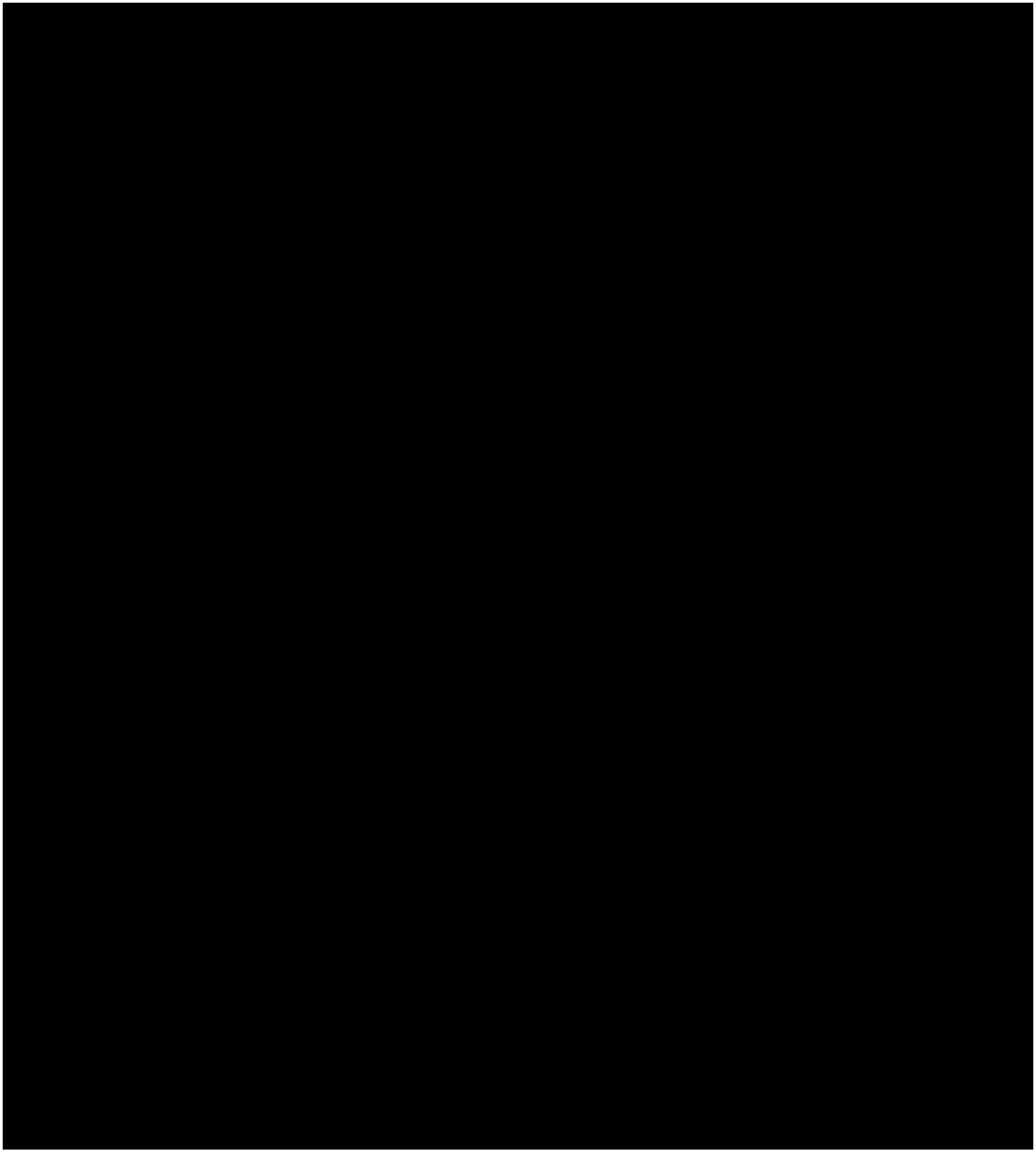
Patrick Engineering, 2013: Third Party Cost Estimate for FutureGen Alliance UIC Class VI Permit Application

Zaluski et al., 2016. Monitoring technology ranking methodology for CO2-EOR sites using the Weyburn-Midale Field as a case study, IJGGC v.54, p.466 - 478

DEUTSCHE BANK AG IRREVOCABLE STANDBY LETTER OF CREDIT

Deutsche Bank

Deutsche Bank AG New York Branch
Trade Finance & Lending
1 Columbus Circle, 17th Floor



Deutsche Bank AG New York Branch
Trade Finance & Lending
1 Columbus Circle, 17th Floor
New York, NY 10019



Very truly yours,
Deutsche Bank AG
New York Branch

[Signature(s) and title(s) of official(s) of issuing institution]

Chairman of the Supervisory Board: Alexander R. Wynaendts
Management Board: Christian Sewing (Chairman), James von Moltke, Karl von Rohr, Fabrizio Campelli, Bernd Leukert, Alexander von zur Mühlen, Christiana Riley, Rebecca Short, Stefan Simon, Olivier Vigneron
Deutsche Bank Aktiengesellschaft domiciled in Frankfurt am Main; Local Court of Frankfurt am Main, HRB No 30 000; VAT ID No DE114103379; www.db.com

IRREVOCABLE STANDBY LETTER OF CREDIT NOTIFICATION LETTER

September 6, 2023

United States Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, D.C. 20460
Attention: UIC Program Director

Re: EPA Identification Number: _____.

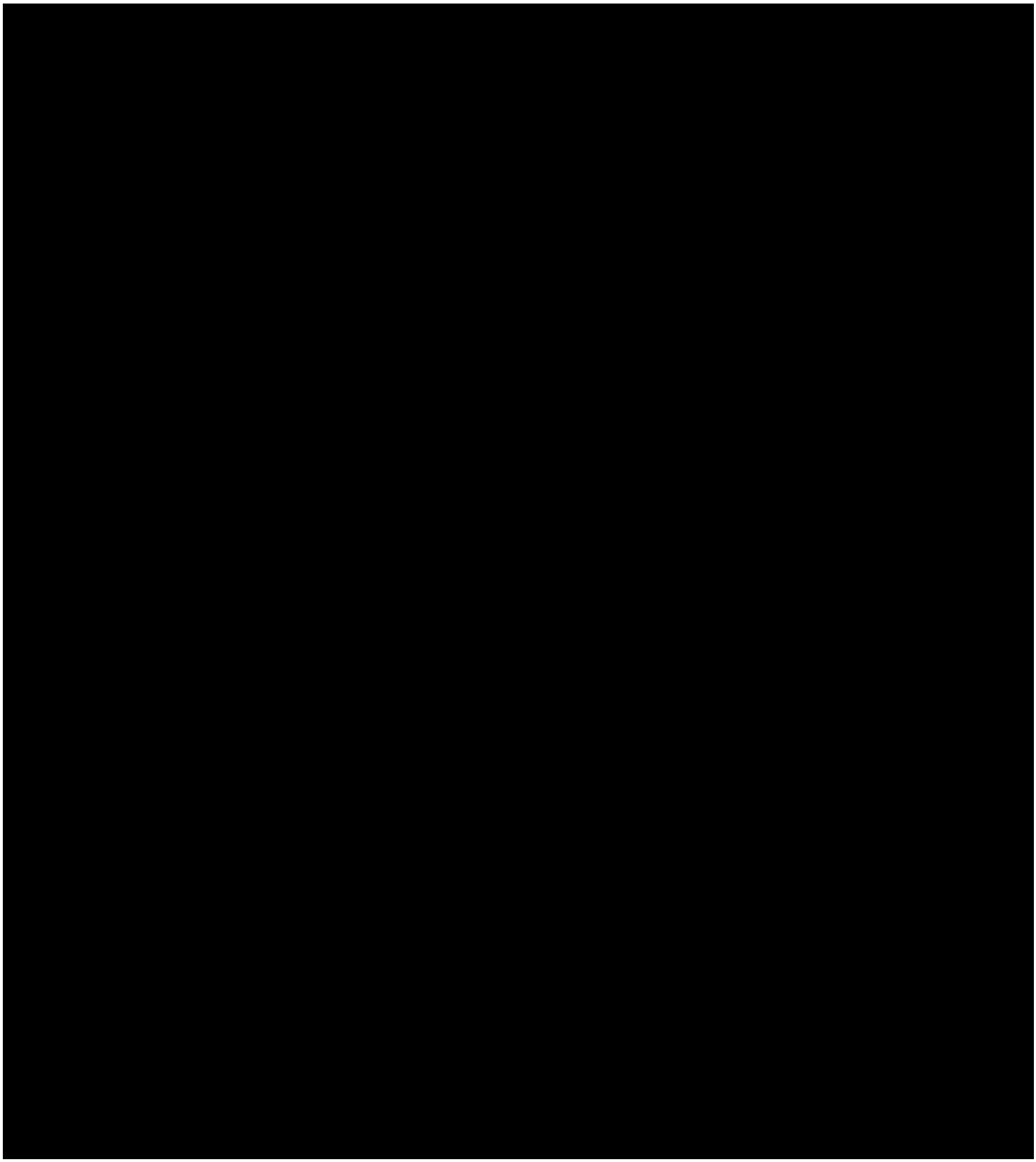
Dear UIC Program Director,

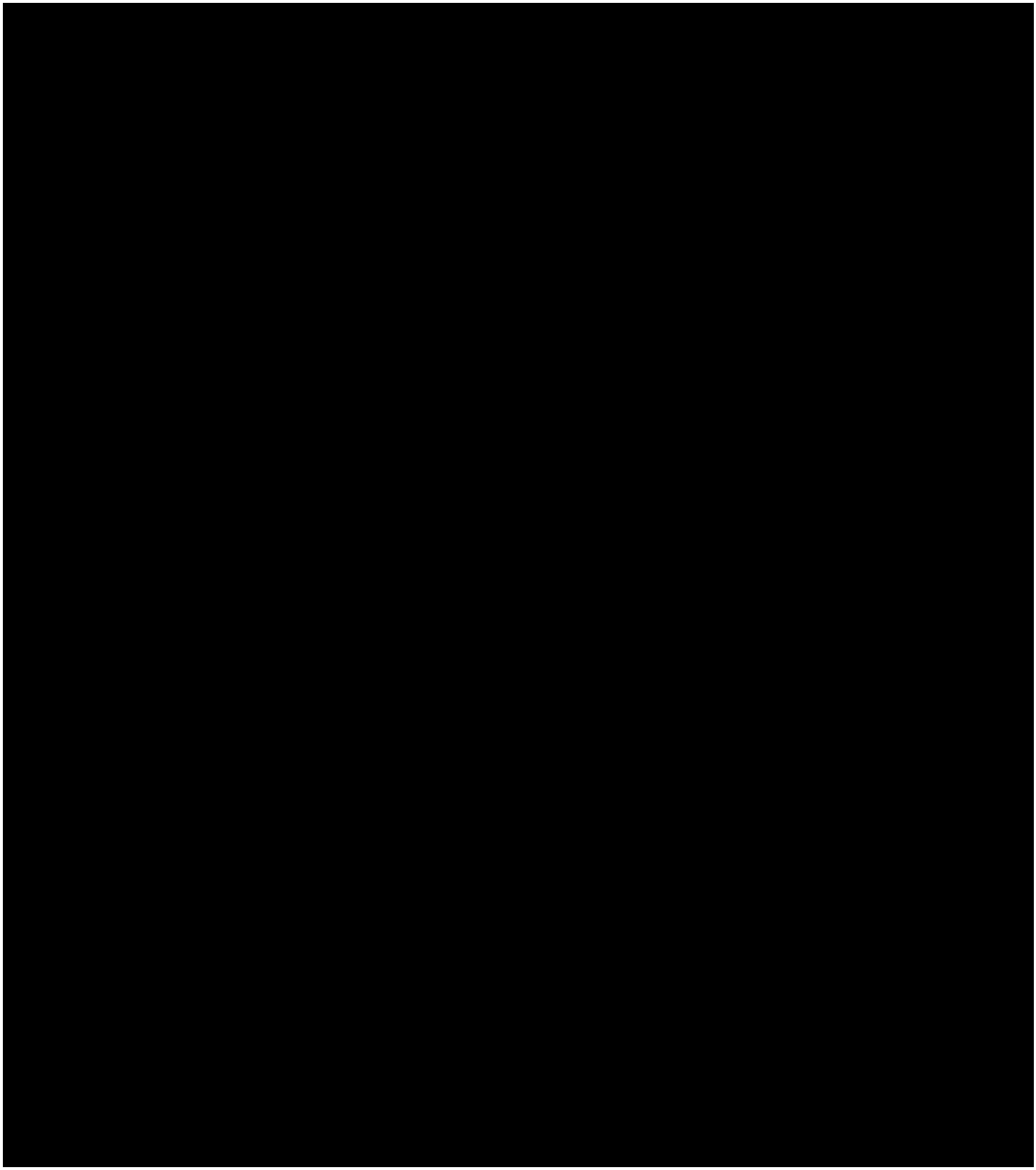
At our direction, effective _____, Deutsche Bank AG New York Branch issued a $_____ Irrevocable Standby Letter of Credit No. _____ in your favor.

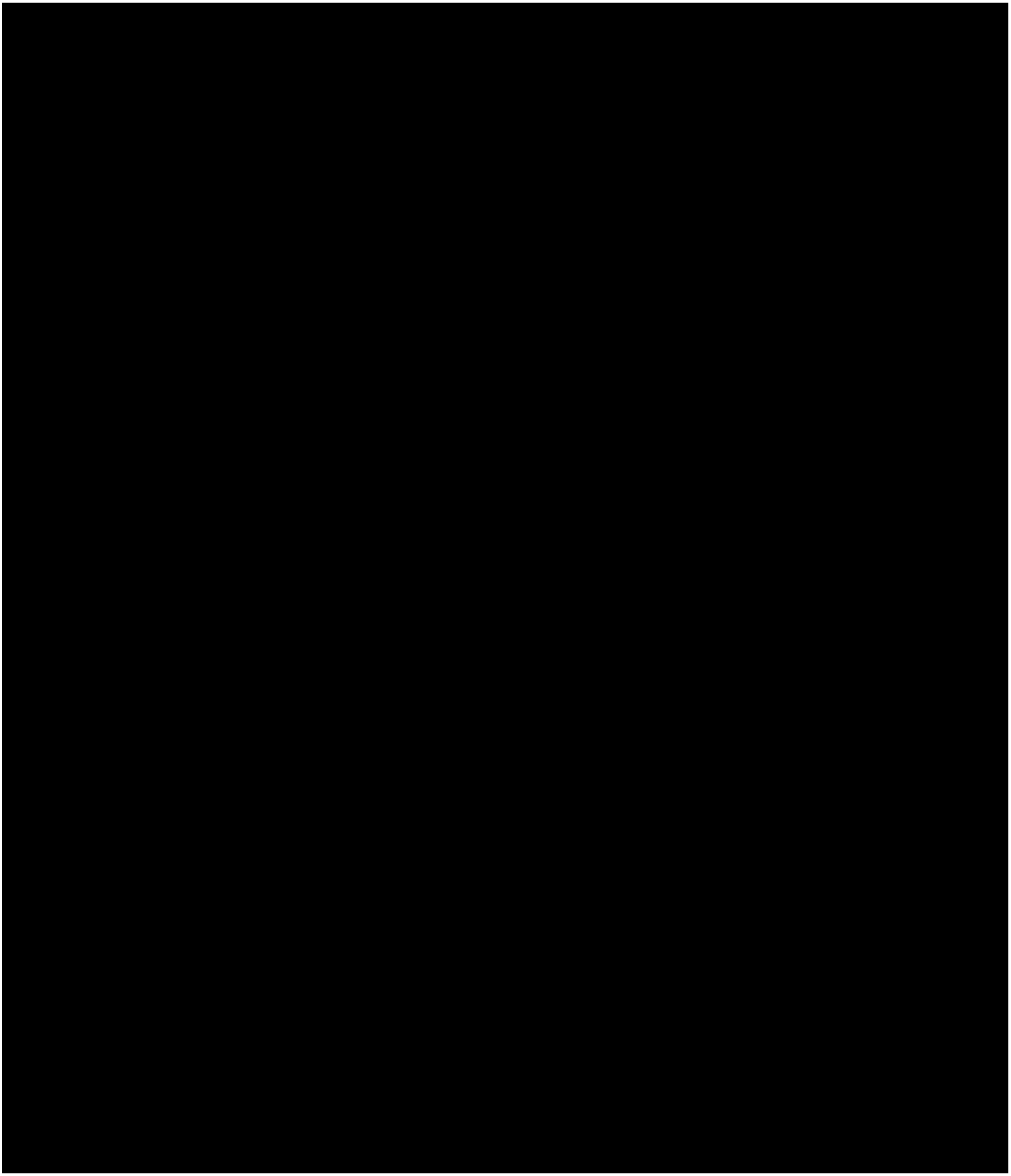
The Irrevocable Standby Letter of Credit was issued to meet the non-emergency response financial assurance requirements associated with the Elk Hills 26R Storage Project located at 28590 Highway 119, Tupman, CA 93276.

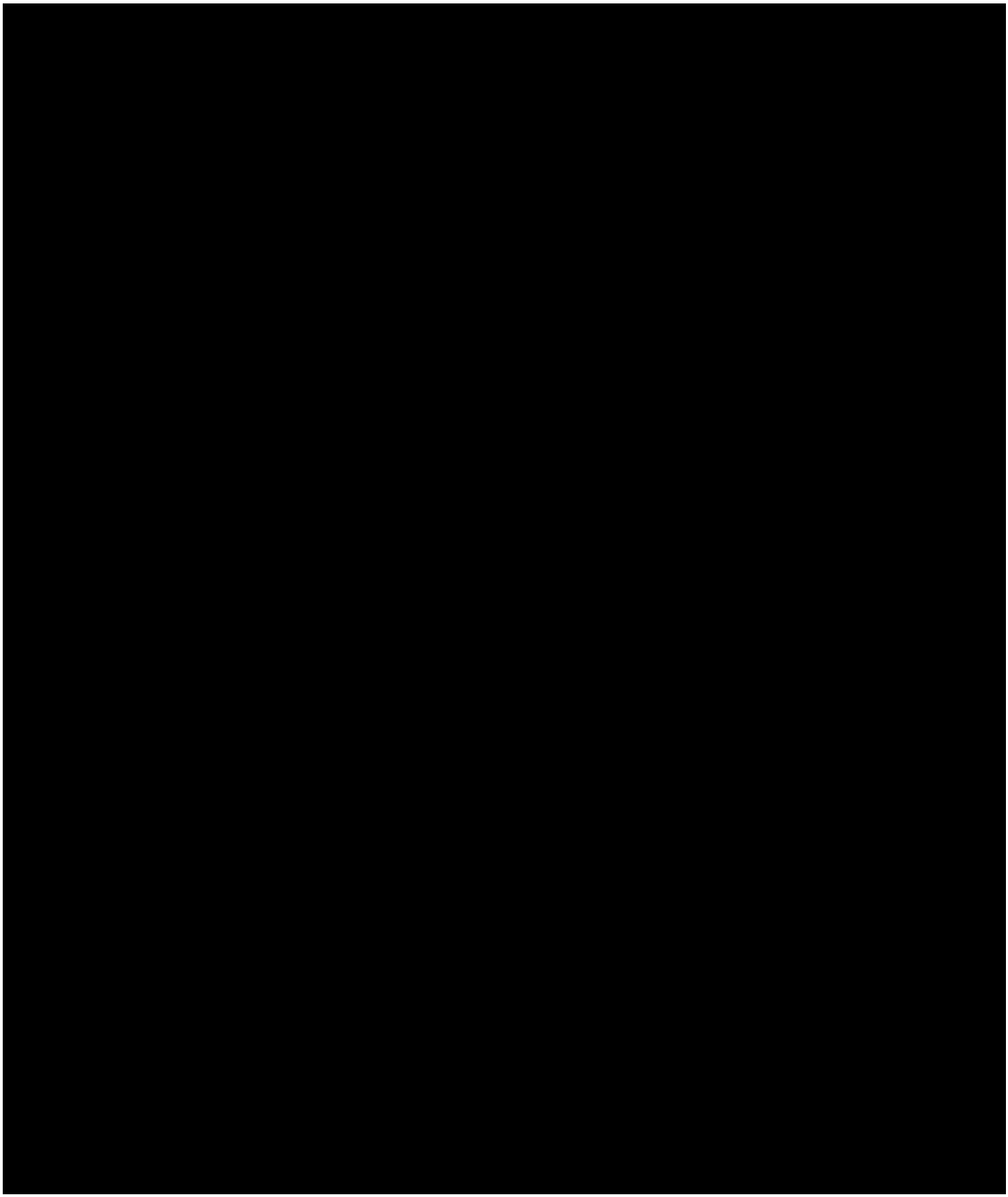
BANK OF NEW YORK MELLON STANDBY TRUST

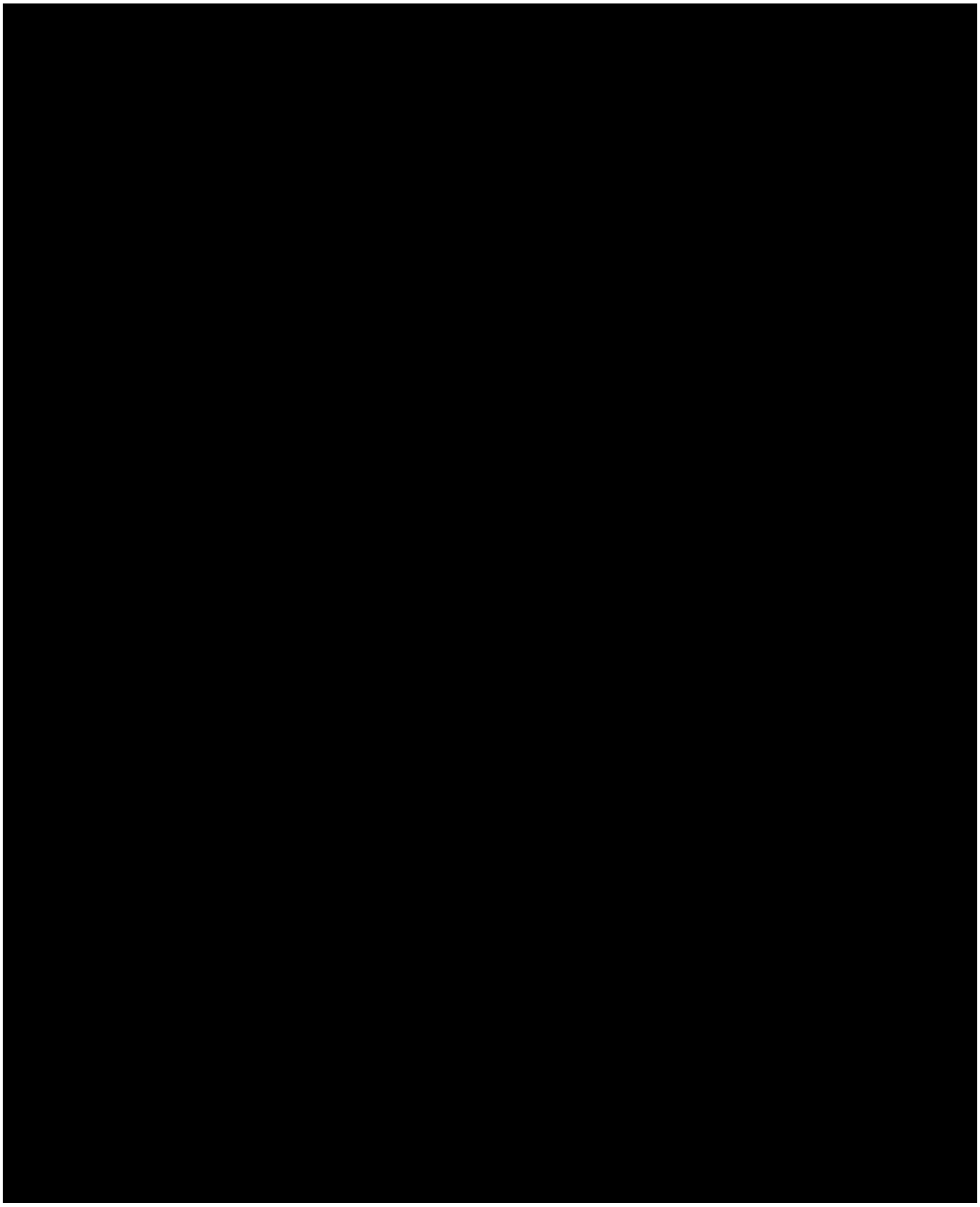
Trust Agreement

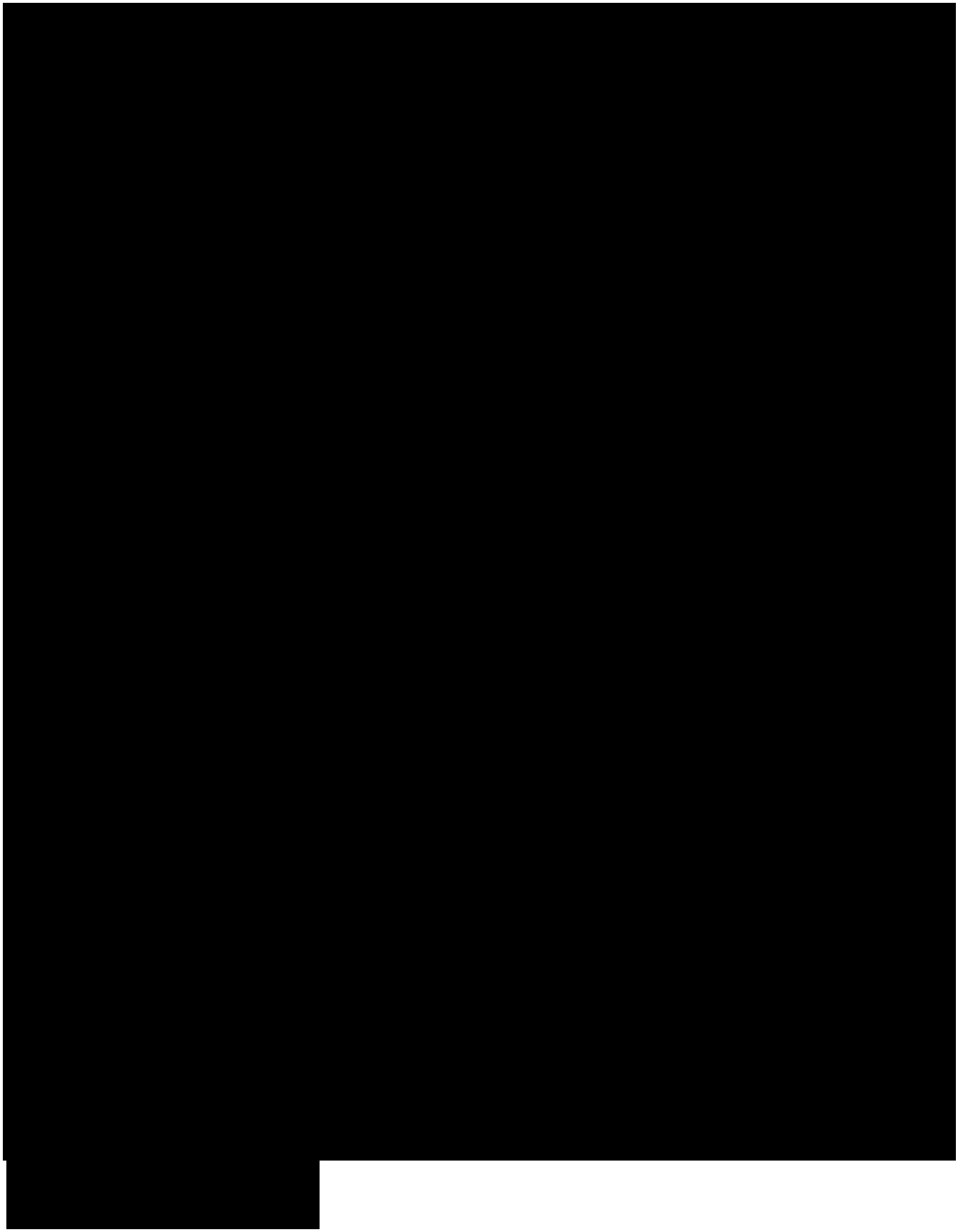














LETTER OF CREDIT COST ESTIMATE AND FUNDING VALUE SUMMARY

Schedule A

Facility	Cost Estimate		
	Corrective action	Injection well plugging	Post injection site care and site closure
EPA Identification number: Elk Hills 26R Storage Project 28590 Highway 119, Tupman, CA 93276	$111,320.00	$1,197,840.00	$7,785,500.00

Schedule B

Facility	Funding Value for Activities
EPA Identification number: Elk Hills 26R Storage Project 28590 Highway 119, Tupman, CA 93276	Irrevocable Standby Letter of Credit No. [839BGC2300XXX] issued by Deutsche Bank AG New York Branch in the amount of [$9,094,660.00].

ASCOT CERTIFICATE OF INSURANCE

55 West 46th Street,
26th Floor
New York, New York 10036

V. Certificate of Insurance

A certificate of insurance, as specified in this chapter, may be worded as follows, except that instructions in brackets are to be replaced with the relevant information and the brackets deleted:

Certificate of Insurance for [emergency and remedial response]

Name and Address of Insured (herein called the "insured"): Carbon TerraVault 1 LLC
1 World Trade Center, Suite 1500, Long Beach, CA 90831

Name and Address of Insurer (herein called the "insurer"): Ascot Specialty Insurance Company; 55 West 46th Street, 26th Floor, New York, New York 10036

Injection Wells covered: [list for each well: The EPA Identification Number, name, address, and the amount of insurance for [emergency and remedial response] (these amounts for all injection wells covered must total the face amount shown below).]

Underground Injection Control Class VI Permit Application Nos. R9UIC-CA6-FY22-1.1, R9UIC-CA6-FY22-1.2, R9UIC-CA6-FY22-1.3 and R9UIC-CA6-FY22-1.4

Face Amount: $25,000,000
Policy Number: ENPU2310001018-01
Effective Date: 05/18/2023

The insurer hereby certifies that it has issued to the Insured the policy of insurance identified above to provide financial assurance for [emergency and remedial response] for the injection wells identified above. The Insurer further warrants that such policy conforms in all respects with the requirements for the fulfillment of [emergency and remedial response] obligations described at 40 CFR 146.94, respectively, as applicable and as such regulations were constituted on the date shown immediately below. It is agreed that any provision of the policy inconsistent with such regulations is hereby amended to eliminate such inconsistency.

The insurer may cancel the policy only for failure to pay the premium and by sending notice of cancellation by certified mail to the owner or operator and to the UIC Program Director for the area in which the injection well(s) is (are) located. EPA requires that cancellation not become final for 120 days beginning on the date of receipt of the notice of cancellation by the UIC Program Director, as evidenced by the return receipts.

Whenever requested by the UIC Program Director, the Insurer agrees to furnish to the UIC Program Director a duplicate original of the policy listed above, including all endorsements thereon.

[Authorized signature of Insurer]



[Name of person signing] Ted Mavraganis
[Title of person signing] Senior Vice President

[Signature of witness or notary:]



[Date] 08/31/2023

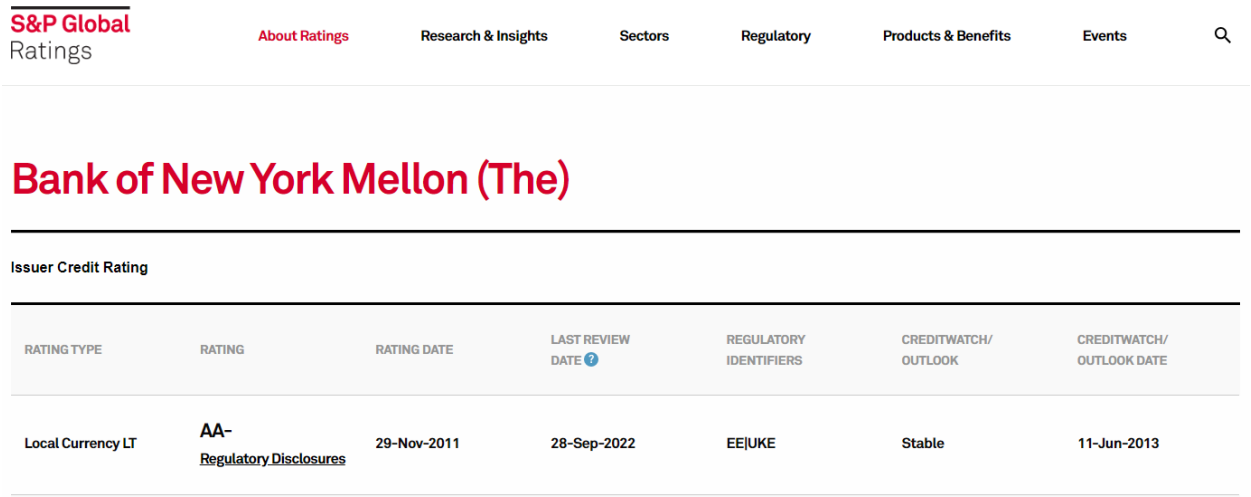
INSURANCE ENDORSEMENT

FINANCIAL STRENGTH DEMONSTRATION

Under 40 CFR 146.85(a)(6)(ii), EPA requires that the owner or operator submit proof of the third party's financial strength. EPA recommends that the owner or operator submit the third party's credit rating or, if the Director determines that the credit rating alone does not sufficiently meet the financial strength requirement, submit the third party's credit rating plus its most recent bond rating and calculated financial ratios. EPA recommends that owners or operators demonstrate that third party providers have a credit rating in the top four categories from either Standard & Poor's or Moody's (i.e., AAA, AA, A, or BBB for Standard & Poor's and Aaa, Aa, A, or Baa for Moody's)

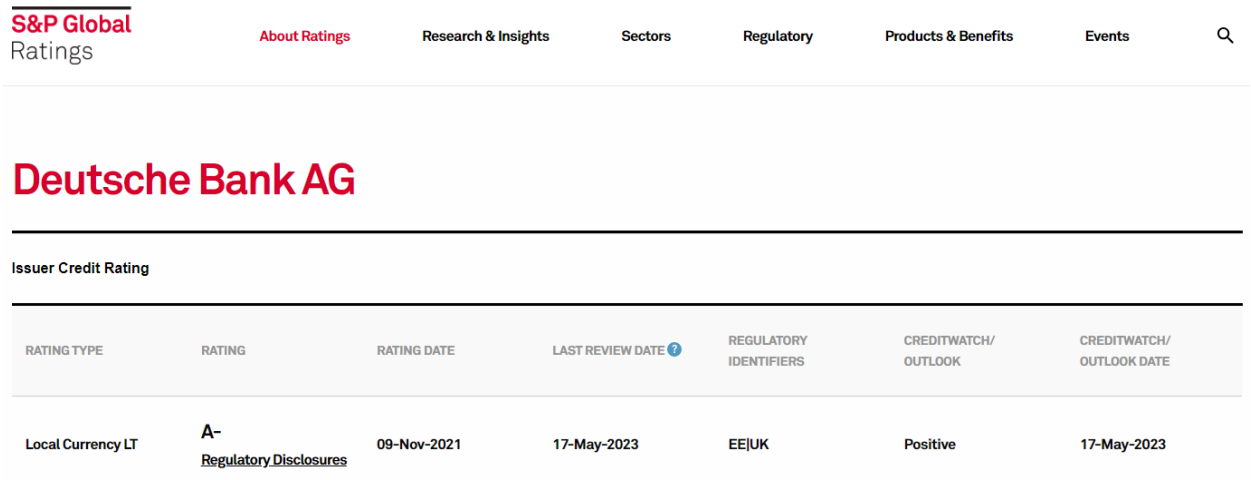
Bank of New York Mellon:

- Standard and Poor's rating: AA-



Deutsche Bank AG New York Branch:

- Standard and Poor's rating: A-



ATTACHMENT I: STIMULATION PLAN

Elk Hills 26R Storage Project

Facility Information

Facility name: CTV I Elk Hills 26R Project
357-7R and 355-7R

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA

Version History

File Name	Version	Date	Description of Change
Att I – Stimulation Plan_v1	1	05/31/22	Original document

Stimulation Plan

The need for stimulation to enhance the injectivity potential of the Monterey Formation 26R reservoir is not anticipated at this time. If it is determined that stimulation techniques are needed, a stimulation plan will be developed and submitted to EPA Region 9 for review and approval prior to conducting any stimulation.

U.S. ENVIRONMENTAL PROTECTION AGENCY

UNDERGROUND INJECTION CONTROL PERMIT

DRAFT PERMIT

CLASS VI INJECTION WELL

Permit Number: R9UIC-CA6-FY22-1.2

Well Name: 345C-36R

Issued to:

Carbon TerraVault JV Storage Company Sub 1, LLC

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C. TESTING AND MONITORING PLAN
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F. EMERGENCY AND REMEDIAL RESPONSE PLAN
G. CONSTRUCTION DETAILS
H. FINANCIAL ASSURANCE DEMONSTRATION
I. STIMULATION PROGRAM

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 9
75 Hawthorne St.
San Francisco, CA 94105-3901

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT: CLASS VI

Permit Number: R9UIC-CA6-FY22-1.2
Facility Name: CTV 1: Elk Hills 26R

Pursuant to the Safe Drinking Water Act and Underground Injection Control regulations of the U.S. Environmental Protection Agency codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 124, 144, 146, and 147,

Carbon TerraVault JV Storage Company Sub 1, LLC of Tupman, CA

hereinafter, the permittee, is hereby authorized to construct and operate a Class VI injection well located in the State of California, Kern County, T 30 S, R 23 E of Mount Diablo Base Meridian, Section 36, 35° 16' 30.3383" N, 119° 27' 27.7825" W, as part of the Elk Hills 26R Carbon Dioxide Storage Project. The well will inject a carbon dioxide stream (carbon dioxide is also called CO_2 in the attachments to this permit) sourced initially from the proposed Lone Cypress hydrogen plant, pre-combustion gas treatment, and the proposed Avnos Direct Air Capture facility (see Attachment B). All three initial carbon dioxide sources are to be located within the Elk Hills oil field. The permittee may request to inject carbon dioxide from additional emission sources in the future, subject to review and approval by EPA, as described in Section N of this permit. The permittee stated in their application that potential future sources of carbon dioxide may include: post combustion capture from the Elk Hills power plant, renewable fuel plants, post combustion capture from steam generators, other power plants, and industrial sources. The carbon dioxide stream, as characterized in the permit application and the administrative record, shall be a liquid, supercritical fluid, or gas. Injection is authorized into the Monterey Formation at a depth of approximately 6,000 feet below ground surface upon the express condition that the permittee meet the restrictions set forth herein. The designated confining zone for this injection is the Reef Ridge Shale Formation.

Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, directs federal agencies, to the greatest extent practical and permitted by law, to identify and address, as appropriate, disproportionate, and adverse human health or environmental impacts on people of color and low-income populations. See Exec. Order No. 12898, 59 Fed. Reg. 7629 (Feb. 11, 1994). Recently, Executive Order 14096, *Revitalizing Our Nation's Commitment to Environmental Justice for All*, supplemented this direction. See Exec. Order No. 14096, 88 Fed. Reg. 25251 (Apr. 21, 2023). As part of the decision-making process for this permit, EPA considered these executive orders and EPA's Environmental Justice Guidance for UIC Class VI Permitting and Primacy (Aug. 17, 2023). EPA's evaluation and consideration of environmental justice for this permit is described in EPA's Fact Sheet.

This permit is for the construction and operation of one Class VI injection well (well name 345C-36R); three other wells at the Elk Hills 26R Carbon Dioxide Storage Project are authorized under separate Class VI permits (Permit Nos. R9UIC-CA6-FY22-1.1, R9UIC-CA6-FY22-1.3 and R9UIC-CA6-FY22-1.4). Injection shall not commence until the operator has received written authorization from the Director of the Water Division of EPA Region 9, in accordance with Section S of this permit.

All references to Title 40 of the Code of Federal Regulations are to all regulations that are in effect on the date that this permit is effective. The following attachments are incorporated into this permit as enforceable conditions:

- A: Summary of Operating Requirements;
- B: Area of Review and Corrective Action Plan;
- C: Testing and Monitoring Plan;
- D: Well Plugging Plan;
- E: Post-injection Site Care and Site Closure Plan;
- F: Emergency and Remedial Response Plan;
- G: Construction Details;
- H: Financial Assurance Demonstration; and
- I: Stimulation Program.

This permit shall become effective on [Insert date], and shall remain in full force and effect during the operating life of the well and the post-injection site care period until site closure is authorized and completed, unless this permit is revoked and reissued, terminated, or modified pursuant to 40 CFR 144.39, 144.40, or 144.41. This permit shall also remain in effect upon delegation of primary enforcement responsibility of the UIC program for Class VI wells to the State of California until such time as the State issues its own permit to the permittee or the State chooses to adopt this permit as a State permit. The permit will expire in one year, if the permittee fails to commence construction on the well, unless a written request in electronic format for an extension of this one-year period has been approved by the Director. The permittee may request an expiration date sooner than the one-year period, provided no construction on the well has commenced. At least every five years from the effective date specified above, the permittee must re-evaluate the Area of Review and comply with 40 CFR 146.84(e). If results from the re-evaluated Area of Review are different from what is predicted in Attachment B of this permit, EPA may require the permittee to update the permit and the attachments.

Signed and Dated: _____

DRAFT

_____

[Insert Name of signing official]
[Insert Title, Office/Division]

PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is authorized to engage in underground injection in accordance with the conditions of this permit. Notwithstanding any other provisions of this permit, the permittee authorized by this permit shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus or formation fluids into underground sources of drinking water (USDWs) or any unauthorized zones. The objective of this permit is to prevent the movement of fluids into or between USDWs or into any unauthorized zones consistent with the requirements at 40 CFR 146.86(a). Any underground injection activity not specifically authorized in this permit is prohibited. For purposes of enforcement, compliance with this permit during its term constitutes compliance with Part C of the Safe Drinking Water Act (SDWA). Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA or any other common or statutory law other than Part C of the SDWA.

Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local laws or regulations. Nothing in this permit, nor compliance with its terms, shall be construed to relieve the permittee of any duties under applicable State or local laws or regulations that are not preempted or superseded by the Federal SDWA Underground Injection Control (UIC) program.

B. PERMIT ACTIONS

1. **Modification, Revocation and Reissuance, and Termination –** The Director of the Water Division of Region 9 of the U.S. Environmental Protection Agency (EPA), hereinafter, the Director, may, for cause or upon request from any interested person, including the permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR 124.5, 144.12, 146.86(a), 144.39, and 144.40. The permit is also subject to minor modifications for cause as specified in 40 CFR 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

2. **Minor Modifications –** Upon the consent of the permittee, the Director may modify this permit to make the corrections or allowances for minor changes in the permitted activity as listed in 40 CFR 144.41. Any permit modification not processed as a minor modification under 40 CFR 144.41 must be made for cause, and with part 124 draft permit and public notice as required in 40 CFR 144.39.

3. **Transfer of Permits** – This permit is not transferable to any person except in accordance with 40 CFR 144.38(a) and Section O(6)(b) of this permit.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR part 2 (Public Information) and 40 CFR 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential business information by the submitter. Any such claim must be asserted at the time of submission by clearly identifying each page with the words "confidential business information" on every page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2.

E. DEFINITION

All terms used in this permit shall have the meaning set forth in the SDWA and Underground Injection Control regulations specified at 40 CFR parts 124, 144, 146, and 147. Unless specifically stated otherwise, all references to "days" in this permit should be interpreted as calendar days.

F. DUTIES AND REQUIREMENTS

1. **Duty to Comply** – The permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application.

2. **Duty to Reapply** – If the permittee wishes to continue an activity regulated by this permit after the expiration or termination of this permit, the permittee must apply for and obtain a new permit.

3. **Penalties for Violations of Permit Conditions** – Any person who violates a permit requirement is subject to civil penalties and other enforcement action under the SDWA. Any person who willfully violates permit conditions may be subject to criminal prosecution under the SDWA and other applicable statutes and regulations.

4. **Need to Halt or Reduce Activity Not a Defense –** It shall not be a defense for the permittee in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

5. **Duty to Mitigate** – The permittee shall take all timely and reasonable steps necessary to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

6. **Proper Operation and Maintenance** – The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control and related appurtenances which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes, among other things, effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

7. **Duty to Provide Information** – The permittee shall furnish to the Director in an electronic format, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit or the UIC regulations. The permittee shall also furnish to the Director, upon request within a time specified, electronic copies of records required to be kept by this permit.

8. **Inspection and Entry** – The permittee shall allow the Director or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

   (a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where electronic or non-electronic records are kept under the conditions of this permit;

   (b) Have access to and copy, at reasonable times, any electronic or non-electronic records that are kept under the conditions of this permit;

   (c) Inspect, at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

   (d) Sample or monitor, at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location, including facilities, equipment or operations regulated or required under this permit.

9. **Signatory Requirements** – All reports or other information, required to be submitted by this permit or requested by the Director shall be signed and certified in accordance with 40 CFR 144.32.

G. AREA OF REVIEW AND CORRECTIVE ACTION

1. The Area of Review (AoR) is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data. The permittee shall maintain and comply with the approved Area of Review and Corrective Action Plan (Attachment B of this permit) which is an enforceable condition of this permit and shall meet the requirements of 40 CFR 146.84.

2. As delineated in Attachment B, 157 wellbores within the AoR require plugging because the wellbores penetrate the injection zone or confining layer and will not be used for injection or monitoring within the 26R storage project. The wells are required to be properly plugged and abandoned prior to authorization of carbon dioxide injection.

3. At least sixty (60) days prior to commencing corrective action, the permittee shall submit procedures for performing corrective action on the identified deficient wells within the AoR and not commence any corrective action until the procedures are approved by the Director.

   (a) As corrective action activities are completed, the permittee shall provide periodic updates, including plugging reports, to the Director.

   (b) Corrective action on all deficient wells in the AoR must be complete, and approved in writing by EPA, before the permittee may commence injection pursuant to Section Q(3) of this permit.

4. At a fixed frequency of every five years, or more frequently when monitoring and operational conditions warrant, the permittee must reevaluate the area of review and perform any necessary corrective action in the manner specified in 40 CFR 146.84. The first reevaluation shall be completed no later than 5 years from the effective date of this permit unless the Director requests an earlier reevaluation. After conducting an AoR reevaluation, the permittee shall update the Area of Review and Corrective Action Plan or demonstrate to the Director that no update is needed.

5. Following each AoR reevaluation, the permittee shall submit the resultant information (i.e., the completed reevaluation analysis, along with either a revised AoR and Corrective Action Plan or a demonstration that the reevaluation analysis determined no revised Plan is needed) in an electronic format to the Director for review and approval. If a revised AoR and Corrective Action Plan is submitted and approved by the Director, the revised Plan becomes an enforceable condition of this permit.

6. To ensure permit activities do not increase environmental impacts, resource needs, and public health risks in already overburdened communities, along with the submittal of a

revised AoR and Corrective Action Plan, the permittee shall submit an updated EJScreen analysis that incorporates the revised AoR boundary.

H. FINANCIAL RESPONSIBILITY

1. **Financial Responsibility** – The permittee shall maintain financial responsibility and resources to meet the requirements of 40 CFR 146.85 and the conditions of this permit. Financial responsibility shall be maintained through all phases of the project. The permittee must maintain financial responsibility until site closure is authorized from the director as described in Section Q of this permit. Compliance with the financial responsibility requirements, including the applicable duration, described in this permit shall not relieve the permittee from complying with any other applicable Federal, State, and local financial responsibility requirements that are not preempted or superseded by the Federal SDWA UIC program.

   The financial instrument(s) must be sufficient to cover the cost of:

   (a) Corrective action (that meets the requirements of 40 CFR 146.84);

   (b) Injection well plugging (that meets the requirements of 40 CFR 146.92);

   (c) Post injection site care and site closure (that meets the requirements of 40 CFR (146.93) and;

   (d) Emergency and remedial response (that meets the requirements of 40 CFR 146.94).

   The permittee submitted a letter of credit, with a standby trust agreement, to cover financial assurance for items 1(a), (b), and (c) and submitted a certificate of insurance with details about a third-party insurance policy it will secure to cover financial assurance for 1(d). The EPA-approved financial assurance mechanisms are found in Attachment H and in the administrative record of this permit.

   The total initial cost estimates for these activities to be covered by the approved financial assurance mechanisms is $33,672,785. This amount covers all four Class VI injection well permits for the Elk Hills 26R CO_2 Storage Project.

2. **Cost Estimate Updates** – During the active life of the geologic sequestration project, the permittee must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) and provide this adjustment to the Director in an electronic format. The permittee must also provide to the Director written updates in an electronic format of adjustments to the cost estimate within 60 days of any amendments to the Project Plans included as Attachments B – F of this permit, which address items (a) through (d) in Section H(1) of this permit.

3. **Notification** –

(a) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the permittee, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase.

(b) Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the permittee has submitted a justification for the reduced cost estimate and received written approval from the Director. For requested reductions in the face amount of a financial instrument, the Director may provide notice to the public of the proposed reduction, prior to finalizing approval of the reduction.

(c) The permittee must notify the Director by certified mail and in an electronic format of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging, post-injection site care and site closure, and any applicable ongoing actions under Corrective Action or Emergency and Remedial Response.

(i) If the permittee or the third-party provider of a financial responsibility instrument is going through a bankruptcy, the permittee must notify the Director by certified mail and in an electronic format of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the permittee as debtor, within 10 days after commencement of the proceeding.

(ii) A permittee who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy.

4. **Establishing Other Coverage** – The permittee must establish other financial assurance or liability coverage acceptable to the Director, within 60 days of the occurrence of the events in Section H(2) or H(3) of this permit.

I. CONSTRUCTION

1. **Siting** – The permittee has demonstrated to the satisfaction of the Director that the well is in an area with suitable geology in accordance with the requirements at 40 CFR 146.83.

2. **Casing and Cementing** – Casing and cement or other materials used in the construction of the well must have sufficient structural strength for the life of the geologic sequestration project. All well materials must be compatible with all fluids with which the materials may

be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must prevent the movement of fluids into or between USDWs for the expected life of the well in accordance with 40 CFR 146.86. The casing and cement used in the construction of this well are shown in Attachment G of this permit and in the administrative record for this permit. Any change must be submitted in an electronic format for approval by the Director before installation.

3. **Tubing and Packer Specifications** – Tubing and packer materials used in the construction of the well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The permittee shall inject only through tubing with a packer set within the long string casing at a point within or below the confining zone immediately above the injection zone. The tubing and packer used in the well are represented in engineering drawings contained in Attachment G of this permit. Any change must be submitted in an electronic format for approval by the Director before installation.

J. PRE-INJECTION TESTING

1. Prior to the Director authorizing injection, the permittee shall perform all pre-injection logging, sampling, and testing specified at 40 CFR 146.87. This testing shall provide data sufficient to address the pre-operational testing objectives identified in Attachment G of this permit, including:

   (a) Logs, surveys, and tests to determine or verify the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in all relevant geologic formations. These tests shall include:

      (i) Deviation checks that meet the requirements of 40 CFR 146.87(a)(1);

      (ii) Logs and tests before and upon installation of the surface casing that meet the requirements of 40 CFR 146.87(a)(2);

      (iii) Logs and tests before and upon installation of the long-string casing that meet the requirements of 40 CFR 146.87(a)(3);

      (iv) Tests to demonstrate internal and external mechanical integrity that meet the requirements of 40 CFR 146.87(a)(4); and

      (v) Any alternative methods that are required by or approved by the Director pursuant to 40 CFR 146.87(a)(5).

   (b) Whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone that meet the requirements of 40 CFR 146.87(b);

(c) Records of the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone that meet the requirements of 40 CFR 146.87(c);

(d) Tests to provide information about the injection and confining zones, including calculated fracture pressure and the physical and chemical characteristics of the injection and confining zones and the formation fluids in the injection zone that meet the requirements of 40 CFR 146.87(d); and

(e) Tests to verify hydrogeologic characteristics of the injection zone that meet the requirements of 40 CFR 146.87(e), including:

(i) A pressure fall-off test; and

(ii) A pumping test or injectivity tests.

2. The permittee shall submit to the Director for approval in an electronic format a schedule for logging and testing activities 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test. The permittee must provide the Director or their representative with the opportunity to witness all logging, sampling, and testing required under this Section.

K. OPERATIONS

1. **Injection Fluids/Carbon Dioxide Sources –** The permittee will capture carbon dioxide from multiple sources during the life of the permit for injection into the Class VI well. Three initial sources of carbon dioxide are approved sources for injection: the proposed Lone Cypress hydrogen plant, pre-combustion gas treatment, and the proposed Avnos Direct Air Capture facility (see Attachment B). The permittee may propose additional sources of carbon dioxide for injection, subject to review and approval by EPA, as described in Section N of this permit.

2. **Injection Pressure Limitation** – The permittee must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case shall injection pressure initiate fractures or propagate existing fractures in the confining zone or cause the movement of injection or formation fluids into a USDW. The maximum injection pressure limit is listed in Attachment A.

3. **Stimulation Program** – Pursuant to requirements at 40 CFR 146.82(a)(9), all stimulation programs proposed by the permittee must be approved by the Director as a permit modification and incorporated into Attachment I of this permit.

4. **Additional Injection Limitation** – No injectate other than that which has been analyzed and approved by the Director under this permit in accordance with Section N of this permit shall be injected except fluids used for rework, and well tests as approved by the Director.

5. **Annulus Fluid** – The permittee must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director.

6. **Annulus/Tubing Pressure Differential** – Except during workovers or times of annulus maintenance, the permittee must maintain on the annulus a pressure that exceeds the operating injection pressure as specified in Attachment A of this permit, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.

7. **Automatic Alarms and Automatic Shut-off System** –

   (a) The permittee must:

      (i) Install, continuously operate, and maintain an automatic alarm and an automatic shut-off system or, at the discretion of the Director, down-hole shut-off systems, or other mechanical devices that provide equivalent protection; and

      (ii) Successfully demonstrate the functionality of the alarm system and shut-off system prior to the Director authorizing injection, and at a minimum of once every twelfth month after the last approved demonstration.

      (iii) Establish well-specific thresholds for activating the shut-off system and submit a revised Attachment A to the Director prior to the Director authorizing injection.

   (b) Testing under this Section must involve subjecting the system to simulated failure conditions and must be witnessed by the Director or his or her representative unless the Director authorizes an unwitnessed test in advance. The permittee must provide notice in an electronic format 30 days prior to running the test and must provide the Director or their representative the opportunity to attend. The test must be documented using either a mechanical or digital device which records the value of the parameter of interest, or by a service company job record. A final report including any additional interpretation necessary for evaluation of the testing must be submitted in an electronic format within the time period specified in Section O(4) of this permit.

8. **Precautions to Prevent Well Blowouts** – At all times, the permittee shall maintain on the well a pressure which will prevent the return of the injection fluid to the surface. The well bore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient or a plug shall be installed which can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. The permittee shall

follow procedures such as those below to assure that a backflow or blowout does not occur:

(a) Limit the temperature and/or corrosivity of the injectate; and

(b) Develop procedures necessary to assure that pressure imbalances do not occur.

9. **Circumstances Under Which Injection Must Cease** –

Injection shall cease when any of the following circumstances arise:

(a) Failure of the well to pass a mechanical integrity test;

(b) A loss of mechanical integrity during operation;

(c) The automatic alarm or automatic shut-off system is triggered;

(d) A significant unexpected change in the annulus or injection pressure;

(e) The Director determines that the well lacks mechanical integrity; or

(f) The permittee is unable to maintain compliance with any permit condition or regulatory requirement and the Director determines that injection should cease.

10. **Approaches for Ceasing Injection** –

(a) The permittee must shut-in the well by gradual reduction in the injection pressure as outlined in Attachment A of this permit; or

(b) The permittee must immediately cease injection and shut-in the well as outlined in the Emergency and Remedial Response Plan (Attachment F of this permit).

L. MECHANICAL INTEGRITY

1. **Standards** – Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the injection well must have and maintain mechanical integrity consistent with 40 CFR 146.89. To meet these requirements, mechanical integrity tests/demonstrations must be witnessed by the Director or an authorized representative of the Director unless prior approval has been granted by the Director to run an un-witnessed test. To conduct testing without an EPA representative, the following procedures must be followed.

(a) The permittee must submit prior notification in an electronic format within the time period specified in Section L(3) of this permit and if EPA informs the permittee that no

EPA representative is available this must be documented in the approved plan and testing report. The permittee must receive permission from the Director to proceed;

(b) The test must be performed in accordance with the Testing and Monitoring Plan (Attachment C of this permit) and documented using either a mechanical or digital device that records the value of the parameter of interest; and

(c) A final report including any additional interpretation necessary for evaluation of the testing must be submitted in an electronic format within the time period specified in Section O(4) of this permit.

2. **Mechanical Integrity Testing** – The permittee shall conduct a casing inspection log and mechanical integrity testing as follows:

(a) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate internal mechanical integrity pursuant to 40 CFR 146.87(a)(4):

(i) A pressure test with liquid or gas; and

(ii) A casing inspection log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(b) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.87(a)(4):

(i) A tracer survey such as an oxygen activation log; or

(ii) A temperature or noise log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(c) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the permittee must continuously monitor injection pressure, injection rate, injection volumes, pressure on the annulus between tubing and long string casing, and annulus fluid volume as specified in 40 CFR 146.88(e) and 146.89(b).

(d) At least once per year, the permittee must perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.89(c):

(i) An Administrator-approved tracer survey such as an oxygen-activation log; or

(ii) A temperature or noise log. The Director may require such tests whenever the well is worked over; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(e) After any workover that may compromise the internal mechanical integrity of the well, the well shall be tested by means of a pressure test approved by the Director and the well must pass the test to demonstrate mechanical integrity.

(f) Prior to plugging the well, the permittee shall demonstrate external mechanical integrity as described in the Injection Well Plugging Plan and that meets the requirements of 40 CFR 146.92(a).

(g) The Director may require the use of any other tests to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator pursuant to requirements at 40 CFR 146.89(e).

3. **Prior Notice and Reporting** –

(a) The permittee shall notify the Director in an electronic format of his or her intent to demonstrate mechanical integrity at least 30 days prior to such demonstration. At the discretion of the Director, a shorter time period may be allowed.

(b) Reports of mechanical integrity demonstrations which include logs must include an interpretation of results by a knowledgeable log analyst. The permittee shall report in an electronic format the results of a mechanical integrity demonstration within the time period specified in Section O(4) of this permit.

4. **Gauge and Meter Calibration** – The permittee shall calibrate all gauges used in mechanical integrity demonstrations and other required monitoring to an accuracy of not less than 0.5 percent of full scale, within one year prior to each required test. The date of the most recent calibration shall be noted on or near the gauge or meter. A copy of the calibration certificate shall be submitted to the Director in an electronic format with the report of the test. Pressure gauge resolution shall be no greater than five psi. Certain mechanical integrity and other testing may require greater accuracy and shall be identified in the procedure submitted to the Director prior to the test.

5. **Loss of Mechanical Integrity** –

(a) If the permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, or fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity as defined by 40 CFR 146.89(a)(1) or (2) is suspected during operation (such as a significant unexpected change in the annulus or injection pressure), the permittee must:

(i) Cease injection in accordance with Sections K(8) and K(9)(a) or (b), and Attachments A or F of this permit;

(ii) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone. If there is evidence of USDW endangerment, implement the Emergency and Remedial Response Plan (Attachment F of this permit);

(iii) Follow the reporting requirements as directed in Section O of this permit;

(iv) Restore and demonstrate mechanical integrity to the satisfaction of the Director and receive written approval from the Director prior to resuming injection; and

(v) After receiving written approval to resume injection, notify the Director in an electronic format when injection is expected to resume.

(b) If a shutdown (*i.e.,* down-hole or at the surface) is triggered, the permittee must immediately investigate and identify as expeditiously as possible the cause of the shutdown. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required indicates that the well may be lacking mechanical integrity, the permittee must take the actions listed above in Section L(5)(a)(i) through (v).

(c) If the well loses mechanical integrity prior to the next scheduled test date, then the well must either be plugged or repaired and retested within 30 days of losing mechanical integrity. The permittee shall not resume injection until mechanical integrity is demonstrated and the Director gives written approval to recommence injection in cases where the well has lost mechanical integrity.

6. **Mechanical Integrity Testing on Request From Director** – The permittee shall demonstrate mechanical integrity at any time upon written notice from the Director.

M. TESTING AND MONITORING

1. **Testing and Monitoring Plan** –

(a) The permittee shall maintain and comply with the approved Testing and Monitoring Plan (Attachment C of this permit) and with the requirements at 40 CFR 144.51(j), 146.88(e), and 146.90. The Testing and Monitoring Plan is an enforceable condition of this permit. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. Procedures for all testing and monitoring under this permit must be submitted to the Director in an electronic format for approval at least 30 days prior to the test. In performing all testing and monitoring under this permit, the permittee must follow the procedures approved by the Director.

If the permittee is unable to follow the EPA-approved procedures, then, the permittee must contact the Director at least 30 days prior to testing to discuss options, if any are feasible. When the test report is submitted, a full explanation must be provided as to why any approved procedures were not followed. If the approved procedures were not followed, EPA may take an appropriate action, including but not limited to, requiring the permittee to re-run the test.

(b) The permittee must update the Testing and Monitoring Plan as required at 40 CFR 146.90 (j) to incorporate monitoring and operational data and in response to AoR reevaluations required under Section G(2) of this permit or demonstrate to the Director that no update is needed. The amended Testing and Monitoring Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation, following any significant changes to the facility such as addition of monitoring wells or newly permitted injection wells within the AoR, or when required by the Director.

(c) Following each update of the Testing and Monitoring Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and approval of the results. Once approved by the Director, the revised Testing and Monitoring Plan will become an enforceable condition of this permit.

2. **Carbon Dioxide Stream Analysis** – The permittee shall analyze the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics, as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(a).

3. **Continuous Monitoring** – The permittee shall maintain continuous monitoring devices and use them to monitor injection pressure, flow rate, volume, the pressure on the annulus between the tubing and the long string of casing, annulus fluid level, and temperature. This monitoring shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(b). The permittee shall maintain for EPA's inspection at the facility an appropriately scaled, continuous record of these monitoring results as well as original files of any digitally recorded information pertaining to these operations.

4. **Corrosion Monitoring** – The permittee shall perform corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion on a quarterly basis using the procedures described in the Testing and Monitoring Plan and in accordance with 40 CFR 146.90(c) to ensure that the well components meet the minimum standards for material strength and performance set forth in 40 CFR 146.86(b).

5. **Ground Water Quality Monitoring** – The permittee shall monitor ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones. This monitoring shall be performed for the parameters identified in the Testing and Monitoring Plan at the

locations and depths, and at frequencies described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(d).

6. **External Mechanical Integrity Testing** – The permittee shall demonstrate external mechanical integrity as described in the Testing and Monitoring Plan and Section L of this permit to meet the requirements of 40 CFR 146.90(e).

7. **Pressure Fall-Off Test** – The permittee shall conduct a pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information. The test shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(f).

8. **Plume and Pressure Front Tracking** –The permittee shall track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) as described in the Testing and Monitoring Plan.

   (a) The permittee shall use direct methods to track the position of the carbon dioxide plume and the pressure front in the injection zone as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(1).

   (b) The permittee shall use indirect methods to track the position of the carbon dioxide plume and pressure front as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(2).

   (c) If any indirect monitoring performed under Section M(8)(b) of this Permit detects increased pressure above the confining zone or other unanticipated results, the permittee shall increase the frequency of geochemical sampling under Section M(8)(a) to monthly sampling.

   (d) If data collection performed under Section M(8)(a) and M(8)(b) of this permit detects increased pressure above the confining zone or other unanticipated results the Director may require installation of additional monitoring wells.

9. **Surface Air and/or Soil Gas Monitoring** –

   (a) The permittee shall conduct any surface air monitoring or soil gas monitoring required by the Director to detect movement of carbon dioxide that could endanger a USDW or public health at the frequency and locations described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(h).

   (b) Any surface air monitoring or soil gas monitoring described in the Testing and Monitoring Plan of this Permit must not conflict with air monitoring requirements set forth by other Federal, State, or local agencies for the project, including monitoring to comply with the approved Monitoring, Reporting, and Verification (MRV) plan under 40 CFR part 98, Subpart RR, monitoring required for California's Low-Carbon Fuel Standard

program compliance, and monitoring required by Kern County pursuant to a Conditional Use Permit (CUP) and environmental impact report (EIR) for the project.

10. **Leak Detection Monitoring** -

(a) The permittee shall conduct any leak detection monitoring at the wellhead required by the Director to ensure injection well integrity and detect movement of carbon dioxide that could endanger a USDW or public health at the frequency and locations described in the Testing and Monitoring Plan.

(b) Any leak detection monitoring described in the Testing and Monitoring Plan of this Permit should be consistent with EPA's document "Leak Detection and Repair – A Best Practices Guide" (October 2007), and must not conflict with leak detection monitoring requirements set forth by other Federal, State, or local agencies for the project, including monitoring to comply with the approved Monitoring, Reporting and Verification (MRV) plan under 40 CFR part 98, subpart RR, monitoring required for California's Low-Carbon Fuel Standard program compliance, and monitoring required by Kern County pursuant to a Conditional Use Permit (CUP) and environmental impact report (EIR) for the project.

11. **Additional Monitoring** – If required by the Director as provided in 40 CFR 146.90(i), the permittee shall perform any additional monitoring determined to be necessary to support, upgrade, and improve computational modeling of the AoR evaluation required under 40 CFR 146.84(c) and to determine compliance with standards under 40 CFR 144.12 or 40 CFR 146.86(a). This monitoring shall be performed as described in a modification to the Testing and Monitoring Plan.

N. INJECTION OF CARBON DIOXIDE FROM ADDITIONAL SOURCES

1. The permittee must receive written approval from the Director before injecting carbon dioxide from a source that is not fully described in Attachment B of this permit. Carbon dioxide from additional sources will not be approved if the Director determines that the carbon dioxide stream from the proposed additional source is incompatible, or will adversely interact, with the injection well material, injection formation, or confining zone.

2. Proposed additional sources of carbon dioxide will be evaluated by EPA to determine if the additional source is approvable, and if so, whether its addition requires a major permit modification or a minor permit modification.

(a) Conditions that will result in a major permit modification include, but are not limited to, if the proposed additional source of carbon dioxide meets any of the following:

i. The addition of the proposed carbon dioxide source would increase the injection volume or injection pressure above the amount authorized in this permit; or

ii. The proposed additional carbon dioxide source is determined to have a chemical composition outside of the range of injectate compositions listed in Attachment B of this permit, or

iii. The addition of the proposed carbon dioxide source would interfere with the operation of the facility or its ability to meet conditions described in the permit; or

iv. The addition of the proposed carbon dioxide source would result in a material and substantial alteration or addition to the permitted Class VI injection activity which justifies the application of permit conditions that are different or absent in the existing permit; or

v. The Director determines that addition of the proposed carbon dioxide source does not meet criteria for a minor permit modification.

3. In proposing an additional source of carbon dioxide for the Director's approval, the permittee shall provide the Director with the following information:

   (a) The analytical parameters of the proposed additional carbon dioxide stream from the proposed source as described in the Testing and Monitoring Plan of this permit;

   (b) A description of the industry in which the proposed additional carbon dioxide stream will be produced from;

   (c) The name and address of the proposed additional carbon dioxide source;

   (d) An evaluation of the impact the proposed carbon dioxide source (the creation, capture, and transportation of carbon dioxide) will have on criteria pollutant and hazardous air pollutant emissions in the area; and

   (e) An assessment of the compatibility of the carbon dioxide stream with subsurface fluids and minerals, and assurance that the construction materials of the injection wells and other wells that may encounter the injected plume are still compatible (e.g., will not corrode over time due to the chemical interactions).

4. All proposed additional sources of carbon dioxide will require pre-approval by Kern County Planning and Natural Resources Department, and any necessary mitigation measures pursuant to an approved Conditional Use Permit and Environmental Impact Report.

5. The public shall be notified within 30 days when a proposed additional carbon dioxide source is submitted to EPA for review.

6. The public shall be notified 30 days before the injection of an EPA-approved additional

carbon dioxide stream is injected.

O. REPORTING AND RECORDKEEPING

1. **Electronic Reporting** – Electronic reports, submittals, notifications, and records made and maintained by the permittee under this permit must be in an electronic format approved by EPA. The permittee shall electronically submit all required reports to the Director at:

   https://epa.velo.pnnl.gov/operators

2. **Semi-Annual Reports** – The permittee shall submit semi-annual reports containing:

   (a) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;

   (b) Monthly average, maximum, and minimum values for injection pressure, flow rate and daily volume, temperature, and annular pressure;

   (c) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;

   (d) A description of any event which triggers the shut-off systems required in Section K(6) of this permit pursuant to 40 CFR 146.88(e), and the response taken;

   (e) The monthly volume or mass of the carbon dioxide stream injected over the reporting period and the volume or mass injected cumulatively over the life of the project;

   (f) Monthly annulus fluid volume added or produced; and

   (g) Results of the continuous monitoring required in Section M(3), including:

      (i) A tabulation of: (1) daily maximum injection pressure; (2) daily minimum annulus pressure; (3) daily minimum value of the difference between simultaneous measurements of annulus and injection pressure; (4) daily volume; (5) daily maximum flow rate; and (6) average annulus tank fluid level; and

      (ii) Graph(s) of the continuous monitoring as required in Section M(3) of this permit, or of daily average values of these parameters. The injection pressure, injection volume and flow rate, annulus fluid level, annulus pressure, and temperature shall be submitted on one or more graphs, using contrasting symbols or colors, or in another manner approved by the Director; and

   (h) Results of any additional monitoring identified in the Testing and Monitoring Plan and described in Section M of this permit.

3. **<u>24-Hour Reporting</u>** –

(a) The permittee shall report to the Director any permit noncompliance which may endanger human health or the environment or any events that require implementation of actions in the Emergency and Remedial Response Plan (Attachment F of this permit). Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such verbal reports shall include, but not be limited to, the following information:

(i) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW, or any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW;

(ii) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;

(iii) Any triggering of the shut-off system required in Section K(6) of this permit (i.e., down-hole or at the surface);

(iv) Any failure to maintain mechanical integrity;

(v) Pursuant to compliance with the requirement at 40 CFR 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere; and

(vi) Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F of this permit).

(b) A written submission shall be provided to the Director in an electronic format within five days of the time the permittee becomes aware of the circumstances described in Section O(3)(a) of this permit. The submission shall contain: a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F of this permit); and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance.

4. **<u>Reports on Well Tests and Workovers</u>** – The permittee shall report, within 30 days, the results of:

(a) Periodic tests of mechanical integrity;

(b) Any well workover, including stimulation;

(c) Any other test of the injection well conducted by the permittee if required by the Director; and

(d) Any test of any monitoring well required by this permit.

5. **Advance Notice Reporting** –

(a) **Well Tests** – The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned workover, stimulation, or other well test.

(b) **Planned Changes** – The permittee shall give written notice to the Director in an electronic format, as soon as possible, of any planned physical alterations or additions to the permitted injection facility other than minor repair/replacement or maintenance activities. An analysis of any new injection fluid and, as specified in Section N of this Permit, an analysis of any additional source of carbon dioxide, shall be submitted to the Director for review and written approval at least 60 days prior to injection; this approval may result in a permit modification.

(c) **Anticipated Noncompliance** – The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

6. **Additional Reports** –

(a) **Compliance Schedules** – Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted in an electronic format by the permittee no later than 30 days following each schedule date.

(b) **Transfer of Permits** – This permit is not transferable to any person except after notice is sent to the Director in an electronic format at least 30 days prior to transfer and the requirements of 40 CFR 144.38(a) have been met. Pursuant to requirements at 40 CFR 144.38(a), the Director will require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

(c) **Other Noncompliance** – The permittee shall report in an electronic format all other instances of noncompliance not otherwise reported with the next monitoring report. The reports shall contain the information listed in Section O(3)(b) of this permit.

(d) **Other Information** – When the permittee becomes aware of failure to submit any relevant facts in the permit application or that incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such

facts or corrected information in an electronic format within 10 days in accordance with 40 CFR 144.51(l)(8).

(e) **Report on Permit Review** – Within 30 days from the effective date of this permit, the permittee shall certify to the Director in an electronic format that he or she has read and is personally familiar with all terms and conditions of this permit.

7. Records –

(a) The permittee shall retain records and all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit (including records from pre-injection, active injection, and post-injection phases) for a period of at least 10 years from collection.

(b) The permittee shall maintain records of all data required to complete the permit application form for this permit and any supplemental information (e.g., modeling inputs for AoR delineations and reevaluations, plan modifications) submitted under 40 CFR 144.27, 144.31, 144.39, and 144.41 for a period of at least 10 years after site closure.

(c) The permittee shall retain records concerning the nature and composition of all injected fluids until 10 years after site closure.

(d) The retention periods specified in Section O(7)(a) through (c) of this permit may be extended by request of the Director at any time. The permittee shall continue to retain records after the retention period specified in Section O(7)(a) through (c) of this permit or any requested extension thereof expires unless the permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

(e) Records of monitoring information shall include:

(i) The date, exact place, and time of sampling or measurements;

(ii) The name(s) of the individual(s) who performed the sampling or measurements;

(iii) A precise description of both sampling methodology and the handling of samples;

(iv) The date(s) analyses were performed;

(v) The name(s) of the individual(s) who performed the analyses;

(vi) The analytical techniques or methods used; and

(vii) The results of such analyses.

P. PUBLIC AVAILABILITY OF MONITORING AND COMPLIANCE DATA

1. The permittee shall develop and maintain a publicly accessible website with all available monitoring data collected under this Permit. The website must be accessible to persons with disabilities and compliant with Section 508, and it shall include:

   (a) Semi-annual monitoring reports and data;

   (b) An executive summary (in both English and Spanish) that interprets the Semi-annual monitoring reports and data;

   (c) Real-time display of data collected for any Surface Air/Soil Gas Monitoring required under Section M(9) and Leak Detection Monitoring required under Section M(10) of this Permit; and

   (d) Notification of any permit non-compliance on a quarterly basis, including the steps taken to resolve the non-compliance, and any actions taken to prevent a re-occurrence of the non-compliance.

Q. WELL PLUGGING, POST-INJECTION SITE CARE, AND SITE CLOSURE

1. **Well Plugging Plan** – The permittee shall maintain and comply with the approved Well Plugging Plan (Attachment D of this permit) which is an enforceable condition of this permit and shall meet the requirements of 40 CFR 146.92.

2. **Revision of Well Plugging Plan** – If the permittee finds it necessary to change the Well Plugging Plan (Attachment D of this permit), a revised plan shall be submitted in an electronic format to the Director for written approval. Any amendments to the Well Plugging Plan must be approved by the Director, must be incorporated into the permit and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41.

3. **Notice of Plugging and Abandonment** – The permittee must notify the Director in writing in an electronic format pursuant to 40 CFR 146.92(c), at least 60 days before plugging, conversion or abandonment of a well. At the discretion of the Director, a shorter notice period may be allowed.

4. **Plugging and Abandonment Approval and Report** –

   (a) The permittee must receive written approval of the Director before plugging the well and shall plug and abandon the well in accordance with 40 CFR 146.92, as provided in the Well Plugging Plan (Attachment D of this permit).

   (b) Within 60 days after plugging, the permittee must submit in an electronic format a plugging report to the Director. The report must be certified as accurate by the

permittee and by the person who performed the plugging operation (if other than the permittee.) The permittee shall retain the well plugging report in an electronic format for 10 years following site closure. The report must include:

(i) A statement that the well was plugged in accordance with the Well Plugging Plan previously approved by the Director (Attachment D of this permit); or

(ii) If the actual plugging differed from the approved plan, a statement describing the actual plugging and an updated plan specifying the differences from the plan previously submitted and explaining why the Director should approve such deviation. If the Director determines that a deviation from the plan incorporated in this permit may endanger USDWs, the permittee shall re-plug the well as required by the Director.

5. **Temporary Abandonment** – If the permittee ceases injection into the well for more than 24 consecutive months, the well is considered to be in a temporarily abandoned status, and the permittee shall plug and abandon the well in accordance with the approved Well Plugging Plan, 40 CFR 144.52 (a)(6), and 40 CFR 146.92, or make a demonstration of non-endangerment of this well while it is in temporary abandonment status. During any periods of temporary abandonment or disuse, the well will be tested to ensure that it maintains mechanical integrity, according to the requirements and frequency specified in Section L(2) of this permit. The permittee shall continue to comply with the conditions of this permit, including all monitoring and reporting requirements according to the frequencies outlined in the permit.

6. **Post-Injection Site Care and Site Closure Plan** –

(a) The permittee shall maintain and comply with the Post-Injection Site Care and Site Closure Plan (Attachment E of this permit), which meets the requirements of 40 CFR 146.93 and is an enforceable condition of this permit. The permittee shall:

(i) Upon cessation of injection, either submit in an electronic format for the Director's approval an amended Post-Injection Site Care and Site Closure Plan or demonstrate through monitoring data and modeling results that no amendment to the plan is needed.

(ii) At any time during the life of the project, the permittee may modify and resubmit in an electronic format the Post-Injection Site Care and Site Closure Plan for the Director's approval. The permittee may, as part of such modifications to the Plan, request a modification to the post-injection site care timeframe that includes documentation of the information at 40 CFR 146.93(c)(1).

(b) The permittee shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs

are not being endangered, as specified in the Post-Injection Site Care and Site Closure Plan and in 40 CFR 146.90, and 40 CFR 146.93, including:

(i) Ground water quality monitoring;

(ii) Tracking the position of the carbon dioxide plume and pressure front including direct pressure monitoring and geochemical plume monitoring and the use of indirect methods;

(iii) Any other required monitoring, e.g., soil gas and/or surface air monitoring described in the Post-Injection Site Care and Site Closure Plan;

(iv) The permittee shall submit in an electronic format the results of all monitoring performed according to the schedule identified in the Post-Injection Site Care and Site Closure Plan; and

(v) The permittee shall continue to conduct post-injection site monitoring for at least 50 years or for the duration of any alternative timeframe approved pursuant to 40 CFR 146.93(c) and the Post-Injection Site Care and Site Closure Plan.

(c) The post-injection monitoring must continue until the project no longer poses an endangerment to USDWs and the demonstration pursuant to 40 CFR 146.93(b)(2) and as described in Section Q(6)(d) of this permit is approved by the Director.

(d) Prior to authorization for site closure, the permittee shall submit to the Director for review and approval, in an electronic format, a demonstration, based on information collected pursuant to Section Q(5)(b) of this permit, that the carbon dioxide plume and the associated pressure front do not pose an endangerment to USDWs and that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs, as required under 40 CFR 146.93(b)(3). The Director reserves the right to amend the post-injection site monitoring requirements (including extending the monitoring period) if the carbon dioxide plume and the associated pressure front have not stabilized or there is a concern that USDWs are being endangered.

(e) The permittee shall notify the Director in an electronic format at least 120 days before site closure. At this time, if any changes to the approved Post-Injection Site Care and Site Closure Plan in Attachment E of this permit are proposed, the permittee shall submit a revised plan.

(f) After the Director has authorized site closure, the permittee shall plug all monitoring wells as specified in Attachment E of this permit – the Post-Injection Site Care and Site Closure Plan – in a manner which will not allow movement of injection or formation fluids that endangers a USDW. The permittee shall also restore the site to its pre-injection condition.

(g) The permittee shall submit a site closure report in an electronic format to the Director within 90 days of site closure. The report must include the information specified at 40 CFR 146.93(f).

(h) The permittee shall record a notation on the deed to the facility property or any other document that is normally examined during a title search that will in perpetuity provide any potential purchaser of the property the following information:

(i) The fact that land has been used to sequester carbon dioxide;

(ii) The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and

(iii) The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.

(i) The permittee shall retain for 10 years following site closure an electronic copy of the site closure report, records collected during the post-injection site care period, and any other records required under 40 CFR 146.91(f)(4). The permittee shall deliver the records in an electronic format to the Director at the conclusion of the retention period.

R. EMERGENCY AND REMEDIAL RESPONSE

1. The Emergency and Remedial Response Plan describes actions the permittee must take to address movement of the injection or formation fluids, including surface leaks of carbon dioxide or other contaminants, that may cause an endangerment to a USDW or public health during construction, operation, and post-injection site care periods. The permittee shall maintain and comply with the approved Emergency and Remedial Response Plan (Attachment F of this permit), which is an enforceable condition of this permit, and with 40 CFR 146.94.

   Prior to the Director authorizing injection, the permittee shall revise the Emergency and Remedial Response Plan to include a description and documentation of the contracts the permittee holds with service providers, including any contracts or access agreements with local emergency response authorities, to perform the actions outlined in the Emergency and Remedial Response Plan, and shall confirm that any required payments were made to Kern County Planning and Natural Resources Department, as required by the approved Conditional Use Permits, for transfer to the Kern County Fire Department for equipment and training specific to the detection and control of emergency situations caused by the release of carbon dioxide.

2. If the permittee obtains evidence that the injected carbon dioxide or associated pressure front may cause endangerment to a USDW or public health, the permittee must:

   (a) Cease injection in accordance with Sections K(8) and K(9)(a) or (b), and Attachments A or F of this permit;

   (b) Take all steps reasonably necessary to identify and characterize any release;

   (c) Notify the Director within 24 hours; and

   (d) Implement the Emergency and Remedial Response Plan (Attachment F of this permit) approved by the Director.

3. At least every five years, or more frequently when monitoring and operational conditions warrant, the permittee shall review and update the Emergency and Remedial Response Plan as required at 40 CFR 146.94(d) or demonstrate to the Director that no update is needed. The amended Emergency and Remedial Response Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation, following any significant changes to the facility such as addition of injection wells, or when required by the Director.

4. Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and confirmation of the results. Once approved by the Director, the revised Emergency and Remedial Response Plan will become an enforceable condition of this permit.

S. COMMENCING INJECTION

The permittee may not commence injection until:

1. Results of the formation testing and logging program and a demonstration that all pre-operational testing objectives have been met as specified in Section J of this permit and in 40 CFR 146.87 are submitted to the Director in an electronic format and subsequently reviewed and approved by the Director;

2. Mechanical integrity of the well has been demonstrated in accordance with 40 CFR 146.89(a)(1) and (2), and in accordance with Section L(1) through (3) of this permit;

3. The completion of corrective action required by the Area of Review and Corrective Action Plan found in Attachment B of this permit in accordance with 40 CFR 146.84;

4. All requirements at 40 CFR 146.82(c) have been met, including but not limited to reviewing and updating of the Area of Review and Corrective Action, Testing and Monitoring, Well

Plugging, Post-Injection Site Care and Site Closure, and Emergency and Remedial Response plans to incorporate final site characterization information, final delineation of the AoR, and the results of pre-injection testing, and information has been submitted in an electronic format, reviewed and approved by the Director;

5. The permittee has submitted the results of an analysis of the physical and chemical characteristic of the carbon dioxide stream for all analytical parameters identified in the Testing and Monitoring Plan (Attachment C of this Permit).

6. Construction is complete and the permittee has submitted to the Director in an electronic format a notice that completed construction is in compliance with 40 CFR 146.86 and Section I of this permit;

7. The Director has inspected or otherwise reviewed the injection well and all submitted information and finds it is in compliance with the conditions of this permit;

8. The Director has approved demonstration of the alarm system and shut-off system under Section K(6) of this permit;

9. The Permittee has revised the Emergency and Remedial Response Plan to include a description and documentation of the contracts the permittee holds with service providers in order to perform the actions outlined in the Emergency and Remedial Response Plan;

10. The Director has approved the publicly accessible website required under Section P of this permit; and

11. The Director has given written authorization to commence injection.

ATTACHMENTS

These attachments include, but are not limited to, permit conditions and plans concerning operating procedures, monitoring and reporting, as required by 40 CFR parts 144 and 146. The permittee shall comply with these conditions and adhere to these plans as approved by the Director, as follows:

A. SUMMARY OF OPERATING REQUIREMENTS

B. AREA OF REVIEW AND CORRECTIVE ACTION PLAN

C. TESTING AND MONITORING PLAN

D. WELL PLUGGING PLAN

E. POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

F. EMERGENCY AND REMEDIAL RESPONSE PLAN

G. CONSTRUCTION DETAILS

H. FINANCIAL ASSURANCE DEMONSTRATION

I. STIMULATION PROGRAM

SUMMARY OF REQUIREMENTS

CLASS VI OPERATING AND REPORTING CONDITIONS

Elk Hills 26R Storage Project

Facility Information

Facility name: Elk Hills 26R Storage Project
345C-36R

Well location: Elk Hills Oil Field, Kern County, CA
35°16'30.3383"N / 6126575.64
119°27'27.7825"W / 2289589.31

Table 1. Injection Well Operating Conditions

PARAMETER/CONDITION	LIMITATION or PERMITTED VALUE
Maximum Injection Pressure - Surface	1888 psi
Maximum Injection Pressure - Bottomhole	3847 psi
Annulus Pressure	3074 psi
Annulus Pressure/Tubing Differential	300 psi
Maximum CO_2 Injection Rate	25 mmscfpd

There will be continuous monitoring of injection pressure, rate and annulus pressure for the injector, as described in the well Construction, Operation and Plugging details (COP) document for 345C-36R.

The maximum injection pressure, which serves to prevent confining-formation fracturing, was determined: using the fracture gradient of 0.701psi/ft obtained from Fracture stimulation data obtained from well 388-26R in the 26R reservoir multiplied by 0.9, per 40 CFR 146.88(a).

Routine Shutdown Procedure

For injection shutdowns occurring under routine conditions (e.g., for well workovers), the permittee will reduce CO_2 injection at a rate of 165 tons per day over a 6 day period to ensure protection of health, safety, and the environment. This procedure applies to routine shutdowns and to “gradual shutdowns” described in the Emergency and Remedial Response plan. (Procedures that address immediately shutting in the well are in the Emergency and Remedial Response Plan of this permit.)

Table 2. Class VI Injection Well Reporting Requirements

ACTIVITY	REPORTING REQUIREMENTS
CO_2 stream characterization	Semi-annually
Injection pressure, injection rate, injection volume, pressure on the annulus, and annulus fluid level	Semi-annually
Corrosion monitoring	Semi-annually
External MITs	Within 30 days of completion of test
Pressure fall-off testing	In the next semi-annual report

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

Table 3. Class VI Project Reporting Requirements

ACTIVITY	REPORTING REQUIREMENTS
Groundwater quality monitoring	Semi-annually
Plume and pressure front tracking	In the next semi-annual report
Monitoring well MITs	Within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Facility Information

Facility name: Elk Hills 26R Storage Project

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment B - AoR_CA	1	01/11/21
Attachment B - AoR_CA	2	05/31/22
Attachment B - AoR_CA	3	12/21/22
Attachment B - AoR_CA	4	05/14/2023
Attachment B – AoR_CA	5	6/23/2023

Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase

- Liquid and gas relative permeability
- Capillary pressure data
- Current saturation, pressure, and temperature estimates

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the Elk Hills 26R project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of CO_2 in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual oil in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.
2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).
3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

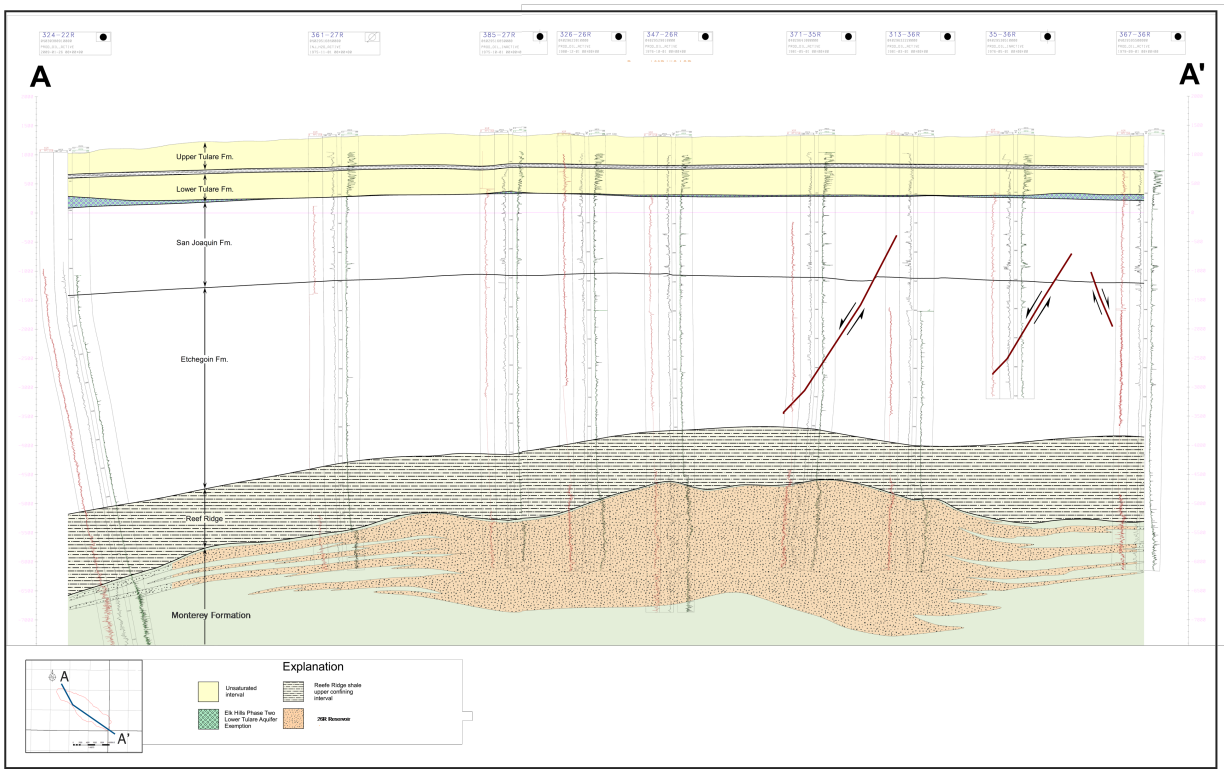
1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al
2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

Site Geology and Hydrology

The 31S field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation 26R sands, present in the southwestern portion of the field pinch out on top of the structure and along strike (Figure 1).

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation 26R, but for all Monterey accumulations in the greater Elk Hills area.

Figure 1: Cross-section A-A' showing lateral Monterey Formation 26R sand pinch-out.



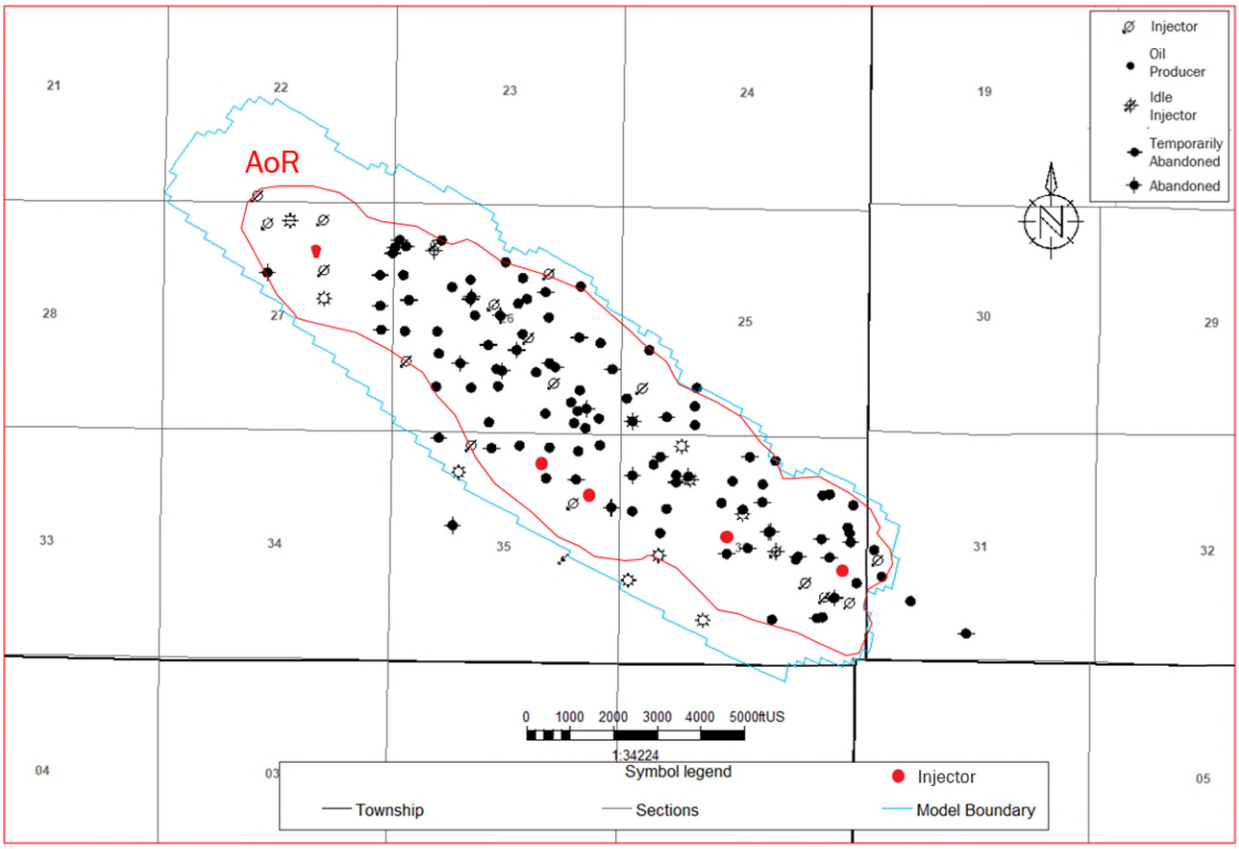
The Elk Hills 26R Class VI injection wells will target injection in the Monterey Formation 26R sands. The Monterey Formation 26R oil and gas reservoir was discovered in the 1940's and has been developed with primary production and pressure maintenance (Table 1: Production and Injection volumes). Starting in the year 1998, pressure maintenance ceased, and the gas cap reservoir was "blown-down", depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 150-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

Table 1: Production and injection volumes for the Monterey Formation 26R reservoir.

Process	Phase	Volume
Production	Oil	222 million barrels
	Gas	1,244 billion cubic feet
	Water	81 million barrels
Injection	Water	114 million barrels
	Gas	841 billion cubic feet

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir, and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

Figure 2: Location of wells with open-hole log data used to develop the static model and computational model boundary.



Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2. The lateral dimensions and vertical thickness of the geomodel were chosen to capture the maximum extent of the mapped 26R reservoir. Well logs from the wells shown in Figure 2 were used to map the extent and delineate the edges of the reservoir where the reservoir sands pinchout or transition to shale. The total grid dimensions were chosen to adequately capture the reservoir properties and heterogeneity, while at the same time maintaining computational efficiency.

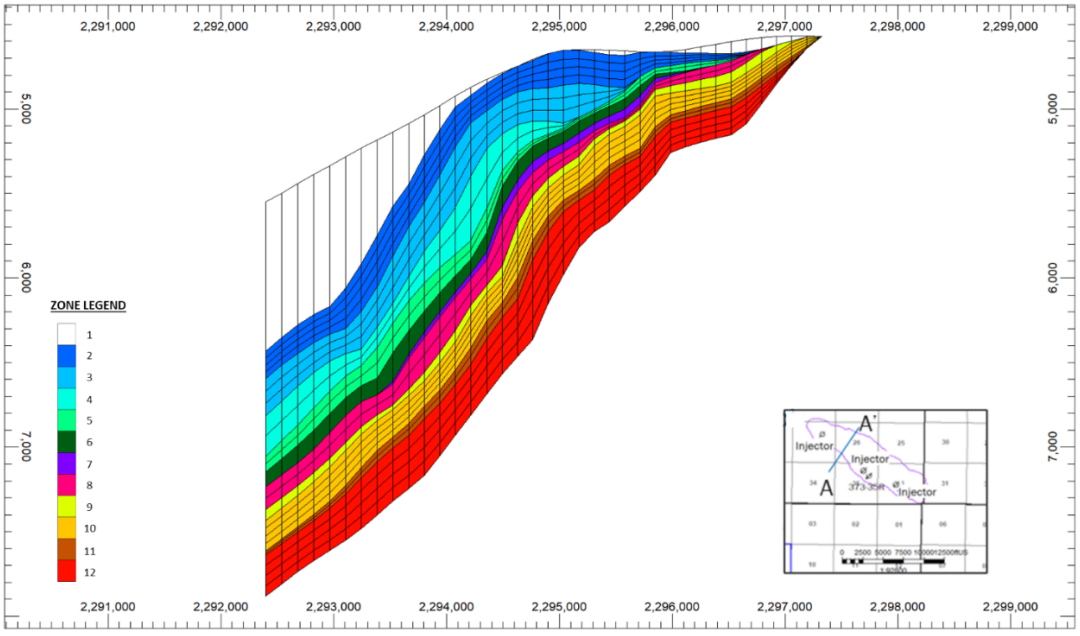
Table 2. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD 83		
Coordinate System Units	Feet		
Zone	CA83-VF		
FIPSZONE	0405	**ADSZONE**	3376
Coordinate of X min	6113669.29	**Coordinate of X max**	6130553.74
Coordinate of Y min	2286478.43	**Coordinate of Y max**	2299980.65
Elevation of bottom of domain	-6651.18	**Elevation of bottom of domain**	-3544.42

The geo-cellular grid is uniformly spaced throughout the 3.7 square mile model area (Figure 2) at 190 feet by 150 feet. The model is oriented at 18 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were selected to define plume extent and edges of the Monterey Formation 26R reservoir.

The reservoir has been separated into 12 zones and 27 layers (Figure 3) respectively and an average grid cell height of 117 feet. Each of the 12 zones is a mappable sand and were modeled separately to ensure stationarity of the geostatistical model. With a data driven geostatistical model, the model can discretize the reservoir into multiple zones. Grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing CO_2 movement. Well data that defines the stratigraphy also defines the structure of the 26R storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

Figure 3: Static model layering of the Monterey Formation 26R reservoir showing the 12 zones, and the 27 layers. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale laterally.



Porosity and Permeability

Figure 2 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Figure 4A shows how the log derived porosity compares to the upscaled model (synthetic) porosity for 363-27R (track five with log derived in black and the Upscaled model / synthetic porosity in blue). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 4B) that is dependent on porosity and clay volume.

Figure 4A: Log derived and Model Upscaled (Synthetic porosity) for 363-27R (track five with log derived in black and the Upscaled model synthetic in blue).

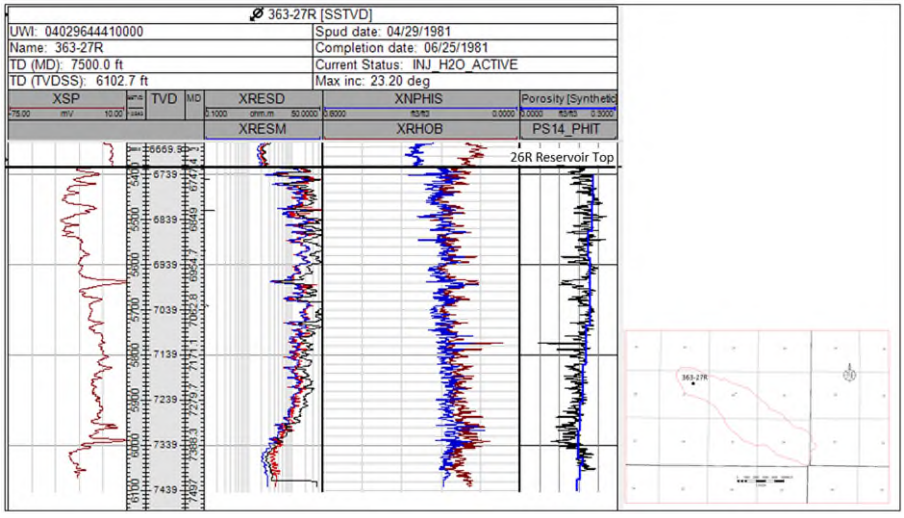


Figure 5B: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.

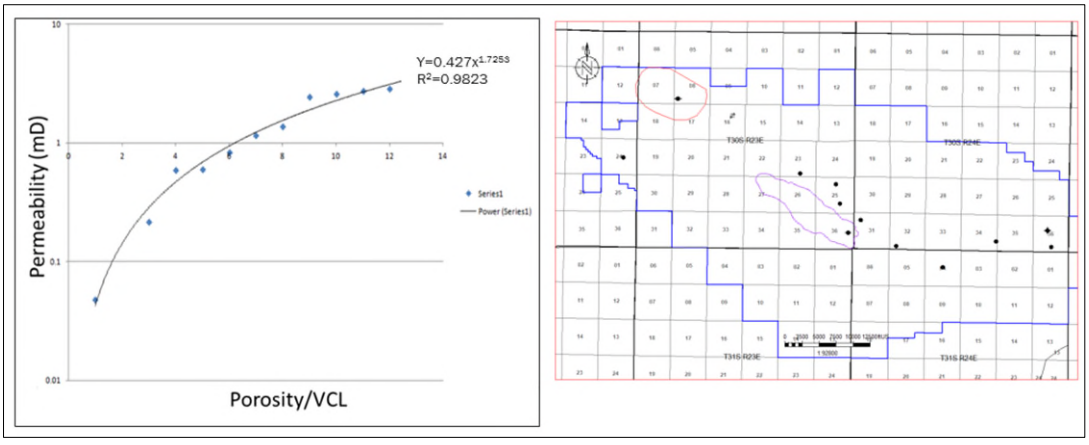


Figure 6: Monterey Formation 26R sands porosity and permeability distribution in the static model.

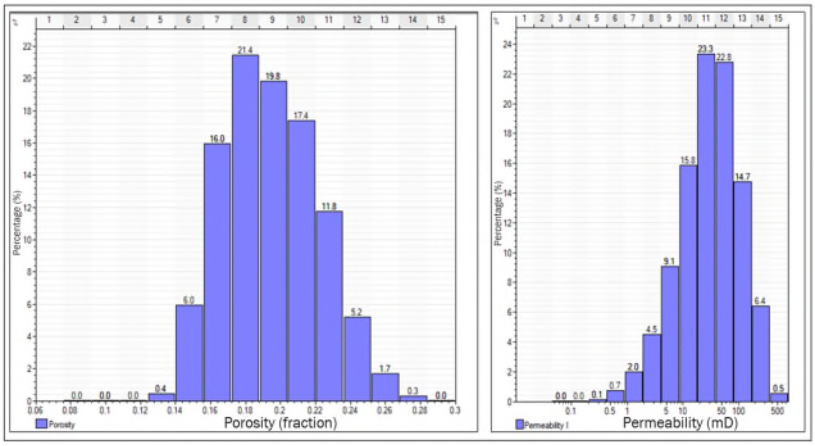
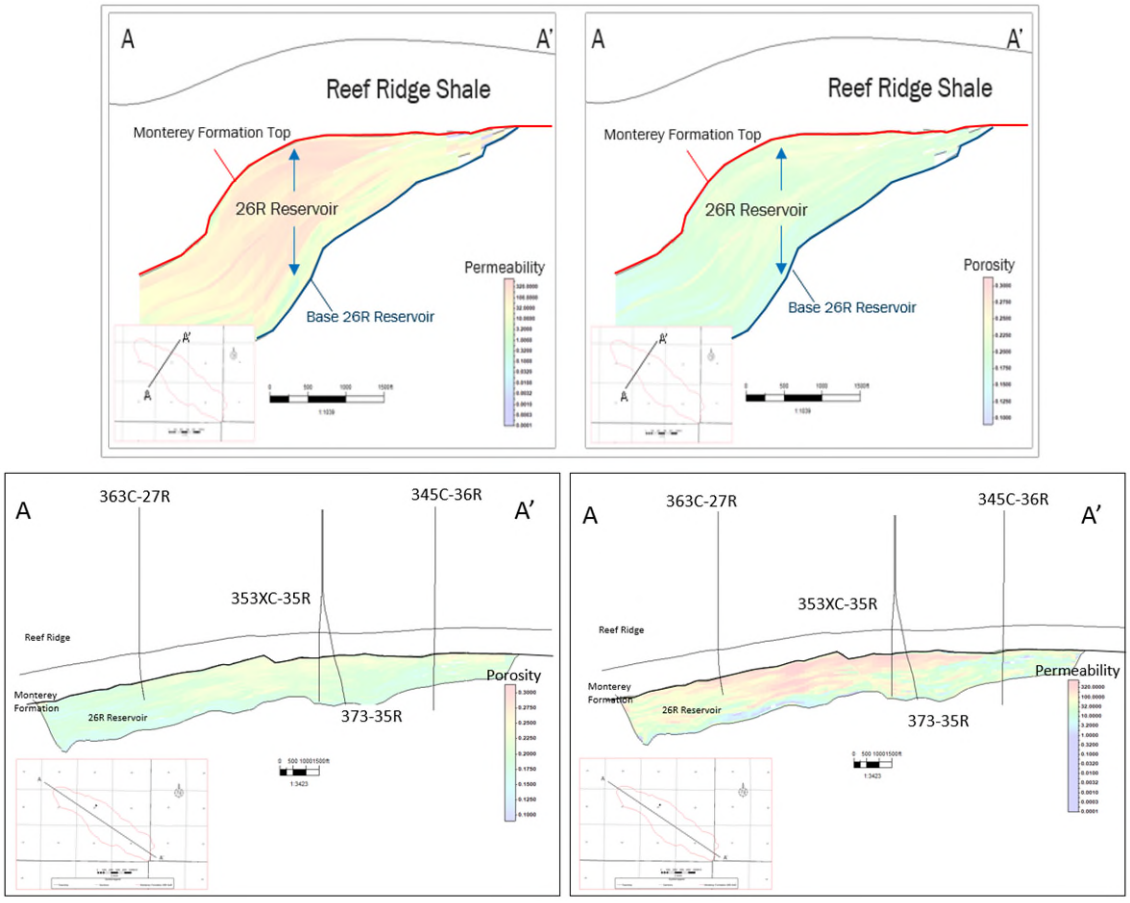


Figure 5 shows porosity and permeability histograms for the Monterey Formation 26R sands in the static model. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 6 shows the permeability and porosity distribution in cross-section A-A'.

Figure 7: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



A variable permeability anisotropy was included in the model, with a Vertical permeability (kv) to horizontal permeability (kh) ratio which ranged from 0.0001 to 1, with a log mean of value of 0.01. The permeability anisotropy was arrived at by upscaling log derived permeability, and then distributing the upscaled log data across the model domain. The log data was upscaled using an arithmetic mean to represent the horizontal permeability, and a harmonic mean to represent the vertical permeability.

Constitutive Relationships and Other Rock Properties

The Monterey Formation 26R reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

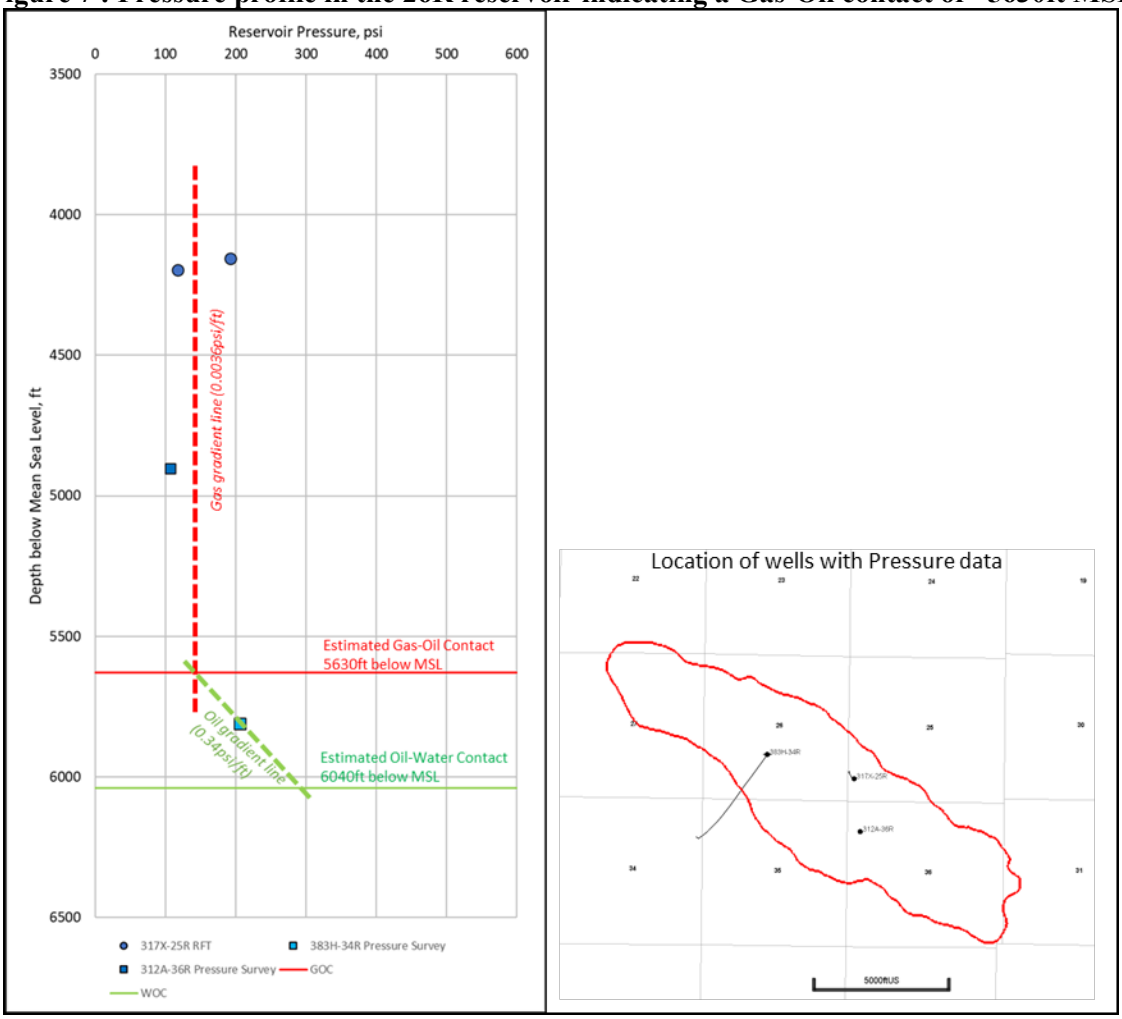
The saturations for the Gas, Oil and Water in the Gas Cap and Oil Band portions of the reservoir were determined using a Material Balance approach. The Pore Volume, discovery fluid contacts, pressure history, cumulative production and injection data for the reservoir, and the PVT properties of the fluids were used to estimate a current average oil, water, and gas saturation for the hydrocarbon portion of the 26R reservoir. These average saturations and estimates of remaining oil in place were used to iterate to a current oil-water and gas-oil contact in the computational model and the CMG GEM simulation model was initialized using the relative permeability curves, capillary pressure curves and current estimate of reservoir pressure.

The most recent data used to help validate the estimated gas-oil contact was pressure data gathered between 2006-2015. The pressure profile from this data was used to help estimate a gas contact of ~5630ft below MSL, using a gas gradient (0.0036psi/ft) and an oil gradient of 0.34psi/ft (see Figure 7). As there has not been evidence of an active aquifer following the blow down of the reservoir, the water contact is estimated to be at or near the original contact of ~6040ft below MSL, which was determined based on well logs obtained during the initial characterization of the reservoir in the 1950's.

Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs, pressure data, material balance and production analysis.

	Gas Cap	Oil Band	Water Zone
Contact (depth sub-sea)	Gas - Oil <5,630	Oil - Water 5630-6,040	> 6,040
Saturation (fraction)	Oil: 15% Water: 33.7% Gas: 51.3%	Oil: 37.1% Water: 25% Gas: 0%	Water: 100%

Figure 7 : Pressure profile in the 26R reservoir indicating a Gas-Oil contact of ~5630ft MSL



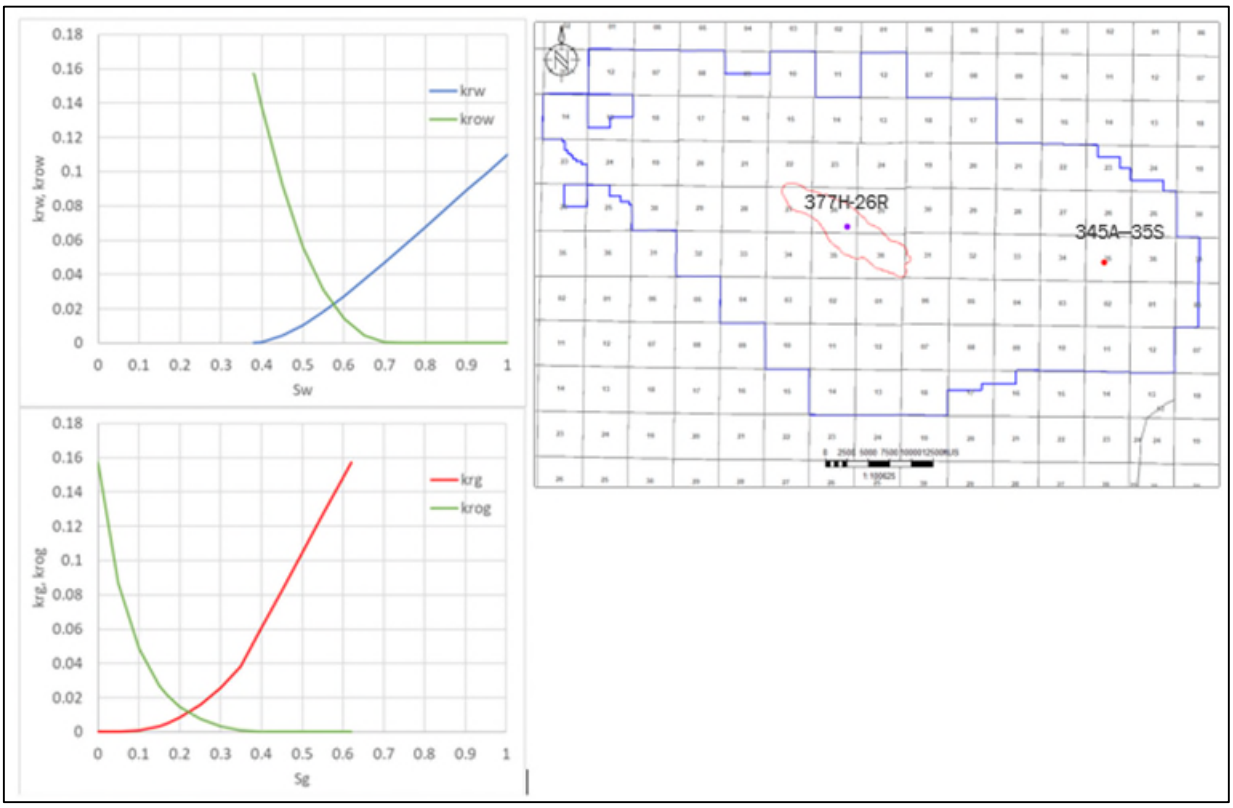
With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving krw, krow, krg, and krog as a function of saturation.

Where,
krg – relative permeability of Gas in a Gas–Oil system
krog – relative permeability of Oil in a Gas–Oil system
krow – relative permeability of Oil in an Oil-Water system
krw – relative permeability of Water in an Oil-Water system

Data acquired from Special Core Analyses (SCAL) determines these relationships. The geomodel modelled two rock types – sand and shale, but for the simulation a single sand rock type was modeled with the shale facies cells being treated as inactive cells. Core obtained from well 377H-26R in the 26R reservoir and equivalent Monterey Formation sandstone from well 345A-35S in the Elk Hills reservoir were used to generate the relative permeability relationships for the sand

facies. The data was normalized with respect to air permeability using end point scaling and a single Corey relative permeability fit was generated. Figure 8 shows the relative permeability curves used in the computational modeling and Figure 9 shows the relative permeability data from wells 377H-26R and 345A-35S in tabular form.

Figure 8: Relative permeability curves for krg-krog and krw-krow used in the computational model study and wells locations for data used to develop the curves.



The functional form of the relative permeability curves are -
krw = krwiro * ((Sw - Swcrit)/(1.0 - Swcrit - Soirw))^{Nw}
krow= krocw * ((So - Sorw)/(1.0 - Swcon - Sorw))^{Now}
krog=krogcg*((Sl - Sorg - Swcon)/(1.0 - Sgcon - Sorg - Swcon))^{Nog}
krg =krgcl *((Sg - Sgcrit)/(1.0 - Sgcrit - Soirg - Swcon))^{Ng}

With the parameters for the curve being -
Swcon - Endpoint Saturation: Connate Water = 0.38
Swcrit - Endpoint Saturation: Critical Water = 0.38
Soirw - Endpoint Saturation: Irreducible Oil for Water-Oil = 0.2
Sorw - Endpoint Saturation: Residual Oil for Water-Oil = 0.22
Soirg - Endpoint Saturation: Irreducible Oil for Gas-Liquid = 0.21
Sorg - Endpoint Saturation: Residual Oil for Gas-Liquid = 0.22
Sgcon - Endpoint Saturation: Connate Gas = 0
Sgcrit - Endpoint Saturation: Critical Gas = 0.05
krocw - Kro at Connate Water = 1

krwiro - Krw at Irreducible Oil = 0.43
krgcl - Krg at Connate Liquid = 0.4
krogcg - Krog at Connate Gas = 1
Nw = 1.3
Now = 3
Nog = 3.8
Ng = 2.5

The end point relative permeabilities of the curves were then scaled by a factor of 0.1547 using Oil to Air permeability ratio from well 345A-35S, so that the curves would be in reference to air permeability, which was used in the simulation model.

Figure 9: Monterey formation relative permeability data from wells 345A-35S and 377H-26R

Well: 345A-35S						
Sample Depth, feet:	7161.80					
Permeability to Air, md:		99.1				
Porosity, fraction:		0.221				
Initial Water Saturation, fraction:		0.380				
Effective Oil Permeability at Swi, md:		15.6				
Oil to Air Permeability ratio		0.1574				
* Relative to the effective permeability to oil at initial water saturation						
Water Displacing Oil				Gas Displacing Oil		
Sw	Relative Permeability to Water	Relative Permeability to Oil		Sg	Relative Permeability to Gas	Relative Permeability to Oil
0.380	0.000	1.000		0.000	-	1.000
0.436	0.026	0.662		0.184	0.002	0.109
0.460	0.053	0.525		0.198	0.005	0.093
0.510	0.108	0.324		0.226	0.014	0.069
0.557	0.176	0.176		0.269	0.040	0.040
0.645	0.328	0.033		0.334	0.106	0.010
0.803	0.615	-		0.405	0.195	-

Well: 377H-26R						
Sample Depth, feet :		5972.8		6015.9		
Permeability to Air, md :		100.0		286		
Porosity, fraction :		0.186		0.213		
Initial Water saturation, fraction		0.234		0.219		
* Relative to the effective permeability to oil at initial water saturation						
Water Displacing Oil				Gas Displacing Oil		
Sw	Relative Permeability to Water	Relative Permeability to Oil		Sg	Relative Permeability to Gas	Relative Permeability to Oil
0.234	0.000	1.000		0.000	0.000	1.000
0.286	0.034	0.851		0.133	0.011	0.332
0.313	0.045	0.764		0.162	0.017	0.252
0.377	0.069	0.541		0.198	0.029	0.170
0.461	0.098	0.292		0.226	0.041	0.131
0.523	0.121	0.147		0.259	0.059	0.091
0.568	0.141	0.070		0.285	0.082	0.070
0.590	0.152	0.040		0.309	0.101	0.051
0.606	0.163	0.025		0.342	0.134	0.035
0.620	0.168	0.018		0.369	0.175	0.022
0.644	0.182	0.009		0.394	0.221	0.015
0.649	0.187	0.006		0.411	0.249	0.011
0.667	0.195	0.003		0.432	0.279	0.007
0.685	0.205	0.001		0.486	0.406	
0.694	0.213					

Mineralization

Based on previous studies on reactive transport modeling and geochemical reactions in CCS applications have shown that the amount of CO2 predicted to be trapped by mineralization reactions is extremely small over a 100 year post injection time frame (IPCC, 2005: IPCC Special report on Carbon Dioxide Capture and Storage) for sandstone reservoirs. In addition, due to the fairly low salinity of the Formation water, stable mineralogy and minor expected on the AoR, reactive transport was not included as a part of the compositional simulation modeling at this time for computational efficiency.

Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation 26R reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

2. Performance data from operating the Monterey Formation 26R oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 10) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 10) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

    iii. Pressure in the reservoir is at 150 - 300 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

3. The 26R reservoir pinches out in the updip and lateral portions of the reservoir, and transitions to shale as shown in Figure 1.

Pressure data obtained while drilling wells in the AoR shows the pressure isolation of the 26R reservoir from the overlying Etchegoin Formation and the Lower Monterey Formation. Figure 11 shows the pressure data obtained for the formations, and location of these wells within the AoR.

Additional pressure data will be gathered and provided to the EPA during the pre-operational testing phase when all production operations in the reservoir have ceased, to confirm the historical understanding.

Figure 10: Monterey Formation 26R production and injection data.

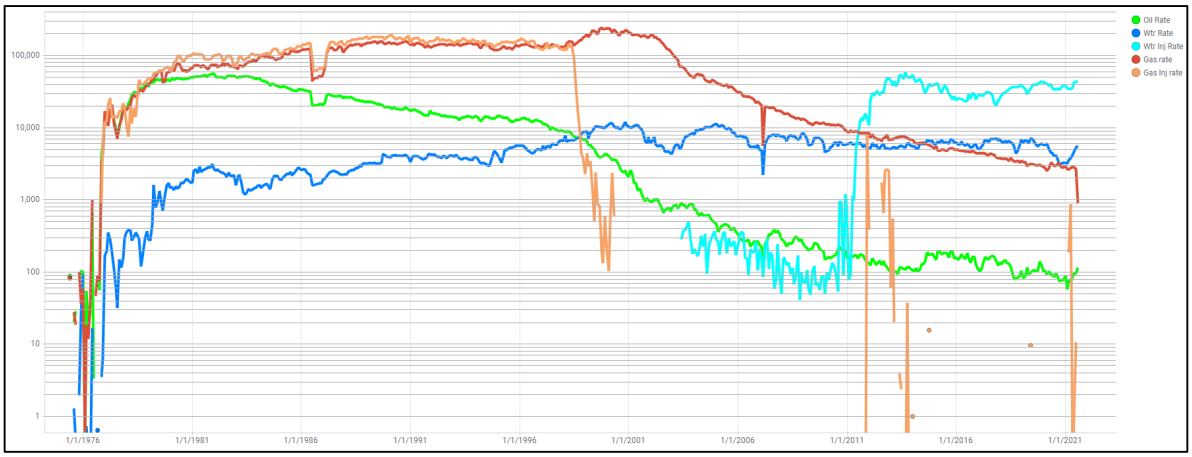
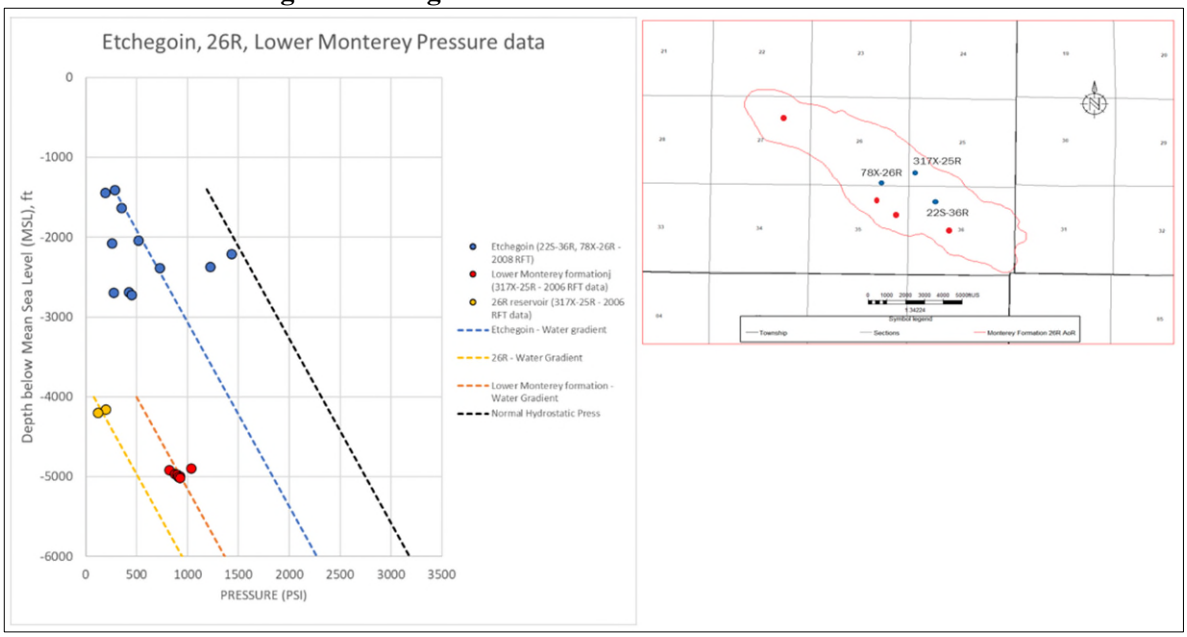


Figure 11: Etchegoin Formation, 26R Reservoir and Lower Monterey Formation repeat formation tester (RFT) pressure data in the AoR shows pressure isolation between the different formations. Data was obtained during the drilling of wells between 2006-2008.



Initial Conditions

Initial model conditions (start of CO_2 injection) of the Monterey Formation 26R reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4. Depths in the Table 4 are depths below Mean Sea Level (MSL), which is used as the reference elevation.

Table 4. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft, below Mean Sea Level)	Data Source
Temperature	210	Fahrenheit	5,630	Fluid Analysis
Formation pressure	150	Pounds per square inch	5,630	Pressure Test
Fluid density	61	Pounds per cubic foot	5,630	Water analysis
Salinity	25,000	Parts per million		Water analysis

Operational Information

Details on the injection operation are presented in Table 5.

Table 5. Operating details.

Operating Information	Injection Well 1 373-35R	Injection Well 2 345C-36R	Injection Well 3 353XC-35R	Injection Well 4 363C-27R
Location (global coordinates)	35.1634 N 119.2824W	35.2743 N 119.4577 W	35.3768 N 119.4732 W	35.2779 N 119.4535 W
Model coordinates (ft) X Y	 6121906 2290081	 6126556 2289316	 6121940 2290248	 6117204 2295938
No. of perforated intervals	13	25	11	12
Perforated interval (ft TVD / MD) Top Bottom	 6807 / 7086 7109 / 7426	 6097 / 6101 7710 / 7720	 6625 / 6810 8373 / 8545	 6698 / 6731 8124 / 8216
Production Casing diameter (in.)	4.5”	4.5”	4.5”	4.5”
Planned injection period Start End	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051
Injection duration (years)	27	27	27	27
Injection rate (t/day)*	993	993	993	993

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

Fracture Pressure and Fracture Gradient

A fracture gradient of 0.701 psi/ft is expected for the 26R reservoir. This is based on fracture stimulation performed on well 388-26R in the 26R reservoir.

CTV will ensure that the injection pressure is below 90% of the fracture pressure as calculated at the top perforation for each injector. The maximum allowable subsurface wellbore injection pressure for the 4 injectors in the project is shown below in Table 6.

Table 6. Injection pressure details.

Injection Pressure Details	Injection Well 1 373-35R	Injection Well 2 345C-36R	Injection Well 3 353XC-35R	Injection Well 4 363C-27R
Fracture Gradient (psi/ft)	0.701	0.701	0.701	0.701
Maximum allowable downhole injection pressure (90% of fracture pressure), psi	4294	3847	4180	4226
Elevation corresponding to maximum allowable bottomhole pressure (ft, TVD / MD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Elevation of top of the perforated interval (ft, TVD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Planned bottom hole injection pressure at top of perforations (psi)	4060	3555	3787	3558
Planned bottom hole injection gradient at top of perforations (psi/ft)	0.596	0.583	0.572	0.531

Proposed Carbon Dioxide Stream

CTV is planning to construct a carbon capture and sequestration "hub" project (*i.e.*, a project that collects carbon dioxide (CO_2) from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC permitted injection well(s)). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The anthropogenic CO_2 will be sourced from:

- Initial onsite emissions:
    - Lone Cypress blue hydrogen plant, up to 200,000 tonnes per annum
    - Elk Hills field gas treatment (pre-combustion for Elk Hills Power Plant), up to 200,000 tonnes per annum
    - Avnos Direct Air Capture (DAC), up to 1,500 tonnes per annum
- Future emission Sources:
    - CalCapture Elk Hills 550 MW natural gas power plant (post combustion), renewable fuel plants, steam generators post combustion and other power plants / industrial sources in the area

CTV expects the CO_2 stream to be sampled at the transfer point from the source and analyzed according to the analytical methods described in the QASP document and the Attachment C – Testing and Monitoring plan document. Should the injectate not meet the minimum requirements, it will be rejected.

The anticipated injection temperature at the wellhead is 90 – 130° F.

For the purposes of Geochemical modeling, CO2 Plume modeling, and Well design, two major types of Injectate compositions were considered based on the source.

- Injectate 1: is a potential injectate stream composition from a Direct Air Capture (DAC) or a Pre-Combustion source (such as the Lone Cypress blue hydrogen facility) or a Post-Combustion source (such as a gas fired power plant or steam generator) where N2 will likely be the major impurity.
- Injectate 2: is a potential injectate stream composition from a Biofuel Capture source (such as a Biodiesel plant) or an Oil & Gas Refinery or Natural Gas processing facilities (such as CO2 capture from the feed gas to the Elk Hills Power plan stated above) where light end Hydrocarbons (Methane, Ethane) will be the major impurity.

Design studies for CO2 capture at the planned Lone Cypress facility and design studies for CO2 capture from feed gas to the Elk Hills power plant were incorporated into the two injectate compositions shown in Table 7, in addition to preliminary injectate specifications provided by other potential sources and from literature studies.

Table 7 : Injectate compositions

Component	Injectate 1	Injectate 2
	Mass%	**Mass%**
CO2	99.213%	99.884%
H2	0.051%	0.006%
N2	0.643%	0.001%
H2O	0.021%	0.000%
CO	0.029%	0.001%
Ar	0.031%	0.000%
O2	0.004%	0.000%
SO2+SO3	0.003%	0.000%
H2S	0.001%	0.014%
CH4	0.004%	0.039%
NOx	0.002%	0.000%
NH3	0.000%	0.000%
C2H6	0.000%	0.053%
Ethylene	0.000%	0.002%
Total	**100.00%**	**100.00%**

For geochemical and plume modeling scenarios, these injectate compositions were simplified to a 4-component system, shown in Table 8. The 4 component simplified compositions cover 99.9% by mass of Injectate 1 & 2 and cover particular impurities of concern (H2S and SO2). The estimated properties of the injectates at downhole conditions are specified in Table 9

Table 8: Simplified 4 component composition for Injectate 1 and Injectate 2

Injectate 1	
Component	**mass%**
CO2	99.213%
N2	0.643%
SO2+SO3	0.003%
H2S	0.001%

Injectate 2	
Component	**mass%**
CO2	99.884%
CH4	0.039%
C2H6	0.053%
H2S	0.014%

No corrosion is expected in the absence of free phase water provided that the entrained water is kept in solution with the CO_2. This will be ensured by maintaining a water specification limit <25 lb/mmscf for the injectates, and this specification will be a condition of custody transfer at the capture facility. For transport through pipelines, which typically use standard alloy pipeline materials, this specification is critical to the mechanical integrity of the pipeline network, and out of specification product will be immediately rejected. Therefore, all product transported through pipeline to the injection wellhead is expected to be dry phase CO_2 with no free phase water present.

Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. CRA tubing will be used in the injection wells to mitigate any potential corrosion impact should free-phase water from the reservoir become present in the wellbore, such as during shut-in events when formation liquids, if present, could backflow into the wellbore. CTV may further optimize the maximum water content specification prior to injection based on technical analysis.

Injectate will be sampled and analyzed as part of the pre-operational testing, to confirm that it is consistent with the well design, Plume modeling and Geochemical modeling assumptions.

Computational Modeling Results

Predictions of System Behavior

The base simulation case was run for a 127 year period, covering 27 years of injection and 100 years of post injection. The simulated injection storage capacity is 38MMT taking the reservoir from current reservoir conditions to initial discovery pressure of 3,250 psi. A 100% CO2 injectate stream was assumed for the base case simulation studies. Additionally, scenarios were also run for the two injectates (Injectate 1 and Injectate 2) detailed in the "Proposed Carbon Dioxide Stream" section. Minimal difference in results was seen between the cases. Table 9 summarizes the expected CO2 injectate properties at reservoir conditions over the life of the project.

Table 9: CO2 injectate properties at reservoir conditions

Injectate property	100% CO2	Injectate 1	Injectate 2
Viscosity, cp	0.019-0.044	0.019-0.043	0.019-0.045
Density, kg/m3	16.6-544.8	16.5-543.5	1.035-545.8
Salinity, ppm	NA	NA	NA
Compressibility factor, Z	0.97-0.59	0.97-0.59	0.97-0.59

The following maps (Figure 12) and cross-sections (Figure 13) show the computational modeling results and development of the CO_2 plume at multiple time-steps. For all layers in the model and at all time-steps, the plume stays within the AoR. The CO2 plume grows rapidly within the first 15 years of injection with majority of the CO2 going into the higher quality upper portion of the 26R reservoir and being controlled by the structure of the reservoir and the closed updip boundary. Thereafter, the CO_2 injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the CO_2 injectate remains as super-critical CO_2.

The CO2 plume reaches its maximum vertical and lateral extent 20 years after the end of injection. The vertical and lateral extent of the CO2 plume predicted by the model aligns well with estimated discovery Oil-Water contacts of the reservoir and the vertical and lateral extent of the reservoir. The extent of the CO2 plume is slightly deeper than discovery fluid contacts in a few areas of the model likely due to gas override during injection and dissolution of the CO2 into the aqueous and oleic phases at the edge of the plume. The CO2 plume is largely stabilized 20 years after the end of injection, with little to no movement of the supercritical phase CO2 seen past this date.

The pressure front (defining as >10psi change from pressure at start of injection) in the reservoir reaches the vertical and areal boundaries of the model 6 years after the start of injection. The pressure in the reservoir reaches its peak at the end of injection. The reservoir pressure stabilizes fairly immediately in the reservoir with end of injection, and < 5psi/year change is expected in the first year after the end of injection. Figure 14 shows the average pore volume pressure vs time.

Figure 12A: Plan view showing the CO2 plume development through time. Plume is at its greatest extent at 20 years post injection.

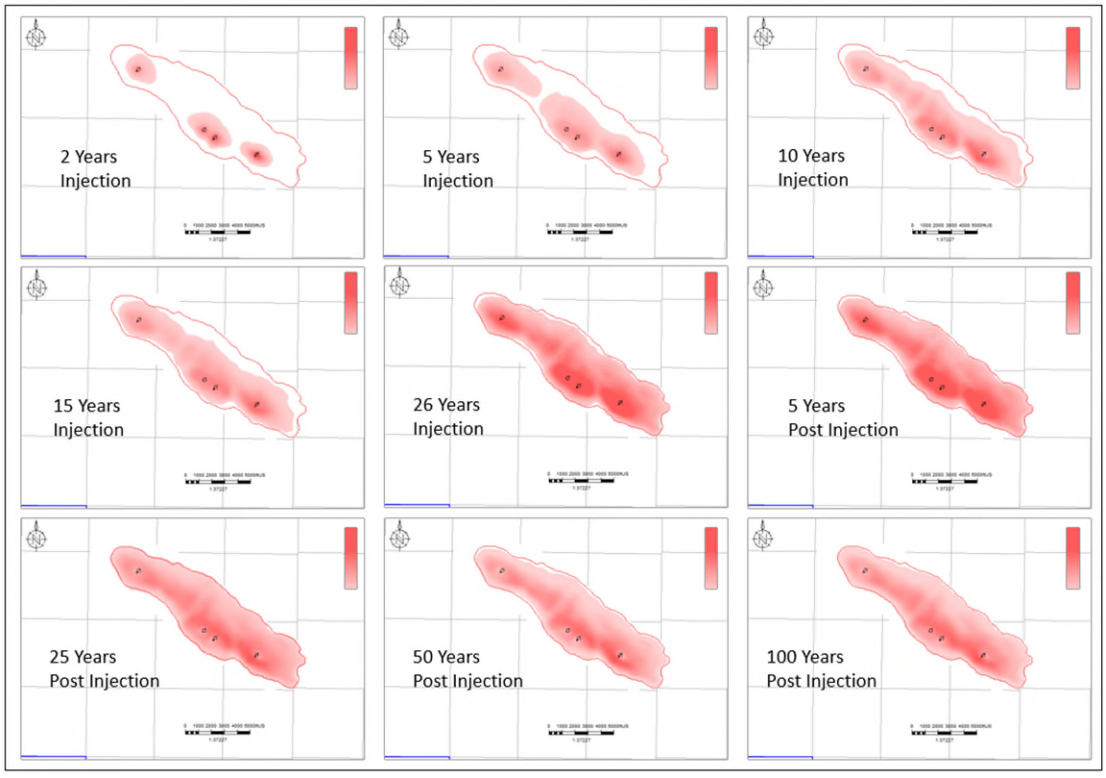


Figure 12B: Plan view showing the gas extent through time. Maps scaled so as to present Gas saturation over a nomial baseline

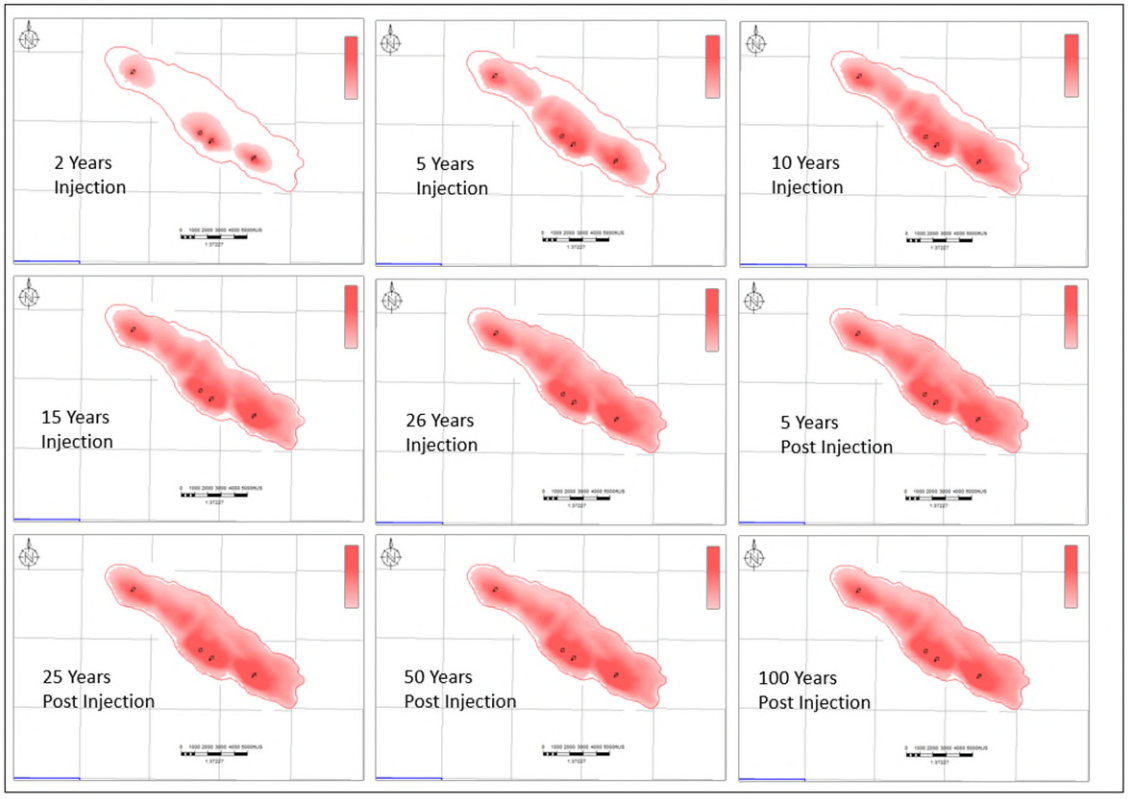


Figure 13A Cross-sections showing the CO2 plume development through varying times during the project.

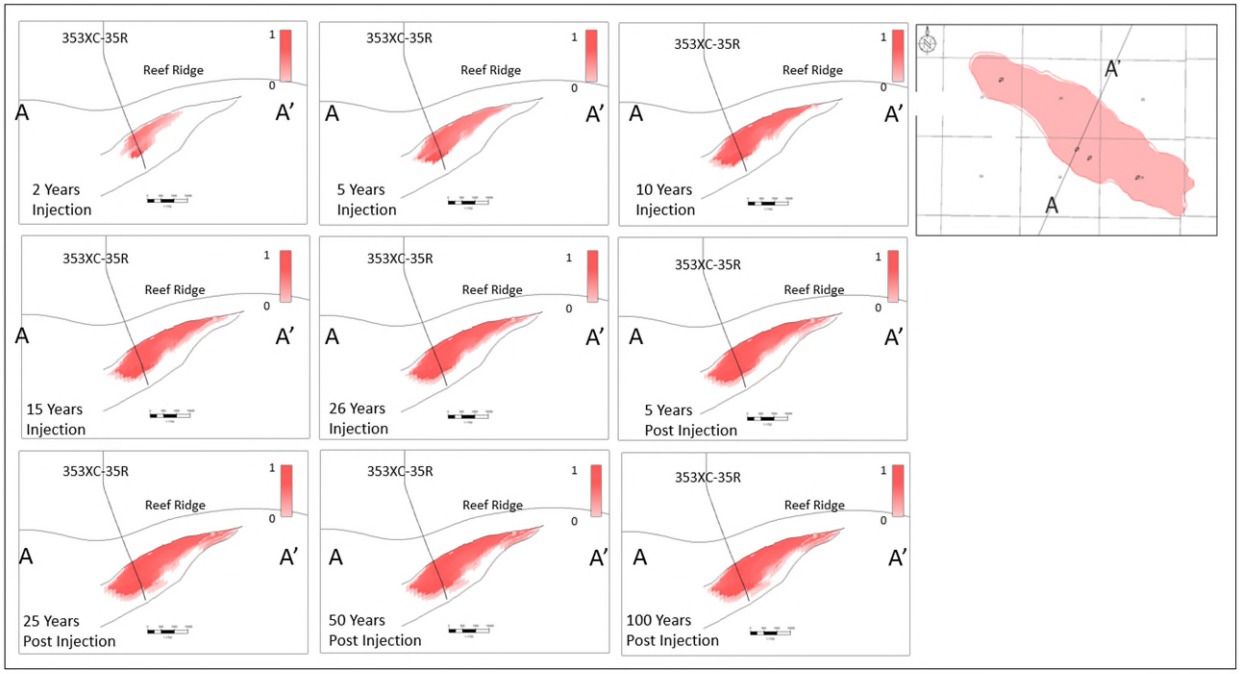


Figure 13B: Cross-sections showing the gas extent through varying times during the project. Maps scaled so as to present Gas saturation over a nomial baseline

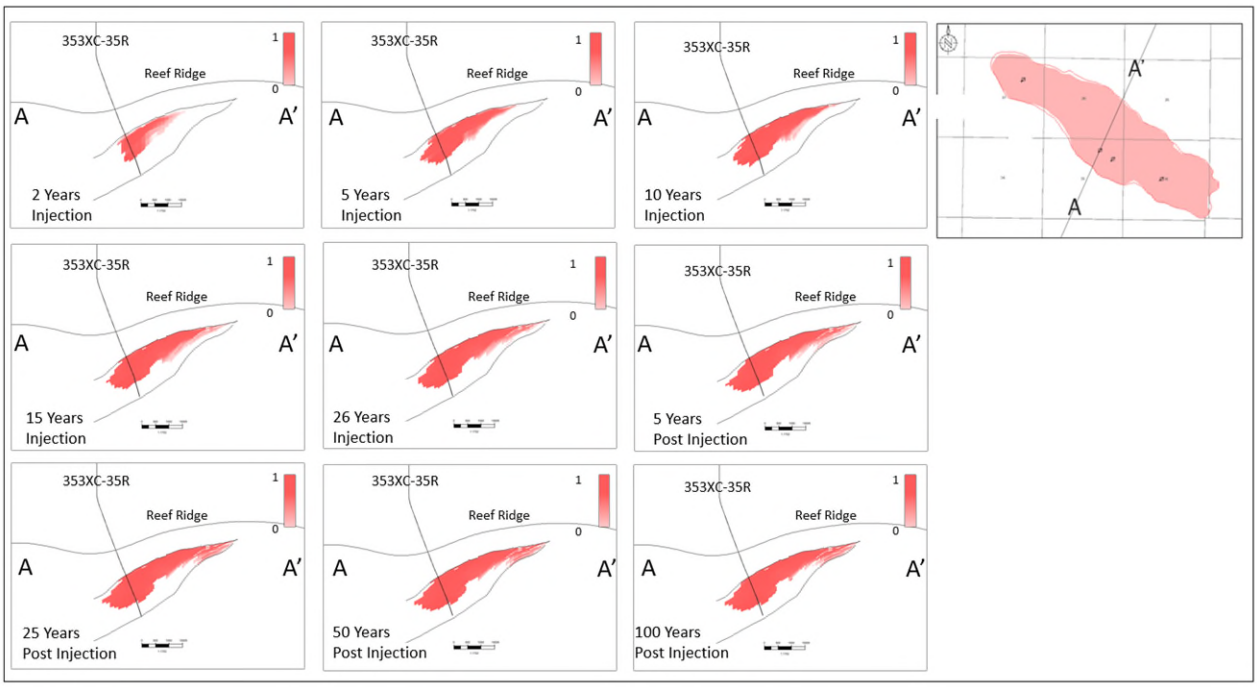
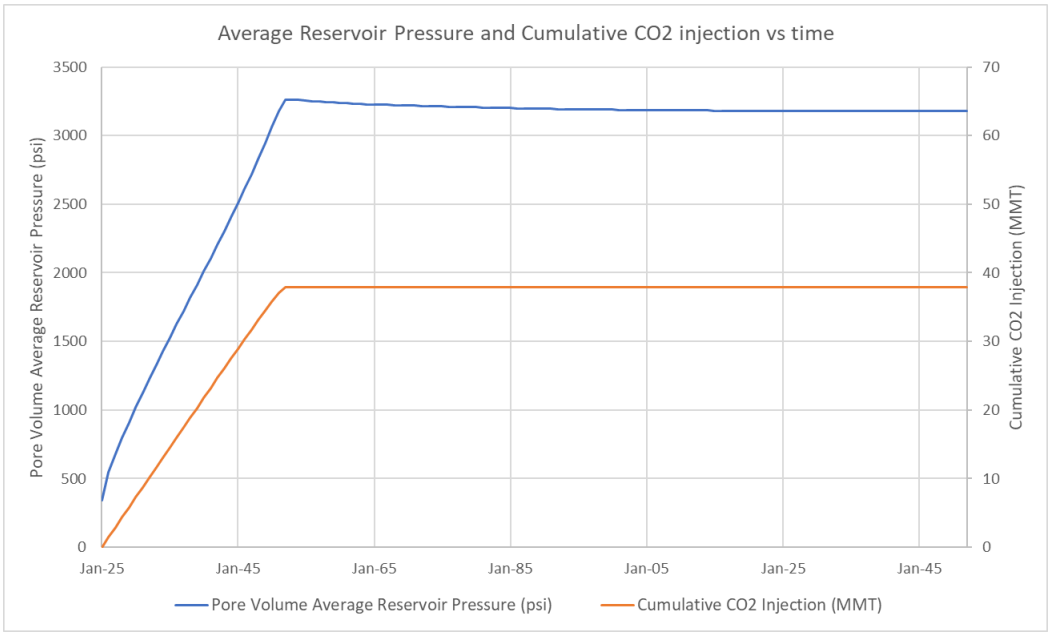
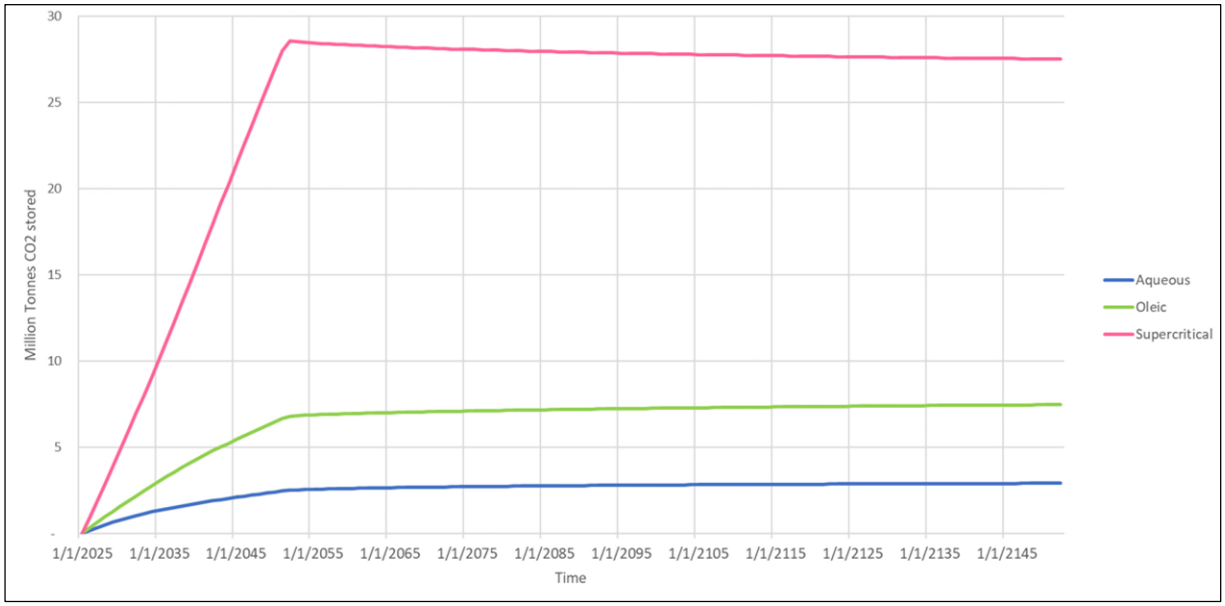


Figure 14: Average Reservoir pressure and cumulative CO2 injection versus time plot



CO_2 injected into the Monterey Formation 26R reservoir will be soluble in both water and oil. Due to remaining saturation of oil and water in the depleted reservoir, total dissolved CO_2 in oil and water is 20% and 8% of the CO_2 injected respectively. The remaining will be stored as super-critical CO_2. Figure 15 shows the cumulative storage for each of the mechanisms.

Figure 15: Storage mechanism through time for the 26R reservoir.



CO_2 Injectate Composition effect on Plume and AoR modeling

The Plume model developed in the Computer Modeling Group (CMG) GEM software was run for the two simplified injectate compositions, and their results were also compared against a 100% CO2 injectate case. The cumulative volume of injectate for all 3 cases was the same.

The CO2 plume for Injectate 1 and Injectate 2 (detailed in the "Proposed Carbon Dioxide stream" section in this document) is consistent with the plume outline for 100% CO2 injectate (Figure 16), which was defined by a 0.03 global CO2 mole fraction for all 3 cases. The 100 year post end of injection plumes for the 3 cases are shown below in Figure 16. The wells that fall within the CO2 plume are the same for all 3 cases.

Additionally, the average Pore Volume pressure was plotted for the 3 cases and there was minimal difference seen between the cases, as shown in Figure 17.

In summary, there is minimal effect of the minor components on the CO2 plume shape and the AoR boundary, for the proposed injectate compositions. As such, CTV's Plume and AoR modeling for Corrective Action assessment is adequate. CTV will confirm that the properties of the injectate are consistent with the model inputs at pre-operational injectate sampling. In addition, the AoR will be reviewed as per the Reevaluation Schedule and Criteria section.

Figure 16: CO2 plume outlines for Injectate 1 (Light Blue), Injectate 2 (Green) and 100% CO2 Cases (Red). Larger Red outline is the model boundary. There are Minimal difference in AoR boundaries between the 3 cases

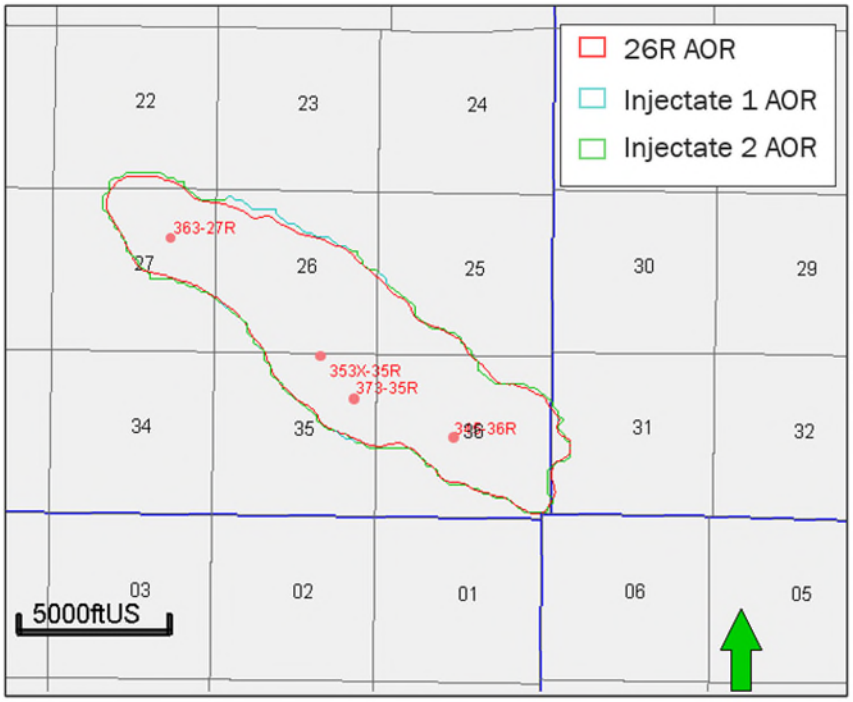
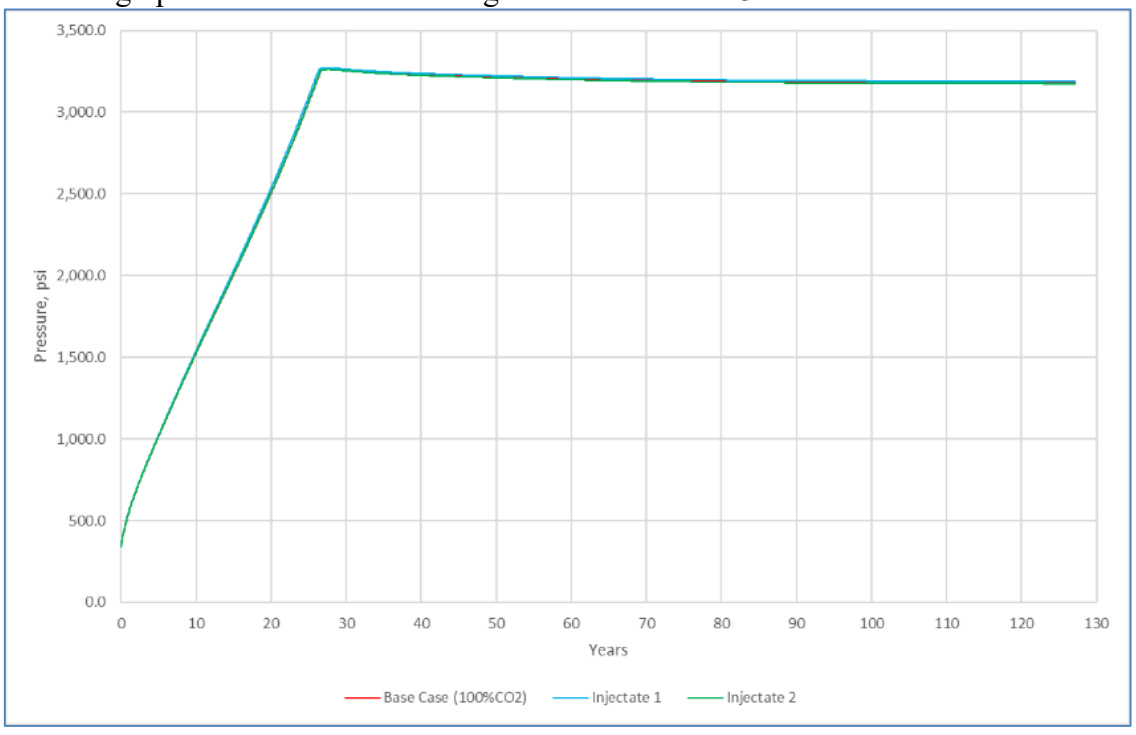


Figure 17: Average reservoir pressure vs time for Injectate 1 (Light blue), Injectate 2 (Green) and base 100% CO2 (Red) cases. Minimal difference in pressure trends between the 3 cases as shown in the graph with the trends tracking each other for the 3 cases.



Model Calibration, Sensitivies and Validation

Previous operators injected 1,244 billion cubic feet of gas into the Monterey Formation 26R reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

The simulation model was run for different initial reservoir pressure and saturation cases to determine the sensitivity of the storage volume and plume extent to these variables. Due to ongoing water injection in the 26R reservoir, sensitivities were run to test the effect of higher reservoir pressure and higher water saturation in the Oil band and Gas cap to see if there would be significant impacts to the storage volume and AoR boundaries.

Sensitivities were also run varying major geomodel inputs into the simulation model (Porosity, Permeability, NTG) and varying the Grid XY dimensions, cell thickness, local grid refinement around injectors, and temperature effects to see if there was a significant change to the storage amount and AoR boundary. Although there was some effect to the total CO2 storage for the different cases, there was minimal change to the maximum extent of the CO2 plume. The porosity, permeability and NTG uncertainty were further modeled stochastically to understand their effect and is discussed in the next section.

- Cell thickness sensitivity case was run by reducing the cell thickness in the overall grid to an average of 18ft. The results of this finer cell thickness model, compared favorably to the Base case model with a < 2% increase in predicted CO2 storage capacity and minimal change to the plume extent.

- The local grid refinement case was run with a finer grid spacing in the 5Acre region around the injector location, with the X-Y grid dimensions reduced to 19ft by 15ft in that region. The results of this case also compared favorably against the base case, with the predicted maximum bottom hole pressure at the injector locations being within 0.5% of the Base Case.

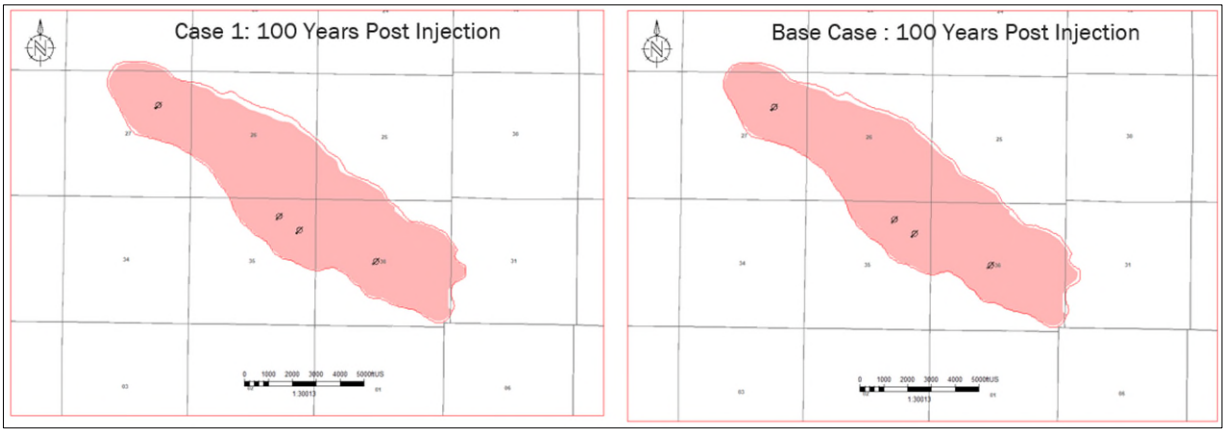
- The Base case model was initialized using a uniform average temperature of 210° F (based on idle well temperature surveys run on wells in the area between 2008 – 2014) and with no thermal effect modeling in the reservoir. A sensitivity case was run using GEM's thermal option to model heat balance and gauge if modeling temperature change in the reservoir with CO2 injection was necessary. The results indicated minimal effect on the system behavior with < 2% change in CO2 storage capacity, and < 2% deviation in reservoir pressure trends.

Table 10 summarizes the sensitivity cases run and their effect on storage volume and the AoR boundary. Figure 18 compares the CO2 plume extent for Case 1 against the Base Case.

Table 10: Summary of sensitivity cases

Case #	Sensitivity Case	Storage Volume effect	AoR boundary effect
1	Pressure : Gas cap pressure increased to 300psi	Decreased volume	Minimal effect to AoR
2	Pressure : Gas cap pressure increased to 500psi	Decreased volume	Minimal effect to AoR
3	Saturation: Higher water saturation in Oil band and Gas cap	Decreased volume	Minimal effect to AoR
4	Porosity: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
5	Porosity: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
6	Permeability: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
7	Permeability: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
8	NTG: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
9	Grid Dimensions: reduced grid XY dimensions to 95 ft x 75ft	No effect	Minimal effect to AoR
10	Cell Thickness: Reduced average cell thickness in Gas cap to 18ft	Increased volume	Minimal effect to AoR
11	Local grid refinement around Injectors: reduced grid X-Y dimension to 19ft x 15ft in 5Acre area around injectors	No effect	Minimal effect to AoR
12	Temperature effect: model was run with GEM's thermal option	Minimal change	Minimal effect to AoR

Figure 18: CO2 plume extent for layer 2 comparing Base Case against Pressure and Saturation sensitivity cases.



These scenarios demonstrated that the AoR, as defined by the maximum extent of CO_2 injectate, is consistent. This provides confidence that the corrective action well review and potential impact is conservative.

Stochastic analysis of effect of Reservoir parameters

A stochastic analysis was carried out using the reservoir parameters – Porosity, permeability, Net to Gross (NTG) ratio and kv-kh ratio. An upper and lower bound of the grid property was entered (directly or using multipliers), along with a distribution (see Table 11) in CMG's CMOST module to generate a set of 50 cases using the Latin Hypercube sampling method. All cases were run with the same bottom hole pressure control on the injectors, and with the same condition of ceasing injection once the reservoir had been brought back up to initial conditions. Although the stochastic analysis showed a range of storage capacity, the P50 estimate was 37MMT, with a P10 of 30MMT and a P90 of 44MMT.

Table 11: Parameters and distributions used for Stochastic analysis

Parameters	Parameter/ Multiplier	Parameter / Multiplier range	Distribution type	Description
Porosity	Multiplier	0.78 - 1.22	Normal distribution	Multiplier range used to have grid mean value range of 0.14 - 0.22
Permeability	Multiplier	0.3 - 3	Log Normal distribution	Multiplier range used to have grid mean value range of ~15 - 150md
Net to Gross ratio (NTG)	Multiplier	0.9 - 1.1	Uniform distribution	A uniform distribution uncertainty of +-10% applied
kv-kh ratio	Parameter	0.001 - 0.2	Log Normal distribution	A kv-kh ratio of 0.001 to 0.2 applied over the entire grid

AoR Delineation

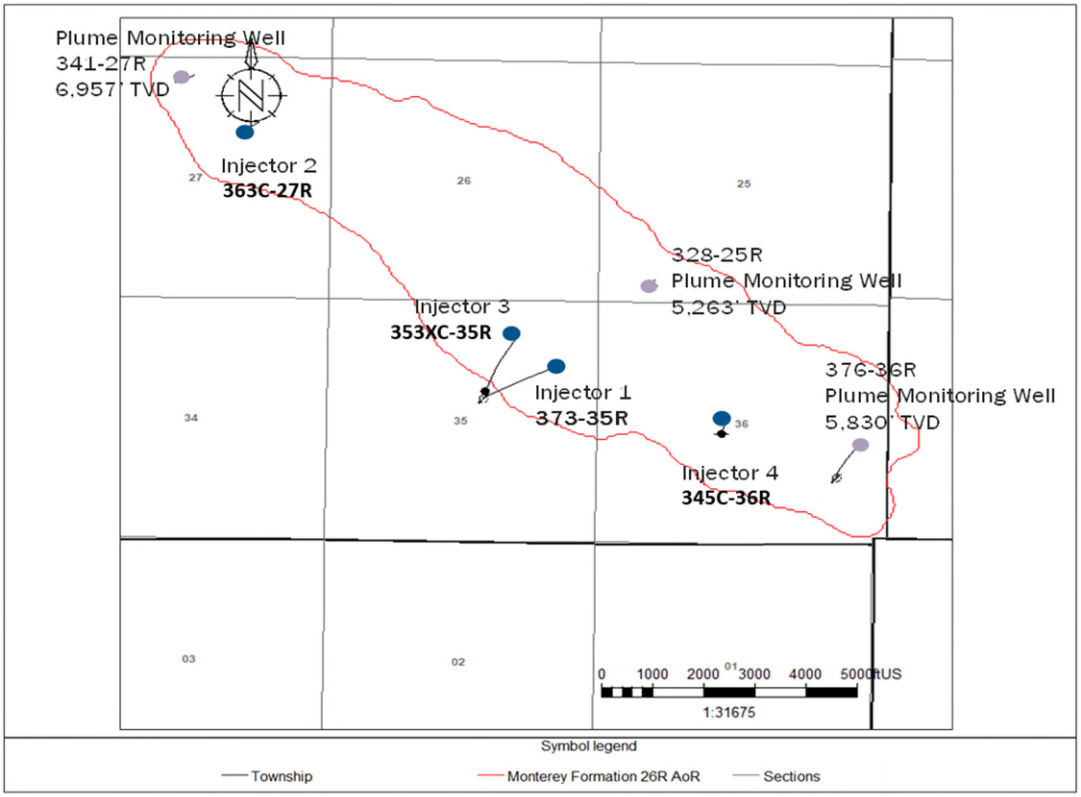
The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. A Global Mole Fraction cut off of 0.03 was used to delineate the plume boundary. In the AoR scenario, CO_2 was injected into the depleted Monterey Formation 26R reservoir until the reservoir pressure reached the discovery pressure of 3,250 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.
Figure 19 shows the AoR, injectors and offset monitoring wells. All wells that are currently operating in the 26R reservoir will cease operations, and wells not associated with the project will be abandoned prior to injection so as to eliminate interference with the AoR delineation and re-establish the confining layer. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

Figure 19: Map showing the location of injection wells and plume monitoring wells.



Corrective Action

The review of all wells within the AoR to determine the need for corrective action is a requirement of 40 CFR 146.84(c).

Tabulation of Wells within the AoR

Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation 26R reservoir was discovered in the 1940's and subsequent development drilling began around 1950. As such, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the over 70-year development history of the reservoir that includes injection of water and gas.

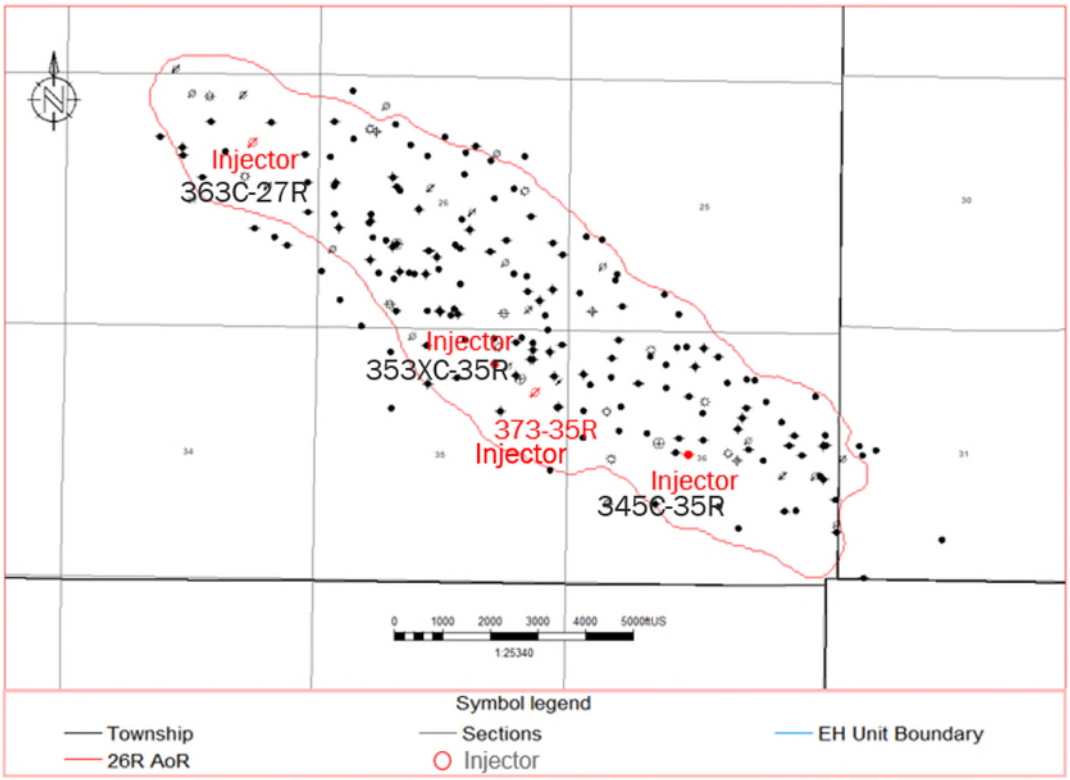
CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Table 12 is a summary of the AoR wells by type. Figure 20 displays the AoR wells' surface locations in map view. *Appendix: Well Table with Corrective Action Assessment* lists the wells individually and provides a description of each well's type, construction, date drilled,

location, depth, and record of plugging and/or completion, as required in 40 CFR 146.84 (c)(2). Additionally the table identifies pre-operational requirements and the corrective action assessment for each wellbore.

Table 12: Wellbores in the AoR by Well Type

Well Type	Count
Oil & Gas Producing Wells	145
Class II Injection/Disposal Wells	22
Pressure Observation wells	2
Plugged back	35
Total	**204**

Figure 20: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation 26R sequestration reservoir reviewed for corrective action.



Corrective Action Assessment Methodology

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q4 2021, and the results of the review are incorporated into the assessment.

The corrective action assessment includes the generation and detailed review of wellbore/casing diagrams for each well in the AoR. The results of the assessment are included in the *Appendix: Well Table with Corrective Action Assessment*. Information used in the review includes depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of Cement (TOC) determination supports the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface.

A well in the AoR is a penetration of the Monterey Formation and/or Reef Ridge Shale that may have multiple wellbores resulting from sidetracking the well. CTV tracks wells at the "wellhead" level using API-10 and at the "wellbore" level using API-12 such that a single well may have multiple wellbores, and each wellbore may or may not penetrate the AoR. The assessment of all penetrations was conducted by evaluating all wellbores, and the summary data provided refers to wellbore penetrations.

Protection of USDW

The Upper Tulare is an unsaturated zone, and the Lower Tulare is an exempt aquifer. There is no USDW in the AoR.

Wells Penetrating the Confining Zone

Of the 204 wellbores penetrating the Reef Ridge formation (Table 13), zero wells have been permanently abandoned to surface. Three wells will be repurposed as CCS monitoring wells, and one well, 373-35R, will be repurposed as a CO_2 injector. Of the remaining, 157 wellbores require plugging because the wellbores penetrate the injection zone and/or confining layer and will not be used for injection or monitoring within the 26R storage project. The wells are not known to be deficient and are not known to require corrective action. The wells will be abandoned prior to CO_2 injection under the asset retirement obligation plan (ARO) to reduce abandonment liability at Elk Hills. 35 wellbores have been plugged back for sidetrack, and as such have the API-12 status of P&A while API-10 status is either Active or Inactive, depending on the status of the current wellbore.

Table 13: Wellbores to be abandoned prior to injection

Wellbores Penetrating Reef Ridge Formation	Wellbores Requiring Corrective Action	P&A Wells Requiring Corrective Action	Wellbores Requiring Pre-Operational Abandonment
204	0	0	157

Monterey Formation 26R Isolation

CTV can demonstrate that the USDW (not present in AoR) is protected and that, with well abandonment prior to injection and implementation of a robust ongoing monitoring program, the CO_2 injected will be confined to the Monterey Formation 26R reservoir.

Plan for Site Access

CTV owns the mineral and pore space for the Monterey Formation 26R reservoir and surface access rights have been guaranteed for the duration of the project.

Corrective Action Schedule

All wellbores within the AoR will, if necessary, be pressure tested, abandoned, re-abandoned, monitored and/or have a technical demonstration of adequate zonal confinement prior to the commencement of CO_2 injection or based on an agreed upon phased schedule after CO_2 injection commences, if conditions allow. Additional evaluation during pre-operational testing will inform the suitability and isolation of wells proposed for use in the project as injectors and monitoring wells. Diagnostics may also be performed, if necessary, to complement abandonment operations. Although no wellbores have been identified for corrective action and no corrective action schedule is required, if additional evaluation efforts result in the identification of wellbores that require corrective action, CTV will notify the EPA and communicate a corrective action plan and schedule.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

4. A review of the full suite of water quality data collected from monitoring wells in addition to CO2 content/saturation (to evaluate the potential for unanticipated reactions between the injected fluid and the rock formation).

5. Review and submission of any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.

6. Reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation). A report describing the comparison of the modeling results will be provided to the EPA with a discussion on whether the results are consistent.

7. Description of the specific actions that will be taken if there are discrepancies between monitoring data and prior modeling results (e.g., remodel the AoR, update all project plans, perform additional corrective action if needed, and submit the results to EPA).

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Changes in pressure or injection rate that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

2. Difference between the computation modeling and observed plume development:

    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation reservoir that are not related to well integrity.

b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results with a deviation greater than +-10% from the Base Case.

c. Any other activity prompting a model recalibration.

3. Seismic monitoring anomalies within two miles of the injection well that are indicative of:

    a. The presence of faults near the confining zone that indicates propagation into the confining zone.

    b. Events reasonably associated with CO_2 injection that are greater than M3.5.

2. Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.

3. Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).

4. Initiation of competing injection projects within the same injection formation within a 1-mile radius of the injection well (including when additional CTV injection wells come online);

5. A significant change in injection operations, as measured by wellhead monitoring;

6. Significant land-use changes that would impact site access; and

7. Any other activity prompting a model recalibration.

CTV will discuss any such events with the UIC Program Director as soon as possible to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan within six months of the triggering event.

ATTACHMENT C: TESTING AND MONITORING PLAN – 345C-36R
40 CFR 146.90

Elk Hills 26R Storage Project

Facility Information

Facility Name: Elk Hills 26R Storage Project
345C-36R

Facility Contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Comments
Attachment C – TM 345C-36R	1	09/30/2023	
Attachment C – TM 345C-36R	2	12/05/2023	Addition of air monitoring.

The Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills 26R storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the CO_2 within the storage zone, supporting AoR re-evaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

Quality Assurance Procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the Appendix to this Testing and Monitoring Plan.

Reporting Procedures

CTV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

CTV will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a). Samples will be collected and analyzed quarterly, starting three months after the date of authorization of injection and every three months thereafter.

The anthropogenic CO_2 will be sourced from:

- Initial onsite emissions:
    - Lone Cypress blue hydrogen plant, up to 200,000 tonnes per annum
    - Elk Hills field gas treatment (pre-combustion for Elk Hills Power Plant), up to 200,000 tonnes per annum
    - Avnos Direct Air Capture (DAC), up to 1,500 tonnes per annum
- Future emission Sources:
    - CalCapture Elk Hills 550 MW natural gas power plant (post combustion), renewable fuel plants, steam generators post combustion and other power plants / industrial sources in the area.

CO_2 injectate from these sources has been incorporated into Table 1 for injectate sampling. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

Sampling Location and Frequency

CO_2 injectate samples will be taken for each injection source and between the final compression stage and the wellhead. Sampling will take place three months after the commencement of injection and every three months thereafter. Sampling process will follow the procedures below.

CTV will increase the frequency and collect additional samples if the following occurs:

1. Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source; and
2. Facility or injector downtime is greater than thirty days.

Analytical Parameters

CTV will analyze the water content and injectate the constituents identified in Table 1 using the methods listed. An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 1. Summary of analytical parameters for CO_2 stream.

Parameter	Analytical Method(s)
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD
Carbon Monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)
Total Hydrocarbons	ISBT 10.0 THA (FID)
Ammonia	ISBT 6.0 (DT)
Ethanol	ISBT 11.0 (GC/FID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Methane, Ethane, Ethylene	ISBT 10.1 (FID)
Hydrogen Sulfide and Sulfur Dioxide	ISBT 14.0 (GC/SCD)
CO_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
δ13C	Isotope ratio mass spectrometry
Water Vapor	ISBT 3.0

Sampling Methods

Stream sampling will occur for each required CO2 analysis and in the last compressor station prior to being sent to the injector. A sampling station will be installed to facilitate collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a full-service laboratory in Bakersfield, 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 4.

Zalco has a chain of custody procedure that includes the following.

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

For each required CO_2 analysis, CTV will report the time each sample was taken, a tabulation of all CO_2 stream analyses (including any quality assurance/quality control samples), an interpretation of the results, any identified changes and explanation of any data gaps.

Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

CTV will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring Devices, Location, and Frequency

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table. Depths of downhole continuous monitoring equipment are specified for each well and labeled in the Appendix_26R - Injection & Monitoring Well Schematics document.

Monitoring for the parameters, except for annulus fluid volume, will be continuous with a 10 second sampling and 30 second recording frequency for both active and shut-in periods. This will be adequate to monitor for changes in the wellbore and the reservoir.

Table 2. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface Downhole 345C-36R: 5690'(MD) 353X-35R: 6390' (MD) 363-27R: 6290' (MD) 373-35R: 7010' (MD)	10 seconds	30 seconds

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection rate	Flowmeter	Surface	10 seconds	30 seconds
Injection volume	Calculated	Surface	10 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	10 seconds	30 seconds
Annulus fluid volume		Surface	4 hours	24 hours
Temperature	Temperature Gauge	Surface Downhole 345C-36R: 5690'(MD) 353XC-35R: 6390' (MD) 363C-27R: 6290' (MD) 373-35R: 7010' (MD)	10 seconds	30 seconds
Temperature	DTS	Along wellbore to packer	10 seconds	30 seconds

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Injection Rate and Pressure Monitoring

Injection pressure, temperature and flow rate will be continuously monitored and recorded by the Elk Hills Central Command Facility (CCF). The injection pressure will be measured and recorded using pressure gauges at surface and downhole. The injectate temperature will be measured with a temperature gauge at the surface. The injection rate will be measured with a Coriolis flowmeter. The meter will be calibrated annually for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent. Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable bottomhole injection pressure. Pressure and temperature gauges will be calibrated annually. Table 6 of the QASP provides operating range and precision specifications.

Calculation of Injection Volume and Mass

The volume and mass of CO_2 injected into the Monterey Formation 26R will be calculated from the injection flow rate and CO_2 density. Density of CO_2 injected into the Monterey Formation 26R will be calculated using PVTP, a fluid thermodynamics package, developed by Petroleum Experts Ltd. PVTP is an industry standard software package that has been used extensively in CO_2 EOR applications to accurately model and match CO_2 PVT properties over a wide range of temperatures and pressures.

Annular Pressure Monitoring

Annulus pressure is monitored continuously to ensure integrity of the downhole packer, tubing, and casing. CTV will monitor the casing-tubing pressure continuously (every 10 seconds) using an electronic pressure gauge. The annulus will be filled with a non-corrosive brine with corrosion inhibitor. The casing-tubing annulus pressure for injection wells 373-35R, 345C-36R, 353XC-35R, 363C-27R will be maintained with at least 100psi at surface, as stated in the injection well operating procedure documents. Monitoring wells will be operated with 100 psi positive annular pressure at surface.

Failure to maintain >100 psi consistently could be an indication of internal or external mechanical integrity failure, provided that thermal (such as material contraction due to cooling) and pressure (such as ballooning due to increasing tubing pressure) transient effects of normal operational changes are properly diagnosed as acceptable deviations. CTV will notify EPA if (1) pressure decreases to 0 psig and cannot be explained by operational conditions, or (2) pressure drops below 100 psi threshold and cannot be maintained or stabilized after three attempts. Additionally, CTV will notify EPA if pressure increases above 1000 psi and cannot be explained by operational conditions.

Corrosion Monitoring 40 CFR 146.90(c)

CTV will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description below.

Monitoring Location and Frequency

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. The corrosion coupons will be installed in the pipeline that feeds CO_2 injectate to the injectors.

Sample Description

Samples of the materials used in the construction of the pipeline, injection wells, and monitoring wells that are directly in contact with CO_2 injectate will be monitored for corrosion. Corrosion coupons of the representative materials shown in Table 3 will be weighed, measured, and photographed prior to installation directly upstream of the wellhead. For well 373-35R, the wellbore materials exposed and in direct contact with injected CO_2 include the N-80 grade long string casing below the packer and the CRA tubing. These casing materials will be included in the corrosion coupon monitoring and are presently included in Table 3. General construction materials for pipeline, tubing and wellhead are shown in Table 3. Materials of construction will be reaffirmed after well and pipeline construction and prior to injection, as part of pre-operational testing. Subsequently, corrosion coupons consistent with final well construction materials will be used for corrosion monitoring.

Table 3. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Casing	N-80 steel (373-35R injection well) K-55 steel (341-27R, 328-25R monitoring wells) Chrome alloy consistent with final well construction for new drill wells
Tubing	Chrome alloy consistent with final well construction
Packer	Chrome alloy consistent with final well construction
Wellhead	Chrome alloy consistent with final well construction

Sample Handling and Measurement

Upon collection, the coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The samples will be handled and assessed in accordance with NACE TM0169/G31 and/or EPA 1110A SW846. Monitoring results will be documented and submitted to the EPA as per 40 CFR 146.91 (a)(7). Table 5 of the QASP document provides detection limit/range and precision.

A detected corrosion rate of greater than 0.3 mils/year will initiate consultation with the EPA. In addition, a casing inspection log may be run to assess the thickness and condition of the casing if the corrosion rate exceeds 0.3 mils/year. CTV will continually update the corrosion monitoring plan as data is acquired.

Above Confining Zone Monitoring

CTV will monitor water quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). The Etchegoin and Tulare Formations are permeable reservoirs above the confining zone.

Etchegoin Formation Monitoring

The Etchegoin Formation is between the Reef Ridge confining zone and the Upper Tulare USDW and will dissipate CO_2 injectate that may migrate upward from the injection zone. The Etchegoin Formation is continuous across the AoR and will be monitored continuously for pressure and temperature changes. Figure 1 shows the location of 355X-26R and the shallow groundwater monitoring well. The well is suitable and appropriate to adequately monitor for pressure and temperature changes within the first porous and continuous sand above the sequestration zone. This sand is present from 4,063’ – 4,087’ MD in 355X-26R.

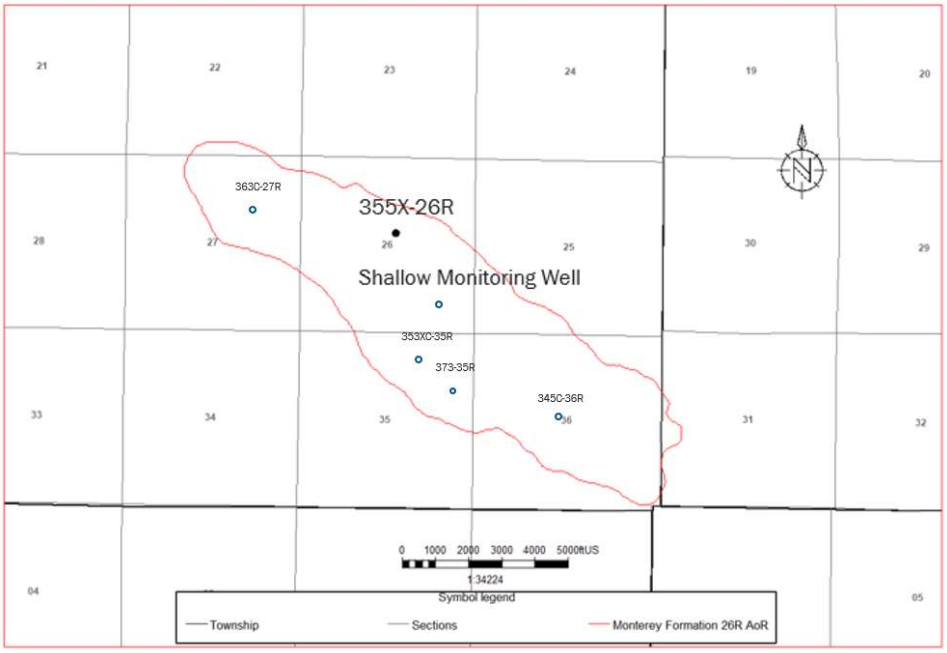


Figure 1: Above confining zone monitoring wells.

The effect of potential leakage from the Monterey Formation to the Etchegoin Formation is an increase in reservoir pressure and decrease in temperature of the Etchegoin. Additionally, potential leakage will create compositional changes detectable with fluid sampling and geochemical monitoring. Pre-injection geochemical composition will be established from baseline water analysis acquired within the Etchegoin Formation during pre-operational testing.

Tulare Formation Monitoring

Monitoring in the Upper Tulare will include pressure, temperature, and fluid sampling. Leakage to the Tulare Formation would increase the reservoir pressure and change the composition of the formation water (increased CO_2 concentration). The Upper Tulare is unsaturated in the AoR. The Upper Tulare Formation will be monitored between 400' – 450' MD in the shallow monitoring well that will be drilled specifically for this project.

Pre-injection geochemical composition will be established from baseline water analysis acquired within the Tulare Formation during pre-operational testing. Subsequent results will be compared against these baseline results for significant changes or anomalies. pH will be monitored as a key indicator of CO_2 presence.

Additional groundwater monitoring wells will be drilled to assess and monitor the Upper Tulare USDW if the following occurs:

1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation 26R CO_2 injection.

2. Upper Tulare Formation pressure or composition changes due to Monterey Formation 26R CO_2 injection.

Monitoring Methods, Location, and Frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well with respect to the AoR. The wells are located within the Elk Hills Oil Field, and CTV owns the surface and mineral rights.

Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	Shallow Water Monitoring Well	Pump	–400’ - 450' MD/VD	Quarterly
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’ - 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’ - 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	400' - 500' MD/VD in each well	Continuous
Etchegoin	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Quarterly
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' 4788' - 4811' 4205' - 4226' (all MD/VD)	Continuous

Analytical Parameters

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 5. Summary of analytical and field parameters for water samples from the USDW monitoring well and the Etchegoin monitoring well.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)
Dissolved CO_2	Coulometric titration, ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Sampling Methods

Samples will be collected using the following procedures:

1. Depth and elevation measurements for water level taken.
2. Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
3. Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
4. Samples preserved and sent to lab as per chain of custody procedure.
5. Closure of well.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by Zalco, a full-service state certified laboratory in Bakersfield, approximately 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3. Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

Internal Mechanical Integrity Testing

A Class VI well has mechanical integrity if there is no significant leak in the casing, tubing, or packer. CTV will conduct an initial annulus pressure test on all injection wells and on monitoring wells that penetrate the confining zone and are configured with tubing and a packer. Additionally, any time the packer is replaced or reset, a SAPT will be performed. The injection and monitoring wells will be configured with continuous recording devices to monitor the pressure on the annulus between the tubing and the casing, and annulus fluid volumes will be measured and recorded. These actions satisfy the requirements of 40 CFR 146.88(e)(1) and 40 CFR 146.89(b).

Standard Annular Pressure Testing (SAPT)

Pascal's Law states that any pressure applied to a fluid filling a closed vessel will be transmitted undiminished, throughout the vessel. This is the basis for the SAPT as the primary means to determine if a well's casing, tubing, packer, and wellhead (the annulus system) are liquid tight. Because the annulus system is not an isolated system, the measured pressure applied may not be constant throughout time. The temperatures along the wellbore must change as injection rates and temperatures change because of heat exchange between injectate and the surrounding formations. When the well is shut in, the wellbore may cool or become warmer as the well materials are subjected to the natural geothermal temperatures, which will result in expansion or contraction of liquid in the annulus. Because liquids are effectively incompressible, annular pressure is expected to fluctuate due to changes in the tubing such as contraction, elongation, and ballooning during transient injection or shut-in periods.

The procedure for conducting SAPT is as follows:

1. CTV will notify the Director to provide the opportunity to witness the testing.

2. Completely fill the tubing/casing annulus with packer fluid consisting of weighted brine and appropriate additives such as corrosion inhibitors, oxygen scavengers, and biocide. The volume to fill should be measured and recorded. The annulus liquid should be temperature stabilized prior to conducting the test.

3. The annulus will be pressurized to a surface pressure which exceeds the maximum injection pressure by at least 100 psi unless an alternate pressure is approved by the EPA Director.

4. Following pressurization, the annular system will be isolated from the source of pressure by a closed valve, or it will be disconnected entirely.

5. The isolation will be maintained for no less than one hour. During this time, pressure measurements will be recorded in at least one-minute intervals.

6. After the SAPT is concluded, the valve to the annulus should be opened to bleed down the pressure. The liquid returns from the annulus should be measured and recorded.

Monitoring wells that do not have a specified maximum tubing pressure will be tested to 1000 psi initially. As reservoir pressure increases during injection and tubing pressure is continuously monitored, SAPT test pressure will be reconsidered. When tubing pressure approaches 100 psi less than the initial SAPT test pressure, i.e. 900 psi, the SAPT will need to be performed again unless an alternative method or test pressure is approved by the EPA Director. Table 6 provides information on the frequency and test pressures for injection and monitoring wells within the project.

Table 6. Internal MIT requirements

Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)	Maximum Injection Pressure (psi)	Test Pressure (psi)
Standard Annular Pressure Test (SAPT)	373-35R[1]	Casing/tubing annulus from surface to packer	Once, upon initial installation	Any time packer is replaced or reset	Not Applicable	1992	2092
	345C-36R[1]					1888	1988
	363C-27R[1]					2020	2120
	353XC-35R[1]					1997	2097
	355X-26R[2]				Any time packer is replaced or reset	--	1000
	341-27R[3] 328-25R[3] 376-36R[3]					--	1000

Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)	Maximum Injection Pressure (psi)	Test Pressure (psi)	
Annular Pressure	373-35R[1] 345C-36R[1] 353XC-35R[1] 363C-27R[1]	Wellhead	Continuous	Continuous	Not Applicable	--		-
	355X-26R[2] 341-27R[3] 328-25R[3] 376-36R[3]				Continuous			-

[1] *CO2 injection well*
[2] *Above Zone monitoring well*
[3] *Injection Zone monitoring well*

The interpretation of the SAPT will compare the pressure change during the test once the initial pressure has stabilized. If the change (gain or loss) in pressure is less than 3% of the test pressure, the well has demonstrated mechanical integrity, pursuant to 40 CFR 146.8(a)(1). If the change in pressure (gain or loss) exceed 3% of the test pressure, the well has failed to demonstrate mechanical integrity.

CTV will utilize an EPA-approved Annular Pressure Test form to record the results of the SAPT if the test is not witnessed by the EPA. If the test indicates the well has demonstrated mechanical integrity, the test form and raw pressure data (original chart recordings or a digitized log of pressure and time) will be provided to the EPA. If the test indicates a failure of mechanical integrity in an injection well, the well will be shut in, no injection will occur, and the EPA Director will be notified within 24 hours.

Continuous Monitoring of Annular Pressure

Injection and monitoring wells will record continuous annular pressure such that internal MIT can be confirmed in real-time based on the interpretation of this data. CTV will identify and investigate pressure deviations that do not align with changes to operating conditions or temperature effects due to seasonal variation. In the event of a casing leak into a permeable zone, the pressure will normally fall. In the event of a tubing or packer leak, the annulus pressure will track injection pressure, although the pressures are not likely to be equal due to friction and density differences.

This data will be provided in the semi-annual report to demonstrate ongoing internal mechanical integrity.

External Mechanical Integrity Testing

CTV will conduct mechanical integrity testing on each injection well at least once per year to demonstrate external mechanical integrity using an approved test method per 146.89(c). CTV will, at a minimum, perform a temperature log on the injection wells.

Testing Methods

Table 7 shows testing methods that may be utilized for MIT on injection and monitoring wells associated with this project. CTV will utilize an approved MIT technique, such as temperature logging with wireline, oxygen-activation logging, or noise logging on CO_2 injection wells as the primary method. While DTS may not be considered an approved temperature logging method for injection well MIT, CTV may seek Director approval in the future prior to using this method. If CTV elects to conduct an alternate MIT, notification including a description of the proposed testing method and procedure will be sent to the EPA for approval.

Since temperature decay logs require injection to cool the wellbore and near wellbore region prior to logging, monitoring wells cannot be tested for external MIT without approval to inject fluid. Additionally, injecting fluid such as H_2O or CO_2 for the purpose of testing may be undesirable for other reasons. Therefore, MIT on monitoring wells will not be conducted using temperature decay logging. Instead, another approved method under 40 CFR 146.89(c) may be utilized, or DTS may be proposed for EPA Director approval for monitoring well MIT.

Table 7. External Mechanical Integrity Testing Methods

Test Description	Location
Temperature Decay Log	Along wellbore using wireline well log
Distributed Temperature Log (DTS)	Along wellbore using fiber optic sensing (DTS), continuous
Oxygen Activation Log (OA)	Along wellbore using wireline well log
Noise Log	Along wellbore using wireline well log

Description of Temperature Logging with Wireline

EPA has specific requirements that must be satisfied for a temperature log to be considered valid for MIT as specified by 40 CFR 146.89(c). CTV will utilize the following procedures and comply with EPA guidance to ensure testing requirements are achieved.

1. Stabilize injection for 24 hours prior to running the temperature log.

2. Run an initial temperature survey logging down from at least 200 feet above the base of the Reef Ridge Shale to the deepest point reachable in the well, while injecting at a rate that allows for safe operations. The temperature sensor should be located as close to the bottom of the tool string as possible. The optimal wireline speed is 30 ft/min, and the acceptable range is between 20 and 50 feet per minute.

3. Shut in the injection to the well and run multiple temperature surveys with 4 hours between runs. The minimum shut-in time following the initial temperature log is 12 hours total, and the superimposed logging passes should be at least 4 hours after the injection pass.

4. Assess the time lapse temperature profiles against the baseline injection survey to identify temperature anomalies that may indicate a failure of well integrity. Evaluate the data to determine if additional passes are needed for interpretation. If CO_2 migration is interpreted in the topmost section of the logging pass such that the top of the migration pathway cannot be identified, additional logging runs over a shallower interval will be required to find the top of migration.

5. Both the printed or digital log and the raw data for at least two logging runs should be provided to the EPA. The printed or digital log should have the following:

    a. The heading must be complete and include all pertinent information to identify the well, well location, date of the survey, etc.

    b. Vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs.

    c. Horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.

    d. The right-hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.

    e. The left-hand track must contain a casing collar log, a legible lithology log such as spontaneous potential (SP) or gamma ray, and identification of the base of USDW, if present.

Description of Temperature Logging using Distributed Temperature Sensing (DTS)

DTS is a fiber optic continuous temperature monitoring system that will be installed in injection and monitoring wells to measure wellbore temperature in real time from the annulus along the length of the tubing. Like a temperature log, the DTS temperature data can be used to assess the internal and external mechanical integrity of injection and monitoring wells. Successful comparisons of DTS temperature logs to wireline temperature logs have been well documented and validate the use of DTS as a temperature log for mechanical integrity testing. By continuously monitoring DTS data, this testing method provides an early detection of temperature changes through the capability to continuously monitor MIT in Realtime, making this technology potentially superior to wireline temperature logging.

The impact to health, safety, and environment of DTS temperature logging is significantly improved in comparison to wireline temperature logging operations. Because the DTS system is installed at the time of well construction or workover, no crew is required to be present at the

wellsite. The following procedure can be performed to acquire a temperature log using DTS for mechanical integrity analysis for an injector:

1. Establish baseline temperature profile that defines the natural gradient along the well prior to injecting.

2. During injection, record the temperature profile for 6 hours prior to shutting in the well.

3. Stop injection and record the temperature for sufficient time to allow cooling.

4. Start injection and record the temperature profile for 6 hours.

5. Compare the baseline analysis to the time-lapse data for assessment of temperature anomalies that may indicate a well failure.

Description of Passive Temperature Logging using DTS

DTS can be used for passive external mechanical integrity monitoring on monitoring wells. This solution has advantages compared to wireline temperature logging on monitoring wells in liquid-depleted reservoirs. DTS will be installed on the tubing string from surface to the packer on the injection wells, the injection zone monitoring wells, and the above zone monitoring well. DTS will detect temperature changes along the wellbore if external mechanical integrity is compromised.

On injection wells, temperature changes associated with external fluid migration will be masked due to the dominating impact of injectate temperature on the wellbore materials. However, during shut-in periods immediately following sustained injection, when warm back can be observed along the length of the DTS fiber, migration pathways of fluids at non-geothermal temperature gradients can be identified. Additionally, lack of deviation from temperature reversion to the geothermal gradient is a demonstration of external mechanical integrity. It is appropriate for the DTS fiber to monitor temperature throughout and above the confining layer, and the configuration of DTS fiber as described above, from surface to the top of the packer, is sufficient to monitor injection wells for external MIT above the injection zone.

On the injection zone monitoring wells, the DTS string will monitor the confining layer and all above layers in real-time. If dense phase CO_2 were to breach the injection zone and migrate upward, the warmer CO_2 would cause a discernible temperature anomaly. If the CO_2 were to change phase to gas phase, a cooling effect would be observed. The high frequency and volume of data is superior to wireline temperature logging, significantly enhancing diagnosis capability and reaction time. DTS is not required to be deployed through the injection zone to assess external MIT within and above the confining layer.

Description of Noise Logging

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. Noise logging may be carried out while injection is

occurring. If ambient noise is greater than 10 mv, injection will be halted. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Run a noise survey from top of Tulare to the deepest point reachable in the Monterey Formation while injecting at a rate that allows for safe operations.

3. Make noise measurements at intervals of 100 feet to create a log on a coarse grid.

4. If any anomalies are evident on the coarse log, construct a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.

5. Make noise measurements at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing:

   a. The base of the lowermost bleed-off zone above the injection interval and

   b. The base of the lowermost USDW.

6. Additional measurements may be made to pinpoint depths at which noise is produced

Description of Oxygen Activation Logging

To ensure the mechanical integrity of the casing, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. OA logging may be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Conduct a baseline Gamma Ray (GR) log and Casing Collar Locator (CCL) log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool. Gamma Ray Log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.

3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches and less than 13- 3/8 inches.

4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.

5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a "no vertical flow behind the casing" section of the well to ensure accurate, repeatable tool response and for measuring background counts.

6. Take, at a minimum, a 15-minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 feet above the injection interval so that turbulence does not affect the readings.

7. Take, at a minimum, a 15-minute stationary reading at a location approximately midway between the base of the lowermost USDW and the confining interval located immediately above the injection interval.

8. Take, at a minimum, a 15-minute stationary reading adjacent to the top of the confining zone.

9. Take, at a minimum, a 15-minute stationary reading at the base of the lowermost USDW.

10. If flow is indicated by the OA log at a location, move up hole or downhole as necessary at no more than 50-foot intervals and take stationary readings to determine the area of fluid migration.

Pressure Fall-Off Testing

Pressure falloff tests are used to measure formation properties in the vicinity of the injection well, and the intent of periodic testing is to monitor for any changes in the near-wellbore environment that may impact injectivity or increase pressure. CTV will perform pressure fall-off tests on each injector during the injection phase every five years as described below to meet the requirements of 40 CFR 146.90(f). CTV will refer to EPA Region 9 UIC Pressure Falloff Requirements for planning and conducting the testing as well as preparing and submitting the monitoring report.

Testing Details

The following procedure will be followed:

1. Injection rate will be held constant for at least one week prior to shut in. The injection pressure will be high enough to produce a pressure decrease upon shut in that will result in valid test data for derivative analysis. The maximum operating pressure will not be exceeded.

2. The injection well will be equipped with surface and downhole pressure and temperature gauges. Bottomhole gauges will have surface readout capabilities and will be the primary source of pressure data for analysis because these gauges will be least affected by wellbore fluid effects. Prior to and throughout the shut-in period, the gauges will collect pressure data in 10 second intervals, which is sufficient and appropriate for pressure-transient analysis. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

3. The injection well will be shut in at the wellhead to minimize wellbore storage effects from compressible fluids. The injection rate of the offset injector will be held constant during the test. Accurate records of offset wells completed within the same zone will be maintained and considered in the interpretation.

4. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage. This desired radial flow regime is identified by a zero slope of the pressure derivative through pressure transient analysis. The data can be analyzed in real time because of the surface readout capabilities of the pressure gauges and can therefore ensure a complete and adequate test before restarting injection.

5. Interference testing may be conducted at the conclusion of the falloff test to demonstrate communication between the wells. The injection rate of the offset injector would be increased or decreased multiple times to create pressure pulses that can be observed by the shut in well.

6. The interpretation of the pressure transient dataset will be performed by a trained engineering professional using proven industry standard methodologies. Anomalies that are identified from the interpretation will be investigated.

7. A report containing the pressure fall-off data and interpretation of the reservoir pressure will be submitted to the EPA in the next semi-annual report. The report will follow the guidance of the EPA Region 9 UIC Pressure Falloff Testing Requirements document.

Carbon Dioxide Plume and Pressure Front Tracking

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

Plume Monitoring Location and Frequency

Figure 2 shows the location of the wells that will monitor the CO_2 plume directly in the targeted 26R reservoir. These wells will actively monitor the development of the CO_2 plume upon the initiation of injection. If the plume development is not consistent with computation modeling results, CTV will assess whether additional monitoring of the plume is necessary. Determination for plume monitoring changes will be made in consultation with the UIC Program Director and would trigger an AoR reevaluation, per the AoR and Corrective Action Plan.

Based on the Base case model, the CO2 plume is expected to arrive at the monitoring well locations at approximately the – 7th year of injection for 376-25R, 8th year of injection for 328-25R and the 9th year of injection for 341-27R.

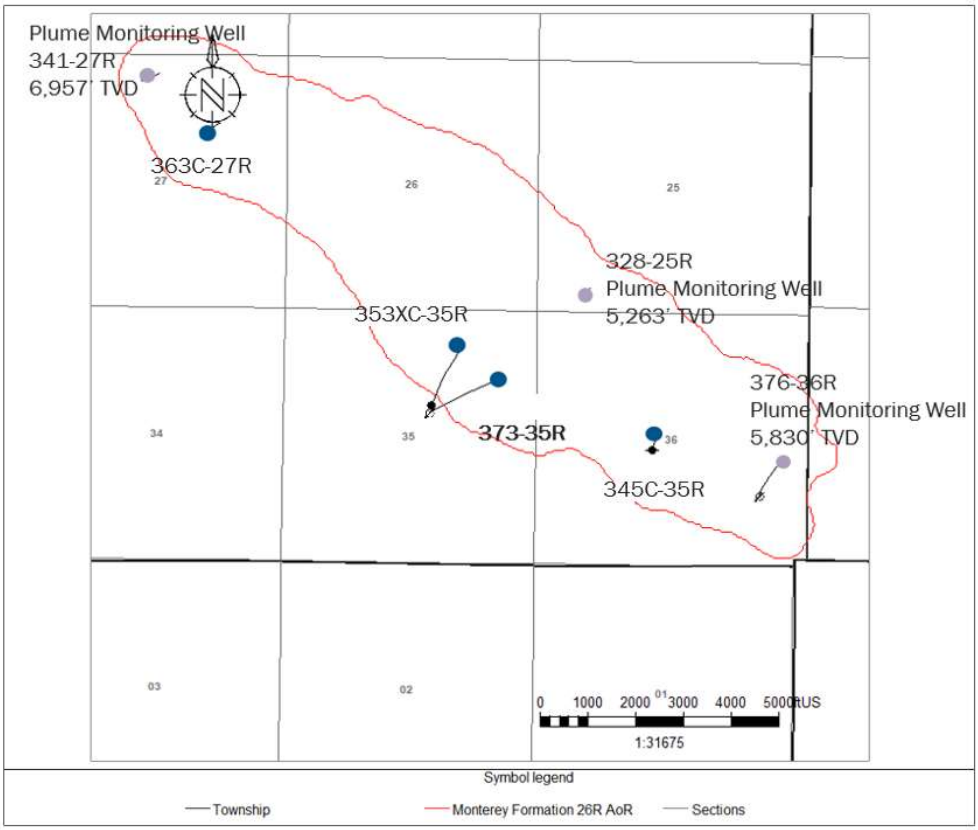


Figure 2: Monterey Formation 26R sequestration reservoir monitoring wells, with true vertical depth in feet of the monitoring interval.

Table 8 presents the methods that CTV will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 9. Detection limits, precisions, and quality control requirements for these methods are presented in Table 3 of the QASP.

Table 8. Plume Monitoring Activities

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Formation 26R	Fluid Sampling	341-27R	6981' - 7237' MD	Once	Quarterly	Annual
		Pressure		6910' MD	Baseline	Continuous	Continuous
		Temperature		6910' MD	Baseline	Continuous	Continuous
		Fluid Sampling	328-25R	5268' - 5800' MD	Once	Quarterly	Annual

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)
	Monterey Formation 26R	Pressure		5188' MD	Baseline	Continuous	Continuous
		Temperature		5188' MD	Baseline	Continuous	Continuous
	Monterey Formation 26R	Fluid Sampling	376-36R	5832' - 6815' MD	Once	Quarterly	Annual
		Pressure		5760' MD	Baseline	Continuous	Continuous
		Temperature		5760' MD	Baseline	Continuous	Continuous
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	341-27R	6981' - 7237' MD	Baseline	Every year from start of injection	Every 5 years
			328-25R	5268' - 5800' MD			
			376-36R	5832' - 6815' MD			

Table 9. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510

Parameters	Analytical Methods
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Plume Monitoring Details

Fluid sampling, pressure monitoring, and temperature monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but more importantly, the CO_2 content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in Table 9.

The DTS from the monitoring wells will provide continuous temperature from packer to surface.

As discussed in the AoR and Corrective Action Plan, 72% of the post-shut-in injected CO_2 will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and formation fluid density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand CO_2 saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every year during the injection phase.

CTV does not plan to conduct VSP monitoring for the depleted 26R oil and gas reservoir. The resolution for the CO2 plume using VSP will be limited due to noise and limited density contrast between the reservoir before and after CO2 injection. Seismic monitoring works especially well in thick, brine filled formations and may not be appropriate for depleted gas reservoirs (page 106 Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance). In addition, the unsaturated Tulare Formation and depleted gas San Joaquin Formation will limit VSP seismic wave responses.

Pressure Front Monitoring Location and Frequency

The aerial extent of plume development in the Monterey Formation 26R reservoir will reach the reservoir boundaries early in the injection phase. Because the reservoir is pressure-depleted, injected CO_2 will quickly fill the available pore space. Table 8 indicates that pressure front monitoring will coincide with direct monitoring of the CO_2 plume using the monitoring wells identified and will support CO_2 plume model and AoR model validation. Monitoring well locations with respect to plume development through time are shown in Figure 3.

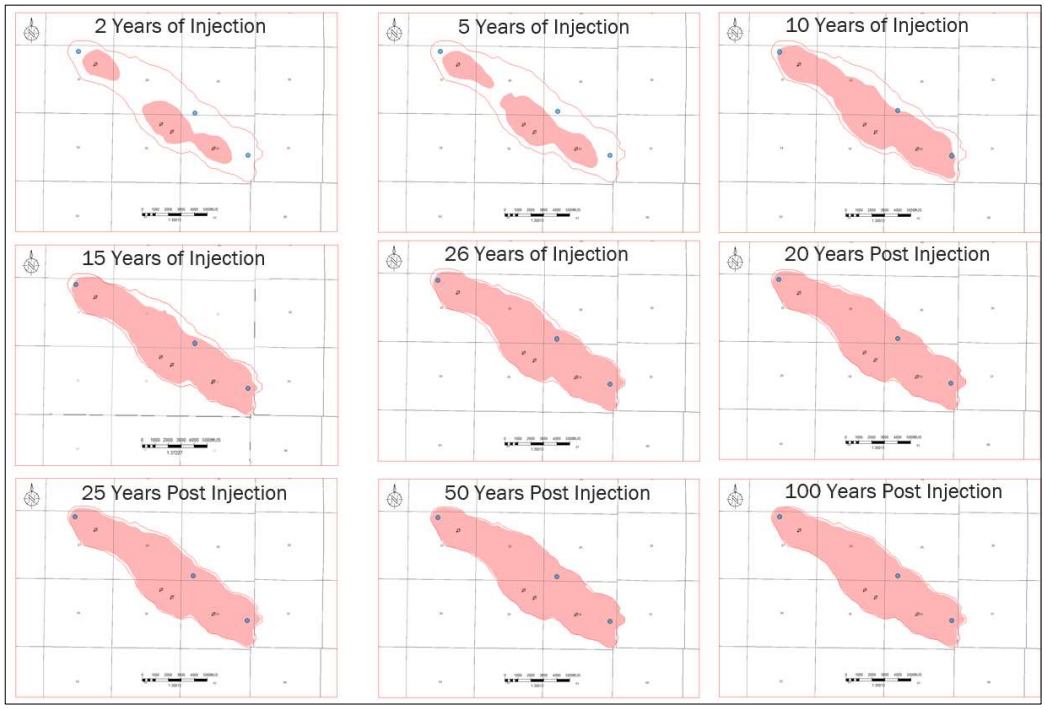


Figure 3: Monitoring well location with maps showing plume development through time from computational modeling.

Monitoring well 328-25R pressure development based on computational modeling is shown in Figure 4. The average pore volume reservoir pressure stabilizes 1 year after the end of injection. This is due to the majority of CO_2 that remains super-critical and low quantity of CO_2 that will be soluble in either the oil or water phases. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

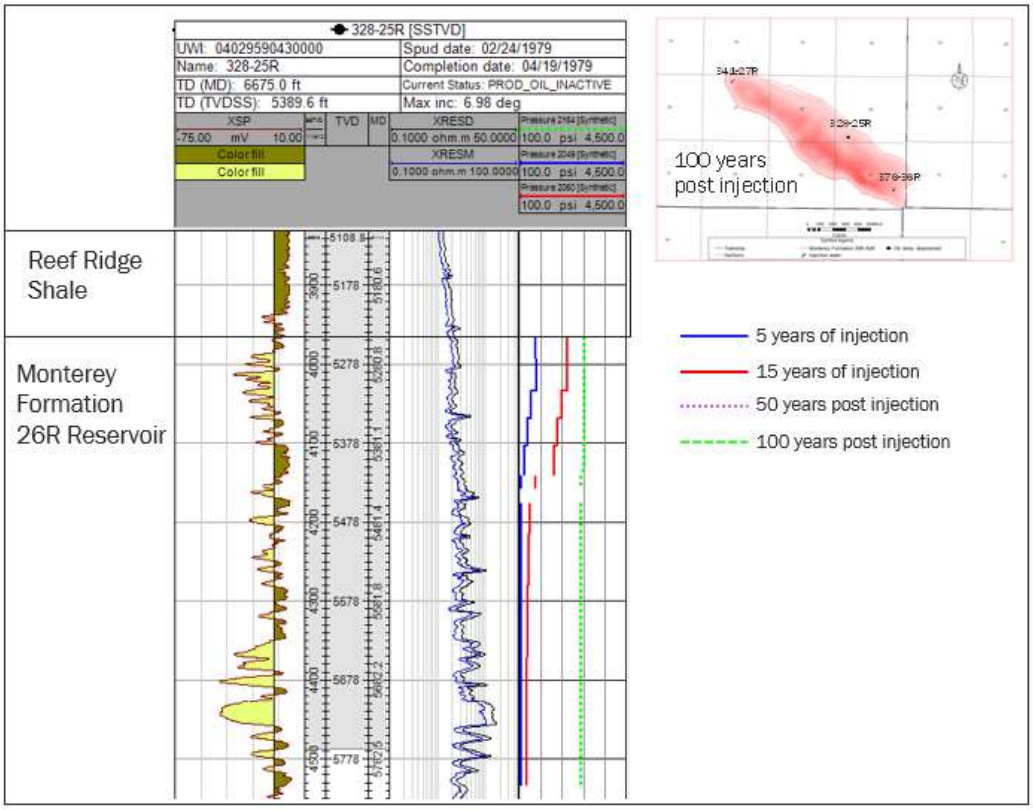


Figure 4: Monitoring well 328-25R showing the pressure increase through time from the computational modeling results.

Pressure Front Monitoring Details

Direct pressure monitoring of the plume will be achieved through installation of pressure and temperature gauges in monitoring wells 341-27R, 328-25R and 376-36R. The depleted Monterey Formation 26R oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 5 shows the pressure in the reservoir post-injection. CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies.

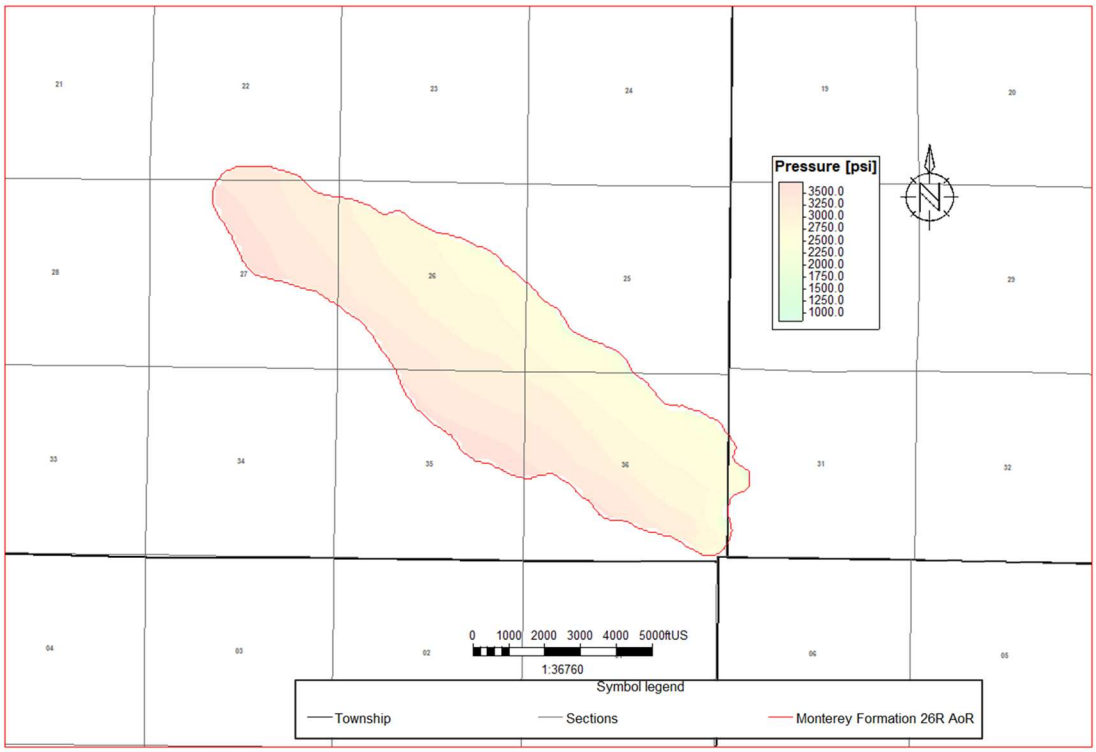


Figure 5: Monterey Formation 26R pressure 50 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.

The modeled pressure increases at monitoring well 328-25R are shown in Figure 4. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

Table 10 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ. Downhole gauge specifications are provided in Table 8 of the QASP document.

Table 10. Pressure-front monitoring activities.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)]	Monterey Fm 26R	Pressure	341-27R	6981' - 7237' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
DIRECT MONITORING	Monterey Fm 26R	Pressure	328-25R	5268' - 5800' MD	Baseline	Continuous
		Temperature			Baseline	Continuous

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
	Monterey Fm 26R	Pressure	376-36R	5832' - 6815' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
Other Plume / Pressure-Front Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Baseline	Continuous

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole seismometers in the Elk Hills Oil Field. This network will be implemented to monitor seismic activity near the project site. Direct pressure monitoring of the storage reservoir will be used in conjunction with the passive seismic monitoring to demonstrate that there are no seismic events affecting CO_2 containment.

Specifications of the network are as follows:

- 7 sensor locations (borehole and near surface) with high-sensitivity 3-component geophones (Figure 6)
- Borehole sensors have been deployed (depths shown in Figure 6) to ensure a good quality signal and to minimize noise. A velocity model will be derived from vertical seismic profiles (VSPs), sonic well logs, and check shots.
- The system will be designed with capability of detecting and locating events >M_w 0.0

Baseline Analysis:

The monitoring network has been installed to collect seismicity data to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

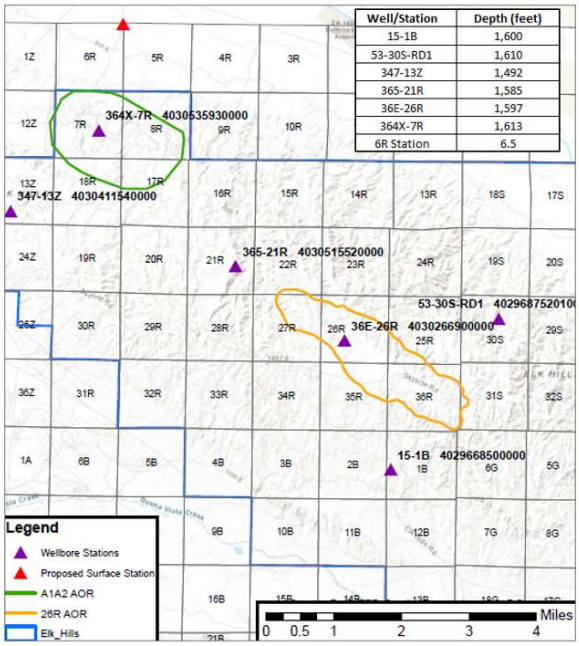


Figure 6: Elk Hills seismic monitoring network station location and depth of geophone sensors.

Monitoring Analysis:

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed continuously.

- Waveform data to be transmitted near real-time via cellular modem or other wireless means and archived in a database

- Event notifications to be automatically sent to required personnel to ensure compliance with CTV's Emergency and Remedial Response Plan

Additionally, CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network. The EPA Director will be notified of seismic activity as per the Emergency and Remedial Response Plan.

Surface Air Monitoring

Surface air monitoring, including broad aerial monitoring and targeted monitoring at wells and pipelines will be conducted.

Continuous Monitoring of AOR

Broad aerial surface air monitoring will be conducted with eddy covariance towers. Eddy covariance towers are a widely used micrometeorological technique for direct high-speed

measurements of the transport of gases, are a recommended component of CCS project surface air monitoring.

Each eddy covariance tower will consist of a solar-powered 3-dimensional sonic anemometer and open-path gas analyzer installed on a stationary tower and will be installed downwind of the prevailing wind direction from potential gas sources. Annual average prevailing wind direction in the vicinity is from the northwest. Proposed tower locations are displayed on Figure 7. Locations were chosen to be downwind (southeast) of the injection wells and surface expression of the simulated CO_2 plumes, to be in locally high topographic locations given the hilly terrain in the project vicinity, and in a location with access for equipment installation and servicing.

Monitoring equipment will be installed at a height of approximately 5 meters (33 feet). In general, the upwind distance represented by the tower height can be determined by the 1:100 rule; in this case with a 5-meter tower height the majority of measured flux will come from an oval-shaped area from near the tower to 500 meters (1,640 feet) upwind.

Gas emission rate is calculated from air density, vertical wind speed, and dry CO_2 mole fraction. Air density fluctuation is assumed to be negligible, wind speed will be measured with the sonic anemometer and CO_2 mole fraction with the gas analyzer. The sonic anemometer will be Campbell Scientific CSAT3 or equivalent, and CO_2 gas analyzer will be LI-COR Biosciences LI-7500A or equivalent. The gas analyzer will be positioned at or slightly below the sonic anemometer level, with a separation distance less than 20 centimeters. Vibration will be minimized by the use of several guy wires attached at the middle of the tower.

Manual cleaning of the gas analyzer will be performed on an as-needed basis when anomalous readings or excessive zero-drift in the data is observed. Factory calibration is assumed to be stable for at least several years and will be checked once per every six months as a precaution.

Data processing will be conducted and will be presented as hourly-averaged CO_2 concentrations and gas emission rates. Detection of anomalous and increasing CO_2 concentrations will lead to eddy covariance tower equipment testing and CARB consultation.

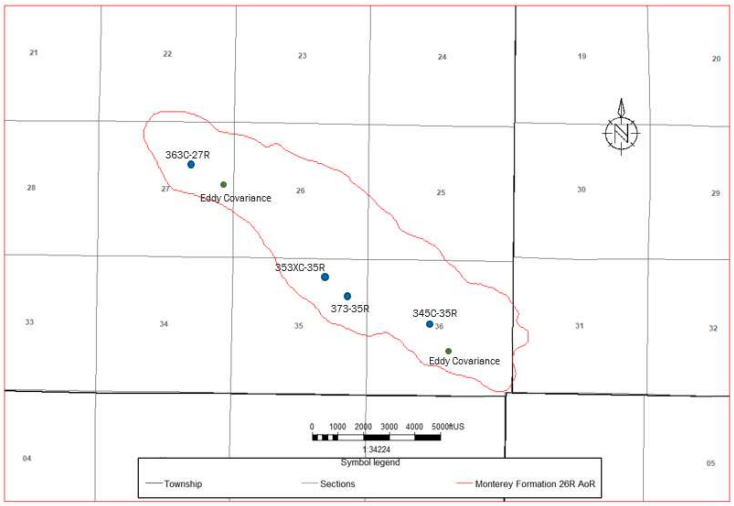


Figure 7: Location of Eddy Covariance monitoring.

Continuous Equipment Monitoring

Surface components of the injection system, including the flowlines and wellheads, will be monitored using equipment that will monitor for elevated CO_2. This leak detection equipment will be integrated with automated warning systems that notify the control center at the central facility, giving the operator the ability to remotely close the valves in the event of an anomalous reading. The central facility uses a SCADA software system to implement operational control decisions on a real-time basis throughout the project to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Monitoring Summary

This proposed monitoring program meets the goals of 40 CFR 146.90(g) by capturing continuous direct measurements of pressure and temperature in the storage reservoir (in-zone), Etchegoin (above zone) and USDW across key points of the AOR, in addition to frequent fluid samples and PNL to track the progress and confinement of the CO_2 plume. This data will also calibrate the dynamic model to predict plume front movement and pressure increase. In addition, the high resolution seismic monitoring network will provide a wide area measurement to indirectly monitor for pressure increase in-zone and above, that can be used in conjunction with the data from the monitoring wells to confirm confinement.

Direct:

The three in-zone monitoring wells are located close to the edges of the AOR, up-dip of the injectors, and thus in the flow direction of the less buoyant injected CO_2. The wells will be continuously measuring pressure and temperature at these locations. The continuous signals of pressure change in the reservoir will be used to update and calibrate the dynamic model and identify any major deviations from the predicted behavior of the reservoir. The continuous temperature measurements will provide data for the arrival of CO_2 at these locations.

In addition to the USDW and Etchegoin monitoring wells, the in-zone monitoring wells will provide confirmation of the confinement of CO_2 to the injection zone by also continuously measuring temperature changes in the Etchegoin and USDW (via DTS). Periodic fluid sampling at these locations will confirm the continuous pressure and temperature data, by providing measurements of CO_2 concentration in the reservoir that can further calibrate the dynamic model. Thus, the direct measurements for the injection zone through these wells will provide adequate special coverage of the development of the plume and pressure front, which can also improve the accuracy of the dynamic model predictions.

The two centrally located monitoring wells in the Etchegoin formation and USDW will continuously measure pressure and temperature in their respective zones, thus providing continuous direct measurements to assess the confinement of the injected CO_2. In addition, the continuous temperature measurements at these two locations, combined with the temperature measurement covering the Etchegoin and USDW at the three in-zone monitoring wells will

provide adequate spatial coverage across the AOR to evaluate confinement of CO_2 in the storage reservoir.

Indirect:

PNL at the three in-zone monitoring wells will provide indirect measurement of gas saturation and CO_2 concentration in the injection zone, which will track the progress and confinement of the plume and further calibrate the dynamic model.

The seismic monitoring network will provide an indirect measurement of the pressure increase in the injection zone, the Etchegoin and the USDW. The seismic monitoring network will be sufficient to resolve events greater than 0 magnitude, with a 1,000 ft vertical resolution at the injection depths and above, giving us the ability to differentiate between events in the injection zone versus events in the shallower Etchegoin or USDW. This provides an indirect way to monitor for pressure increases in-zone or above zone via seismic events that could be triggered from pressure changes due to CO_2 injection or fluid migration.

Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan

WELL PLUGGING PLAN

CTV I ELK HILLS 26R PROJECT

Injection Well 345C-36R

Facility Information

Facility Name: Elk Hills 26R Storage Project

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_345C-36R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – COP Details_345C-36R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – COP Details_345C-36R_V3	3	1/10/23	Revisions made based on questions received from the EPA 01/06/23
Attachment G – COP Details_345C-36R_V4	4	05/14/2023	Revisions made based on questions received from the EPA 3/2023
Attachment D – Well Plugging Plan_345C-36R_V5	5	11/29/2023	Separating Construction and Plugging Plans into Separate Attachments

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

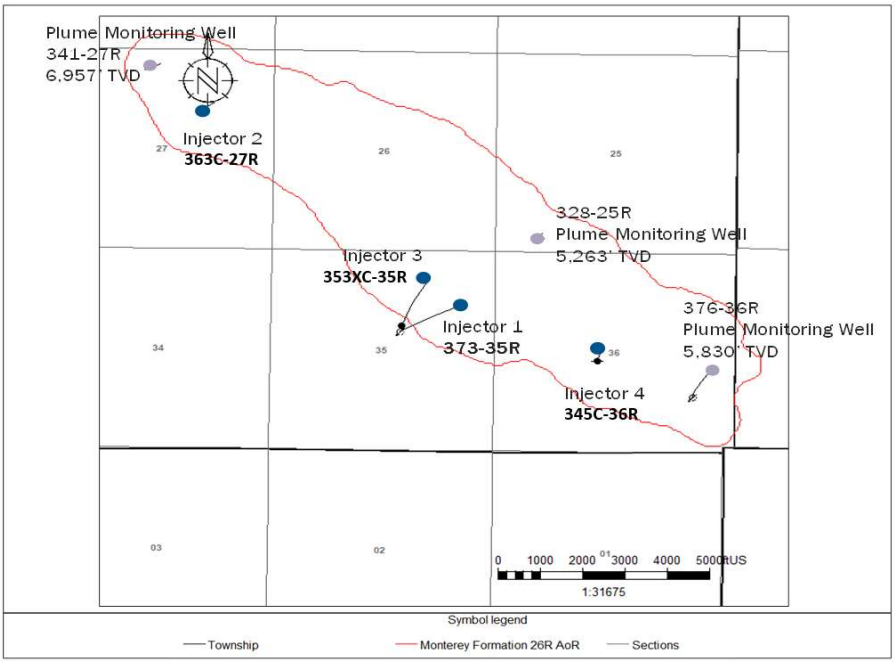


Figure 1: Map showing the location of injection wells and monitoring wells.

Figure 2 and *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Plugging

CTV will conduct injection well plugging and abandonment according to the procedures below. The proposed injection well plugging plan will ensure that the proposed materials and procedures for injection well plugging are appropriate to the well's construction and the site's geology and geochemistry.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The planned external MIT method will be a temperature log or other approved external MIT (Table 1) and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Table 1: External Mechanical Integrity Testing Methods

Test Description	Location
Temperature Decay Log	Along wellbore using wireline well log
Distributed Temperature Log (DTS)	Along wellbore using fiber optic sensing (DTS), continuous
Oxygen Activation Log (OA)	Along wellbore using wireline well log
Noise Log	Along wellbore using wireline well log

Information on Plugs

CTV will use the materials and methods noted in Table 2 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an

effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 2, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures.

Table 2: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	3.92	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft)	7900	2563	1135	39
Sacks of cement to be used (each plug)	168	24	24	5
Slurry volume to be pumped (bbl)	34.41	4.92	4.92	1.02
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	5600	2438	1010	14
Bottom of plug (ft)	7900	2563	1135	39
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or CT Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. Wellbore Bullheading will be conducted at appropriate rates so as to ensure no fracturing of the surrounding formation occurs and the cement plugs are not compromised in any way. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

9. Once the fourth cement plug is placed at surface, casing will be cut 5' below ground level. A metal cap will be welded onto the top of the cut casing, stamped with the well name and API. Surface location will then be backfilled and restored to pre-operation conditions.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has <10,000 mg/L TDS):

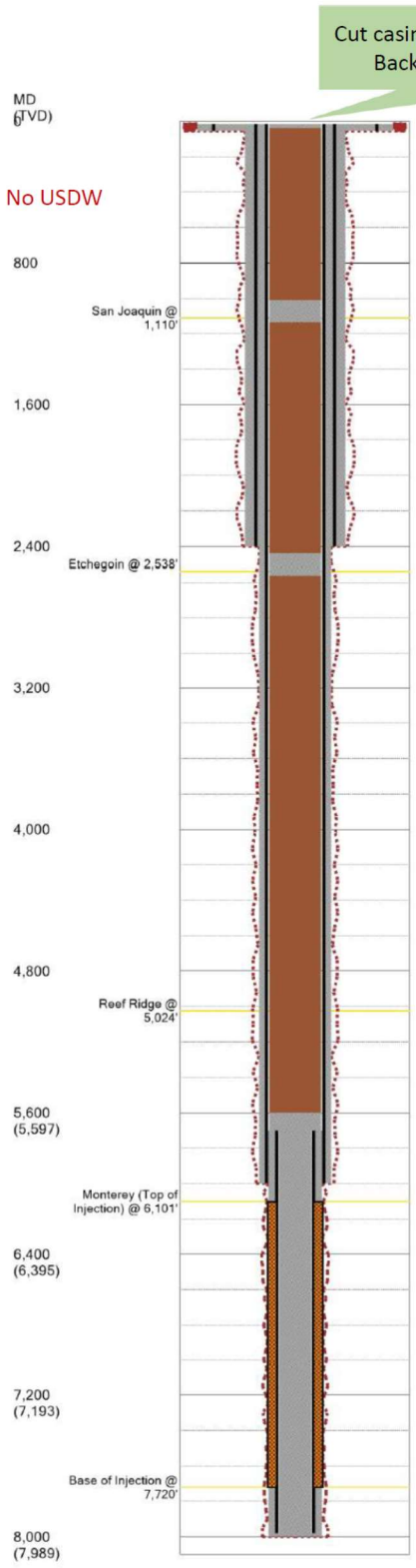
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.

    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits.

In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

  - In 26R, this interval would be located at the top of the San Joaquin formation.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.



Well	345C-36R			
Plugs	**Plug 1**	**Plug 2**	**Plug 3**	**Plug 4**
Hole Size (in.)	3.92	6.276	6.276	6.276
Bottom of tubing (ft)	7900	2563	1135	39
Cement Volume (sacks)	168	24	24	5
Slurry Volume (bbl)	34.41	4.92	4.92	1.02
Slurry Weight (lb/gal)	15.8	15.8	15.8	15.8
Top of plug (ft)	5600	2438	1010	14
Bottom of Plug (ft)	7900	2563	1135	39
Type of Cement	Class G	Class G	Class G	Class G
Method of placement	Balanced Plug, Retainer, or CT Plug			

Figure 2: Injection Well 345C-36R, Abandonment Schematic

ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

CTV I Elk Hills 26R Project

Facility Information

Facility name: Elk Hills 26R Storage Project

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment E -PISC_SC	1	01/11/21
Attachment E -PISC_SC V2	2	05/31/22
Attachment E -PISC_SC V3	3	12/21/22

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault 1 LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

Based on the modeling of the pressure front as part of the AoR delineation, pressure at the injection well is expected to stabilize within one year after injection ceases. Injection limits will be based

on the fracture pressure of the Monterey Formation 26R reservoir and final pressure post injection will target the initial reservoir pressure at the time of discovery. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the AoR and Corrective Action Plan.

Discussion

The Monterey Formation 26R reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. This operating strategy was developed to minimize the potential for induced seismicity and to ensure confinement of the injectate.

The maximum pressure differential between the injection wellbore and the depleted Monterey Formation 26R storage reservoir exists prior to the commencement of CO_2 injection. Through time, the injection pressure differential will shrink, until at the time of project abandonment when the reservoir pressure will be at the initial conditions of the reservoir. Figure 1 shows the pressure of the Monterey Formation 26R reservoir through time from computational modeling.

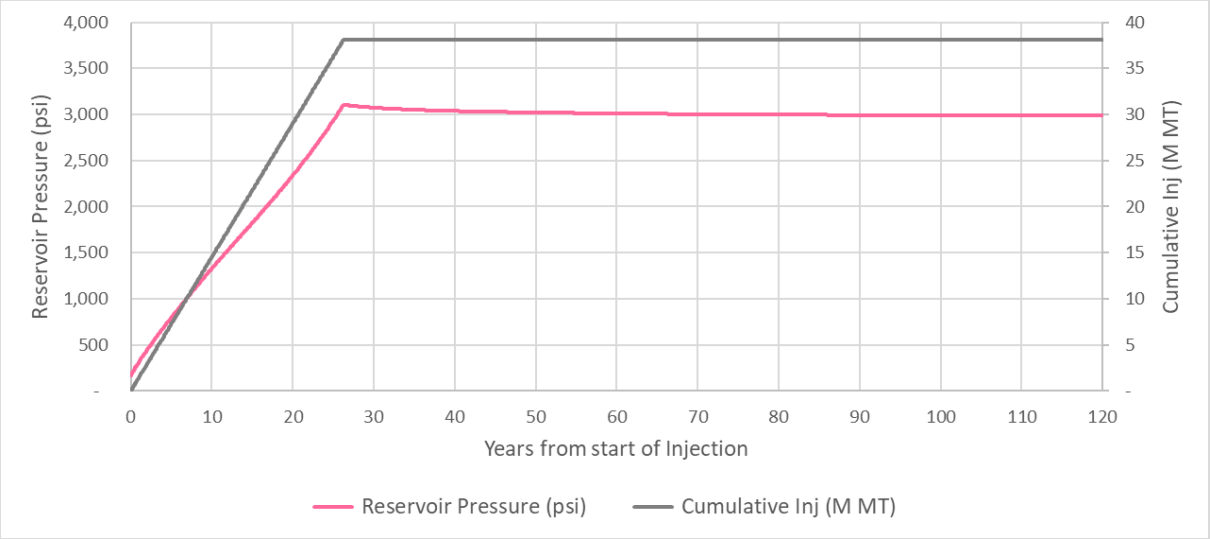


Figure 1: Reservoir pressure and Cumulative injection.

Pressure after 50 and 100 years post-injection are the same in monitoring well 328-25R (Figure 2) indicating plume stabilization. The low water saturation within the Monterey Formation 26R storage reservoir results in 72% of the CO_2 injectate remaining super-critical, minimizing the quantity of CO_2 dissolving in formation water through time.

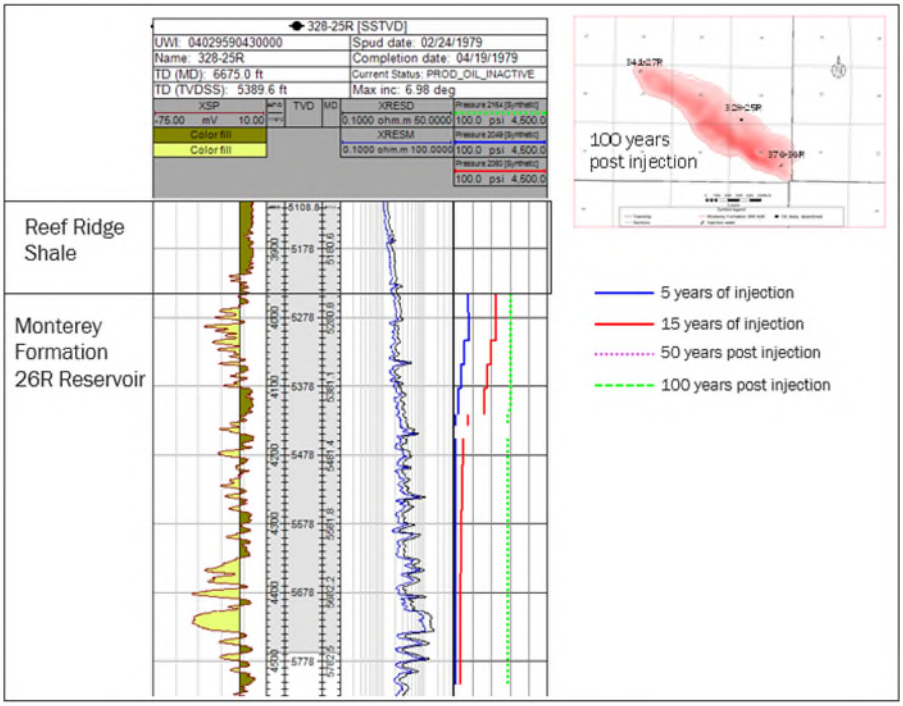


Figure 2: Pressure at the 328-25R monitoring well. Pressure after 50 and 100 years post-injection are the same indicating plume stabilization.

Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 3 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

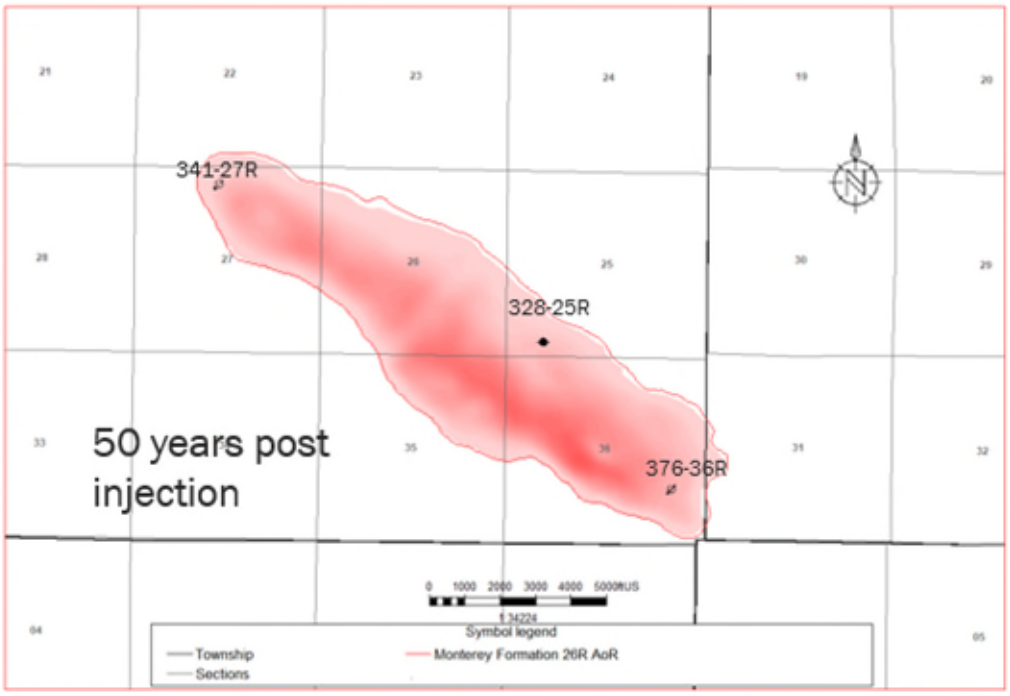


Figure 3: Map of the predicted extent of the CO_2 plume post-injection after 50 years with plume monitoring well locations . The pressure of the 26R reservoir will be at or beneath the initial pressure at the time of discovery.

Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include pressure monitoring and fluid composition monitoring in the storage reservoir and reservoirs above the injection zone. Post-injection monitoring, as described in the following sections, will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days of the anniversary date of final injection, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

The Testing and Monitoring Plan describes the monitoring strategies within the injection zone, above the injection zone, and within the USDW-containing reservoir. In addition to monitoring the zones above the injection zone for stabilized pressure and absence of CO2, the injection zone will be monitored for pressure stabilization as the best method to confirm confinement within the storage reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.

The Quality Assurance and Surveillance Plan (QASP) for all testing and monitoring activities during the injection and post-injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Throughout the AoR there is no USDW groundwater but a zone of unsaturated sands in the Upper Tulare. A shallow groundwater monitoring well will continuously assess reservoir pressure. Groundwater samples will be analyzed annually for indicators of CO_2 movement into the formation.

CTV own the mineral rights for the Monterey Formation 26R reservoir. Surface access is guaranteed for the life of the project as CTV is a wholly owned subsidiary of California Resources Corporation, owner of the surface rights.

Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ. Figure 4 shows the monitoring well locations. Table 3 shows the sampling and recording frequencies for continuous pressure monitoring in the shallow monitoring well. The pressures of these reservoirs may be affected by regional water recharge, injection, or withdrawal. For the Tulare Formation monitoring, CTV will compare these results to other groundwater monitoring wells in the Elk Hills Oil Field.

Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Post-Injection)
Tulare	Fluid Sampling	Shallow Water Monitoring Well	Pump	400’- 450' MD/VD	Annual
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’- 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’- 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	800' - 1100' MD/VD in each well	Continuous
Etchegoin	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Annual
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' MD/VD 4788' - 4811' MD/VD 4205' - 4226' MD/VD	Continuous

Table 2. Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn and T1)	ICP-MS EPA Method 6020
Cations (Ca, FE, K, Mg, Na, Si)	ICP-OEC EPA Method 6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300.0
Dissolved CO2	Coulometric Titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
Alkalinity	Method 2320B
δ13C	Isotope ratio mass spectrometry
pH	EPA 150.1
Total Dissolved Solids (TDS)	Gravimetry; Method 2540 C
Specific Conductance (field)	APHA 2510
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

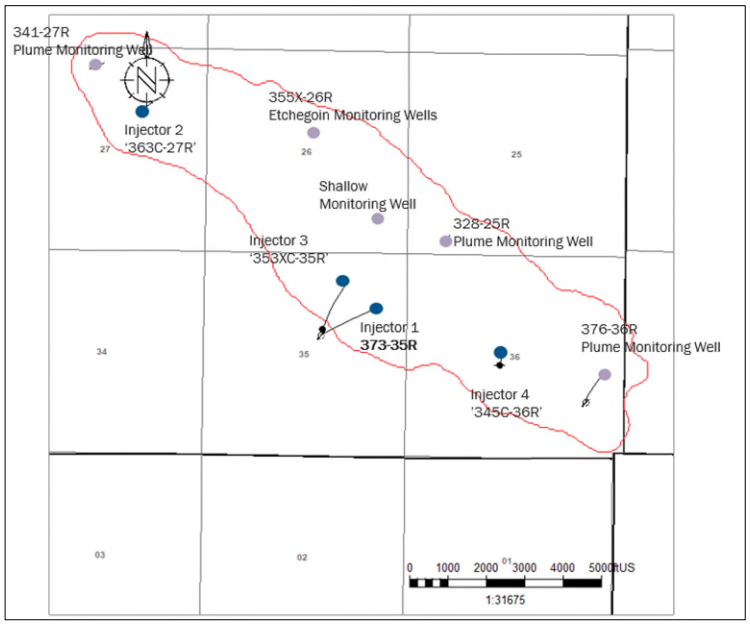


Figure 4: Map showing AoR and well locations for monitoring.

Table 3. Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
During active injection	Pressure Gauge	Shallow Monitoring Well	5 hours	5 hours
Post injection	Pressure Gauge	Shallow Monitoring Well	12 hours	12 hours

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the associated increase in pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the CO_2 plume, including the activities, locations, and frequencies CTV will employ. The parameters to be analyzed as part of fluid sampling in the Monterey Formation 26R (and associated analytical methods) are presented in Table 2.

Table 4. Post-injection phase plume monitoring.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Post-Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm 26R	Fluid Sampling	341-27R	6981' - 7237' MD	Annual
		Pressure		6910' MD	Continuous
		Temperature		6910' MD	Continuous
	Monterey Fm 26R	Fluid Sampling	328-25R	5268' - 5800' MD	Annual
		Pressure		5188' MD	Continuous
		Temperature		5188' MD	Continuous
	Monterey Fm 26R	Fluid Sampling	376-36R	5832' - 6815' MD	Annual

		Pressure		5760' MD	Continuous
		Temperature		5760' MD	Continuous
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	341-27R	6981' - 7237' MD	Every 5 years
			328-25R	5268' - 5800' MD	
			376-36R	5832' - 6815' MD	

Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn and T1)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na and Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300.0
Dissolved CO2	Coulometric Titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
Alkalinity	Method 2320B
δ13C	Isotope ratio mass spectrometry
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Total Dissolved Solids (TDS)	Gravimetry; Method 2540 C
Specific Conductance (field)	APHA 2510
pH (field)	EPA 150.1
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Fluid sampling will be performed as described in B.1. of the QASP. Sample handling and custody will be performed as described in B.3. of the QASP. Quality Control will be ensured using the methods described in B.5. of the QASP.

CTV will employ indirect and direct methods to monitor the pressure front. Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies. Direct monitoring will include pressure gauges to monitor the pressure of the CO_2 plume in the three Monterey Formation 26R monitoring wells. Additionally, seismic monitoring via installed surface and shallow borehole seismometers well will be utilized to detect micro-seismic events. Figures 4 and 5 show the location of the monitoring wells and the predicted extent of the CO_2 plume in map view and cross-section.

Table 6. Post-injection phase pressure-front monitoring.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Post-Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm 26R	Pressure	341-27R	6981' - 7237' MD	Continuous
		Temperature			Continuous
	Monterey Fm 26R	Pressure	328-25R	5268' - 5800' MD	Continuous
		Temperature			Continuous
	Monterey Fm 26R	Pressure	376-36R	5832' - 6815' MD	Continuous
		Temperature			Continuous
Pressure-Front Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Continuous

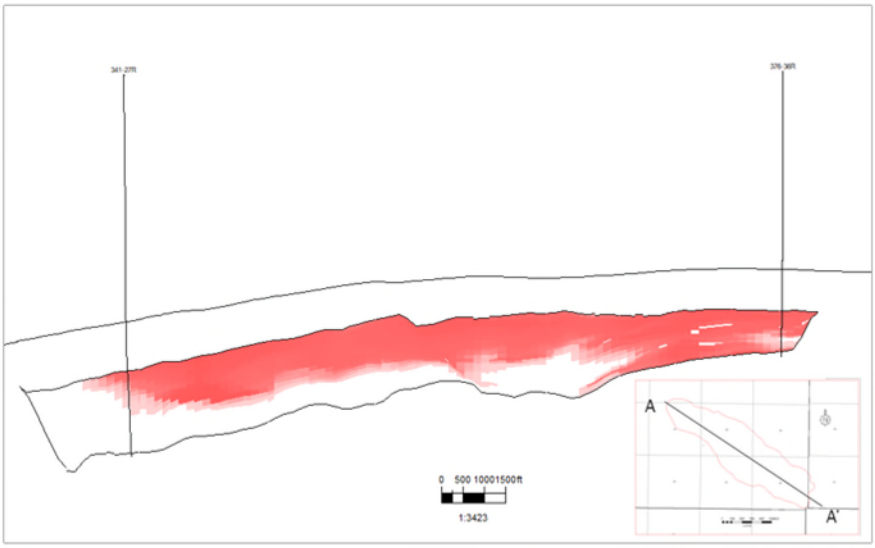


Figure 5: Cross-section showing plume CO2 plume 100 years post injection and 341-27R and 376-36R monitoring wells for post-injection monitoring.

Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period; i.e. well-based monitoring data, sample analysis, and the results from updated site models.

Non-Endangerment Demonstration Criteria [40 CFR 143.93(b)(2) or (3)]

Prior to authorization of site closure, CTV will submit a demonstration of non-endangerment of USDWs to the Director.

CTV will provide a report to the Director that demonstrated USDW non-endangerment based on the evaluation of site monitoring data. The report will detail how the non-endangerment determination is based on site-specific conditions, supported with the computational model. All relevant monitoring data and interpretations will be provided.

Summary of Monitoring Data

A summary of the site monitoring data, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project. Data submission will be in a format acceptable to the Director and will include:

1. A narrative that explains the monitoring activities,

2. Dates of all monitoring events,

3. Changes to the monitoring program over time,

4. An explanation of all monitoring information that has existed at the site,

5. Explanation of how the monitoring data from injection and PISC has varied from the baseline data during site characterization, and

6. Summary of any emergencies that occurred during the injection and post-injection phases of the project. Included will be a description of how any issues have been resolved and that there is no endangerment to the USDW.

Evaluation of the CO2 Plume and the AoR

Computational modeling results calibrated with monitoring data (e.g., pressure) will be used to support that the plume has stabilized and that the pressure change is negligible (less than 10 psi per year) and poses no risk for potential vertical migration. Computational modeling results calibrated with monitoring data from storage reservoir, USDW and above zone will be used to demonstrate:

1. the lack of CO2 leakage over the project timeframe,

2. the accuracy of the model to predict and represent the storage reservoir, and

3. the computational model adequately defined the AoR.

Evaluation of Reservoir Pressure

Monitoring data will be reviewed to ensure that the CO2 plume has stabilized post-injection and that the reservoir pressure change is negligible (less than 10 psi per year). This demonstration will be supported by the computational model that has been calibrated with the most recent monitoring data. The plume is trapped by structure and pinch-out of the reservoir sands. Plume migration is minimal, as such pressure stabilization will be used for non-endangerment assessment.

Evaluation of Potential Conduits for Fluid Movement

Wells that require corrective action will be reviewed and assessed prior to PISC and Site Closure, this includes monitoring wells, injection wells and other wells that penetrate within the AoR and the confining layer. Final demonstration will be made that natural and artificial conduits will not allow fluid migration from the storage reservoir.

Evaluation of Seismicity Monitoring

Demonstration will be made that the plume has stabilized and the pressure change is negligible (less than 10 psi per year), minimizing the risk for induced seismicity after site closure. Final review will be made with the seismicity monitoring to demonstrate seal integrity and that there is no further endangerment of to the USDW

Site Closure Plan [40 CFR 146.93(e)]

CTV will conduct site closure activities to meet the requirements of 40 CFR 146.93(e), with notification to the permitting agencies at least 120 days prior to its intent to close the site. Upon approval of the permitting agencies, CTV will plug the injection and monitoring wells, restore the site, and submit a site closure plan to the EPA. A site closure report will be prepared and submitted within 90 days following site closure supported by the following.

1. Verification of injector and monitoring well plugging,

2. Notifications to state and local authorities as per 40 CFR 146.93 (f)(2)

3. Composition and volume of the injected CO2, and

4. Post-injection monitoring records

CTV will record a notation to the property's deed that will indicate:

1. The property was used for CO2 sequestration, the period of injection and the volume of CO2 injected,

2. The formation that the fluid was injected, and

3. The name of the local agency to which a plat of survey with injection well locations was submitted.

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

CTV I: Elk Hills 26R Project

Facility Information

Facility name: CTV I: Elk Hills 26R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment F -ERR Plan	1	01/11/21
Attachment F -ERR Plan	2	05/31/22
Attachment F -ERR Plan	3	12/10/22

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault I LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

The Emergency and Remedial Response Plan would be implemented in response to events that could be detected in the course of monitoring pursuant to the Testing and Monitoring Plan, including exceedances of Actionable Testing limits described in the QASP (Table 7: Actionable Testing and Monitoring Outputs).

If CTV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.

3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in the individual Well Construction, Operating and Plugging details (COP) documents) is appropriate.

Local Resources and Infrastructure

Resources in the vicinity of the CTV I Elk Hills 26R Project that may be affected as a result of an emergency event at the project site include:

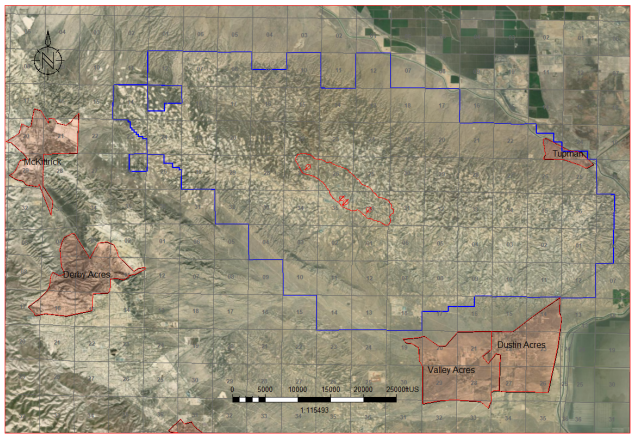
1. Elk Hills oil and gas production resources not associated with the CTV I Elk Hills 26R Project. These oil and gas operations are operated by California Resources Corporation (CRC) an owner of the CTV I Elk Hills 26R Project.
2. Upper Tulare USDW overlying the CO_2 plume. The USDW is not being utilized in the AoR and CTV does not expect usage in the foreseeable future.
3. The nearest census designated area is Valley Acres, 3.6 miles from the AoR. The population was 527 at the 2010 U.S. Census.

Infrastructure in the vicinity of the CTV I Elk Hills 26R Project that that may be affected as a result of an emergency at the project site include:

1. Elk Hills infrastructure owned and operated by CRC that is associated with oil and gas operations.

Resources and infrastructure addressed in this plan are shown in Figure 1.

Figure 1: Map of the site resources and infrastructure. The project is located 3.36 miles from the census designated area of Valley Acres.



Potential Risk Scenarios

The following events related to the CTV I Elk Hills 26R Project that could potentially result in an emergency response:

- Well integrity failure
- Injection well or monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- Potential Brine or CO2 Leakage to a USDW;
- A natural disaster (e.g. tornado, lightning strike); or
- Induced or natural seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

Well Integrity Failure

Integrity loss at the injection well and/or verification well may endanger USDWs. Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).

Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
    - Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

Severity: Low to moderate, dependent on the magnitude of the event.

Timing of event: Injection/Post-Injection

Avoidance measures: Well maintenance, monitoring and control of injection flow and pressure.

Detection methods: Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual (CO_2 at surface).

Potential response actions:

- Notify the plant superintendent and project manager.
- Limit access to wellhead to authorized personnel only.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (loss or increase of pressure or fluid volumes and/or loss of mechanical integrity during testing and maintenance):
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Communicate with CTV personnel and local authorities to initiate evacuation plans, as necessary.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
    - If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
    - Preform a well log/MIT to detect CO2 movement outside of the casing.
    - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).
- For a Minor emergency (downhole and surface sensor/monitoring equipment failure):
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.

- Shut-in injection well and vent CO_2 from surface facilities.
- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
- Perform a well log/MIT to detect CO2 movement outside of the casing.
- Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Injection Well or Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Severity: Low

Timing of event: Injection

Avoidance measures: Well maintenance, and careful monitoring and control of injection flow and pressure.

Detection methods: Anomalies in monitoring data, and visual failure of equipment.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (failure of sensors that will require shutdown of well to repair, requires extended repair time (>48 hours) and/or well intervention to remediate):
    - Contact security to restrict access to the Elk Hills 26R Storage site.

- Communicate with CTV personnel and local authorities to isolate the area and initiate evacuation plans, as necessary.
- Initiate shutdown plan.
- Shut-in injection well and vent CO_2 from surface facilities.
- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
- Verify whether contamination has occurred via handheld CO_2 monitors.
- Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.

- For a Minor emergency (sensor or monitoring failure that does not require shutdown of the well to repair):
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan and refer to Major or Serious emergency guidelines.
  - Evaluate the cause of failure, and mitigate if necessary (i.e., repair equipment).
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response Personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) movement out of the injection zone or CO_2 leakage into a USDW. This may be identified through elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO2 leakage into a USDW. For example, a pressure increase of 50 PSI (not tied to seasonal changes) or a pH of 1.

Severity: Serious

Timing of event: Injection

Avoidance measures: CTV will operate the project to ensure containment of CO_2. Contamination to USDWs will be avoided by:

1. Ensuring injection well integrity through well maintenance and mechanical integrity testing
2. Maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer.
3. Reviewing monitoring well data to understand plume extent.
4. Monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

Detection methods: Pressure or water composition change in Etchegoin Formation or USDW monitoring well. Detection limits are 0.001 PSI for the pressure gauge and 0.2 for pH.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Shut-in all injection wells and vent CO_2 from surface facilities.
    - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
        - Remediate unacceptable impacts to the affected USDW.
    - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
    - Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to aerate CO_2-laden water).
    - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.
    - If there is a well integrity issue perform MITs, refer to the Mechanical Integrity Failure scenario.

- If the leak poses a risk to air quality a perimeter will be established vi hand-held air monitoring devices.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, groundwater remediation equipment, cement or casing and air and water testing equipment.

Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. Natural disasters (e.g. tornado or lightning strike) may disturb surface and/or subsurface facilities.

Severity: Minor to catastrophic

Timing of event: Pre-injection, injection, and/or post injection phases.

Avoidance measures: N/A

Detection methods: N/A

Potential response actions:

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
  - Initiate shutdown plan.
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Shut-in all injection wells and vent CO_2 from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - If contamination has occurred refer to the Potential Brine or CO_2 Leakage to USDW scenario.
  - Communicate with CTV personnel and local authorities to initiate evacuation procedures (if necessary).
  - If there is a well integrity issue for the injector or monitoring well, refer to the Mechanical Integrity Failure scenario.

- Perform MITs on the injection wells to identify if a loss of external mechanical integrity occurred.
- If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

- For a Minor emergency:
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan.
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Shut-in all injection wells and vent CO_2 from surface facilities. Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Induced or Natural Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a two-mile radius of the injection wells.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the Elk Hills 26R site for seismic activity. In addition to the CTV seismic monitoring, the Southern California Earthquake Data Center has deployed a network to monitor natural seismicity in the area.

Severity: Minor to Major

Timing of event: Injection / post injection

Avoidance measures: N/A

Detection methods: The seismic monitoring network.

Potential response Actions:

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table 2. Seismic monitoring system, for seismic events > M1.5 with an epicenter within a two-mile radius of the injection well.

Operating State	Threshold Condition[1,2]	Response Action[3]
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels. 2. Document the event in semiannual reports to the EPA.
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the injection wells if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 5. Document the event in semiannual reports to the EPA.
Orange	Seismic event greater than M1.5 and local observation or felt report Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the injection wells if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 5. Report findings to the UIC Program Director and perform corrective actions. 6. Document the event in semiannual reports to the EPA

[1] Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition[1,2]	Response Action[3]
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate gradual shutdown of the injection wells if it is determined appropriate. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 9. If USDW contamination is detected or endangerment, or CO2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and perform corrective actions. 12. Document the event in semiannual reports to the EPA.
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4]	1. Initiate shutdown plan for all injection wells. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

Operating State	Threshold Condition[1,2]	Response Action[3]
	Or Seismic event >M3.5	4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 8. Determine if leaks to ground water or surface water occurred. 9. If USDW contamination or endangerment is detected, or CO_2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and perform corrective actions. 12. Document the event in semiannual reports to the EPA.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Ken Haney (661- 763-6101)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director (24 hour contact)

Bill Blair (562-743-8336)

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	**Phone Number**
Local police	9-1-1 (Emergency) 661-861-3110 (Non-emergency)
California Governor's Office of Emergency Services (Cal OES)	(916) 845-8506
UIC Program Director (EPA Region 9)	David Albright (albright.david@epa.gov)
EPA National Response Center (24 hours)	800-424-8802
Kern County Fire Department	9-1-1 (Emergency) 661-324-6551 (Non-emergency)
California Air Resources Board (CARB)	800-242-4450
Poison Control Center	800-342-9293
California Office of Emergency Services (24 hours)	800-852-7550
State Water Quality Control Board (Central Valley)	916-255-3000
Kern Medical	661-326-2000

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

Emergency Communications Plan

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For

responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within 30 days, or other time prescribed by the EPA director, following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

Staff Training and Exercise Procedures

All CTV staff and contractors operating at the CO_2 sequestration facilities, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

CO_2 Facilities Training

Onsite and classroom training for facility and infrastructure security, maintenance, and operations.

CO_2 Safety Training

Carbon dioxide detection equipment: Operation and maintenance of personal monitors, portable multi-gas monitors and stationary monitors throughout the facility.

Carbon Dioxide Hazards: Accidental exposure, adverse health effects, workplace exposure limits and first aid.

Emergency Response: Training in the event of CO2 leakage and exercise and drills simulating potential emergency situations.

WELL CONSTRUCTION PLAN

CTV I ELK HILLS 26R PROJECT

Injection Well 345C-36R

Facility Information

Facility Name: Elk Hills 26R Storage Project

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_345C-36R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – COP Details_345C-36R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – COP Details_345C-36R_V3	3	1/10/23	Revisions made based on questions received from the EPA 01/06/23
Attachment G – COP Details_345C-36R_V4	4	05/14/2023	Revisions made based on questions received from the EPA 3/2023
Attachment G – COP Details_345C-36R_V5	5	11/29/2023	Separating Construction and Plugging Plans into Separate Attachments

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

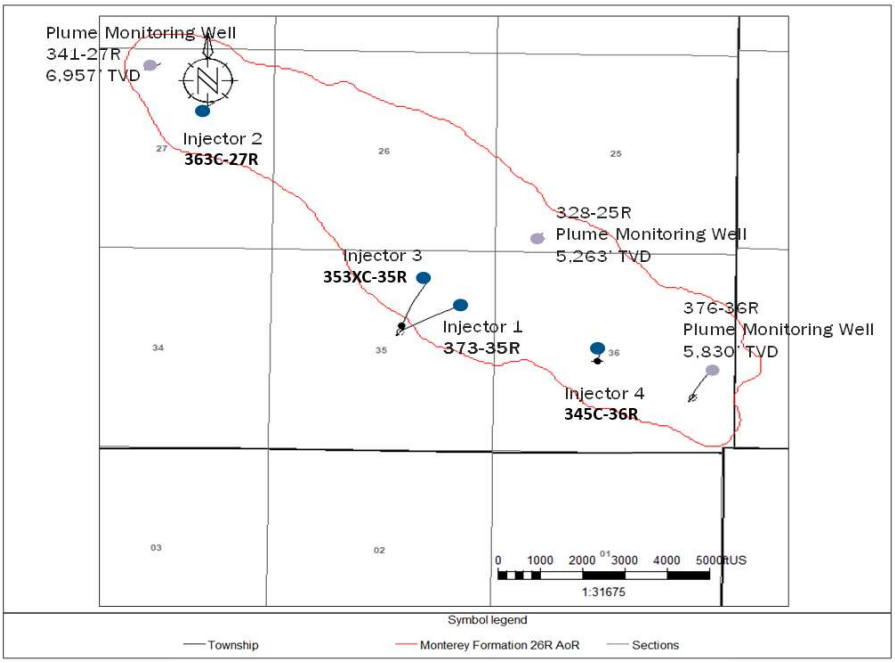


Figure 1: Map showing the location of injection wells and monitoring wells.

Figure 3 and *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Construction

Construction of new injection and monitoring wells will occur during pre-operational testing. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO_2 injection rates: to prevent migration of fluids out of the injection zone, to protect the shallow formations, and to allow for monitoring, as described by the following.

- Well designs will be sufficient to withstand all anticipated load cases including safety factors
- Multiple cemented casing strings will protect shallow formations from contacting injection fluid
- All casing strings will be cemented in place with volume sufficient to place cement to surface using industry-proven recommended practices for slurry design and placement
- Cement bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer
- Mechanical integrity testing (MIT) will be performed on the tubing and the tubing/casing annulus
- Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired and MIT to be conducted
- All wellhead equipment and downhole tubulars will be designed to accommodate the dimensions necessary for deployment of monitoring equipment such as wireline-conveyed logging tools and sampling devices
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
- Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion.

- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
- Casing – 13Cr L-80 or other corrosion resistant alloy in specified sections of production string (ie. flow-wetted casing)
- Cement – portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 where good cement bond between formation and casing exists.
- Tubing – 13Cr L-80 or other corrosion resistant alloy
- Packer – corrosion resistant alloy and hardened elastomer

Well materials follow the following standards:

- API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
- API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
- API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing and Cementing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure specified in the Operational Procedures section.

The 26R reservoir has been depleted and reservoir pressure is low. The temperature is approximately 210 degrees Fahrenheit. These conditions are not extreme, and CTV has extensive experience successfully constructing wells in depleted reservoirs. Standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement.

Operational parameters acquired throughout the cementing operation will be used to compare modeled versus actual pressure and rate. The presence of circulated cement at surface will also be a primary indicator of effective cement placement. Cement evaluation logging will be conducted to confirm cement placement and isolation.

Table 1: Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14' - 54'	20	19.124	94	H-40	Short	2.62	1530	520
Surface	14' - 2400'	9.625	8.835	40	L-80	Long	2.62	5750	3090
Long string	14' - 5600' 5600' - 6000'	7	6.276	26	L-80 L-80 CRA	Long	2.62	7240	5410
Liner	5700' - 7980'	4.5	3.92	13.5	L-80 CRA	Long	2.62	9020	8540

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

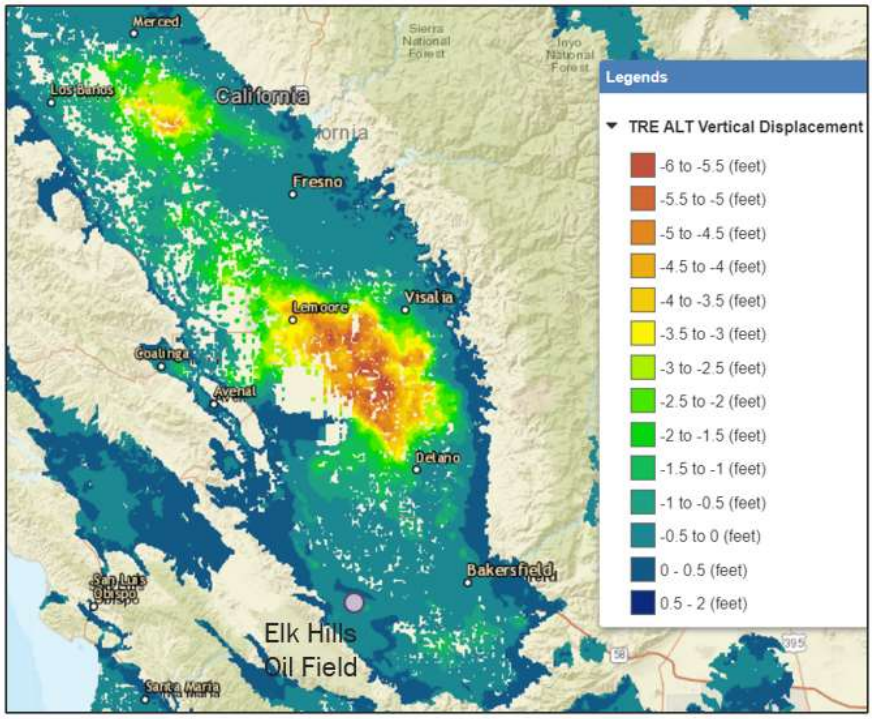


Figure 2: Subsidence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Tubing and Packer

The information in the tables provided in the Tables 2 and 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined prior to completion during pre-operational testing. A suitable corrosion-resistant alloy will be selected and installed once the CO_2 stream impurities and impurity concentrations have been determined. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel.

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 2: Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	5,700	4.5	4.00	11.6	L-80 CRA	Premium	7,780	6,350

Table 3: Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	5,700	30.3	26 - 32	5.875"	4.00"

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rates, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan detail the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The EPA Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design 345C-36R with a surface shut-off valve at the wellhead and not a down-hole device.

Pre-Injection Testing Plan

The following tests and logs will be acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The testing activities described in this attachment are restricted to the pre-injection phase. Testing and

monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring document.

Deviation Checks

Deviation measurements will be conducted approximately every 120' during construction of the well.

Tests and Logs

The following logs are expected to be acquired during the drilling or prior to the completion of 345C-36R:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Mud Log
- Acoustic Cement Bond Log

Demonstration of mechanical integrity

Table 4: Summary of tests to be performed prior to injection

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log. The mechanical integrity testing procedures are described in the Testing and Monitoring document.

Annulus Pressure Test Procedures

1. The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test.

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less equal to or greater than the highest annular pressure specified in the Operating Procedures document. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve.

4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals.

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Injectivity and Pressure Fall-Off Testing for Injection Wells

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV will complete injectivity and pressure fall off testing prior to CO_2 injection, pursuant to 40 CFR §146.87(e).

CTV will consider pressure fall-off testing throughout the injection phase to complement reservoir monitoring if injection rate decreases along with a simultaneous injection pressure increase outside the results from computational modeling.

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

A surface gauge at the wellhead and a downhole gauge set above the packer with real-time surface readout capability will be used for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the reviews. This information is summarized below (along with the planned tests that will address each data need that was described in the initial permit application materials submitted in November 2021) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c) and 146.87.

Regional Geology and Geologic Structure

• Perform pressure build-up testing (anticipated testing method: pressure build-up test).

• Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

• Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

• Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

• Determine if there are any heterogeneities within the Monterey 26R injection zone that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; planned and completed core, log, and seismic analysis).

CO2 Stream Compatibility with Subsurface Fluids and Minerals

• Confirm the composition and water content of the CO2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses, benchtop studies).

• Confirm that the properties of the CO2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).

• Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of the geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

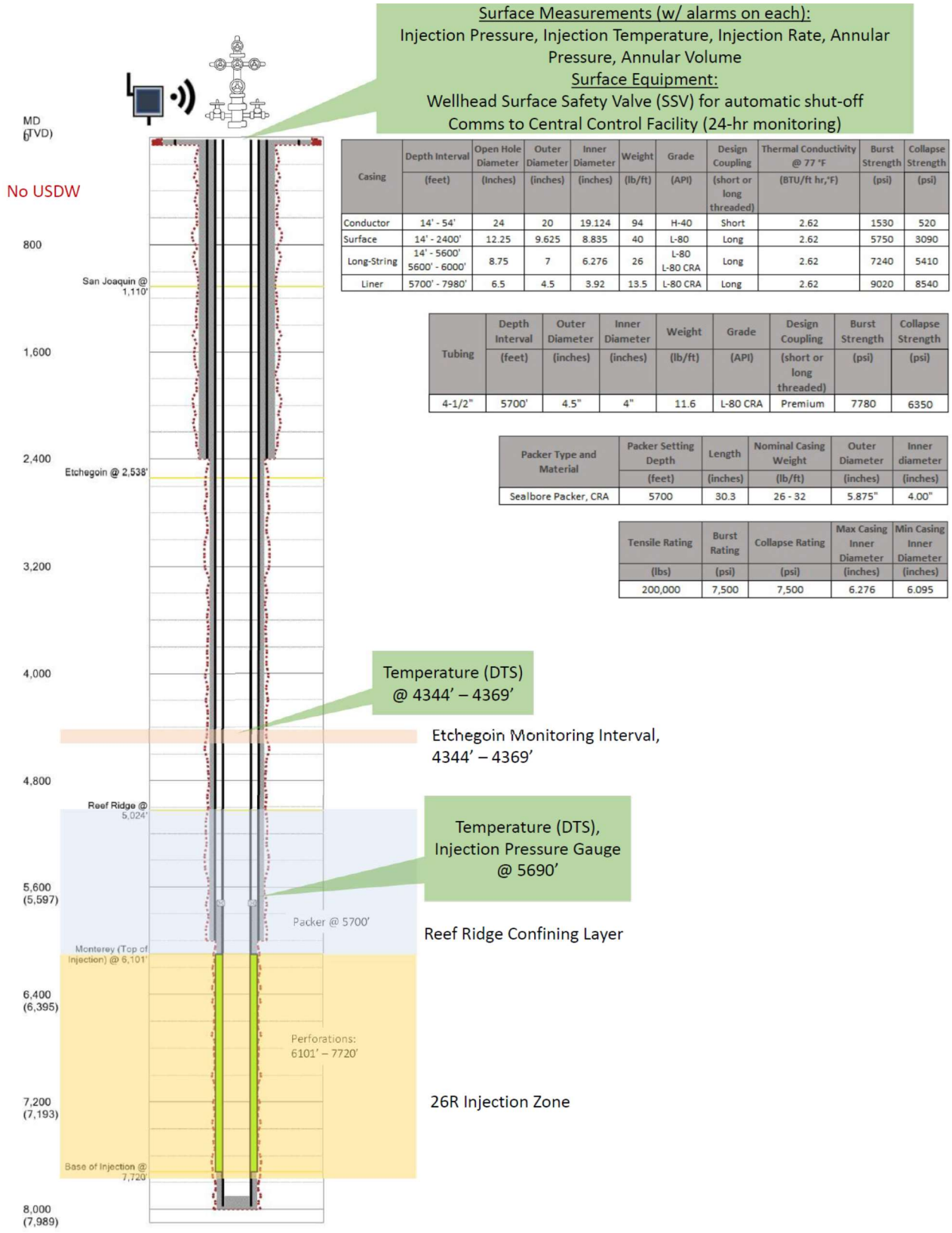
• Collect baseline pressure data in the Etchegoin Formation to support upward confinement between the Monterey and shallower formations (anticipated testing method: pressure build-up test).

• Determine the porosity and permeability of the Reef Ridge Shale at the location of each of the 26R project wells (anticipated testing methods: core and log data during well drilling).

• Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

• Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).



Casing	Depth Interval (feet)	Open Hole Diameter (inches)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)	Thermal Conductivity @ 77 °F (BTU/ft hr,°F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14' - 54'	24	20	19.124	94	H-40	Short	2.62	1530	520
Surface	14' - 2400'	12.25	9.625	8.835	40	L-80	Long	2.62	5750	3090
Long-String	14' - 5600' 5600' - 6000'	8.75	7	6.276	26	L-80 L-80 CRA	Long	2.62	7240	5410
Liner	5700' - 7980'	6.5	4.5	3.92	13.5	L-80 CRA	Long	2.62	9020	8540

Tubing	Depth Interval (feet)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)	Burst Strength (psi)	Collapse Strength (psi)
4-1/2"	5700'	4.5"	4"	11.6	L-80 CRA	Premium	7780	6350

Packer Type and Material	Packer Setting Depth (feet)	Length (inches)	Nominal Casing Weight (lb/ft)	Outer Diameter (inches)	Inner diameter (inches)
Sealbore Packer, CRA	5700	30.3	26 - 32	5.875"	4.00"

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max Casing Inner Diameter (inches)	Min Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Figure 3: Injection Well 345C-36R, CO_2 Injection Schematic

ATTACHMENT H: FINANCIAL ASSURANCE DEMONSTRATION
40 CFR 146.85

CTV I: Elk Hills 26R Project

Document Version History

Version	Revision Date	File Name	Description of Change
1	9/29/2023	Att H_Financial Responsibility_26R	Compilation of financial responsibility documents in one attachment

Facility Information

Facility name: CTV I: Elk Hills 26R

Facility contact: Travis Hurst / Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Financial Instruments

Carbon TerraVault (CTV) is providing financial responsibility information pursuant to 40 CFR 146.85. CTV is using the following financial instruments:

- Letter of Credit to cover the costs of corrective action, injection well plugging, post-injection site care, and site closure.
- Certificate of Insurance to cover costs of emergency and remedial response

The estimated costs of each of these activities, as provided by CTV, are presented in Table 1.

CTV has provided financial assurance for Emergency and Remedial Response by procuring an environmental insurance policy. If needed the limits will be re-determined by a reasonable estimate of the cost of these activities prior to the commencement of injection operations. The Elk Hills 26R project environmental insurance policy covers all emergency and remedial response activities arising from the assets. The selected insurance carrier has issued a financial assurance certificate in compliance with state and federal regulations that is provided below.

Table 1. Cost Estimates for Activities to be Covered by Financial Responsibility.

Activity	Instrument	Total Cost ($)
Corrective Action	Letter of Credit	111,320
Plugging Injection Wells	Letter of Credit	1,197,840
Post-Injection Site Care	Letter of Credit	6,790,750
Site Closure	Letter of Credit	994,750
Emergency and Remedial Response	Certificate of Insurance	24,578,125

The following supporting information is provided below to satisfy Financial Responsibility requirements:

- Daniel B. Stephens & Associates, Inc. (DBS&A) third party cost estimate
- Deutsche Bank AG Irrevocable Standby Letter of Credit
- Irrevocable Standby Letter of Credit Notification Letter
- Bank of New York Mellon Standby Trust
- Letter of Credit Cost Estimate and Funding Value Summary
- Ascot Certificate of Insurance
- Insurance Endorsement
- Financial Strength Demonstration

DBS&A THIRD PARTY COST ESTIMATE

CLASS VI FINANCIAL RESPONSIBILITY DEMONSTRATION

COST ESTIMATE

CTV I 26R

Carbon TerraVault (CTV) had the following cost estimate prepared by third party contractor, Daniel B. Stephens & Associates, Inc., completed on 9/5/2023.

Table 1. Financial Responsibility Cost Summary

Activity	Estimated Cost	Reference
Corrective Action	$ 111,320	Table 2
Injection Well Abandonment	$ 1,197,840	Table 3
Post-Injection Site Care	$ 6,790,750	Table 4
Site Closure	$ 994,750	Table 5
Emergency and Remedial Response	$ 24,578,125	Table 6
Total	**$**	**33,672,785**

All values in 2022 dollars

Table 2. Costs, Corrective Action Total

Activity	Unit		Unit Cost	Total	Reference
Revise Numerical Model	400	hrs	$ 220	$ 88,000	-
Review CalGEM Well Database	40	hrs	$ 220	$ 8,800	-
Plug Deficient Wells	0	wells	-	$ -	A
Project Management	1	each		$ 14,520	B
			Total	**$ 111,320**	

Notes

A: Per Attachment B, as required wells will be abandoned prior to injection as part of asset retirement obligations

B: 15% of project costs

Table 3. Costs, Injection Well Abandonment

Location	Unit Cost		Depth (ft)	Cost	Reference
Injector 4 345C-36R	30	$/ft	8,680	$ 260,400	A
Injector 1 373-35R	30	$/ft	8,680	$ 260,400	A
Injector 3 353XC-35R	30	$/ft	8,680	$ 260,400	A
Injector 2 363C-27R	30	$/ft	8,680	$ 260,400	A
Documentation, project management	1	each	-	$ 156,240	B
			TOTAL	**$ 1,197,840**	

Notes

A: Abandonment costs from Driltek, 2021; well construction from Attachment G 'Injection Well 1 353XC-35R', Table

B: 15% of project costs

Table 4. Post Injection Site Care Costs

Activity	Unit		Events, 50 years	Unit Cost	Total	Reference
USDW geochemical monitoring/fluid sampling	1	well	50	$ 6,000	$ 300,000	A
Above Confining zone geochemical, pressure monitoring	1	well	50	$ 5,600	$ 280,000	A
Injection zone geochemical, pressure monitoring	3	well	50	$ 5,600	$ 840,000	A
Monitoring well O&M, Above confining zone	1	well	3	$ 30,000	$ 90,000	B
Injection zone monitoring well O&M	3	wells	10	$ 84,000	$ 2,520,000	-
Indirect Plume Monitoring (Pulsed neutron)	1	survey	10	$ 37,500	$ 375,000	C
Mechanical Integrity Test, Injection zone	3	well	10	$ 50,000	$ 1,500,000	B
Reporting/Project Management	1	each	-	$ 885,750	$ 885,750	D
				Total	**$**	**6,790,750**

Notes:

A: Assumes 1 geochemical monitoring event per year per well and continuous pressure monitoring with automated gage; shallow groundwater well have a higher testing cost than the other monitoring wells due to the potential time required to obtain a stabilized sample from a reservoir with low water deliverability.

B: Patrick Engineering, 2013; assumes $2,000 base cost + $4.25/ft (+12%)

C: Zaluski et al., 2016; assumes 8 well survey (inflation adjusted); technology and frequency from PISC plan Table 4

D: 15% of project costs

Assumes:

1 USDW Monitoring Well (exempt or unsaturated)

1 Above Confining Zone Monitoring Well

3 Injection Zone Monitoring Wells

4 Injection wells

Table 5. Costs, Site Closure

Activity	Unit		Unit Cost	Total	Reference
Non-endangerment report	1	each	$ 45,000	$ 45,000	-
Injection zone monitoring well plugging	3	wells	$ 200,000	$ 600,000	A
Above-confining zone monitoring well plugging	1	wells	$ 170,000	$ 170,000	A
USDW Monitoring well plugging	1	well	$ 50,000	$ 50,000	
Plugging documentation, project management	1	each		$ 129,750	B
			Total	**$**	**994,750**

Notes
A: Abandonment costs from Driltek, 2021
B: 15% of project costs

Assumes:
1 USDW Monitoring Well (exempt or unsaturated)
1 Above Confining Zone Monitoring Well
3 Injection Zone Monitoring Wells
4 injection wells

Table 6. Emergency Response

Groundwater Contamination Causal Investigation

Activity	Unit		Unit Cost	Total	Reference
Planning/permitting	1	each	$ 1,381,875	$ 1,381,875	B
Monitoring wells, depth 1,000 ft	5	well	$ 385,000	$ 1,925,000	A
Monitoring wells, depth 5,000 ft	3	well	$ 1,925,000	$ 5,775,000	A
Abandoned well investigation	51	well	$ 27,500	$ 1,402,500	D
Former Injection Well Investigation	4	well	$ 27,500	$ 110,000	-
Reporting/Project Management	1	each	$ 921,250	$ 921,250	C
Total				**$**	**11,515,625**

Groundwater Contamination Remediation

Activity	Unit		Unit Cost	Total	Reference
Planning/permitting	1	each	$ 1,567,500	$ 1,567,500	B
Pumping well, depth 1,000 ft	4	well	$ 350,000	$ 1,400,000	A
Pumping well, depth 5,000 ft	4	well	$ 1,925,000	$ 7,700,000	A
Groundwater extraction	1	year	$ 300,000	$ 300,000	-
Above-ground CO_2 removal (aeration)	1	unit	$ 150,000	$ 150,000	-
Former injection well repair	4	well	$ 225,000	$ 900,000	-
Reporting/Project Management	1	each	$ 1,045,000	$ 1,045,000	C
Total				**$**	**13,062,500**

Total, Causal Investigation and Remediation	**$**	**24,578,125**

Notes

A: Assumes $385/ft for permitting, installation, field oversight, logging drilling, and waste

B: 15% of project costs

C: 10% of project costs separate from Planning/permitting

D: Assumes 25% of wellbores penetrating Reef Ridge Formation, Attachment B Table 9

References

Driltek, 2021: Personal communication with Driltek regarding well abandonment costs, California

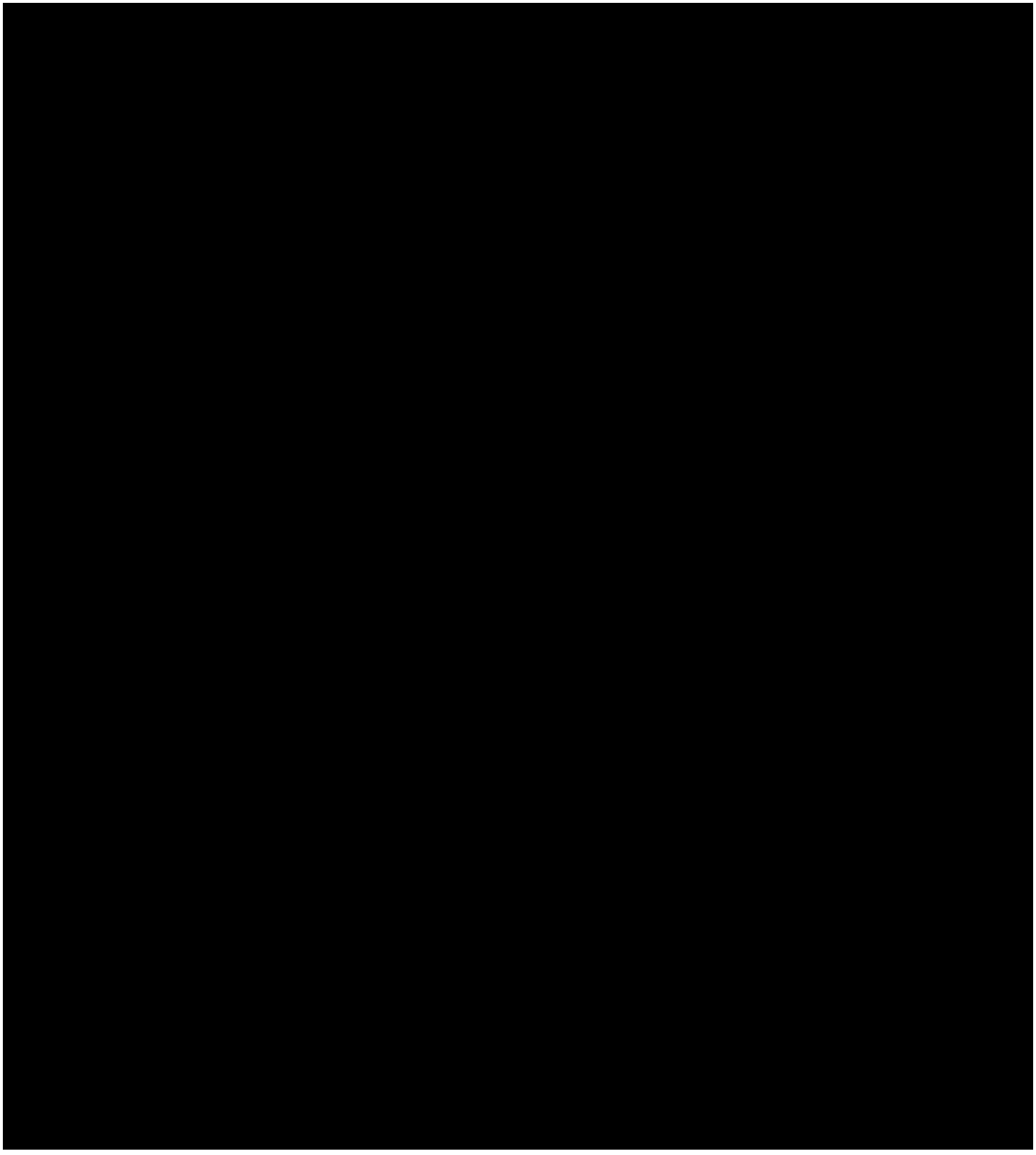
Patrick Engineering, 2013: Third Party Cost Estimate for FutureGen Alliance UIC Class VI Permit Application

Zaluski et al., 2016. Monitoring technology ranking methodology for CO2-EOR sites using the Weyburn-Midale Field as a case study, IJGGC v.54, p.466 - 478

DEUTSCHE BANK AG IRREVOCABLE STANDBY LETTER OF CREDIT

Deutsche Bank

Deutsche Bank AG New York Branch
Trade Finance & Lending
1 Columbus Circle, 17th Floor



Deutsche Bank AG New York Branch
Trade Finance & Lending
1 Columbus Circle, 17th Floor
New York, NY 10019



Very truly yours,
Deutsche Bank AG
New York Branch

[Signature(s) and title(s) of official(s) of issuing institution]

Chairman of the Supervisory Board: Alexander R. Wynaendts
Management Board: Christian Sewing (Chairman), James von Moltke, Karl von Rohr, Fabrizio Campelli, Bernd Leukert, Alexander von zur Mühlen, Christiana Riley, Rebecca Short, Stefan Simon, Olivier Vigneron
Deutsche Bank Aktiengesellschaft domiciled in Frankfurt am Main; Local Court of Frankfurt am Main, HRB No 30 000; VAT ID No DE114103379; www.db.com

IRREVOCABLE STANDBY LETTER OF CREDIT NOTIFICATION LETTER

September 6, 2023

United States Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, D.C. 20460
Attention: UIC Program Director

Re: EPA Identification Number: _____.

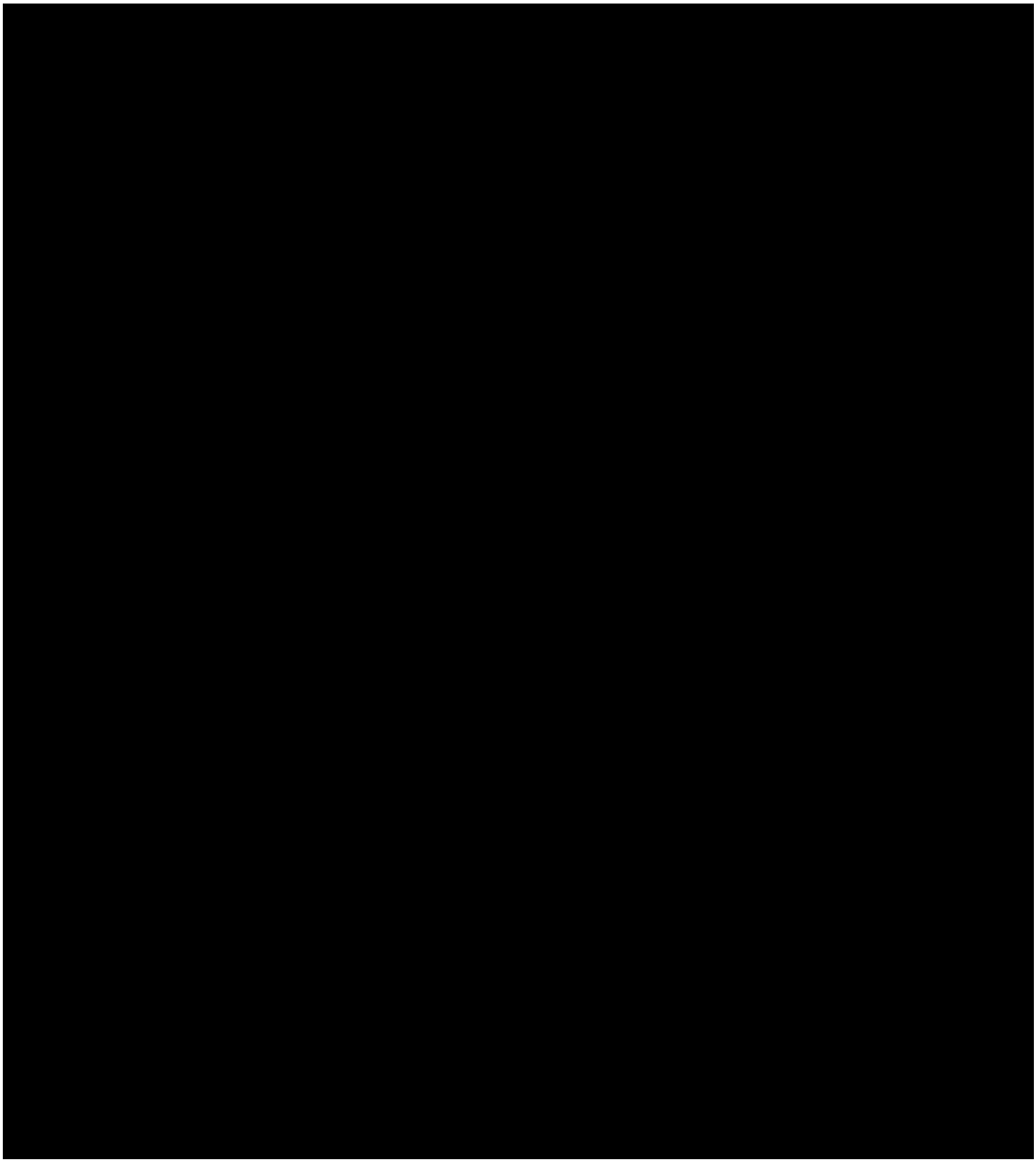
Dear UIC Program Director,

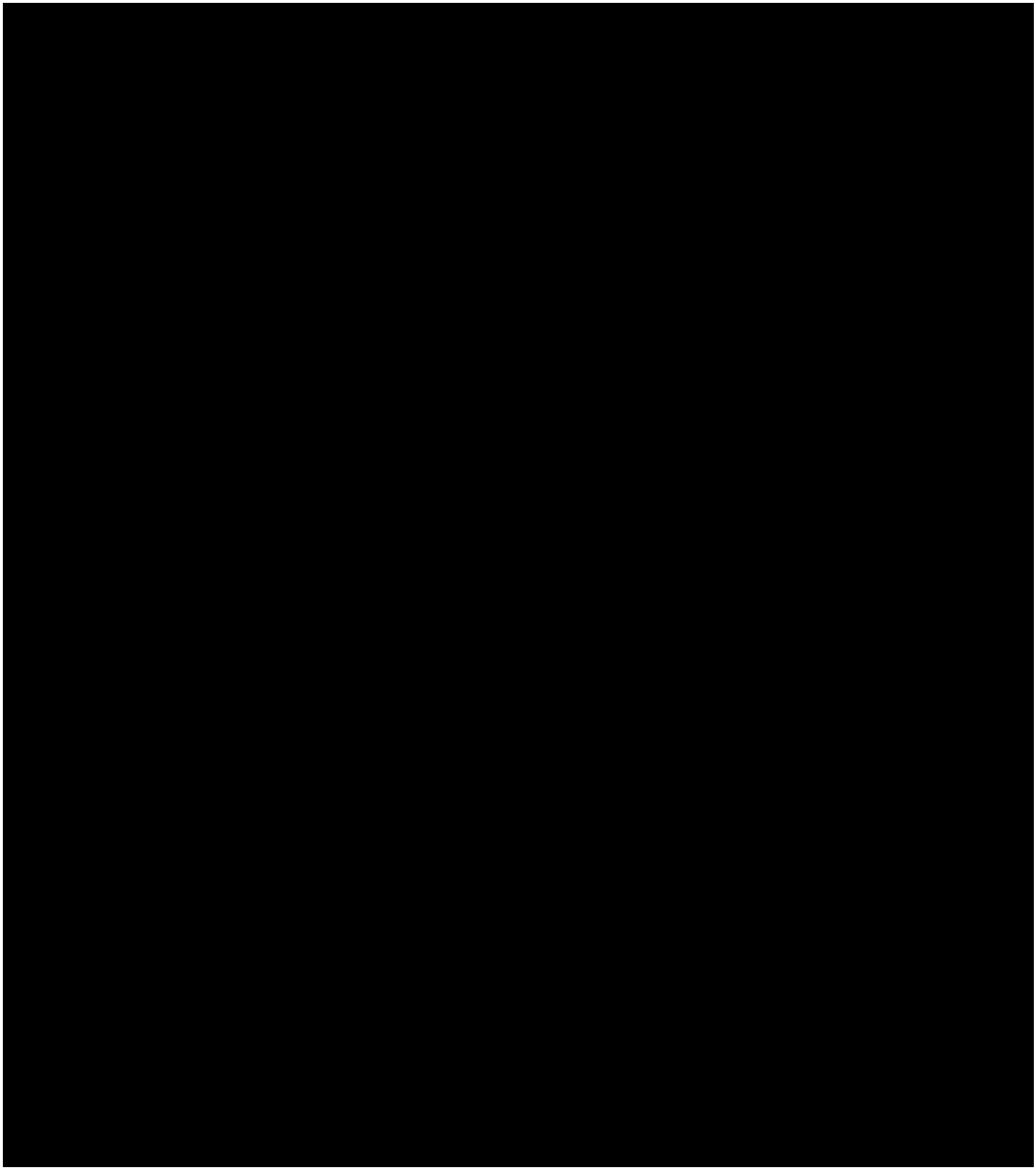
At our direction, effective _____, Deutsche Bank AG New York Branch issued a $_____ Irrevocable Standby Letter of Credit No. _____ in your favor.

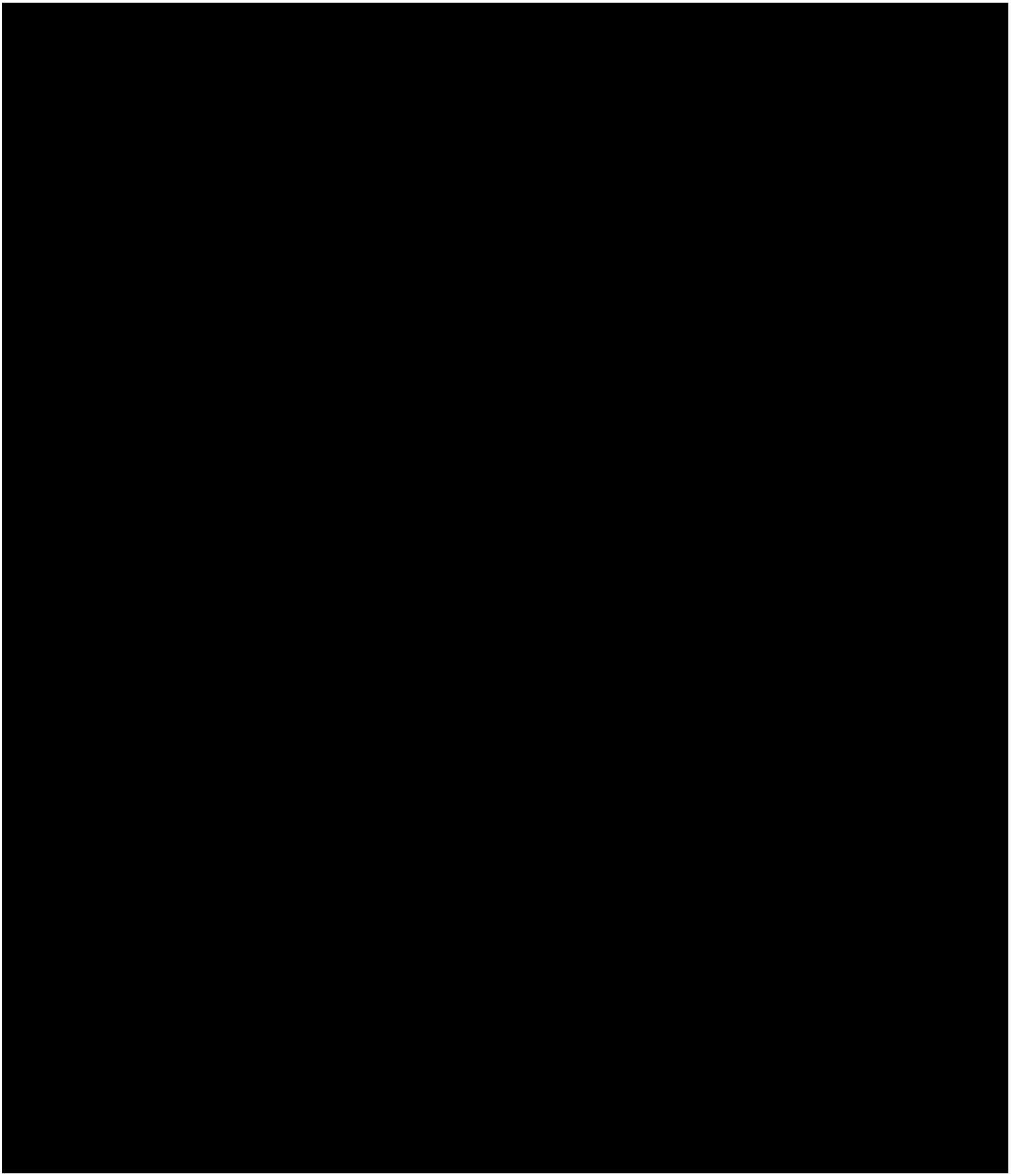
The Irrevocable Standby Letter of Credit was issued to meet the non-emergency response financial assurance requirements associated with the Elk Hills 26R Storage Project located at 28590 Highway 119, Tupman, CA 93276.

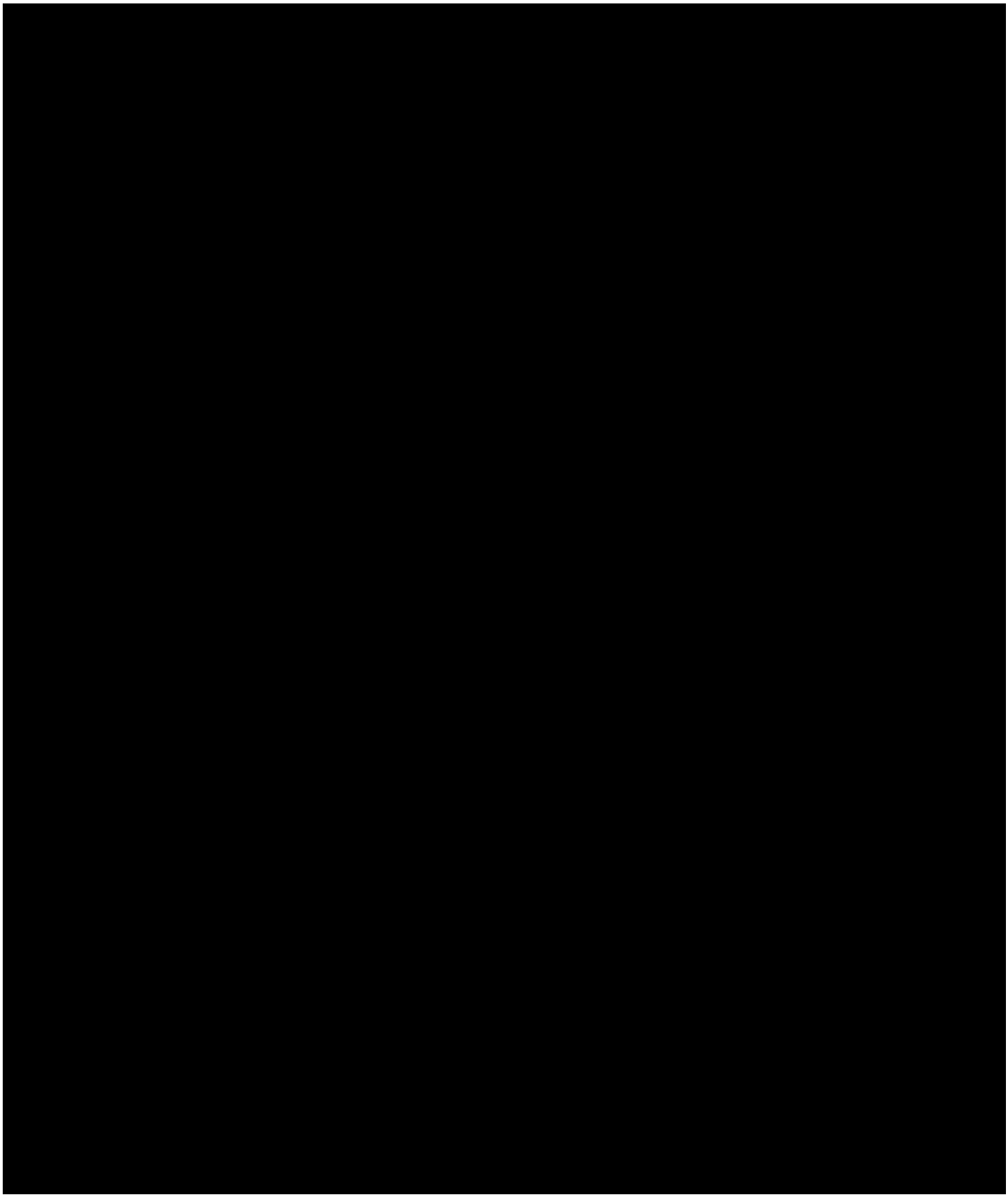
BANK OF NEW YORK MELLON STANDBY TRUST

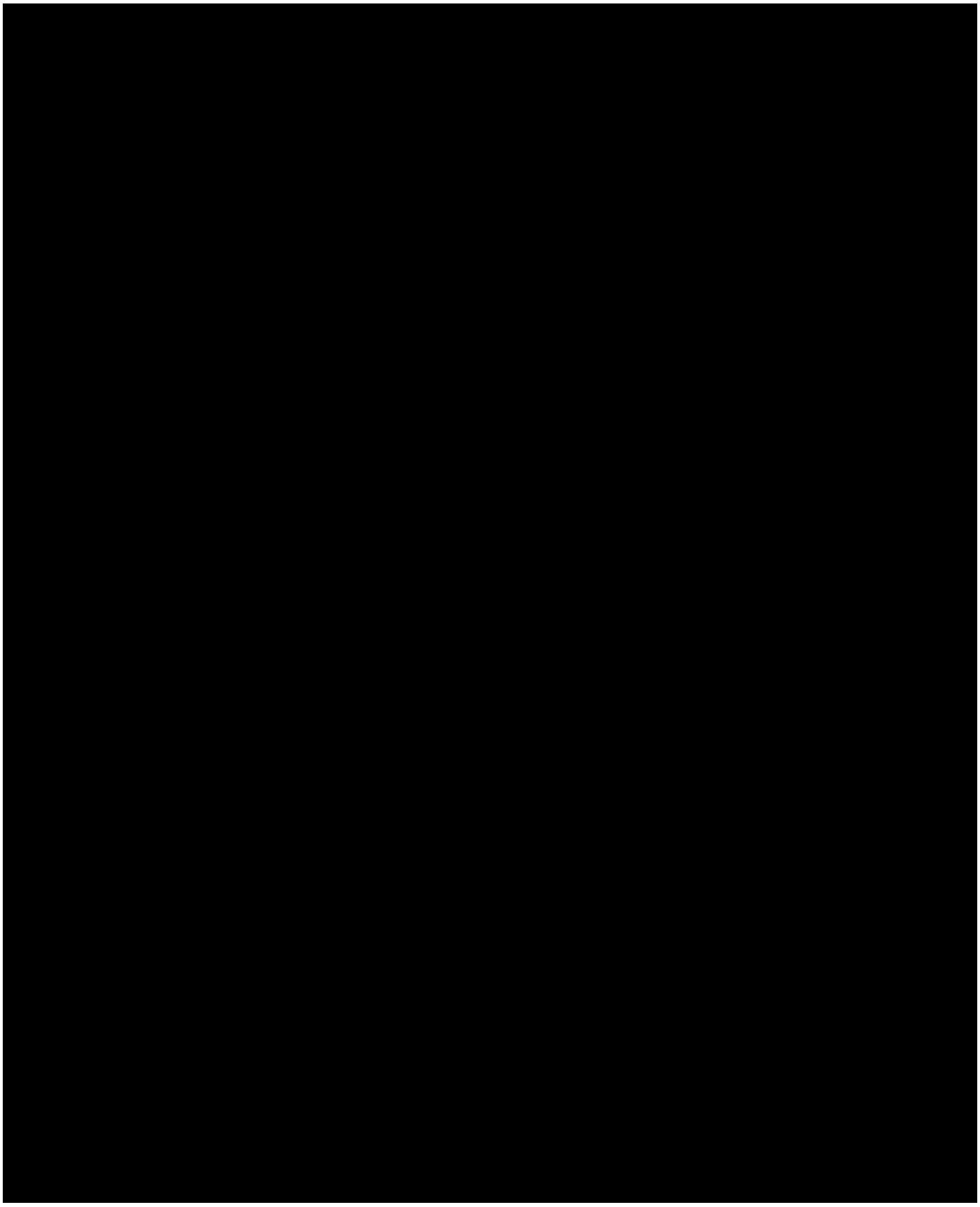
Trust Agreement

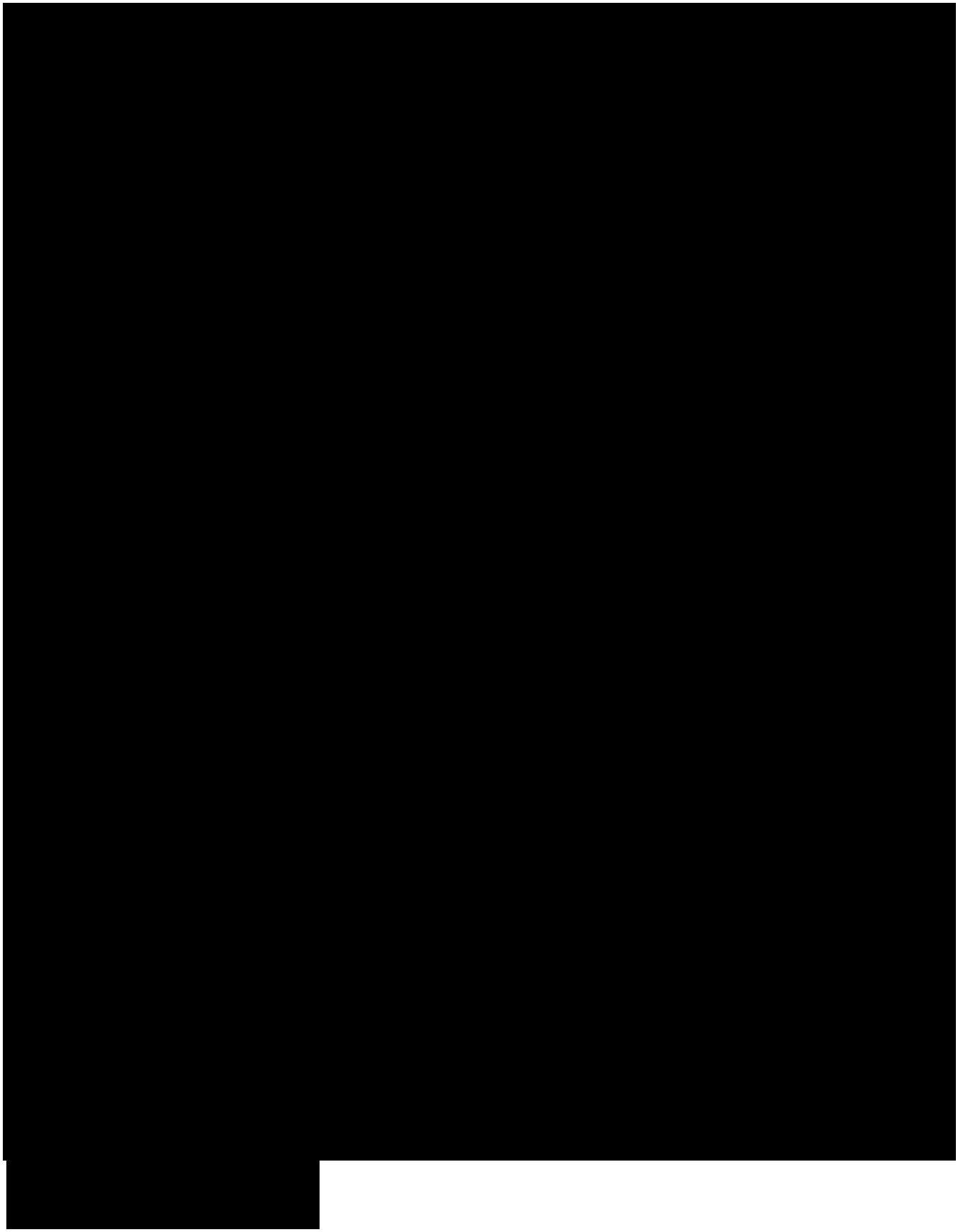














LETTER OF CREDIT COST ESTIMATE AND FUNDING VALUE SUMMARY

Schedule A

Facility	Cost Estimate		
	Corrective action	Injection well plugging	Post injection site care and site closure
EPA Identification number: Elk Hills 26R Storage Project 28590 Highway 119, Tupman, CA 93276	$111,320.00	$1,197,840.00	$7,785,500.00

Schedule B

Facility	Funding Value for Activities
EPA Identification number: Elk Hills 26R Storage Project 28590 Highway 119, Tupman, CA 93276	Irrevocable Standby Letter of Credit No. [839BGC2300XXX] issued by Deutsche Bank AG New York Branch in the amount of [$9,094,660.00].

ASCOT CERTIFICATE OF INSURANCE

55 West 46th Street,
26th Floor
New York, New York 10036

V. Certificate of Insurance

A certificate of insurance, as specified in this chapter, may be worded as follows, except that instructions in brackets are to be replaced with the relevant information and the brackets deleted:

Certificate of Insurance for [emergency and remedial response]

Name and Address of Insured (herein called the "insured"): Carbon TerraVault 1 LLC
1 World Trade Center, Suite 1500, Long Beach, CA 90831

Name and Address of Insurer (herein called the "insurer"): Ascot Specialty Insurance Company; 55 West 46th Street, 26th Floor, New York, New York 10036

Injection Wells covered: [list for each well: The EPA Identification Number, name, address, and the amount of insurance for [emergency and remedial response] (these amounts for all injection wells covered must total the face amount shown below).]

Underground Injection Control Class VI Permit Application Nos. R9UIC-CA6-FY22-1.1, R9UIC-CA6-FY22-1.2, R9UIC-CA6-FY22-1.3 and R9UIC-CA6-FY22-1.4

Face Amount: $25,000,000
Policy Number: ENPU2310001018-01
Effective Date: 05/18/2023

The insurer hereby certifies that it has issued to the Insured the policy of insurance identified above to provide financial assurance for [emergency and remedial response] for the injection wells identified above. The Insurer further warrants that such policy conforms in all respects with the requirements for the fulfillment of [emergency and remedial response] obligations described at 40 CFR 146.94, respectively, as applicable and as such regulations were constituted on the date shown immediately below. It is agreed that any provision of the policy inconsistent with such regulations is hereby amended to eliminate such inconsistency.

The insurer may cancel the policy only for failure to pay the premium and by sending notice of cancellation by certified mail to the owner or operator and to the UIC Program Director for the area in which the injection well(s) is (are) located. EPA requires that cancellation not become final for 120 days beginning on the date of receipt of the notice of cancellation by the UIC Program Director, as evidenced by the return receipts.

Whenever requested by the UIC Program Director, the Insurer agrees to furnish to the UIC Program Director a duplicate original of the policy listed above, including all endorsements thereon.

[Authorized signature of Insurer]



[Name of person signing] Ted Mavraganis
[Title of person signing] Senior Vice President

[Signature of witness or notary:]



[Date] 08/31/2023

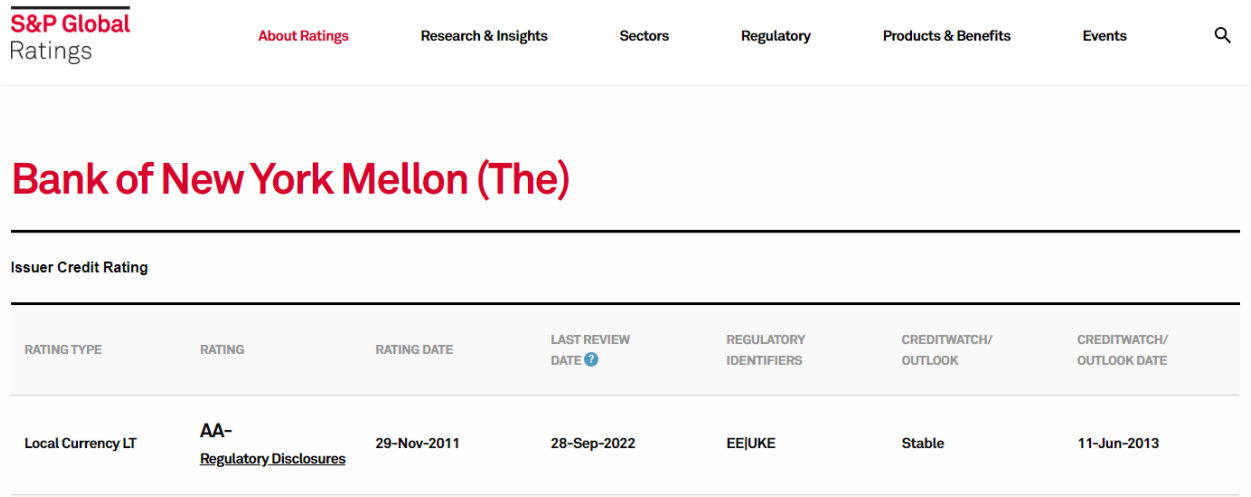
INSURANCE ENDORSEMENT

FINANCIAL STRENGTH DEMONSTRATION

Under 40 CFR 146.85(a)(6)(ii), EPA requires that the owner or operator submit proof of the third party's financial strength. EPA recommends that the owner or operator submit the third party's credit rating or, if the Director determines that the credit rating alone does not sufficiently meet the financial strength requirement, submit the third party's credit rating plus its most recent bond rating and calculated financial ratios. EPA recommends that owners or operators demonstrate that third party providers have a credit rating in the top four categories from either Standard & Poor's or Moody's (i.e., AAA, AA, A, or BBB for Standard & Poor's and Aaa, Aa, A, or Baa for Moody's)

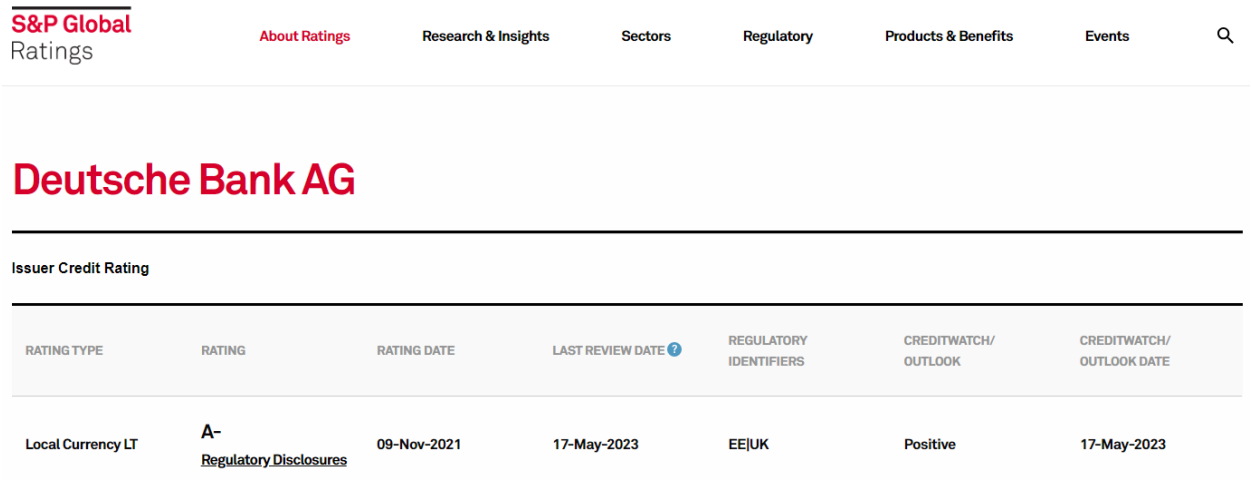
Bank of New York Mellon:

- Standard and Poor's rating: AA-



Deutsche Bank AG New York Branch:

- Standard and Poor's rating: A-



ATTACHMENT I: STIMULATION PLAN

Elk Hills 26R Storage Project

Facility Information

Facility name: CTV I Elk Hills 26R Project
357-7R and 355-7R

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA

Version History

File Name	Version	Date	Description of Change
Att I – Stimulation Plan_v1	1	05/31/22	Original document

Stimulation Plan

The need for stimulation to enhance the injectivity potential of the Monterey Formation 26R reservoir is not anticipated at this time. If it is determined that stimulation techniques are needed, a stimulation plan will be developed and submitted to EPA Region 9 for review and approval prior to conducting any stimulation.

U.S. ENVIRONMENTAL PROTECTION AGENCY

UNDERGROUND INJECTION CONTROL PERMIT

DRAFT PERMIT

CLASS VI INJECTION WELL

Permit Number: R9UIC-CA6-FY22-1.3

Well Name: 353XC-35R

Issued to:

Carbon TerraVault JV Storage Company Sub 1, LLC

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 9
75 Hawthorne St.
San Francisco, CA 94105-3901

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT: CLASS VI

Permit Number: R9UIC-CA6-FY22-1.3
Facility Name: CTV 1: Elk Hills 26R

Pursuant to the Safe Drinking Water Act and Underground Injection Control regulations of the U.S. Environmental Protection Agency codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 124, 144, 146, and 147,

Carbon TerraVault JV Storage Company Sub 1, LLC of Tupman, CA

hereinafter, the permittee, is hereby authorized to construct and operate a Class VI injection well located in the State of California, Kern County, T 30 S, R 23 E of Mount Diablo Base Meridian, Section 35, 35° 16' 36.1768" N, 119° 28' 24.4060" W, as part of the Elk Hills 26R Carbon Dioxide Storage Project. The well will inject a carbon dioxide stream (carbon dioxide is also called CO_2 in the attachments to this permit) sourced initially from the proposed Lone Cypress hydrogen plant, pre-combustion gas treatment, and the proposed Avnos Direct Air Capture facility (see Attachment B). All three initial carbon dioxide sources are to be located within the Elk Hills oil field. The permittee may request to inject carbon dioxide from additional emission sources in the future, subject to review and approval by EPA, as described in Section N of this permit. The permittee stated in their application that potential future sources of carbon dioxide may include: post combustion capture from the Elk Hills power plant, renewable fuel plants, post combustion capture from steam generators, other power plants, and industrial sources. The carbon dioxide stream, as characterized in the permit application and the administrative record, shall be a liquid, supercritical fluid, or gas. Injection is authorized into the Monterey Formation at a depth of approximately 6,000 feet below ground surface upon the express condition that the permittee meet the restrictions set forth herein. The designated confining zone for this injection is the Reef Ridge Shale Formation.

Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, directs federal agencies, to the greatest extent practical and permitted by law, to identify and address, as appropriate, disproportionate, and adverse human health or environmental impacts on people of color and low-income populations. See Exec. Order No. 12898, 59 Fed. Reg. 7629 (Feb. 11, 1994). Recently, Executive Order 14096, *Revitalizing Our Nation's Commitment to Environmental Justice for All*, supplemented this direction. See Exec. Order No. 14096, 88 Fed. Reg. 25251 (Apr. 21, 2023). As part of the decision-making process for this permit, EPA considered these executive orders and EPA's Environmental Justice Guidance for UIC Class VI Permitting and Primacy (Aug. 17, 2023). EPA's evaluation and consideration of environmental justice for this permit is described in EPA's Fact Sheet.

This permit is for the construction and operation of one Class VI injection well (well name 353XC-35R); three other wells at the Elk Hills 26R Carbon Dioxide Storage Project are authorized under separate Class VI permits (Permit Nos. R9UIC-CA6-FY22-1.1, R9UIC-CA6-FY22-1.2 and R9UIC-CA6-FY22-1.4). Injection shall not commence until the operator has received written authorization from the Director of the Water Division of EPA Region 9, in accordance with Section S of this permit.

All references to Title 40 of the Code of Federal Regulations are to all regulations that are in effect on the date that this permit is effective. The following attachments are incorporated into this permit as enforceable conditions:

- A: Summary of Operating Requirements;
- B: Area of Review and Corrective Action Plan;
- C: Testing and Monitoring Plan;
- D: Well Plugging Plan;
- E: Post-injection Site Care and Site Closure Plan;
- F: Emergency and Remedial Response Plan;
- G: Construction Details;
- H: Financial Assurance Demonstration; and
- I: Stimulation Program.

This permit shall become effective on [Insert date], and shall remain in full force and effect during the operating life of the well and the post-injection site care period until site closure is authorized and completed, unless this permit is revoked and reissued, terminated, or modified pursuant to 40 CFR 144.39, 144.40, or 144.41. This permit shall also remain in effect upon delegation of primary enforcement responsibility of the UIC program for Class VI wells to the State of California until such time as the State issues its own permit to the permittee or the State chooses to adopt this permit as a State permit. The permit will expire in one year, if the permittee fails to commence construction on the well, unless a written request in electronic format for an extension of this one-year period has been approved by the Director. The permittee may request an expiration date sooner than the one-year period, provided no construction on the well has commenced. At least every five years from the effective date specified above, the permittee must re-evaluate the Area of Review and comply with 40 CFR 146.84(e). If results from the re-evaluated Area of Review are different from what is predicted in Attachment B of this permit, EPA may require the permittee to update the permit and the attachments.

Signed and Dated: _____

DRAFT

_____

[Insert Name of signing official]
[Insert Title, Office/Division]

PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is authorized to engage in underground injection in accordance with the conditions of this permit. Notwithstanding any other provisions of this permit, the permittee authorized by this permit shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus or formation fluids into underground sources of drinking water (USDWs) or any unauthorized zones. The objective of this permit is to prevent the movement of fluids into or between USDWs or into any unauthorized zones consistent with the requirements at 40 CFR 146.86(a). Any underground injection activity not specifically authorized in this permit is prohibited. For purposes of enforcement, compliance with this permit during its term constitutes compliance with Part C of the Safe Drinking Water Act (SDWA). Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA or any other common or statutory law other than Part C of the SDWA.

Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local laws or regulations. Nothing in this permit, nor compliance with its terms, shall be construed to relieve the permittee of any duties under applicable State or local laws or regulations that are not preempted or superseded by the Federal SDWA Underground Injection Control (UIC) program.

B. PERMIT ACTIONS

1. **Modification, Revocation and Reissuance, and Termination –** The Director of the Water Division of Region 9 of the U.S. Environmental Protection Agency (EPA), hereinafter, the Director, may, for cause or upon request from any interested person, including the permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR 124.5, 144.12, 146.86(a), 144.39, and 144.40. The permit is also subject to minor modifications for cause as specified in 40 CFR 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

2. **Minor Modifications –** Upon the consent of the permittee, the Director may modify this permit to make the corrections or allowances for minor changes in the permitted activity as listed in 40 CFR 144.41. Any permit modification not processed as a minor modification under 40 CFR 144.41 must be made for cause, and with part 124 draft permit and public notice as required in 40 CFR 144.39.

3. **Transfer of Permits** – This permit is not transferable to any person except in accordance with 40 CFR 144.38(a) and Section O(6)(b) of this permit.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR part 2 (Public Information) and 40 CFR 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential business information by the submitter. Any such claim must be asserted at the time of submission by clearly identifying each page with the words "confidential business information" on every page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2.

E. DEFINITION

All terms used in this permit shall have the meaning set forth in the SDWA and Underground Injection Control regulations specified at 40 CFR parts 124, 144, 146, and 147. Unless specifically stated otherwise, all references to "days" in this permit should be interpreted as calendar days.

F. DUTIES AND REQUIREMENTS

1. **Duty to Comply** – The permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application.

2. **Duty to Reapply** – If the permittee wishes to continue an activity regulated by this permit after the expiration or termination of this permit, the permittee must apply for and obtain a new permit.

3. **Penalties for Violations of Permit Conditions** – Any person who violates a permit requirement is subject to civil penalties and other enforcement action under the SDWA. Any person who willfully violates permit conditions may be subject to criminal prosecution under the SDWA and other applicable statutes and regulations.

4. **Need to Halt or Reduce Activity Not a Defense –** It shall not be a defense for the permittee in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

5. **Duty to Mitigate** – The permittee shall take all timely and reasonable steps necessary to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

6. **Proper Operation and Maintenance** – The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control and related appurtenances which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes, among other things, effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

7. **Duty to Provide Information** – The permittee shall furnish to the Director in an electronic format, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit or the UIC regulations. The permittee shall also furnish to the Director, upon request within a time specified, electronic copies of records required to be kept by this permit.

8. **Inspection and Entry** – The permittee shall allow the Director or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

   (a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where electronic or non-electronic records are kept under the conditions of this permit;

   (b) Have access to and copy, at reasonable times, any electronic or non-electronic records that are kept under the conditions of this permit;

   (c) Inspect, at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

   (d) Sample or monitor, at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location, including facilities, equipment or operations regulated or required under this permit.

9. **Signatory Requirements** – All reports or other information, required to be submitted by this permit or requested by the Director shall be signed and certified in accordance with 40 CFR 144.32.

G. AREA OF REVIEW AND CORRECTIVE ACTION

1. The Area of Review (AoR) is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data. The permittee shall maintain and comply with the approved Area of Review and Corrective Action Plan (Attachment B of this permit) which is an enforceable condition of this permit and shall meet the requirements of 40 CFR 146.84.

2. As delineated in Attachment B, 157 wellbores within the AoR require plugging because the wellbores penetrate the injection zone or confining layer and will not be used for injection or monitoring within the 26R storage project. The wells are required to be properly plugged and abandoned prior to authorization of carbon dioxide injection.

3. At least sixty (60) days prior to commencing corrective action, the permittee shall submit procedures for performing corrective action on the identified deficient wells within the AoR and not commence any corrective action until the procedures are approved by the Director.

   (a) As corrective action activities are completed, the permittee shall provide periodic updates, including plugging reports, to the Director.

   (b) Corrective action on all deficient wells in the AoR must be complete, and approved in writing by EPA, before the permittee may commence injection pursuant to Section Q(3) of this permit.

4. At a fixed frequency of every five years, or more frequently when monitoring and operational conditions warrant, the permittee must reevaluate the area of review and perform any necessary corrective action in the manner specified in 40 CFR 146.84. The first reevaluation shall be completed no later than 5 years from the effective date of this permit unless the Director requests an earlier reevaluation. After conducting an AoR reevaluation, the permittee shall update the Area of Review and Corrective Action Plan or demonstrate to the Director that no update is needed.

5. Following each AoR reevaluation, the permittee shall submit the resultant information (i.e., the completed reevaluation analysis, along with either a revised AoR and Corrective Action Plan or a demonstration that the reevaluation analysis determined no revised Plan is needed) in an electronic format to the Director for review and approval. If a revised AoR and Corrective Action Plan is submitted and approved by the Director, the revised Plan becomes an enforceable condition of this permit.

6. To ensure permit activities do not increase environmental impacts, resource needs, and public health risks in already overburdened communities, along with the submittal of a

revised AoR and Corrective Action Plan, the permittee shall submit an updated EJScreen analysis that incorporates the revised AoR boundary.

H. FINANCIAL RESPONSIBILITY

1. **Financial Responsibility** – The permittee shall maintain financial responsibility and resources to meet the requirements of 40 CFR 146.85 and the conditions of this permit. Financial responsibility shall be maintained through all phases of the project. The permittee must maintain financial responsibility until site closure is authorized from the director as described in Section Q of this permit. Compliance with the financial responsibility requirements, including the applicable duration, described in this permit shall not relieve the permittee from complying with any other applicable Federal, State, and local financial responsibility requirements that are not preempted or superseded by the Federal SDWA UIC program.

   The financial instrument(s) must be sufficient to cover the cost of:

   (a) Corrective action (that meets the requirements of 40 CFR 146.84);

   (b) Injection well plugging (that meets the requirements of 40 CFR 146.92);

   (c) Post injection site care and site closure (that meets the requirements of 40 CFR (146.93) and;

   (d) Emergency and remedial response (that meets the requirements of 40 CFR 146.94).

   The permittee submitted a letter of credit, with a standby trust agreement, to cover financial assurance for items 1(a), (b), and (c) and submitted a certificate of insurance with details about a third-party insurance policy it will secure to cover financial assurance for 1(d). The EPA-approved financial assurance mechanisms are found in Attachment H and in the administrative record of this permit.

   The total initial cost estimates for these activities to be covered by the approved financial assurance mechanisms is $33,672,785. This amount covers all four Class VI injection well permits for the Elk Hills 26R CO_2 Storage Project.

2. **Cost Estimate Updates** – During the active life of the geologic sequestration project, the permittee must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) and provide this adjustment to the Director in an electronic format. The permittee must also provide to the Director written updates in an electronic format of adjustments to the cost estimate within 60 days of any amendments to the Project Plans included as Attachments B – F of this permit, which address items (a) through (d) in Section H(1) of this permit.

3. **Notification** –

(a) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the permittee, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase.

(b) Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the permittee has submitted a justification for the reduced cost estimate and received written approval from the Director. For requested reductions in the face amount of a financial instrument, the Director may provide notice to the public of the proposed reduction, prior to finalizing approval of the reduction.

(c) The permittee must notify the Director by certified mail and in an electronic format of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging, post-injection site care and site closure, and any applicable ongoing actions under Corrective Action or Emergency and Remedial Response.

(i) If the permittee or the third-party provider of a financial responsibility instrument is going through a bankruptcy, the permittee must notify the Director by certified mail and in an electronic format of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the permittee as debtor, within 10 days after commencement of the proceeding.

(ii) A permittee who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy.

4. **Establishing Other Coverage** – The permittee must establish other financial assurance or liability coverage acceptable to the Director, within 60 days of the occurrence of the events in Section H(2) or H(3) of this permit.

I. CONSTRUCTION

1. **Siting** – The permittee has demonstrated to the satisfaction of the Director that the well is in an area with suitable geology in accordance with the requirements at 40 CFR 146.83.

2. **Casing and Cementing** – Casing and cement or other materials used in the construction of the well must have sufficient structural strength for the life of the geologic sequestration project. All well materials must be compatible with all fluids with which the materials may

be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must prevent the movement of fluids into or between USDWs for the expected life of the well in accordance with 40 CFR 146.86. The casing and cement used in the construction of this well are shown in Attachment G of this permit and in the administrative record for this permit. Any change must be submitted in an electronic format for approval by the Director before installation.

3. **Tubing and Packer Specifications** – Tubing and packer materials used in the construction of the well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The permittee shall inject only through tubing with a packer set within the long string casing at a point within or below the confining zone immediately above the injection zone. The tubing and packer used in the well are represented in engineering drawings contained in Attachment G of this permit. Any change must be submitted in an electronic format for approval by the Director before installation.

J. PRE-INJECTION TESTING

1. Prior to the Director authorizing injection, the permittee shall perform all pre-injection logging, sampling, and testing specified at 40 CFR 146.87. This testing shall provide data sufficient to address the pre-operational testing objectives identified in Attachment G of this permit, including:

   (a) Logs, surveys, and tests to determine or verify the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in all relevant geologic formations. These tests shall include:

      (i) Deviation checks that meet the requirements of 40 CFR 146.87(a)(1);

      (ii) Logs and tests before and upon installation of the surface casing that meet the requirements of 40 CFR 146.87(a)(2);

      (iii) Logs and tests before and upon installation of the long-string casing that meet the requirements of 40 CFR 146.87(a)(3);

      (iv) Tests to demonstrate internal and external mechanical integrity that meet the requirements of 40 CFR 146.87(a)(4); and

      (v) Any alternative methods that are required by or approved by the Director pursuant to 40 CFR 146.87(a)(5).

   (b) Whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone that meet the requirements of 40 CFR 146.87(b);

(c) Records of the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone that meet the requirements of 40 CFR 146.87(c);

(d) Tests to provide information about the injection and confining zones, including calculated fracture pressure and the physical and chemical characteristics of the injection and confining zones and the formation fluids in the injection zone that meet the requirements of 40 CFR 146.87(d); and

(e) Tests to verify hydrogeologic characteristics of the injection zone that meet the requirements of 40 CFR 146.87(e), including:

(i) A pressure fall-off test; and

(ii) A pumping test or injectivity tests.

2. The permittee shall submit to the Director for approval in an electronic format a schedule for logging and testing activities 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test. The permittee must provide the Director or their representative with the opportunity to witness all logging, sampling, and testing required under this Section.

K. OPERATIONS

1. **Injection Fluids/Carbon Dioxide Sources –** The permittee will capture carbon dioxide from multiple sources during the life of the permit for injection into the Class VI well. Three initial sources of carbon dioxide are approved sources for injection: the proposed Lone Cypress hydrogen plant, pre-combustion gas treatment, and the proposed Avnos Direct Air Capture facility (see Attachment B). The permittee may propose additional sources of carbon dioxide for injection, subject to review and approval by EPA, as described in Section N of this permit.

2. **Injection Pressure Limitation** – The permittee must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case shall injection pressure initiate fractures or propagate existing fractures in the confining zone or cause the movement of injection or formation fluids into a USDW. The maximum injection pressure limit is listed in Attachment A.

3. **Stimulation Program** – Pursuant to requirements at 40 CFR 146.82(a)(9), all stimulation programs proposed by the permittee must be approved by the Director as a permit modification and incorporated into Attachment I of this permit.

4. **Additional Injection Limitation** – No injectate other than that which has been analyzed and approved by the Director under this permit in accordance with Section N of this permit shall be injected except fluids used for rework, and well tests as approved by the Director.

5. **Annulus Fluid** – The permittee must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director.

6. **Annulus/Tubing Pressure Differential** – Except during workovers or times of annulus maintenance, the permittee must maintain on the annulus a pressure that exceeds the operating injection pressure as specified in Attachment A of this permit, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.

7. **Automatic Alarms and Automatic Shut-off System** –

   (a) The permittee must:

      (i) Install, continuously operate, and maintain an automatic alarm and an automatic shut-off system or, at the discretion of the Director, down-hole shut-off systems, or other mechanical devices that provide equivalent protection; and

      (ii) Successfully demonstrate the functionality of the alarm system and shut-off system prior to the Director authorizing injection, and at a minimum of once every twelfth month after the last approved demonstration.

      (iii) Establish well-specific thresholds for activating the shut-off system and submit a revised Attachment A to the Director prior to the Director authorizing injection.

   (b) Testing under this Section must involve subjecting the system to simulated failure conditions and must be witnessed by the Director or his or her representative unless the Director authorizes an unwitnessed test in advance. The permittee must provide notice in an electronic format 30 days prior to running the test and must provide the Director or their representative the opportunity to attend. The test must be documented using either a mechanical or digital device which records the value of the parameter of interest, or by a service company job record. A final report including any additional interpretation necessary for evaluation of the testing must be submitted in an electronic format within the time period specified in Section O(4) of this permit.

8. **Precautions to Prevent Well Blowouts** – At all times, the permittee shall maintain on the well a pressure which will prevent the return of the injection fluid to the surface. The well bore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient or a plug shall be installed which can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. The permittee shall

follow procedures such as those below to assure that a backflow or blowout does not occur:

(a) Limit the temperature and/or corrosivity of the injectate; and

(b) Develop procedures necessary to assure that pressure imbalances do not occur.

9. **Circumstances Under Which Injection Must Cease** –

Injection shall cease when any of the following circumstances arise:

(a) Failure of the well to pass a mechanical integrity test;

(b) A loss of mechanical integrity during operation;

(c) The automatic alarm or automatic shut-off system is triggered;

(d) A significant unexpected change in the annulus or injection pressure;

(e) The Director determines that the well lacks mechanical integrity; or

(f) The permittee is unable to maintain compliance with any permit condition or regulatory requirement and the Director determines that injection should cease.

10. **Approaches for Ceasing Injection** –

(a) The permittee must shut-in the well by gradual reduction in the injection pressure as outlined in Attachment A of this permit; or

(b) The permittee must immediately cease injection and shut-in the well as outlined in the Emergency and Remedial Response Plan (Attachment F of this permit).

L. MECHANICAL INTEGRITY

1. **Standards** – Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the injection well must have and maintain mechanical integrity consistent with 40 CFR 146.89. To meet these requirements, mechanical integrity tests/demonstrations must be witnessed by the Director or an authorized representative of the Director unless prior approval has been granted by the Director to run an un-witnessed test. To conduct testing without an EPA representative, the following procedures must be followed.

(a) The permittee must submit prior notification in an electronic format within the time period specified in Section L(3) of this permit and if EPA informs the permittee that no

EPA representative is available this must be documented in the approved plan and testing report. The permittee must receive permission from the Director to proceed;

(b) The test must be performed in accordance with the Testing and Monitoring Plan (Attachment C of this permit) and documented using either a mechanical or digital device that records the value of the parameter of interest; and

(c) A final report including any additional interpretation necessary for evaluation of the testing must be submitted in an electronic format within the time period specified in Section O(4) of this permit.

2. **Mechanical Integrity Testing** – The permittee shall conduct a casing inspection log and mechanical integrity testing as follows:

(a) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate internal mechanical integrity pursuant to 40 CFR 146.87(a)(4):

(i) A pressure test with liquid or gas; and

(ii) A casing inspection log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(b) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.87(a)(4):

(i) A tracer survey such as an oxygen activation log; or

(ii) A temperature or noise log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(c) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the permittee must continuously monitor injection pressure, injection rate, injection volumes, pressure on the annulus between tubing and long string casing, and annulus fluid volume as specified in 40 CFR 146.88(e) and 146.89(b).

(d) At least once per year, the permittee must perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.89(c):

(i) An Administrator-approved tracer survey such as an oxygen-activation log; or

(ii) A temperature or noise log. The Director may require such tests whenever the well is worked over; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(e) After any workover that may compromise the internal mechanical integrity of the well, the well shall be tested by means of a pressure test approved by the Director and the well must pass the test to demonstrate mechanical integrity.

(f) Prior to plugging the well, the permittee shall demonstrate external mechanical integrity as described in the Injection Well Plugging Plan and that meets the requirements of 40 CFR 146.92(a).

(g) The Director may require the use of any other tests to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator pursuant to requirements at 40 CFR 146.89(e).

3. **Prior Notice and Reporting** –

(a) The permittee shall notify the Director in an electronic format of his or her intent to demonstrate mechanical integrity at least 30 days prior to such demonstration. At the discretion of the Director, a shorter time period may be allowed.

(b) Reports of mechanical integrity demonstrations which include logs must include an interpretation of results by a knowledgeable log analyst. The permittee shall report in an electronic format the results of a mechanical integrity demonstration within the time period specified in Section O(4) of this permit.

4. **Gauge and Meter Calibration** – The permittee shall calibrate all gauges used in mechanical integrity demonstrations and other required monitoring to an accuracy of not less than 0.5 percent of full scale, within one year prior to each required test. The date of the most recent calibration shall be noted on or near the gauge or meter. A copy of the calibration certificate shall be submitted to the Director in an electronic format with the report of the test. Pressure gauge resolution shall be no greater than five psi. Certain mechanical integrity and other testing may require greater accuracy and shall be identified in the procedure submitted to the Director prior to the test.

5. **Loss of Mechanical Integrity** –

(a) If the permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, or fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity as defined by 40 CFR 146.89(a)(1) or (2) is suspected during operation (such as a significant unexpected change in the annulus or injection pressure), the permittee must:

(i) Cease injection in accordance with Sections K(8) and K(9)(a) or (b), and Attachments A or F of this permit;

(ii) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone. If there is evidence of USDW endangerment, implement the Emergency and Remedial Response Plan (Attachment F of this permit);

(iii) Follow the reporting requirements as directed in Section O of this permit;

(iv) Restore and demonstrate mechanical integrity to the satisfaction of the Director and receive written approval from the Director prior to resuming injection; and

(v) After receiving written approval to resume injection, notify the Director in an electronic format when injection is expected to resume.

(b) If a shutdown (*i.e.,* down-hole or at the surface) is triggered, the permittee must immediately investigate and identify as expeditiously as possible the cause of the shutdown. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required indicates that the well may be lacking mechanical integrity, the permittee must take the actions listed above in Section L(5)(a)(i) through (v).

(c) If the well loses mechanical integrity prior to the next scheduled test date, then the well must either be plugged or repaired and retested within 30 days of losing mechanical integrity. The permittee shall not resume injection until mechanical integrity is demonstrated and the Director gives written approval to recommence injection in cases where the well has lost mechanical integrity.

6. **Mechanical Integrity Testing on Request From Director** – The permittee shall demonstrate mechanical integrity at any time upon written notice from the Director.

M. TESTING AND MONITORING

1. **Testing and Monitoring Plan** –

(a) The permittee shall maintain and comply with the approved Testing and Monitoring Plan (Attachment C of this permit) and with the requirements at 40 CFR 144.51(j), 146.88(e), and 146.90. The Testing and Monitoring Plan is an enforceable condition of this permit. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. Procedures for all testing and monitoring under this permit must be submitted to the Director in an electronic format for approval at least 30 days prior to the test. In performing all testing and monitoring under this permit, the permittee must follow the procedures approved by the Director.

If the permittee is unable to follow the EPA-approved procedures, then, the permittee must contact the Director at least 30 days prior to testing to discuss options, if any are feasible. When the test report is submitted, a full explanation must be provided as to why any approved procedures were not followed. If the approved procedures were not followed, EPA may take an appropriate action, including but not limited to, requiring the permittee to re-run the test.

(b) The permittee must update the Testing and Monitoring Plan as required at 40 CFR 146.90 (j) to incorporate monitoring and operational data and in response to AoR reevaluations required under Section G(2) of this permit or demonstrate to the Director that no update is needed. The amended Testing and Monitoring Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation, following any significant changes to the facility such as addition of monitoring wells or newly permitted injection wells within the AoR, or when required by the Director.

(c) Following each update of the Testing and Monitoring Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and approval of the results. Once approved by the Director, the revised Testing and Monitoring Plan will become an enforceable condition of this permit.

2. **Carbon Dioxide Stream Analysis** – The permittee shall analyze the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics, as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(a).

3. **Continuous Monitoring** – The permittee shall maintain continuous monitoring devices and use them to monitor injection pressure, flow rate, volume, the pressure on the annulus between the tubing and the long string of casing, annulus fluid level, and temperature. This monitoring shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(b). The permittee shall maintain for EPA's inspection at the facility an appropriately scaled, continuous record of these monitoring results as well as original files of any digitally recorded information pertaining to these operations.

4. **Corrosion Monitoring** – The permittee shall perform corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion on a quarterly basis using the procedures described in the Testing and Monitoring Plan and in accordance with 40 CFR 146.90(c) to ensure that the well components meet the minimum standards for material strength and performance set forth in 40 CFR 146.86(b).

5. **Ground Water Quality Monitoring** – The permittee shall monitor ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones. This monitoring shall be performed for the parameters identified in the Testing and Monitoring Plan at the

locations and depths, and at frequencies described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(d).

6. **External Mechanical Integrity Testing** – The permittee shall demonstrate external mechanical integrity as described in the Testing and Monitoring Plan and Section L of this permit to meet the requirements of 40 CFR 146.90(e).

7. **Pressure Fall-Off Test** – The permittee shall conduct a pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information. The test shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(f).

8. **Plume and Pressure Front Tracking** –The permittee shall track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) as described in the Testing and Monitoring Plan.

   (a) The permittee shall use direct methods to track the position of the carbon dioxide plume and the pressure front in the injection zone as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(1).

   (b) The permittee shall use indirect methods to track the position of the carbon dioxide plume and pressure front as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(2).

   (c) If any indirect monitoring performed under Section M(8)(b) of this Permit detects increased pressure above the confining zone or other unanticipated results, the permittee shall increase the frequency of geochemical sampling under Section M(8)(a) to monthly sampling.

   (d) If data collection performed under Section M(8)(a) and M(8)(b) of this permit detects increased pressure above the confining zone or other unanticipated results the Director may require installation of additional monitoring wells.

9. **Surface Air and/or Soil Gas Monitoring** –

   (a) The permittee shall conduct any surface air monitoring or soil gas monitoring required by the Director to detect movement of carbon dioxide that could endanger a USDW or public health at the frequency and locations described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(h).

   (b) Any surface air monitoring or soil gas monitoring described in the Testing and Monitoring Plan of this Permit must not conflict with air monitoring requirements set forth by other Federal, State, or local agencies for the project, including monitoring to comply with the approved Monitoring, Reporting, and Verification (MRV) plan under 40 CFR part 98, Subpart RR, monitoring required for California's Low-Carbon Fuel Standard

program compliance, and monitoring required by Kern County pursuant to a Conditional Use Permit (CUP) and environmental impact report (EIR) for the project.

10. **Leak Detection Monitoring** -

(a) The permittee shall conduct any leak detection monitoring at the wellhead required by the Director to ensure injection well integrity and detect movement of carbon dioxide that could endanger a USDW or public health at the frequency and locations described in the Testing and Monitoring Plan.

(b) Any leak detection monitoring described in the Testing and Monitoring Plan of this Permit should be consistent with EPA's document "Leak Detection and Repair – A Best Practices Guide" (October 2007), and must not conflict with leak detection monitoring requirements set forth by other Federal, State, or local agencies for the project, including monitoring to comply with the approved Monitoring, Reporting and Verification (MRV) plan under 40 CFR part 98, subpart RR, monitoring required for California's Low-Carbon Fuel Standard program compliance, and monitoring required by Kern County pursuant to a Conditional Use Permit (CUP) and environmental impact report (EIR) for the project.

11. **Additional Monitoring** – If required by the Director as provided in 40 CFR 146.90(i), the permittee shall perform any additional monitoring determined to be necessary to support, upgrade, and improve computational modeling of the AoR evaluation required under 40 CFR 146.84(c) and to determine compliance with standards under 40 CFR 144.12 or 40 CFR 146.86(a). This monitoring shall be performed as described in a modification to the Testing and Monitoring Plan.

N. INJECTION OF CARBON DIOXIDE FROM ADDITIONAL SOURCES

1. The permittee must receive written approval from the Director before injecting carbon dioxide from a source that is not fully described in Attachment B of this permit. Carbon dioxide from additional sources will not be approved if the Director determines that the carbon dioxide stream from the proposed additional source is incompatible, or will adversely interact, with the injection well material, injection formation, or confining zone.

2. Proposed additional sources of carbon dioxide will be evaluated by EPA to determine if the additional source is approvable, and if so, whether its addition requires a major permit modification or a minor permit modification.

(a) Conditions that will result in a major permit modification include, but are not limited to, if the proposed additional source of carbon dioxide meets any of the following:

i. The addition of the proposed carbon dioxide source would increase the injection volume or injection pressure above the amount authorized in this permit; or

ii. The proposed additional carbon dioxide source is determined to have a chemical composition outside of the range of injectate compositions listed in Attachment B of this permit, or

iii. The addition of the proposed carbon dioxide source would interfere with the operation of the facility or its ability to meet conditions described in the permit; or

iv. The addition of the proposed carbon dioxide source would result in a material and substantial alteration or addition to the permitted Class VI injection activity which justifies the application of permit conditions that are different or absent in the existing permit; or

v. The Director determines that addition of the proposed carbon dioxide source does not meet criteria for a minor permit modification.

3. In proposing an additional source of carbon dioxide for the Director's approval, the permittee shall provide the Director with the following information:

   (a) The analytical parameters of the proposed additional carbon dioxide stream from the proposed source as described in the Testing and Monitoring Plan of this permit;

   (b) A description of the industry in which the proposed additional carbon dioxide stream will be produced from;

   (c) The name and address of the proposed additional carbon dioxide source;

   (d) An evaluation of the impact the proposed carbon dioxide source (the creation, capture, and transportation of carbon dioxide) will have on criteria pollutant and hazardous air pollutant emissions in the area; and

   (e) An assessment of the compatibility of the carbon dioxide stream with subsurface fluids and minerals, and assurance that the construction materials of the injection wells and other wells that may encounter the injected plume are still compatible (e.g., will not corrode over time due to the chemical interactions).

4. All proposed additional sources of carbon dioxide will require pre-approval by Kern County Planning and Natural Resources Department, and any necessary mitigation measures pursuant to an approved Conditional Use Permit and Environmental Impact Report.

5. The public shall be notified within 30 days when a proposed additional carbon dioxide source is submitted to EPA for review.

6. The public shall be notified 30 days before the injection of an EPA-approved additional

carbon dioxide stream is injected.

O. REPORTING AND RECORDKEEPING

1. **Electronic Reporting** – Electronic reports, submittals, notifications, and records made and maintained by the permittee under this permit must be in an electronic format approved by EPA. The permittee shall electronically submit all required reports to the Director at:

   https://epa.velo.pnnl.gov/operators

2. **Semi-Annual Reports** – The permittee shall submit semi-annual reports containing:

   (a) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;

   (b) Monthly average, maximum, and minimum values for injection pressure, flow rate and daily volume, temperature, and annular pressure;

   (c) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;

   (d) A description of any event which triggers the shut-off systems required in Section K(6) of this permit pursuant to 40 CFR 146.88(e), and the response taken;

   (e) The monthly volume or mass of the carbon dioxide stream injected over the reporting period and the volume or mass injected cumulatively over the life of the project;

   (f) Monthly annulus fluid volume added or produced; and

   (g) Results of the continuous monitoring required in Section M(3), including:

      (i) A tabulation of: (1) daily maximum injection pressure; (2) daily minimum annulus pressure; (3) daily minimum value of the difference between simultaneous measurements of annulus and injection pressure; (4) daily volume; (5) daily maximum flow rate; and (6) average annulus tank fluid level; and

      (ii) Graph(s) of the continuous monitoring as required in Section M(3) of this permit, or of daily average values of these parameters. The injection pressure, injection volume and flow rate, annulus fluid level, annulus pressure, and temperature shall be submitted on one or more graphs, using contrasting symbols or colors, or in another manner approved by the Director; and

   (h) Results of any additional monitoring identified in the Testing and Monitoring Plan and described in Section M of this permit.

3. **<u>24-Hour Reporting</u>** –

(a) The permittee shall report to the Director any permit noncompliance which may endanger human health or the environment or any events that require implementation of actions in the Emergency and Remedial Response Plan (Attachment F of this permit). Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such verbal reports shall include, but not be limited to, the following information:

(i) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW, or any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW;

(ii) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;

(iii) Any triggering of the shut-off system required in Section K(6) of this permit (i.e., down-hole or at the surface);

(iv) Any failure to maintain mechanical integrity;

(v) Pursuant to compliance with the requirement at 40 CFR 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere; and

(vi) Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F of this permit).

(b) A written submission shall be provided to the Director in an electronic format within five days of the time the permittee becomes aware of the circumstances described in Section O(3)(a) of this permit. The submission shall contain: a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F of this permit); and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance.

4. **<u>Reports on Well Tests and Workovers</u>** – The permittee shall report, within 30 days, the results of:

(a) Periodic tests of mechanical integrity;

(b) Any well workover, including stimulation;

(c) Any other test of the injection well conducted by the permittee if required by the Director; and

(d) Any test of any monitoring well required by this permit.

5. **Advance Notice Reporting** –

(a) **Well Tests** – The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned workover, stimulation, or other well test.

(b) **Planned Changes** – The permittee shall give written notice to the Director in an electronic format, as soon as possible, of any planned physical alterations or additions to the permitted injection facility other than minor repair/replacement or maintenance activities. An analysis of any new injection fluid and, as specified in Section N of this Permit, an analysis of any additional source of carbon dioxide, shall be submitted to the Director for review and written approval at least 60 days prior to injection; this approval may result in a permit modification.

(c) **Anticipated Noncompliance** – The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

6. **Additional Reports** –

(a) **Compliance Schedules** – Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted in an electronic format by the permittee no later than 30 days following each schedule date.

(b) **Transfer of Permits** – This permit is not transferable to any person except after notice is sent to the Director in an electronic format at least 30 days prior to transfer and the requirements of 40 CFR 144.38(a) have been met. Pursuant to requirements at 40 CFR 144.38(a), the Director will require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

(c) **Other Noncompliance** – The permittee shall report in an electronic format all other instances of noncompliance not otherwise reported with the next monitoring report. The reports shall contain the information listed in Section O(3)(b) of this permit.

(d) **Other Information** – When the permittee becomes aware of failure to submit any relevant facts in the permit application or that incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such

facts or corrected information in an electronic format within 10 days in accordance with 40 CFR 144.51(l)(8).

(e) **Report on Permit Review** – Within 30 days from the effective date of this permit, the permittee shall certify to the Director in an electronic format that he or she has read and is personally familiar with all terms and conditions of this permit.

7. Records –

(a) The permittee shall retain records and all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit (including records from pre-injection, active injection, and post-injection phases) for a period of at least 10 years from collection.

(b) The permittee shall maintain records of all data required to complete the permit application form for this permit and any supplemental information (e.g., modeling inputs for AoR delineations and reevaluations, plan modifications) submitted under 40 CFR 144.27, 144.31, 144.39, and 144.41 for a period of at least 10 years after site closure.

(c) The permittee shall retain records concerning the nature and composition of all injected fluids until 10 years after site closure.

(d) The retention periods specified in Section O(7)(a) through (c) of this permit may be extended by request of the Director at any time. The permittee shall continue to retain records after the retention period specified in Section O(7)(a) through (c) of this permit or any requested extension thereof expires unless the permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

(e) Records of monitoring information shall include:

(i) The date, exact place, and time of sampling or measurements;

(ii) The name(s) of the individual(s) who performed the sampling or measurements;

(iii) A precise description of both sampling methodology and the handling of samples;

(iv) The date(s) analyses were performed;

(v) The name(s) of the individual(s) who performed the analyses;

(vi) The analytical techniques or methods used; and

(vii) The results of such analyses.

P. PUBLIC AVAILABILITY OF MONITORING AND COMPLIANCE DATA

1. The permittee shall develop and maintain a publicly accessible website with all available monitoring data collected under this Permit. The website must be accessible to persons with disabilities and compliant with Section 508, and it shall include:

   (a) Semi-annual monitoring reports and data;

   (b) An executive summary (in both English and Spanish) that interprets the Semi-annual monitoring reports and data;

   (c) Real-time display of data collected for any Surface Air/Soil Gas Monitoring required under Section M(9) and Leak Detection Monitoring required under Section M(10) of this Permit; and

   (d) Notification of any permit non-compliance on a quarterly basis, including the steps taken to resolve the non-compliance, and any actions taken to prevent a re-occurrence of the non-compliance.

Q. WELL PLUGGING, POST-INJECTION SITE CARE, AND SITE CLOSURE

1. **Well Plugging Plan** – The permittee shall maintain and comply with the approved Well Plugging Plan (Attachment D of this permit) which is an enforceable condition of this permit and shall meet the requirements of 40 CFR 146.92.

2. **Revision of Well Plugging Plan** – If the permittee finds it necessary to change the Well Plugging Plan (Attachment D of this permit), a revised plan shall be submitted in an electronic format to the Director for written approval. Any amendments to the Well Plugging Plan must be approved by the Director, must be incorporated into the permit and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41.

3. **Notice of Plugging and Abandonment** – The permittee must notify the Director in writing in an electronic format pursuant to 40 CFR 146.92(c), at least 60 days before plugging, conversion or abandonment of a well. At the discretion of the Director, a shorter notice period may be allowed.

4. **Plugging and Abandonment Approval and Report** –

   (a) The permittee must receive written approval of the Director before plugging the well and shall plug and abandon the well in accordance with 40 CFR 146.92, as provided in the Well Plugging Plan (Attachment D of this permit).

   (b) Within 60 days after plugging, the permittee must submit in an electronic format a plugging report to the Director. The report must be certified as accurate by the

permittee and by the person who performed the plugging operation (if other than the permittee.) The permittee shall retain the well plugging report in an electronic format for 10 years following site closure. The report must include:

(i) A statement that the well was plugged in accordance with the Well Plugging Plan previously approved by the Director (Attachment D of this permit); or

(ii) If the actual plugging differed from the approved plan, a statement describing the actual plugging and an updated plan specifying the differences from the plan previously submitted and explaining why the Director should approve such deviation. If the Director determines that a deviation from the plan incorporated in this permit may endanger USDWs, the permittee shall re-plug the well as required by the Director.

5. **Temporary Abandonment** – If the permittee ceases injection into the well for more than 24 consecutive months, the well is considered to be in a temporarily abandoned status, and the permittee shall plug and abandon the well in accordance with the approved Well Plugging Plan, 40 CFR 144.52 (a)(6), and 40 CFR 146.92, or make a demonstration of non-endangerment of this well while it is in temporary abandonment status. During any periods of temporary abandonment or disuse, the well will be tested to ensure that it maintains mechanical integrity, according to the requirements and frequency specified in Section L(2) of this permit. The permittee shall continue to comply with the conditions of this permit, including all monitoring and reporting requirements according to the frequencies outlined in the permit.

6. **Post-Injection Site Care and Site Closure Plan** –

(a) The permittee shall maintain and comply with the Post-Injection Site Care and Site Closure Plan (Attachment E of this permit), which meets the requirements of 40 CFR 146.93 and is an enforceable condition of this permit. The permittee shall:

(i) Upon cessation of injection, either submit in an electronic format for the Director's approval an amended Post-Injection Site Care and Site Closure Plan or demonstrate through monitoring data and modeling results that no amendment to the plan is needed.

(ii) At any time during the life of the project, the permittee may modify and resubmit in an electronic format the Post-Injection Site Care and Site Closure Plan for the Director's approval. The permittee may, as part of such modifications to the Plan, request a modification to the post-injection site care timeframe that includes documentation of the information at 40 CFR 146.93(c)(1).

(b) The permittee shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs

are not being endangered, as specified in the Post-Injection Site Care and Site Closure Plan and in 40 CFR 146.90, and 40 CFR 146.93, including:

(i) Ground water quality monitoring;

(ii) Tracking the position of the carbon dioxide plume and pressure front including direct pressure monitoring and geochemical plume monitoring and the use of indirect methods;

(iii) Any other required monitoring, e.g., soil gas and/or surface air monitoring described in the Post-Injection Site Care and Site Closure Plan;

(iv) The permittee shall submit in an electronic format the results of all monitoring performed according to the schedule identified in the Post-Injection Site Care and Site Closure Plan; and

(v) The permittee shall continue to conduct post-injection site monitoring for at least 50 years or for the duration of any alternative timeframe approved pursuant to 40 CFR 146.93(c) and the Post-Injection Site Care and Site Closure Plan.

(c) The post-injection monitoring must continue until the project no longer poses an endangerment to USDWs and the demonstration pursuant to 40 CFR 146.93(b)(2) and as described in Section Q(6)(d) of this permit is approved by the Director.

(d) Prior to authorization for site closure, the permittee shall submit to the Director for review and approval, in an electronic format, a demonstration, based on information collected pursuant to Section Q(5)(b) of this permit, that the carbon dioxide plume and the associated pressure front do not pose an endangerment to USDWs and that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs, as required under 40 CFR 146.93(b)(3). The Director reserves the right to amend the post-injection site monitoring requirements (including extending the monitoring period) if the carbon dioxide plume and the associated pressure front have not stabilized or there is a concern that USDWs are being endangered.

(e) The permittee shall notify the Director in an electronic format at least 120 days before site closure. At this time, if any changes to the approved Post-Injection Site Care and Site Closure Plan in Attachment E of this permit are proposed, the permittee shall submit a revised plan.

(f) After the Director has authorized site closure, the permittee shall plug all monitoring wells as specified in Attachment E of this permit – the Post-Injection Site Care and Site Closure Plan – in a manner which will not allow movement of injection or formation fluids that endangers a USDW. The permittee shall also restore the site to its pre-injection condition.

(g) The permittee shall submit a site closure report in an electronic format to the Director within 90 days of site closure. The report must include the information specified at 40 CFR 146.93(f).

(h) The permittee shall record a notation on the deed to the facility property or any other document that is normally examined during a title search that will in perpetuity provide any potential purchaser of the property the following information:

(i) The fact that land has been used to sequester carbon dioxide;

(ii) The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and

(iii) The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.

(i) The permittee shall retain for 10 years following site closure an electronic copy of the site closure report, records collected during the post-injection site care period, and any other records required under 40 CFR 146.91(f)(4). The permittee shall deliver the records in an electronic format to the Director at the conclusion of the retention period.

R. EMERGENCY AND REMEDIAL RESPONSE

1. The Emergency and Remedial Response Plan describes actions the permittee must take to address movement of the injection or formation fluids, including surface leaks of carbon dioxide or other contaminants, that may cause an endangerment to a USDW or public health during construction, operation, and post-injection site care periods. The permittee shall maintain and comply with the approved Emergency and Remedial Response Plan (Attachment F of this permit), which is an enforceable condition of this permit, and with 40 CFR 146.94.

   Prior to the Director authorizing injection, the permittee shall revise the Emergency and Remedial Response Plan to include a description and documentation of the contracts the permittee holds with service providers, including any contracts or access agreements with local emergency response authorities, to perform the actions outlined in the Emergency and Remedial Response Plan, and shall confirm that any required payments were made to Kern County Planning and Natural Resources Department, as required by the approved Conditional Use Permits, for transfer to the Kern County Fire Department for equipment and training specific to the detection and control of emergency situations caused by the release of carbon dioxide.

2. If the permittee obtains evidence that the injected carbon dioxide or associated pressure front may cause endangerment to a USDW or public health, the permittee must:

   (a) Cease injection in accordance with Sections K(8) and K(9)(a) or (b), and Attachments A or F of this permit;

   (b) Take all steps reasonably necessary to identify and characterize any release;

   (c) Notify the Director within 24 hours; and

   (d) Implement the Emergency and Remedial Response Plan (Attachment F of this permit) approved by the Director.

3. At least every five years, or more frequently when monitoring and operational conditions warrant, the permittee shall review and update the Emergency and Remedial Response Plan as required at 40 CFR 146.94(d) or demonstrate to the Director that no update is needed. The amended Emergency and Remedial Response Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation, following any significant changes to the facility such as addition of injection wells, or when required by the Director.

4. Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and confirmation of the results. Once approved by the Director, the revised Emergency and Remedial Response Plan will become an enforceable condition of this permit.

S. COMMENCING INJECTION

The permittee may not commence injection until:

1. Results of the formation testing and logging program and a demonstration that all pre-operational testing objectives have been met as specified in Section J of this permit and in 40 CFR 146.87 are submitted to the Director in an electronic format and subsequently reviewed and approved by the Director;

2. Mechanical integrity of the well has been demonstrated in accordance with 40 CFR 146.89(a)(1) and (2), and in accordance with Section L(1) through (3) of this permit;

3. The completion of corrective action required by the Area of Review and Corrective Action Plan found in Attachment B of this permit in accordance with 40 CFR 146.84;

4. All requirements at 40 CFR 146.82(c) have been met, including but not limited to reviewing and updating of the Area of Review and Corrective Action, Testing and Monitoring, Well

Plugging, Post-Injection Site Care and Site Closure, and Emergency and Remedial Response plans to incorporate final site characterization information, final delineation of the AoR, and the results of pre-injection testing, and information has been submitted in an electronic format, reviewed and approved by the Director;

5. The permittee has submitted the results of an analysis of the physical and chemical characteristic of the carbon dioxide stream for all analytical parameters identified in the Testing and Monitoring Plan (Attachment C of this Permit).

6. Construction is complete and the permittee has submitted to the Director in an electronic format a notice that completed construction is in compliance with 40 CFR 146.86 and Section I of this permit;

7. The Director has inspected or otherwise reviewed the injection well and all submitted information and finds it is in compliance with the conditions of this permit;

8. The Director has approved demonstration of the alarm system and shut-off system under Section K(6) of this permit;

9. The Permittee has revised the Emergency and Remedial Response Plan to include a description and documentation of the contracts the permittee holds with service providers in order to perform the actions outlined in the Emergency and Remedial Response Plan;

10. The Director has approved the publicly accessible website required under Section P of this permit; and

11. The Director has given written authorization to commence injection.

ATTACHMENTS

These attachments include, but are not limited to, permit conditions and plans concerning operating procedures, monitoring and reporting, as required by 40 CFR parts 144 and 146. The permittee shall comply with these conditions and adhere to these plans as approved by the Director, as follows:

A. SUMMARY OF OPERATING REQUIREMENTS

B. AREA OF REVIEW AND CORRECTIVE ACTION PLAN

C. TESTING AND MONITORING PLAN

D. WELL PLUGGING PLAN

E. POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

F. EMERGENCY AND REMEDIAL RESPONSE PLAN

G. CONSTRUCTION DETAILS

H. FINANCIAL ASSURANCE DEMONSTRATION

I. STIMULATION PROGRAM

SUMMARY OF REQUIREMENTS

CLASS VI OPERATING AND REPORTING CONDITIONS

Elk Hills 26R Storage Project

Facility Information

Facility name: Elk Hills 26R Storage Project
353XC-35R

Well location: Elk Hills Oil Field, Kern County, CA
35°16'36.1768"N / 6121890
119°28'24.4060"W / 2290248

Table 1. Injection Well Operating Conditions

PARAMETER/CONDITION	LIMITATION or PERMITTED VALUE
Maximum Injection Pressure - Surface	1997 psi
Maximum Injection Pressure - Bottomhole	4180 psi
Annulus Pressure	3314 psi
Annulus Pressure/Tubing Differential	551 psi
Maximum CO_2 Injection Rate	25 mmscfpd

There will be continuous monitoring of injection pressure, rate and annulus pressure for the injector, as described in the well Construction, Operation and Plugging details (COP) document for 353XC-35R.

The maximum injection pressure, which serves to prevent confining-formation fracturing, was determined: using the fracture gradient of 0.701psi/ft obtained from Fracture stimulation data obtained from well 388-26R in the 26R reservoir multiplied by 0.9, per 40 CFR 146.88(a).

Routine Shutdown Procedure

For injection shutdowns occurring under routine conditions (e.g., for well workovers), the permittee will reduce CO_2 injection at a rate of 165 tons per day over a 6 day period to ensure protection of health, safety, and the environment. This procedure applies to routine shutdowns and to “gradual shutdowns” described in the Emergency and Remedial Response plan. (Procedures that address immediately shutting in the well are in the Emergency and Remedial Response Plan of this permit.)

Table 2. Class VI Injection Well Reporting Requirements

ACTIVITY	REPORTING REQUIREMENTS
CO_2 stream characterization	Semi-annually
Injection pressure, injection rate, injection volume, pressure on the annulus, and annulus fluid level	Semi-annually
Corrosion monitoring	Semi-annually
External MITs	Within 30 days of completion of test
Pressure fall-off testing	In the next semi-annual report

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

Table 3. Class VI Project Reporting Requirements

ACTIVITY	REPORTING REQUIREMENTS
Groundwater quality monitoring	Semi-annually
Plume and pressure front tracking	In the next semi-annual report
Monitoring well MITs	Within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Facility Information

Facility name: Elk Hills 26R Storage Project

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment B - AoR_CA	1	01/11/21
Attachment B - AoR_CA	2	05/31/22
Attachment B - AoR_CA	3	12/21/22
Attachment B - AoR_CA	4	05/14/2023
Attachment B – AoR_CA	5	6/23/2023

Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase

- Liquid and gas relative permeability
- Capillary pressure data
- Current saturation, pressure, and temperature estimates

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the Elk Hills 26R project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of CO_2 in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual oil in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.
2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).
3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

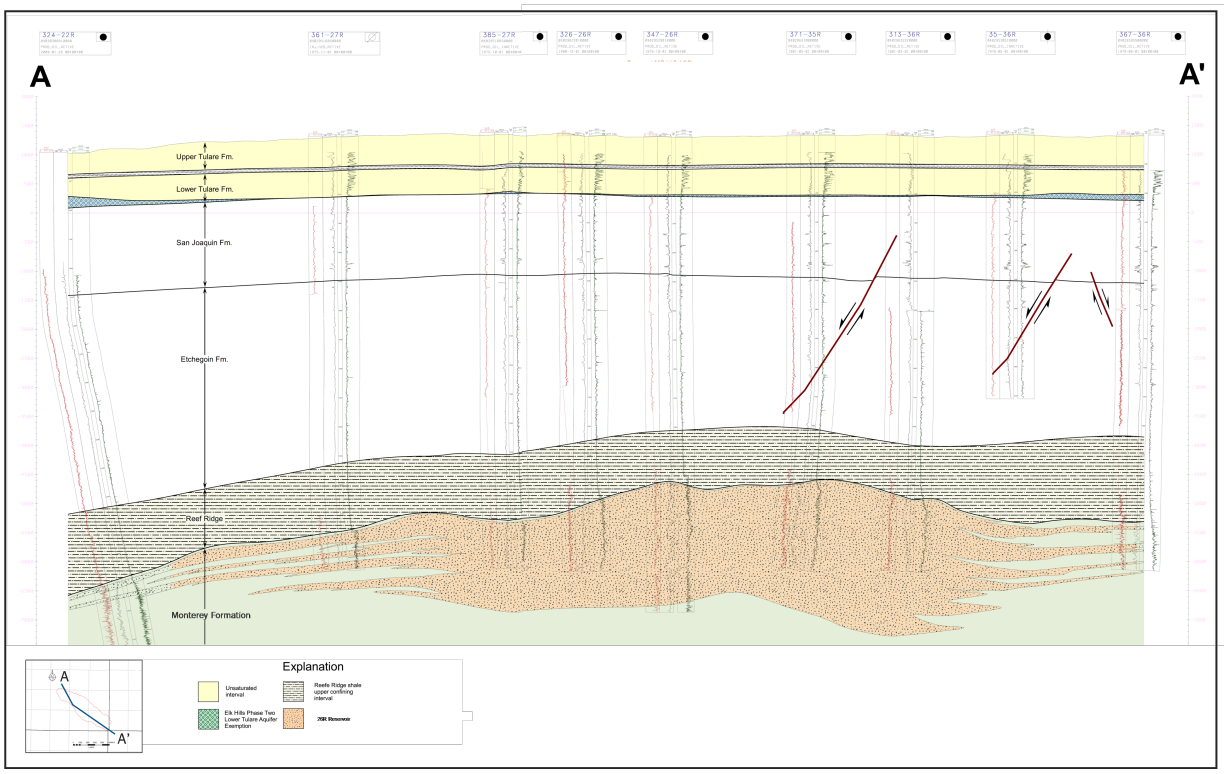
1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al
2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

Site Geology and Hydrology

The 31S field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation 26R sands, present in the southwestern portion of the field pinch out on top of the structure and along strike (Figure 1).

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation 26R, but for all Monterey accumulations in the greater Elk Hills area.

Figure 1: Cross-section A-A' showing lateral Monterey Formation 26R sand pinch-out.



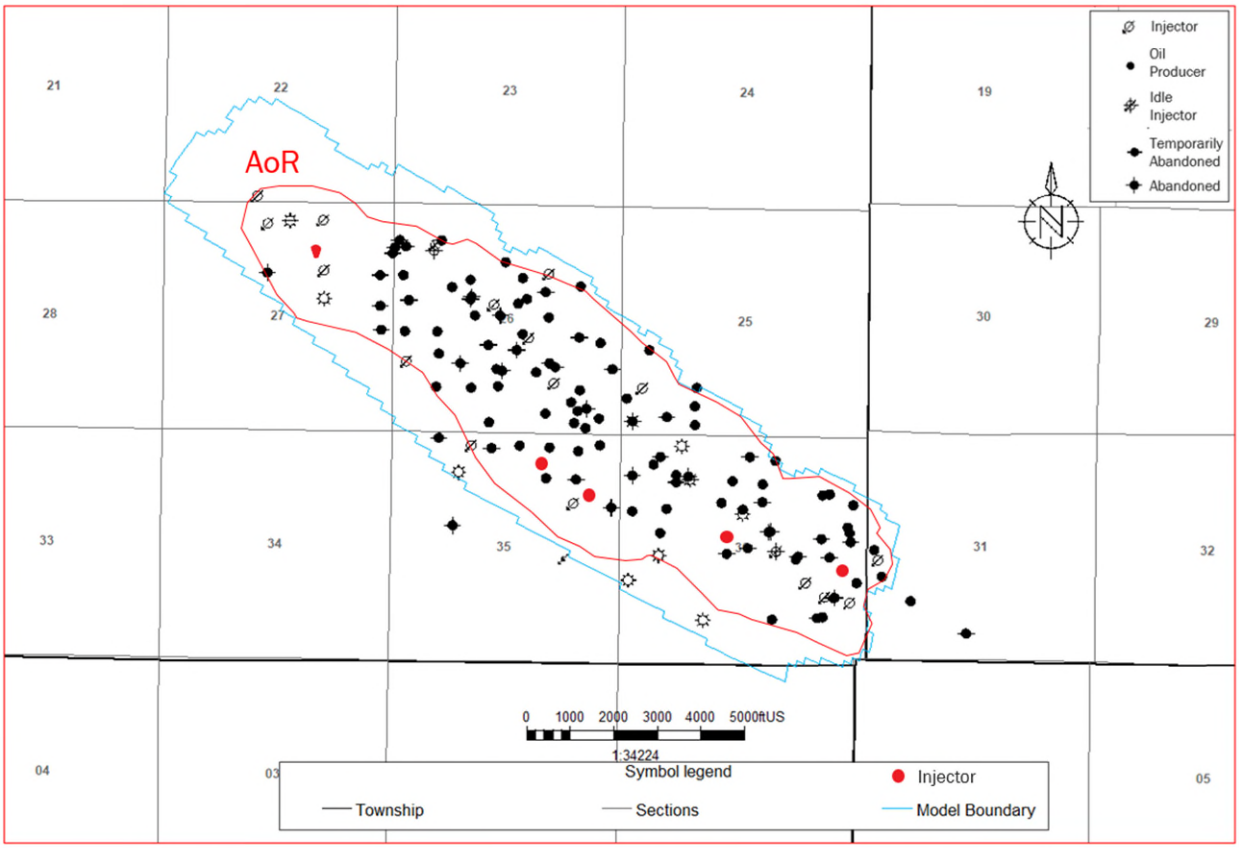
The Elk Hills 26R Class VI injection wells will target injection in the Monterey Formation 26R sands. The Monterey Formation 26R oil and gas reservoir was discovered in the 1940's and has been developed with primary production and pressure maintenance (Table 1: Production and Injection volumes). Starting in the year 1998, pressure maintenance ceased, and the gas cap reservoir was "blown-down", depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 150-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

Table 1: Production and injection volumes for the Monterey Formation 26R reservoir.

Process	Phase	Volume
Production	Oil	222 million barrels
	Gas	1,244 billion cubic feet
	Water	81 million barrels
Injection	Water	114 million barrels
	Gas	841 billion cubic feet

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir, and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

Figure 2: Location of wells with open-hole log data used to develop the static model and computational model boundary.



Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2. The lateral dimensions and vertical thickness of the geomodel were chosen to capture the maximum extent of the mapped 26R reservoir. Well logs from the wells shown in Figure 2 were used to map the extent and delineate the edges of the reservoir where the reservoir sands pinchout or transition to shale. The total grid dimensions were chosen to adequately capture the reservoir properties and heterogeneity, while at the same time maintaining computational efficiency.

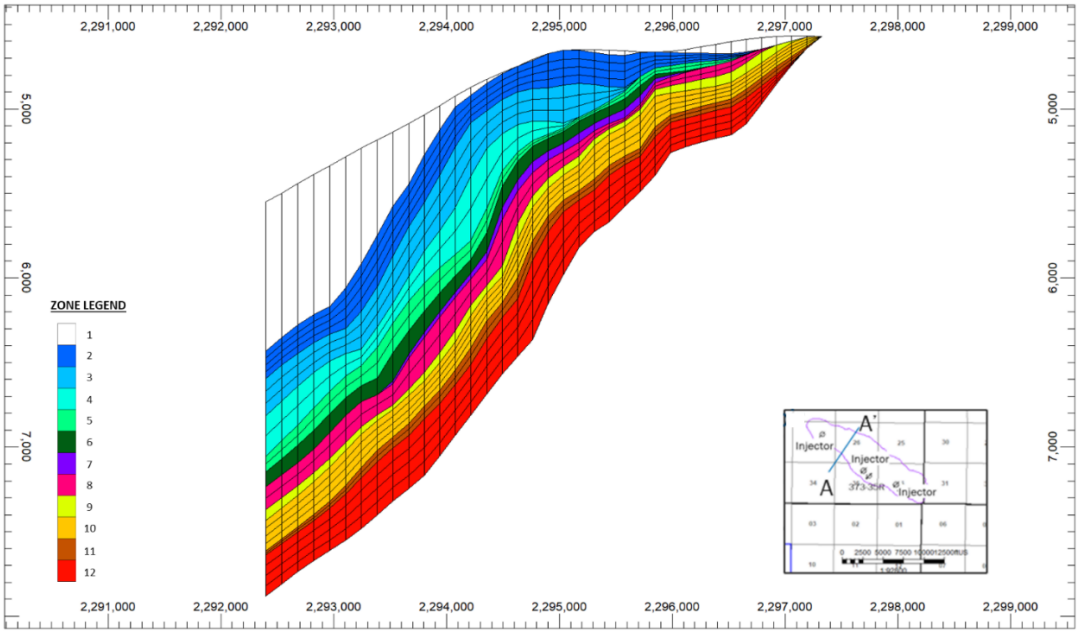
Table 2. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD 83		
Coordinate System Units	Feet		
Zone	CA83-VF		
FIPSZONE	0405	**ADSZONE**	3376
Coordinate of X min	6113669.29	**Coordinate of X max**	6130553.74
Coordinate of Y min	2286478.43	**Coordinate of Y max**	2299980.65
Elevation of bottom of domain	-6651.18	**Elevation of bottom of domain**	-3544.42

The geo-cellular grid is uniformly spaced throughout the 3.7 square mile model area (Figure 2) at 190 feet by 150 feet. The model is oriented at 18 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were selected to define plume extent and edges of the Monterey Formation 26R reservoir.

The reservoir has been separated into 12 zones and 27 layers (Figure 3) respectively and an average grid cell height of 117 feet. Each of the 12 zones is a mappable sand and were modeled separately to ensure stationarity of the geostatistical model. With a data driven geostatistical model, the model can discretize the reservoir into multiple zones. Grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing CO_2 movement. Well data that defines the stratigraphy also defines the structure of the 26R storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

Figure 3: Static model layering of the Monterey Formation 26R reservoir showing the 12 zones, and the 27 layers. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale laterally.



Porosity and Permeability

Figure 2 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Figure 4A shows how the log derived porosity compares to the upscaled model (synthetic) porosity for 363-27R (track five with log derived in black and the Upscaled model / synthetic porosity in blue). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 4B) that is dependent on porosity and clay volume.

Figure 4A: Log derived and Model Upscaled (Synthetic porosity) for 363-27R (track five with log derived in black and the Upscaled model synthetic in blue).

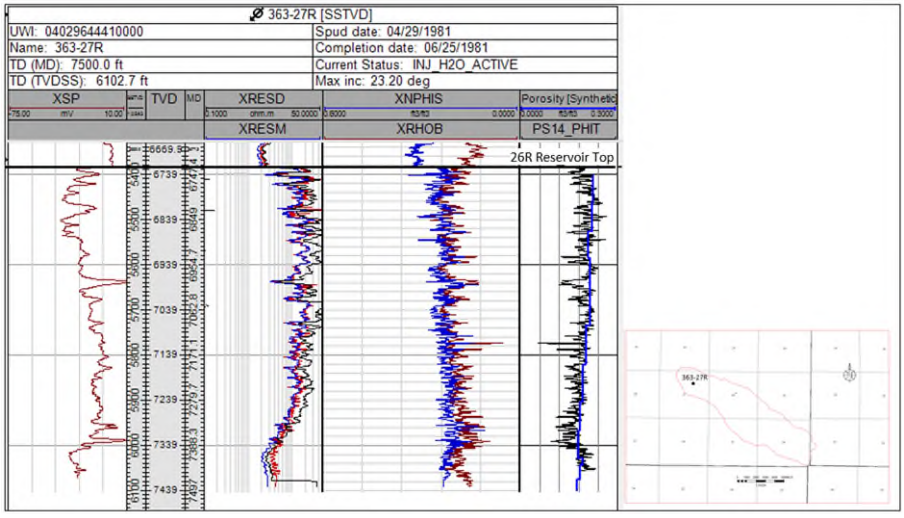


Figure 5B: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.

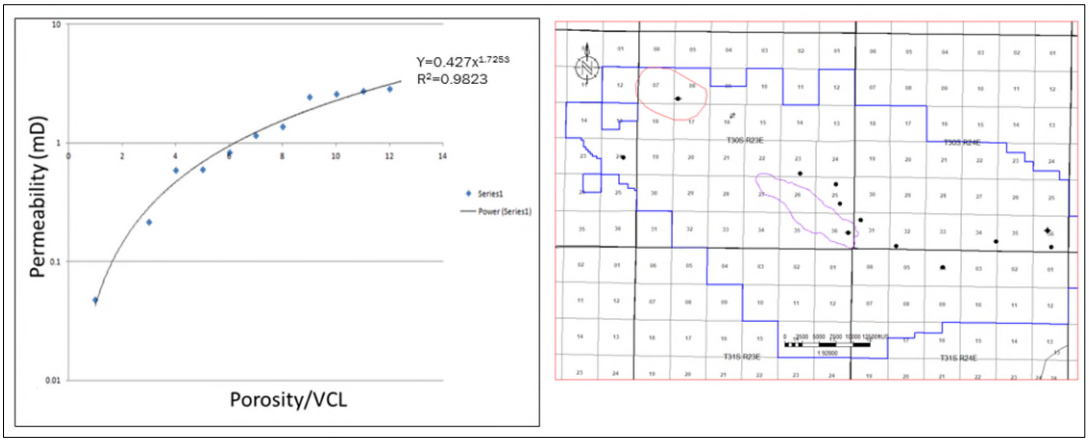


Figure 6: Monterey Formation 26R sands porosity and permeability distribution in the static model.

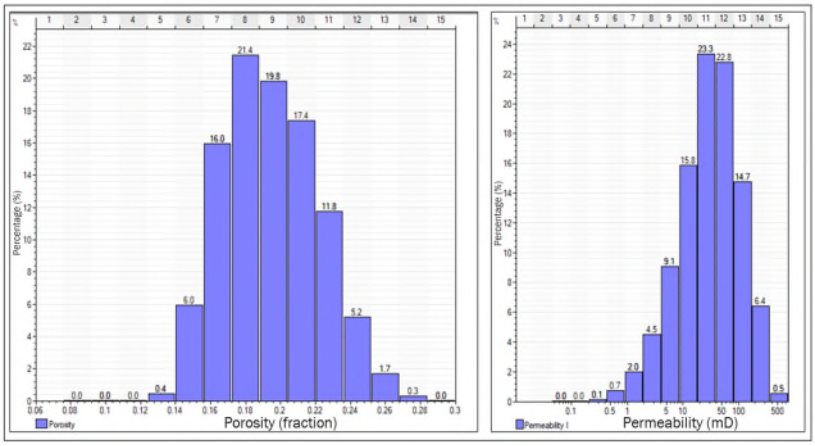
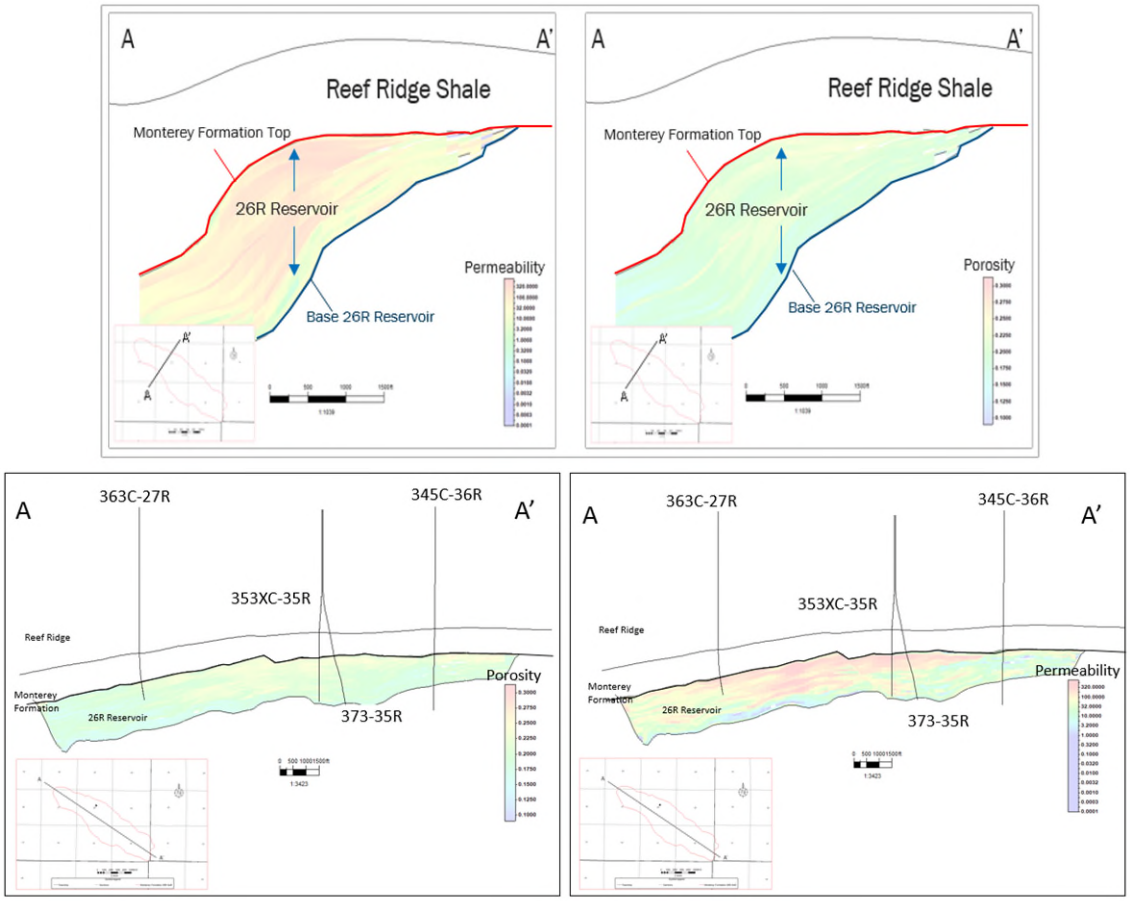


Figure 5 shows porosity and permeability histograms for the Monterey Formation 26R sands in the static model. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 6 shows the permeability and porosity distribution in cross-section A-A'.

Figure 7: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



A variable permeability anisotropy was included in the model, with a Vertical permeability (kv) to horizontal permeability (kh) ratio which ranged from 0.0001 to 1, with a log mean of value of 0.01. The permeability anisotropy was arrived at by upscaling log derived permeability, and then distributing the upscaled log data across the model domain. The log data was upscaled using an arithmetic mean to represent the horizontal permeability, and a harmonic mean to represent the vertical permeability.

Constitutive Relationships and Other Rock Properties

The Monterey Formation 26R reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

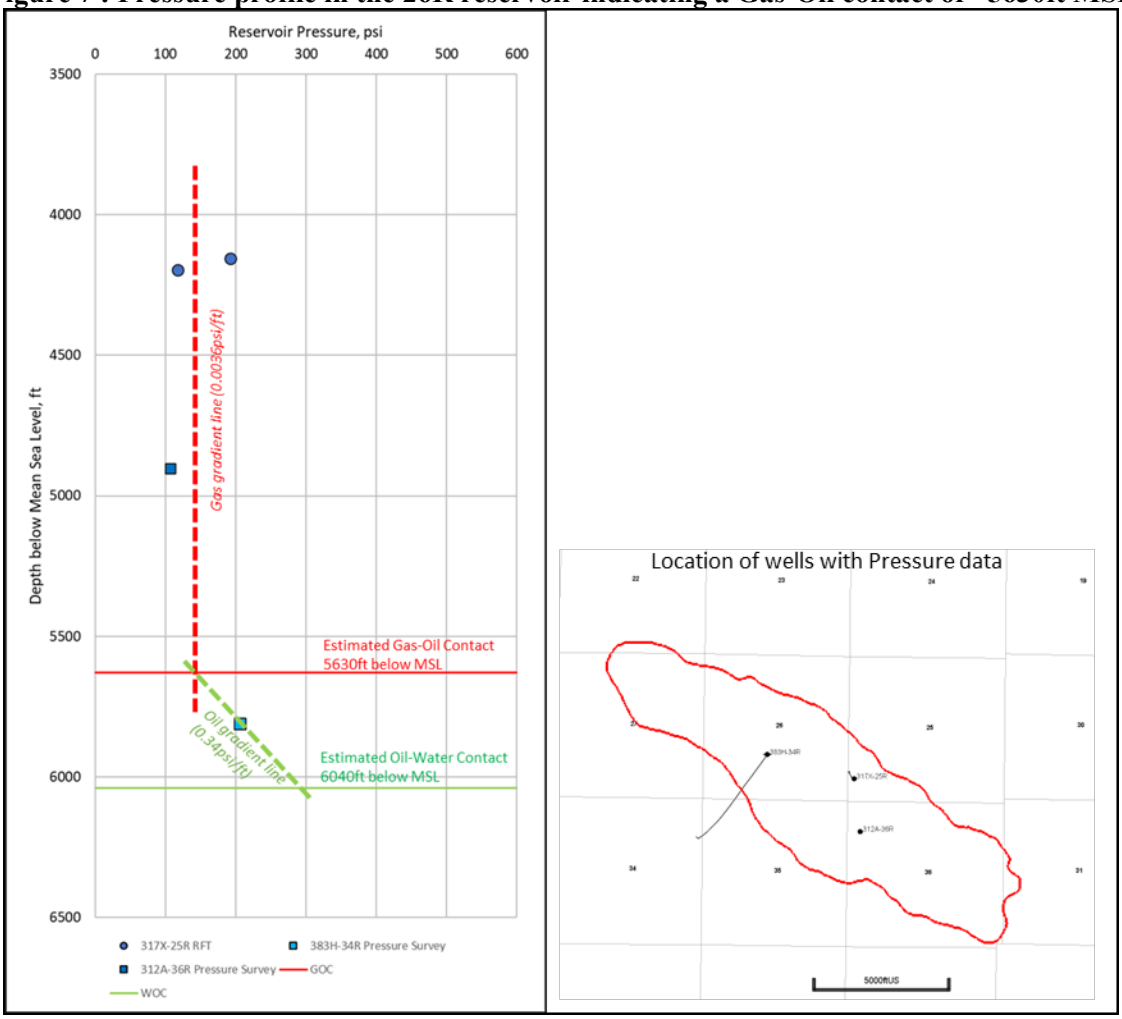
The saturations for the Gas, Oil and Water in the Gas Cap and Oil Band portions of the reservoir were determined using a Material Balance approach. The Pore Volume, discovery fluid contacts, pressure history, cumulative production and injection data for the reservoir, and the PVT properties of the fluids were used to estimate a current average oil, water, and gas saturation for the hydrocarbon portion of the 26R reservoir. These average saturations and estimates of remaining oil in place were used to iterate to a current oil-water and gas-oil contact in the computational model and the CMG GEM simulation model was initialized using the relative permeability curves, capillary pressure curves and current estimate of reservoir pressure.

The most recent data used to help validate the estimated gas-oil contact was pressure data gathered between 2006-2015. The pressure profile from this data was used to help estimate a gas contact of ~5630ft below MSL, using a gas gradient (0.0036psi/ft) and an oil gradient of 0.34psi/ft (see Figure 7). As there has not been evidence of an active aquifer following the blow down of the reservoir, the water contact is estimated to be at or near the original contact of ~6040ft below MSL, which was determined based on well logs obtained during the initial characterization of the reservoir in the 1950's.

Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs, pressure data, material balance and production analysis.

	Gas Cap	Oil Band	Water Zone
Contact (depth sub-sea)	Gas - Oil <5,630	Oil - Water 5630-6,040	> 6,040
Saturation (fraction)	Oil: 15% Water: 33.7% Gas: 51.3%	Oil: 37.1% Water: 25% Gas: 0%	Water: 100%

Figure 7 : Pressure profile in the 26R reservoir indicating a Gas-Oil contact of ~5630ft MSL



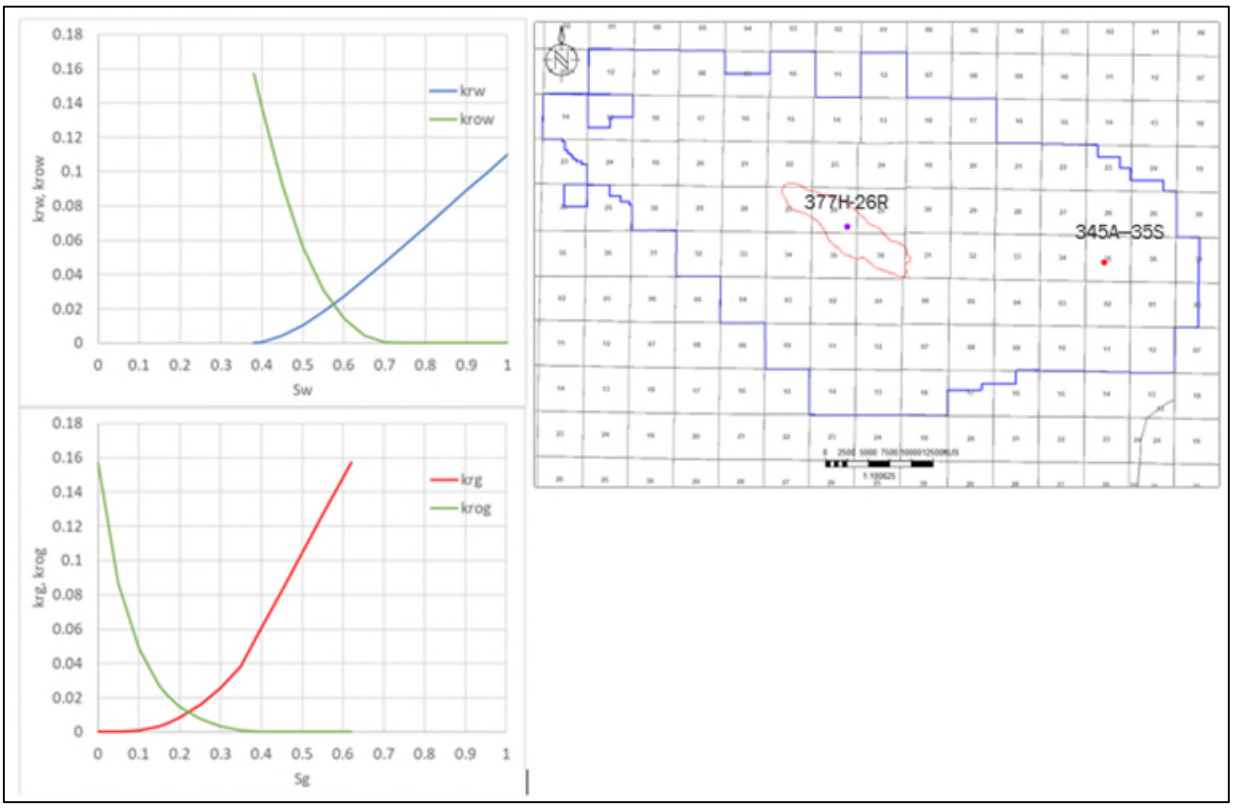
With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving krw, krow, krg, and krog as a function of saturation.

Where,
krg – relative permeability of Gas in a Gas–Oil system
krog – relative permeability of Oil in a Gas–Oil system
krow – relative permeability of Oil in an Oil-Water system
krw – relative permeability of Water in an Oil-Water system

Data acquired from Special Core Analyses (SCAL) determines these relationships. The geomodel modelled two rock types – sand and shale, but for the simulation a single sand rock type was modeled with the shale facies cells being treated as inactive cells. Core obtained from well 377H-26R in the 26R reservoir and equivalent Monterey Formation sandstone from well 345A-35S in the Elk Hills reservoir were used to generate the relative permeability relationships for the sand

facies. The data was normalized with respect to air permeability using end point scaling and a single Corey relative permeability fit was generated. Figure 8 shows the relative permeability curves used in the computational modeling and Figure 9 shows the relative permeability data from wells 377H-26R and 345A-35S in tabular form.

Figure 8: Relative permeability curves for krg-krog and krw-krow used in the computational model study and wells locations for data used to develop the curves.



The functional form of the relative permeability curves are -
krw = krwiro * ((Sw - Swcrit)/(1.0 - Swcrit - Soirw))^{Nw}
krow= krocw * ((So - Sorw)/(1.0 - Swcon - Sorw))^{Now}
krog=krogcg*((Sl - Sorg - Swcon)/(1.0 - Sgcon - Sorg - Swcon))^{Nog}
krg =krgcl *((Sg - Sgcrit)/(1.0 - Sgcrit - Soirg - Swcon))^{Ng}

With the parameters for the curve being -
Swcon - Endpoint Saturation: Connate Water = 0.38
Swcrit - Endpoint Saturation: Critical Water = 0.38
Soirw - Endpoint Saturation: Irreducible Oil for Water-Oil = 0.2
Sorw - Endpoint Saturation: Residual Oil for Water-Oil = 0.22
Soirg - Endpoint Saturation: Irreducible Oil for Gas-Liquid = 0.21
Sorg - Endpoint Saturation: Residual Oil for Gas-Liquid = 0.22
Sgcon - Endpoint Saturation: Connate Gas = 0
Sgcrit - Endpoint Saturation: Critical Gas = 0.05
krocw - Kro at Connate Water = 1

krwiro - Krw at Irreducible Oil = 0.43
krgcl - Krg at Connate Liquid = 0.4
krogcg - Krog at Connate Gas = 1
Nw = 1.3
Now = 3
Nog = 3.8
Ng = 2.5

The end point relative permeabilities of the curves were then scaled by a factor of 0.1547 using Oil to Air permeability ratio from well 345A-35S, so that the curves would be in reference to air permeability, which was used in the simulation model.

Figure 9: Monterey formation relative permeability data from wells 345A-35S and 377H-26R

Well: 345A-35S						
Sample Depth, feet:	7161.80					
Permeability to Air, md:		99.1				
Porosity, fraction:		0.221				
Initial Water Saturation, fraction:		0.380				
Effective Oil Permeability at Swi, md:		15.6				
Oil to Air Permeability ratio		0.1574				
* Relative to the effective permeability to oil at initial water saturation						
Water Displacing Oil				Gas Displacing Oil		
Sw	Relative Permeability to Water	Relative Permeability to Oil		Sg	Relative Permeability to Gas	Relative Permeability to Oil
0.380	0.000	1.000		0.000	-	1.000
0.436	0.026	0.662		0.184	0.002	0.109
0.460	0.053	0.525		0.198	0.005	0.093
0.510	0.108	0.324		0.226	0.014	0.069
0.557	0.176	0.176		0.269	0.040	0.040
0.645	0.328	0.033		0.334	0.106	0.010
0.803	0.615	-		0.405	0.195	-

Well: 377H-26R						
Sample Depth, feet :		5972.8		6015.9		
Permeability to Air, md :		100.0		286		
Porosity, fraction :		0.186		0.213		
Initial Water saturation, fraction		0.234		0.219		
* Relative to the effective permeability to oil at initial water saturation						
Water Displacing Oil				Gas Displacing Oil		
Sw	Relative Permeability to Water	Relative Permeability to Oil		Sg	Relative Permeability to Gas	Relative Permeability to Oil
0.234	0.000	1.000		0.000	0.000	1.000
0.286	0.034	0.851		0.133	0.011	0.332
0.313	0.045	0.764		0.162	0.017	0.252
0.377	0.069	0.541		0.198	0.029	0.170
0.461	0.098	0.292		0.226	0.041	0.131
0.523	0.121	0.147		0.259	0.059	0.091
0.568	0.141	0.070		0.285	0.082	0.070
0.590	0.152	0.040		0.309	0.101	0.051
0.606	0.163	0.025		0.342	0.134	0.035
0.620	0.168	0.018		0.369	0.175	0.022
0.644	0.182	0.009		0.394	0.221	0.015
0.649	0.187	0.006		0.411	0.249	0.011
0.667	0.195	0.003		0.432	0.279	0.007
0.685	0.205	0.001		0.486	0.406	
0.694	0.213					

Mineralization

Based on previous studies on reactive transport modeling and geochemical reactions in CCS applications have shown that the amount of CO2 predicted to be trapped by mineralization reactions is extremely small over a 100 year post injection time frame (IPCC, 2005: IPCC Special report on Carbon Dioxide Capture and Storage) for sandstone reservoirs. In addition, due to the fairly low salinity of the Formation water, stable mineralogy and minor expected on the AoR, reactive transport was not included as a part of the compositional simulation modeling at this time for computational efficiency.

Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation 26R reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

2. Performance data from operating the Monterey Formation 26R oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 10) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 10) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

    iii. Pressure in the reservoir is at 150 - 300 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

3. The 26R reservoir pinches out in the updip and lateral portions of the reservoir, and transitions to shale as shown in Figure 1.

Pressure data obtained while drilling wells in the AoR shows the pressure isolation of the 26R reservoir from the overlying Etchegoin Formation and the Lower Monterey Formation. Figure 11 shows the pressure data obtained for the formations, and location of these wells within the AoR.

Additional pressure data will be gathered and provided to the EPA during the pre-operational testing phase when all production operations in the reservoir have ceased, to confirm the historical understanding.

Figure 10: Monterey Formation 26R production and injection data.

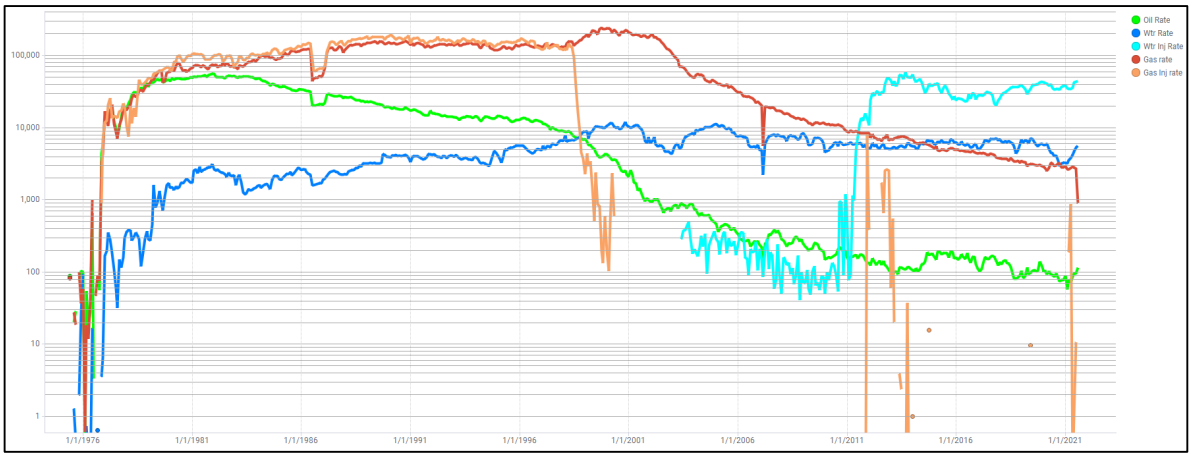
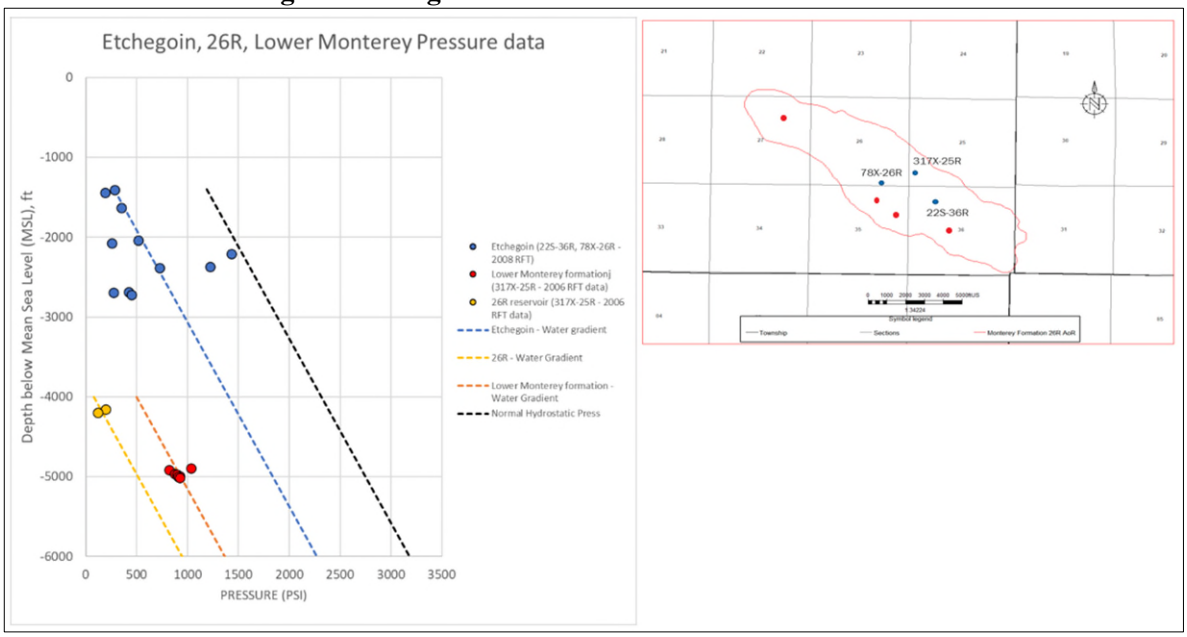


Figure 11: Etchegoin Formation, 26R Reservoir and Lower Monterey Formation repeat formation tester (RFT) pressure data in the AoR shows pressure isolation between the different formations. Data was obtained during the drilling of wells between 2006-2008.



Initial Conditions

Initial model conditions (start of CO_2 injection) of the Monterey Formation 26R reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4. Depths in the Table 4 are depths below Mean Sea Level (MSL), which is used as the reference elevation.

Table 4. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft, below Mean Sea Level)	Data Source
Temperature	210	Fahrenheit	5,630	Fluid Analysis
Formation pressure	150	Pounds per square inch	5,630	Pressure Test
Fluid density	61	Pounds per cubic foot	5,630	Water analysis
Salinity	25,000	Parts per million		Water analysis

Operational Information

Details on the injection operation are presented in Table 5.

Table 5. Operating details.

Operating Information	Injection Well 1 373-35R	Injection Well 2 345C-36R	Injection Well 3 353XC-35R	Injection Well 4 363C-27R
Location (global coordinates)	35.1634 N 119.2824W	35.2743 N 119.4577 W	35.3768 N 119.4732 W	35.2779 N 119.4535 W
Model coordinates (ft) X Y	 6121906 2290081	 6126556 2289316	 6121940 2290248	 6117204 2295938
No. of perforated intervals	13	25	11	12
Perforated interval (ft TVD / MD) Top Bottom	 6807 / 7086 7109 / 7426	 6097 / 6101 7710 / 7720	 6625 / 6810 8373 / 8545	 6698 / 6731 8124 / 8216
Production Casing diameter (in.)	4.5”	4.5”	4.5”	4.5”
Planned injection period Start End	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051
Injection duration (years)	27	27	27	27
Injection rate (t/day)*	993	993	993	993

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

Fracture Pressure and Fracture Gradient

A fracture gradient of 0.701 psi/ft is expected for the 26R reservoir. This is based on fracture stimulation performed on well 388-26R in the 26R reservoir.

CTV will ensure that the injection pressure is below 90% of the fracture pressure as calculated at the top perforation for each injector. The maximum allowable subsurface wellbore injection pressure for the 4 injectors in the project is shown below in Table 6.

Table 6. Injection pressure details.

Injection Pressure Details	Injection Well 1 373-35R	Injection Well 2 345C-36R	Injection Well 3 353XC-35R	Injection Well 4 363C-27R
Fracture Gradient (psi/ft)	0.701	0.701	0.701	0.701
Maximum allowable downhole injection pressure (90% of fracture pressure), psi	4294	3847	4180	4226
Elevation corresponding to maximum allowable bottomhole pressure (ft, TVD / MD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Elevation of top of the perforated interval (ft, TVD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Planned bottom hole injection pressure at top of perforations (psi)	4060	3555	3787	3558
Planned bottom hole injection gradient at top of perforations (psi/ft)	0.596	0.583	0.572	0.531

Proposed Carbon Dioxide Stream

CTV is planning to construct a carbon capture and sequestration "hub" project (*i.e.*, a project that collects carbon dioxide (CO_2) from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC permitted injection well(s)). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The anthropogenic CO_2 will be sourced from:

- Initial onsite emissions:
    - Lone Cypress blue hydrogen plant, up to 200,000 tonnes per annum
    - Elk Hills field gas treatment (pre-combustion for Elk Hills Power Plant), up to 200,000 tonnes per annum
    - Avnos Direct Air Capture (DAC), up to 1,500 tonnes per annum
- Future emission Sources:
    - CalCapture Elk Hills 550 MW natural gas power plant (post combustion), renewable fuel plants, steam generators post combustion and other power plants / industrial sources in the area

CTV expects the CO_2 stream to be sampled at the transfer point from the source and analyzed according to the analytical methods described in the QASP document and the Attachment C – Testing and Monitoring plan document. Should the injectate not meet the minimum requirements, it will be rejected.

The anticipated injection temperature at the wellhead is 90 – 130° F.

For the purposes of Geochemical modeling, CO2 Plume modeling, and Well design, two major types of Injectate compositions were considered based on the source.

- Injectate 1: is a potential injectate stream composition from a Direct Air Capture (DAC) or a Pre-Combustion source (such as the Lone Cypress blue hydrogen facility) or a Post-Combustion source (such as a gas fired power plant or steam generator) where N2 will likely be the major impurity.
- Injectate 2: is a potential injectate stream composition from a Biofuel Capture source (such as a Biodiesel plant) or an Oil & Gas Refinery or Natural Gas processing facilities (such as CO2 capture from the feed gas to the Elk Hills Power plan stated above) where light end Hydrocarbons (Methane, Ethane) will be the major impurity.

Design studies for CO2 capture at the planned Lone Cypress facility and design studies for CO2 capture from feed gas to the Elk Hills power plant were incorporated into the two injectate compositions shown in Table 7, in addition to preliminary injectate specifications provided by other potential sources and from literature studies.

Table 7 : Injectate compositions

Component	Injectate 1	Injectate 2
	Mass%	**Mass%**
CO2	99.213%	99.884%
H2	0.051%	0.006%
N2	0.643%	0.001%
H2O	0.021%	0.000%
CO	0.029%	0.001%
Ar	0.031%	0.000%
O2	0.004%	0.000%
SO2+SO3	0.003%	0.000%
H2S	0.001%	0.014%
CH4	0.004%	0.039%
NOx	0.002%	0.000%
NH3	0.000%	0.000%
C2H6	0.000%	0.053%
Ethylene	0.000%	0.002%
Total	**100.00%**	**100.00%**

For geochemical and plume modeling scenarios, these injectate compositions were simplified to a 4-component system, shown in Table 8. The 4 component simplified compositions cover 99.9% by mass of Injectate 1 & 2 and cover particular impurities of concern (H2S and SO2). The estimated properties of the injectates at downhole conditions are specified in Table 9

Table 8: Simplified 4 component composition for Injectate 1 and Injectate 2

Injectate 1	
Component	**mass%**
CO2	99.213%
N2	0.643%
SO2+SO3	0.003%
H2S	0.001%

Injectate 2	
Component	**mass%**
CO2	99.884%
CH4	0.039%
C2H6	0.053%
H2S	0.014%

No corrosion is expected in the absence of free phase water provided that the entrained water is kept in solution with the CO_2. This will be ensured by maintaining a water specification limit <25 lb/mmscf for the injectates, and this specification will be a condition of custody transfer at the capture facility. For transport through pipelines, which typically use standard alloy pipeline materials, this specification is critical to the mechanical integrity of the pipeline network, and out of specification product will be immediately rejected. Therefore, all product transported through pipeline to the injection wellhead is expected to be dry phase CO_2 with no free phase water present.

Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. CRA tubing will be used in the injection wells to mitigate any potential corrosion impact should free-phase water from the reservoir become present in the wellbore, such as during shut-in events when formation liquids, if present, could backflow into the wellbore. CTV may further optimize the maximum water content specification prior to injection based on technical analysis.

Injectate will be sampled and analyzed as part of the pre-operational testing, to confirm that it is consistent with the well design, Plume modeling and Geochemical modeling assumptions.

Computational Modeling Results

Predictions of System Behavior

The base simulation case was run for a 127 year period, covering 27 years of injection and 100 years of post injection. The simulated injection storage capacity is 38MMT taking the reservoir from current reservoir conditions to initial discovery pressure of 3,250 psi. A 100% CO2 injectate stream was assumed for the base case simulation studies. Additionally, scenarios were also run for the two injectates (Injectate 1 and Injectate 2) detailed in the "Proposed Carbon Dioxide Stream" section. Minimal difference in results was seen between the cases. Table 9 summarizes the expected CO2 injectate properties at reservoir conditions over the life of the project.

Table 9: CO2 injectate properties at reservoir conditions

Injectate property	100% CO2	Injectate 1	Injectate 2
Viscosity, cp	0.019-0.044	0.019-0.043	0.019-0.045
Density, kg/m3	16.6-544.8	16.5-543.5	1.035-545.8
Salinity, ppm	NA	NA	NA
Compressibility factor, Z	0.97-0.59	0.97-0.59	0.97-0.59

The following maps (Figure 12) and cross-sections (Figure 13) show the computational modeling results and development of the CO_2 plume at multiple time-steps. For all layers in the model and at all time-steps, the plume stays within the AoR. The CO2 plume grows rapidly within the first 15 years of injection with majority of the CO2 going into the higher quality upper portion of the 26R reservoir and being controlled by the structure of the reservoir and the closed updip boundary. Thereafter, the CO_2 injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the CO_2 injectate remains as super-critical CO_2.

The CO2 plume reaches its maximum vertical and lateral extent 20 years after the end of injection. The vertical and lateral extent of the CO2 plume predicted by the model aligns well with estimated discovery Oil-Water contacts of the reservoir and the vertical and lateral extent of the reservoir. The extent of the CO2 plume is slightly deeper than discovery fluid contacts in a few areas of the model likely due to gas override during injection and dissolution of the CO2 into the aqueous and oleic phases at the edge of the plume. The CO2 plume is largely stabilized 20 years after the end of injection, with little to no movement of the supercritical phase CO2 seen past this date.

The pressure front (defining as >10psi change from pressure at start of injection) in the reservoir reaches the vertical and areal boundaries of the model 6 years after the start of injection. The pressure in the reservoir reaches its peak at the end of injection. The reservoir pressure stabilizes fairly immediately in the reservoir with end of injection, and < 5psi/year change is expected in the first year after the end of injection. Figure 14 shows the average pore volume pressure vs time.

Figure 12A: Plan view showing the CO2 plume development through time. Plume is at its greatest extent at 20 years post injection.

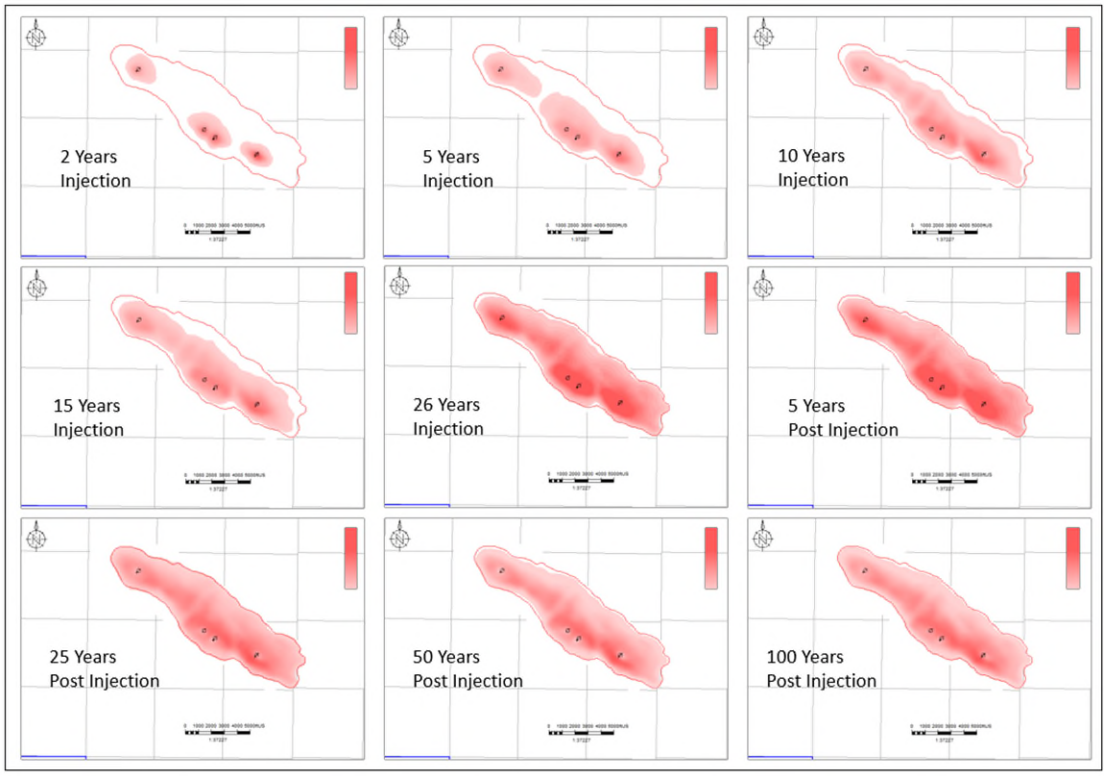


Figure 12B: Plan view showing the gas extent through time. Maps scaled so as to present Gas saturation over a nomial baseline

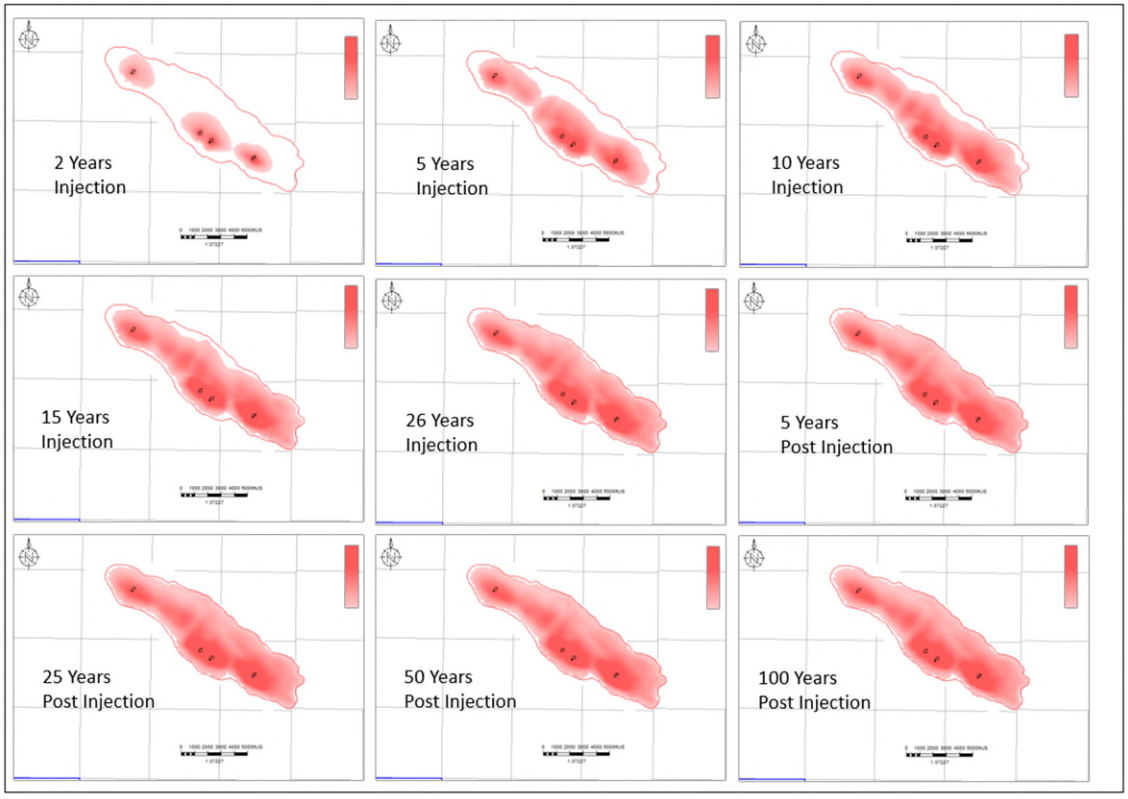


Figure 13A Cross-sections showing the CO2 plume development through varying times during the project.

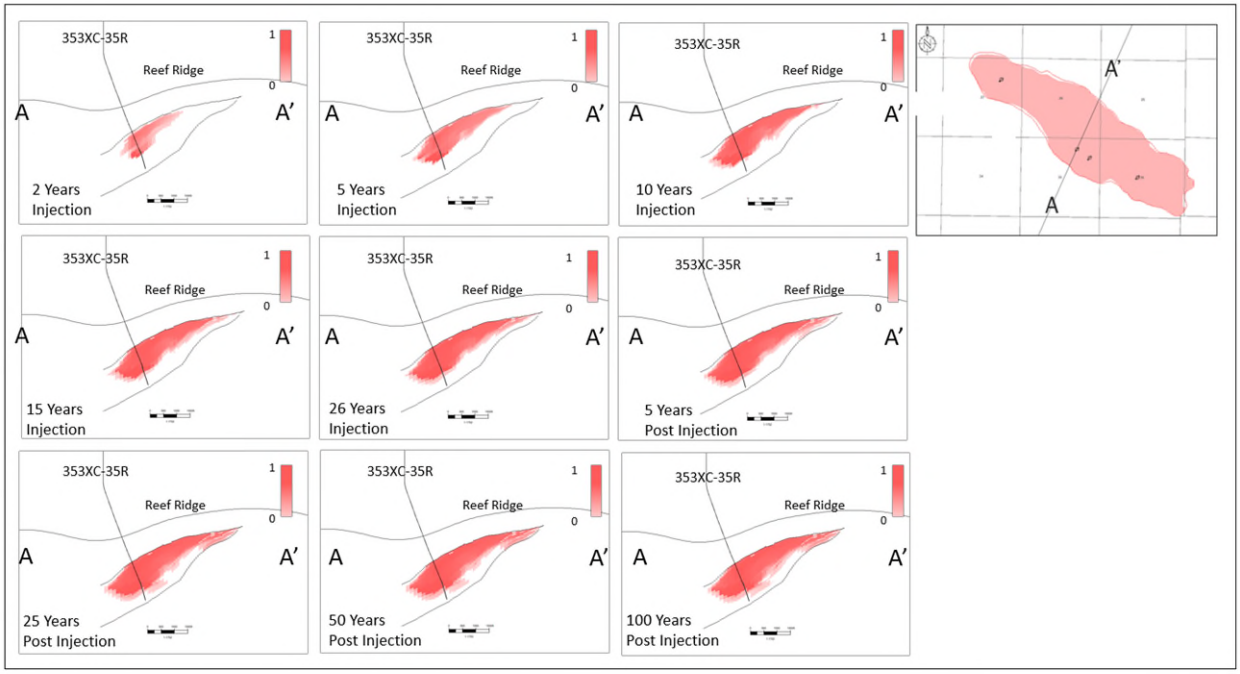


Figure 13B: Cross-sections showing the gas extent through varying times during the project. Maps scaled so as to present Gas saturation over a nomial baseline

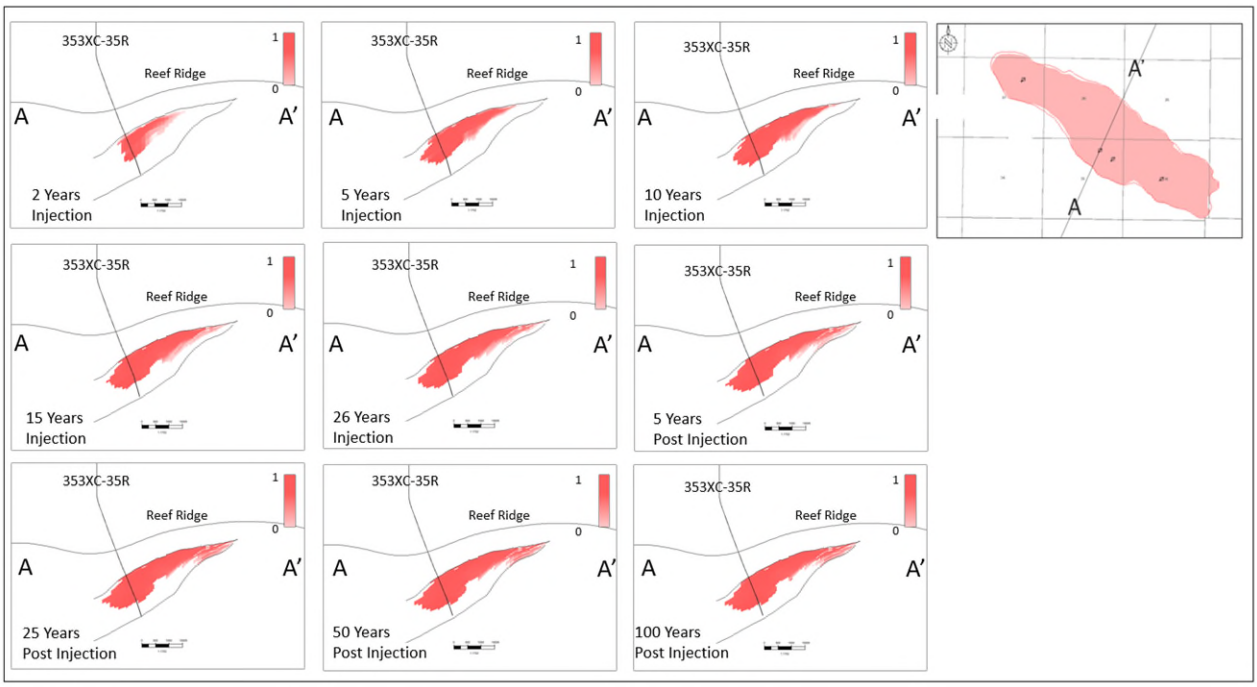
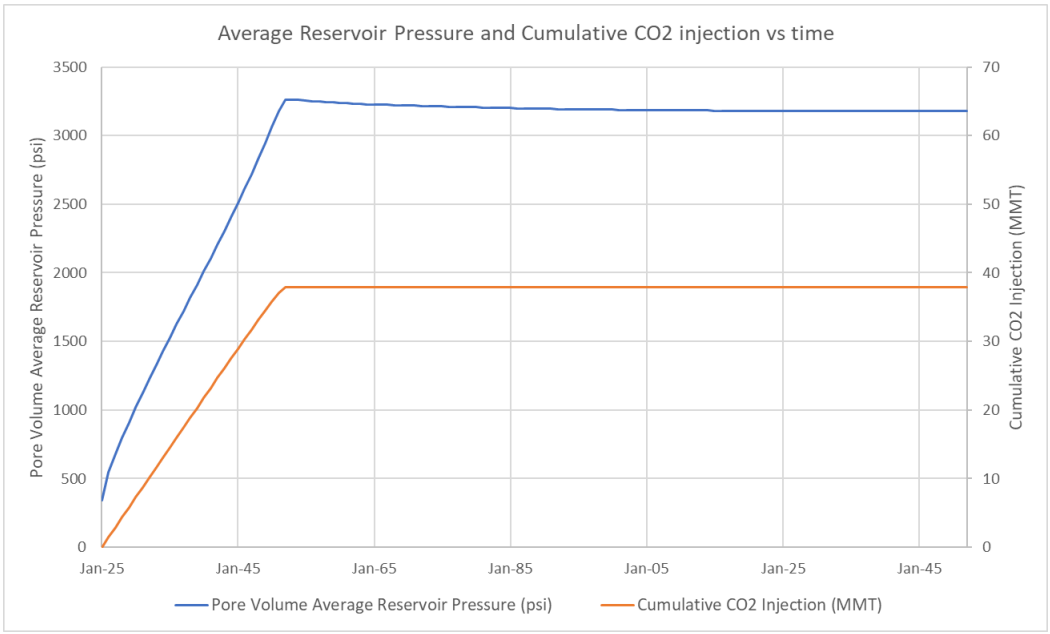
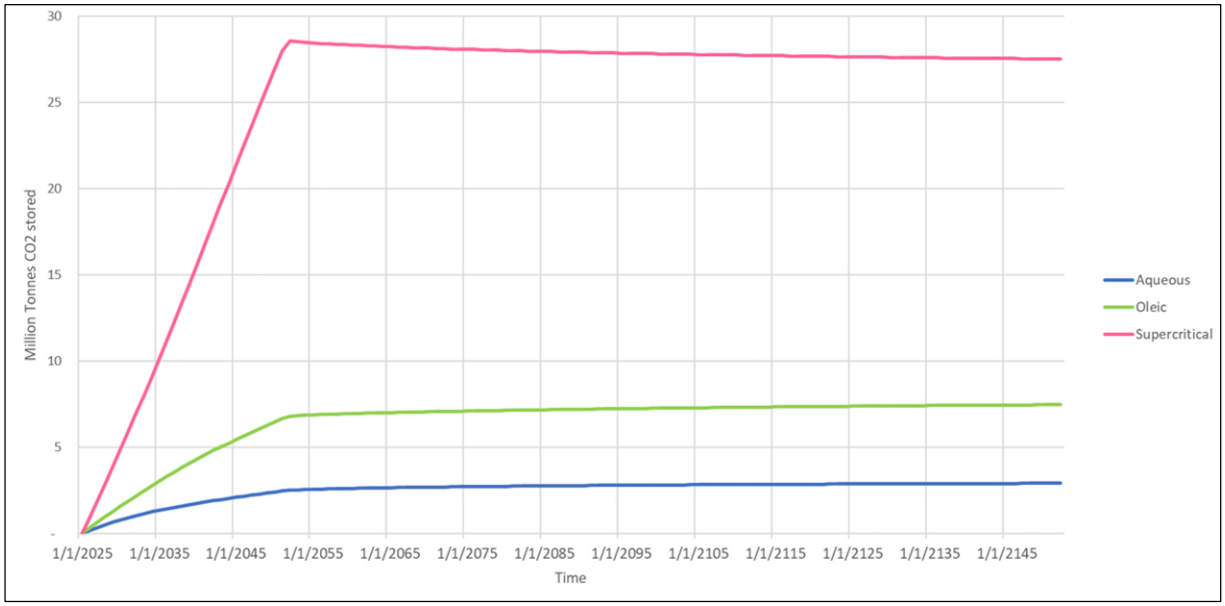


Figure 14: Average Reservoir pressure and cumulative CO2 injection versus time plot



CO_2 injected into the Monterey Formation 26R reservoir will be soluble in both water and oil. Due to remaining saturation of oil and water in the depleted reservoir, total dissolved CO_2 in oil and water is 20% and 8% of the CO_2 injected respectively. The remaining will be stored as super-critical CO_2. Figure 15 shows the cumulative storage for each of the mechanisms.

Figure 15: Storage mechanism through time for the 26R reservoir.



CO_2 Injectate Composition effect on Plume and AoR modeling

The Plume model developed in the Computer Modeling Group (CMG) GEM software was run for the two simplified injectate compositions, and their results were also compared against a 100% CO2 injectate case. The cumulative volume of injectate for all 3 cases was the same.

The CO2 plume for Injectate 1 and Injectate 2 (detailed in the "Proposed Carbon Dioxide stream" section in this document) is consistent with the plume outline for 100% CO2 injectate (Figure 16), which was defined by a 0.03 global CO2 mole fraction for all 3 cases. The 100 year post end of injection plumes for the 3 cases are shown below in Figure 16. The wells that fall within the CO2 plume are the same for all 3 cases.

Additionally, the average Pore Volume pressure was plotted for the 3 cases and there was minimal difference seen between the cases, as shown in Figure 17.

In summary, there is minimal effect of the minor components on the CO2 plume shape and the AoR boundary, for the proposed injectate compositions. As such, CTV's Plume and AoR modeling for Corrective Action assessment is adequate. CTV will confirm that the properties of the injectate are consistent with the model inputs at pre-operational injectate sampling. In addition, the AoR will be reviewed as per the Reevaluation Schedule and Criteria section.

Figure 16: CO2 plume outlines for Injectate 1 (Light Blue), Injectate 2 (Green) and 100% CO2 Cases (Red). Larger Red outline is the model boundary. There are Minimal difference in AoR boundaries between the 3 cases

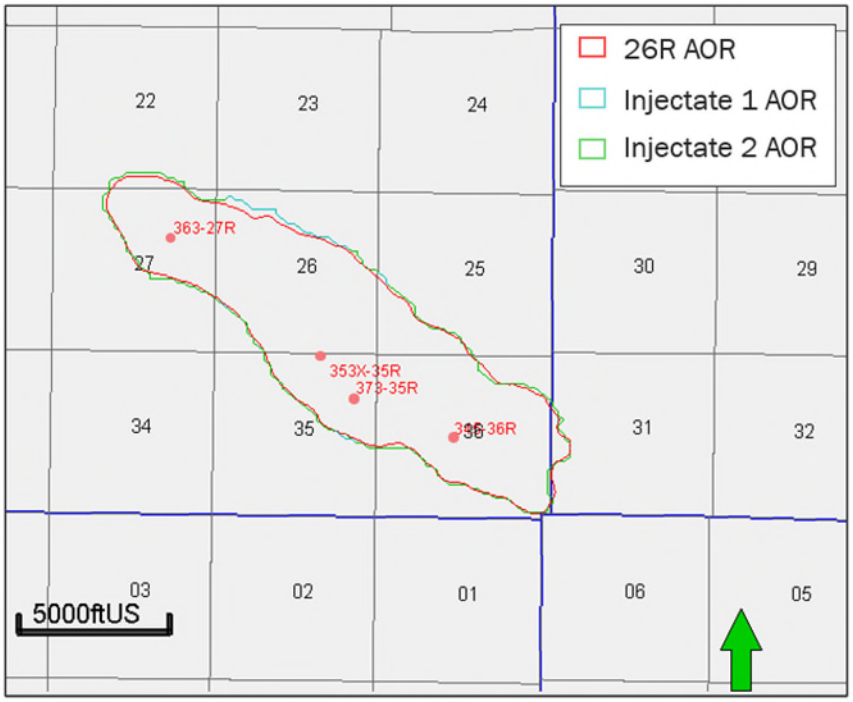
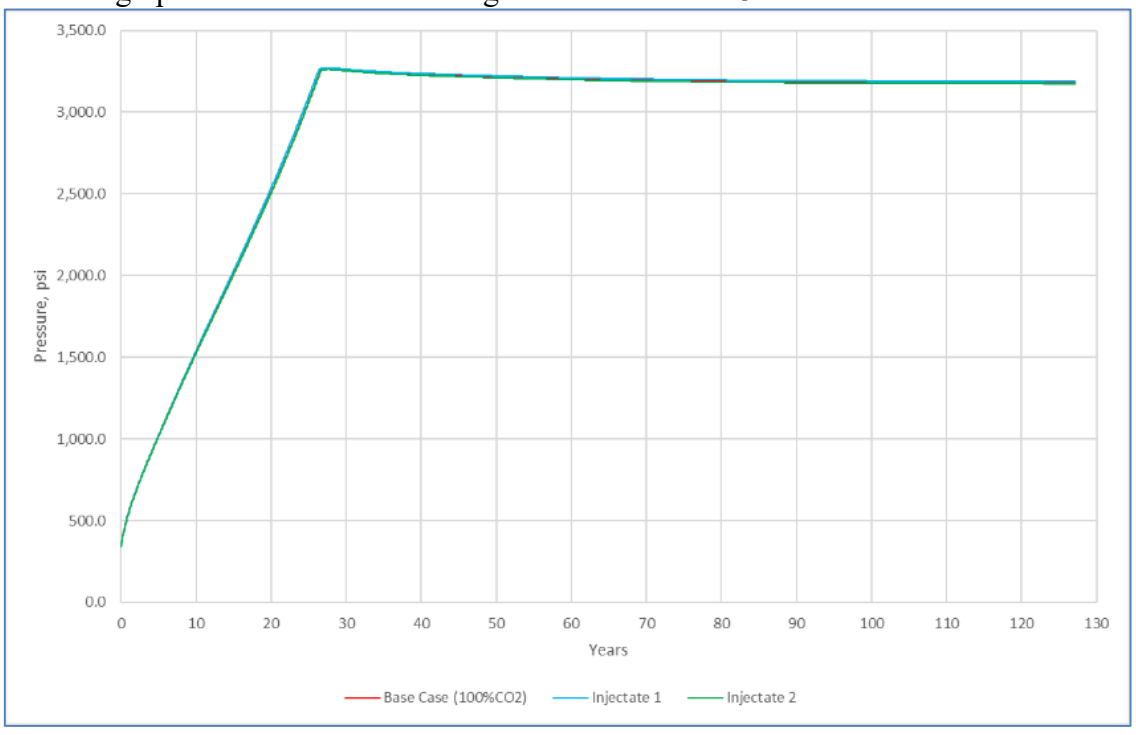


Figure 17: Average reservoir pressure vs time for Injectate 1 (Light blue), Injectate 2 (Green) and base 100% CO2 (Red) cases. Minimal difference in pressure trends between the 3 cases as shown in the graph with the trends tracking each other for the 3 cases.



Model Calibration, Sensitivies and Validation

Previous operators injected 1,244 billion cubic feet of gas into the Monterey Formation 26R reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

The simulation model was run for different initial reservoir pressure and saturation cases to determine the sensitivity of the storage volume and plume extent to these variables. Due to ongoing water injection in the 26R reservoir, sensitivities were run to test the effect of higher reservoir pressure and higher water saturation in the Oil band and Gas cap to see if there would be significant impacts to the storage volume and AoR boundaries.

Sensitivities were also run varying major geomodel inputs into the simulation model (Porosity, Permeability, NTG) and varying the Grid XY dimensions, cell thickness, local grid refinement around injectors, and temperature effects to see if there was a significant change to the storage amount and AoR boundary. Although there was some effect to the total CO2 storage for the different cases, there was minimal change to the maximum extent of the CO2 plume. The porosity, permeability and NTG uncertainty were further modeled stochastically to understand their effect and is discussed in the next section.

- Cell thickness sensitivity case was run by reducing the cell thickness in the overall grid to an average of 18ft. The results of this finer cell thickness model, compared favorably to the Base case model with a < 2% increase in predicted CO2 storage capacity and minimal change to the plume extent.

- The local grid refinement case was run with a finer grid spacing in the 5Acre region around the injector location, with the X-Y grid dimensions reduced to 19ft by 15ft in that region. The results of this case also compared favorably against the base case, with the predicted maximum bottom hole pressure at the injector locations being within 0.5% of the Base Case.

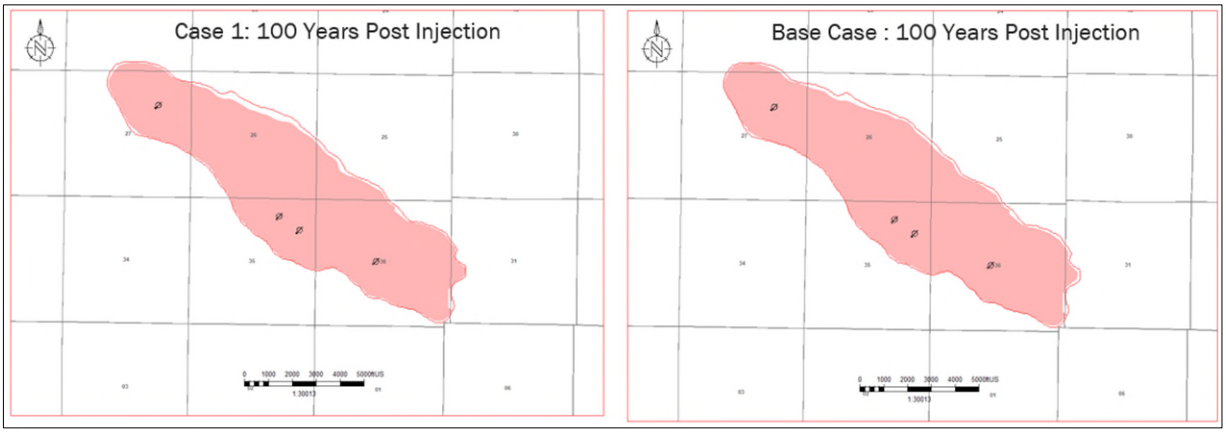
- The Base case model was initialized using a uniform average temperature of 210° F (based on idle well temperature surveys run on wells in the area between 2008 – 2014) and with no thermal effect modeling in the reservoir. A sensitivity case was run using GEM's thermal option to model heat balance and gauge if modeling temperature change in the reservoir with CO2 injection was necessary. The results indicated minimal effect on the system behavior with < 2% change in CO2 storage capacity, and < 2% deviation in reservoir pressure trends.

Table 10 summarizes the sensitivity cases run and their effect on storage volume and the AoR boundary. Figure 18 compares the CO2 plume extent for Case 1 against the Base Case.

Table 10: Summary of sensitivity cases

Case #	Sensitivity Case	Storage Volume effect	AoR boundary effect
1	Pressure : Gas cap pressure increased to 300psi	Decreased volume	Minimal effect to AoR
2	Pressure : Gas cap pressure increased to 500psi	Decreased volume	Minimal effect to AoR
3	Saturation: Higher water saturation in Oil band and Gas cap	Decreased volume	Minimal effect to AoR
4	Porosity: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
5	Porosity: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
6	Permeability: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
7	Permeability: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
8	NTG: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
9	Grid Dimensions: reduced grid XY dimensions to 95 ft x 75ft	No effect	Minimal effect to AoR
10	Cell Thickness: Reduced average cell thickness in Gas cap to 18ft	Increased volume	Minimal effect to AoR
11	Local grid refinement around Injectors: reduced grid X-Y dimension to 19ft x 15ft in 5Acre area around injectors	No effect	Minimal effect to AoR
12	Temperature effect: model was run with GEM's thermal option	Minimal change	Minimal effect to AoR

Figure 18: CO2 plume extent for layer 2 comparing Base Case against Pressure and Saturation sensitivity cases.



These scenarios demonstrated that the AoR, as defined by the maximum extent of CO_2 injectate, is consistent. This provides confidence that the corrective action well review and potential impact is conservative.

Stochastic analysis of effect of Reservoir parameters

A stochastic analysis was carried out using the reservoir parameters – Porosity, permeability, Net to Gross (NTG) ratio and kv-kh ratio. An upper and lower bound of the grid property was entered (directly or using multipliers), along with a distribution (see Table 11) in CMG's CMOST module to generate a set of 50 cases using the Latin Hypercube sampling method. All cases were run with the same bottom hole pressure control on the injectors, and with the same condition of ceasing injection once the reservoir had been brought back up to initial conditions. Although the stochastic analysis showed a range of storage capacity, the P50 estimate was 37MMT, with a P10 of 30MMT and a P90 of 44MMT.

Table 11: Parameters and distributions used for Stochastic analysis

Parameters	Parameter/ Multiplier	Parameter / Multiplier range	Distribution type	Description
Porosity	Multiplier	0.78 - 1.22	Normal distribution	Multiplier range used to have grid mean value range of 0.14 - 0.22
Permeability	Multiplier	0.3 - 3	Log Normal distribution	Multiplier range used to have grid mean value range of ~15 - 150md
Net to Gross ratio (NTG)	Multiplier	0.9 - 1.1	Uniform distribution	A uniform distribution uncertainty of +-10% applied
kv-kh ratio	Parameter	0.001 - 0.2	Log Normal distribution	A kv-kh ratio of 0.001 to 0.2 applied over the entire grid

AoR Delineation

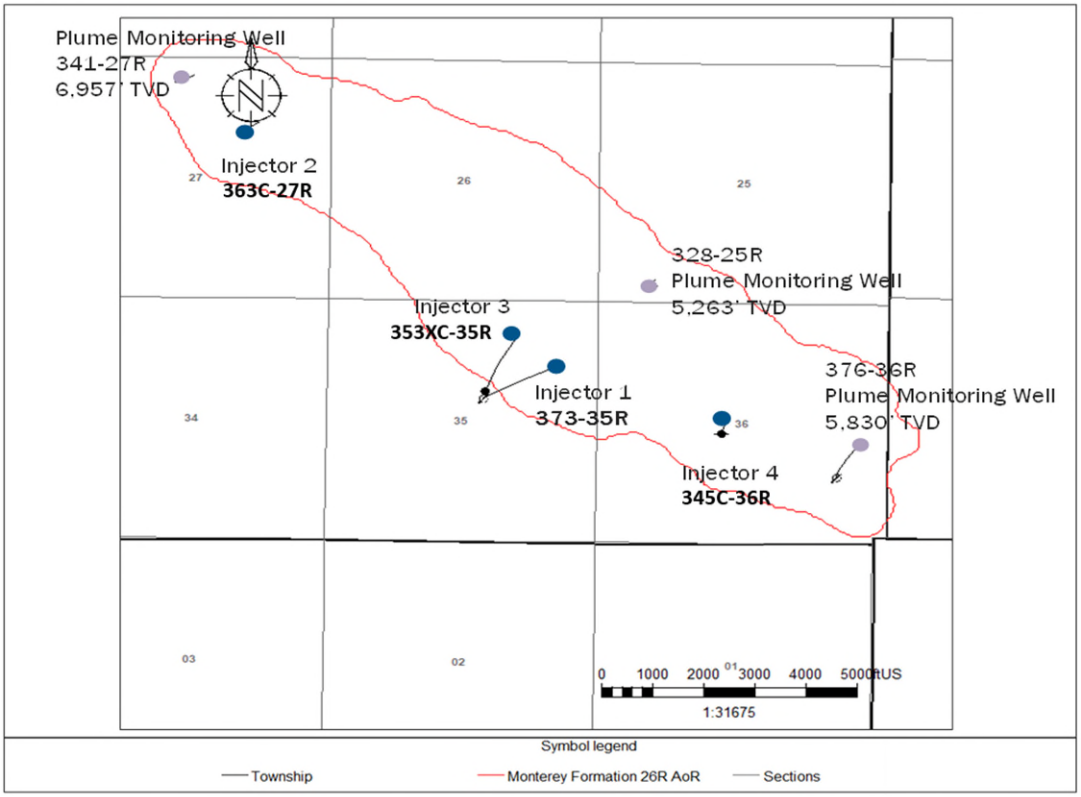
The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. A Global Mole Fraction cut off of 0.03 was used to delineate the plume boundary. In the AoR scenario, CO_2 was injected into the depleted Monterey Formation 26R reservoir until the reservoir pressure reached the discovery pressure of 3,250 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.
Figure 19 shows the AoR, injectors and offset monitoring wells. All wells that are currently operating in the 26R reservoir will cease operations, and wells not associated with the project will be abandoned prior to injection so as to eliminate interference with the AoR delineation and re-establish the confining layer. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

Figure 19: Map showing the location of injection wells and plume monitoring wells.



Corrective Action

The review of all wells within the AoR to determine the need for corrective action is a requirement of 40 CFR 146.84(c).

Tabulation of Wells within the AoR

Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation 26R reservoir was discovered in the 1940's and subsequent development drilling began around 1950. As such, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the over 70-year development history of the reservoir that includes injection of water and gas.

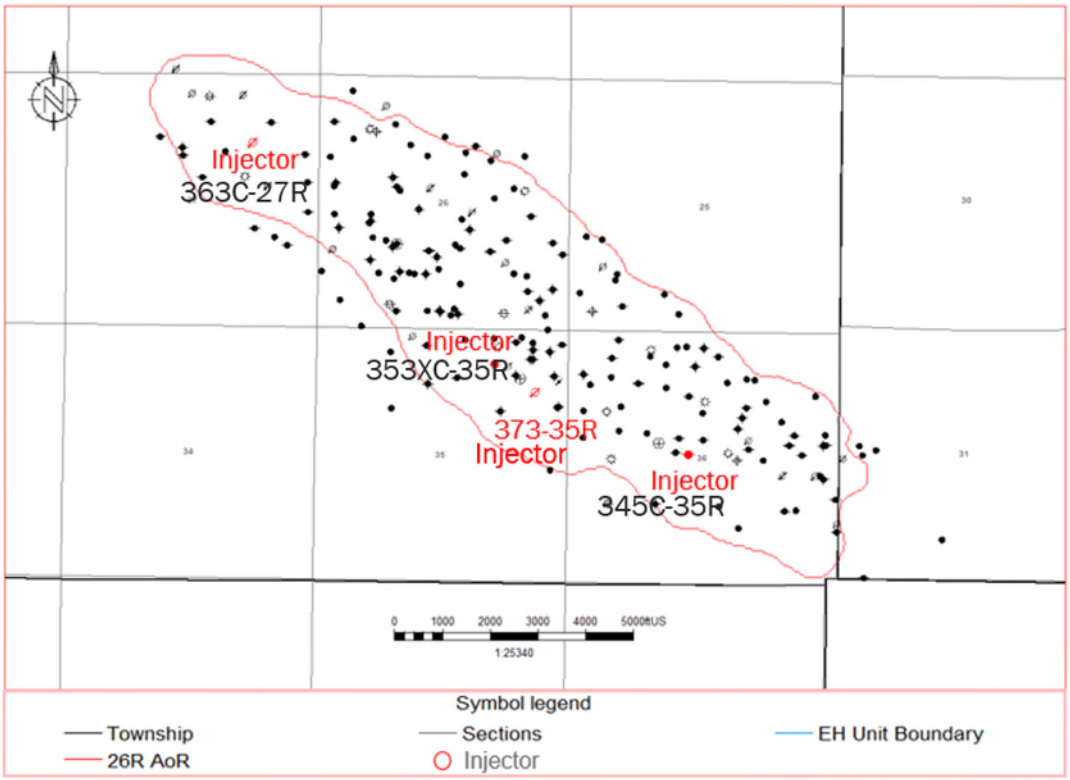
CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Table 12 is a summary of the AoR wells by type. Figure 20 displays the AoR wells' surface locations in map view. *Appendix: Well Table with Corrective Action Assessment* lists the wells individually and provides a description of each well's type, construction, date drilled,

location, depth, and record of plugging and/or completion, as required in 40 CFR 146.84 (c)(2). Additionally the table identifies pre-operational requirements and the corrective action assessment for each wellbore.

Table 12: Wellbores in the AoR by Well Type

Well Type	Count
Oil & Gas Producing Wells	145
Class II Injection/Disposal Wells	22
Pressure Observation wells	2
Plugged back	35
Total	**204**

Figure 20: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation 26R sequestration reservoir reviewed for corrective action.



Corrective Action Assessment Methodology

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q4 2021, and the results of the review are incorporated into the assessment.

The corrective action assessment includes the generation and detailed review of wellbore/casing diagrams for each well in the AoR. The results of the assessment are included in the *Appendix: Well Table with Corrective Action Assessment*. Information used in the review includes depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of Cement (TOC) determination supports the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface.

A well in the AoR is a penetration of the Monterey Formation and/or Reef Ridge Shale that may have multiple wellbores resulting from sidetracking the well. CTV tracks wells at the "wellhead" level using API-10 and at the "wellbore" level using API-12 such that a single well may have multiple wellbores, and each wellbore may or may not penetrate the AoR. The assessment of all penetrations was conducted by evaluating all wellbores, and the summary data provided refers to wellbore penetrations.

Protection of USDW

The Upper Tulare is an unsaturated zone, and the Lower Tulare is an exempt aquifer. There is no USDW in the AoR.

Wells Penetrating the Confining Zone

Of the 204 wellbores penetrating the Reef Ridge formation (Table 13), zero wells have been permanently abandoned to surface. Three wells will be repurposed as CCS monitoring wells, and one well, 373-35R, will be repurposed as a CO_2 injector. Of the remaining, 157 wellbores require plugging because the wellbores penetrate the injection zone and/or confining layer and will not be used for injection or monitoring within the 26R storage project. The wells are not known to be deficient and are not known to require corrective action. The wells will be abandoned prior to CO_2 injection under the asset retirement obligation plan (ARO) to reduce abandonment liability at Elk Hills. 35 wellbores have been plugged back for sidetrack, and as such have the API-12 status of P&A while API-10 status is either Active or Inactive, depending on the status of the current wellbore.

Table 13: Wellbores to be abandoned prior to injection

Wellbores Penetrating Reef Ridge Formation	Wellbores Requiring Corrective Action	P&A Wells Requiring Corrective Action	Wellbores Requiring Pre-Operational Abandonment
204	0	0	157

Monterey Formation 26R Isolation

CTV can demonstrate that the USDW (not present in AoR) is protected and that, with well abandonment prior to injection and implementation of a robust ongoing monitoring program, the CO_2 injected will be confined to the Monterey Formation 26R reservoir.

Plan for Site Access

CTV owns the mineral and pore space for the Monterey Formation 26R reservoir and surface access rights have been guaranteed for the duration of the project.

Corrective Action Schedule

All wellbores within the AoR will, if necessary, be pressure tested, abandoned, re-abandoned, monitored and/or have a technical demonstration of adequate zonal confinement prior to the commencement of CO_2 injection or based on an agreed upon phased schedule after CO_2 injection commences, if conditions allow. Additional evaluation during pre-operational testing will inform the suitability and isolation of wells proposed for use in the project as injectors and monitoring wells. Diagnostics may also be performed, if necessary, to complement abandonment operations. Although no wellbores have been identified for corrective action and no corrective action schedule is required, if additional evaluation efforts result in the identification of wellbores that require corrective action, CTV will notify the EPA and communicate a corrective action plan and schedule.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

4. A review of the full suite of water quality data collected from monitoring wells in addition to CO2 content/saturation (to evaluate the potential for unanticipated reactions between the injected fluid and the rock formation).

5. Review and submission of any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.

6. Reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation). A report describing the comparison of the modeling results will be provided to the EPA with a discussion on whether the results are consistent.

7. Description of the specific actions that will be taken if there are discrepancies between monitoring data and prior modeling results (e.g., remodel the AoR, update all project plans, perform additional corrective action if needed, and submit the results to EPA).

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Changes in pressure or injection rate that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

2. Difference between the computation modeling and observed plume development:

    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation reservoir that are not related to well integrity.

b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results with a deviation greater than +-10% from the Base Case.

c. Any other activity prompting a model recalibration.

3. Seismic monitoring anomalies within two miles of the injection well that are indicative of:

    a. The presence of faults near the confining zone that indicates propagation into the confining zone.

    b. Events reasonably associated with CO_2 injection that are greater than M3.5.

2. Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.

3. Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).

4. Initiation of competing injection projects within the same injection formation within a 1-mile radius of the injection well (including when additional CTV injection wells come online);

5. A significant change in injection operations, as measured by wellhead monitoring;

6. Significant land-use changes that would impact site access; and

7. Any other activity prompting a model recalibration.

CTV will discuss any such events with the UIC Program Director as soon as possible to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan within six months of the triggering event.

ATTACHMENT C: TESTING AND MONITORING PLAN – 353XC-35R
40 CFR 146.90

Elk Hills 26R Storage Project

Facility Information

Facility Name: Elk Hills 26R Storage Project
353XC-35R

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Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Comments
Attachment C – TM 353XC-35R	1	09/30/2023	
Attachment C – TM 353XC-35R	2	09/30/2023	Addition of air monitoring.

The Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills 26R storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the CO_2 within the storage zone, supporting AoR re-evaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

Quality Assurance Procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the Appendix to this Testing and Monitoring Plan.

Reporting Procedures

CTV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

CTV will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a). Samples will be collected and analyzed quarterly, starting three months after the date of authorization of injection and every three months thereafter.

The anthropogenic CO_2 will be sourced from:

- Initial onsite emissions:
    - Lone Cypress blue hydrogen plant, up to 200,000 tonnes per annum
    - Elk Hills field gas treatment (pre-combustion for Elk Hills Power Plant), up to 200,000 tonnes per annum
    - Avnos Direct Air Capture (DAC), up to 1,500 tonnes per annum
- Future emission Sources:
    - CalCapture Elk Hills 550 MW natural gas power plant (post combustion), renewable fuel plants, steam generators post combustion and other power plants / industrial sources in the area.

CO_2 injectate from these sources has been incorporated into Table 1 for injectate sampling. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

Sampling Location and Frequency

CO_2 injectate samples will be taken for each injection source and between the final compression stage and the wellhead. Sampling will take place three months after the commencement of injection and every three months thereafter. Sampling process will follow the procedures below.

CTV will increase the frequency and collect additional samples if the following occurs:

1. Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source; and
2. Facility or injector downtime is greater than thirty days.

Analytical Parameters

CTV will analyze the water content and injectate the constituents identified in Table 1 using the methods listed. An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 1. Summary of analytical parameters for CO_2 stream.

Parameter	Analytical Method(s)
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD
Carbon Monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)
Total Hydrocarbons	ISBT 10.0 THA (FID)
Ammonia	ISBT 6.0 (DT)
Ethanol	ISBT 11.0 (GC/FID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Methane, Ethane, Ethylene	ISBT 10.1 (FID)
Hydrogen Sulfide and Sulfur Dioxide	ISBT 14.0 (GC/SCD)
CO_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
δ13C	Isotope ratio mass spectrometry
Water Vapor	ISBT 3.0

Sampling Methods

Stream sampling will occur for each required CO2 analysis and in the last compressor station prior to being sent to the injector. A sampling station will be installed to facilitate collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a full-service laboratory in Bakersfield, 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 4.

Zalco has a chain of custody procedure that includes the following.

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

For each required CO_2 analysis, CTV will report the time each sample was taken, a tabulation of all CO_2 stream analyses (including any quality assurance/quality control samples), an interpretation of the results, any identified changes and explanation of any data gaps.

Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

CTV will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring Devices, Location, and Frequency

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table. Depths of downhole continuous monitoring equipment are specified for each well and labeled in the Appendix_26R - Injection & Monitoring Well Schematics document.

Monitoring for the parameters, except for annulus fluid volume, will be continuous with a 10 second sampling and 30 second recording frequency for both active and shut-in periods. This will be adequate to monitor for changes in the wellbore and the reservoir.

Table 2. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface Downhole 345C-36R: 5690'(MD) 353X-35R: 6390' (MD) 363-27R: 6290' (MD) 373-35R: 7010' (MD)	10 seconds	30 seconds

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection rate	Flowmeter	Surface	10 seconds	30 seconds
Injection volume	Calculated	Surface	10 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	10 seconds	30 seconds
Annulus fluid volume		Surface	4 hours	24 hours
Temperature	Temperature Gauge	Surface Downhole 345C-36R: 5690'(MD) 353XC-35R: 6390' (MD) 363C-27R: 6290' (MD) 373-35R: 7010' (MD)	10 seconds	30 seconds
Temperature	DTS	Along wellbore to packer	10 seconds	30 seconds

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Injection Rate and Pressure Monitoring

Injection pressure, temperature and flow rate will be continuously monitored and recorded by the Elk Hills Central Command Facility (CCF). The injection pressure will be measured and recorded using pressure gauges at surface and downhole. The injectate temperature will be measured with a temperature gauge at the surface. The injection rate will be measured with a Coriolis flowmeter. The meter will be calibrated annually for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent. Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable bottomhole injection pressure. Pressure and temperature gauges will be calibrated annually. Table 6 of the QASP provides operating range and precision specifications.

Calculation of Injection Volume and Mass

The volume and mass of CO_2 injected into the Monterey Formation 26R will be calculated from the injection flow rate and CO_2 density. Density of CO_2 injected into the Monterey Formation 26R will be calculated using PVTP, a fluid thermodynamics package, developed by Petroleum Experts Ltd. PVTP is an industry standard software package that has been used extensively in CO_2 EOR applications to accurately model and match CO_2 PVT properties over a wide range of temperatures and pressures.

Annular Pressure Monitoring

Annulus pressure is monitored continuously to ensure integrity of the downhole packer, tubing, and casing. CTV will monitor the casing-tubing pressure continuously (every 10 seconds) using an electronic pressure gauge. The annulus will be filled with a non-corrosive brine with corrosion inhibitor. The casing-tubing annulus pressure for injection wells 373-35R, 345C-36R, 353XC-35R, 363C-27R will be maintained with at least 100psi at surface, as stated in the injection well operating procedure documents. Monitoring wells will be operated with 100 psi positive annular pressure at surface.

Failure to maintain >100 psi consistently could be an indication of internal or external mechanical integrity failure, provided that thermal (such as material contraction due to cooling) and pressure (such as ballooning due to increasing tubing pressure) transient effects of normal operational changes are properly diagnosed as acceptable deviations. CTV will notify EPA if (1) pressure decreases to 0 psig and cannot be explained by operational conditions, or (2) pressure drops below 100 psi threshold and cannot be maintained or stabilized after three attempts. Additionally, CTV will notify EPA if pressure increases above 1000 psi and cannot be explained by operational conditions.

Corrosion Monitoring 40 CFR 146.90(c)

CTV will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description below.

Monitoring Location and Frequency

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. The corrosion coupons will be installed in the pipeline that feeds CO_2 injectate to the injectors.

Sample Description

Samples of the materials used in the construction of the pipeline, injection wells, and monitoring wells that are directly in contact with CO_2 injectate will be monitored for corrosion. Corrosion coupons of the representative materials shown in Table 3 will be weighed, measured, and photographed prior to installation directly upstream of the wellhead. For well 373-35R, the wellbore materials exposed and in direct contact with injected CO_2 include the N-80 grade long string casing below the packer and the CRA tubing. These casing materials will be included in the corrosion coupon monitoring and are presently included in Table 3. General construction materials for pipeline, tubing and wellhead are shown in Table 3. Materials of construction will be reaffirmed after well and pipeline construction and prior to injection, as part of pre-operational testing. Subsequently, corrosion coupons consistent with final well construction materials will be used for corrosion monitoring.

Table 3. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Casing	N-80 steel (373-35R injection well) K-55 steel (341-27R, 328-25R monitoring wells) Chrome alloy consistent with final well construction for new drill wells
Tubing	Chrome alloy consistent with final well construction
Packer	Chrome alloy consistent with final well construction
Wellhead	Chrome alloy consistent with final well construction

Sample Handling and Measurement

Upon collection, the coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The samples will be handled and assessed in accordance with NACE TM0169/G31 and/or EPA 1110A SW846. Monitoring results will be documented and submitted to the EPA as per 40 CFR 146.91 (a)(7). Table 5 of the QASP document provides detection limit/range and precision.

A detected corrosion rate of greater than 0.3 mils/year will initiate consultation with the EPA. In addition, a casing inspection log may be run to assess the thickness and condition of the casing if the corrosion rate exceeds 0.3 mils/year. CTV will continually update the corrosion monitoring plan as data is acquired.

Above Confining Zone Monitoring

CTV will monitor water quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). The Etchegoin and Tulare Formations are permeable reservoirs above the confining zone.

Etchegoin Formation Monitoring

The Etchegoin Formation is between the Reef Ridge confining zone and the Upper Tulare USDW and will dissipate CO_2 injectate that may migrate upward from the injection zone. The Etchegoin Formation is continuous across the AoR and will be monitored continuously for pressure and temperature changes. Figure 1 shows the location of 355X-26R and the shallow groundwater monitoring well. The well is suitable and appropriate to adequately monitor for pressure and temperature changes within the first porous and continuous sand above the sequestration zone. This sand is present from 4,063’ – 4,087’ MD in 355X-26R.

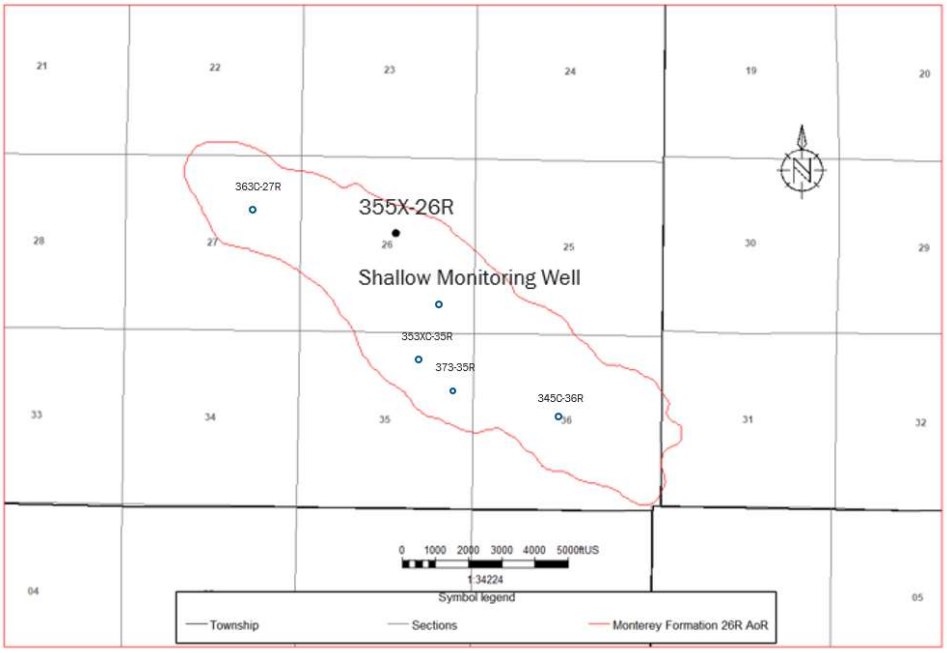


Figure 1: Above confining zone monitoring wells.

The effect of potential leakage from the Monterey Formation to the Etchegoin Formation is an increase in reservoir pressure and decrease in temperature of the Etchegoin. Additionally, potential leakage will create compositional changes detectable with fluid sampling and geochemical monitoring. Pre-injection geochemical composition will be established from baseline water analysis acquired within the Etchegoin Formation during pre-operational testing.

Tulare Formation Monitoring

Monitoring in the Upper Tulare will include pressure, temperature, and fluid sampling. Leakage to the Tulare Formation would increase the reservoir pressure and change the composition of the formation water (increased CO_2 concentration). The Upper Tulare is unsaturated in the AoR. The Upper Tulare Formation will be monitored between 400' – 450' MD in the shallow monitoring well that will be drilled specifically for this project.

Pre-injection geochemical composition will be established from baseline water analysis acquired within the Tulare Formation during pre-operational testing. Subsequent results will be compared against these baseline results for significant changes or anomalies. pH will be monitored as a key indicator of CO_2 presence.

Additional groundwater monitoring wells will be drilled to assess and monitor the Upper Tulare USDW if the following occurs:

1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation 26R CO_2 injection.

2. Upper Tulare Formation pressure or composition changes due to Monterey Formation 26R CO_2 injection.

Monitoring Methods, Location, and Frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well with respect to the AoR. The wells are located within the Elk Hills Oil Field, and CTV owns the surface and mineral rights.

Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	Shallow Water Monitoring Well	Pump	–400’ - 450' MD/VD	Quarterly
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’ - 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’ - 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	400' - 500' MD/VD in each well	Continuous
Etchegoin	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Quarterly
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' 4788' - 4811' 4205' - 4226' (all MD/VD)	Continuous

Analytical Parameters

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 5. Summary of analytical and field parameters for water samples from the USDW monitoring well and the Etchegoin monitoring well.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)
Dissolved CO_2	Coulometric titration, ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Sampling Methods

Samples will be collected using the following procedures:

1. Depth and elevation measurements for water level taken.
2. Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
3. Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
4. Samples preserved and sent to lab as per chain of custody procedure.
5. Closure of well.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by Zalco, a full-service state certified laboratory in Bakersfield, approximately 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3. Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

Internal Mechanical Integrity Testing

A Class VI well has mechanical integrity if there is no significant leak in the casing, tubing, or packer. CTV will conduct an initial annulus pressure test on all injection wells and on monitoring wells that penetrate the confining zone and are configured with tubing and a packer. Additionally, any time the packer is replaced or reset, a SAPT will be performed. The injection and monitoring wells will be configured with continuous recording devices to monitor the pressure on the annulus between the tubing and the casing, and annulus fluid volumes will be measured and recorded. These actions satisfy the requirements of 40 CFR 146.88(e)(1) and 40 CFR 146.89(b).

Standard Annular Pressure Testing (SAPT)

Pascal's Law states that any pressure applied to a fluid filling a closed vessel will be transmitted undiminished, throughout the vessel. This is the basis for the SAPT as the primary means to determine if a well's casing, tubing, packer, and wellhead (the annulus system) are liquid tight. Because the annulus system is not an isolated system, the measured pressure applied may not be constant throughout time. The temperatures along the wellbore must change as injection rates and temperatures change because of heat exchange between injectate and the surrounding formations. When the well is shut in, the wellbore may cool or become warmer as the well materials are subjected to the natural geothermal temperatures, which will result in expansion or contraction of liquid in the annulus. Because liquids are effectively incompressible, annular pressure is expected to fluctuate due to changes in the tubing such as contraction, elongation, and ballooning during transient injection or shut-in periods.

The procedure for conducting SAPT is as follows:

1. CTV will notify the Director to provide the opportunity to witness the testing.

2. Completely fill the tubing/casing annulus with packer fluid consisting of weighted brine and appropriate additives such as corrosion inhibitors, oxygen scavengers, and biocide. The volume to fill should be measured and recorded. The annulus liquid should be temperature stabilized prior to conducting the test.

3. The annulus will be pressurized to a surface pressure which exceeds the maximum injection pressure by at least 100 psi unless an alternate pressure is approved by the EPA Director.

4. Following pressurization, the annular system will be isolated from the source of pressure by a closed valve, or it will be disconnected entirely.

5. The isolation will be maintained for no less than one hour. During this time, pressure measurements will be recorded in at least one-minute intervals.

6. After the SAPT is concluded, the valve to the annulus should be opened to bleed down the pressure. The liquid returns from the annulus should be measured and recorded.

Monitoring wells that do not have a specified maximum tubing pressure will be tested to 1000 psi initially. As reservoir pressure increases during injection and tubing pressure is continuously monitored, SAPT test pressure will be reconsidered. When tubing pressure approaches 100 psi less than the initial SAPT test pressure, i.e. 900 psi, the SAPT will need to be performed again unless an alternative method or test pressure is approved by the EPA Director. Table 6 provides information on the frequency and test pressures for injection and monitoring wells within the project.

Table 6. Internal MIT requirements

Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)	Maximum Injection Pressure (psi)	Test Pressure (psi)
Standard Annular Pressure Test (SAPT)	373-35R[1]	Casing/tubing annulus from surface to packer	Once, upon initial installation	Any time packer is replaced or reset	Not Applicable	1992	2092
	345C-36R[1]					1888	1988
	363C-27R[1]					2020	2120
	353XC-35R[1]					1997	2097
	355X-26R[2]				Any time packer is replaced or reset	--	1000
	341-27R[3] 328-25R[3] 376-36R[3]					--	1000

Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)	Maximum Injection Pressure (psi)	Test Pressure (psi)	
Annular Pressure	373-35R[1] 345C-36R[1] 353XC-35R[1] 363C-27R[1]	Wellhead	Continuous	Continuous	Not Applicable	--		-
	355X-26R[2] 341-27R[3] 328-25R[3] 376-36R[3]				Continuous			-

[1] *CO2 injection well*
[2] *Above Zone monitoring well*
[3] *Injection Zone monitoring well*

The interpretation of the SAPT will compare the pressure change during the test once the initial pressure has stabilized. If the change (gain or loss) in pressure is less than 3% of the test pressure, the well has demonstrated mechanical integrity, pursuant to 40 CFR 146.8(a)(1). If the change in pressure (gain or loss) exceed 3% of the test pressure, the well has failed to demonstrate mechanical integrity.

CTV will utilize an EPA-approved Annular Pressure Test form to record the results of the SAPT if the test is not witnessed by the EPA. If the test indicates the well has demonstrated mechanical integrity, the test form and raw pressure data (original chart recordings or a digitized log of pressure and time) will be provided to the EPA. If the test indicates a failure of mechanical integrity in an injection well, the well will be shut in, no injection will occur, and the EPA Director will be notified within 24 hours.

Continuous Monitoring of Annular Pressure

Injection and monitoring wells will record continuous annular pressure such that internal MIT can be confirmed in real-time based on the interpretation of this data. CTV will identify and investigate pressure deviations that do not align with changes to operating conditions or temperature effects due to seasonal variation. In the event of a casing leak into a permeable zone, the pressure will normally fall. In the event of a tubing or packer leak, the annulus pressure will track injection pressure, although the pressures are not likely to be equal due to friction and density differences.

This data will be provided in the semi-annual report to demonstrate ongoing internal mechanical integrity.

External Mechanical Integrity Testing

CTV will conduct mechanical integrity testing on each injection well at least once per year to demonstrate external mechanical integrity using an approved test method per 146.89(c). CTV will, at a minimum, perform a temperature log on the injection wells.

Testing Methods

Table 7 shows testing methods that may be utilized for MIT on injection and monitoring wells associated with this project. CTV will utilize an approved MIT technique, such as temperature logging with wireline, oxygen-activation logging, or noise logging on CO_2 injection wells as the primary method. While DTS may not be considered an approved temperature logging method for injection well MIT, CTV may seek Director approval in the future prior to using this method. If CTV elects to conduct an alternate MIT, notification including a description of the proposed testing method and procedure will be sent to the EPA for approval.

Since temperature decay logs require injection to cool the wellbore and near wellbore region prior to logging, monitoring wells cannot be tested for external MIT without approval to inject fluid. Additionally, injecting fluid such as H_2O or CO_2 for the purpose of testing may be undesirable for other reasons. Therefore, MIT on monitoring wells will not be conducted using temperature decay logging. Instead, another approved method under 40 CFR 146.89(c) may be utilized, or DTS may be proposed for EPA Director approval for monitoring well MIT.

Table 7. External Mechanical Integrity Testing Methods

Test Description	Location
Temperature Decay Log	Along wellbore using wireline well log
Distributed Temperature Log (DTS)	Along wellbore using fiber optic sensing (DTS), continuous
Oxygen Activation Log (OA)	Along wellbore using wireline well log
Noise Log	Along wellbore using wireline well log

Description of Temperature Logging with Wireline

EPA has specific requirements that must be satisfied for a temperature log to be considered valid for MIT as specified by 40 CFR 146.89(c). CTV will utilize the following procedures and comply with EPA guidance to ensure testing requirements are achieved.

1. Stabilize injection for 24 hours prior to running the temperature log.

2. Run an initial temperature survey logging down from at least 200 feet above the base of the Reef Ridge Shale to the deepest point reachable in the well, while injecting at a rate that allows for safe operations. The temperature sensor should be located as close to the bottom of the tool string as possible. The optimal wireline speed is 30 ft/min, and the acceptable range is between 20 and 50 feet per minute.

3. Shut in the injection to the well and run multiple temperature surveys with 4 hours between runs. The minimum shut-in time following the initial temperature log is 12 hours total, and the superimposed logging passes should be at least 4 hours after the injection pass.

4. Assess the time lapse temperature profiles against the baseline injection survey to identify temperature anomalies that may indicate a failure of well integrity. Evaluate the data to determine if additional passes are needed for interpretation. If CO_2 migration is interpreted in the topmost section of the logging pass such that the top of the migration pathway cannot be identified, additional logging runs over a shallower interval will be required to find the top of migration.

5. Both the printed or digital log and the raw data for at least two logging runs should be provided to the EPA. The printed or digital log should have the following:

    a. The heading must be complete and include all pertinent information to identify the well, well location, date of the survey, etc.

    b. Vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs.

    c. Horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.

    d. The right-hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.

    e. The left-hand track must contain a casing collar log, a legible lithology log such as spontaneous potential (SP) or gamma ray, and identification of the base of USDW, if present.

Description of Temperature Logging using Distributed Temperature Sensing (DTS)

DTS is a fiber optic continuous temperature monitoring system that will be installed in injection and monitoring wells to measure wellbore temperature in real time from the annulus along the length of the tubing. Like a temperature log, the DTS temperature data can be used to assess the internal and external mechanical integrity of injection and monitoring wells. Successful comparisons of DTS temperature logs to wireline temperature logs have been well documented and validate the use of DTS as a temperature log for mechanical integrity testing. By continuously monitoring DTS data, this testing method provides an early detection of temperature changes through the capability to continuously monitor MIT in Realtime, making this technology potentially superior to wireline temperature logging.

The impact to health, safety, and environment of DTS temperature logging is significantly improved in comparison to wireline temperature logging operations. Because the DTS system is installed at the time of well construction or workover, no crew is required to be present at the

wellsite. The following procedure can be performed to acquire a temperature log using DTS for mechanical integrity analysis for an injector:

1. Establish baseline temperature profile that defines the natural gradient along the well prior to injecting.

2. During injection, record the temperature profile for 6 hours prior to shutting in the well.

3. Stop injection and record the temperature for sufficient time to allow cooling.

4. Start injection and record the temperature profile for 6 hours.

5. Compare the baseline analysis to the time-lapse data for assessment of temperature anomalies that may indicate a well failure.

Description of Passive Temperature Logging using DTS

DTS can be used for passive external mechanical integrity monitoring on monitoring wells. This solution has advantages compared to wireline temperature logging on monitoring wells in liquid-depleted reservoirs. DTS will be installed on the tubing string from surface to the packer on the injection wells, the injection zone monitoring wells, and the above zone monitoring well. DTS will detect temperature changes along the wellbore if external mechanical integrity is compromised.

On injection wells, temperature changes associated with external fluid migration will be masked due to the dominating impact of injectate temperature on the wellbore materials. However, during shut-in periods immediately following sustained injection, when warm back can be observed along the length of the DTS fiber, migration pathways of fluids at non-geothermal temperature gradients can be identified. Additionally, lack of deviation from temperature reversion to the geothermal gradient is a demonstration of external mechanical integrity. It is appropriate for the DTS fiber to monitor temperature throughout and above the confining layer, and the configuration of DTS fiber as described above, from surface to the top of the packer, is sufficient to monitor injection wells for external MIT above the injection zone.

On the injection zone monitoring wells, the DTS string will monitor the confining layer and all above layers in real-time. If dense phase CO_2 were to breach the injection zone and migrate upward, the warmer CO_2 would cause a discernible temperature anomaly. If the CO_2 were to change phase to gas phase, a cooling effect would be observed. The high frequency and volume of data is superior to wireline temperature logging, significantly enhancing diagnosis capability and reaction time. DTS is not required to be deployed through the injection zone to assess external MIT within and above the confining layer.

Description of Noise Logging

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. Noise logging may be carried out while injection is

occurring. If ambient noise is greater than 10 mv, injection will be halted. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Run a noise survey from top of Tulare to the deepest point reachable in the Monterey Formation while injecting at a rate that allows for safe operations.

3. Make noise measurements at intervals of 100 feet to create a log on a coarse grid.

4. If any anomalies are evident on the coarse log, construct a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.

5. Make noise measurements at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing:

   a. The base of the lowermost bleed-off zone above the injection interval and

   b. The base of the lowermost USDW.

6. Additional measurements may be made to pinpoint depths at which noise is produced

Description of Oxygen Activation Logging

To ensure the mechanical integrity of the casing, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. OA logging may be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Conduct a baseline Gamma Ray (GR) log and Casing Collar Locator (CCL) log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool. Gamma Ray Log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.

3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches and less than 13- 3/8 inches.

4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.

5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a "no vertical flow behind the casing" section of the well to ensure accurate, repeatable tool response and for measuring background counts.

6. Take, at a minimum, a 15-minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 feet above the injection interval so that turbulence does not affect the readings.

7. Take, at a minimum, a 15-minute stationary reading at a location approximately midway between the base of the lowermost USDW and the confining interval located immediately above the injection interval.

8. Take, at a minimum, a 15-minute stationary reading adjacent to the top of the confining zone.

9. Take, at a minimum, a 15-minute stationary reading at the base of the lowermost USDW.

10. If flow is indicated by the OA log at a location, move up hole or downhole as necessary at no more than 50-foot intervals and take stationary readings to determine the area of fluid migration.

Pressure Fall-Off Testing

Pressure falloff tests are used to measure formation properties in the vicinity of the injection well, and the intent of periodic testing is to monitor for any changes in the near-wellbore environment that may impact injectivity or increase pressure. CTV will perform pressure fall-off tests on each injector during the injection phase every five years as described below to meet the requirements of 40 CFR 146.90(f). CTV will refer to EPA Region 9 UIC Pressure Falloff Requirements for planning and conducting the testing as well as preparing and submitting the monitoring report.

Testing Details

The following procedure will be followed:

1. Injection rate will be held constant for at least one week prior to shut in. The injection pressure will be high enough to produce a pressure decrease upon shut in that will result in valid test data for derivative analysis. The maximum operating pressure will not be exceeded.

2. The injection well will be equipped with surface and downhole pressure and temperature gauges. Bottomhole gauges will have surface readout capabilities and will be the primary source of pressure data for analysis because these gauges will be least affected by wellbore fluid effects. Prior to and throughout the shut-in period, the gauges will collect pressure data in 10 second intervals, which is sufficient and appropriate for pressure-transient analysis. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

3. The injection well will be shut in at the wellhead to minimize wellbore storage effects from compressible fluids. The injection rate of the offset injector will be held constant during the test. Accurate records of offset wells completed within the same zone will be maintained and considered in the interpretation.

4. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage. This desired radial flow regime is identified by a zero slope of the pressure derivative through pressure transient analysis. The data can be analyzed in real time because of the surface readout capabilities of the pressure gauges and can therefore ensure a complete and adequate test before restarting injection.

5. Interference testing may be conducted at the conclusion of the falloff test to demonstrate communication between the wells. The injection rate of the offset injector would be increased or decreased multiple times to create pressure pulses that can be observed by the shut in well.

6. The interpretation of the pressure transient dataset will be performed by a trained engineering professional using proven industry standard methodologies. Anomalies that are identified from the interpretation will be investigated.

7. A report containing the pressure fall-off data and interpretation of the reservoir pressure will be submitted to the EPA in the next semi-annual report. The report will follow the guidance of the EPA Region 9 UIC Pressure Falloff Testing Requirements document.

Carbon Dioxide Plume and Pressure Front Tracking

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

Plume Monitoring Location and Frequency

Figure 2 shows the location of the wells that will monitor the CO_2 plume directly in the targeted 26R reservoir. These wells will actively monitor the development of the CO_2 plume upon the initiation of injection. If the plume development is not consistent with computation modeling results, CTV will assess whether additional monitoring of the plume is necessary. Determination for plume monitoring changes will be made in consultation with the UIC Program Director and would trigger an AoR reevaluation, per the AoR and Corrective Action Plan.

Based on the Base case model, the CO2 plume is expected to arrive at the monitoring well locations at approximately the – 7th year of injection for 376-25R, 8th year of injection for 328-25R and the 9th year of injection for 341-27R.

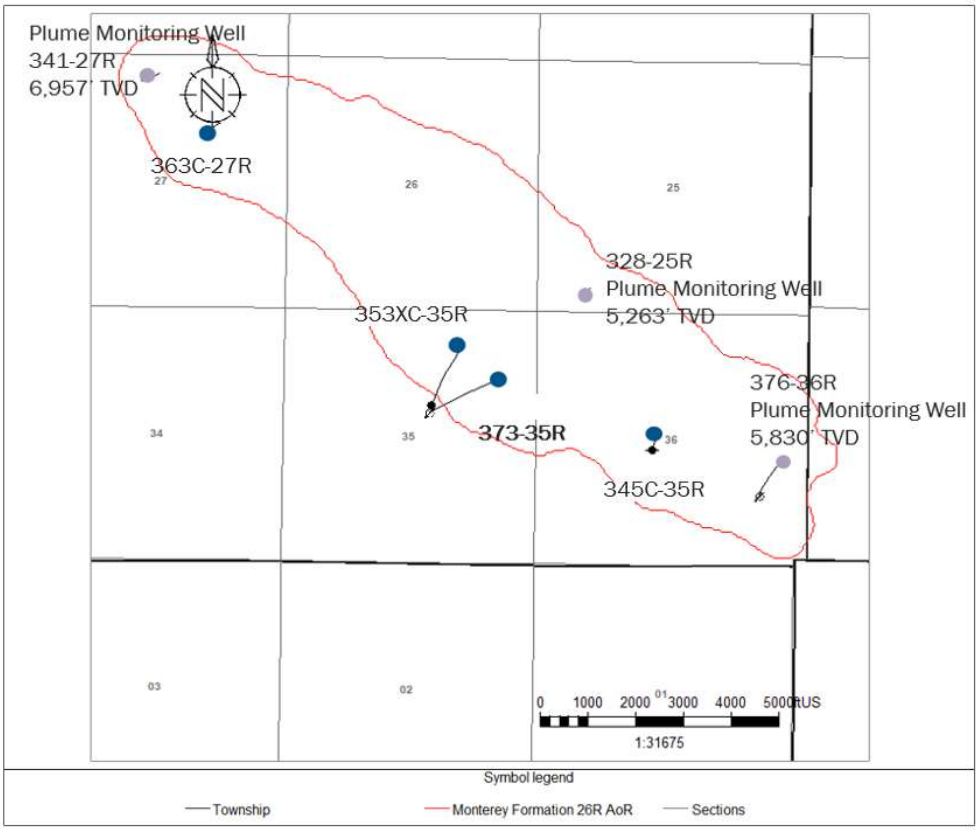


Figure 2: Monterey Formation 26R sequestration reservoir monitoring wells, with true vertical depth in feet of the monitoring interval.

Table 8 presents the methods that CTV will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 9. Detection limits, precisions, and quality control requirements for these methods are presented in Table 3 of the QASP.

Table 8. Plume Monitoring Activities

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Formation 26R	Fluid Sampling	341-27R	6981' - 7237' MD	Once	Quarterly	Annual
		Pressure		6910' MD	Baseline	Continuous	Continuous
		Temperature		6910' MD	Baseline	Continuous	Continuous
		Fluid Sampling	328-25R	5268' - 5800' MD	Once	Quarterly	Annual

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)
	Monterey Formation 26R	Pressure		5188' MD	Baseline	Continuous	Continuous
		Temperature		5188' MD	Baseline	Continuous	Continuous
	Monterey Formation 26R	Fluid Sampling	376-36R	5832' - 6815' MD	Once	Quarterly	Annual
		Pressure		5760' MD	Baseline	Continuous	Continuous
		Temperature		5760' MD	Baseline	Continuous	Continuous
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	341-27R	6981' - 7237' MD	Baseline	Every year from start of injection	Every 5 years
			328-25R	5268' - 5800' MD			
			376-36R	5832' - 6815' MD			

Table 9. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510

Parameters	Analytical Methods
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Plume Monitoring Details

Fluid sampling, pressure monitoring, and temperature monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but more importantly, the CO_2 content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in Table 9.

The DTS from the monitoring wells will provide continuous temperature from packer to surface.

As discussed in the AoR and Corrective Action Plan, 72% of the post-shut-in injected CO_2 will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and formation fluid density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand CO_2 saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every year during the injection phase.

CTV does not plan to conduct VSP monitoring for the depleted 26R oil and gas reservoir. The resolution for the CO2 plume using VSP will be limited due to noise and limited density contrast between the reservoir before and after CO2 injection. Seismic monitoring works especially well in thick, brine filled formations and may not be appropriate for depleted gas reservoirs (page 106 Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance). In addition, the unsaturated Tulare Formation and depleted gas San Joaquin Formation will limit VSP seismic wave responses.

Pressure Front Monitoring Location and Frequency

The aerial extent of plume development in the Monterey Formation 26R reservoir will reach the reservoir boundaries early in the injection phase. Because the reservoir is pressure-depleted, injected CO_2 will quickly fill the available pore space. Table 8 indicates that pressure front monitoring will coincide with direct monitoring of the CO_2 plume using the monitoring wells identified and will support CO_2 plume model and AoR model validation. Monitoring well locations with respect to plume development through time are shown in Figure 3.

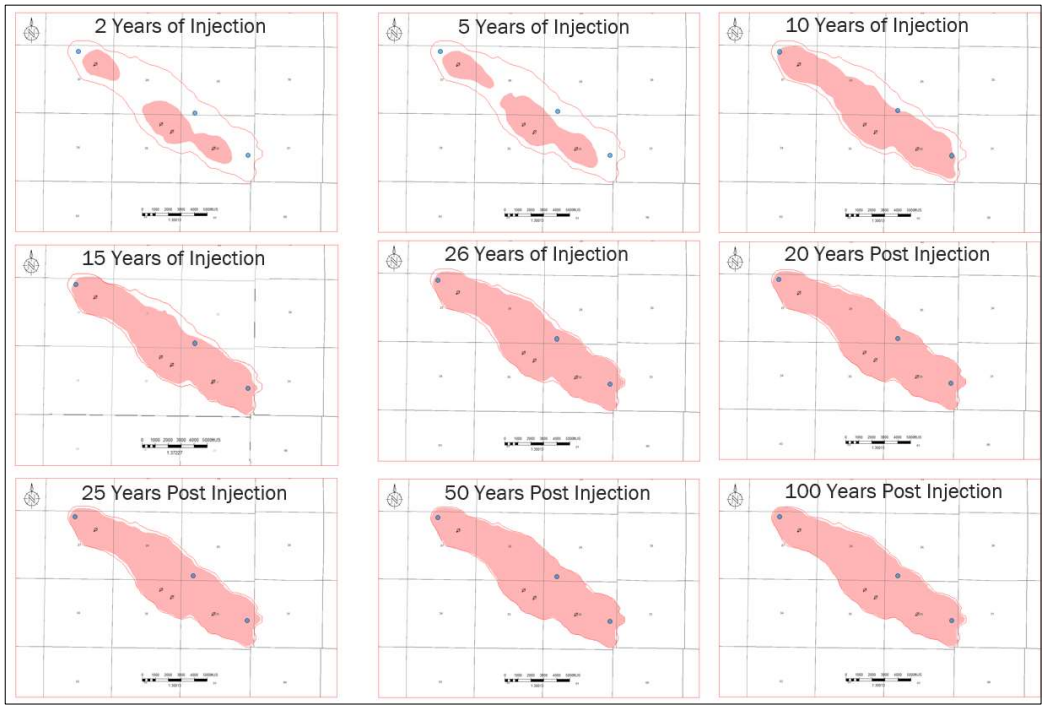


Figure 3: Monitoring well location with maps showing plume development through time from computational modeling.

Monitoring well 328-25R pressure development based on computational modeling is shown in Figure 4. The average pore volume reservoir pressure stabilizes 1 year after the end of injection. This is due to the majority of CO_2 that remains super-critical and low quantity of CO_2 that will be soluble in either the oil or water phases. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

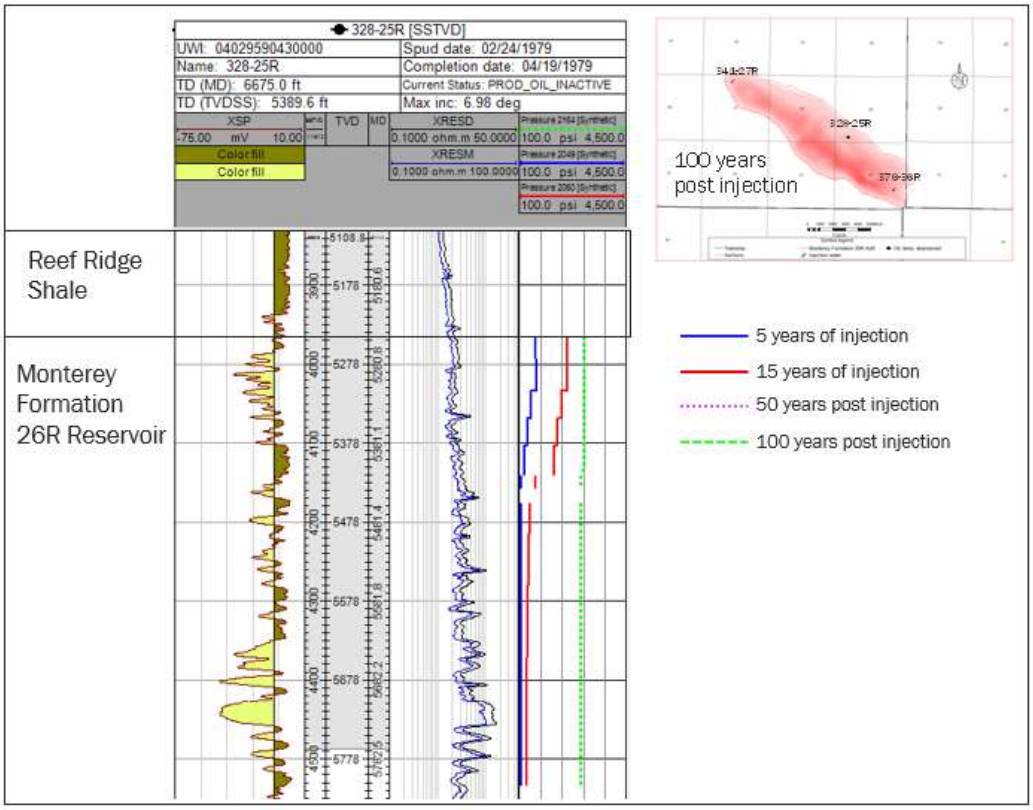


Figure 4: Monitoring well 328-25R showing the pressure increase through time from the computational modeling results.

Pressure Front Monitoring Details

Direct pressure monitoring of the plume will be achieved through installation of pressure and temperature gauges in monitoring wells 341-27R, 328-25R and 376-36R. The depleted Monterey Formation 26R oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 5 shows the pressure in the reservoir post-injection. CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies.

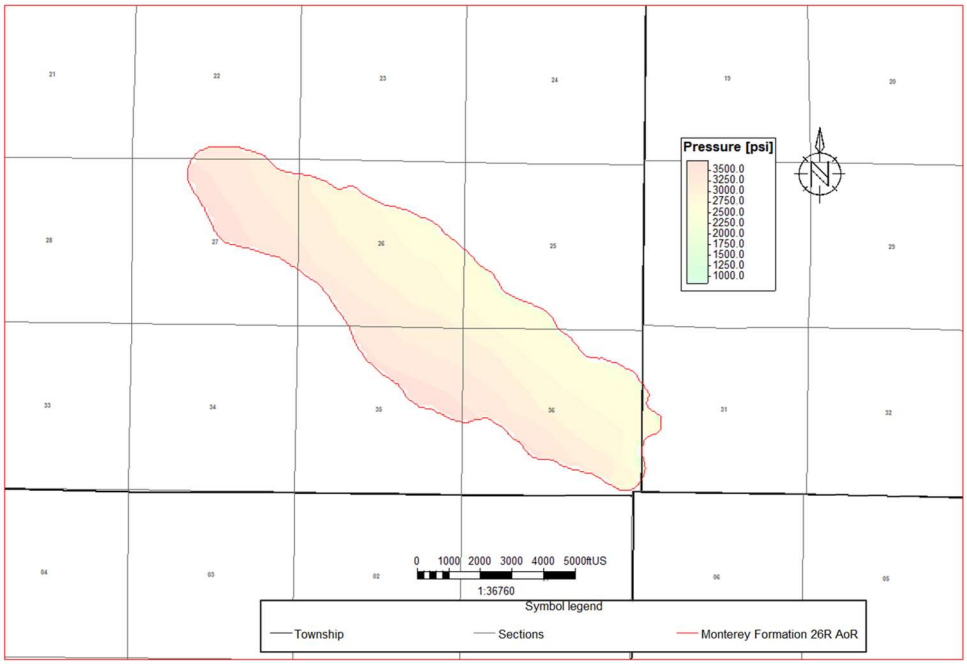


Figure 5: Monterey Formation 26R pressure 50 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.

The modeled pressure increases at monitoring well 328-25R are shown in Figure 4. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

Table 10 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ. Downhole gauge specifications are provided in Table 8 of the QASP document.

Table 10. Pressure-front monitoring activities.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm 26R	Pressure	341-27R	6981' - 7237' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
	Monterey Fm 26R	Pressure	328-25R	5268' - 5800' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
		Pressure	376-36R		Baseline	Continuous

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
	Monterey Fm 26R	Temperature		5832' - 6815' MD	Baseline	Continuous
Other Plume / Pressure-Front Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Baseline	Continuous

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole seismometers in the Elk Hills Oil Field. This network will be implemented to monitor seismic activity near the project site. Direct pressure monitoring of the storage reservoir will be used in conjunction with the passive seismic monitoring to demonstrate that there are no seismic events affecting CO_2 containment.

Specifications of the network are as follows:

- 7 sensor locations (borehole and near surface) with high-sensitivity 3-component geophones (Figure 6)
- Borehole sensors have been deployed (depths shown in Figure 6) to ensure a good quality signal and to minimize noise. A velocity model will be derived from vertical seismic profiles (VSPs), sonic well logs, and check shots.
- The system will be designed with capability of detecting and locating events >M_w 0.0

Baseline Analysis:

The monitoring network has been installed to collect seismicity data to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

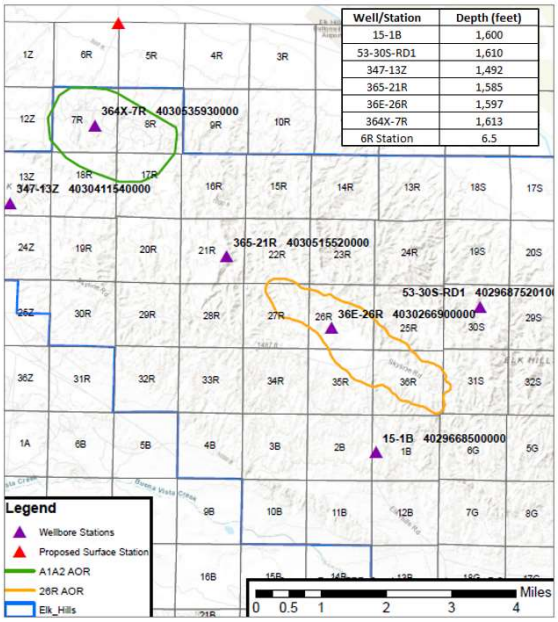


Figure 6: Elk Hills seismic monitoring network station location and depth of geophone sensors.

Monitoring Analysis:

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed continuously.

- Waveform data to be transmitted near real-time via cellular modem or other wireless means and archived in a database

- Event notifications to be automatically sent to required personnel to ensure compliance with CTV's Emergency and Remedial Response Plan

Additionally, CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network. The EPA Director will be notified of seismic activity as per the Emergency and Remedial Response Plan.

Surface Air Monitoring

Surface air monitoring, including broad aerial monitoring and targeted monitoring at wells and pipelines will be conducted.

Continuous Monitoring of AOR

Broad aerial surface air monitoring will be conducted with eddy covariance towers. Eddy covariance towers are a widely used micrometeorological technique for direct high-speed

measurements of the transport of gases, are a recommended component of CCS project surface air monitoring.

Each eddy covariance tower will consist of a solar-powered 3-dimensional sonic anemometer and open-path gas analyzer installed on a stationary tower and will be installed downwind of the prevailing wind direction from potential gas sources. Annual average prevailing wind direction in the vicinity is from the northwest. Proposed tower locations are displayed on Figure 7. Locations were chosen to be downwind (southeast) of the injection wells and surface expression of the simulated CO_2 plumes, to be in locally high topographic locations given the hilly terrain in the project vicinity, and in a location with access for equipment installation and servicing.

Monitoring equipment will be installed at a height of approximately 5 meters (33 feet). In general, the upwind distance represented by the tower height can be determined by the 1:100 rule; in this case with a 5-meter tower height the majority of measured flux will come from an oval-shaped area from near the tower to 500 meters (1,640 feet) upwind.

Gas emission rate is calculated from air density, vertical wind speed, and dry CO_2 mole fraction. Air density fluctuation is assumed to be negligible, wind speed will be measured with the sonic anemometer and CO_2 mole fraction with the gas analyzer. The sonic anemometer will be Campbell Scientific CSAT3 or equivalent, and CO_2 gas analyzer will be LI-COR Biosciences LI-7500A or equivalent. The gas analyzer will be positioned at or slightly below the sonic anemometer level, with a separation distance less than 20 centimeters. Vibration will be minimized by the use of several guy wires attached at the middle of the tower.

Manual cleaning of the gas analyzer will be performed on an as-needed basis when anomalous readings or excessive zero-drift in the data is observed. Factory calibration is assumed to be stable for at least several years and will be checked once per every six months as a precaution.

Data processing will be conducted and will be presented as hourly-averaged CO_2 concentrations and gas emission rates. Detection of anomalous and increasing CO_2 concentrations will lead to eddy covariance tower equipment testing and CARB consultation.

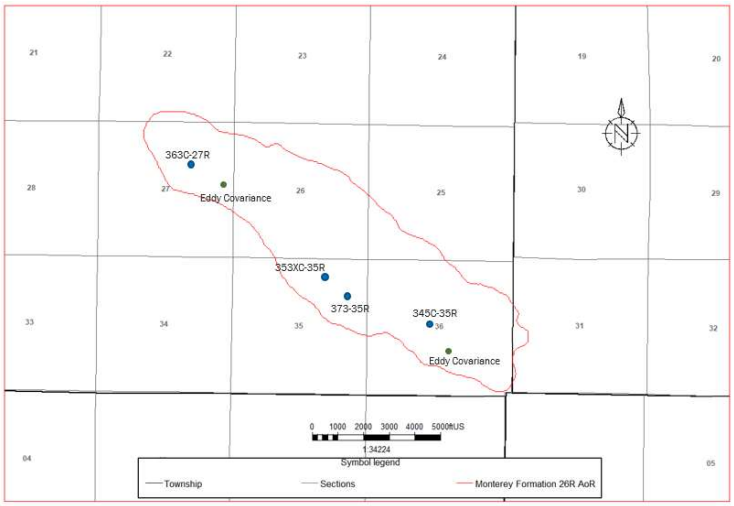


Figure 7: Location of Eddy Covariance monitoring.

Continuous Equipment Monitoring

Surface components of the injection system, including the flowlines and wellheads, will be monitored using equipment that will monitor for elevated CO_2. This leak detection equipment will be integrated with automated warning systems that notify the control center at the central facility, giving the operator the ability to remotely close the valves in the event of an anomalous reading. The central facility uses a SCADA software system to implement operational control decisions on a real-time basis throughout the project to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Monitoring Summary

This proposed monitoring program meets the goals of 40 CFR 146.90(g) by capturing continuous direct measurements of pressure and temperature in the storage reservoir (in-zone), Etchegoin (above zone) and USDW across key points of the AOR, in addition to frequent fluid samples and PNL to track the progress and confinement of the CO_2 plume. This data will also calibrate the dynamic model to predict plume front movement and pressure increase. In addition, the high resolution seismic monitoring network will provide a wide area measurement to indirectly monitor for pressure increase in-zone and above, that can be used in conjunction with the data from the monitoring wells to confirm confinement.

Direct:

The three in-zone monitoring wells are located close to the edges of the AOR, up-dip of the injectors, and thus in the flow direction of the less buoyant injected CO_2. The wells will be continuously measuring pressure and temperature at these locations. The continuous signals of pressure change in the reservoir will be used to update and calibrate the dynamic model and identify any major deviations from the predicted behavior of the reservoir. The continuous temperature measurements will provide data for the arrival of CO_2 at these locations.

In addition to the USDW and Etchegoin monitoring wells, the in-zone monitoring wells will provide confirmation of the confinement of CO_2 to the injection zone by also continuously measuring temperature changes in the Etchegoin and USDW (via DTS). Periodic fluid sampling at these locations will confirm the continuous pressure and temperature data, by providing measurements of CO_2 concentration in the reservoir that can further calibrate the dynamic model. Thus, the direct measurements for the injection zone through these wells will provide adequate special coverage of the development of the plume and pressure front, which can also improve the accuracy of the dynamic model predictions.

The two centrally located monitoring wells in the Etchegoin formation and USDW will continuously measure pressure and temperature in their respective zones, thus providing continuous direct measurements to assess the confinement of the injected CO_2. In addition, the continuous temperature measurements at these two locations, combined with the temperature measurement covering the Etchegoin and USDW at the three in-zone monitoring wells will provide adequate spatial coverage across the AOR to evaluate confinement of CO_2 in the storage reservoir.

Indirect:

PNL at the three in-zone monitoring wells will provide indirect measurement of gas saturation and CO_2 concentration in the injection zone, which will track the progress and confinement of the plume and further calibrate the dynamic model.

The seismic monitoring network will provide an indirect measurement of the pressure increase in the injection zone, the Etchegoin and the USDW. The seismic monitoring network will be sufficient to resolve events greater than 0 magnitude, with a 1,000 ft vertical resolution at the injection depths and above, giving us the ability to differentiate between events in the injection zone versus events in the shallower Etchegoin or USDW. This provides an indirect way to monitor for pressure increases in-zone or above zone via seismic events that could be triggered from pressure changes due to CO_2 injection or fluid migration.

Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan

WELL PLUGGING PLAN

CTV I ELK HILLS 26R PROJECT

Injection Well 353XC-35R

Facility Information

Facility Name: Elk Hills 26R Storage Project

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_353XC-35R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – COP Details_353XC-35R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – COP Details_353XC-35R_V3	3	1/11/23	Revisions made based on questions received from the EPA 01/06/23
Attachment G – COP Details_353XC-35R_V4	4	05/14/2023	Revisions made based on questions received from the EPA 03/2023
Attachment D – Well Plugging Plan_353XC-35R_V5	5	11/29/2023	Separating Construction and Plugging Plans into Separate Attachments

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

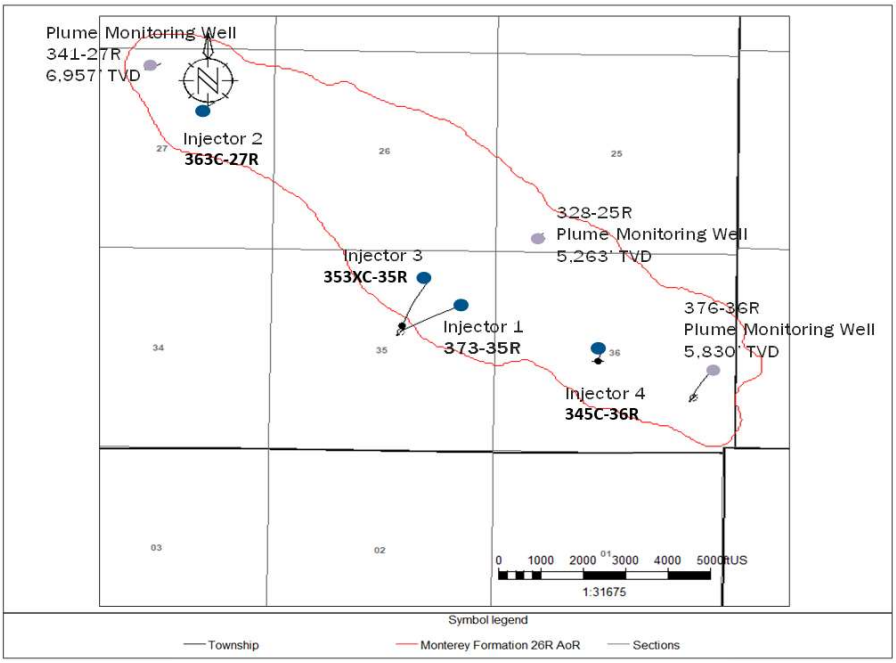


Figure 1: Map showing the location of injection wells and monitoring wells.

Figure 2 and *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Plugging

CTV will conduct injection well plugging and abandonment according to the procedures below. The proposed injection well plugging plan will ensure that the proposed materials and procedures for injection well plugging are appropriate to the well's construction and the site's geology and geochemistry.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The planned external MIT method will be a temperature log or other approved external MIT (Table 1) and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Table 1: External Mechanical Integrity Testing Methods

Test Description	Location
Temperature Decay Log	Along wellbore using wireline well log
Distributed Temperature Log (DTS)	Along wellbore using fiber optic sensing (DTS), continuous
Oxygen Activation Log (OA)	Along wellbore using wireline well log
Noise Log	Along wellbore using wireline well log

Information on Plugs

CTV will use the materials and methods noted in Table 2 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an

effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 2, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures.

Table 2: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	3.92	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft)	8600	2523	1091	39
Sacks of cement to be used (each plug)	168	24	24	5
Slurry volume to be pumped (bbl)	34.41	4.92	4.92	1.02
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	6300	2398	966	14
Bottom of plug (ft)	8600	2523	1091	39
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or CT Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. Wellbore Bullheading will be conducted at appropriate rates so as to ensure no fracturing of the surrounding formation occurs and the cement plugs are not compromised in any way. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

9. Once the fourth cement plug is placed at surface, casing will be cut 5' below ground level. A metal cap will be welded onto the top of the cut casing, stamped with the well name and API. Surface location will then be backfilled and restored to pre-operation conditions.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has <10,000 mg/L TDS):

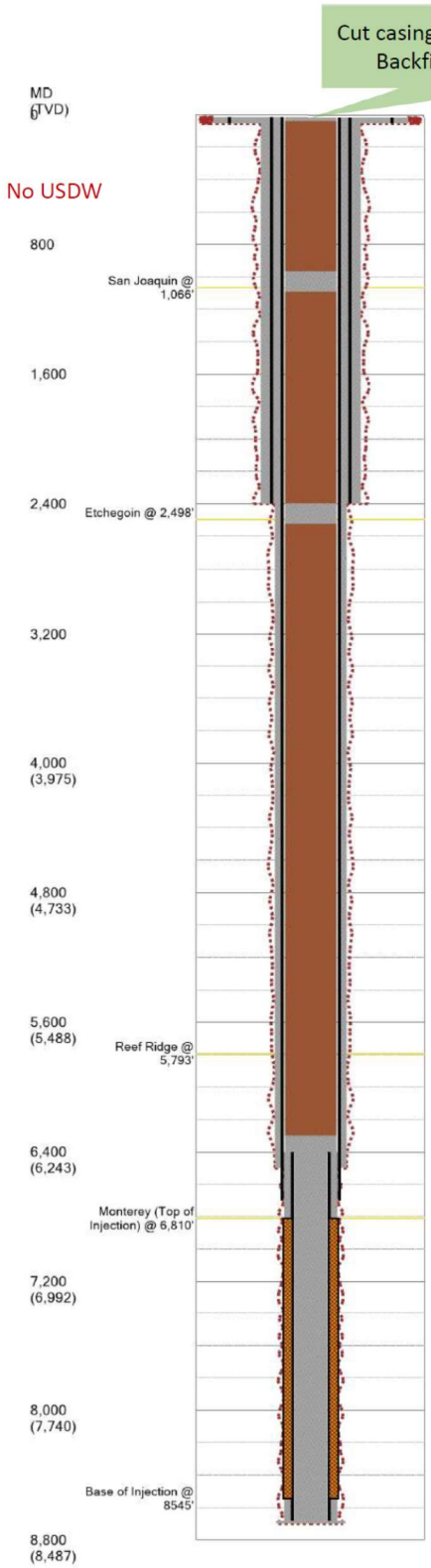
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.

    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits.

In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

  - In 26R, this interval would be located at the top of the San Joaquin Formation.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.



Well	353XC-35R			
Plugs	**Plug 1**	**Plug 2**	**Plug 3**	**Plug 4**
Hole Size (in.)	3.92	6.276	6.276	6.276
Bottom of tubing (ft)	8600	2523	1091	39
Cement Volume (sacks)	168	24	24	5
Slurry Volume (bbl)	34.41	4.92	4.92	1.02
Slurry Weight (lb/gal)	15.8	15.8	15.8	15.8
Top of plug (ft)	6300	2398	966	14
Bottom of Plug (ft)	8600	2523	1091	39
Type of Cement	Class G	Class G	Class G	Class G
Method of placement	Balanced Plug, Retainer, or CT Plug			

Figure 2: Injection Well 353XC-35R, Abandonment Schematic

ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

CTV I Elk Hills 26R Project

Facility Information

Facility name: Elk Hills 26R Storage Project

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment E -PISC_SC	1	01/11/21
Attachment E -PISC_SC V2	2	05/31/22
Attachment E -PISC_SC V3	3	12/21/22

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault 1 LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

Based on the modeling of the pressure front as part of the AoR delineation, pressure at the injection well is expected to stabilize within one year after injection ceases. Injection limits will be based

on the fracture pressure of the Monterey Formation 26R reservoir and final pressure post injection will target the initial reservoir pressure at the time of discovery. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the AoR and Corrective Action Plan.

Discussion

The Monterey Formation 26R reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. This operating strategy was developed to minimize the potential for induced seismicity and to ensure confinement of the injectate.

The maximum pressure differential between the injection wellbore and the depleted Monterey Formation 26R storage reservoir exists prior to the commencement of CO_2 injection. Through time, the injection pressure differential will shrink, until at the time of project abandonment when the reservoir pressure will be at the initial conditions of the reservoir. Figure 1 shows the pressure of the Monterey Formation 26R reservoir through time from computational modeling.

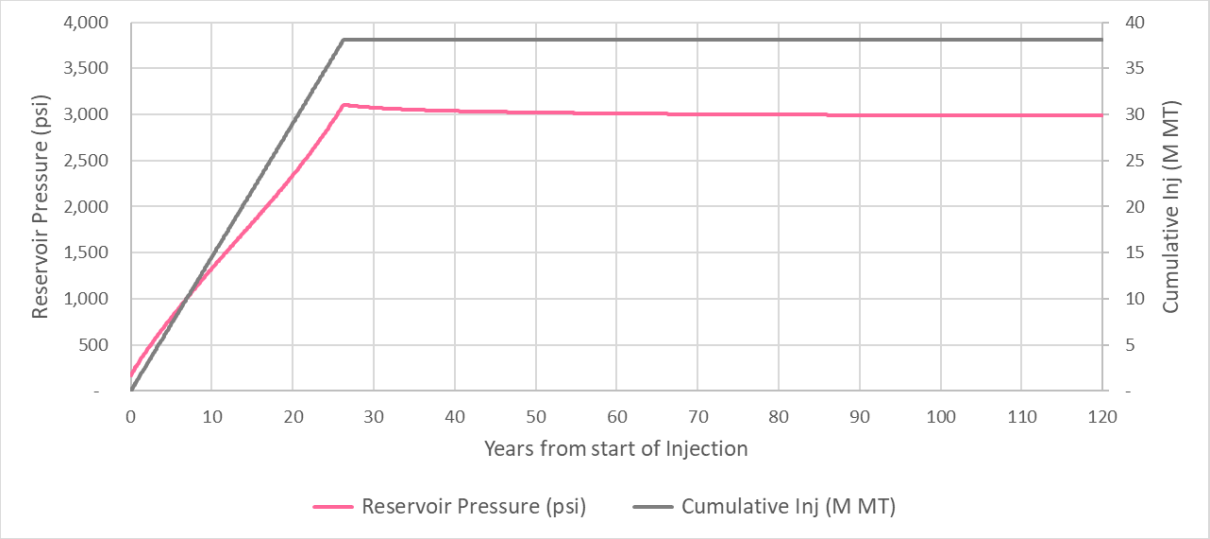


Figure 1: Reservoir pressure and Cumulative injection.

Pressure after 50 and 100 years post-injection are the same in monitoring well 328-25R (Figure 2) indicating plume stabilization. The low water saturation within the Monterey Formation 26R storage reservoir results in 72% of the CO_2 injectate remaining super-critical, minimizing the quantity of CO_2 dissolving in formation water through time.

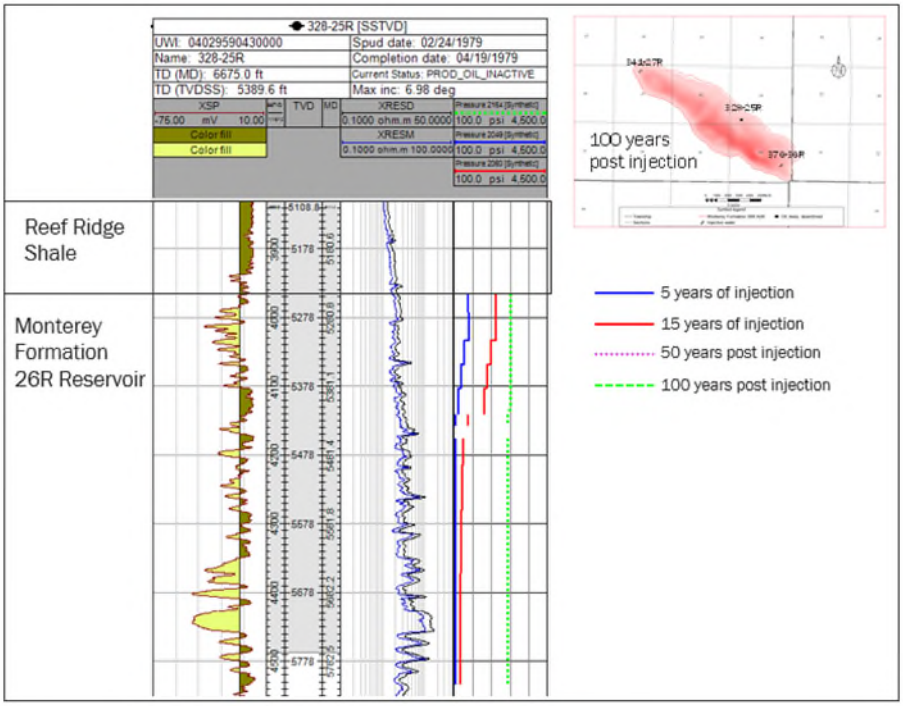


Figure 2: Pressure at the 328-25R monitoring well. Pressure after 50 and 100 years post-injection are the same indicating plume stabilization.

Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 3 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

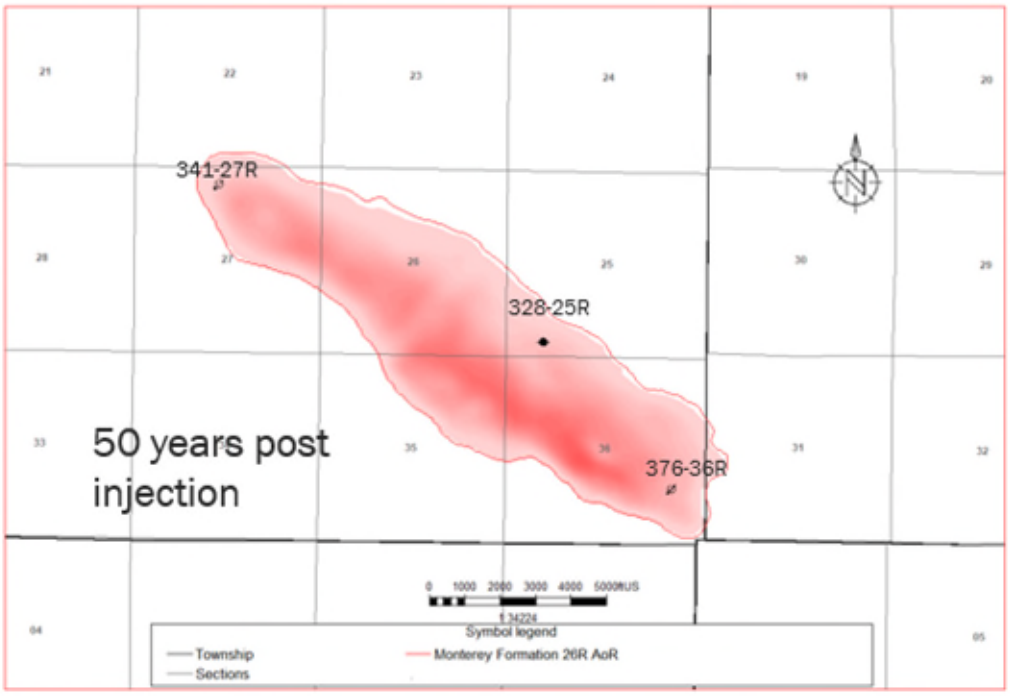


Figure 3: Map of the predicted extent of the CO_2 plume post-injection after 50 years with plume monitoring well locations . The pressure of the 26R reservoir will be at or beneath the initial pressure at the time of discovery.

Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include pressure monitoring and fluid composition monitoring in the storage reservoir and reservoirs above the injection zone. Post-injection monitoring, as described in the following sections, will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days of the anniversary date of final injection, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

The Testing and Monitoring Plan describes the monitoring strategies within the injection zone, above the injection zone, and within the USDW-containing reservoir. In addition to monitoring the zones above the injection zone for stabilized pressure and absence of CO2, the injection zone will be monitored for pressure stabilization as the best method to confirm confinement within the storage reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.

The Quality Assurance and Surveillance Plan (QASP) for all testing and monitoring activities during the injection and post-injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Throughout the AoR there is no USDW groundwater but a zone of unsaturated sands in the Upper Tulare. A shallow groundwater monitoring well will continuously assess reservoir pressure. Groundwater samples will be analyzed annually for indicators of CO_2 movement into the formation.

CTV own the mineral rights for the Monterey Formation 26R reservoir. Surface access is guaranteed for the life of the project as CTV is a wholly owned subsidiary of California Resources Corporation, owner of the surface rights.

Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ. Figure 4 shows the monitoring well locations. Table 3 shows the sampling and recording frequencies for continuous pressure monitoring in the shallow monitoring well. The pressures of these reservoirs may be affected by regional water recharge, injection, or withdrawal. For the Tulare Formation monitoring, CTV will compare these results to other groundwater monitoring wells in the Elk Hills Oil Field.

Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Post-Injection)
Tulare	Fluid Sampling	Shallow Water Monitoring Well	Pump	400’- 450' MD/VD	Annual
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’- 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’- 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	800' - 1100' MD/VD in each well	Continuous
Etchegoin	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Annual
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' MD/VD 4788' - 4811' MD/VD 4205' - 4226' MD/VD	Continuous

Table 2. Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn and T1)	ICP-MS EPA Method 6020
Cations (Ca, FE, K, Mg, Na, Si)	ICP-OEC EPA Method 6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300.0
Dissolved CO2	Coulometric Titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
Alkalinity	Method 2320B
δ13C	Isotope ratio mass spectrometry
pH	EPA 150.1
Total Dissolved Solids (TDS)	Gravimetry; Method 2540 C
Specific Conductance (field)	APHA 2510
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

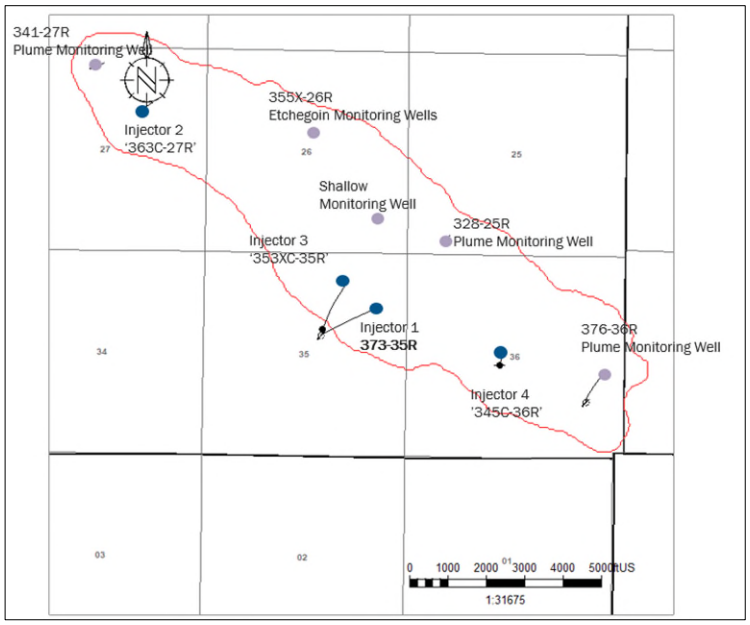


Figure 4: Map showing AoR and well locations for monitoring.

Table 3. Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
During active injection	Pressure Gauge	Shallow Monitoring Well	5 hours	5 hours
Post injection	Pressure Gauge	Shallow Monitoring Well	12 hours	12 hours

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the associated increase in pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the CO_2 plume, including the activities, locations, and frequencies CTV will employ. The parameters to be analyzed as part of fluid sampling in the Monterey Formation 26R (and associated analytical methods) are presented in Table 2.

Table 4. Post-injection phase plume monitoring.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Post-Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm 26R	Fluid Sampling	341-27R	6981' - 7237' MD	Annual
		Pressure		6910' MD	Continuous
		Temperature		6910' MD	Continuous
	Monterey Fm 26R	Fluid Sampling	328-25R	5268' - 5800' MD	Annual
		Pressure		5188' MD	Continuous
		Temperature		5188' MD	Continuous
	Monterey Fm 26R	Fluid Sampling	376-36R	5832' - 6815' MD	Annual

		Pressure		5760' MD	Continuous
		Temperature		5760' MD	Continuous
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	341-27R	6981' - 7237' MD	Every 5 years
			328-25R	5268' - 5800' MD	
			376-36R	5832' - 6815' MD	

Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn and T1)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na and Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300.0
Dissolved CO2	Coulometric Titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
Alkalinity	Method 2320B
δ13C	Isotope ratio mass spectrometry
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Total Dissolved Solids (TDS)	Gravimetry; Method 2540 C
Specific Conductance (field)	APHA 2510
pH (field)	EPA 150.1
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Fluid sampling will be performed as described in B.1. of the QASP. Sample handling and custody will be performed as described in B.3. of the QASP. Quality Control will be ensured using the methods described in B.5. of the QASP.

CTV will employ indirect and direct methods to monitor the pressure front. Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies. Direct monitoring will include pressure gauges to monitor the pressure of the CO_2 plume in the three Monterey Formation 26R monitoring wells. Additionally, seismic monitoring via installed surface and shallow borehole seismometers well will be utilized to detect micro-seismic events. Figures 4 and 5 show the location of the monitoring wells and the predicted extent of the CO_2 plume in map view and cross-section.

Table 6. Post-injection phase pressure-front monitoring.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Post-Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm 26R	Pressure	341-27R	6981' - 7237' MD	Continuous
		Temperature			Continuous
	Monterey Fm 26R	Pressure	328-25R	5268' - 5800' MD	Continuous
		Temperature			Continuous
	Monterey Fm 26R	Pressure	376-36R	5832' - 6815' MD	Continuous
		Temperature			Continuous
Pressure-Front Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Continuous

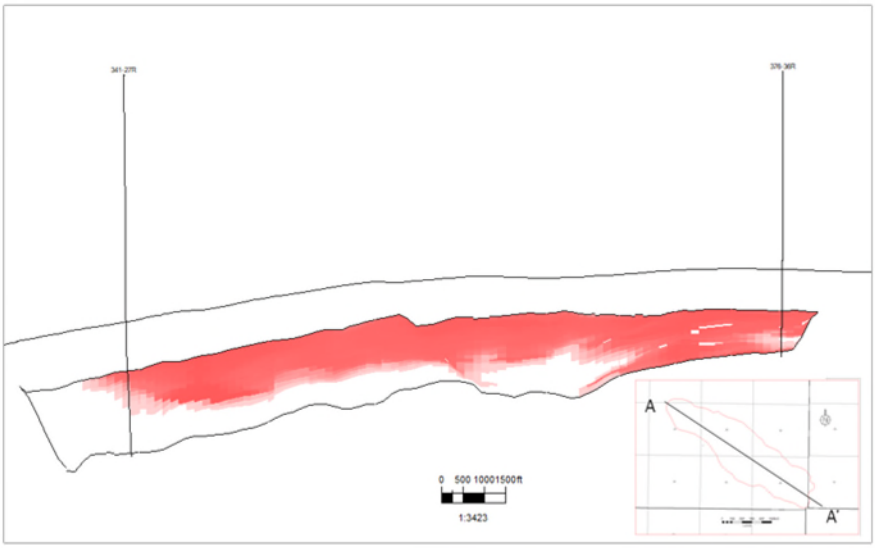


Figure 5: Cross-section showing plume CO2 plume 100 years post injection and 341-27R and 376-36R monitoring wells for post-injection monitoring.

Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period; i.e. well-based monitoring data, sample analysis, and the results from updated site models.

Non-Endangerment Demonstration Criteria [40 CFR 143.93(b)(2) or (3)]

Prior to authorization of site closure, CTV will submit a demonstration of non-endangerment of USDWs to the Director.

CTV will provide a report to the Director that demonstrated USDW non-endangerment based on the evaluation of site monitoring data. The report will detail how the non-endangerment determination is based on site-specific conditions, supported with the computational model. All relevant monitoring data and interpretations will be provided.

Summary of Monitoring Data

A summary of the site monitoring data, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project. Data submission will be in a format acceptable to the Director and will include:

1. A narrative that explains the monitoring activities,

2. Dates of all monitoring events,

3. Changes to the monitoring program over time,

4. An explanation of all monitoring information that has existed at the site,

5. Explanation of how the monitoring data from injection and PISC has varied from the baseline data during site characterization, and

6. Summary of any emergencies that occurred during the injection and post-injection phases of the project. Included will be a description of how any issues have been resolved and that there is no endangerment to the USDW.

Evaluation of the CO2 Plume and the AoR

Computational modeling results calibrated with monitoring data (e.g., pressure) will be used to support that the plume has stabilized and that the pressure change is negligible (less than 10 psi per year) and poses no risk for potential vertical migration. Computational modeling results calibrated with monitoring data from storage reservoir, USDW and above zone will be used to demonstrate:

1. the lack of CO2 leakage over the project timeframe,

2. the accuracy of the model to predict and represent the storage reservoir, and

3. the computational model adequately defined the AoR.

Evaluation of Reservoir Pressure

Monitoring data will be reviewed to ensure that the CO2 plume has stabilized post-injection and that the reservoir pressure change is negligible (less than 10 psi per year). This demonstration will be supported by the computational model that has been calibrated with the most recent monitoring data. The plume is trapped by structure and pinch-out of the reservoir sands. Plume migration is minimal, as such pressure stabilization will be used for non-endangerment assessment.

Evaluation of Potential Conduits for Fluid Movement

Wells that require corrective action will be reviewed and assessed prior to PISC and Site Closure, this includes monitoring wells, injection wells and other wells that penetrate within the AoR and the confining layer. Final demonstration will be made that natural and artificial conduits will not allow fluid migration from the storage reservoir.

Evaluation of Seismicity Monitoring

Demonstration will be made that the plume has stabilized and the pressure change is negligible (less than 10 psi per year), minimizing the risk for induced seismicity after site closure. Final review will be made with the seismicity monitoring to demonstrate seal integrity and that there is no further endangerment of to the USDW

Site Closure Plan [40 CFR 146.93(e)]

CTV will conduct site closure activities to meet the requirements of 40 CFR 146.93(e), with notification to the permitting agencies at least 120 days prior to its intent to close the site. Upon approval of the permitting agencies, CTV will plug the injection and monitoring wells, restore the site, and submit a site closure plan to the EPA. A site closure report will be prepared and submitted within 90 days following site closure supported by the following.

1. Verification of injector and monitoring well plugging,

2. Notifications to state and local authorities as per 40 CFR 146.93 (f)(2)

3. Composition and volume of the injected CO2, and

4. Post-injection monitoring records

CTV will record a notation to the property's deed that will indicate:

1. The property was used for CO2 sequestration, the period of injection and the volume of CO2 injected,

2. The formation that the fluid was injected, and

3. The name of the local agency to which a plat of survey with injection well locations was submitted.

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

CTV I: Elk Hills 26R Project

Facility Information

Facility name: CTV I: Elk Hills 26R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment F -ERR Plan	1	01/11/21
Attachment F -ERR Plan	2	05/31/22
Attachment F -ERR Plan	3	12/10/22

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault I LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

The Emergency and Remedial Response Plan would be implemented in response to events that could be detected in the course of monitoring pursuant to the Testing and Monitoring Plan, including exceedances of Actionable Testing limits described in the QASP (Table 7: Actionable Testing and Monitoring Outputs).

If CTV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.

3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in the individual Well Construction, Operating and Plugging details (COP) documents) is appropriate.

Local Resources and Infrastructure

Resources in the vicinity of the CTV I Elk Hills 26R Project that may be affected as a result of an emergency event at the project site include:

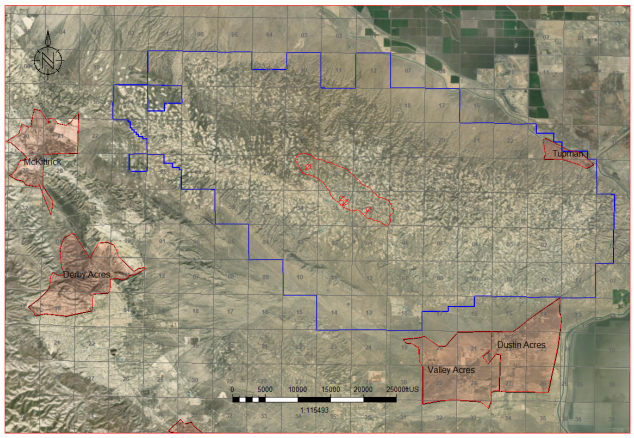
1. Elk Hills oil and gas production resources not associated with the CTV I Elk Hills 26R Project. These oil and gas operations are operated by California Resources Corporation (CRC) an owner of the CTV I Elk Hills 26R Project.
2. Upper Tulare USDW overlying the CO_2 plume. The USDW is not being utilized in the AoR and CTV does not expect usage in the foreseeable future.
3. The nearest census designated area is Valley Acres, 3.6 miles from the AoR. The population was 527 at the 2010 U.S. Census.

Infrastructure in the vicinity of the CTV I Elk Hills 26R Project that that may be affected as a result of an emergency at the project site include:

1. Elk Hills infrastructure owned and operated by CRC that is associated with oil and gas operations.

Resources and infrastructure addressed in this plan are shown in Figure 1.

Figure 1: Map of the site resources and infrastructure. The project is located 3.36 miles from the census designated area of Valley Acres.



Potential Risk Scenarios

The following events related to the CTV I Elk Hills 26R Project that could potentially result in an emergency response:

- Well integrity failure
- Injection well or monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- Potential Brine or CO2 Leakage to a USDW;
- A natural disaster (e.g. tornado, lightning strike); or
- Induced or natural seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

Well Integrity Failure

Integrity loss at the injection well and/or verification well may endanger USDWs. Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).

Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
    - Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

Severity: Low to moderate, dependent on the magnitude of the event.

Timing of event: Injection/Post-Injection

Avoidance measures: Well maintenance, monitoring and control of injection flow and pressure.

Detection methods: Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual (CO_2 at surface).

Potential response actions:

- Notify the plant superintendent and project manager.
- Limit access to wellhead to authorized personnel only.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (loss or increase of pressure or fluid volumes and/or loss of mechanical integrity during testing and maintenance):
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Communicate with CTV personnel and local authorities to initiate evacuation plans, as necessary.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
    - If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
    - Preform a well log/MIT to detect CO2 movement outside of the casing.
    - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).
- For a Minor emergency (downhole and surface sensor/monitoring equipment failure):
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.

- Shut-in injection well and vent CO_2 from surface facilities.
- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
- Perform a well log/MIT to detect CO2 movement outside of the casing.
- Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Injection Well or Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Severity: Low

Timing of event: Injection

Avoidance measures: Well maintenance, and careful monitoring and control of injection flow and pressure.

Detection methods: Anomalies in monitoring data, and visual failure of equipment.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (failure of sensors that will require shutdown of well to repair, requires extended repair time (>48 hours) and/or well intervention to remediate):
    - Contact security to restrict access to the Elk Hills 26R Storage site.

- Communicate with CTV personnel and local authorities to isolate the area and initiate evacuation plans, as necessary.
- Initiate shutdown plan.
- Shut-in injection well and vent CO_2 from surface facilities.
- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
- Verify whether contamination has occurred via handheld CO_2 monitors.
- Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.

- For a Minor emergency (sensor or monitoring failure that does not require shutdown of the well to repair):
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan and refer to Major or Serious emergency guidelines.
  - Evaluate the cause of failure, and mitigate if necessary (i.e., repair equipment).
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response Personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) movement out of the injection zone or CO_2 leakage into a USDW. This may be identified through elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO2 leakage into a USDW. For example, a pressure increase of 50 PSI (not tied to seasonal changes) or a pH of 1.

Severity: Serious

Timing of event: Injection

Avoidance measures: CTV will operate the project to ensure containment of CO_2. Contamination to USDWs will be avoided by:

1. Ensuring injection well integrity through well maintenance and mechanical integrity testing
2. Maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer.
3. Reviewing monitoring well data to understand plume extent.
4. Monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

Detection methods: Pressure or water composition change in Etchegoin Formation or USDW monitoring well. Detection limits are 0.001 PSI for the pressure gauge and 0.2 for pH.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Shut-in all injection wells and vent CO_2 from surface facilities.
    - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
        - Remediate unacceptable impacts to the affected USDW.
    - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
    - Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to aerate CO_2-laden water).
    - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.
    - If there is a well integrity issue perform MITs, refer to the Mechanical Integrity Failure scenario.

- If the leak poses a risk to air quality a perimeter will be established vi hand-held air monitoring devices.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, groundwater remediation equipment, cement or casing and air and water testing equipment.

Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. Natural disasters (e.g. tornado or lightning strike) may disturb surface and/or subsurface facilities.

Severity: Minor to catastrophic

Timing of event: Pre-injection, injection, and/or post injection phases.

Avoidance measures: N/A

Detection methods: N/A

Potential response actions:

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
  - Initiate shutdown plan.
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Shut-in all injection wells and vent CO_2 from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - If contamination has occurred refer to the Potential Brine or CO_2 Leakage to USDW scenario.
  - Communicate with CTV personnel and local authorities to initiate evacuation procedures (if necessary).
  - If there is a well integrity issue for the injector or monitoring well, refer to the Mechanical Integrity Failure scenario.

- Perform MITs on the injection wells to identify if a loss of external mechanical integrity occurred.
- If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

- For a Minor emergency:
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan.
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Shut-in all injection wells and vent CO_2 from surface facilities. Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Induced or Natural Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a two-mile radius of the injection wells.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the Elk Hills 26R site for seismic activity. In addition to the CTV seismic monitoring, the Southern California Earthquake Data Center has deployed a network to monitor natural seismicity in the area.

Severity: Minor to Major

Timing of event: Injection / post injection

Avoidance measures: N/A

Detection methods: The seismic monitoring network.

Potential response Actions:

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table 2. Seismic monitoring system, for seismic events > M1.5 with an epicenter within a two-mile radius of the injection well.

Operating State	Threshold Condition[1,2]	Response Action[3]
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels. 2. Document the event in semiannual reports to the EPA.
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the injection wells if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 5. Document the event in semiannual reports to the EPA.
Orange	Seismic event greater than M1.5 and local observation or felt report Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the injection wells if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 5. Report findings to the UIC Program Director and perform corrective actions. 6. Document the event in semiannual reports to the EPA

[1] Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition[1,2]	Response Action[3]
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate gradual shutdown of the injection wells if it is determined appropriate. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 9. If USDW contamination is detected or endangerment, or CO2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and perform corrective actions. 12. Document the event in semiannual reports to the EPA.
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4]	1. Initiate shutdown plan for all injection wells. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

Operating State	Threshold Condition[1,2]	Response Action[3]
	Or Seismic event >M3.5	4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 8. Determine if leaks to ground water or surface water occurred. 9. If USDW contamination or endangerment is detected, or CO_2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and perform corrective actions. 12. Document the event in semiannual reports to the EPA.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Ken Haney (661- 763-6101)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director (24 hour contact)

Bill Blair (562-743-8336)

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	**Phone Number**
Local police	9-1-1 (Emergency) 661-861-3110 (Non-emergency)
California Governor's Office of Emergency Services (Cal OES)	(916) 845-8506
UIC Program Director (EPA Region 9)	David Albright (albright.david@epa.gov)
EPA National Response Center (24 hours)	800-424-8802
Kern County Fire Department	9-1-1 (Emergency) 661-324-6551 (Non-emergency)
California Air Resources Board (CARB)	800-242-4450
Poison Control Center	800-342-9293
California Office of Emergency Services (24 hours)	800-852-7550
State Water Quality Control Board (Central Valley)	916-255-3000
Kern Medical	661-326-2000

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

Emergency Communications Plan

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For

responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within 30 days, or other time prescribed by the EPA director, following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

Staff Training and Exercise Procedures

All CTV staff and contractors operating at the CO_2 sequestration facilities, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

CO_2 Facilities Training

Onsite and classroom training for facility and infrastructure security, maintenance, and operations.

CO_2 Safety Training

Carbon dioxide detection equipment: Operation and maintenance of personal monitors, portable multi-gas monitors and stationary monitors throughout the facility.

Carbon Dioxide Hazards: Accidental exposure, adverse health effects, workplace exposure limits and first aid.

Emergency Response: Training in the event of CO2 leakage and exercise and drills simulating potential emergency situations.

WELL CONSTRUCTION PLAN

CTV I ELK HILLS 26R PROJECT

Injection Well 353XC-35R

Facility Information

Facility Name: Elk Hills 26R Storage Project

Facility Contact: Travis Hurst / Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_353XC-35R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – COP Details_353XC-35R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – COP Details_353XC-35R_V3	3	1/11/23	Revisions made based on questions received from the EPA 01/06/23
Attachment G – COP Details_353XC-35R_V4	4	05/14/2023	Revisions made based on questions received from the EPA 03/2023
Attachment G – COP Details_353XC-35R_V5	5	11/29/2023	Separating Construction and Plugging Plans into Separate Attachments

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

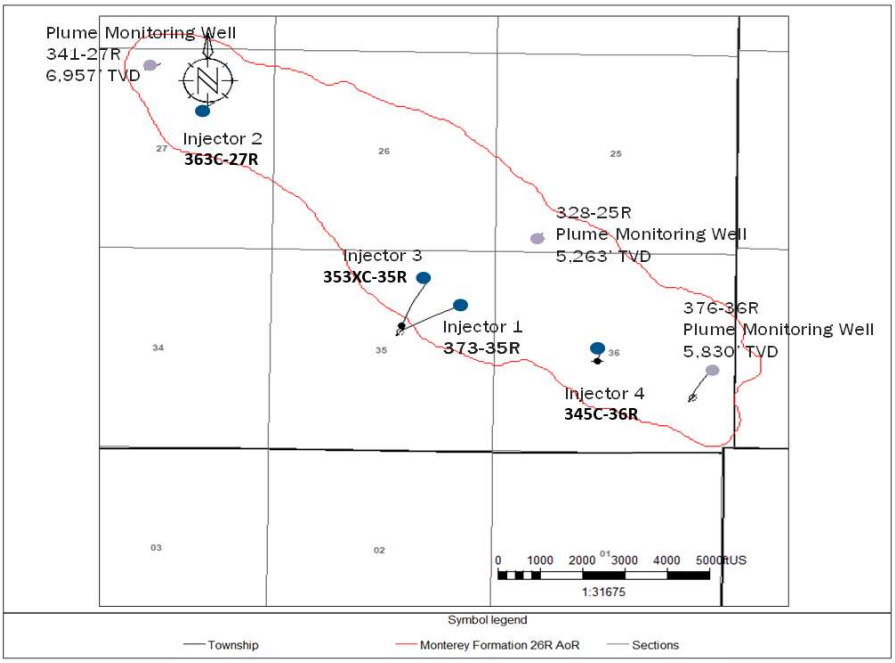


Figure 1: Map showing the location of injection wells and monitoring wells.

Figure 3 and *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Construction

Construction of new injection and monitoring wells will occur during pre-operational testing. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO_2 injection rates: to prevent migration of fluids out of the injection zone, to protect the shallow formations, and to allow for monitoring, as described by the following.

- Well designs will be sufficient to withstand all anticipated load cases including safety factors
- Multiple cemented casing strings will protect shallow formations from contacting injection fluid
- All casing strings will be cemented in place with volume sufficient to place cement to surface using industry-proven recommended practices for slurry design and placement
- Cement bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer
- Mechanical integrity testing (MIT) will be performed on the tubing and the tubing/casing annulus
- Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired and MIT to be conducted
- All wellhead equipment and downhole tubulars will be designed to accommodate the dimensions necessary for deployment of monitoring equipment such as wireline-conveyed logging tools and sampling devices
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
- Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion.

- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
- Casing – 13Cr L-80 or other corrosion resistant alloy in specified sections of production string (ie. flow-wetted casing)
- Cement – Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 where good cement bond between formation and casing exists.
- Tubing – 13Cr L-80 or other corrosion resistant alloy
- Packer – corrosion resistant alloy and hardened elastomer

Well materials follow the following standards:

- API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
- API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
- API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing and Cementing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure specified in the Operational Procedures section.

The 26R reservoir has been depleted and reservoir pressure is low. The temperature is approximately 210 degrees Fahrenheit. These conditions are not extreme, and CTV has extensive experience successfully constructing wells in depleted reservoirs. Standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement.

Operational parameters acquired throughout the cementing operation will be used to compare modeled versus actual pressure and rate. The presence of circulated cement at surface will also be a primary indicator of effective cement placement. Cement evaluation logging will be conducted to confirm cement placement and isolation.

Table 1: Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14' - 54'	20	19.124	94	H-40	Short	2.62	1530	520
Surface	14' - 2400'	9.625	8.835	40	L-80	Long	2.62	5750	3090
Long string	14' - 6300' 6300' - 6700'	7	6.276	26	L-80 L-80 CRA	Long	2.62	7240	5410
Liner	6400' - 8680'	4.5	3.92	13.5	L-80 CRA	Long	2.62	9020	8540

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

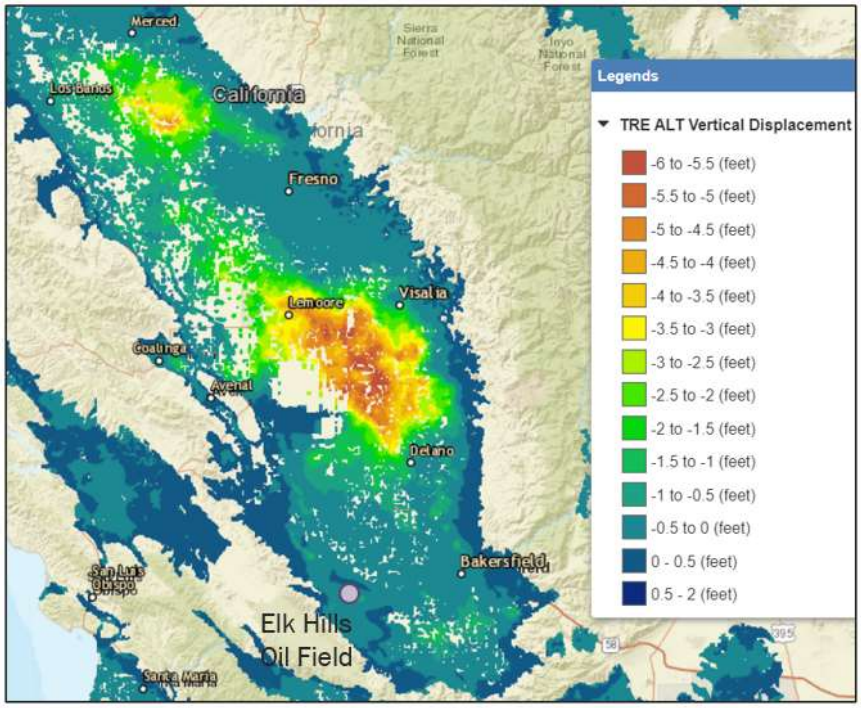


Figure 2: Subsidence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Tubing and Packer

The information in the tables provided in the Tables 2 and 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined prior to completion during pre-operational testing. A suitable corrosion-resistant alloy will be selected and installed once the CO_2 stream impurities and impurity concentrations have been determined. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel.

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 2: Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	6,400	4.5	4.00	11.6	L-80 CRA	Premium	7,780	6,350

Table 3: Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	6,400	30.3	26 - 32	5.875"	4.00"

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rates, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan detail the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The EPA Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design 353XC-35R with a surface shut-off valve at the wellhead and not a down-hole device.

Pre-Injection Testing Plan

The following tests and logs will be acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The testing activities described in this attachment are restricted to the pre-injection phase. Testing and

monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring document.

Deviation Checks

Deviation measurements will be conducted approximately every 120' during construction of the well.

Tests and Logs

The following logs are expected to be acquired during the drilling or prior to the completion of 353XC-35R:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Mud Log
- Acoustic Cement Bond Log

Demonstration of mechanical integrity

Table 4: Summary of tests to be performed prior to injection

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log. The mechanical integrity testing procedures are described in the Testing and Monitoring document.

Annulus Pressure Test Procedures

1. The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test.

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less equal to or greater than the highest annular pressure specified in the Operating Procedures document. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve.

4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals.

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Injectivity and Pressure Fall-Off Testing for Injection Wells

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV will complete injectivity and pressure fall off testing prior to CO_2 injection, pursuant to 40 CFR §146.87(e).

CTV will consider pressure fall-off testing throughout the injection phase to complement reservoir monitoring if injection rate decreases along with a simultaneous injection pressure increase outside the results from computational modeling.

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

A surface gauge at the wellhead and a downhole gauge set above the packer with real-time surface readout capability will be used for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the reviews. This information is summarized below (along with the planned tests that will address each data need that was described in the initial permit application materials submitted in November 2021) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c) and 146.87.

Regional Geology and Geologic Structure

• Perform pressure build-up testing (anticipated testing method: pressure build-up test).

• Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

• Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

• Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

• Determine if there are any heterogeneities within the Monterey 26R injection zone that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; planned and completed core, log, and seismic analysis).

CO2 Stream Compatibility with Subsurface Fluids and Minerals

• Confirm the composition and water content of the CO2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses, benchtop studies).

• Confirm that the properties of the CO2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).

• Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of the geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

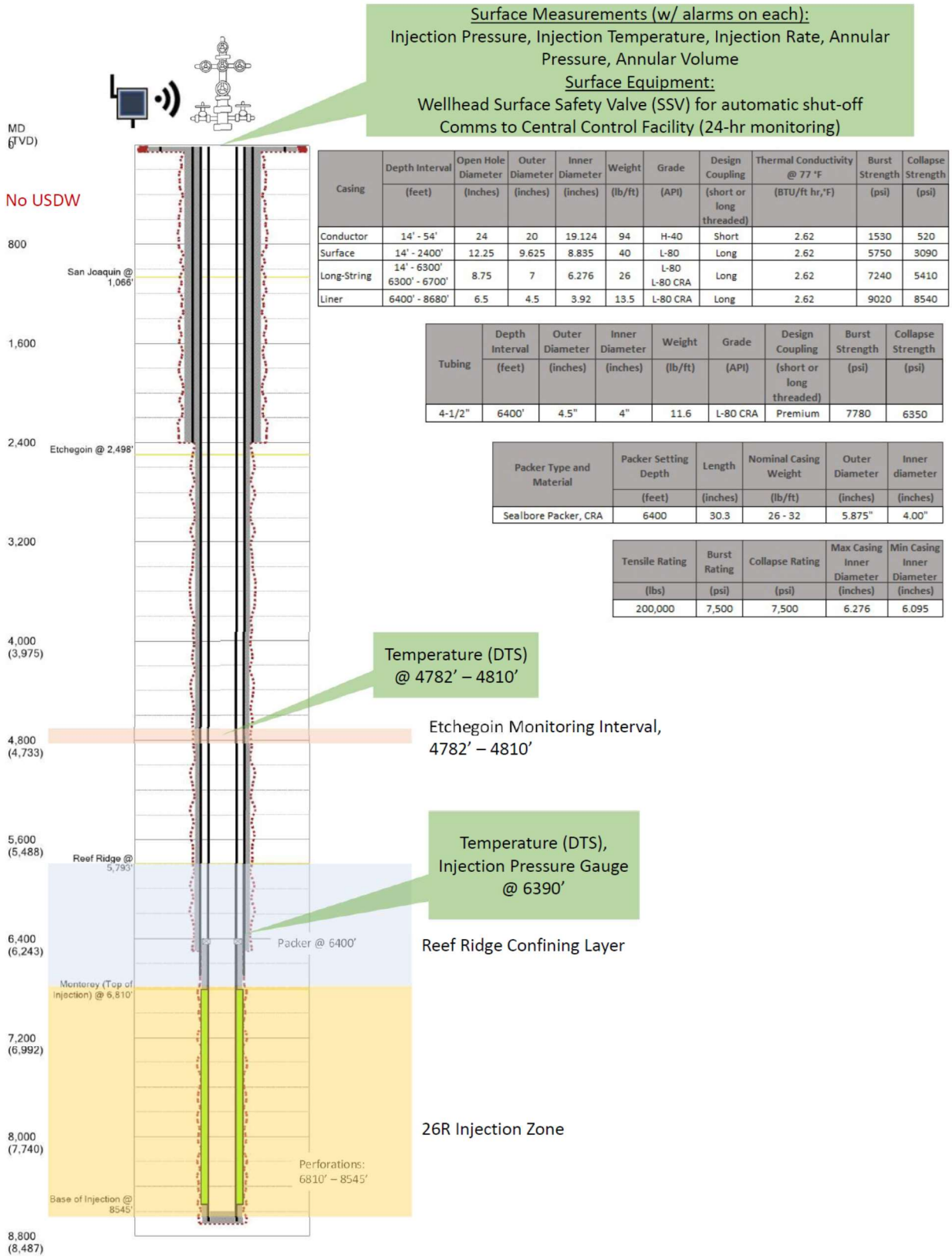
• Collect baseline pressure data in the Etchegoin Formation to support upward confinement between the Monterey and shallower formations (anticipated testing method: pressure build-up test).

• Determine the porosity and permeability of the Reef Ridge Shale at the location of each of the 26R project wells (anticipated testing methods: core and log data during well drilling).

• Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

• Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).



Casing	Depth Interval (feet)	Open Hole Diameter (Inches)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)	Thermal Conductivity @ 77 °F (BTU/ft hr,°F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14' - 54'	24	20	19.124	94	H-40	Short	2.62	1530	520
Surface	14' - 2400'	12.25	9.625	8.835	40	L-80	Long	2.62	5750	3090
Long-String	14' - 6300' 6300' - 6700'	8.75	7	6.276	26	L-80 L-80 CRA	Long	2.62	7240	5410
Liner	6400' - 8680'	6.5	4.5	3.92	13.5	L-80 CRA	Long	2.62	9020	8540

Tubing	Depth Interval (feet)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)	Burst Strength (psi)	Collapse Strength (psi)
4-1/2"	6400'	4.5"	4"	11.6	L-80 CRA	Premium	7780	6350

Packer Type and Material	Packer Setting Depth (feet)	Length (inches)	Nominal Casing Weight (lb/ft)	Outer Diameter (inches)	Inner diameter (inches)
Sealbore Packer, CRA	6400	30.3	26 - 32	5.875"	4.00"

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max Casing Inner Diameter (inches)	Min Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Figure 3: Injection Well 353XC-35R, CO_2 Injection Schematic

ATTACHMENT H: FINANCIAL ASSURANCE DEMONSTRATION
40 CFR 146.85

CTV I: Elk Hills 26R Project

Document Version History

Version	Revision Date	File Name	Description of Change
1	9/29/2023	Att H_Financial Responsibility_26R	Compilation of financial responsibility documents in one attachment

Facility Information

Facility name: CTV I: Elk Hills 26R

Facility contact: Travis Hurst / Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Financial Instruments

Carbon TerraVault (CTV) is providing financial responsibility information pursuant to 40 CFR 146.85. CTV is using the following financial instruments:

- Letter of Credit to cover the costs of corrective action, injection well plugging, post-injection site care, and site closure.
- Certificate of Insurance to cover costs of emergency and remedial response

The estimated costs of each of these activities, as provided by CTV, are presented in Table 1.

CTV has provided financial assurance for Emergency and Remedial Response by procuring an environmental insurance policy. If needed the limits will be re-determined by a reasonable estimate of the cost of these activities prior to the commencement of injection operations. The Elk Hills 26R project environmental insurance policy covers all emergency and remedial response activities arising from the assets. The selected insurance carrier has issued a financial assurance certificate in compliance with state and federal regulations that is provided below.

Table 1. Cost Estimates for Activities to be Covered by Financial Responsibility.

Activity	Instrument	Total Cost ($)
Corrective Action	Letter of Credit	111,320
Plugging Injection Wells	Letter of Credit	1,197,840
Post-Injection Site Care	Letter of Credit	6,790,750
Site Closure	Letter of Credit	994,750
Emergency and Remedial Response	Certificate of Insurance	24,578,125

The following supporting information is provided below to satisfy Financial Responsibility requirements:

- Daniel B. Stephens & Associates, Inc. (DBS&A) third party cost estimate
- Deutsche Bank AG Irrevocable Standby Letter of Credit
- Irrevocable Standby Letter of Credit Notification Letter
- Bank of New York Mellon Standby Trust
- Letter of Credit Cost Estimate and Funding Value Summary
- Ascot Certificate of Insurance
- Insurance Endorsement
- Financial Strength Demonstration

DBS&A THIRD PARTY COST ESTIMATE

CLASS VI FINANCIAL RESPONSIBILITY DEMONSTRATION

COST ESTIMATE

CTV I 26R

Carbon TerraVault (CTV) had the following cost estimate prepared by third party contractor, Daniel B. Stephens & Associates, Inc., completed on 9/5/2023.

Table 1. Financial Responsibility Cost Summary

Activity	Estimated Cost	Reference
Corrective Action	$ 111,320	Table 2
Injection Well Abandonment	$ 1,197,840	Table 3
Post-Injection Site Care	$ 6,790,750	Table 4
Site Closure	$ 994,750	Table 5
Emergency and Remedial Response	$ 24,578,125	Table 6
Total	**$**	**33,672,785**

All values in 2022 dollars

Table 2. Costs, Corrective Action Total

Activity	Unit		Unit Cost	Total	Reference
Revise Numerical Model	400	hrs	$ 220	$ 88,000	-
Review CalGEM Well Database	40	hrs	$ 220	$ 8,800	-
Plug Deficient Wells	0	wells	-	$ -	A
Project Management	1	each		$ 14,520	B
			Total	**$ 111,320**	

Notes

A: Per Attachment B, as required wells will be abandoned prior to injection as part of asset retirement obligations

B: 15% of project costs

Table 3. Costs, Injection Well Abandonment

Location	Unit Cost		Depth (ft)	Cost	Reference
Injector 4 345C-36R	30	$/ft	8,680	$ 260,400	A
Injector 1 373-35R	30	$/ft	8,680	$ 260,400	A
Injector 3 353XC-35R	30	$/ft	8,680	$ 260,400	A
Injector 2 363C-27R	30	$/ft	8,680	$ 260,400	A
Documentation, project management	1	each	-	$ 156,240	B
			TOTAL	**$ 1,197,840**	

Notes

A: Abandonment costs from Driltek, 2021; well construction from Attachment G 'Injection Well 1 353XC-35R', Table

B: 15% of project costs

Table 4. Post Injection Site Care Costs

Activity	Unit		Events, 50 years	Unit Cost	Total	Reference
USDW geochemical monitoring/fluid sampling	1	well	50	$ 6,000	$ 300,000	A
Above Confining zone geochemical, pressure monitoring	1	well	50	$ 5,600	$ 280,000	A
Injection zone geochemical, pressure monitoring	3	well	50	$ 5,600	$ 840,000	A
Monitoring well O&M, Above confining zone	1	well	3	$ 30,000	$ 90,000	B
Injection zone monitoring well O&M	3	wells	10	$ 84,000	$ 2,520,000	-
Indirect Plume Monitoring (Pulsed neutron)	1	survey	10	$ 37,500	$ 375,000	C
Mechanical Integrity Test, Injection zone	3	well	10	$ 50,000	$ 1,500,000	B
Reporting/Project Management	1	each	-	$ 885,750	$ 885,750	D
				Total	**$**	**6,790,750**

Notes:

A: Assumes 1 geochemical monitoring event per year per well and continuous pressure monitoring with automated gage; shallow groundwater well have a higher testing cost than the other monitoring wells due to the potential time required to obtain a stabilized sample from a reservoir with low water deliverability.

B: Patrick Engineering, 2013; assumes $2,000 base cost + $4.25/ft (+12%)

C: Zaluski et al., 2016; assumes 8 well survey (inflation adjusted); technology and frequency from PISC plan Table 4

D: 15% of project costs

Assumes:

1 USDW Monitoring Well (exempt or unsaturated)

1 Above Confining Zone Monitoring Well

3 Injection Zone Monitoring Wells

4 Injection wells

Table 5. Costs, Site Closure

Activity	Unit		Unit Cost	Total	Reference
Non-endangerment report	1	each	$ 45,000	$ 45,000	-
Injection zone monitoring well plugging	3	wells	$ 200,000	$ 600,000	A
Above-confining zone monitoring well plugging	1	wells	$ 170,000	$ 170,000	A
USDW Monitoring well plugging	1	well	$ 50,000	$ 50,000	
Plugging documentation, project management	1	each		$ 129,750	B
			Total	**$**	**994,750**

Notes
A: Abandonment costs from Driltek, 2021
B: 15% of project costs

Assumes:
1 USDW Monitoring Well (exempt or unsaturated)
1 Above Confining Zone Monitoring Well
3 Injection Zone Monitoring Wells
4 injection wells

Table 6. Emergency Response

Groundwater Contamination Causal Investigation

Activity	Unit		Unit Cost	Total	Reference
Planning/permitting	1	each	$ 1,381,875	$ 1,381,875	B
Monitoring wells, depth 1,000 ft	5	well	$ 385,000	$ 1,925,000	A
Monitoring wells, depth 5,000 ft	3	well	$ 1,925,000	$ 5,775,000	A
Abandoned well investigation	51	well	$ 27,500	$ 1,402,500	D
Former Injection Well Investigation	4	well	$ 27,500	$ 110,000	-
Reporting/Project Management	1	each	$ 921,250	$ 921,250	C
Total				**$**	**11,515,625**

Groundwater Contamination Remediation

Activity	Unit		Unit Cost	Total	Reference
Planning/permitting	1	each	$ 1,567,500	$ 1,567,500	B
Pumping well, depth 1,000 ft	4	well	$ 350,000	$ 1,400,000	A
Pumping well, depth 5,000 ft	4	well	$ 1,925,000	$ 7,700,000	A
Groundwater extraction	1	year	$ 300,000	$ 300,000	-
Above-ground CO_2 removal (aeration)	1	unit	$ 150,000	$ 150,000	-
Former injection well repair	4	well	$ 225,000	$ 900,000	-
Reporting/Project Management	1	each	$ 1,045,000	$ 1,045,000	C
Total				**$**	**13,062,500**

Total, Causal Investigation and Remediation	**$**	**24,578,125**

Notes

A: Assumes $385/ft for permitting, installation, field oversight, logging drilling, and waste

B: 15% of project costs

C: 10% of project costs separate from Planning/permitting

D: Assumes 25% of wellbores penetrating Reef Ridge Formation, Attachment B Table 9

References

Driltek, 2021: Personal communication with Driltek regarding well abandonment costs, California

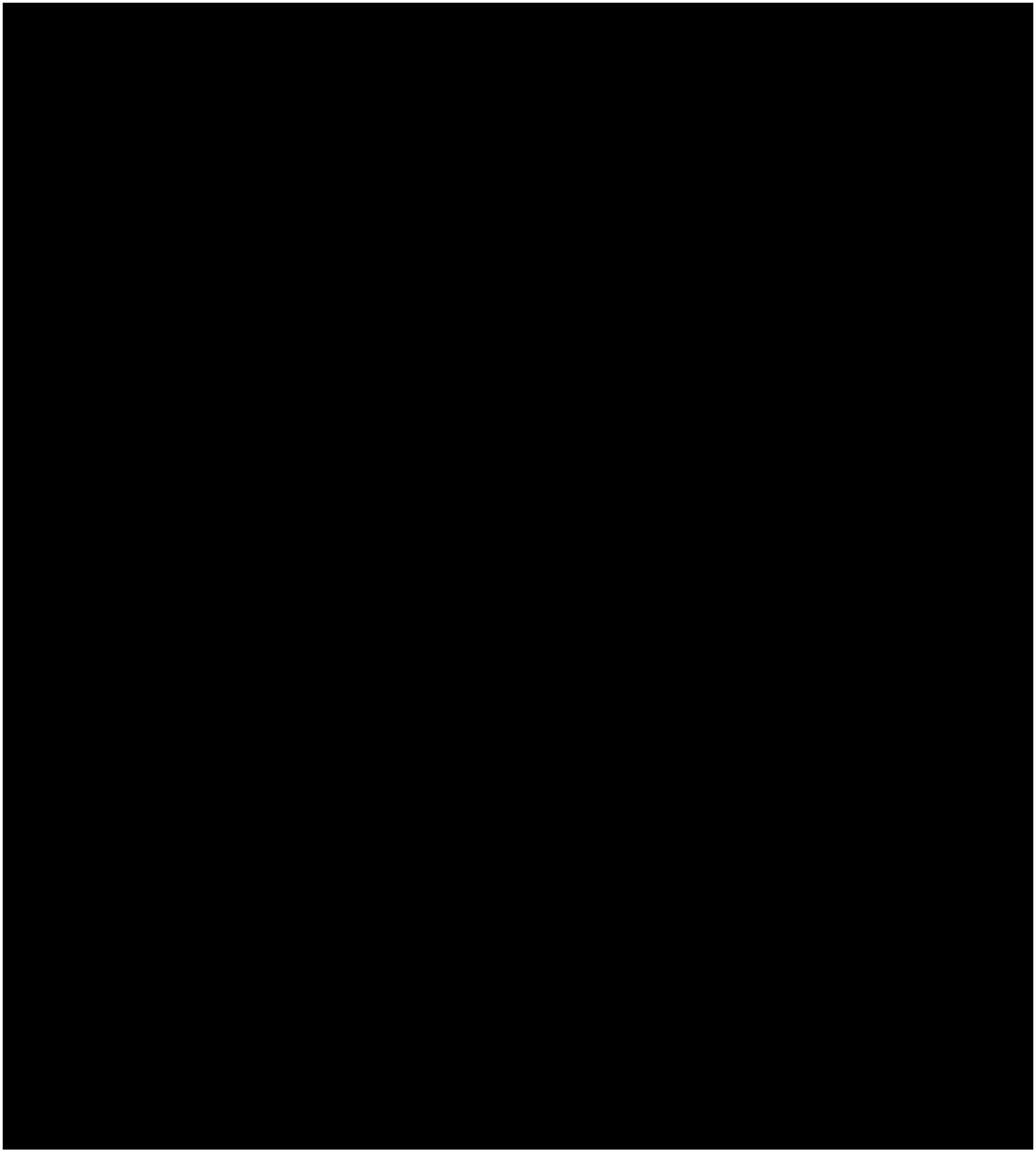
Patrick Engineering, 2013: Third Party Cost Estimate for FutureGen Alliance UIC Class VI Permit Application

Zaluski et al., 2016. Monitoring technology ranking methodology for CO2-EOR sites using the Weyburn-Midale Field as a case study, IJGGC v.54, p.466 - 478

DEUTSCHE BANK AG IRREVOCABLE STANDBY LETTER OF CREDIT

Deutsche Bank

Deutsche Bank AG New York Branch
Trade Finance & Lending
1 Columbus Circle, 17th Floor



Deutsche Bank AG New York Branch
Trade Finance & Lending
1 Columbus Circle, 17th Floor
New York, NY 10019



Very truly yours,
Deutsche Bank AG
New York Branch

[Signature(s) and title(s) of official(s) of issuing institution]

Chairman of the Supervisory Board: Alexander R. Wynaendts
Management Board: Christian Sewing (Chairman), James von Moltke, Karl von Rohr, Fabrizio Campelli, Bernd Leukert, Alexander von zur Mühlen, Christiana Riley, Rebecca Short, Stefan Simon, Olivier Vigneron
Deutsche Bank Aktiengesellschaft domiciled in Frankfurt am Main; Local Court of Frankfurt am Main, HRB No 30 000; VAT ID No DE114103379; www.db.com

IRREVOCABLE STANDBY LETTER OF CREDIT NOTIFICATION LETTER

September 6, 2023

United States Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, D.C. 20460
Attention: UIC Program Director

Re: EPA Identification Number: _____.

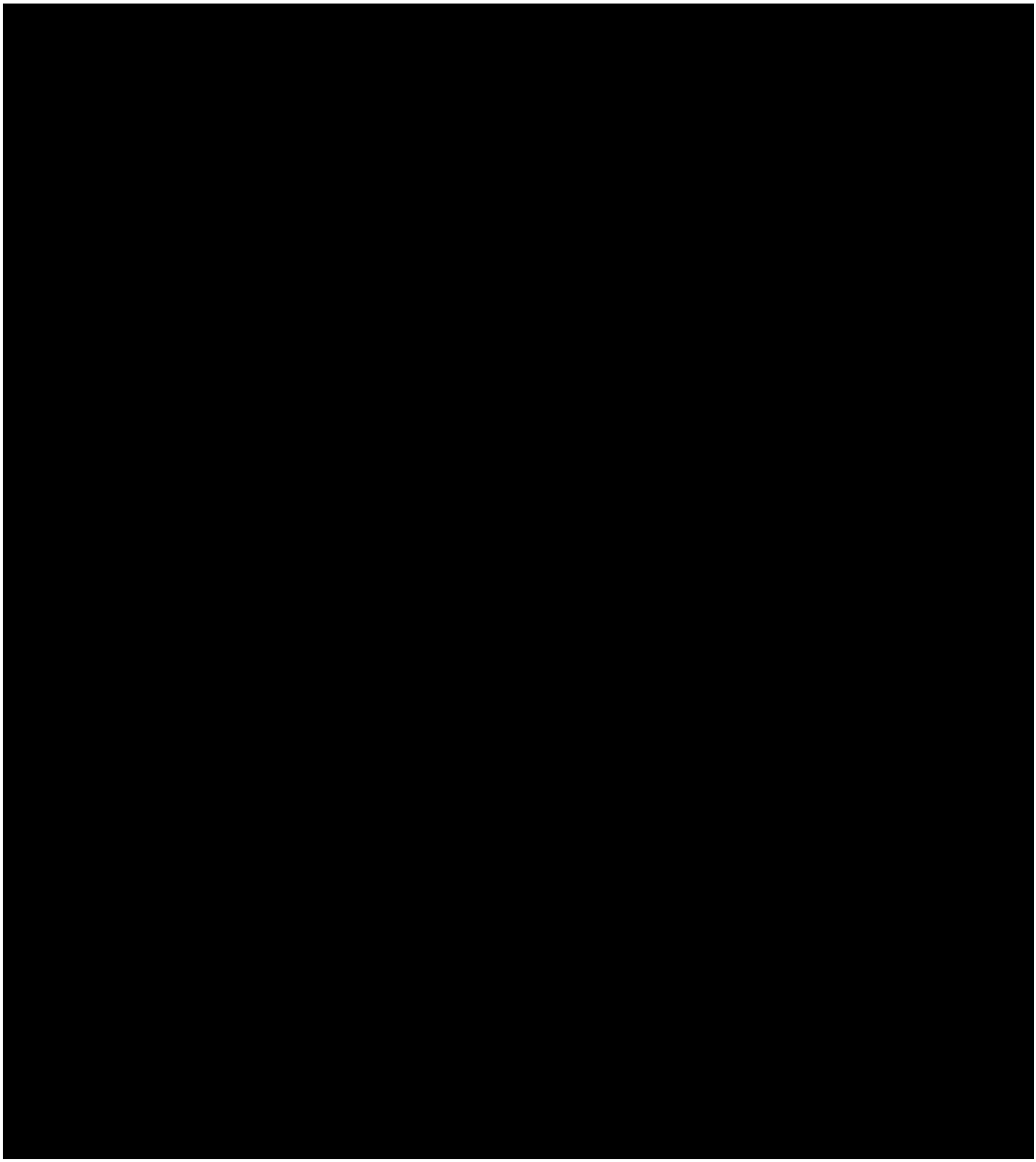
Dear UIC Program Director,

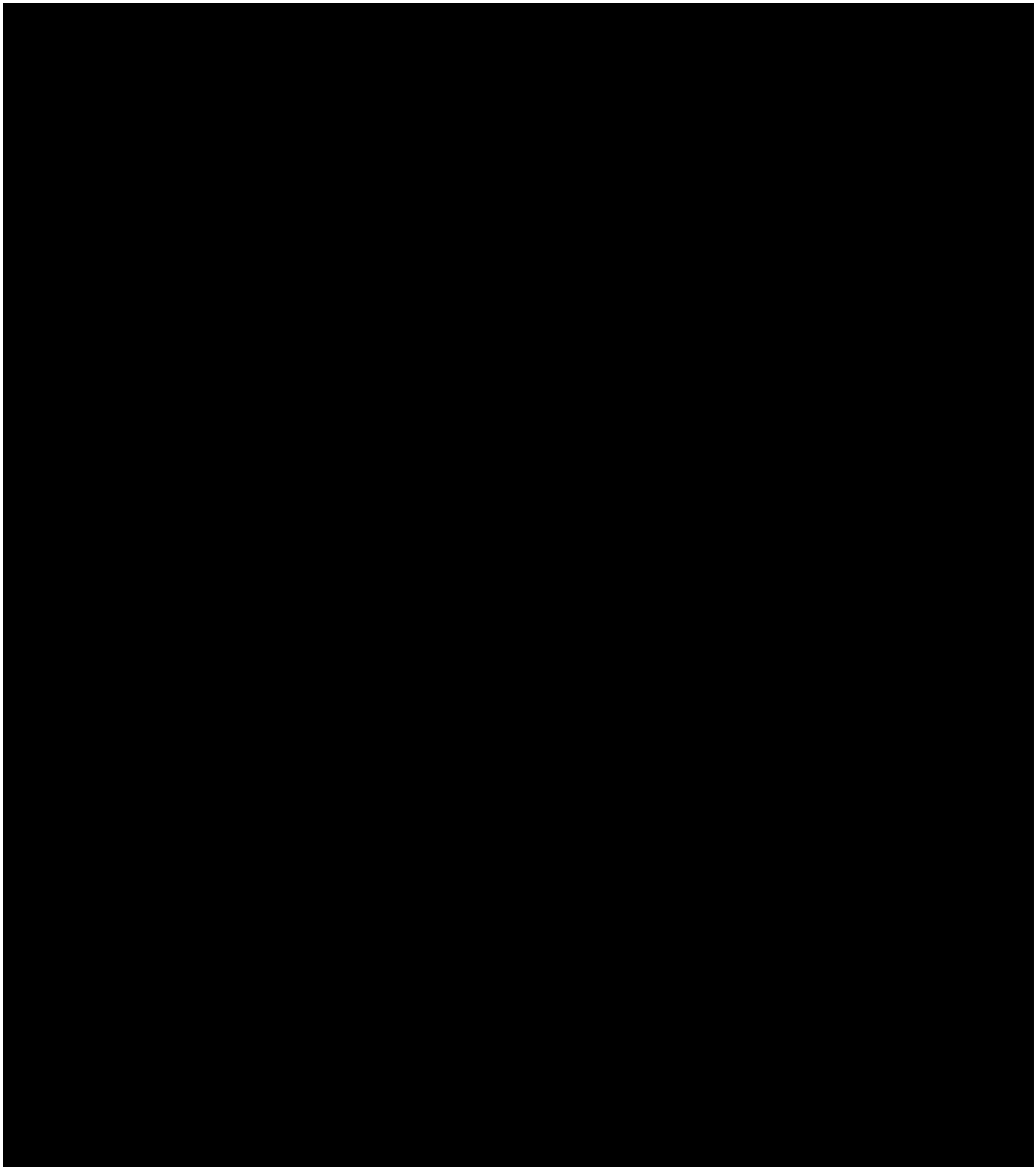
At our direction, effective _____, Deutsche Bank AG New York Branch issued a $_____ Irrevocable Standby Letter of Credit No. _____ in your favor.

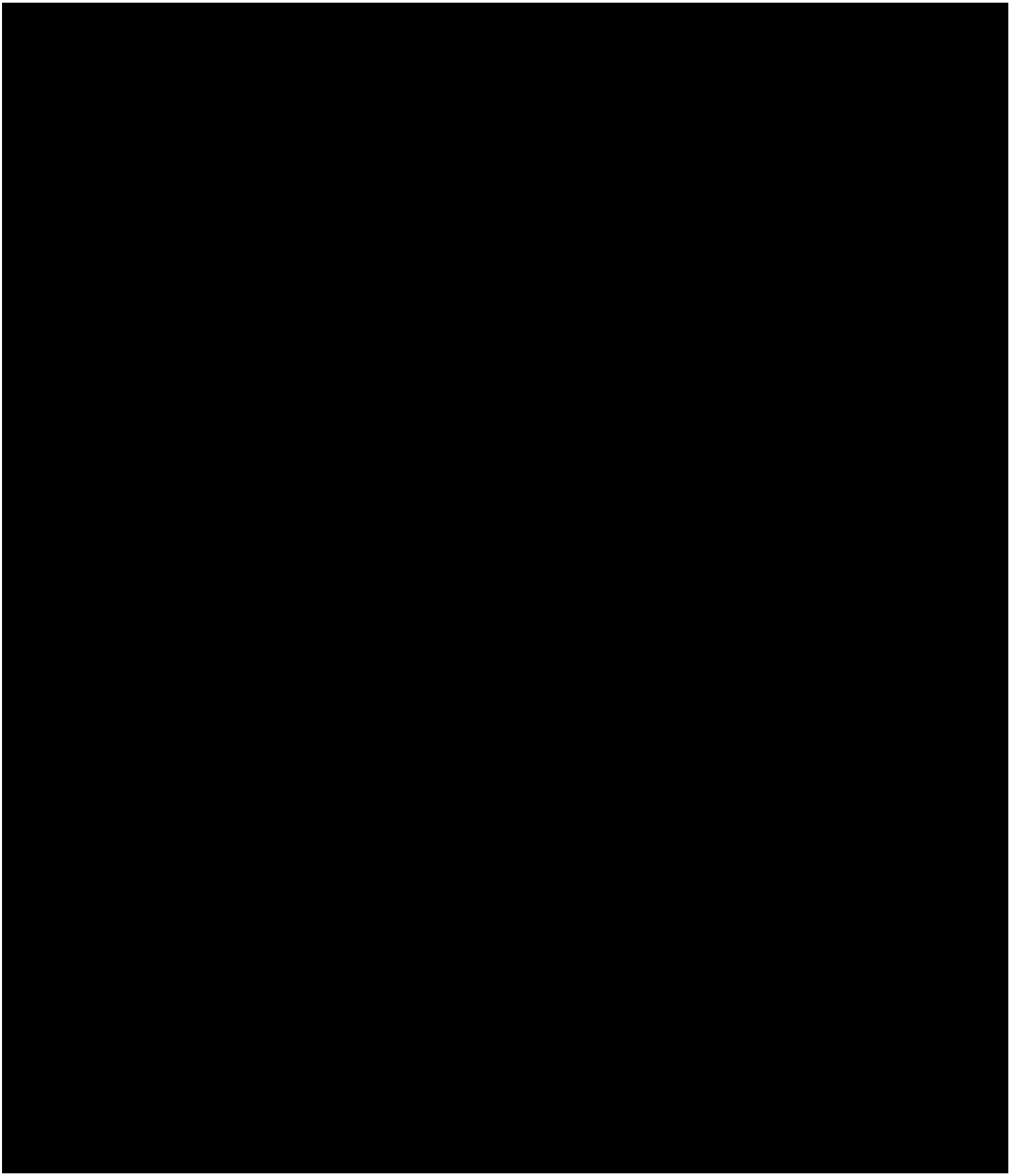
The Irrevocable Standby Letter of Credit was issued to meet the non-emergency response financial assurance requirements associated with the Elk Hills 26R Storage Project located at 28590 Highway 119, Tupman, CA 93276.

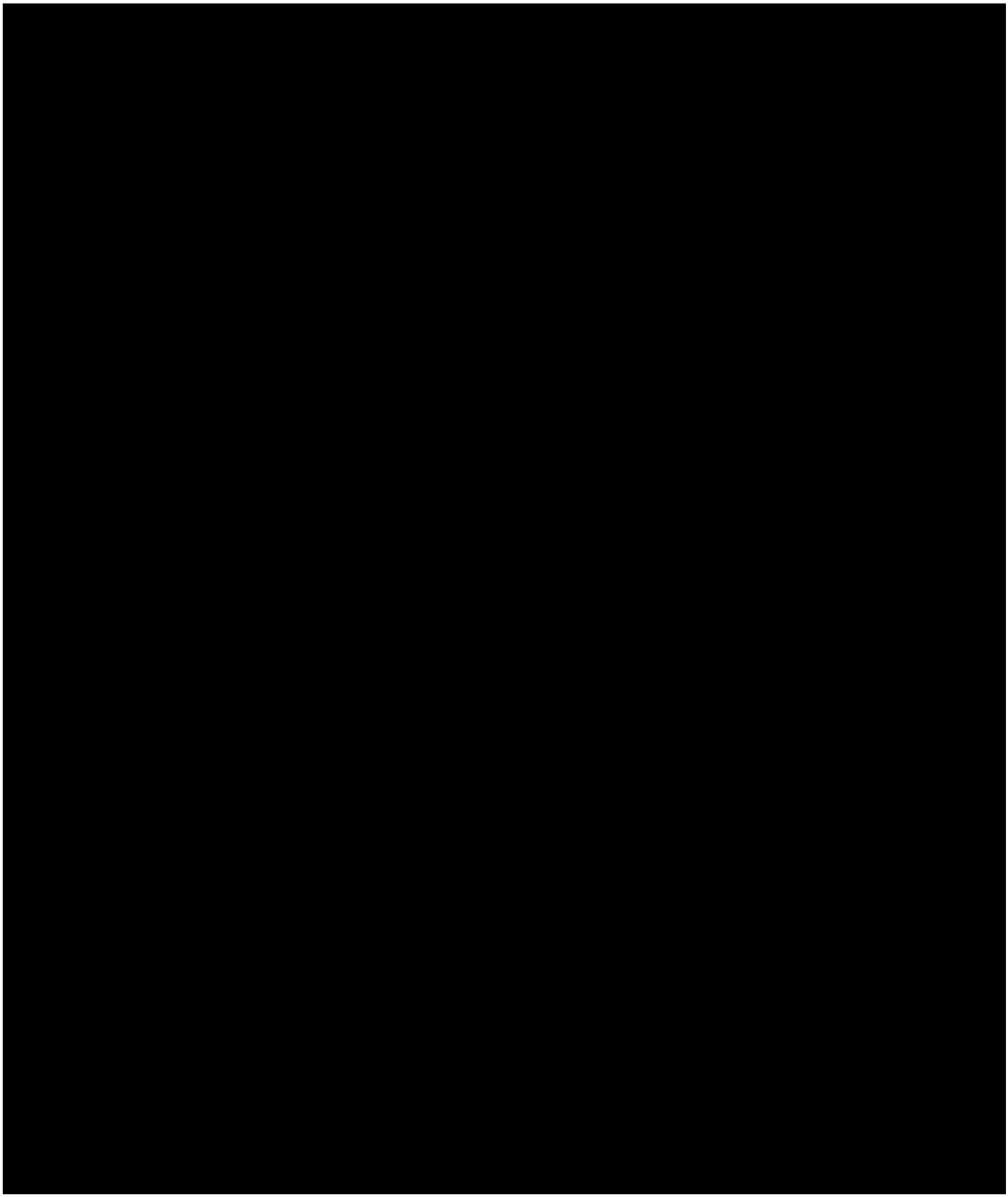
BANK OF NEW YORK MELLON STANDBY TRUST

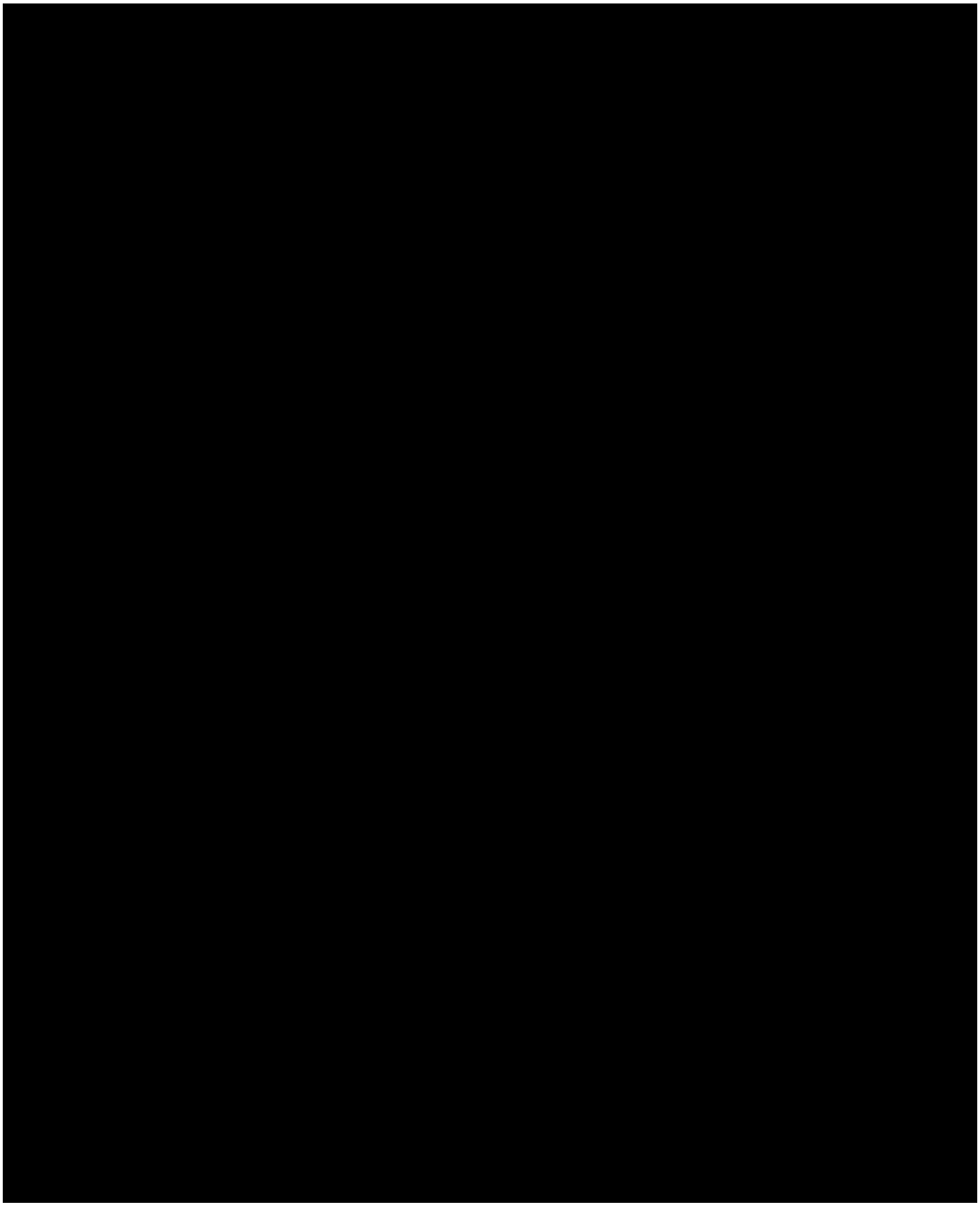
Trust Agreement

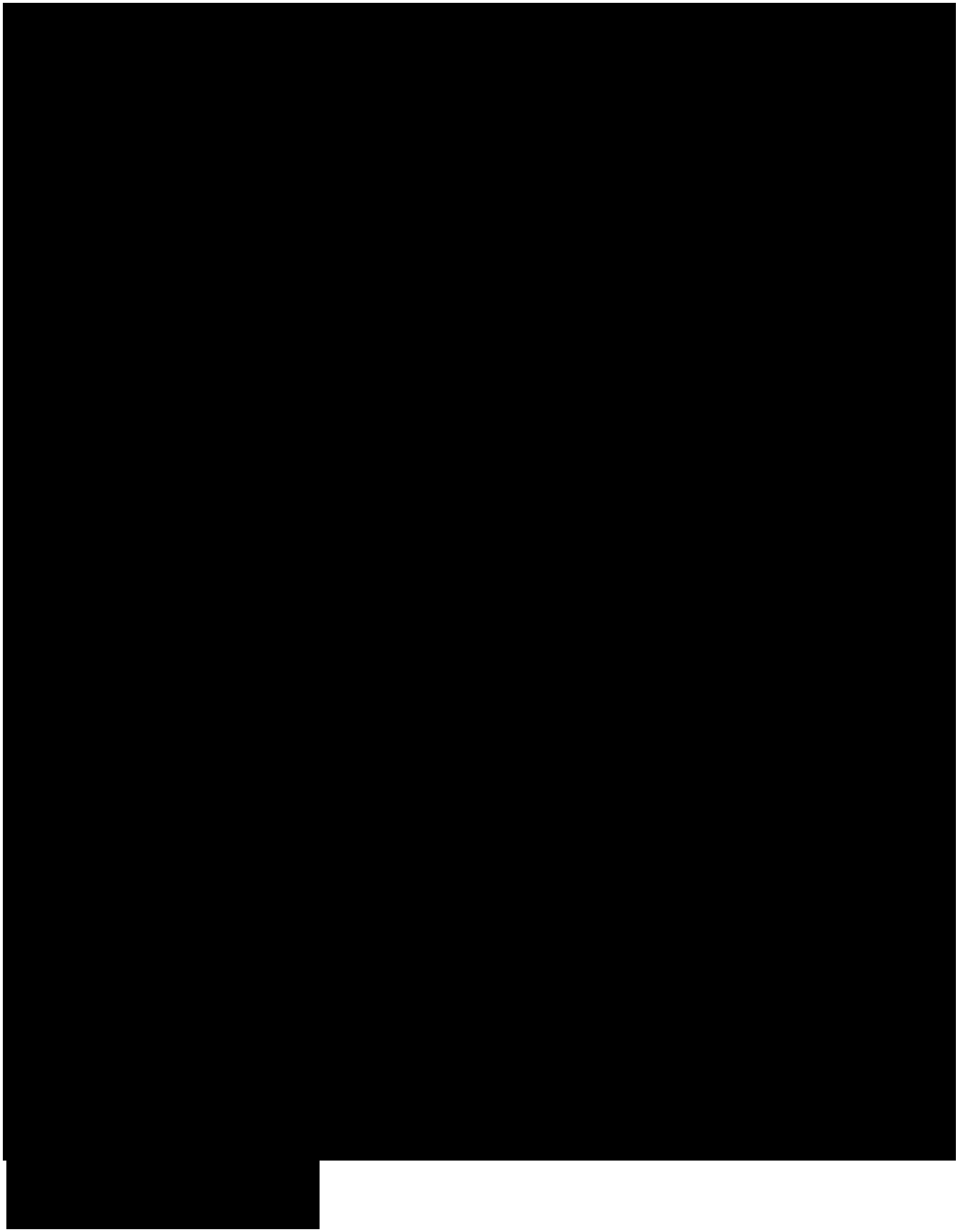














LETTER OF CREDIT COST ESTIMATE AND FUNDING VALUE SUMMARY

Schedule A

Facility	Cost Estimate		
	Corrective action	Injection well plugging	Post injection site care and site closure
EPA Identification number: Elk Hills 26R Storage Project 28590 Highway 119, Tupman, CA 93276	$111,320.00	$1,197,840.00	$7,785,500.00

Schedule B

Facility	Funding Value for Activities
EPA Identification number: Elk Hills 26R Storage Project 28590 Highway 119, Tupman, CA 93276	Irrevocable Standby Letter of Credit No. [839BGC2300XXX] issued by Deutsche Bank AG New York Branch in the amount of [$9,094,660.00].

ASCOT CERTIFICATE OF INSURANCE

55 West 46th Street,
26th Floor
New York, New York 10036

V. Certificate of Insurance

A certificate of insurance, as specified in this chapter, may be worded as follows, except that instructions in brackets are to be replaced with the relevant information and the brackets deleted:

Certificate of Insurance for [emergency and remedial response]

Name and Address of Insured (herein called the "insured"): Carbon TerraVault 1 LLC
1 World Trade Center, Suite 1500, Long Beach, CA 90831

Name and Address of Insurer (herein called the "insurer"): Ascot Specialty Insurance Company; 55 West 46th Street, 26th Floor, New York, New York 10036

Injection Wells covered: [list for each well: The EPA Identification Number, name, address, and the amount of insurance for [emergency and remedial response] (these amounts for all injection wells covered must total the face amount shown below).]

Underground Injection Control Class VI Permit Application Nos. R9UIC-CA6-FY22-1.1, R9UIC-CA6-FY22-1.2, R9UIC-CA6-FY22-1.3 and R9UIC-CA6-FY22-1.4

Face Amount: $25,000,000
Policy Number: ENPU2310001018-01
Effective Date: 05/18/2023

The insurer hereby certifies that it has issued to the Insured the policy of insurance identified above to provide financial assurance for [emergency and remedial response] for the injection wells identified above. The Insurer further warrants that such policy conforms in all respects with the requirements for the fulfillment of [emergency and remedial response] obligations described at 40 CFR 146.94, respectively, as applicable and as such regulations were constituted on the date shown immediately below. It is agreed that any provision of the policy inconsistent with such regulations is hereby amended to eliminate such inconsistency.

The insurer may cancel the policy only for failure to pay the premium and by sending notice of cancellation by certified mail to the owner or operator and to the UIC Program Director for the area in which the injection well(s) is (are) located. EPA requires that cancellation not become final for 120 days beginning on the date of receipt of the notice of cancellation by the UIC Program Director, as evidenced by the return receipts.

Whenever requested by the UIC Program Director, the Insurer agrees to furnish to the UIC Program Director a duplicate original of the policy listed above, including all endorsements thereon.

[Authorized signature of Insurer]



[Name of person signing] Ted Mavraganis
[Title of person signing] Senior Vice President

[Signature of witness or notary:]



[Date] 08/31/2023

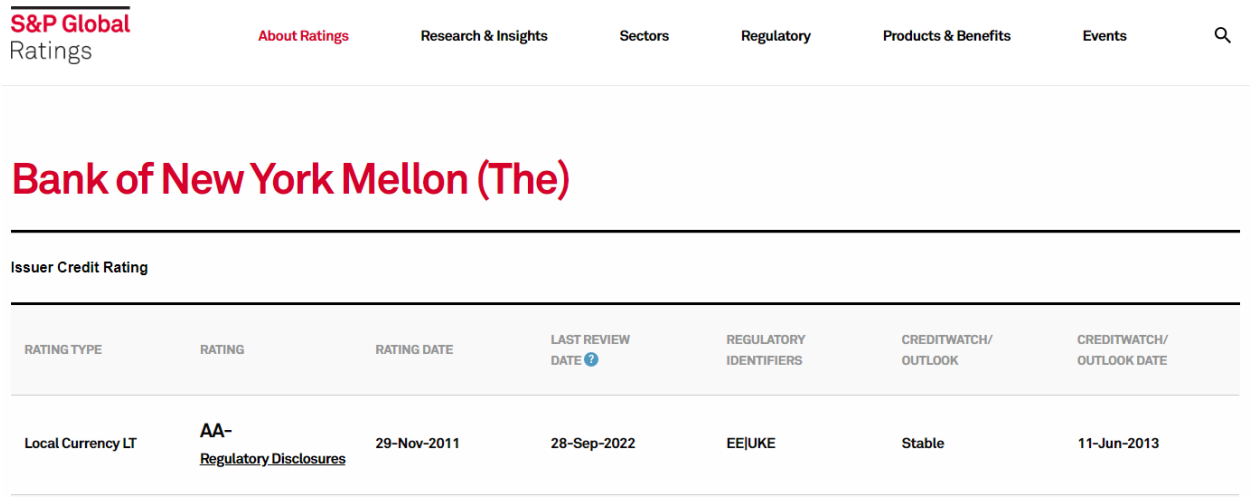
INSURANCE ENDORSEMENT

FINANCIAL STRENGTH DEMONSTRATION

Under 40 CFR 146.85(a)(6)(ii), EPA requires that the owner or operator submit proof of the third party's financial strength. EPA recommends that the owner or operator submit the third party's credit rating or, if the Director determines that the credit rating alone does not sufficiently meet the financial strength requirement, submit the third party's credit rating plus its most recent bond rating and calculated financial ratios. EPA recommends that owners or operators demonstrate that third party providers have a credit rating in the top four categories from either Standard & Poor's or Moody's (i.e., AAA, AA, A, or BBB for Standard & Poor's and Aaa, Aa, A, or Baa for Moody's)

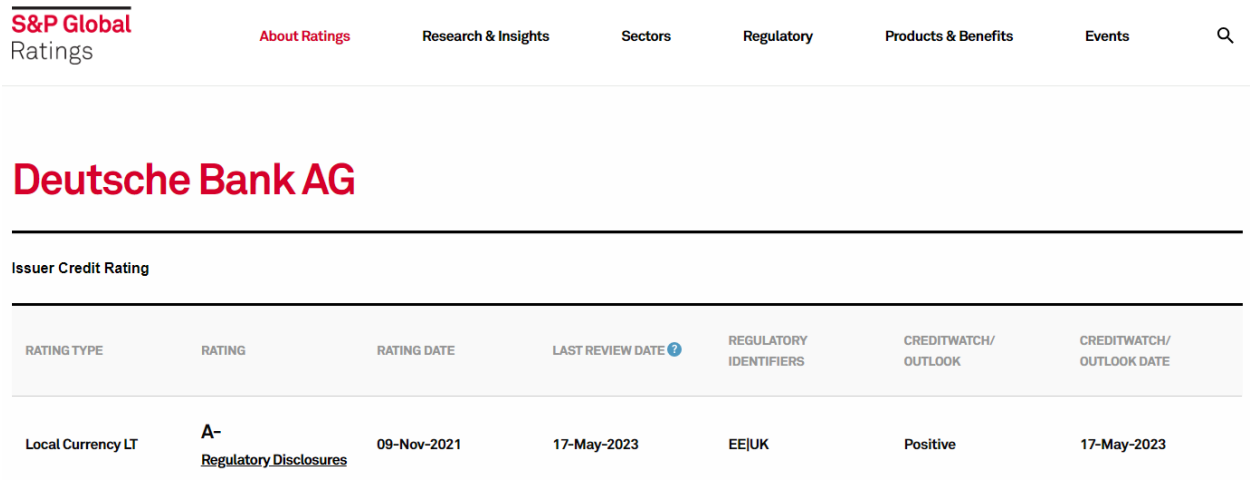
Bank of New York Mellon:

- Standard and Poor's rating: AA-



Deutsche Bank AG New York Branch:

- Standard and Poor's rating: A-



ATTACHMENT I: STIMULATION PLAN

Elk Hills 26R Storage Project

Facility Information

Facility name: CTV I Elk Hills 26R Project
357-7R and 355-7R

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA

Version History

File Name	Version	Date	Description of Change
Att I – Stimulation Plan_v1	1	05/31/22	Original document

Stimulation Plan

The need for stimulation to enhance the injectivity potential of the Monterey Formation 26R reservoir is not anticipated at this time. If it is determined that stimulation techniques are needed, a stimulation plan will be developed and submitted to EPA Region 9 for review and approval prior to conducting any stimulation.

U.S. ENVIRONMENTAL PROTECTION AGENCY

UNDERGROUND INJECTION CONTROL PERMIT

DRAFT PERMIT

CLASS VI INJECTION WELL

Permit Number: R9UIC-CA6-FY22-1.4

Well Name: 363C-27R

Issued to:

Carbon TerraVault JV Storage Company Sub 1, LLC

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 9
75 Hawthorne St.
San Francisco, CA 94105-3901

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
UNDERGROUND INJECTION CONTROL PERMIT: CLASS VI

Permit Number: R9UIC-CA6-FY22-1.4
Facility Name: CTV 1: Elk Hills 26R

Pursuant to the Safe Drinking Water Act and Underground Injection Control regulations of the U.S. Environmental Protection Agency codified at Title 40 of the Code of Federal Regulations (40 CFR) Parts 124, 144, 146, and 147,

Carbon TerraVault JV Storage Company Sub 1, LLC of Tupman, CA

hereinafter, the permittee, is hereby authorized to construct and operate a Class VI injection well located in the State of California, Kern County, T 30 S, R 23 E of Mount Diablo Base Meridian, Section 27, 35° 17' 31.0601" N, 119° 29' 21.4525" W, as part of the Elk Hills 26R Carbon Dioxide Storage Project. The well will inject a carbon dioxide stream (carbon dioxide is also called CO_2 in the attachments to this permit) sourced initially from the proposed Lone Cypress hydrogen plant, pre-combustion gas treatment, and the proposed Avnos Direct Air Capture facility (see Attachment B). All three initial carbon dioxide sources are to be located within the Elk Hills oil field. The permittee may request to inject carbon dioxide from additional emission sources in the future, subject to review and approval by EPA, as described in Section N of this permit. The permittee stated in their application that potential future sources of carbon dioxide may include: post combustion capture from the Elk Hills power plant, renewable fuel plants, post combustion capture from steam generators, other power plants, and industrial sources. The carbon dioxide stream, as characterized in the permit application and the administrative record, shall be a liquid, supercritical fluid, or gas. Injection is authorized into the Monterey Formation at a depth of approximately 6,000 feet below ground surface upon the express condition that the permittee meet the restrictions set forth herein. The designated confining zone for this injection is the Reef Ridge Shale Formation.

Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, directs federal agencies, to the greatest extent practical and permitted by law, to identify and address, as appropriate, disproportionate, and adverse human health or environmental impacts on people of color and low-income populations. See Exec. Order No. 12898, 59 Fed. Reg. 7629 (Feb. 11, 1994). Recently, Executive Order 14096, *Revitalizing Our Nation's Commitment to Environmental Justice for All*, supplemented this direction. See Exec. Order No. 14096, 88 Fed. Reg. 25251 (Apr. 21, 2023). As part of the decision-making process for this permit, EPA considered these executive orders and EPA's Environmental Justice Guidance for UIC Class VI Permitting and Primacy (Aug. 17, 2023). EPA's evaluation and consideration of environmental justice for this permit is described in EPA's Fact Sheet.

This permit is for the construction and operation of one Class VI injection well (well name 363C-27R); three other wells at the Elk Hills 26R Carbon Dioxide Storage Project are authorized under separate Class VI permits (Permit Nos. R9UIC-CA6-FY22-1.1, R9UIC-CA6-FY22-1.2 and R9UIC-CA6-FY22-1.3). Injection shall not commence until the operator has received written authorization from the Director of the Water Division of EPA Region 9, in accordance with Section S of this permit.

All references to Title 40 of the Code of Federal Regulations are to all regulations that are in effect on the date that this permit is effective. The following attachments are incorporated into this permit as enforceable conditions:

- A: Summary of Operating Requirements;
- B: Area of Review and Corrective Action Plan;
- C: Testing and Monitoring Plan;
- D: Well Plugging Plan;
- E: Post-injection Site Care and Site Closure Plan;
- F: Emergency and Remedial Response Plan;
- G: Construction Details;
- H: Financial Assurance Demonstration; and
- I: Stimulation Program.

This permit shall become effective on [Insert date], and shall remain in full force and effect during the operating life of the well and the post-injection site care period until site closure is authorized and completed, unless this permit is revoked and reissued, terminated, or modified pursuant to 40 CFR 144.39, 144.40, or 144.41. This permit shall also remain in effect upon delegation of primary enforcement responsibility of the UIC program for Class VI wells to the State of California until such time as the State issues its own permit to the permittee or the State chooses to adopt this permit as a State permit. The permit will expire in one year, if the permittee fails to commence construction on the well, unless a written request in electronic format for an extension of this one-year period has been approved by the Director. The permittee may request an expiration date sooner than the one-year period, provided no construction on the well has commenced. At least every five years from the effective date specified above, the permittee must re-evaluate the Area of Review and comply with 40 CFR 146.84(e). If results from the re-evaluated Area of Review are different from what is predicted in Attachment B of this permit, EPA may require the permittee to update the permit and the attachments.

Signed and Dated: _____

DRAFT

_____

[Insert Name of signing official]
[Insert Title, Office/Division]

PERMIT CONDITIONS

A. EFFECT OF PERMIT

The permittee is authorized to engage in underground injection in accordance with the conditions of this permit. Notwithstanding any other provisions of this permit, the permittee authorized by this permit shall not construct, operate, maintain, convert, plug, abandon, or conduct any other injection activity in a manner that allows the movement of injection, annulus or formation fluids into underground sources of drinking water (USDWs) or any unauthorized zones. The objective of this permit is to prevent the movement of fluids into or between USDWs or into any unauthorized zones consistent with the requirements at 40 CFR 146.86(a). Any underground injection activity not specifically authorized in this permit is prohibited. For purposes of enforcement, compliance with this permit during its term constitutes compliance with Part C of the Safe Drinking Water Act (SDWA). Such compliance does not constitute a defense to any action brought under Section 1431 of the SDWA or any other common or statutory law other than Part C of the SDWA.

Issuance of this permit does not convey property rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, any invasion of other private rights, or any infringement of State or local laws or regulations. Nothing in this permit, nor compliance with its terms, shall be construed to relieve the permittee of any duties under applicable State or local laws or regulations that are not preempted or superseded by the Federal SDWA Underground Injection Control (UIC) program.

B. PERMIT ACTIONS

1. **Modification, Revocation and Reissuance, and Termination –** The Director of the Water Division of Region 9 of the U.S. Environmental Protection Agency (EPA), hereinafter, the Director, may, for cause or upon request from any interested person, including the permittee, modify, revoke and reissue, or terminate this permit in accordance with 40 CFR 124.5, 144.12, 146.86(a), 144.39, and 144.40. The permit is also subject to minor modifications for cause as specified in 40 CFR 144.41. The filing of a request for a permit modification, revocation and reissuance, or termination, or the notification of planned changes, or anticipated noncompliance on the part of the permittee does not stay the applicability or enforceability of any permit condition.

2. **Minor Modifications –** Upon the consent of the permittee, the Director may modify this permit to make the corrections or allowances for minor changes in the permitted activity as listed in 40 CFR 144.41. Any permit modification not processed as a minor modification under 40 CFR 144.41 must be made for cause, and with part 124 draft permit and public notice as required in 40 CFR 144.39.

3. **Transfer of Permits** – This permit is not transferable to any person except in accordance with 40 CFR 144.38(a) and Section O(6)(b) of this permit.

C. SEVERABILITY

The provisions of this permit are severable, and if any provision of this permit or the application of any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

D. CONFIDENTIALITY

In accordance with 40 CFR part 2 (Public Information) and 40 CFR 144.5, any information submitted to EPA pursuant to this permit may be claimed as confidential business information by the submitter. Any such claim must be asserted at the time of submission by clearly identifying each page with the words "confidential business information" on every page containing such information. If no claim is made at the time of submission, EPA may make the information available to the public without further notice. If a claim is asserted, the validity of the claim will be assessed in accordance with the procedures in 40 CFR Part 2.

E. DEFINITION

All terms used in this permit shall have the meaning set forth in the SDWA and Underground Injection Control regulations specified at 40 CFR parts 124, 144, 146, and 147. Unless specifically stated otherwise, all references to "days" in this permit should be interpreted as calendar days.

F. DUTIES AND REQUIREMENTS

1. **Duty to Comply** – The permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation of the SDWA and is grounds for enforcement action, permit termination, revocation and reissuance, modification, or for denial of a permit renewal application.

2. **Duty to Reapply** – If the permittee wishes to continue an activity regulated by this permit after the expiration or termination of this permit, the permittee must apply for and obtain a new permit.

3. **Penalties for Violations of Permit Conditions** – Any person who violates a permit requirement is subject to civil penalties and other enforcement action under the SDWA. Any person who willfully violates permit conditions may be subject to criminal prosecution under the SDWA and other applicable statutes and regulations.

4. **Need to Halt or Reduce Activity Not a Defense –** It shall not be a defense for the permittee in an enforcement action to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

5. **Duty to Mitigate** – The permittee shall take all timely and reasonable steps necessary to minimize or correct any adverse impact on the environment resulting from noncompliance with this permit.

6. **Proper Operation and Maintenance** – The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control and related appurtenances which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance includes, among other things, effective performance, adequate funding, adequate operator staffing and training, and adequate laboratory and process controls, including appropriate quality assurance procedures. This provision requires the operation of back-up or auxiliary facilities or similar systems only when necessary to achieve compliance with the conditions of this permit.

7. **Duty to Provide Information** – The permittee shall furnish to the Director in an electronic format, within a time specified, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit or the UIC regulations. The permittee shall also furnish to the Director, upon request within a time specified, electronic copies of records required to be kept by this permit.

8. **Inspection and Entry** – The permittee shall allow the Director or an authorized representative, upon the presentation of credentials and other documents as may be required by law, to:

   (a) Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where electronic or non-electronic records are kept under the conditions of this permit;

   (b) Have access to and copy, at reasonable times, any electronic or non-electronic records that are kept under the conditions of this permit;

   (c) Inspect, at reasonable times, any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and

   (d) Sample or monitor, at reasonable times, for the purposes of assuring permit compliance or as otherwise authorized by the SDWA, any substances or parameters at any location, including facilities, equipment or operations regulated or required under this permit.

9. **Signatory Requirements** – All reports or other information, required to be submitted by this permit or requested by the Director shall be signed and certified in accordance with 40 CFR 144.32.

G. AREA OF REVIEW AND CORRECTIVE ACTION

1. The Area of Review (AoR) is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data. The permittee shall maintain and comply with the approved Area of Review and Corrective Action Plan (Attachment B of this permit) which is an enforceable condition of this permit and shall meet the requirements of 40 CFR 146.84.

2. As delineated in Attachment B, 157 wellbores within the AoR require plugging because the wellbores penetrate the injection zone or confining layer and will not be used for injection or monitoring within the 26R storage project. The wells are required to be properly plugged and abandoned prior to authorization of carbon dioxide injection.

3. At least sixty (60) days prior to commencing corrective action, the permittee shall submit procedures for performing corrective action on the identified deficient wells within the AoR and not commence any corrective action until the procedures are approved by the Director.

   (a) As corrective action activities are completed, the permittee shall provide periodic updates, including plugging reports, to the Director.

   (b) Corrective action on all deficient wells in the AoR must be complete, and approved in writing by EPA, before the permittee may commence injection pursuant to Section Q(3) of this permit.

4. At a fixed frequency of every five years, or more frequently when monitoring and operational conditions warrant, the permittee must reevaluate the area of review and perform any necessary corrective action in the manner specified in 40 CFR 146.84. The first reevaluation shall be completed no later than 5 years from the effective date of this permit unless the Director requests an earlier reevaluation. After conducting an AoR reevaluation, the permittee shall update the Area of Review and Corrective Action Plan or demonstrate to the Director that no update is needed.

5. Following each AoR reevaluation, the permittee shall submit the resultant information (i.e., the completed reevaluation analysis, along with either a revised AoR and Corrective Action Plan or a demonstration that the reevaluation analysis determined no revised Plan is needed) in an electronic format to the Director for review and approval. If a revised AoR and Corrective Action Plan is submitted and approved by the Director, the revised Plan becomes an enforceable condition of this permit.

6. To ensure permit activities do not increase environmental impacts, resource needs, and public health risks in already overburdened communities, along with the submittal of a

revised AoR and Corrective Action Plan, the permittee shall submit an updated EJScreen analysis that incorporates the revised AoR boundary.

H. FINANCIAL RESPONSIBILITY

1. **Financial Responsibility** – The permittee shall maintain financial responsibility and resources to meet the requirements of 40 CFR 146.85 and the conditions of this permit. Financial responsibility shall be maintained through all phases of the project. The permittee must maintain financial responsibility until site closure is authorized from the director as described in Section Q of this permit. Compliance with the financial responsibility requirements, including the applicable duration, described in this permit shall not relieve the permittee from complying with any other applicable Federal, State, and local financial responsibility requirements that are not preempted or superseded by the Federal SDWA UIC program.

   The financial instrument(s) must be sufficient to cover the cost of:

   (a) Corrective action (that meets the requirements of 40 CFR 146.84);

   (b) Injection well plugging (that meets the requirements of 40 CFR 146.92);

   (c) Post injection site care and site closure (that meets the requirements of 40 CFR (146.93) and;

   (d) Emergency and remedial response (that meets the requirements of 40 CFR 146.94).

   The permittee submitted a letter of credit, with a standby trust agreement, to cover financial assurance for items 1(a), (b), and (c) and submitted a certificate of insurance with details about a third-party insurance policy it will secure to cover financial assurance for 1(d). The EPA-approved financial assurance mechanisms are found in Attachment H and in the administrative record of this permit.

   The total initial cost estimates for these activities to be covered by the approved financial assurance mechanisms is $33,672,785. This amount covers all four Class VI injection well permits for the Elk Hills 26R CO_2 Storage Project.

2. **Cost Estimate Updates** – During the active life of the geologic sequestration project, the permittee must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) and provide this adjustment to the Director in an electronic format. The permittee must also provide to the Director written updates in an electronic format of adjustments to the cost estimate within 60 days of any amendments to the Project Plans included as Attachments B – F of this permit, which address items (a) through (d) in Section H(1) of this permit.

3. **Notification** –

(a) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the permittee, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase.

(b) Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the permittee has submitted a justification for the reduced cost estimate and received written approval from the Director. For requested reductions in the face amount of a financial instrument, the Director may provide notice to the public of the proposed reduction, prior to finalizing approval of the reduction.

(c) The permittee must notify the Director by certified mail and in an electronic format of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging, post-injection site care and site closure, and any applicable ongoing actions under Corrective Action or Emergency and Remedial Response.

(i) If the permittee or the third-party provider of a financial responsibility instrument is going through a bankruptcy, the permittee must notify the Director by certified mail and in an electronic format of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the permittee as debtor, within 10 days after commencement of the proceeding.

(ii) A permittee who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy.

4. **Establishing Other Coverage** – The permittee must establish other financial assurance or liability coverage acceptable to the Director, within 60 days of the occurrence of the events in Section H(2) or H(3) of this permit.

I. CONSTRUCTION

1. **Siting** – The permittee has demonstrated to the satisfaction of the Director that the well is in an area with suitable geology in accordance with the requirements at 40 CFR 146.83.

2. **Casing and Cementing** – Casing and cement or other materials used in the construction of the well must have sufficient structural strength for the life of the geologic sequestration project. All well materials must be compatible with all fluids with which the materials may

be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must prevent the movement of fluids into or between USDWs for the expected life of the well in accordance with 40 CFR 146.86. The casing and cement used in the construction of this well are shown in Attachment G of this permit and in the administrative record for this permit. Any change must be submitted in an electronic format for approval by the Director before installation.

3. **Tubing and Packer Specifications** – Tubing and packer materials used in the construction of the well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The permittee shall inject only through tubing with a packer set within the long string casing at a point within or below the confining zone immediately above the injection zone. The tubing and packer used in the well are represented in engineering drawings contained in Attachment G of this permit. Any change must be submitted in an electronic format for approval by the Director before installation.

J. PRE-INJECTION TESTING

1. Prior to the Director authorizing injection, the permittee shall perform all pre-injection logging, sampling, and testing specified at 40 CFR 146.87. This testing shall provide data sufficient to address the pre-operational testing objectives identified in Attachment G of this permit, including:

   (a) Logs, surveys, and tests to determine or verify the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in all relevant geologic formations. These tests shall include:

      (i) Deviation checks that meet the requirements of 40 CFR 146.87(a)(1);

      (ii) Logs and tests before and upon installation of the surface casing that meet the requirements of 40 CFR 146.87(a)(2);

      (iii) Logs and tests before and upon installation of the long-string casing that meet the requirements of 40 CFR 146.87(a)(3);

      (iv) Tests to demonstrate internal and external mechanical integrity that meet the requirements of 40 CFR 146.87(a)(4); and

      (v) Any alternative methods that are required by or approved by the Director pursuant to 40 CFR 146.87(a)(5).

   (b) Whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone that meet the requirements of 40 CFR 146.87(b);

(c) Records of the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone that meet the requirements of 40 CFR 146.87(c);

(d) Tests to provide information about the injection and confining zones, including calculated fracture pressure and the physical and chemical characteristics of the injection and confining zones and the formation fluids in the injection zone that meet the requirements of 40 CFR 146.87(d); and

(e) Tests to verify hydrogeologic characteristics of the injection zone that meet the requirements of 40 CFR 146.87(e), including:

(i) A pressure fall-off test; and

(ii) A pumping test or injectivity tests.

2. The permittee shall submit to the Director for approval in an electronic format a schedule for logging and testing activities 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test. The permittee must provide the Director or their representative with the opportunity to witness all logging, sampling, and testing required under this Section.

K. OPERATIONS

1. **Injection Fluids/Carbon Dioxide Sources –** The permittee will capture carbon dioxide from multiple sources during the life of the permit for injection into the Class VI well. Three initial sources of carbon dioxide are approved sources for injection: the proposed Lone Cypress hydrogen plant, pre-combustion gas treatment, and the proposed Avnos Direct Air Capture facility (see Attachment B). The permittee may propose additional sources of carbon dioxide for injection, subject to review and approval by EPA, as described in Section N of this permit.

2. **Injection Pressure Limitation** – The permittee must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case shall injection pressure initiate fractures or propagate existing fractures in the confining zone or cause the movement of injection or formation fluids into a USDW. The maximum injection pressure limit is listed in Attachment A.

3. **Stimulation Program** – Pursuant to requirements at 40 CFR 146.82(a)(9), all stimulation programs proposed by the permittee must be approved by the Director as a permit modification and incorporated into Attachment I of this permit.

4. **Additional Injection Limitation** – No injectate other than that which has been analyzed and approved by the Director under this permit in accordance with Section N of this permit shall be injected except fluids used for rework, and well tests as approved by the Director.

5. **Annulus Fluid** – The permittee must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director.

6. **Annulus/Tubing Pressure Differential** – Except during workovers or times of annulus maintenance, the permittee must maintain on the annulus a pressure that exceeds the operating injection pressure as specified in Attachment A of this permit, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.

7. **Automatic Alarms and Automatic Shut-off System** –

   (a) The permittee must:

      (i) Install, continuously operate, and maintain an automatic alarm and an automatic shut-off system or, at the discretion of the Director, down-hole shut-off systems, or other mechanical devices that provide equivalent protection; and

      (ii) Successfully demonstrate the functionality of the alarm system and shut-off system prior to the Director authorizing injection, and at a minimum of once every twelfth month after the last approved demonstration.

      (iii) Establish well-specific thresholds for activating the shut-off system and submit a revised Attachment A to the Director prior to the Director authorizing injection.

   (b) Testing under this Section must involve subjecting the system to simulated failure conditions and must be witnessed by the Director or his or her representative unless the Director authorizes an unwitnessed test in advance. The permittee must provide notice in an electronic format 30 days prior to running the test and must provide the Director or their representative the opportunity to attend. The test must be documented using either a mechanical or digital device which records the value of the parameter of interest, or by a service company job record. A final report including any additional interpretation necessary for evaluation of the testing must be submitted in an electronic format within the time period specified in Section O(4) of this permit.

8. **Precautions to Prevent Well Blowouts** – At all times, the permittee shall maintain on the well a pressure which will prevent the return of the injection fluid to the surface. The well bore must be filled with a high specific gravity fluid during workovers to maintain a positive (downward) gradient or a plug shall be installed which can resist the pressure differential. A blowout preventer must be installed and kept in proper operational condition whenever the wellhead is removed to work on the well. The permittee shall

follow procedures such as those below to assure that a backflow or blowout does not occur:

(a) Limit the temperature and/or corrosivity of the injectate; and

(b) Develop procedures necessary to assure that pressure imbalances do not occur.

9. **Circumstances Under Which Injection Must Cease** –

Injection shall cease when any of the following circumstances arise:

(a) Failure of the well to pass a mechanical integrity test;

(b) A loss of mechanical integrity during operation;

(c) The automatic alarm or automatic shut-off system is triggered;

(d) A significant unexpected change in the annulus or injection pressure;

(e) The Director determines that the well lacks mechanical integrity; or

(f) The permittee is unable to maintain compliance with any permit condition or regulatory requirement and the Director determines that injection should cease.

10. **Approaches for Ceasing Injection** –

(a) The permittee must shut-in the well by gradual reduction in the injection pressure as outlined in Attachment A of this permit; or

(b) The permittee must immediately cease injection and shut-in the well as outlined in the Emergency and Remedial Response Plan (Attachment F of this permit).

L. MECHANICAL INTEGRITY

1. **Standards** – Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the injection well must have and maintain mechanical integrity consistent with 40 CFR 146.89. To meet these requirements, mechanical integrity tests/demonstrations must be witnessed by the Director or an authorized representative of the Director unless prior approval has been granted by the Director to run an un-witnessed test. To conduct testing without an EPA representative, the following procedures must be followed.

(a) The permittee must submit prior notification in an electronic format within the time period specified in Section L(3) of this permit and if EPA informs the permittee that no

EPA representative is available this must be documented in the approved plan and testing report. The permittee must receive permission from the Director to proceed;

(b) The test must be performed in accordance with the Testing and Monitoring Plan (Attachment C of this permit) and documented using either a mechanical or digital device that records the value of the parameter of interest; and

(c) A final report including any additional interpretation necessary for evaluation of the testing must be submitted in an electronic format within the time period specified in Section O(4) of this permit.

2. **Mechanical Integrity Testing** – The permittee shall conduct a casing inspection log and mechanical integrity testing as follows:

(a) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate internal mechanical integrity pursuant to 40 CFR 146.87(a)(4):

(i) A pressure test with liquid or gas; and

(ii) A casing inspection log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(b) Prior to receiving authorization to inject, the permittee shall perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.87(a)(4):

(i) A tracer survey such as an oxygen activation log; or

(ii) A temperature or noise log; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(c) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the permittee must continuously monitor injection pressure, injection rate, injection volumes, pressure on the annulus between tubing and long string casing, and annulus fluid volume as specified in 40 CFR 146.88(e) and 146.89(b).

(d) At least once per year, the permittee must perform the following testing to demonstrate external mechanical integrity pursuant to 40 CFR 146.89(c):

(i) An Administrator-approved tracer survey such as an oxygen-activation log; or

(ii) A temperature or noise log. The Director may require such tests whenever the well is worked over; or

(iii) An alternative approved by the Director that has been approved by the Administrator pursuant to requirements at 40 CFR 146.89(e).

(e) After any workover that may compromise the internal mechanical integrity of the well, the well shall be tested by means of a pressure test approved by the Director and the well must pass the test to demonstrate mechanical integrity.

(f) Prior to plugging the well, the permittee shall demonstrate external mechanical integrity as described in the Injection Well Plugging Plan and that meets the requirements of 40 CFR 146.92(a).

(g) The Director may require the use of any other tests to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator pursuant to requirements at 40 CFR 146.89(e).

3. **Prior Notice and Reporting** –

(a) The permittee shall notify the Director in an electronic format of his or her intent to demonstrate mechanical integrity at least 30 days prior to such demonstration. At the discretion of the Director, a shorter time period may be allowed.

(b) Reports of mechanical integrity demonstrations which include logs must include an interpretation of results by a knowledgeable log analyst. The permittee shall report in an electronic format the results of a mechanical integrity demonstration within the time period specified in Section O(4) of this permit.

4. **Gauge and Meter Calibration** – The permittee shall calibrate all gauges used in mechanical integrity demonstrations and other required monitoring to an accuracy of not less than 0.5 percent of full scale, within one year prior to each required test. The date of the most recent calibration shall be noted on or near the gauge or meter. A copy of the calibration certificate shall be submitted to the Director in an electronic format with the report of the test. Pressure gauge resolution shall be no greater than five psi. Certain mechanical integrity and other testing may require greater accuracy and shall be identified in the procedure submitted to the Director prior to the test.

5. **Loss of Mechanical Integrity** –

(a) If the permittee or the Director finds that the well fails to demonstrate mechanical integrity during a test, or fails to maintain mechanical integrity during operation, or that a loss of mechanical integrity as defined by 40 CFR 146.89(a)(1) or (2) is suspected during operation (such as a significant unexpected change in the annulus or injection pressure), the permittee must:

(i) Cease injection in accordance with Sections K(8) and K(9)(a) or (b), and Attachments A or F of this permit;

(ii) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone. If there is evidence of USDW endangerment, implement the Emergency and Remedial Response Plan (Attachment F of this permit);

(iii) Follow the reporting requirements as directed in Section O of this permit;

(iv) Restore and demonstrate mechanical integrity to the satisfaction of the Director and receive written approval from the Director prior to resuming injection; and

(v) After receiving written approval to resume injection, notify the Director in an electronic format when injection is expected to resume.

(b) If a shutdown (*i.e.,* down-hole or at the surface) is triggered, the permittee must immediately investigate and identify as expeditiously as possible the cause of the shutdown. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required indicates that the well may be lacking mechanical integrity, the permittee must take the actions listed above in Section L(5)(a)(i) through (v).

(c) If the well loses mechanical integrity prior to the next scheduled test date, then the well must either be plugged or repaired and retested within 30 days of losing mechanical integrity. The permittee shall not resume injection until mechanical integrity is demonstrated and the Director gives written approval to recommence injection in cases where the well has lost mechanical integrity.

6. **Mechanical Integrity Testing on Request From Director** – The permittee shall demonstrate mechanical integrity at any time upon written notice from the Director.

M. TESTING AND MONITORING

1. **Testing and Monitoring Plan** –

(a) The permittee shall maintain and comply with the approved Testing and Monitoring Plan (Attachment C of this permit) and with the requirements at 40 CFR 144.51(j), 146.88(e), and 146.90. The Testing and Monitoring Plan is an enforceable condition of this permit. Samples and measurements taken for the purpose of monitoring shall be representative of the monitored activity. Procedures for all testing and monitoring under this permit must be submitted to the Director in an electronic format for approval at least 30 days prior to the test. In performing all testing and monitoring under this permit, the permittee must follow the procedures approved by the Director.

If the permittee is unable to follow the EPA-approved procedures, then, the permittee must contact the Director at least 30 days prior to testing to discuss options, if any are feasible. When the test report is submitted, a full explanation must be provided as to why any approved procedures were not followed. If the approved procedures were not followed, EPA may take an appropriate action, including but not limited to, requiring the permittee to re-run the test.

(b) The permittee must update the Testing and Monitoring Plan as required at 40 CFR 146.90 (j) to incorporate monitoring and operational data and in response to AoR reevaluations required under Section G(2) of this permit or demonstrate to the Director that no update is needed. The amended Testing and Monitoring Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation, following any significant changes to the facility such as addition of monitoring wells or newly permitted injection wells within the AoR, or when required by the Director.

(c) Following each update of the Testing and Monitoring Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and approval of the results. Once approved by the Director, the revised Testing and Monitoring Plan will become an enforceable condition of this permit.

2. **Carbon Dioxide Stream Analysis** – The permittee shall analyze the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics, as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(a).

3. **Continuous Monitoring** – The permittee shall maintain continuous monitoring devices and use them to monitor injection pressure, flow rate, volume, the pressure on the annulus between the tubing and the long string of casing, annulus fluid level, and temperature. This monitoring shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(b). The permittee shall maintain for EPA's inspection at the facility an appropriately scaled, continuous record of these monitoring results as well as original files of any digitally recorded information pertaining to these operations.

4. **Corrosion Monitoring** – The permittee shall perform corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion on a quarterly basis using the procedures described in the Testing and Monitoring Plan and in accordance with 40 CFR 146.90(c) to ensure that the well components meet the minimum standards for material strength and performance set forth in 40 CFR 146.86(b).

5. **Ground Water Quality Monitoring** – The permittee shall monitor ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones. This monitoring shall be performed for the parameters identified in the Testing and Monitoring Plan at the

locations and depths, and at frequencies described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(d).

6. **External Mechanical Integrity Testing** – The permittee shall demonstrate external mechanical integrity as described in the Testing and Monitoring Plan and Section L of this permit to meet the requirements of 40 CFR 146.90(e).

7. **Pressure Fall-Off Test** – The permittee shall conduct a pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information. The test shall be performed as described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(f).

8. **Plume and Pressure Front Tracking** –The permittee shall track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) as described in the Testing and Monitoring Plan.

   (a) The permittee shall use direct methods to track the position of the carbon dioxide plume and the pressure front in the injection zone as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(1).

   (b) The permittee shall use indirect methods to track the position of the carbon dioxide plume and pressure front as described in the Testing and Monitoring Plan and to meet the requirements of 40 CFR 146.90(g)(2).

   (c) If any indirect monitoring performed under Section M(8)(b) of this Permit detects increased pressure above the confining zone or other unanticipated results, the permittee shall increase the frequency of geochemical sampling under Section M(8)(a) to monthly sampling.

   (d) If data collection performed under Section M(8)(a) and M(8)(b) of this permit detects increased pressure above the confining zone or other unanticipated results the Director may require installation of additional monitoring wells.

9. **Surface Air and/or Soil Gas Monitoring** –

   (a) The permittee shall conduct any surface air monitoring or soil gas monitoring required by the Director to detect movement of carbon dioxide that could endanger a USDW or public health at the frequency and locations described in the Testing and Monitoring Plan to meet the requirements of 40 CFR 146.90(h).

   (b) Any surface air monitoring or soil gas monitoring described in the Testing and Monitoring Plan of this Permit must not conflict with air monitoring requirements set forth by other Federal, State, or local agencies for the project, including monitoring to comply with the approved Monitoring, Reporting, and Verification (MRV) plan under 40 CFR part 98, Subpart RR, monitoring required for California's Low-Carbon Fuel Standard

program compliance, and monitoring required by Kern County pursuant to a Conditional Use Permit (CUP) and environmental impact report (EIR) for the project.

10. **Leak Detection Monitoring** -

(a) The permittee shall conduct any leak detection monitoring at the wellhead required by the Director to ensure injection well integrity and detect movement of carbon dioxide that could endanger a USDW or public health at the frequency and locations described in the Testing and Monitoring Plan.

(b) Any leak detection monitoring described in the Testing and Monitoring Plan of this Permit should be consistent with EPA's document "Leak Detection and Repair – A Best Practices Guide" (October 2007), and must not conflict with leak detection monitoring requirements set forth by other Federal, State, or local agencies for the project, including monitoring to comply with the approved Monitoring, Reporting and Verification (MRV) plan under 40 CFR part 98, subpart RR, monitoring required for California's Low-Carbon Fuel Standard program compliance, and monitoring required by Kern County pursuant to a Conditional Use Permit (CUP) and environmental impact report (EIR) for the project.

11. **Additional Monitoring** – If required by the Director as provided in 40 CFR 146.90(i), the permittee shall perform any additional monitoring determined to be necessary to support, upgrade, and improve computational modeling of the AoR evaluation required under 40 CFR 146.84(c) and to determine compliance with standards under 40 CFR 144.12 or 40 CFR 146.86(a). This monitoring shall be performed as described in a modification to the Testing and Monitoring Plan.

N. INJECTION OF CARBON DIOXIDE FROM ADDITIONAL SOURCES

1. The permittee must receive written approval from the Director before injecting carbon dioxide from a source that is not fully described in Attachment B of this permit. Carbon dioxide from additional sources will not be approved if the Director determines that the carbon dioxide stream from the proposed additional source is incompatible, or will adversely interact, with the injection well material, injection formation, or confining zone.

2. Proposed additional sources of carbon dioxide will be evaluated by EPA to determine if the additional source is approvable, and if so, whether its addition requires a major permit modification or a minor permit modification.

(a) Conditions that will result in a major permit modification include, but are not limited to, if the proposed additional source of carbon dioxide meets any of the following:

i. The addition of the proposed carbon dioxide source would increase the injection volume or injection pressure above the amount authorized in this permit; or

ii. The proposed additional carbon dioxide source is determined to have a chemical composition outside of the range of injectate compositions listed in Attachment B of this permit, or

iii. The addition of the proposed carbon dioxide source would interfere with the operation of the facility or its ability to meet conditions described in the permit; or

iv. The addition of the proposed carbon dioxide source would result in a material and substantial alteration or addition to the permitted Class VI injection activity which justifies the application of permit conditions that are different or absent in the existing permit; or

v. The Director determines that addition of the proposed carbon dioxide source does not meet criteria for a minor permit modification.

3. In proposing an additional source of carbon dioxide for the Director's approval, the permittee shall provide the Director with the following information:

   (a) The analytical parameters of the proposed additional carbon dioxide stream from the proposed source as described in the Testing and Monitoring Plan of this permit;

   (b) A description of the industry in which the proposed additional carbon dioxide stream will be produced from;

   (c) The name and address of the proposed additional carbon dioxide source;

   (d) An evaluation of the impact the proposed carbon dioxide source (the creation, capture, and transportation of carbon dioxide) will have on criteria pollutant and hazardous air pollutant emissions in the area; and

   (e) An assessment of the compatibility of the carbon dioxide stream with subsurface fluids and minerals, and assurance that the construction materials of the injection wells and other wells that may encounter the injected plume are still compatible (e.g., will not corrode over time due to the chemical interactions).

4. All proposed additional sources of carbon dioxide will require pre-approval by Kern County Planning and Natural Resources Department, and any necessary mitigation measures pursuant to an approved Conditional Use Permit and Environmental Impact Report.

5. The public shall be notified within 30 days when a proposed additional carbon dioxide source is submitted to EPA for review.

6. The public shall be notified 30 days before the injection of an EPA-approved additional

carbon dioxide stream is injected.

O. REPORTING AND RECORDKEEPING

1. **Electronic Reporting** – Electronic reports, submittals, notifications, and records made and maintained by the permittee under this permit must be in an electronic format approved by EPA. The permittee shall electronically submit all required reports to the Director at:

   https://epa.velo.pnnl.gov/operators

2. **Semi-Annual Reports** – The permittee shall submit semi-annual reports containing:

   (a) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;

   (b) Monthly average, maximum, and minimum values for injection pressure, flow rate and daily volume, temperature, and annular pressure;

   (c) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;

   (d) A description of any event which triggers the shut-off systems required in Section K(6) of this permit pursuant to 40 CFR 146.88(e), and the response taken;

   (e) The monthly volume or mass of the carbon dioxide stream injected over the reporting period and the volume or mass injected cumulatively over the life of the project;

   (f) Monthly annulus fluid volume added or produced; and

   (g) Results of the continuous monitoring required in Section M(3), including:

      (i) A tabulation of: (1) daily maximum injection pressure; (2) daily minimum annulus pressure; (3) daily minimum value of the difference between simultaneous measurements of annulus and injection pressure; (4) daily volume; (5) daily maximum flow rate; and (6) average annulus tank fluid level; and

      (ii) Graph(s) of the continuous monitoring as required in Section M(3) of this permit, or of daily average values of these parameters. The injection pressure, injection volume and flow rate, annulus fluid level, annulus pressure, and temperature shall be submitted on one or more graphs, using contrasting symbols or colors, or in another manner approved by the Director; and

   (h) Results of any additional monitoring identified in the Testing and Monitoring Plan and described in Section M of this permit.

3. **<u>24-Hour Reporting</u>** –

(a) The permittee shall report to the Director any permit noncompliance which may endanger human health or the environment or any events that require implementation of actions in the Emergency and Remedial Response Plan (Attachment F of this permit). Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. Such verbal reports shall include, but not be limited to, the following information:

(i) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW, or any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW;

(ii) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;

(iii) Any triggering of the shut-off system required in Section K(6) of this permit (i.e., down-hole or at the surface);

(iv) Any failure to maintain mechanical integrity;

(v) Pursuant to compliance with the requirement at 40 CFR 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere; and

(vi) Actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F of this permit).

(b) A written submission shall be provided to the Director in an electronic format within five days of the time the permittee becomes aware of the circumstances described in Section O(3)(a) of this permit. The submission shall contain: a description of the noncompliance and its cause; the period of noncompliance, including exact dates and times, and, if the noncompliance has not been corrected, the anticipated time it is expected to continue as well as actions taken to implement appropriate protocols outlined in the Emergency and Remedial Response Plan (Attachment F of this permit); and steps taken or planned to reduce, eliminate and prevent recurrence of the noncompliance.

4. **<u>Reports on Well Tests and Workovers</u>** – The permittee shall report, within 30 days, the results of:

(a) Periodic tests of mechanical integrity;

(b) Any well workover, including stimulation;

(c) Any other test of the injection well conducted by the permittee if required by the Director; and

(d) Any test of any monitoring well required by this permit.

5. **Advance Notice Reporting** –

(a) **Well Tests** – The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned workover, stimulation, or other well test.

(b) **Planned Changes** – The permittee shall give written notice to the Director in an electronic format, as soon as possible, of any planned physical alterations or additions to the permitted injection facility other than minor repair/replacement or maintenance activities. An analysis of any new injection fluid and, as specified in Section N of this Permit, an analysis of any additional source of carbon dioxide, shall be submitted to the Director for review and written approval at least 60 days prior to injection; this approval may result in a permit modification.

(c) **Anticipated Noncompliance** – The permittee shall give at least 30 days advance written notice to the Director in an electronic format of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

6. **Additional Reports** –

(a) **Compliance Schedules** – Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule of this permit shall be submitted in an electronic format by the permittee no later than 30 days following each schedule date.

(b) **Transfer of Permits** – This permit is not transferable to any person except after notice is sent to the Director in an electronic format at least 30 days prior to transfer and the requirements of 40 CFR 144.38(a) have been met. Pursuant to requirements at 40 CFR 144.38(a), the Director will require modification or revocation and reissuance of the permit to change the name of the permittee and incorporate such other requirements as may be necessary under the SDWA.

(c) **Other Noncompliance** – The permittee shall report in an electronic format all other instances of noncompliance not otherwise reported with the next monitoring report. The reports shall contain the information listed in Section O(3)(b) of this permit.

(d) **Other Information** – When the permittee becomes aware of failure to submit any relevant facts in the permit application or that incorrect information was submitted in a permit application or in any report to the Director, the permittee shall submit such

facts or corrected information in an electronic format within 10 days in accordance with 40 CFR 144.51(l)(8).

(e) **Report on Permit Review** – Within 30 days from the effective date of this permit, the permittee shall certify to the Director in an electronic format that he or she has read and is personally familiar with all terms and conditions of this permit.

7. Records –

(a) The permittee shall retain records and all monitoring information, including all calibration and maintenance records and all original chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit (including records from pre-injection, active injection, and post-injection phases) for a period of at least 10 years from collection.

(b) The permittee shall maintain records of all data required to complete the permit application form for this permit and any supplemental information (e.g., modeling inputs for AoR delineations and reevaluations, plan modifications) submitted under 40 CFR 144.27, 144.31, 144.39, and 144.41 for a period of at least 10 years after site closure.

(c) The permittee shall retain records concerning the nature and composition of all injected fluids until 10 years after site closure.

(d) The retention periods specified in Section O(7)(a) through (c) of this permit may be extended by request of the Director at any time. The permittee shall continue to retain records after the retention period specified in Section O(7)(a) through (c) of this permit or any requested extension thereof expires unless the permittee delivers the records to the Director or obtains written approval from the Director to discard the records.

(e) Records of monitoring information shall include:

(i) The date, exact place, and time of sampling or measurements;

(ii) The name(s) of the individual(s) who performed the sampling or measurements;

(iii) A precise description of both sampling methodology and the handling of samples;

(iv) The date(s) analyses were performed;

(v) The name(s) of the individual(s) who performed the analyses;

(vi) The analytical techniques or methods used; and

(vii) The results of such analyses.

P. PUBLIC AVAILABILITY OF MONITORING AND COMPLIANCE DATA

1. The permittee shall develop and maintain a publicly accessible website with all available monitoring data collected under this Permit. The website must be accessible to persons with disabilities and compliant with Section 508, and it shall include:

   (a) Semi-annual monitoring reports and data;

   (b) An executive summary (in both English and Spanish) that interprets the Semi-annual monitoring reports and data;

   (c) Real-time display of data collected for any Surface Air/Soil Gas Monitoring required under Section M(9) and Leak Detection Monitoring required under Section M(10) of this Permit; and

   (d) Notification of any permit non-compliance on a quarterly basis, including the steps taken to resolve the non-compliance, and any actions taken to prevent a re-occurrence of the non-compliance.

Q. WELL PLUGGING, POST-INJECTION SITE CARE, AND SITE CLOSURE

1. **Well Plugging Plan** – The permittee shall maintain and comply with the approved Well Plugging Plan (Attachment D of this permit) which is an enforceable condition of this permit and shall meet the requirements of 40 CFR 146.92.

2. **Revision of Well Plugging Plan** – If the permittee finds it necessary to change the Well Plugging Plan (Attachment D of this permit), a revised plan shall be submitted in an electronic format to the Director for written approval. Any amendments to the Well Plugging Plan must be approved by the Director, must be incorporated into the permit and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41.

3. **Notice of Plugging and Abandonment** – The permittee must notify the Director in writing in an electronic format pursuant to 40 CFR 146.92(c), at least 60 days before plugging, conversion or abandonment of a well. At the discretion of the Director, a shorter notice period may be allowed.

4. **Plugging and Abandonment Approval and Report** –

   (a) The permittee must receive written approval of the Director before plugging the well and shall plug and abandon the well in accordance with 40 CFR 146.92, as provided in the Well Plugging Plan (Attachment D of this permit).

   (b) Within 60 days after plugging, the permittee must submit in an electronic format a plugging report to the Director. The report must be certified as accurate by the

permittee and by the person who performed the plugging operation (if other than the permittee.) The permittee shall retain the well plugging report in an electronic format for 10 years following site closure. The report must include:

(i) A statement that the well was plugged in accordance with the Well Plugging Plan previously approved by the Director (Attachment D of this permit); or

(ii) If the actual plugging differed from the approved plan, a statement describing the actual plugging and an updated plan specifying the differences from the plan previously submitted and explaining why the Director should approve such deviation. If the Director determines that a deviation from the plan incorporated in this permit may endanger USDWs, the permittee shall re-plug the well as required by the Director.

5. **Temporary Abandonment** – If the permittee ceases injection into the well for more than 24 consecutive months, the well is considered to be in a temporarily abandoned status, and the permittee shall plug and abandon the well in accordance with the approved Well Plugging Plan, 40 CFR 144.52 (a)(6), and 40 CFR 146.92, or make a demonstration of non-endangerment of this well while it is in temporary abandonment status. During any periods of temporary abandonment or disuse, the well will be tested to ensure that it maintains mechanical integrity, according to the requirements and frequency specified in Section L(2) of this permit. The permittee shall continue to comply with the conditions of this permit, including all monitoring and reporting requirements according to the frequencies outlined in the permit.

6. **Post-Injection Site Care and Site Closure Plan** –

(a) The permittee shall maintain and comply with the Post-Injection Site Care and Site Closure Plan (Attachment E of this permit), which meets the requirements of 40 CFR 146.93 and is an enforceable condition of this permit. The permittee shall:

(i) Upon cessation of injection, either submit in an electronic format for the Director's approval an amended Post-Injection Site Care and Site Closure Plan or demonstrate through monitoring data and modeling results that no amendment to the plan is needed.

(ii) At any time during the life of the project, the permittee may modify and resubmit in an electronic format the Post-Injection Site Care and Site Closure Plan for the Director's approval. The permittee may, as part of such modifications to the Plan, request a modification to the post-injection site care timeframe that includes documentation of the information at 40 CFR 146.93(c)(1).

(b) The permittee shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs

are not being endangered, as specified in the Post-Injection Site Care and Site Closure Plan and in 40 CFR 146.90, and 40 CFR 146.93, including:

(i) Ground water quality monitoring;

(ii) Tracking the position of the carbon dioxide plume and pressure front including direct pressure monitoring and geochemical plume monitoring and the use of indirect methods;

(iii) Any other required monitoring, e.g., soil gas and/or surface air monitoring described in the Post-Injection Site Care and Site Closure Plan;

(iv) The permittee shall submit in an electronic format the results of all monitoring performed according to the schedule identified in the Post-Injection Site Care and Site Closure Plan; and

(v) The permittee shall continue to conduct post-injection site monitoring for at least 50 years or for the duration of any alternative timeframe approved pursuant to 40 CFR 146.93(c) and the Post-Injection Site Care and Site Closure Plan.

(c) The post-injection monitoring must continue until the project no longer poses an endangerment to USDWs and the demonstration pursuant to 40 CFR 146.93(b)(2) and as described in Section Q(6)(d) of this permit is approved by the Director.

(d) Prior to authorization for site closure, the permittee shall submit to the Director for review and approval, in an electronic format, a demonstration, based on information collected pursuant to Section Q(5)(b) of this permit, that the carbon dioxide plume and the associated pressure front do not pose an endangerment to USDWs and that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs, as required under 40 CFR 146.93(b)(3). The Director reserves the right to amend the post-injection site monitoring requirements (including extending the monitoring period) if the carbon dioxide plume and the associated pressure front have not stabilized or there is a concern that USDWs are being endangered.

(e) The permittee shall notify the Director in an electronic format at least 120 days before site closure. At this time, if any changes to the approved Post-Injection Site Care and Site Closure Plan in Attachment E of this permit are proposed, the permittee shall submit a revised plan.

(f) After the Director has authorized site closure, the permittee shall plug all monitoring wells as specified in Attachment E of this permit – the Post-Injection Site Care and Site Closure Plan – in a manner which will not allow movement of injection or formation fluids that endangers a USDW. The permittee shall also restore the site to its pre-injection condition.

(g) The permittee shall submit a site closure report in an electronic format to the Director within 90 days of site closure. The report must include the information specified at 40 CFR 146.93(f).

(h) The permittee shall record a notation on the deed to the facility property or any other document that is normally examined during a title search that will in perpetuity provide any potential purchaser of the property the following information:

(i) The fact that land has been used to sequester carbon dioxide;

(ii) The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and

(iii) The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.

(i) The permittee shall retain for 10 years following site closure an electronic copy of the site closure report, records collected during the post-injection site care period, and any other records required under 40 CFR 146.91(f)(4). The permittee shall deliver the records in an electronic format to the Director at the conclusion of the retention period.

R. EMERGENCY AND REMEDIAL RESPONSE

1. The Emergency and Remedial Response Plan describes actions the permittee must take to address movement of the injection or formation fluids, including surface leaks of carbon dioxide or other contaminants, that may cause an endangerment to a USDW or public health during construction, operation, and post-injection site care periods. The permittee shall maintain and comply with the approved Emergency and Remedial Response Plan (Attachment F of this permit), which is an enforceable condition of this permit, and with 40 CFR 146.94.

   Prior to the Director authorizing injection, the permittee shall revise the Emergency and Remedial Response Plan to include a description and documentation of the contracts the permittee holds with service providers, including any contracts or access agreements with local emergency response authorities, to perform the actions outlined in the Emergency and Remedial Response Plan, and shall confirm that any required payments were made to Kern County Planning and Natural Resources Department, as required by the approved Conditional Use Permits, for transfer to the Kern County Fire Department for equipment and training specific to the detection and control of emergency situations caused by the release of carbon dioxide.

2. If the permittee obtains evidence that the injected carbon dioxide or associated pressure front may cause endangerment to a USDW or public health, the permittee must:

   (a) Cease injection in accordance with Sections K(8) and K(9)(a) or (b), and Attachments A or F of this permit;

   (b) Take all steps reasonably necessary to identify and characterize any release;

   (c) Notify the Director within 24 hours; and

   (d) Implement the Emergency and Remedial Response Plan (Attachment F of this permit) approved by the Director.

3. At least every five years, or more frequently when monitoring and operational conditions warrant, the permittee shall review and update the Emergency and Remedial Response Plan as required at 40 CFR 146.94(d) or demonstrate to the Director that no update is needed. The amended Emergency and Remedial Response Plan or demonstration shall be submitted to the Director in an electronic format within one year of an AoR reevaluation, following any significant changes to the facility such as addition of injection wells, or when required by the Director.

4. Following each update of the Emergency and Remedial Response Plan or a demonstration that no update is needed, the permittee shall submit the resultant information in an electronic format to the Director for review and confirmation of the results. Once approved by the Director, the revised Emergency and Remedial Response Plan will become an enforceable condition of this permit.

S. COMMENCING INJECTION

The permittee may not commence injection until:

1. Results of the formation testing and logging program and a demonstration that all pre-operational testing objectives have been met as specified in Section J of this permit and in 40 CFR 146.87 are submitted to the Director in an electronic format and subsequently reviewed and approved by the Director;

2. Mechanical integrity of the well has been demonstrated in accordance with 40 CFR 146.89(a)(1) and (2), and in accordance with Section L(1) through (3) of this permit;

3. The completion of corrective action required by the Area of Review and Corrective Action Plan found in Attachment B of this permit in accordance with 40 CFR 146.84;

4. All requirements at 40 CFR 146.82(c) have been met, including but not limited to reviewing and updating of the Area of Review and Corrective Action, Testing and Monitoring, Well

Plugging, Post-Injection Site Care and Site Closure, and Emergency and Remedial Response plans to incorporate final site characterization information, final delineation of the AoR, and the results of pre-injection testing, and information has been submitted in an electronic format, reviewed and approved by the Director;

5. The permittee has submitted the results of an analysis of the physical and chemical characteristic of the carbon dioxide stream for all analytical parameters identified in the Testing and Monitoring Plan (Attachment C of this Permit).

6. Construction is complete and the permittee has submitted to the Director in an electronic format a notice that completed construction is in compliance with 40 CFR 146.86 and Section I of this permit;

7. The Director has inspected or otherwise reviewed the injection well and all submitted information and finds it is in compliance with the conditions of this permit;

8. The Director has approved demonstration of the alarm system and shut-off system under Section K(6) of this permit;

9. The Permittee has revised the Emergency and Remedial Response Plan to include a description and documentation of the contracts the permittee holds with service providers in order to perform the actions outlined in the Emergency and Remedial Response Plan;

10. The Director has approved the publicly accessible website required under Section P of this permit; and

11. The Director has given written authorization to commence injection.

ATTACHMENTS

These attachments include, but are not limited to, permit conditions and plans concerning operating procedures, monitoring and reporting, as required by 40 CFR parts 144 and 146. The permittee shall comply with these conditions and adhere to these plans as approved by the Director, as follows:

A. SUMMARY OF OPERATING REQUIREMENTS

B. AREA OF REVIEW AND CORRECTIVE ACTION PLAN

C. TESTING AND MONITORING PLAN

D. WELL PLUGGING PLAN

E. POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

F. EMERGENCY AND REMEDIAL RESPONSE PLAN

G. CONSTRUCTION DETAILS

H. FINANCIAL ASSURANCE DEMONSTRATION

I. STIMULATION PROGRAM

SUMMARY OF REQUIREMENTS

CLASS VI OPERATING AND REPORTING CONDITIONS

Elk Hills 26R Storage Project

Facility Information

Facility name: Elk Hills 26R Storage Project
363C-27R

Well location: Elk Hills Oil Field, Kern County, CA
35°17'31.0601"N / 6117242.96
119°29'21.4525"W / 2295866.13

Table 1. Injection Well Operating Conditions

PARAMETER/CONDITION	LIMITATION or PERMITTED VALUE
Maximum Injection Pressure - Surface	2020 psi
Maximum Injection Pressure - Bottomhole	4226 psi
Annulus Pressure	3206 psi
Annulus Pressure/Tubing Differential	535 psi
Maximum CO_2 Injection Rate	25 mmscfpd

There will be continuous monitoring of injection pressure, rate and annulus pressure for the injector, as described in the well Construction, Operation and Plugging document for 363C-26R.

The maximum injection pressure, which serves to prevent confining-formation fracturing, was determined: using the fracture gradient of 0.701psi/ft obtained from Fracture stimulation data obtained from well 388-26R in the 26R reservoir multiplied by 0.9, per 40 CFR 146.88(a).

Routine Shutdown Procedure

For injection shutdowns occurring under routine conditions (e.g., for well workovers), the permittee will reduce CO_2 injection at a rate of 165 tons per day over a 6 day period to ensure protection of health, safety, and the environment. This procedure applies to routine shutdowns and to “gradual shutdowns” described in the Emergency and Remedial Response plan. (Procedures that address immediately shutting in the well are in the Emergency and Remedial Response Plan of this permit.)

Table 2. Class VI Injection Well Reporting Requirements

ACTIVITY	REPORTING REQUIREMENTS
CO_2 stream characterization	Semi-annually
Injection pressure, injection rate, injection volume, pressure on the annulus, and annulus fluid level	Semi-annually
Corrosion monitoring	Semi-annually
External MITs	Within 30 days of completion of test
Pressure fall-off testing	In the next semi-annual report

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

Table 3. Class VI Project Reporting Requirements

ACTIVITY	REPORTING REQUIREMENTS
Groundwater quality monitoring	Semi-annually
Plume and pressure front tracking	In the next semi-annual report
Monitoring well MITs	Within 30 days of completion of test
Financial responsibility updates pursuant to H.2 and H.3(a) of this permit	Within 60 days of update

Note: All testing and monitoring frequencies and methodologies are included in the Testing and Monitoring Plan of this permit.

ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Facility Information

Facility name: Elk Hills 26R Storage Project

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment B - AoR_CA	1	01/11/21
Attachment B - AoR_CA	2	05/31/22
Attachment B - AoR_CA	3	12/21/22
Attachment B - AoR_CA	4	05/14/2023
Attachment B – AoR_CA	5	6/23/2023

Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase

- Liquid and gas relative permeability
- Capillary pressure data
- Current saturation, pressure, and temperature estimates

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the Elk Hills 26R project, the AoR encompasses the maximum aerial extent of the CO_2 plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO_2 plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of CO_2 in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of CO_2 and residual oil in the reservoir. Solubility of CO_2 in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of CO_2 stored and simulates lateral and vertical movement of the CO_2 to define the AoR.

The simulator predicts the evolution of the CO_2 plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.
2. Forecasting the CO_2 plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).
3. Assessing the movement of CO_2 after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO_2 sequestration peer reviewed papers, including:

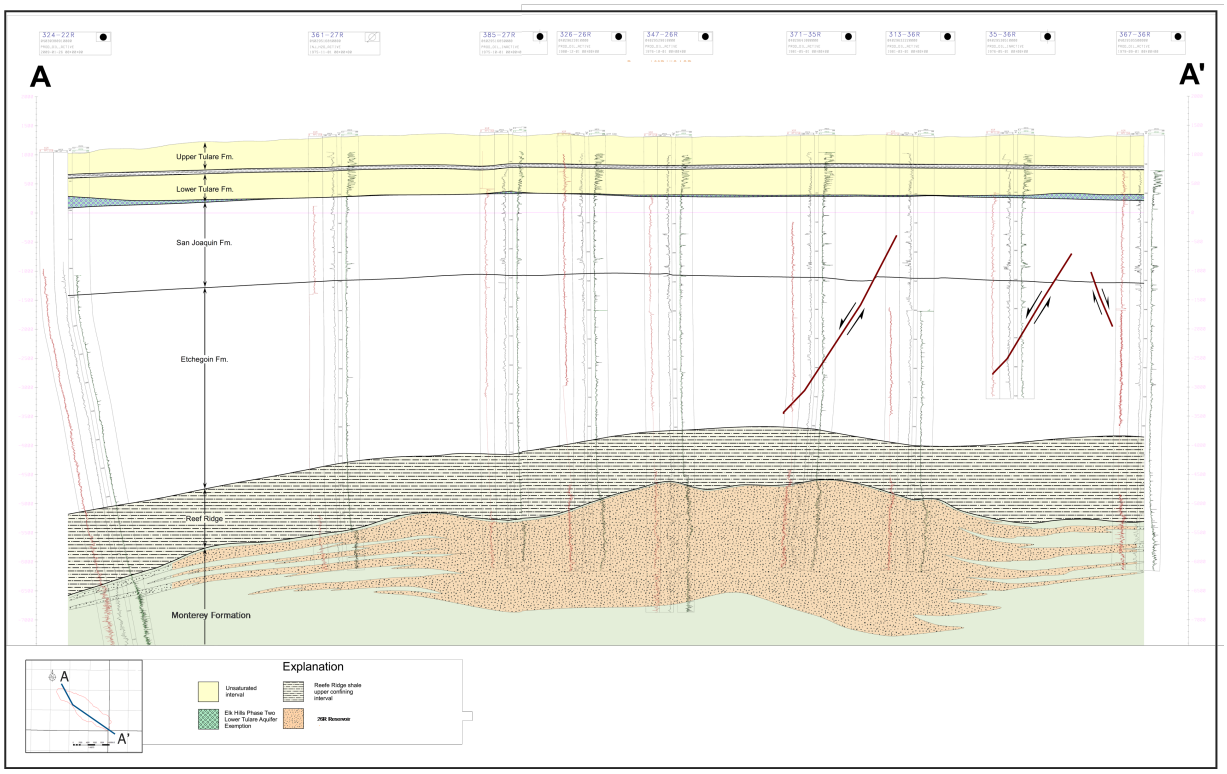
1. Simulation of CO_2 EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al
2. Model Predictions Via History Matching of CO_2 Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al
3. Geomechanical Risk Mitigation for CO_2 Sequestration in Saline Aquifers. Tran, Davis et al.

Site Geology and Hydrology

The 31S field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation 26R sands, present in the southwestern portion of the field pinch out on top of the structure and along strike (Figure 1).

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation 26R, but for all Monterey accumulations in the greater Elk Hills area.

Figure 1: Cross-section A-A' showing lateral Monterey Formation 26R sand pinch-out.



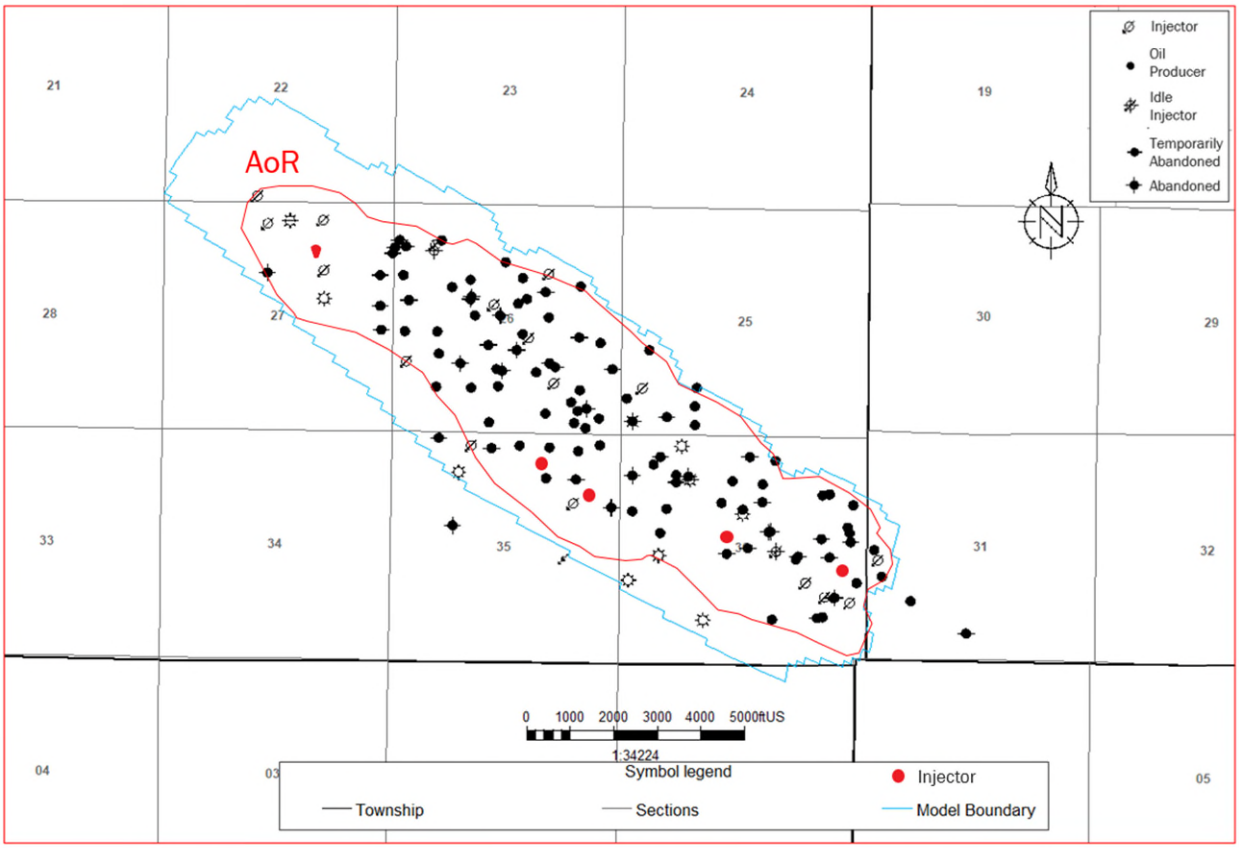
The Elk Hills 26R Class VI injection wells will target injection in the Monterey Formation 26R sands. The Monterey Formation 26R oil and gas reservoir was discovered in the 1940's and has been developed with primary production and pressure maintenance (Table 1: Production and Injection volumes). Starting in the year 1998, pressure maintenance ceased, and the gas cap reservoir was "blown-down", depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 150-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

Table 1: Production and injection volumes for the Monterey Formation 26R reservoir.

Process	Phase	Volume
Production	Oil	222 million barrels
	Gas	1,244 billion cubic feet
	Water	81 million barrels
Injection	Water	114 million barrels
	Gas	841 billion cubic feet

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology, and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir, and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

Figure 2: Location of wells with open-hole log data used to develop the static model and computational model boundary.



Model Domain

A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2. The lateral dimensions and vertical thickness of the geomodel were chosen to capture the maximum extent of the mapped 26R reservoir. Well logs from the wells shown in Figure 2 were used to map the extent and delineate the edges of the reservoir where the reservoir sands pinchout or transition to shale. The total grid dimensions were chosen to adequately capture the reservoir properties and heterogeneity, while at the same time maintaining computational efficiency.

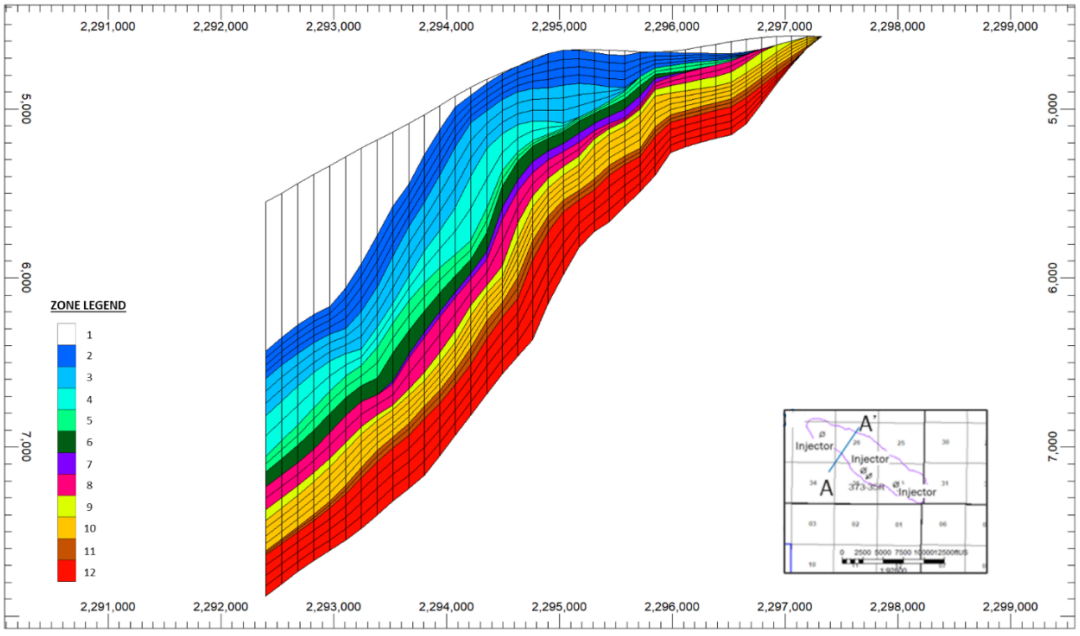
Table 2. Model domain information.

Coordinate System	State Plane		
Horizontal Datum	NAD 83		
Coordinate System Units	Feet		
Zone	CA83-VF		
FIPSZONE	0405	**ADSZONE**	3376
Coordinate of X min	6113669.29	**Coordinate of X max**	6130553.74
Coordinate of Y min	2286478.43	**Coordinate of Y max**	2299980.65
Elevation of bottom of domain	-6651.18	**Elevation of bottom of domain**	-3544.42

The geo-cellular grid is uniformly spaced throughout the 3.7 square mile model area (Figure 2) at 190 feet by 150 feet. The model is oriented at 18 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were selected to define plume extent and edges of the Monterey Formation 26R reservoir.

The reservoir has been separated into 12 zones and 27 layers (Figure 3) respectively and an average grid cell height of 117 feet. Each of the 12 zones is a mappable sand and were modeled separately to ensure stationarity of the geostatistical model. With a data driven geostatistical model, the model can discretize the reservoir into multiple zones. Grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing CO_2 movement. Well data that defines the stratigraphy also defines the structure of the 26R storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

Figure 3: Static model layering of the Monterey Formation 26R reservoir showing the 12 zones, and the 27 layers. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale laterally.



Porosity and Permeability

Figure 2 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Figure 4A shows how the log derived porosity compares to the upscaled model (synthetic) porosity for 363-27R (track five with log derived in black and the Upscaled model / synthetic porosity in blue). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 4B) that is dependent on porosity and clay volume.

Figure 4A: Log derived and Model Upscaled (Synthetic porosity) for 363-27R (track five with log derived in black and the Upscaled model synthetic in blue).

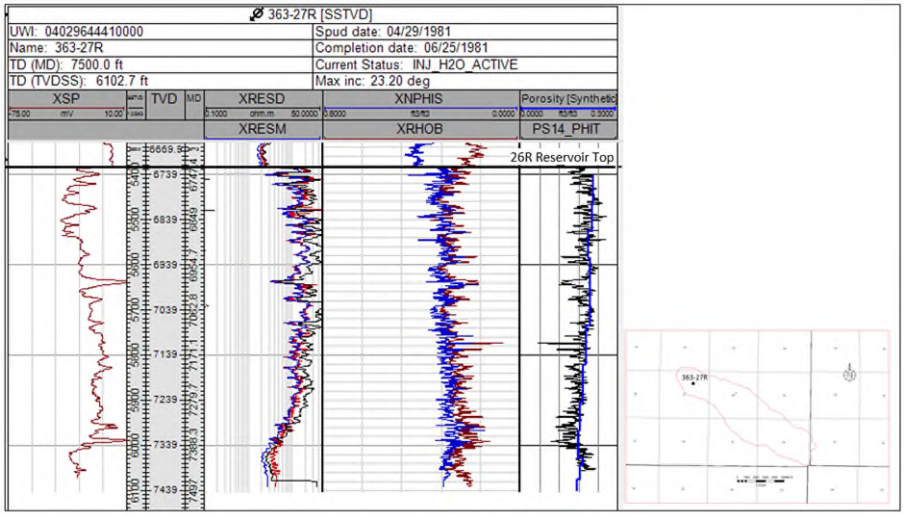


Figure 5B: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.

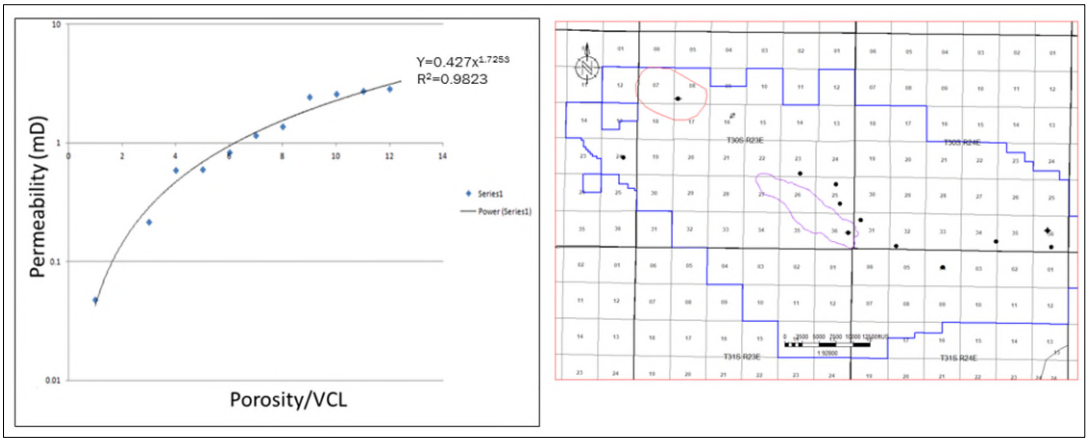


Figure 6: Monterey Formation 26R sands porosity and permeability distribution in the static model.

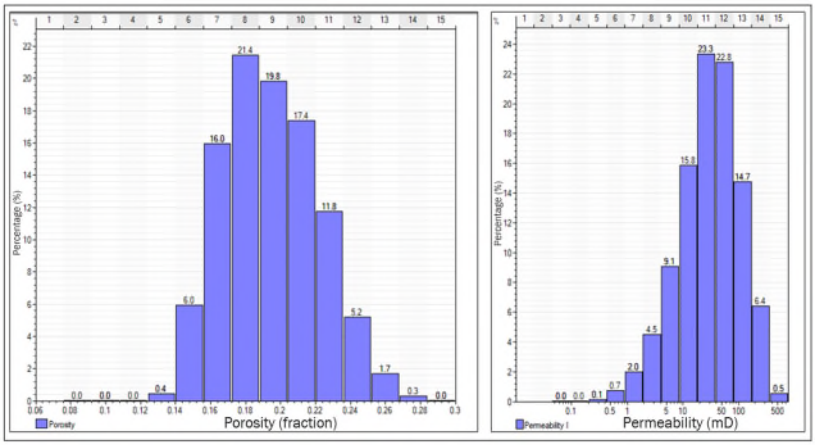
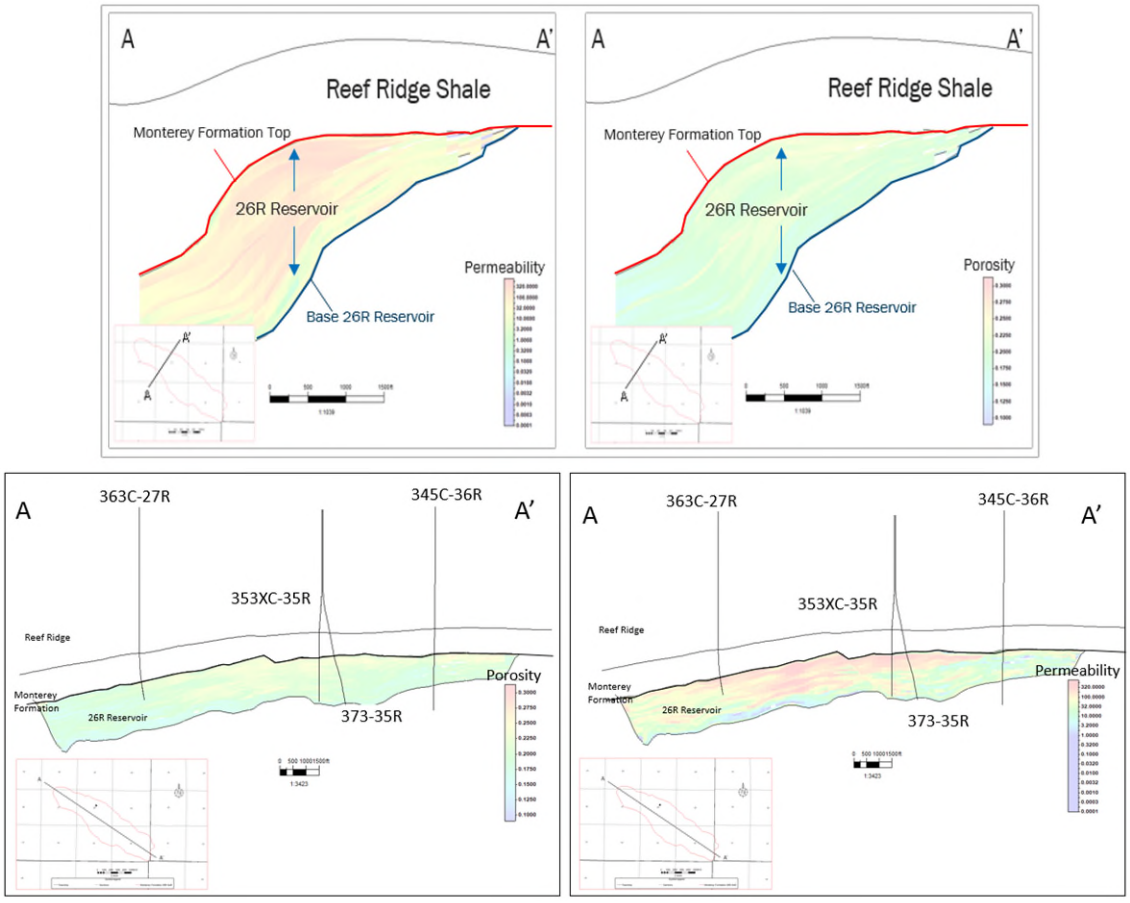


Figure 5 shows porosity and permeability histograms for the Monterey Formation 26R sands in the static model. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 6 shows the permeability and porosity distribution in cross-section A-A'.

Figure 7: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.



A variable permeability anisotropy was included in the model, with a Vertical permeability (kv) to horizontal permeability (kh) ratio which ranged from 0.0001 to 1, with a log mean of value of 0.01. The permeability anisotropy was arrived at by upscaling log derived permeability, and then distributing the upscaled log data across the model domain. The log data was upscaled using an arithmetic mean to represent the horizontal permeability, and a harmonic mean to represent the vertical permeability.

Constitutive Relationships and Other Rock Properties

The Monterey Formation 26R reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

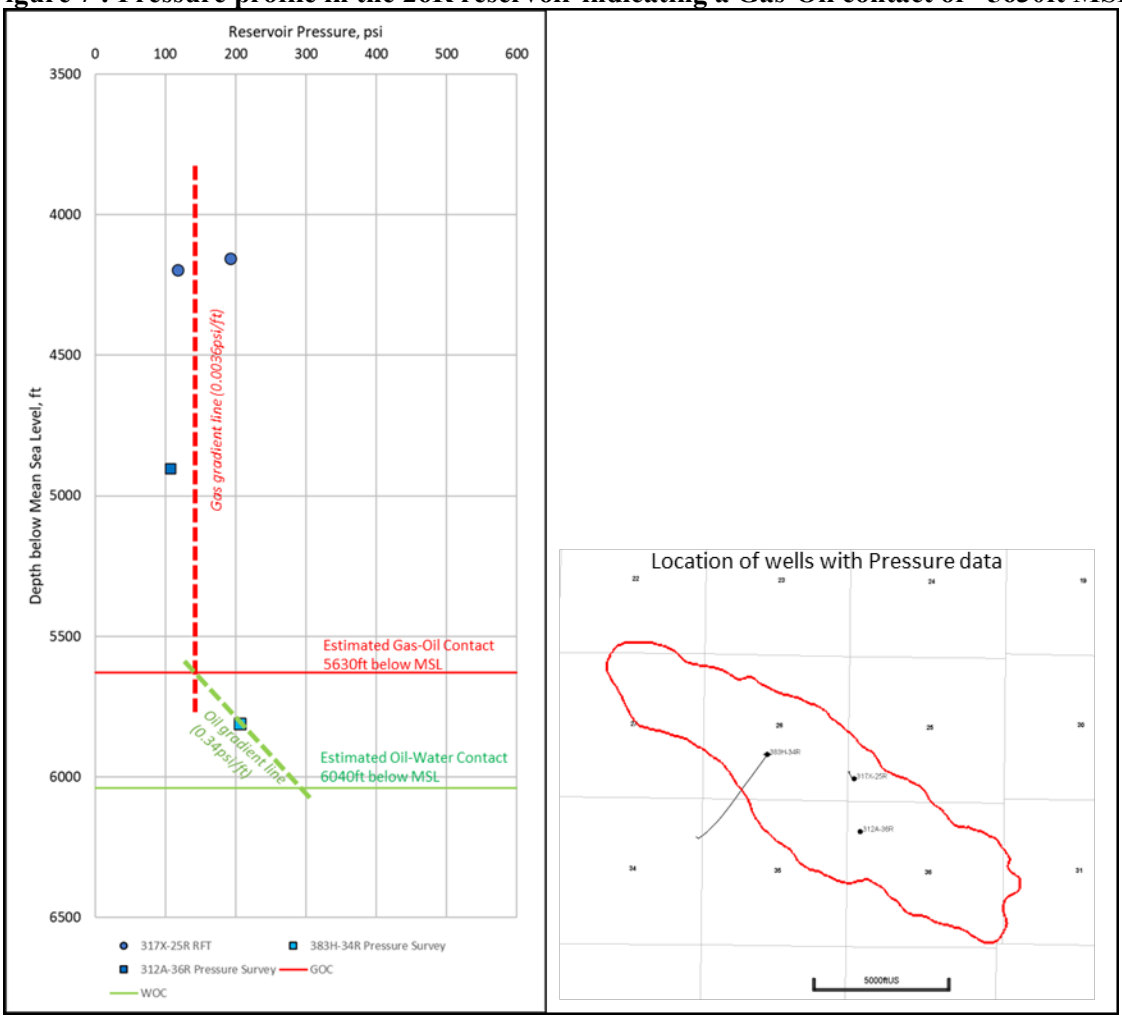
The saturations for the Gas, Oil and Water in the Gas Cap and Oil Band portions of the reservoir were determined using a Material Balance approach. The Pore Volume, discovery fluid contacts, pressure history, cumulative production and injection data for the reservoir, and the PVT properties of the fluids were used to estimate a current average oil, water, and gas saturation for the hydrocarbon portion of the 26R reservoir. These average saturations and estimates of remaining oil in place were used to iterate to a current oil-water and gas-oil contact in the computational model and the CMG GEM simulation model was initialized using the relative permeability curves, capillary pressure curves and current estimate of reservoir pressure.

The most recent data used to help validate the estimated gas-oil contact was pressure data gathered between 2006-2015. The pressure profile from this data was used to help estimate a gas contact of ~5630ft below MSL, using a gas gradient (0.0036psi/ft) and an oil gradient of 0.34psi/ft (see Figure 7). As there has not been evidence of an active aquifer following the blow down of the reservoir, the water contact is estimated to be at or near the original contact of ~6040ft below MSL, which was determined based on well logs obtained during the initial characterization of the reservoir in the 1950's.

Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs, pressure data, material balance and production analysis.

	Gas Cap	Oil Band	Water Zone
Contact (depth sub-sea)	Gas - Oil <5,630	Oil - Water 5630-6,040	> 6,040
Saturation (fraction)	Oil: 15% Water: 33.7% Gas: 51.3%	Oil: 37.1% Water: 25% Gas: 0%	Water: 100%

Figure 7 : Pressure profile in the 26R reservoir indicating a Gas-Oil contact of ~5630ft MSL



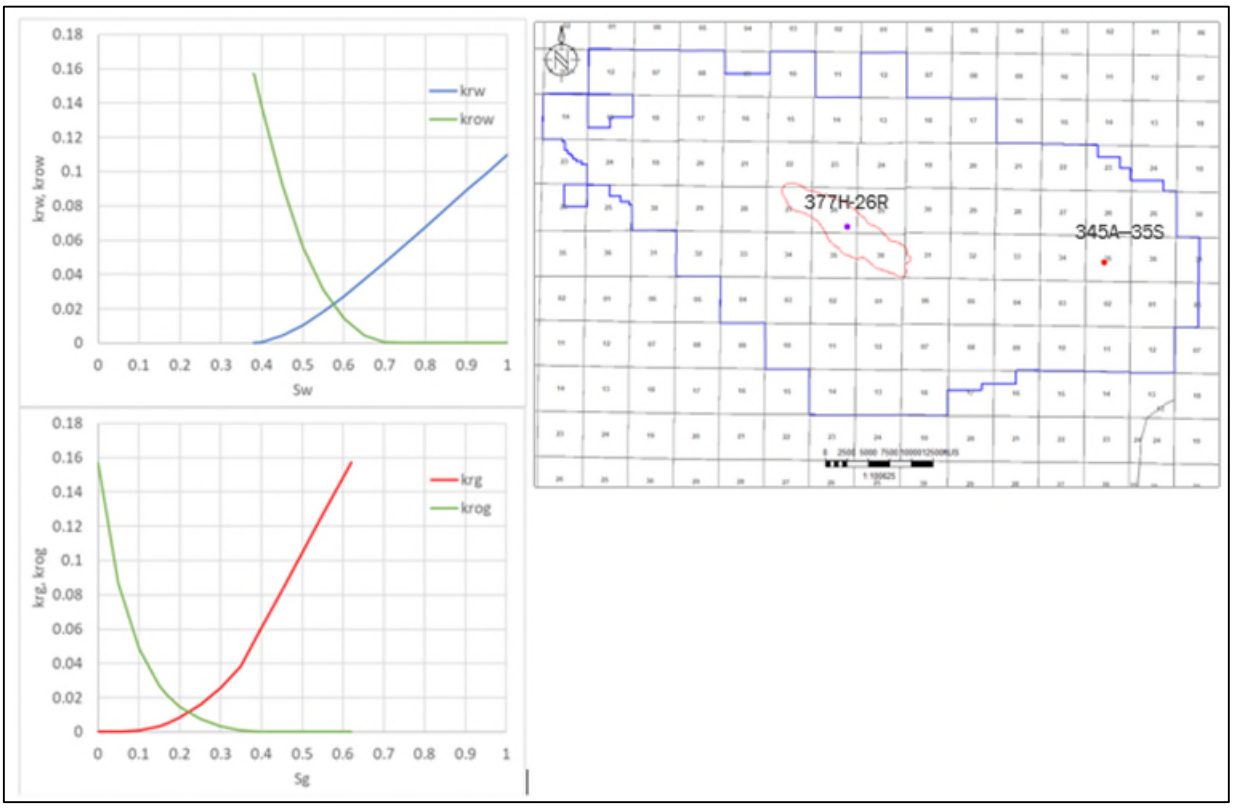
With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving krw, krow, krg, and krog as a function of saturation.

Where,
krg – relative permeability of Gas in a Gas–Oil system
krog – relative permeability of Oil in a Gas–Oil system
krow – relative permeability of Oil in an Oil-Water system
krw – relative permeability of Water in an Oil-Water system

Data acquired from Special Core Analyses (SCAL) determines these relationships. The geomodel modelled two rock types – sand and shale, but for the simulation a single sand rock type was modeled with the shale facies cells being treated as inactive cells. Core obtained from well 377H-26R in the 26R reservoir and equivalent Monterey Formation sandstone from well 345A-35S in the Elk Hills reservoir were used to generate the relative permeability relationships for the sand

facies. The data was normalized with respect to air permeability using end point scaling and a single Corey relative permeability fit was generated. Figure 8 shows the relative permeability curves used in the computational modeling and Figure 9 shows the relative permeability data from wells 377H-26R and 345A-35S in tabular form.

Figure 8: Relative permeability curves for krg-krog and krw-krow used in the computational model study and wells locations for data used to develop the curves.



The functional form of the relative permeability curves are -
krw = krwiro * ((Sw - Swcrit)/(1.0 - Swcrit - Soirw))^{Nw}
krow= krocw * ((So - Sorw)/(1.0 - Swcon - Sorw))^{Now}
krog=krogcg*((Sl - Sorg - Swcon)/(1.0 - Sgcon - Sorg - Swcon))^{Nog}
krg =krgcl *((Sg - Sgcrit)/(1.0 - Sgcrit - Soirg - Swcon))^{Ng}

With the parameters for the curve being -
Swcon - Endpoint Saturation: Connate Water = 0.38
Swcrit - Endpoint Saturation: Critical Water = 0.38
Soirw - Endpoint Saturation: Irreducible Oil for Water-Oil = 0.2
Sorw - Endpoint Saturation: Residual Oil for Water-Oil = 0.22
Soirg - Endpoint Saturation: Irreducible Oil for Gas-Liquid = 0.21
Sorg - Endpoint Saturation: Residual Oil for Gas-Liquid = 0.22
Sgcon - Endpoint Saturation: Connate Gas = 0
Sgcrit - Endpoint Saturation: Critical Gas = 0.05
krocw - Kro at Connate Water = 1

krwiro - Krw at Irreducible Oil = 0.43
krgcl - Krg at Connate Liquid = 0.4
krogcg - Krog at Connate Gas = 1
Nw = 1.3
Now = 3
Nog = 3.8
Ng = 2.5

The end point relative permeabilities of the curves were then scaled by a factor of 0.1547 using Oil to Air permeability ratio from well 345A-35S, so that the curves would be in reference to air permeability, which was used in the simulation model.

Figure 9: Monterey formation relative permeability data from wells 345A-35S and 377H-26R

Well: 345A-35S						
Sample Depth, feet:	7161.80					
Permeability to Air, md:		99.1				
Porosity, fraction:		0.221				
Initial Water Saturation, fraction:		0.380				
Effective Oil Permeability at Swi, md:		15.6				
Oil to Air Permeability ratio		0.1574				
* Relative to the effective permeability to oil at initial water saturation						
Water Displacing Oil				Gas Displacing Oil		
Sw	Relative Permeability to Water	Relative Permeability to Oil		Sg	Relative Permeability to Gas	Relative Permeability to Oil
0.380	0.000	1.000		0.000	-	1.000
0.436	0.026	0.662		0.184	0.002	0.109
0.460	0.053	0.525		0.198	0.005	0.093
0.510	0.108	0.324		0.226	0.014	0.069
0.557	0.176	0.176		0.269	0.040	0.040
0.645	0.328	0.033		0.334	0.106	0.010
0.803	0.615	-		0.405	0.195	-

Well: 377H-26R						
Sample Depth, feet :		5972.8		6015.9		
Permeability to Air, md :		100.0		286		
Porosity, fraction :		0.186		0.213		
Initial Water saturation, fraction		0.234		0.219		
* Relative to the effective permeability to oil at initial water saturation						
Water Displacing Oil				Gas Displacing Oil		
Sw	Relative Permeability to Water	Relative Permeability to Oil		Sg	Relative Permeability to Gas	Relative Permeability to Oil
0.234	0.000	1.000		0.000	0.000	1.000
0.286	0.034	0.851		0.133	0.011	0.332
0.313	0.045	0.764		0.162	0.017	0.252
0.377	0.069	0.541		0.198	0.029	0.170
0.461	0.098	0.292		0.226	0.041	0.131
0.523	0.121	0.147		0.259	0.059	0.091
0.568	0.141	0.070		0.285	0.082	0.070
0.590	0.152	0.040		0.309	0.101	0.051
0.606	0.163	0.025		0.342	0.134	0.035
0.620	0.168	0.018		0.369	0.175	0.022
0.644	0.182	0.009		0.394	0.221	0.015
0.649	0.187	0.006		0.411	0.249	0.011
0.667	0.195	0.003		0.432	0.279	0.007
0.685	0.205	0.001		0.486	0.406	
0.694	0.213					

Mineralization

Based on previous studies on reactive transport modeling and geochemical reactions in CCS applications have shown that the amount of CO2 predicted to be trapped by mineralization reactions is extremely small over a 100 year post injection time frame (IPCC, 2005: IPCC Special report on Carbon Dioxide Capture and Storage) for sandstone reservoirs. In addition, due to the fairly low salinity of the Formation water, stable mineralogy and minor expected on the AoR, reactive transport was not included as a part of the compositional simulation modeling at this time for computational efficiency.

Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation 26R reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

2. Performance data from operating the Monterey Formation 26R oil and gas reservoir indicates no connection to an active aquifer.

    i. Historical production data (Figure 10) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 10) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

    iii. Pressure in the reservoir is at 150 - 300 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

3. The 26R reservoir pinches out in the updip and lateral portions of the reservoir, and transitions to shale as shown in Figure 1.

Pressure data obtained while drilling wells in the AoR shows the pressure isolation of the 26R reservoir from the overlying Etchegoin Formation and the Lower Monterey Formation. Figure 11 shows the pressure data obtained for the formations, and location of these wells within the AoR.

Additional pressure data will be gathered and provided to the EPA during the pre-operational testing phase when all production operations in the reservoir have ceased, to confirm the historical understanding.

Figure 10: Monterey Formation 26R production and injection data.

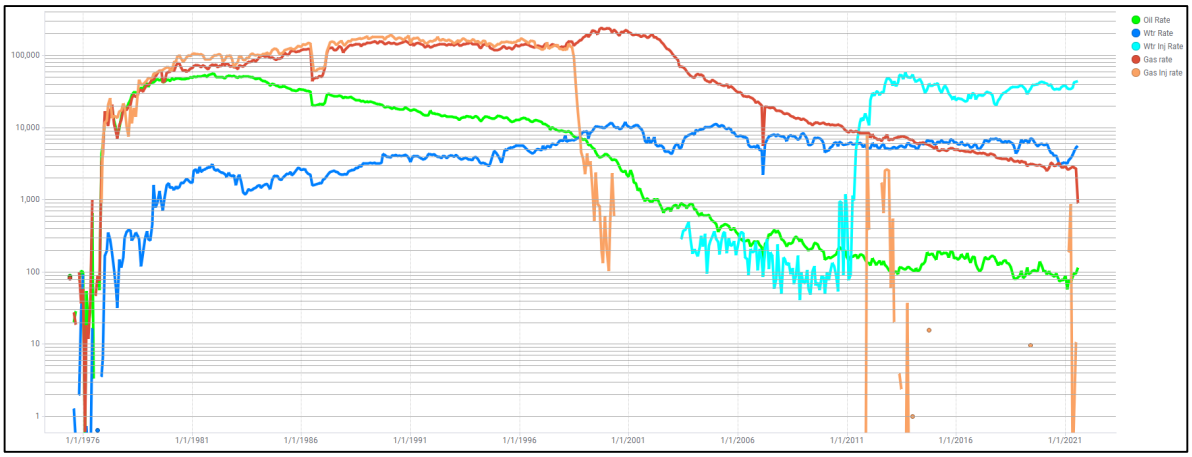
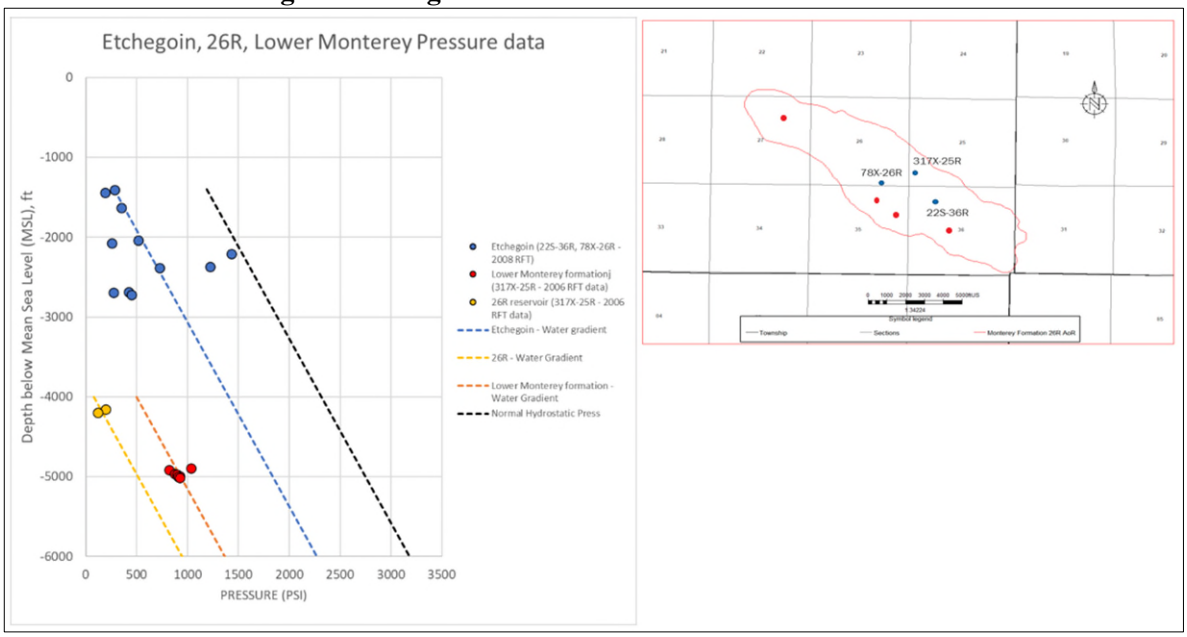


Figure 11: Etchegoin Formation, 26R Reservoir and Lower Monterey Formation repeat formation tester (RFT) pressure data in the AoR shows pressure isolation between the different formations. Data was obtained during the drilling of wells between 2006-2008.



Initial Conditions

Initial model conditions (start of CO_2 injection) of the Monterey Formation 26R reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4. Depths in the Table 4 are depths below Mean Sea Level (MSL), which is used as the reference elevation.

Table 4. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft, below Mean Sea Level)	Data Source
Temperature	210	Fahrenheit	5,630	Fluid Analysis
Formation pressure	150	Pounds per square inch	5,630	Pressure Test
Fluid density	61	Pounds per cubic foot	5,630	Water analysis
Salinity	25,000	Parts per million		Water analysis

Operational Information

Details on the injection operation are presented in Table 5.

Table 5. Operating details.

Operating Information	Injection Well 1 373-35R	Injection Well 2 345C-36R	Injection Well 3 353XC-35R	Injection Well 4 363C-27R
Location (global coordinates)	35.1634 N 119.2824W	35.2743 N 119.4577 W	35.3768 N 119.4732 W	35.2779 N 119.4535 W
Model coordinates (ft) X Y	 6121906 2290081	 6126556 2289316	 6121940 2290248	 6117204 2295938
No. of perforated intervals	13	25	11	12
Perforated interval (ft TVD / MD) Top Bottom	 6807 / 7086 7109 / 7426	 6097 / 6101 7710 / 7720	 6625 / 6810 8373 / 8545	 6698 / 6731 8124 / 8216
Production Casing diameter (in.)	4.5”	4.5”	4.5”	4.5”
Planned injection period Start End	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051	 1/1/2025 9/1/2051
Injection duration (years)	27	27	27	27
Injection rate (t/day)*	993	993	993	993

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

Fracture Pressure and Fracture Gradient

A fracture gradient of 0.701 psi/ft is expected for the 26R reservoir. This is based on fracture stimulation performed on well 388-26R in the 26R reservoir.

CTV will ensure that the injection pressure is below 90% of the fracture pressure as calculated at the top perforation for each injector. The maximum allowable subsurface wellbore injection pressure for the 4 injectors in the project is shown below in Table 6.

Table 6. Injection pressure details.

Injection Pressure Details	Injection Well 1 373-35R	Injection Well 2 345C-36R	Injection Well 3 353XC-35R	Injection Well 4 363C-27R
Fracture Gradient (psi/ft)	0.701	0.701	0.701	0.701
Maximum allowable downhole injection pressure (90% of fracture pressure), psi	4294	3847	4180	4226
Elevation corresponding to maximum allowable bottomhole pressure (ft, TVD / MD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Elevation of top of the perforated interval (ft, TVD)	6807 / 7086	6097 / 6101	6625 / 6810	6698 / 6731
Planned bottom hole injection pressure at top of perforations (psi)	4060	3555	3787	3558
Planned bottom hole injection gradient at top of perforations (psi/ft)	0.596	0.583	0.572	0.531

Proposed Carbon Dioxide Stream

CTV is planning to construct a carbon capture and sequestration "hub" project (*i.e.*, a project that collects carbon dioxide (CO_2) from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC permitted injection well(s)). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The anthropogenic CO_2 will be sourced from:

- Initial onsite emissions:
    - Lone Cypress blue hydrogen plant, up to 200,000 tonnes per annum
    - Elk Hills field gas treatment (pre-combustion for Elk Hills Power Plant), up to 200,000 tonnes per annum
    - Avnos Direct Air Capture (DAC), up to 1,500 tonnes per annum
- Future emission Sources:
    - CalCapture Elk Hills 550 MW natural gas power plant (post combustion), renewable fuel plants, steam generators post combustion and other power plants / industrial sources in the area

CTV expects the CO_2 stream to be sampled at the transfer point from the source and analyzed according to the analytical methods described in the QASP document and the Attachment C – Testing and Monitoring plan document. Should the injectate not meet the minimum requirements, it will be rejected.

The anticipated injection temperature at the wellhead is 90 – 130° F.

For the purposes of Geochemical modeling, CO2 Plume modeling, and Well design, two major types of Injectate compositions were considered based on the source.

- Injectate 1: is a potential injectate stream composition from a Direct Air Capture (DAC) or a Pre-Combustion source (such as the Lone Cypress blue hydrogen facility) or a Post-Combustion source (such as a gas fired power plant or steam generator) where N2 will likely be the major impurity.
- Injectate 2: is a potential injectate stream composition from a Biofuel Capture source (such as a Biodiesel plant) or an Oil & Gas Refinery or Natural Gas processing facilities (such as CO2 capture from the feed gas to the Elk Hills Power plan stated above) where light end Hydrocarbons (Methane, Ethane) will be the major impurity.

Design studies for CO2 capture at the planned Lone Cypress facility and design studies for CO2 capture from feed gas to the Elk Hills power plant were incorporated into the two injectate compositions shown in Table 7, in addition to preliminary injectate specifications provided by other potential sources and from literature studies.

Table 7 : Injectate compositions

Component	Injectate 1	Injectate 2
	Mass%	**Mass%**
CO2	99.213%	99.884%
H2	0.051%	0.006%
N2	0.643%	0.001%
H2O	0.021%	0.000%
CO	0.029%	0.001%
Ar	0.031%	0.000%
O2	0.004%	0.000%
SO2+SO3	0.003%	0.000%
H2S	0.001%	0.014%
CH4	0.004%	0.039%
NOx	0.002%	0.000%
NH3	0.000%	0.000%
C2H6	0.000%	0.053%
Ethylene	0.000%	0.002%
Total	**100.00%**	**100.00%**

For geochemical and plume modeling scenarios, these injectate compositions were simplified to a 4-component system, shown in Table 8. The 4 component simplified compositions cover 99.9% by mass of Injectate 1 & 2 and cover particular impurities of concern (H2S and SO2). The estimated properties of the injectates at downhole conditions are specified in Table 9

Table 8: Simplified 4 component composition for Injectate 1 and Injectate 2

Injectate 1	
Component	**mass%**
CO2	99.213%
N2	0.643%
SO2+SO3	0.003%
H2S	0.001%

Injectate 2	
Component	**mass%**
CO2	99.884%
CH4	0.039%
C2H6	0.053%
H2S	0.014%

No corrosion is expected in the absence of free phase water provided that the entrained water is kept in solution with the CO_2. This will be ensured by maintaining a water specification limit <25 lb/mmscf for the injectates, and this specification will be a condition of custody transfer at the capture facility. For transport through pipelines, which typically use standard alloy pipeline materials, this specification is critical to the mechanical integrity of the pipeline network, and out of specification product will be immediately rejected. Therefore, all product transported through pipeline to the injection wellhead is expected to be dry phase CO_2 with no free phase water present.

Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. CRA tubing will be used in the injection wells to mitigate any potential corrosion impact should free-phase water from the reservoir become present in the wellbore, such as during shut-in events when formation liquids, if present, could backflow into the wellbore. CTV may further optimize the maximum water content specification prior to injection based on technical analysis.

Injectate will be sampled and analyzed as part of the pre-operational testing, to confirm that it is consistent with the well design, Plume modeling and Geochemical modeling assumptions.

Computational Modeling Results

Predictions of System Behavior

The base simulation case was run for a 127 year period, covering 27 years of injection and 100 years of post injection. The simulated injection storage capacity is 38MMT taking the reservoir from current reservoir conditions to initial discovery pressure of 3,250 psi. A 100% CO2 injectate stream was assumed for the base case simulation studies. Additionally, scenarios were also run for the two injectates (Injectate 1 and Injectate 2) detailed in the "Proposed Carbon Dioxide Stream" section. Minimal difference in results was seen between the cases. Table 9 summarizes the expected CO2 injectate properties at reservoir conditions over the life of the project.

Table 9: CO2 injectate properties at reservoir conditions

Injectate property	100% CO2	Injectate 1	Injectate 2
Viscosity, cp	0.019-0.044	0.019-0.043	0.019-0.045
Density, kg/m3	16.6-544.8	16.5-543.5	1.035-545.8
Salinity, ppm	NA	NA	NA
Compressibility factor, Z	0.97-0.59	0.97-0.59	0.97-0.59

The following maps (Figure 12) and cross-sections (Figure 13) show the computational modeling results and development of the CO_2 plume at multiple time-steps. For all layers in the model and at all time-steps, the plume stays within the AoR. The CO2 plume grows rapidly within the first 15 years of injection with majority of the CO2 going into the higher quality upper portion of the 26R reservoir and being controlled by the structure of the reservoir and the closed updip boundary. Thereafter, the CO_2 injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the CO_2 injectate remains as super-critical CO_2.

The CO2 plume reaches its maximum vertical and lateral extent 20 years after the end of injection. The vertical and lateral extent of the CO2 plume predicted by the model aligns well with estimated discovery Oil-Water contacts of the reservoir and the vertical and lateral extent of the reservoir. The extent of the CO2 plume is slightly deeper than discovery fluid contacts in a few areas of the model likely due to gas override during injection and dissolution of the CO2 into the aqueous and oleic phases at the edge of the plume. The CO2 plume is largely stabilized 20 years after the end of injection, with little to no movement of the supercritical phase CO2 seen past this date.

The pressure front (defining as >10psi change from pressure at start of injection) in the reservoir reaches the vertical and areal boundaries of the model 6 years after the start of injection. The pressure in the reservoir reaches its peak at the end of injection. The reservoir pressure stabilizes fairly immediately in the reservoir with end of injection, and < 5psi/year change is expected in the first year after the end of injection. Figure 14 shows the average pore volume pressure vs time.

Figure 12A: Plan view showing the CO2 plume development through time. Plume is at its greatest extent at 20 years post injection.

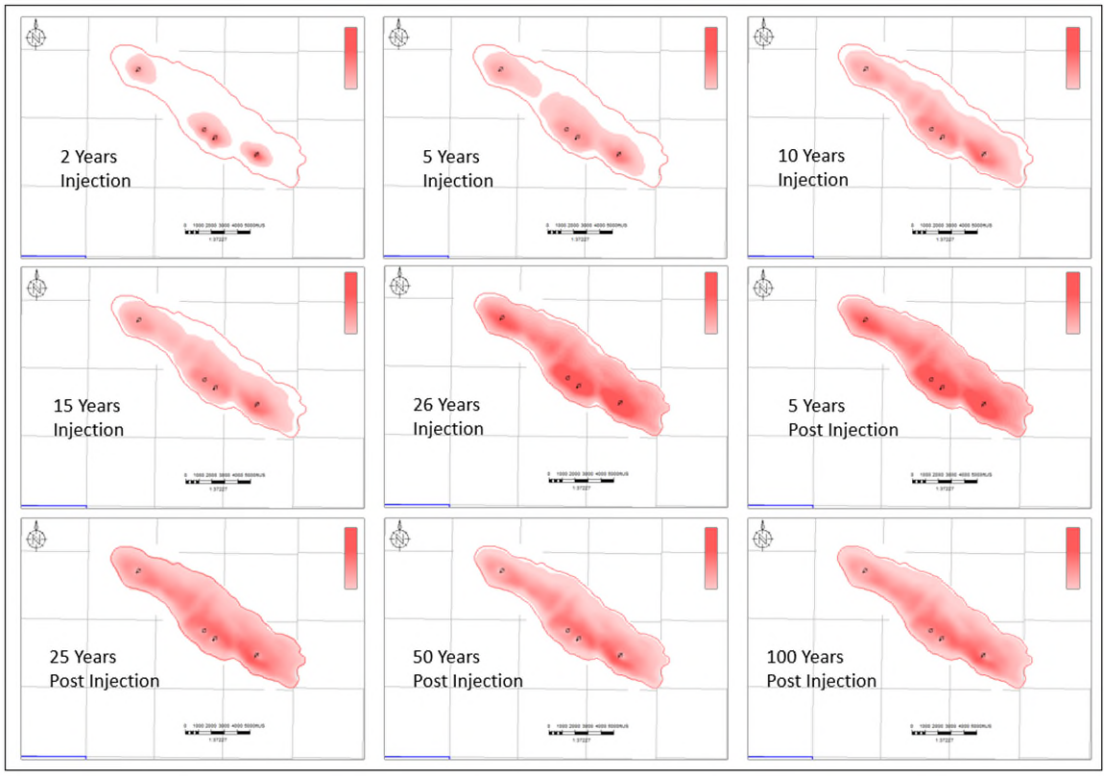


Figure 12B: Plan view showing the gas extent through time. Maps scaled so as to present Gas saturation over a nomial baseline

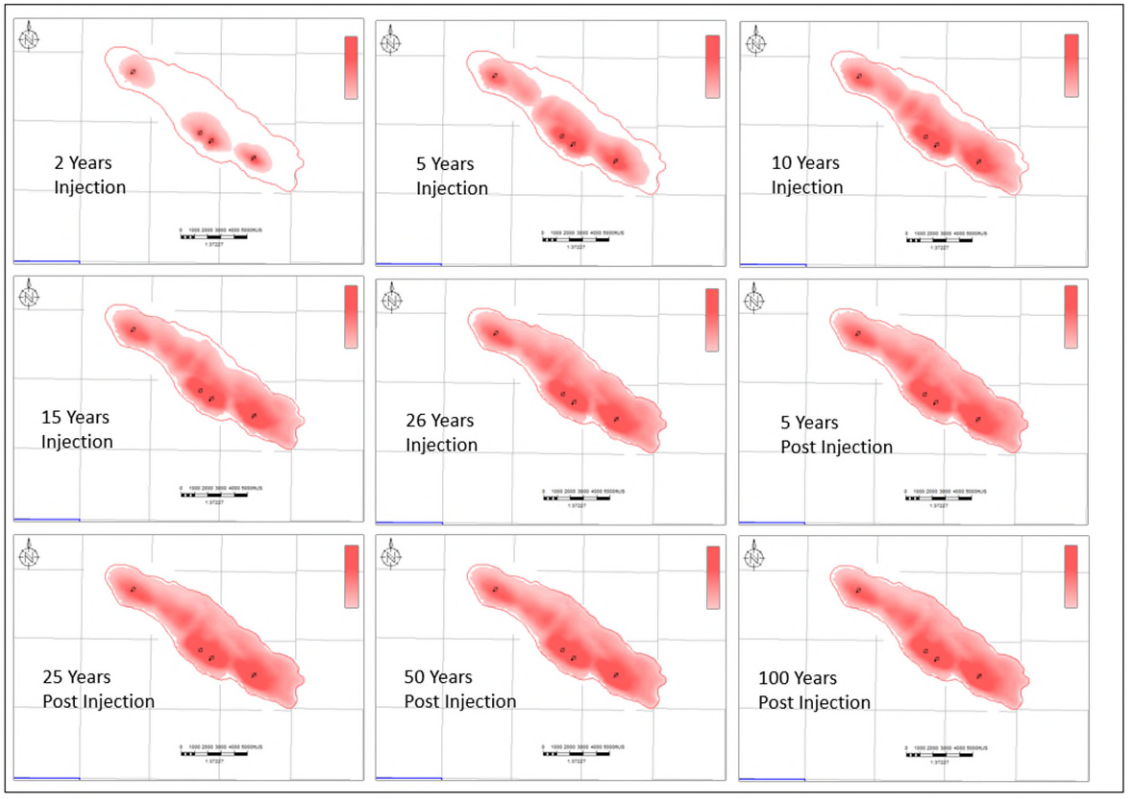


Figure 13A Cross-sections showing the CO2 plume development through varying times during the project.

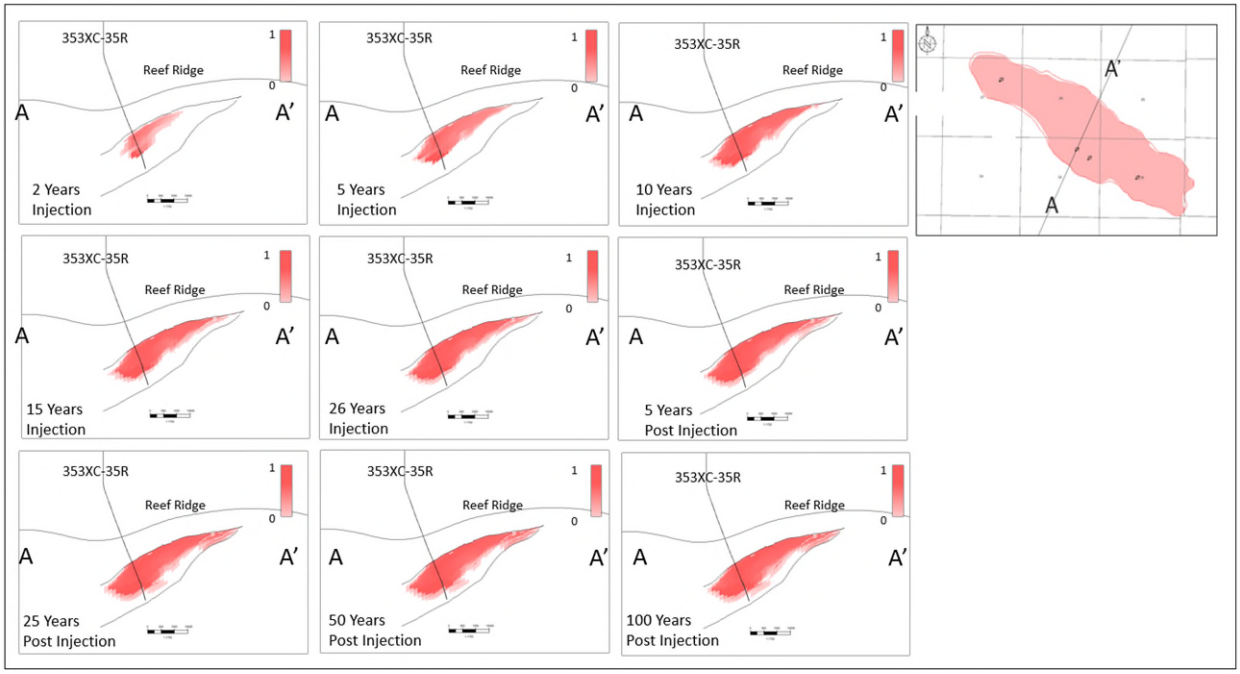


Figure 13B: Cross-sections showing the gas extent through varying times during the project. Maps scaled so as to present Gas saturation over a nomial baseline

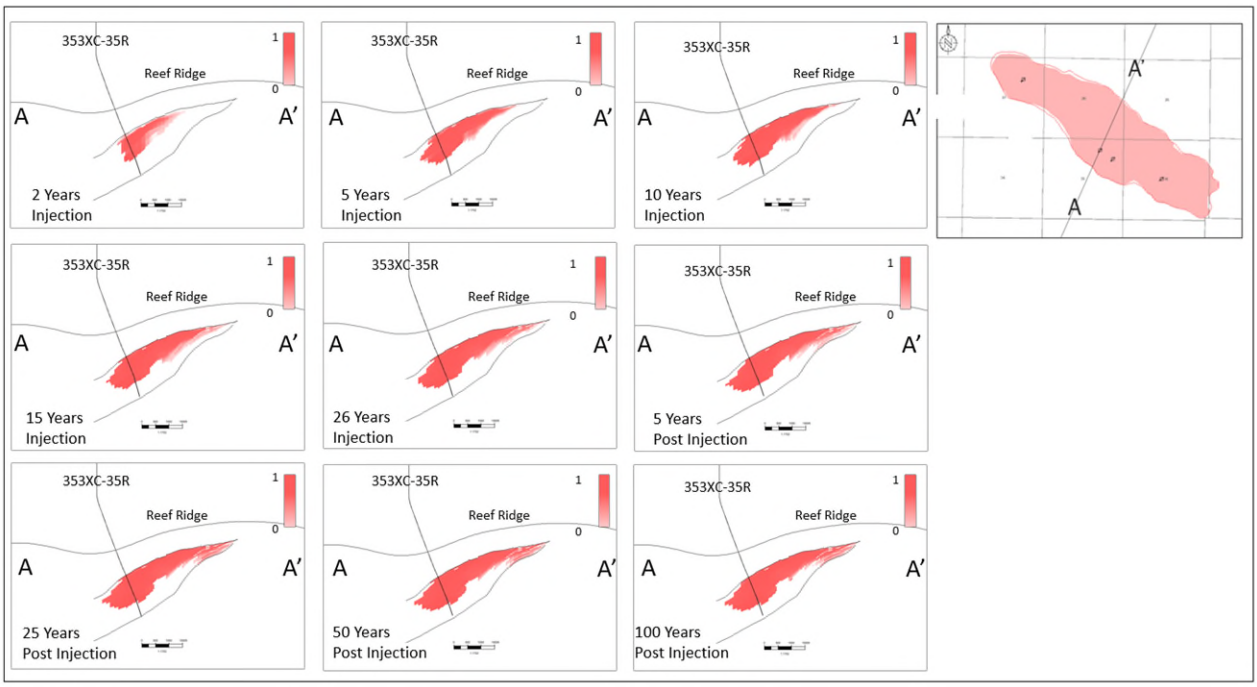
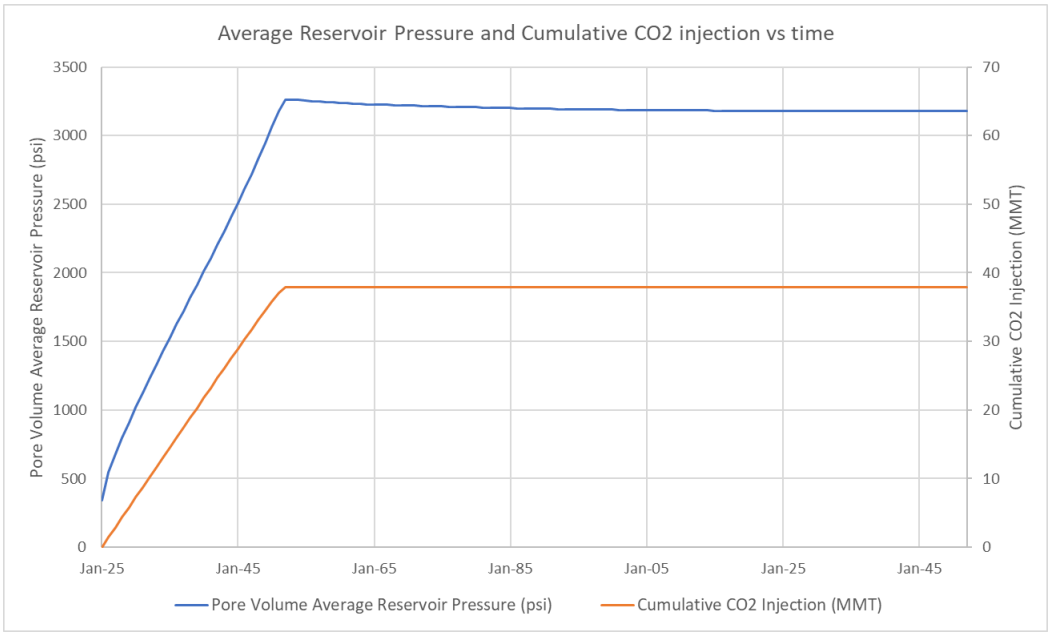
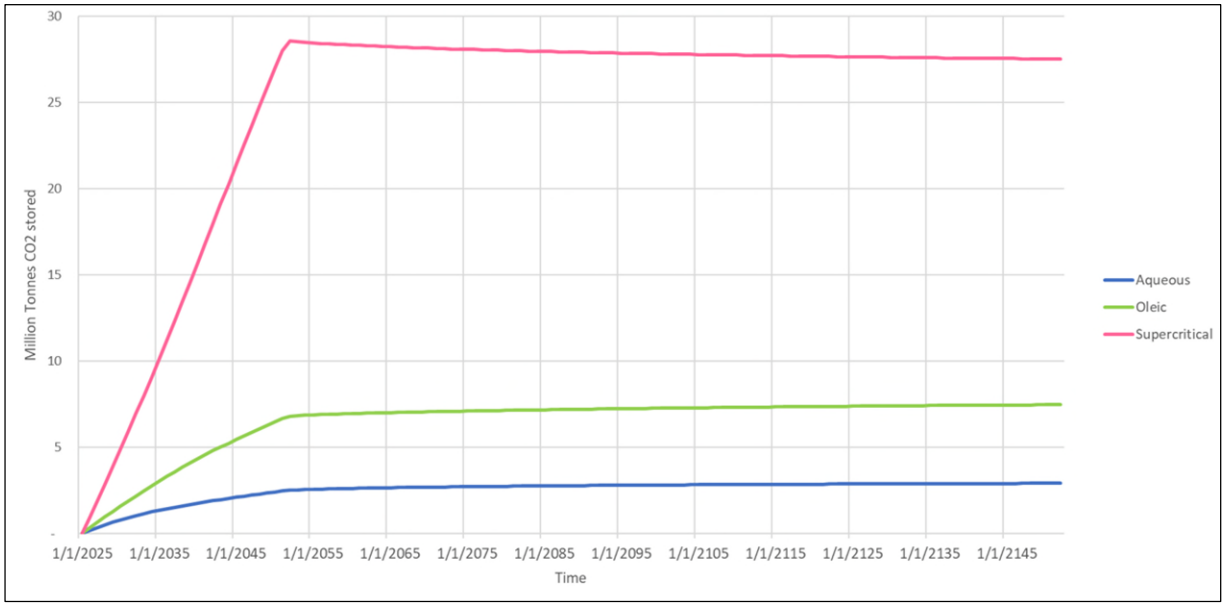


Figure 14: Average Reservoir pressure and cumulative CO2 injection versus time plot



CO_2 injected into the Monterey Formation 26R reservoir will be soluble in both water and oil. Due to remaining saturation of oil and water in the depleted reservoir, total dissolved CO_2 in oil and water is 20% and 8% of the CO_2 injected respectively. The remaining will be stored as super-critical CO_2. Figure 15 shows the cumulative storage for each of the mechanisms.

Figure 15: Storage mechanism through time for the 26R reservoir.



CO_2 Injectate Composition effect on Plume and AoR modeling

The Plume model developed in the Computer Modeling Group (CMG) GEM software was run for the two simplified injectate compositions, and their results were also compared against a 100% CO2 injectate case. The cumulative volume of injectate for all 3 cases was the same.

The CO2 plume for Injectate 1 and Injectate 2 (detailed in the "Proposed Carbon Dioxide stream" section in this document) is consistent with the plume outline for 100% CO2 injectate (Figure 16), which was defined by a 0.03 global CO2 mole fraction for all 3 cases. The 100 year post end of injection plumes for the 3 cases are shown below in Figure 16. The wells that fall within the CO2 plume are the same for all 3 cases.

Additionally, the average Pore Volume pressure was plotted for the 3 cases and there was minimal difference seen between the cases, as shown in Figure 17.

In summary, there is minimal effect of the minor components on the CO2 plume shape and the AoR boundary, for the proposed injectate compositions. As such, CTV's Plume and AoR modeling for Corrective Action assessment is adequate. CTV will confirm that the properties of the injectate are consistent with the model inputs at pre-operational injectate sampling. In addition, the AoR will be reviewed as per the Reevaluation Schedule and Criteria section.

Figure 16: CO2 plume outlines for Injectate 1 (Light Blue), Injectate 2 (Green) and 100% CO2 Cases (Red). Larger Red outline is the model boundary. There are Minimal difference in AoR boundaries between the 3 cases

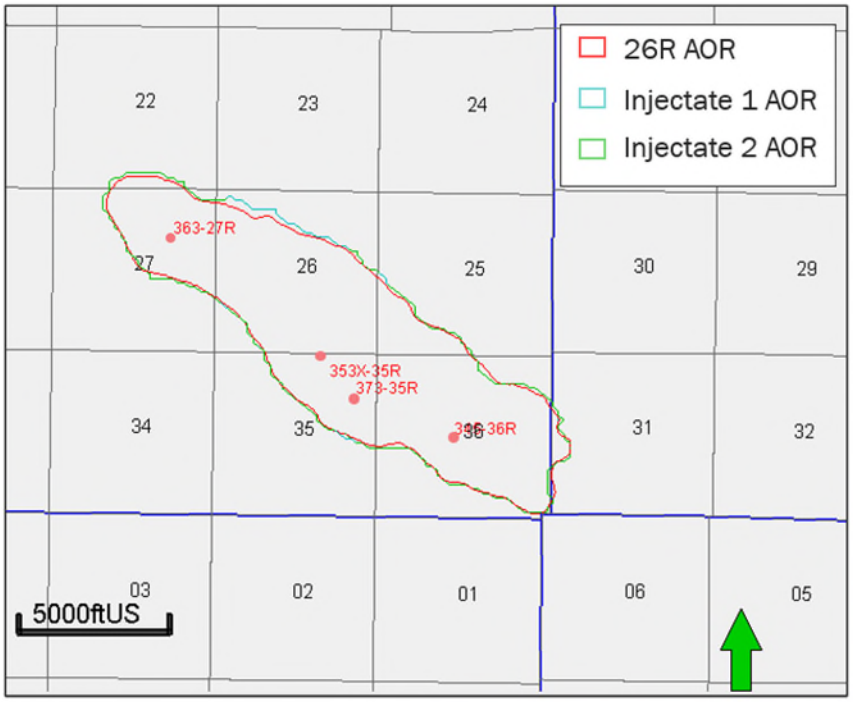
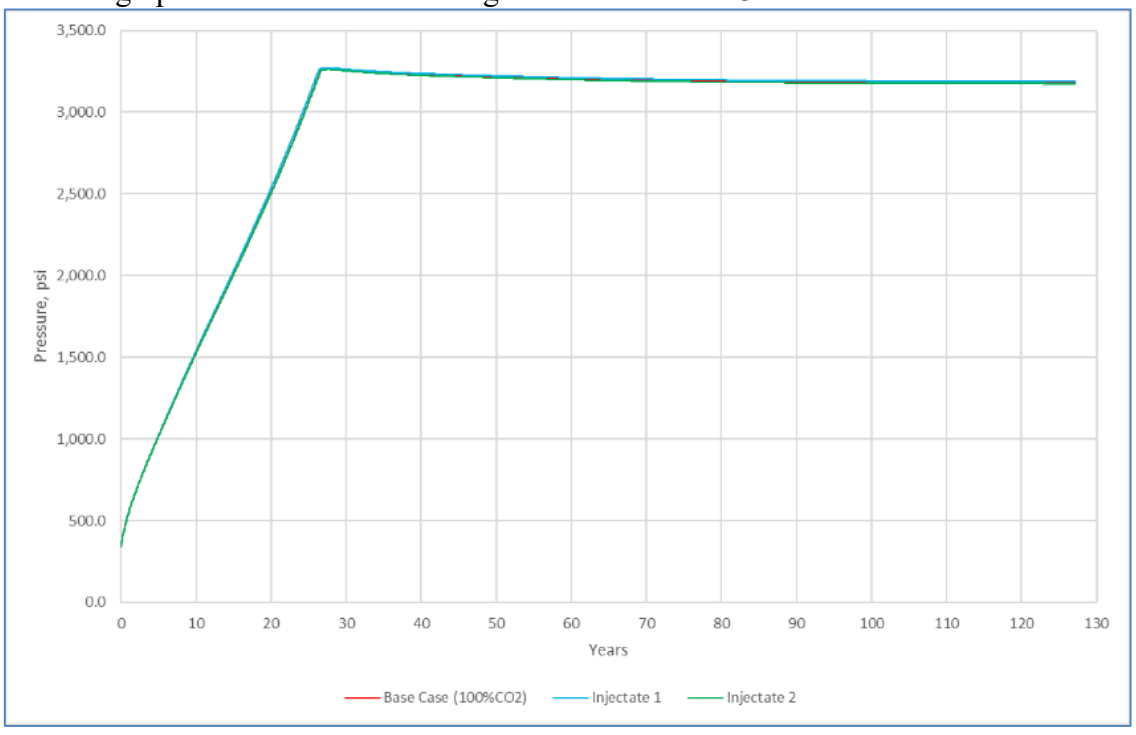


Figure 17: Average reservoir pressure vs time for Injectate 1 (Light blue), Injectate 2 (Green) and base 100% CO2 (Red) cases. Minimal difference in pressure trends between the 3 cases as shown in the graph with the trends tracking each other for the 3 cases.



Model Calibration, Sensitivies and Validation

Previous operators injected 1,244 billion cubic feet of gas into the Monterey Formation 26R reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

The simulation model was run for different initial reservoir pressure and saturation cases to determine the sensitivity of the storage volume and plume extent to these variables. Due to ongoing water injection in the 26R reservoir, sensitivities were run to test the effect of higher reservoir pressure and higher water saturation in the Oil band and Gas cap to see if there would be significant impacts to the storage volume and AoR boundaries.

Sensitivities were also run varying major geomodel inputs into the simulation model (Porosity, Permeability, NTG) and varying the Grid XY dimensions, cell thickness, local grid refinement around injectors, and temperature effects to see if there was a significant change to the storage amount and AoR boundary. Although there was some effect to the total CO2 storage for the different cases, there was minimal change to the maximum extent of the CO2 plume. The porosity, permeability and NTG uncertainty were further modeled stochastically to understand their effect and is discussed in the next section.

- Cell thickness sensitivity case was run by reducing the cell thickness in the overall grid to an average of 18ft. The results of this finer cell thickness model, compared favorably to the Base case model with a < 2% increase in predicted CO2 storage capacity and minimal change to the plume extent.

- The local grid refinement case was run with a finer grid spacing in the 5Acre region around the injector location, with the X-Y grid dimensions reduced to 19ft by 15ft in that region. The results of this case also compared favorably against the base case, with the predicted maximum bottom hole pressure at the injector locations being within 0.5% of the Base Case.

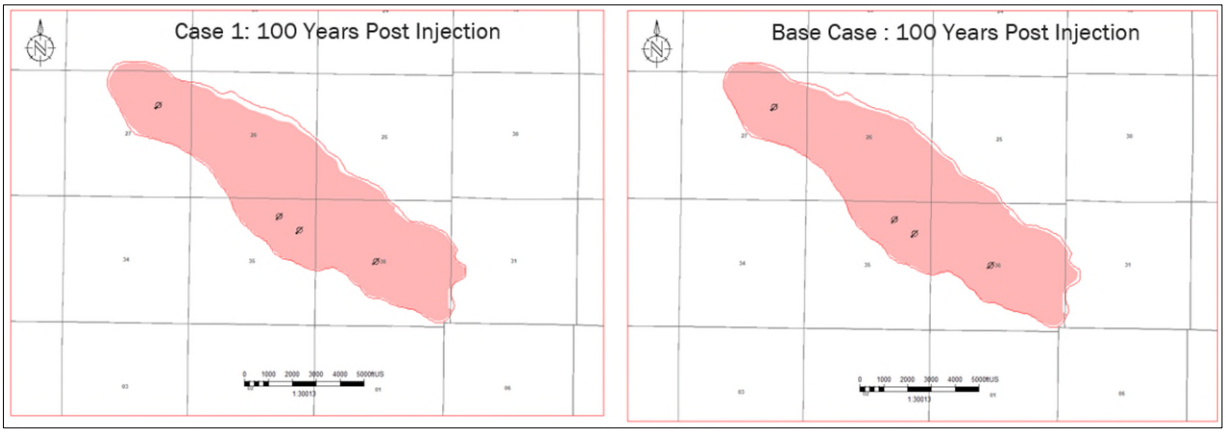
- The Base case model was initialized using a uniform average temperature of 210° F (based on idle well temperature surveys run on wells in the area between 2008 – 2014) and with no thermal effect modeling in the reservoir. A sensitivity case was run using GEM's thermal option to model heat balance and gauge if modeling temperature change in the reservoir with CO2 injection was necessary. The results indicated minimal effect on the system behavior with < 2% change in CO2 storage capacity, and < 2% deviation in reservoir pressure trends.

Table 10 summarizes the sensitivity cases run and their effect on storage volume and the AoR boundary. Figure 18 compares the CO2 plume extent for Case 1 against the Base Case.

Table 10: Summary of sensitivity cases

Case #	Sensitivity Case	Storage Volume effect	AoR boundary effect
1	Pressure : Gas cap pressure increased to 300psi	Decreased volume	Minimal effect to AoR
2	Pressure : Gas cap pressure increased to 500psi	Decreased volume	Minimal effect to AoR
3	Saturation: Higher water saturation in Oil band and Gas cap	Decreased volume	Minimal effect to AoR
4	Porosity: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
5	Porosity: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
6	Permeability: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
7	Permeability: increased by 10% from Base Case	Increased volume	Minimal effect to AoR
8	NTG: reduced by 10% from Base Case	Decreased volume	Minimal effect to AoR
9	Grid Dimensions: reduced grid XY dimensions to 95 ft x 75ft	No effect	Minimal effect to AoR
10	Cell Thickness: Reduced average cell thickness in Gas cap to 18ft	Increased volume	Minimal effect to AoR
11	Local grid refinement around Injectors: reduced grid X-Y dimension to 19ft x 15ft in 5Acre area around injectors	No effect	Minimal effect to AoR
12	Temperature effect: model was run with GEM's thermal option	Minimal change	Minimal effect to AoR

Figure 18: CO2 plume extent for layer 2 comparing Base Case against Pressure and Saturation sensitivity cases.



These scenarios demonstrated that the AoR, as defined by the maximum extent of CO_2 injectate, is consistent. This provides confidence that the corrective action well review and potential impact is conservative.

Stochastic analysis of effect of Reservoir parameters

A stochastic analysis was carried out using the reservoir parameters – Porosity, permeability, Net to Gross (NTG) ratio and kv-kh ratio. An upper and lower bound of the grid property was entered (directly or using multipliers), along with a distribution (see Table 11) in CMG's CMOST module to generate a set of 50 cases using the Latin Hypercube sampling method. All cases were run with the same bottom hole pressure control on the injectors, and with the same condition of ceasing injection once the reservoir had been brought back up to initial conditions. Although the stochastic analysis showed a range of storage capacity, the P50 estimate was 37MMT, with a P10 of 30MMT and a P90 of 44MMT.

Table 11: Parameters and distributions used for Stochastic analysis

Parameters	Parameter/ Multiplier	Parameter / Multiplier range	Distribution type	Description
Porosity	Multiplier	0.78 - 1.22	Normal distribution	Multiplier range used to have grid mean value range of 0.14 - 0.22
Permeability	Multiplier	0.3 - 3	Log Normal distribution	Multiplier range used to have grid mean value range of ~15 - 150md
Net to Gross ratio (NTG)	Multiplier	0.9 - 1.1	Uniform distribution	A uniform distribution uncertainty of +-10% applied
kv-kh ratio	Parameter	0.001 - 0.2	Log Normal distribution	A kv-kh ratio of 0.001 to 0.2 applied over the entire grid

AoR Delineation

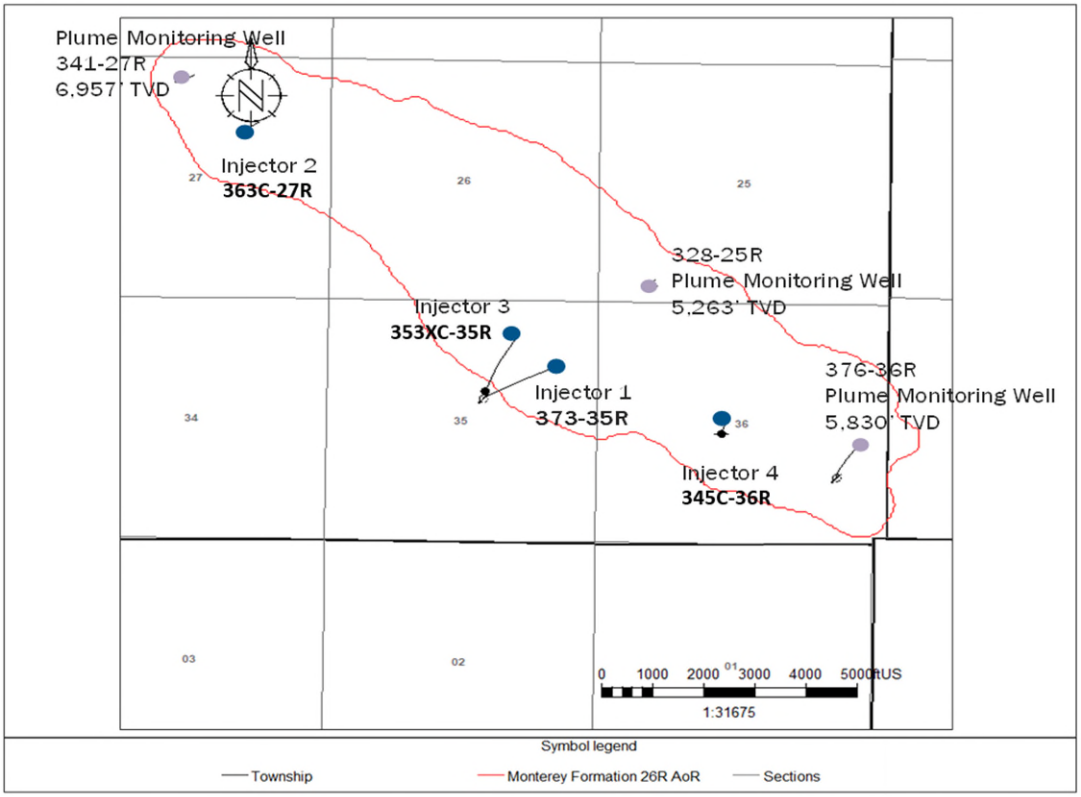
The AoR was determined by the largest extent of the CO_2 plume from computational modeling results. A Global Mole Fraction cut off of 0.03 was used to delineate the plume boundary. In the AoR scenario, CO_2 was injected into the depleted Monterey Formation 26R reservoir until the reservoir pressure reached the discovery pressure of 3,250 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.
Figure 19 shows the AoR, injectors and offset monitoring wells. All wells that are currently operating in the 26R reservoir will cease operations, and wells not associated with the project will be abandoned prior to injection so as to eliminate interference with the AoR delineation and re-establish the confining layer. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and CO_2 plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. CO_2 plume and water contact will be calculated from monitoring well pressure, CO_2 saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

Figure 19: Map showing the location of injection wells and plume monitoring wells.



Corrective Action

The review of all wells within the AoR to determine the need for corrective action is a requirement of 40 CFR 146.84(c).

Tabulation of Wells within the AoR

Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation 26R reservoir was discovered in the 1940's and subsequent development drilling began around 1950. As such, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the over 70-year development history of the reservoir that includes injection of water and gas.

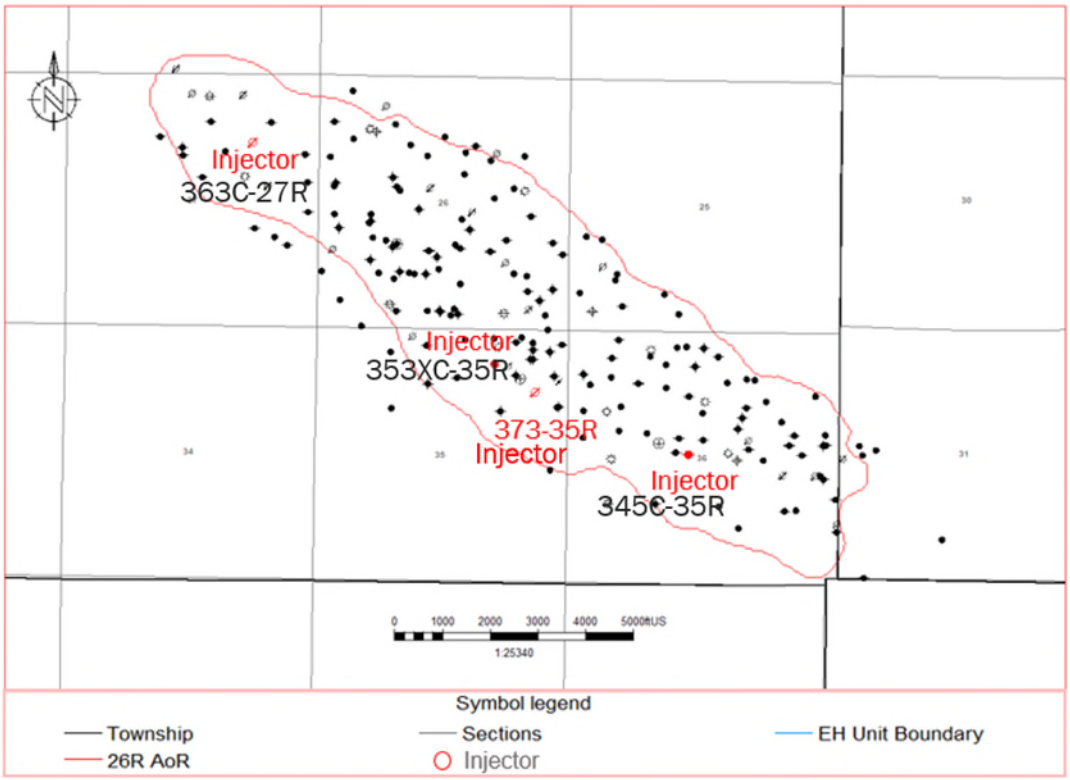
CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Table 12 is a summary of the AoR wells by type. Figure 20 displays the AoR wells' surface locations in map view. *Appendix: Well Table with Corrective Action Assessment* lists the wells individually and provides a description of each well's type, construction, date drilled,

location, depth, and record of plugging and/or completion, as required in 40 CFR 146.84 (c)(2). Additionally the table identifies pre-operational requirements and the corrective action assessment for each wellbore.

Table 12: Wellbores in the AoR by Well Type

Well Type	Count
Oil & Gas Producing Wells	145
Class II Injection/Disposal Wells	22
Pressure Observation wells	2
Plugged back	35
Total	**204**

Figure 20: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation 26R sequestration reservoir reviewed for corrective action.



Corrective Action Assessment Methodology

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q4 2021, and the results of the review are incorporated into the assessment.

The corrective action assessment includes the generation and detailed review of wellbore/casing diagrams for each well in the AoR. The results of the assessment are included in the *Appendix: Well Table with Corrective Action Assessment*. Information used in the review includes depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of Cement (TOC) determination supports the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface.

A well in the AoR is a penetration of the Monterey Formation and/or Reef Ridge Shale that may have multiple wellbores resulting from sidetracking the well. CTV tracks wells at the "wellhead" level using API-10 and at the "wellbore" level using API-12 such that a single well may have multiple wellbores, and each wellbore may or may not penetrate the AoR. The assessment of all penetrations was conducted by evaluating all wellbores, and the summary data provided refers to wellbore penetrations.

Protection of USDW

The Upper Tulare is an unsaturated zone, and the Lower Tulare is an exempt aquifer. There is no USDW in the AoR.

Wells Penetrating the Confining Zone

Of the 204 wellbores penetrating the Reef Ridge formation (Table 13), zero wells have been permanently abandoned to surface. Three wells will be repurposed as CCS monitoring wells, and one well, 373-35R, will be repurposed as a CO_2 injector. Of the remaining, 157 wellbores require plugging because the wellbores penetrate the injection zone and/or confining layer and will not be used for injection or monitoring within the 26R storage project. The wells are not known to be deficient and are not known to require corrective action. The wells will be abandoned prior to CO_2 injection under the asset retirement obligation plan (ARO) to reduce abandonment liability at Elk Hills. 35 wellbores have been plugged back for sidetrack, and as such have the API-12 status of P&A while API-10 status is either Active or Inactive, depending on the status of the current wellbore.

Table 13: Wellbores to be abandoned prior to injection

Wellbores Penetrating Reef Ridge Formation	Wellbores Requiring Corrective Action	P&A Wells Requiring Corrective Action	Wellbores Requiring Pre-Operational Abandonment
204	0	0	157

Monterey Formation 26R Isolation

CTV can demonstrate that the USDW (not present in AoR) is protected and that, with well abandonment prior to injection and implementation of a robust ongoing monitoring program, the CO_2 injected will be confined to the Monterey Formation 26R reservoir.

Plan for Site Access

CTV owns the mineral and pore space for the Monterey Formation 26R reservoir and surface access rights have been guaranteed for the duration of the project.

Corrective Action Schedule

All wellbores within the AoR will, if necessary, be pressure tested, abandoned, re-abandoned, monitored and/or have a technical demonstration of adequate zonal confinement prior to the commencement of CO_2 injection or based on an agreed upon phased schedule after CO_2 injection commences, if conditions allow. Additional evaluation during pre-operational testing will inform the suitability and isolation of wells proposed for use in the project as injectors and monitoring wells. Diagnostics may also be performed, if necessary, to complement abandonment operations. Although no wellbores have been identified for corrective action and no corrective action schedule is required, if additional evaluation efforts result in the identification of wellbores that require corrective action, CTV will notify the EPA and communicate a corrective action plan and schedule.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

Reevaluation Schedule and Criteria

AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO_2 injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. CO_2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and CO_2 concentration data in 1 and 2 above.

4. A review of the full suite of water quality data collected from monitoring wells in addition to CO2 content/saturation (to evaluate the potential for unanticipated reactions between the injected fluid and the rock formation).

5. Review and submission of any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.

6. Reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation). A report describing the comparison of the modeling results will be provided to the EPA with a discussion on whether the results are consistent.

7. Description of the specific actions that will be taken if there are discrepancies between monitoring data and prior modeling results (e.g., remodel the AoR, update all project plans, perform additional corrective action if needed, and submit the results to EPA).

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Changes in pressure or injection rate that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.

2. Difference between the computation modeling and observed plume development:

    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation reservoir that are not related to well integrity.

b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results with a deviation greater than +-10% from the Base Case.

c. Any other activity prompting a model recalibration.

3. Seismic monitoring anomalies within two miles of the injection well that are indicative of:

    a. The presence of faults near the confining zone that indicates propagation into the confining zone.

    b. Events reasonably associated with CO_2 injection that are greater than M3.5.

2. Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.

3. Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).

4. Initiation of competing injection projects within the same injection formation within a 1-mile radius of the injection well (including when additional CTV injection wells come online);

5. A significant change in injection operations, as measured by wellhead monitoring;

6. Significant land-use changes that would impact site access; and

7. Any other activity prompting a model recalibration.

CTV will discuss any such events with the UIC Program Director as soon as possible to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan within six months of the triggering event.

ATTACHMENT C: TESTING AND MONITORING PLAN - 363C-27R
40 CFR 146.90

Elk Hills 26R Storage Project

Facility Information

Facility Name: Elk Hills 26R Storage Project
363C-27R

Facility Contact: Travis Hurst / CCS Project Manager
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Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Comments
Attachment C – TM 363C-27R	1	09/30/2023	
Attachment C – TM 363C-27R	2	12/05/2023	Addition of air monitoring.

The Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills 26R storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the CO_2 within the storage zone, supporting AoR re-evaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

Quality Assurance Procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the Appendix to this Testing and Monitoring Plan.

Reporting Procedures

CTV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

CTV will analyze the CO_2 stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a). Samples will be collected and analyzed quarterly, starting three months after the date of authorization of injection and every three months thereafter.

The anthropogenic CO_2 will be sourced from:

- Initial onsite emissions:
    - Lone Cypress blue hydrogen plant, up to 200,000 tonnes per annum
    - Elk Hills field gas treatment (pre-combustion for Elk Hills Power Plant), up to 200,000 tonnes per annum
    - Avnos Direct Air Capture (DAC), up to 1,500 tonnes per annum
- Future emission Sources:
    - CalCapture Elk Hills 550 MW natural gas power plant (post combustion), renewable fuel plants, steam generators post combustion and other power plants / industrial sources in the area.

CO_2 injectate from these sources has been incorporated into Table 1 for injectate sampling. Notification will be sent to the EPA prior to switching or adding CO_2 sources, at which time the sampling procedures can be reassessed.

Sampling Location and Frequency

CO_2 injectate samples will be taken for each injection source and between the final compression stage and the wellhead. Sampling will take place three months after the commencement of injection and every three months thereafter. Sampling process will follow the procedures below.

CTV will increase the frequency and collect additional samples if the following occurs:

1. Significant changes in the chemical or physical characteristics of the CO_2 injectate, such as a change in the CO_2 injectate source; and
2. Facility or injector downtime is greater than thirty days.

Analytical Parameters

CTV will analyze the water content and injectate the constituents identified in Table 1 using the methods listed. An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 1. Summary of analytical parameters for CO_2 stream.

Parameter	Analytical Method(s)
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD
Carbon Monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)
Total Hydrocarbons	ISBT 10.0 THA (FID)
Ammonia	ISBT 6.0 (DT)
Ethanol	ISBT 11.0 (GC/FID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Methane, Ethane, Ethylene	ISBT 10.1 (FID)
Hydrogen Sulfide and Sulfur Dioxide	ISBT 14.0 (GC/SCD)
CO_2 purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD
δ13C	Isotope ratio mass spectrometry
Water Vapor	ISBT 3.0

Sampling Methods

Stream sampling will occur for each required CO2 analysis and in the last compressor station prior to being sent to the injector. A sampling station will be installed to facilitate collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a full-service laboratory in Bakersfield, 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 4.

Zalco has a chain of custody procedure that includes the following.

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

For each required CO_2 analysis, CTV will report the time each sample was taken, a tabulation of all CO_2 stream analyses (including any quality assurance/quality control samples), an interpretation of the results, any identified changes and explanation of any data gaps.

Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

CTV will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

Monitoring Devices, Location, and Frequency

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table. Depths of downhole continuous monitoring equipment are specified for each well and labeled in the Appendix_26R - Injection & Monitoring Well Schematics document.

Monitoring for the parameters, except for annulus fluid volume, will be continuous with a 10 second sampling and 30 second recording frequency for both active and shut-in periods. This will be adequate to monitor for changes in the wellbore and the reservoir.

Table 2. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface Downhole 345C-36R: 5690'(MD) 353X-35R: 6390' (MD) 363-27R: 6290' (MD) 373-35R: 7010' (MD)	10 seconds	30 seconds

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection rate	Flowmeter	Surface	10 seconds	30 seconds
Injection volume	Calculated	Surface	10 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	10 seconds	30 seconds
Annulus fluid volume		Surface	4 hours	24 hours
Temperature	Temperature Gauge	Surface Downhole 345C-36R: 5690'(MD) 353XC-35R: 6390' (MD) 363C-27R: 6290' (MD) 373-35R: 7010' (MD)	10 seconds	30 seconds
Temperature	DTS	Along wellbore to packer	10 seconds	30 seconds

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Injection Rate and Pressure Monitoring

Injection pressure, temperature and flow rate will be continuously monitored and recorded by the Elk Hills Central Command Facility (CCF). The injection pressure will be measured and recorded using pressure gauges at surface and downhole. The injectate temperature will be measured with a temperature gauge at the surface. The injection rate will be measured with a Coriolis flowmeter. The meter will be calibrated annually for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent. Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable bottomhole injection pressure. Pressure and temperature gauges will be calibrated annually. Table 6 of the QASP provides operating range and precision specifications.

Calculation of Injection Volume and Mass

The volume and mass of CO_2 injected into the Monterey Formation 26R will be calculated from the injection flow rate and CO_2 density. Density of CO_2 injected into the Monterey Formation 26R will be calculated using PVTP, a fluid thermodynamics package, developed by Petroleum Experts Ltd. PVTP is an industry standard software package that has been used extensively in CO_2 EOR applications to accurately model and match CO_2 PVT properties over a wide range of temperatures and pressures.

Annular Pressure Monitoring

Annulus pressure is monitored continuously to ensure integrity of the downhole packer, tubing, and casing. CTV will monitor the casing-tubing pressure continuously (every 10 seconds) using an electronic pressure gauge. The annulus will be filled with a non-corrosive brine with corrosion inhibitor. The casing-tubing annulus pressure for injection wells 373-35R, 345C-36R, 353XC-35R, 363C-27R will be maintained with at least 100psi at surface, as stated in the injection well operating procedure documents. Monitoring wells will be operated with 100 psi positive annular pressure at surface.

Failure to maintain >100 psi consistently could be an indication of internal or external mechanical integrity failure, provided that thermal (such as material contraction due to cooling) and pressure (such as ballooning due to increasing tubing pressure) transient effects of normal operational changes are properly diagnosed as acceptable deviations. CTV will notify EPA if (1) pressure decreases to 0 psig and cannot be explained by operational conditions, or (2) pressure drops below 100 psi threshold and cannot be maintained or stabilized after three attempts. Additionally, CTV will notify EPA if pressure increases above 1000 psi and cannot be explained by operational conditions.

Corrosion Monitoring 40 CFR 146.90(c)

CTV will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description below.

Monitoring Location and Frequency

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. The corrosion coupons will be installed in the pipeline that feeds CO_2 injectate to the injectors.

Sample Description

Samples of the materials used in the construction of the pipeline, injection wells, and monitoring wells that are directly in contact with CO_2 injectate will be monitored for corrosion. Corrosion coupons of the representative materials shown in Table 3 will be weighed, measured, and photographed prior to installation directly upstream of the wellhead. For well 373-35R, the wellbore materials exposed and in direct contact with injected CO_2 include the N-80 grade long string casing below the packer and the CRA tubing. These casing materials will be included in the corrosion coupon monitoring and are presently included in Table 3. General construction materials for pipeline, tubing and wellhead are shown in Table 3. Materials of construction will be reaffirmed after well and pipeline construction and prior to injection, as part of pre-operational testing. Subsequently, corrosion coupons consistent with final well construction materials will be used for corrosion monitoring.

Table 3. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel
Casing	N-80 steel (373-35R injection well) K-55 steel (341-27R, 328-25R monitoring wells) Chrome alloy consistent with final well construction for new drill wells
Tubing	Chrome alloy consistent with final well construction
Packer	Chrome alloy consistent with final well construction
Wellhead	Chrome alloy consistent with final well construction

Sample Handling and Measurement

Upon collection, the coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The samples will be handled and assessed in accordance with NACE TM0169/G31 and/or EPA 1110A SW846. Monitoring results will be documented and submitted to the EPA as per 40 CFR 146.91 (a)(7). Table 5 of the QASP document provides detection limit/range and precision.

A detected corrosion rate of greater than 0.3 mils/year will initiate consultation with the EPA. In addition, a casing inspection log may be run to assess the thickness and condition of the casing if the corrosion rate exceeds 0.3 mils/year. CTV will continually update the corrosion monitoring plan as data is acquired.

Above Confining Zone Monitoring

CTV will monitor water quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). The Etchegoin and Tulare Formations are permeable reservoirs above the confining zone.

Etchegoin Formation Monitoring

The Etchegoin Formation is between the Reef Ridge confining zone and the Upper Tulare USDW and will dissipate CO_2 injectate that may migrate upward from the injection zone. The Etchegoin Formation is continuous across the AoR and will be monitored continuously for pressure and temperature changes. Figure 1 shows the location of 355X-26R and the shallow groundwater monitoring well. The well is suitable and appropriate to adequately monitor for pressure and temperature changes within the first porous and continuous sand above the sequestration zone. This sand is present from 4,063’ – 4,087’ MD in 355X-26R.

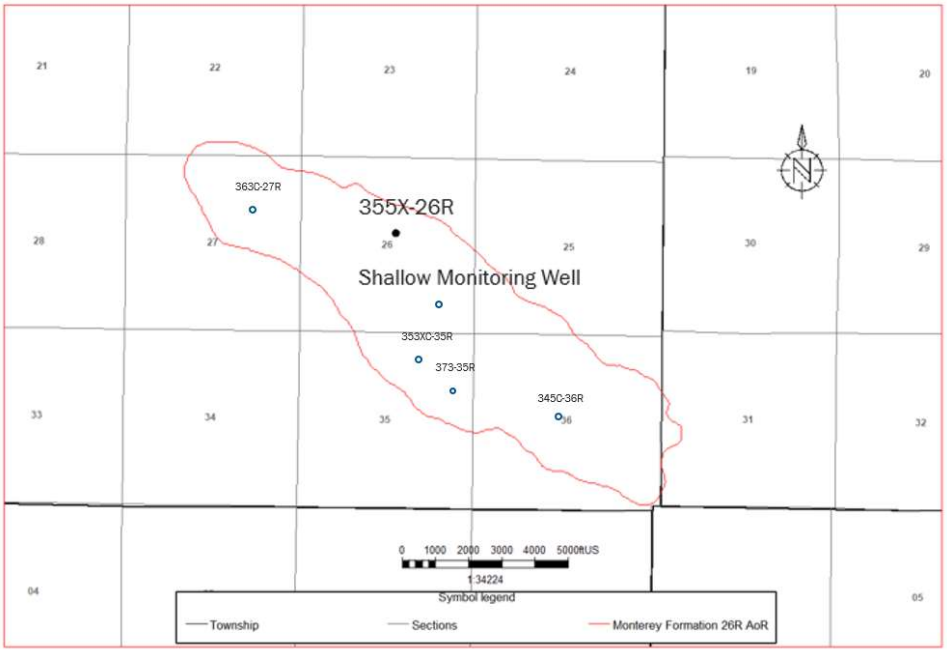


Figure 1: Above confining zone monitoring wells.

The effect of potential leakage from the Monterey Formation to the Etchegoin Formation is an increase in reservoir pressure and decrease in temperature of the Etchegoin. Additionally, potential leakage will create compositional changes detectable with fluid sampling and geochemical monitoring. Pre-injection geochemical composition will be established from baseline water analysis acquired within the Etchegoin Formation during pre-operational testing.

Tulare Formation Monitoring

Monitoring in the Upper Tulare will include pressure, temperature, and fluid sampling. Leakage to the Tulare Formation would increase the reservoir pressure and change the composition of the formation water (increased CO_2 concentration). The Upper Tulare is unsaturated in the AoR. The Upper Tulare Formation will be monitored between 400' – 450' MD in the shallow monitoring well that will be drilled specifically for this project.

Pre-injection geochemical composition will be established from baseline water analysis acquired within the Tulare Formation during pre-operational testing. Subsequent results will be compared against these baseline results for significant changes or anomalies. pH will be monitored as a key indicator of CO_2 presence.

Additional groundwater monitoring wells will be drilled to assess and monitor the Upper Tulare USDW if the following occurs:

1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation 26R CO_2 injection.

2. Upper Tulare Formation pressure or composition changes due to Monterey Formation 26R CO_2 injection.

Monitoring Methods, Location, and Frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well with respect to the AoR. The wells are located within the Elk Hills Oil Field, and CTV owns the surface and mineral rights.

Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	Shallow Water Monitoring Well	Pump	–400’ - 450' MD/VD	Quarterly
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’ - 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’ - 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	400' - 500' MD/VD in each well	Continuous
Etchegoin	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Quarterly
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' 4788' - 4811' 4205' - 4226' (all MD/VD)	Continuous

Analytical Parameters

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 5. Summary of analytical and field parameters for water samples from the USDW monitoring well and the Etchegoin monitoring well.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0, Rev. 2.1, Part A (1993)
Dissolved CO_2	Coulometric titration, ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Sampling Methods

Samples will be collected using the following procedures:

1. Depth and elevation measurements for water level taken.
2. Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
3. Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
4. Samples preserved and sent to lab as per chain of custody procedure.
5. Closure of well.

Laboratory Selection and Chain of Custody Procedures

Samples will be sent to, and analysis conducted by Zalco, a full-service state certified laboratory in Bakersfield, approximately 20 miles from the Elk Hills 26R Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3. Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

Internal Mechanical Integrity Testing

A Class VI well has mechanical integrity if there is no significant leak in the casing, tubing, or packer. CTV will conduct an initial annulus pressure test on all injection wells and on monitoring wells that penetrate the confining zone and are configured with tubing and a packer. Additionally, any time the packer is replaced or reset, a SAPT will be performed. The injection and monitoring wells will be configured with continuous recording devices to monitor the pressure on the annulus between the tubing and the casing, and annulus fluid volumes will be measured and recorded. These actions satisfy the requirements of 40 CFR 146.88(e)(1) and 40 CFR 146.89(b).

Standard Annular Pressure Testing (SAPT)

Pascal's Law states that any pressure applied to a fluid filling a closed vessel will be transmitted undiminished, throughout the vessel. This is the basis for the SAPT as the primary means to determine if a well's casing, tubing, packer, and wellhead (the annulus system) are liquid tight. Because the annulus system is not an isolated system, the measured pressure applied may not be constant throughout time. The temperatures along the wellbore must change as injection rates and temperatures change because of heat exchange between injectate and the surrounding formations. When the well is shut in, the wellbore may cool or become warmer as the well materials are subjected to the natural geothermal temperatures, which will result in expansion or contraction of liquid in the annulus. Because liquids are effectively incompressible, annular pressure is expected to fluctuate due to changes in the tubing such as contraction, elongation, and ballooning during transient injection or shut-in periods.

The procedure for conducting SAPT is as follows:

1. CTV will notify the Director to provide the opportunity to witness the testing.

2. Completely fill the tubing/casing annulus with packer fluid consisting of weighted brine and appropriate additives such as corrosion inhibitors, oxygen scavengers, and biocide. The volume to fill should be measured and recorded. The annulus liquid should be temperature stabilized prior to conducting the test.

3. The annulus will be pressurized to a surface pressure which exceeds the maximum injection pressure by at least 100 psi unless an alternate pressure is approved by the EPA Director.

4. Following pressurization, the annular system will be isolated from the source of pressure by a closed valve, or it will be disconnected entirely.

5. The isolation will be maintained for no less than one hour. During this time, pressure measurements will be recorded in at least one-minute intervals.

6. After the SAPT is concluded, the valve to the annulus should be opened to bleed down the pressure. The liquid returns from the annulus should be measured and recorded.

Monitoring wells that do not have a specified maximum tubing pressure will be tested to 1000 psi initially. As reservoir pressure increases during injection and tubing pressure is continuously monitored, SAPT test pressure will be reconsidered. When tubing pressure approaches 100 psi less than the initial SAPT test pressure, i.e. 900 psi, the SAPT will need to be performed again unless an alternative method or test pressure is approved by the EPA Director. Table 6 provides information on the frequency and test pressures for injection and monitoring wells within the project.

Table 6. Internal MIT requirements

Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)	Maximum Injection Pressure (psi)	Test Pressure (psi)
Standard Annular Pressure Test (SAPT)	373-35R[1]	Casing/tubing annulus from surface to packer	Once, upon initial installation	Any time packer is replaced or reset	Not Applicable	1992	2092
	345C-36R[1]					1888	1988
	363C-27R[1]					2020	2120
	353XC-35R[1]					1997	2097
	355X-26R[2]				Any time packer is replaced or reset	--	1000
	341-27R[3] 328-25R[3] 376-36R[3]					--	1000

Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)	Maximum Injection Pressure (psi)	Test Pressure (psi)	
Annular Pressure	373-35R[1] 345C-36R[1] 353XC-35R[1] 363C-27R[1]	Wellhead	Continuous	Continuous	Not Applicable	--		-
	355X-26R[2] 341-27R[3] 328-25R[3] 376-36R[3]				Continuous			-

[1] *CO2 injection well*
[2] *Above Zone monitoring well*
[3] *Injection Zone monitoring well*

The interpretation of the SAPT will compare the pressure change during the test once the initial pressure has stabilized. If the change (gain or loss) in pressure is less than 3% of the test pressure, the well has demonstrated mechanical integrity, pursuant to 40 CFR 146.8(a)(1). If the change in pressure (gain or loss) exceed 3% of the test pressure, the well has failed to demonstrate mechanical integrity.

CTV will utilize an EPA-approved Annular Pressure Test form to record the results of the SAPT if the test is not witnessed by the EPA. If the test indicates the well has demonstrated mechanical integrity, the test form and raw pressure data (original chart recordings or a digitized log of pressure and time) will be provided to the EPA. If the test indicates a failure of mechanical integrity in an injection well, the well will be shut in, no injection will occur, and the EPA Director will be notified within 24 hours.

Continuous Monitoring of Annular Pressure

Injection and monitoring wells will record continuous annular pressure such that internal MIT can be confirmed in real-time based on the interpretation of this data. CTV will identify and investigate pressure deviations that do not align with changes to operating conditions or temperature effects due to seasonal variation. In the event of a casing leak into a permeable zone, the pressure will normally fall. In the event of a tubing or packer leak, the annulus pressure will track injection pressure, although the pressures are not likely to be equal due to friction and density differences.

This data will be provided in the semi-annual report to demonstrate ongoing internal mechanical integrity.

External Mechanical Integrity Testing

CTV will conduct mechanical integrity testing on each injection well at least once per year to demonstrate external mechanical integrity using an approved test method per 146.89(c). CTV will, at a minimum, perform a temperature log on the injection wells.

Testing Methods

Table 7 shows testing methods that may be utilized for MIT on injection and monitoring wells associated with this project. CTV will utilize an approved MIT technique, such as temperature logging with wireline, oxygen-activation logging, or noise logging on CO_2 injection wells as the primary method. While DTS may not be considered an approved temperature logging method for injection well MIT, CTV may seek Director approval in the future prior to using this method. If CTV elects to conduct an alternate MIT, notification including a description of the proposed testing method and procedure will be sent to the EPA for approval.

Since temperature decay logs require injection to cool the wellbore and near wellbore region prior to logging, monitoring wells cannot be tested for external MIT without approval to inject fluid. Additionally, injecting fluid such as H_2O or CO_2 for the purpose of testing may be undesirable for other reasons. Therefore, MIT on monitoring wells will not be conducted using temperature decay logging. Instead, another approved method under 40 CFR 146.89(c) may be utilized, or DTS may be proposed for EPA Director approval for monitoring well MIT.

Table 7. External Mechanical Integrity Testing Methods

Test Description	Location
Temperature Decay Log	Along wellbore using wireline well log
Distributed Temperature Log (DTS)	Along wellbore using fiber optic sensing (DTS), continuous
Oxygen Activation Log (OA)	Along wellbore using wireline well log
Noise Log	Along wellbore using wireline well log

Description of Temperature Logging with Wireline

EPA has specific requirements that must be satisfied for a temperature log to be considered valid for MIT as specified by 40 CFR 146.89(c). CTV will utilize the following procedures and comply with EPA guidance to ensure testing requirements are achieved.

1. Stabilize injection for 24 hours prior to running the temperature log.

2. Run an initial temperature survey logging down from at least 200 feet above the base of the Reef Ridge Shale to the deepest point reachable in the well, while injecting at a rate that allows for safe operations. The temperature sensor should be located as close to the bottom of the tool string as possible. The optimal wireline speed is 30 ft/min, and the acceptable range is between 20 and 50 feet per minute.

3. Shut in the injection to the well and run multiple temperature surveys with 4 hours between runs. The minimum shut-in time following the initial temperature log is 12 hours total, and the superimposed logging passes should be at least 4 hours after the injection pass.

4. Assess the time lapse temperature profiles against the baseline injection survey to identify temperature anomalies that may indicate a failure of well integrity. Evaluate the data to determine if additional passes are needed for interpretation. If CO_2 migration is interpreted in the topmost section of the logging pass such that the top of the migration pathway cannot be identified, additional logging runs over a shallower interval will be required to find the top of migration.

5. Both the printed or digital log and the raw data for at least two logging runs should be provided to the EPA. The printed or digital log should have the following:

    a. The heading must be complete and include all pertinent information to identify the well, well location, date of the survey, etc.

    b. Vertical depth scale of the log should be 1 or 2 in. per 100 ft. to match lithology logs.

    c. Horizontal temperature scale should be no more than one Fahrenheit degree per inch spacing.

    d. The right-hand tracks must contain the "absolute" temperature and the "differential" temperature curves with both log runs identified and clearly superimposed for comparison and interpretation purposes.

    e. The left-hand track must contain a casing collar log, a legible lithology log such as spontaneous potential (SP) or gamma ray, and identification of the base of USDW, if present.

Description of Temperature Logging using Distributed Temperature Sensing (DTS)

DTS is a fiber optic continuous temperature monitoring system that will be installed in injection and monitoring wells to measure wellbore temperature in real time from the annulus along the length of the tubing. Like a temperature log, the DTS temperature data can be used to assess the internal and external mechanical integrity of injection and monitoring wells. Successful comparisons of DTS temperature logs to wireline temperature logs have been well documented and validate the use of DTS as a temperature log for mechanical integrity testing. By continuously monitoring DTS data, this testing method provides an early detection of temperature changes through the capability to continuously monitor MIT in Realtime, making this technology potentially superior to wireline temperature logging.

The impact to health, safety, and environment of DTS temperature logging is significantly improved in comparison to wireline temperature logging operations. Because the DTS system is installed at the time of well construction or workover, no crew is required to be present at the

wellsite. The following procedure can be performed to acquire a temperature log using DTS for mechanical integrity analysis for an injector:

1. Establish baseline temperature profile that defines the natural gradient along the well prior to injecting.

2. During injection, record the temperature profile for 6 hours prior to shutting in the well.

3. Stop injection and record the temperature for sufficient time to allow cooling.

4. Start injection and record the temperature profile for 6 hours.

5. Compare the baseline analysis to the time-lapse data for assessment of temperature anomalies that may indicate a well failure.

Description of Passive Temperature Logging using DTS

DTS can be used for passive external mechanical integrity monitoring on monitoring wells. This solution has advantages compared to wireline temperature logging on monitoring wells in liquid-depleted reservoirs. DTS will be installed on the tubing string from surface to the packer on the injection wells, the injection zone monitoring wells, and the above zone monitoring well. DTS will detect temperature changes along the wellbore if external mechanical integrity is compromised.

On injection wells, temperature changes associated with external fluid migration will be masked due to the dominating impact of injectate temperature on the wellbore materials. However, during shut-in periods immediately following sustained injection, when warm back can be observed along the length of the DTS fiber, migration pathways of fluids at non-geothermal temperature gradients can be identified. Additionally, lack of deviation from temperature reversion to the geothermal gradient is a demonstration of external mechanical integrity. It is appropriate for the DTS fiber to monitor temperature throughout and above the confining layer, and the configuration of DTS fiber as described above, from surface to the top of the packer, is sufficient to monitor injection wells for external MIT above the injection zone.

On the injection zone monitoring wells, the DTS string will monitor the confining layer and all above layers in real-time. If dense phase CO_2 were to breach the injection zone and migrate upward, the warmer CO_2 would cause a discernible temperature anomaly. If the CO_2 were to change phase to gas phase, a cooling effect would be observed. The high frequency and volume of data is superior to wireline temperature logging, significantly enhancing diagnosis capability and reaction time. DTS is not required to be deployed through the injection zone to assess external MIT within and above the confining layer.

Description of Noise Logging

To ensure the mechanical integrity of the casing of the injection well, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. Noise logging may be carried out while injection is

occurring. If ambient noise is greater than 10 mv, injection will be halted. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Run a noise survey from top of Tulare to the deepest point reachable in the Monterey Formation while injecting at a rate that allows for safe operations.

3. Make noise measurements at intervals of 100 feet to create a log on a coarse grid.

4. If any anomalies are evident on the coarse log, construct a finer grid by making noise measurements at intervals of 20 feet within the coarse intervals containing high noise levels.

5. Make noise measurements at intervals of 10 feet through the first 50 feet above the injection interval and at intervals of 20 feet within the 100-foot intervals containing:

   a. The base of the lowermost bleed-off zone above the injection interval and

   b. The base of the lowermost USDW.

6. Additional measurements may be made to pinpoint depths at which noise is produced

Description of Oxygen Activation Logging

To ensure the mechanical integrity of the casing, logging data will be recorded across the wellbore from surface down to primary caprock. Bottom hole pressure data near the packer will also be provided. OA logging may be carried out while injection is occurring. The following procedures will be employed:

1. Move in and rig up an electrical logging unit with lubricator.

2. Conduct a baseline Gamma Ray (GR) log and Casing Collar Locator (CCL) log from the top of the injection zone to the surface prior to taking the stationary readings with the OA tool. Gamma Ray Log is necessary to evaluate the contribution of naturally occurring background radiation to the total gamma radiation count detected by the OA tool. There are different types of natural radiation emitted from various geologic formations or zones and the natural radiation may change over time.

3. The OA log shall be used only for casing diameters of greater than 1-11/16 inches and less than 13- 3/8 inches.

4. All stationary readings should be taken with the well injecting fluid at the normal rate with minimal rate and pressure fluctuations.

5. Prior to taking the stationary readings, the OA tool must be properly calibrated in a "no vertical flow behind the casing" section of the well to ensure accurate, repeatable tool response and for measuring background counts.

6. Take, at a minimum, a 15-minute stationary reading adjacent to the confining interval located immediately above the injection interval. This must be at least 10 feet above the injection interval so that turbulence does not affect the readings.

7. Take, at a minimum, a 15-minute stationary reading at a location approximately midway between the base of the lowermost USDW and the confining interval located immediately above the injection interval.

8. Take, at a minimum, a 15-minute stationary reading adjacent to the top of the confining zone.

9. Take, at a minimum, a 15-minute stationary reading at the base of the lowermost USDW.

10. If flow is indicated by the OA log at a location, move up hole or downhole as necessary at no more than 50-foot intervals and take stationary readings to determine the area of fluid migration.

Pressure Fall-Off Testing

Pressure falloff tests are used to measure formation properties in the vicinity of the injection well, and the intent of periodic testing is to monitor for any changes in the near-wellbore environment that may impact injectivity or increase pressure. CTV will perform pressure fall-off tests on each injector during the injection phase every five years as described below to meet the requirements of 40 CFR 146.90(f). CTV will refer to EPA Region 9 UIC Pressure Falloff Requirements for planning and conducting the testing as well as preparing and submitting the monitoring report.

Testing Details

The following procedure will be followed:

1. Injection rate will be held constant for at least one week prior to shut in. The injection pressure will be high enough to produce a pressure decrease upon shut in that will result in valid test data for derivative analysis. The maximum operating pressure will not be exceeded.

2. The injection well will be equipped with surface and downhole pressure and temperature gauges. Bottomhole gauges will have surface readout capabilities and will be the primary source of pressure data for analysis because these gauges will be least affected by wellbore fluid effects. Prior to and throughout the shut-in period, the gauges will collect pressure data in 10 second intervals, which is sufficient and appropriate for pressure-transient analysis. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

3. The injection well will be shut in at the wellhead to minimize wellbore storage effects from compressible fluids. The injection rate of the offset injector will be held constant during the test. Accurate records of offset wells completed within the same zone will be maintained and considered in the interpretation.

4. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage. This desired radial flow regime is identified by a zero slope of the pressure derivative through pressure transient analysis. The data can be analyzed in real time because of the surface readout capabilities of the pressure gauges and can therefore ensure a complete and adequate test before restarting injection.

5. Interference testing may be conducted at the conclusion of the falloff test to demonstrate communication between the wells. The injection rate of the offset injector would be increased or decreased multiple times to create pressure pulses that can be observed by the shut in well.

6. The interpretation of the pressure transient dataset will be performed by a trained engineering professional using proven industry standard methodologies. Anomalies that are identified from the interpretation will be investigated.

7. A report containing the pressure fall-off data and interpretation of the reservoir pressure will be submitted to the EPA in the next semi-annual report. The report will follow the guidance of the EPA Region 9 UIC Pressure Falloff Testing Requirements document.

Carbon Dioxide Plume and Pressure Front Tracking

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

Plume Monitoring Location and Frequency

Figure 2 shows the location of the wells that will monitor the CO_2 plume directly in the targeted 26R reservoir. These wells will actively monitor the development of the CO_2 plume upon the initiation of injection. If the plume development is not consistent with computation modeling results, CTV will assess whether additional monitoring of the plume is necessary. Determination for plume monitoring changes will be made in consultation with the UIC Program Director and would trigger an AoR reevaluation, per the AoR and Corrective Action Plan.

Based on the Base case model, the CO2 plume is expected to arrive at the monitoring well locations at approximately the – 7th year of injection for 376-25R, 8th year of injection for 328-25R and the 9th year of injection for 341-27R.

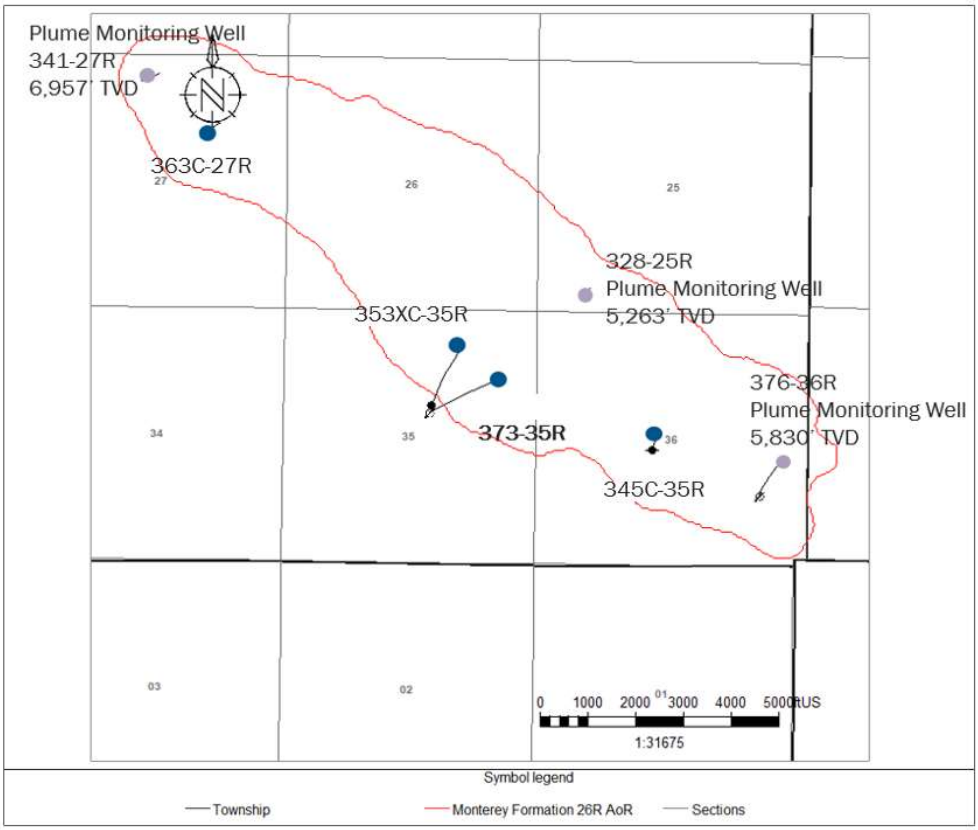


Figure 2: Monterey Formation 26R sequestration reservoir monitoring wells, with true vertical depth in feet of the monitoring interval.

Table 8 presents the methods that CTV will use to monitor the position of the CO_2 plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 9. Detection limits, precisions, and quality control requirements for these methods are presented in Table 3 of the QASP.

Table 8. Plume Monitoring Activities

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Formation 26R	Fluid Sampling	341-27R	6981' - 7237' MD	Once	Quarterly	Annual
		Pressure		6910' MD	Baseline	Continuous	Continuous
		Temperature		6910' MD	Baseline	Continuous	Continuous
		Fluid Sampling	328-25R	5268' - 5800' MD	Once	Quarterly	Annual

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection Phase)	Frequency (Post-Injection Phase)
	Monterey Formation 26R	Pressure		5188' MD	Baseline	Continuous	Continuous
		Temperature		5188' MD	Baseline	Continuous	Continuous
	Monterey Formation 26R	Fluid Sampling	376-36R	5832' - 6815' MD	Once	Quarterly	Annual
		Pressure		5760' MD	Baseline	Continuous	Continuous
		Temperature		5760' MD	Baseline	Continuous	Continuous
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	341-27R	6981' - 7237' MD	Baseline	Every year from start of injection	Every 5 years
			328-25R	5268' - 5800' MD			
			376-36R	5832' - 6815' MD			

Table 9. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-AES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510

Parameters	Analytical Methods
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Plume Monitoring Details

Fluid sampling, pressure monitoring, and temperature monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but more importantly, the CO_2 content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in Table 9.

The DTS from the monitoring wells will provide continuous temperature from packer to surface.

As discussed in the AoR and Corrective Action Plan, 72% of the post-shut-in injected CO_2 will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved CO_2, and formation fluid density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand CO_2 saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every year during the injection phase.

CTV does not plan to conduct VSP monitoring for the depleted 26R oil and gas reservoir. The resolution for the CO2 plume using VSP will be limited due to noise and limited density contrast between the reservoir before and after CO2 injection. Seismic monitoring works especially well in thick, brine filled formations and may not be appropriate for depleted gas reservoirs (page 106 Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance). In addition, the unsaturated Tulare Formation and depleted gas San Joaquin Formation will limit VSP seismic wave responses.

Pressure Front Monitoring Location and Frequency

The aerial extent of plume development in the Monterey Formation 26R reservoir will reach the reservoir boundaries early in the injection phase. Because the reservoir is pressure-depleted, injected CO_2 will quickly fill the available pore space. Table 8 indicates that pressure front monitoring will coincide with direct monitoring of the CO_2 plume using the monitoring wells identified and will support CO_2 plume model and AoR model validation. Monitoring well locations with respect to plume development through time are shown in Figure 3.

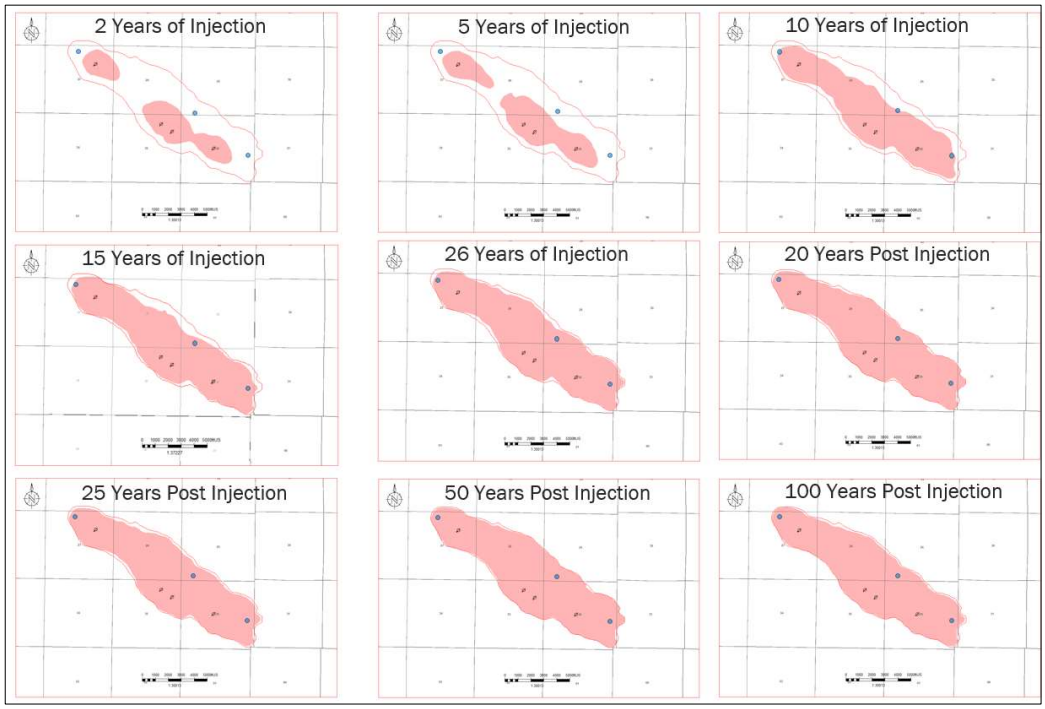


Figure 3: Monitoring well location with maps showing plume development through time from computational modeling.

Monitoring well 328-25R pressure development based on computational modeling is shown in Figure 4. The average pore volume reservoir pressure stabilizes 1 year after the end of injection. This is due to the majority of CO_2 that remains super-critical and low quantity of CO_2 that will be soluble in either the oil or water phases. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

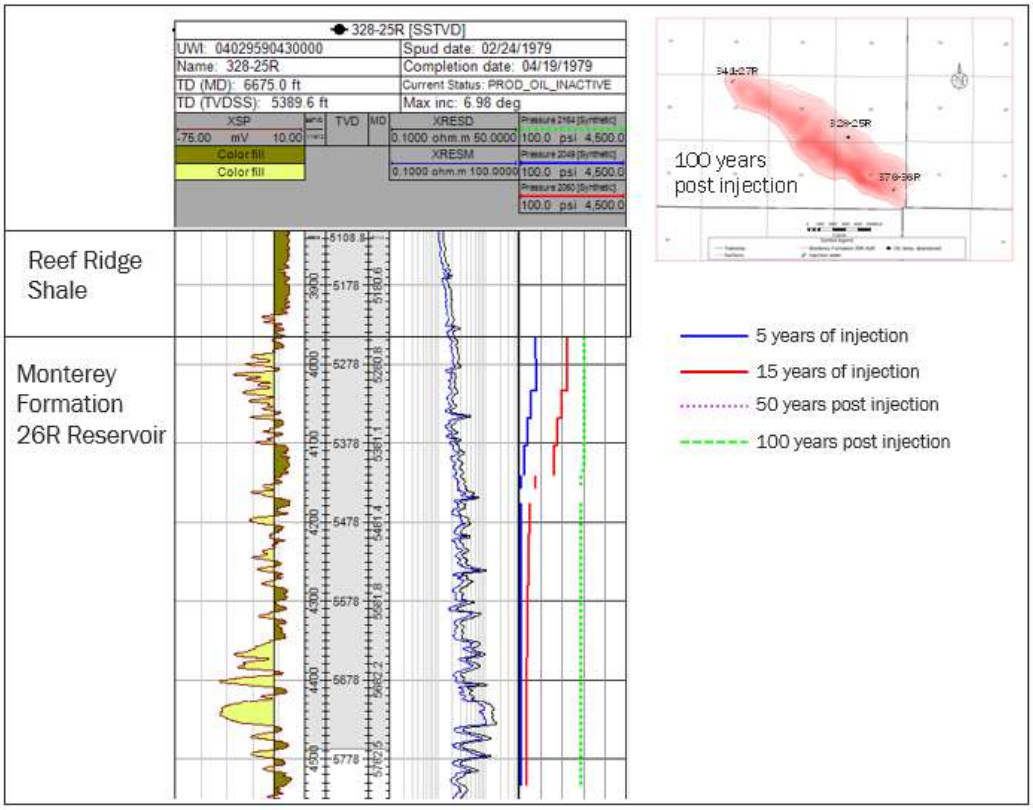


Figure 4: Monitoring well 328-25R showing the pressure increase through time from the computational modeling results.

Pressure Front Monitoring Details

Direct pressure monitoring of the plume will be achieved through installation of pressure and temperature gauges in monitoring wells 341-27R, 328-25R and 376-36R. The depleted Monterey Formation 26R oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 5 shows the pressure in the reservoir post-injection. CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies.

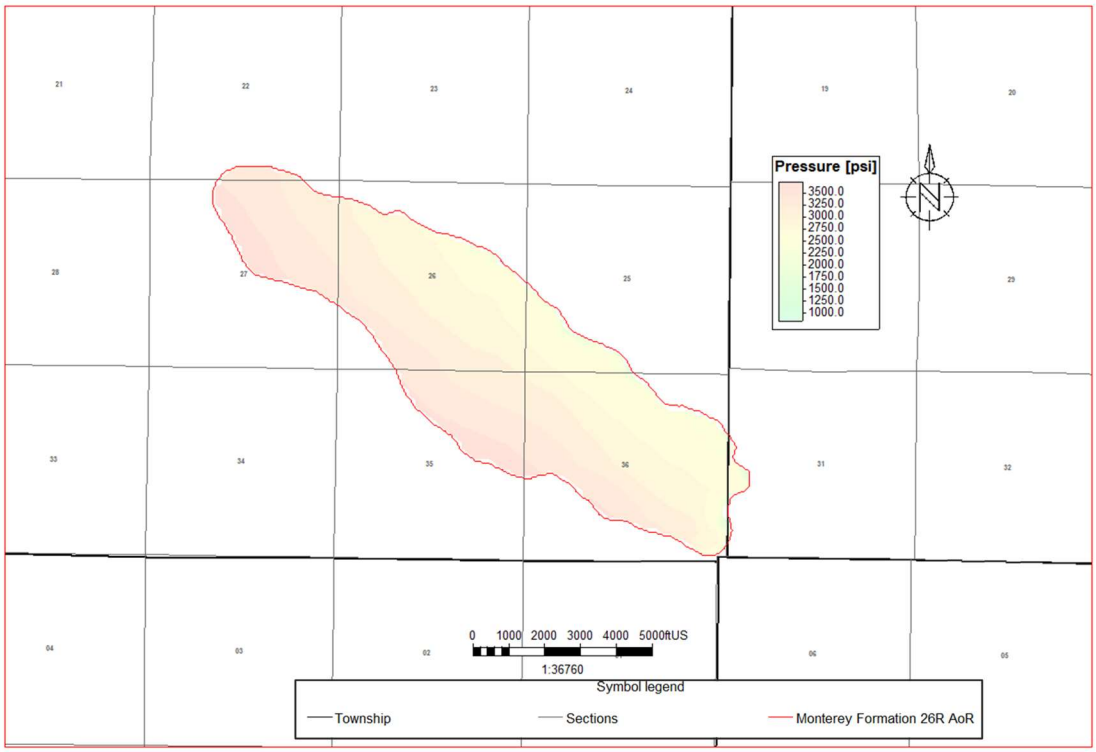


Figure 5: Monterey Formation 26R pressure 50 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.

The modeled pressure increases at monitoring well 328-25R are shown in Figure 4. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

Table 10 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ. Downhole gauge specifications are provided in Table 8 of the QASP document.

Table 10. Pressure-front monitoring activities.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)]	Monterey Fm 26R	Pressure	341-27R	6981' - 7237' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
DIRECT MONITORING	Monterey Fm 26R	Pressure	328-25R	5268' - 5800' MD	Baseline	Continuous
		Temperature			Baseline	Continuous

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Baseline)	Frequency (Injection)
	Monterey Fm 26R	Pressure	376-36R	5832' - 6815' MD	Baseline	Continuous
		Temperature			Baseline	Continuous
Other Plume / Pressure-Front Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Baseline	Continuous

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole seismometers in the Elk Hills Oil Field. This network will be implemented to monitor seismic activity near the project site. Direct pressure monitoring of the storage reservoir will be used in conjunction with the passive seismic monitoring to demonstrate that there are no seismic events affecting CO_2 containment.

Specifications of the network are as follows:

- 7 sensor locations (borehole and near surface) with high-sensitivity 3-component geophones (Figure 6)
- Borehole sensors have been deployed (depths shown in Figure 6) to ensure a good quality signal and to minimize noise. A velocity model will be derived from vertical seismic profiles (VSPs), sonic well logs, and check shots.
- The system will be designed with capability of detecting and locating events >M_w 0.0

Baseline Analysis:

The monitoring network has been installed to collect seismicity data to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

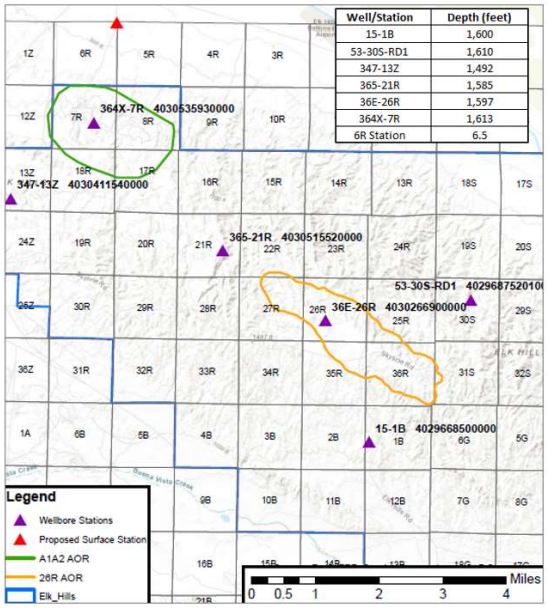


Figure 6: Elk Hills seismic monitoring network station location and depth of geophone sensors.

Monitoring Analysis:

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed continuously.

- Waveform data to be transmitted near real-time via cellular modem or other wireless means and archived in a database

- Event notifications to be automatically sent to required personnel to ensure compliance with CTV's Emergency and Remedial Response Plan

Additionally, CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network. The EPA Director will be notified of seismic activity as per the Emergency and Remedial Response Plan.

Surface Air Monitoring

Surface air monitoring, including broad aerial monitoring and targeted monitoring at wells and pipelines will be conducted.

Continuous Monitoring of AOR

Broad aerial surface air monitoring will be conducted with eddy covariance towers. Eddy covariance towers are a widely used micrometeorological technique for direct high-speed

measurements of the transport of gases, are a recommended component of CCS project surface air monitoring.

Each eddy covariance tower will consist of a solar-powered 3-dimensional sonic anemometer and open-path gas analyzer installed on a stationary tower and will be installed downwind of the prevailing wind direction from potential gas sources. Annual average prevailing wind direction in the vicinity is from the northwest. Proposed tower locations are displayed on Figure 7. Locations were chosen to be downwind (southeast) of the injection wells and surface expression of the simulated CO_2 plumes, to be in locally high topographic locations given the hilly terrain in the project vicinity, and in a location with access for equipment installation and servicing.

Monitoring equipment will be installed at a height of approximately 5 meters (33 feet). In general, the upwind distance represented by the tower height can be determined by the 1:100 rule; in this case with a 5-meter tower height the majority of measured flux will come from an oval-shaped area from near the tower to 500 meters (1,640 feet) upwind.

Gas emission rate is calculated from air density, vertical wind speed, and dry CO_2 mole fraction. Air density fluctuation is assumed to be negligible, wind speed will be measured with the sonic anemometer and CO_2 mole fraction with the gas analyzer. The sonic anemometer will be Campbell Scientific CSAT3 or equivalent, and CO_2 gas analyzer will be LI-COR Biosciences LI-7500A or equivalent. The gas analyzer will be positioned at or slightly below the sonic anemometer level, with a separation distance less than 20 centimeters. Vibration will be minimized by the use of several guy wires attached at the middle of the tower.

Manual cleaning of the gas analyzer will be performed on an as-needed basis when anomalous readings or excessive zero-drift in the data is observed. Factory calibration is assumed to be stable for at least several years and will be checked once per every six months as a precaution.

Data processing will be conducted and will be presented as hourly-averaged CO_2 concentrations and gas emission rates. Detection of anomalous and increasing CO_2 concentrations will lead to eddy covariance tower equipment testing and CARB consultation.

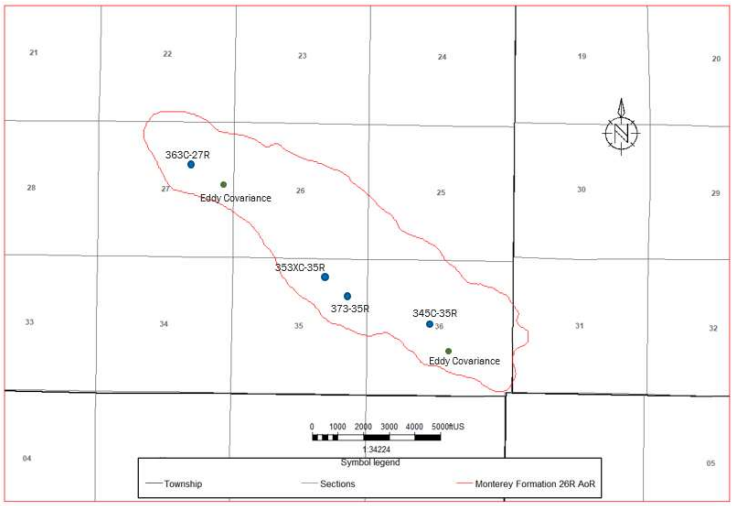


Figure 7: Location of Eddy Covariance monitoring.

Continuous Equipment Monitoring

Surface components of the injection system, including the flowlines and wellheads, will be monitored using equipment that will monitor for elevated CO_2. This leak detection equipment will be integrated with automated warning systems that notify the control center at the central facility, giving the operator the ability to remotely close the valves in the event of an anomalous reading. The central facility uses a SCADA software system to implement operational control decisions on a real-time basis throughout the project to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Monitoring Summary

This proposed monitoring program meets the goals of 40 CFR 146.90(g) by capturing continuous direct measurements of pressure and temperature in the storage reservoir (in-zone), Etchegoin (above zone) and USDW across key points of the AOR, in addition to frequent fluid samples and PNL to track the progress and confinement of the CO_2 plume. This data will also calibrate the dynamic model to predict plume front movement and pressure increase. In addition, the high resolution seismic monitoring network will provide a wide area measurement to indirectly monitor for pressure increase in-zone and above, that can be used in conjunction with the data from the monitoring wells to confirm confinement.

Direct:

The three in-zone monitoring wells are located close to the edges of the AOR, up-dip of the injectors, and thus in the flow direction of the less buoyant injected CO_2. The wells will be continuously measuring pressure and temperature at these locations. The continuous signals of pressure change in the reservoir will be used to update and calibrate the dynamic model and identify any major deviations from the predicted behavior of the reservoir. The continuous temperature measurements will provide data for the arrival of CO_2 at these locations.

In addition to the USDW and Etchegoin monitoring wells, the in-zone monitoring wells will provide confirmation of the confinement of CO_2 to the injection zone by also continuously measuring temperature changes in the Etchegoin and USDW (via DTS). Periodic fluid sampling at these locations will confirm the continuous pressure and temperature data, by providing measurements of CO_2 concentration in the reservoir that can further calibrate the dynamic model. Thus, the direct measurements for the injection zone through these wells will provide adequate special coverage of the development of the plume and pressure front, which can also improve the accuracy of the dynamic model predictions.

The two centrally located monitoring wells in the Etchegoin formation and USDW will continuously measure pressure and temperature in their respective zones, thus providing continuous direct measurements to assess the confinement of the injected CO_2. In addition, the continuous temperature measurements at these two locations, combined with the temperature measurement covering the Etchegoin and USDW at the three in-zone monitoring wells will provide adequate spatial coverage across the AOR to evaluate confinement of CO_2 in the storage reservoir.

Indirect:

PNL at the three in-zone monitoring wells will provide indirect measurement of gas saturation and CO_2 concentration in the injection zone, which will track the progress and confinement of the plume and further calibrate the dynamic model.

The seismic monitoring network will provide an indirect measurement of the pressure increase in the injection zone, the Etchegoin and the USDW. The seismic monitoring network will be sufficient to resolve events greater than 0 magnitude, with a 1,000 ft vertical resolution at the injection depths and above, giving us the ability to differentiate between events in the injection zone versus events in the shallower Etchegoin or USDW. This provides an indirect way to monitor for pressure increases in-zone or above zone via seismic events that could be triggered from pressure changes due to CO_2 injection or fluid migration.

Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan

WELL PLUGGING PLAN

CTV I ELK HILLS 26R PROJECT

Injection Well 363C-27R

Facility Information

Facility Name: Elk Hills 26R Storage Project

Facility Contact: Travis Hurst / CCS Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_363C-27R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – COP Details_363C-27R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – COP Details_363C-27R_V3	3	01/11/23	Revisions made based on questions received from the EPA 01/11/23
Attachment G – COP Details_363C-27R_V4	4	05/14/2023	Revisions made based on questions received from the EPA 03/2023
Attachment D – Well Plugging Plan_363C-27R_V5	5	11/29/2023	Separating Construction and Plugging Plans into Separate Attachments

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

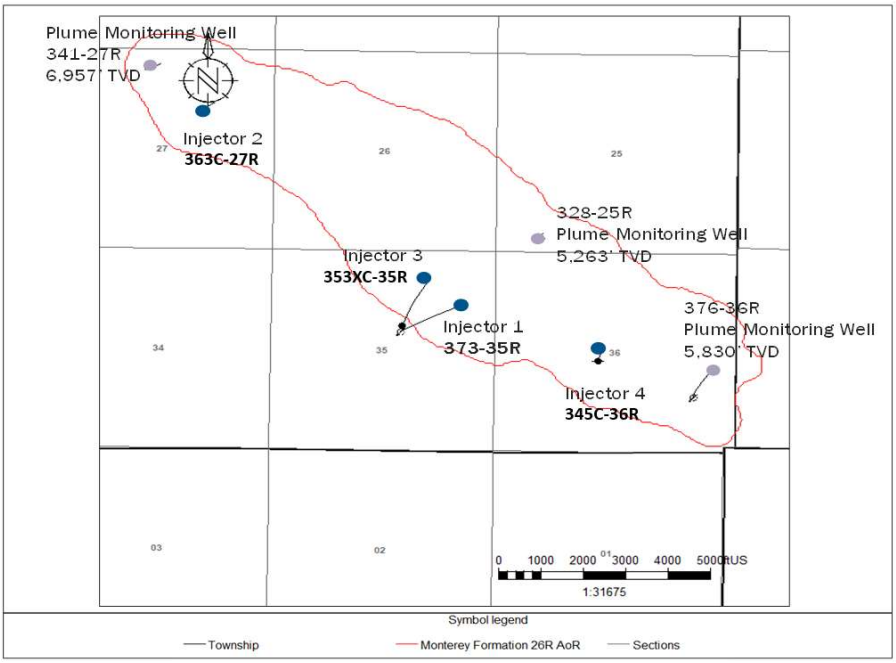


Figure 1: Map showing the location of injection wells and monitoring wells.

Figure 2 and *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Plugging

CTV will conduct injection well plugging and abandonment according to the procedures below. The proposed injection well plugging plan will ensure that the proposed materials and procedures for injection well plugging are appropriate to the well's construction and the site's geology and geochemistry.

Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity test prior to plugging the monitoring well as required by 40 CFR 146.92(a). A temperature log or other approved external MIT will be run over the entire depth. The planned external MIT method will be a temperature log or other approved external MIT (Table 1) and the procedure will be EPA-approved and consistent with procedures outlined in the Testing and Monitoring Plan. If a temperature log is run for external MIT, the temperature data will be evaluated for anomalies in the temperature profile by comparing to baseline temperature data acquired prior to injection of CO_2 and during the injection phase. If another approved external MIT method is used, it will be compared to baseline pre-injection data and/or other data acquired throughout the injection phase which the EPA has deemed acceptable.

Table 1: External Mechanical Integrity Testing Methods

Test Description	Location
Temperature Decay Log	Along wellbore using wireline well log
Distributed Temperature Log (DTS)	Along wellbore using fiber optic sensing (DTS), continuous
Oxygen Activation Log (OA)	Along wellbore using wireline well log
Noise Log	Along wellbore using wireline well log

Information on Plugs

CTV will use the materials and methods noted in Table 2 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A standard portland cement blend will be designed with a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The properties of this cement blend will be at least equivalent to the properties of Class G portland cement, and the cement plug will provide an

effective, long-term barrier to prevent migration of CO_2 into and within the wellbore. This cement is widely used in CO_2-EOR wells and has been demonstrated to have properties that are not deleterious with CO_2.

The wells will have this cement placed as detailed in Table 2, and all portions of the wellbore that are not plugged with cement will be filled with sufficiently weighted abandonment mud. The cement will be set in plug segments per CTV's standard procedures.

Table 2: Plugging details

Plug Information	**Plug #1**	**Plug #2**	**Plug #3**	**Plug #4**
Diameter of boring in which plug will be placed (in.)	3.92	6.276	6.276	6.276
Depth to bottom of tubing or drill pipe (ft)	8300	2476	1054	39
Sacks of cement to be used (each plug)	154	24	24	5
Slurry volume to be pumped (bbl)	31.54	4.92	4.92	1.02
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	6200	2351	929	14
Bottom of plug (ft)	8300	2476	1054	39
Type of cement or other material	Class G Portland	Class G Portland	Class G Portland	Class G Portland
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced Plug, Retainer, or CT Plug			

Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan.

Plugging Procedures

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Kill fluid of appropriate density is bullheaded into the wellbore to prevent reservoir fluid inflow and acts as a buffer fluid to flush the wellbore. Wellbore Bullheading will be conducted at appropriate rates so as to ensure no fracturing of the surrounding formation occurs and the cement plugs are not compromised in any way. After at least one wellbore volume of fluid is pumped, the well is observed to ensure static conditions, which is an indication that (1) the weighted fluid is preventing fluid migration into the wellbore and (2) that there is no CO_2 in the wellbore. If CO_2 were present in the wellbore, it would migrate to surface due to density difference and expand in volume under decreasing hydrostatic pressure, resulting in non-static (flowing) conditions at surface.

3. Tubulars and downhole equipment are removed from the casing, and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up hole while cementing operations continue.

5. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up hole while operations are paused to wait on cement.

6. Once the cement has set, the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval.

7. Abandonment mud is placed between cement plugs while pulling the coiled tubing up hole to the base of the next plug.

8. This process, beginning with step 4, is repeated for each cement plug until cement is placed to surface.

9. Once the fourth cement plug is placed at surface, casing will be cut 5' below ground level. A metal cap will be welded onto the top of the cut casing, stamped with the well name and API. Surface location will then be backfilled and restored to pre-operation conditions.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.

- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has <10,000 mg/L TDS):

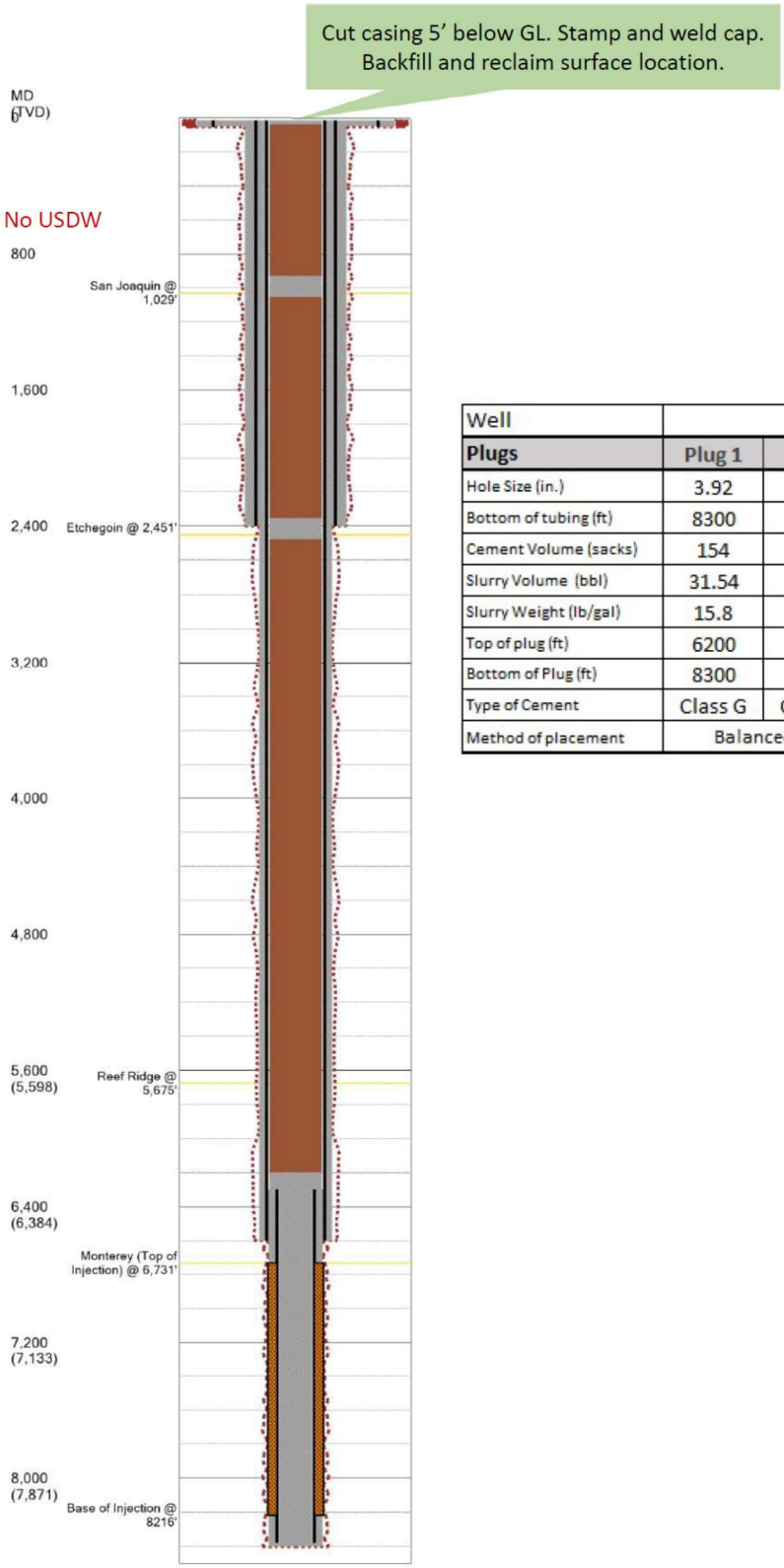
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.

    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits.

In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.

  - In 26R, this interval would be located at the top of the San Joaquin formation.

- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.



Well	363C-27R			
Plugs	**Plug 1**	**Plug 2**	**Plug 3**	**Plug 4**
Hole Size (in.)	3.92	6.276	6.276	6.276
Bottom of tubing (ft)	8300	2476	1054	39
Cement Volume (sacks)	154	24	24	5
Slurry Volume (bbl)	31.54	4.92	4.92	1.02
Slurry Weight (lb/gal)	15.8	15.8	15.8	15.8
Top of plug (ft)	6200	2351	929	14
Bottom of Plug (ft)	8300	2476	1054	39
Type of Cement	Class G	Class G	Class G	Class G
Method of placement	Balanced Plug, Retainer, or CT Plug			

Figure 2: Injection Well 363C-27R, Abandonment Schematic

ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

CTV I Elk Hills 26R Project

Facility Information

Facility name: Elk Hills 26R Storage Project

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment E -PISC_SC	1	01/11/21
Attachment E -PISC_SC V2	2	05/31/22
Attachment E -PISC_SC V3	3	12/21/22

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault 1 LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

Based on the modeling of the pressure front as part of the AoR delineation, pressure at the injection well is expected to stabilize within one year after injection ceases. Injection limits will be based

on the fracture pressure of the Monterey Formation 26R reservoir and final pressure post injection will target the initial reservoir pressure at the time of discovery. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the AoR and Corrective Action Plan.

Discussion

The Monterey Formation 26R reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. This operating strategy was developed to minimize the potential for induced seismicity and to ensure confinement of the injectate.

The maximum pressure differential between the injection wellbore and the depleted Monterey Formation 26R storage reservoir exists prior to the commencement of CO_2 injection. Through time, the injection pressure differential will shrink, until at the time of project abandonment when the reservoir pressure will be at the initial conditions of the reservoir. Figure 1 shows the pressure of the Monterey Formation 26R reservoir through time from computational modeling.

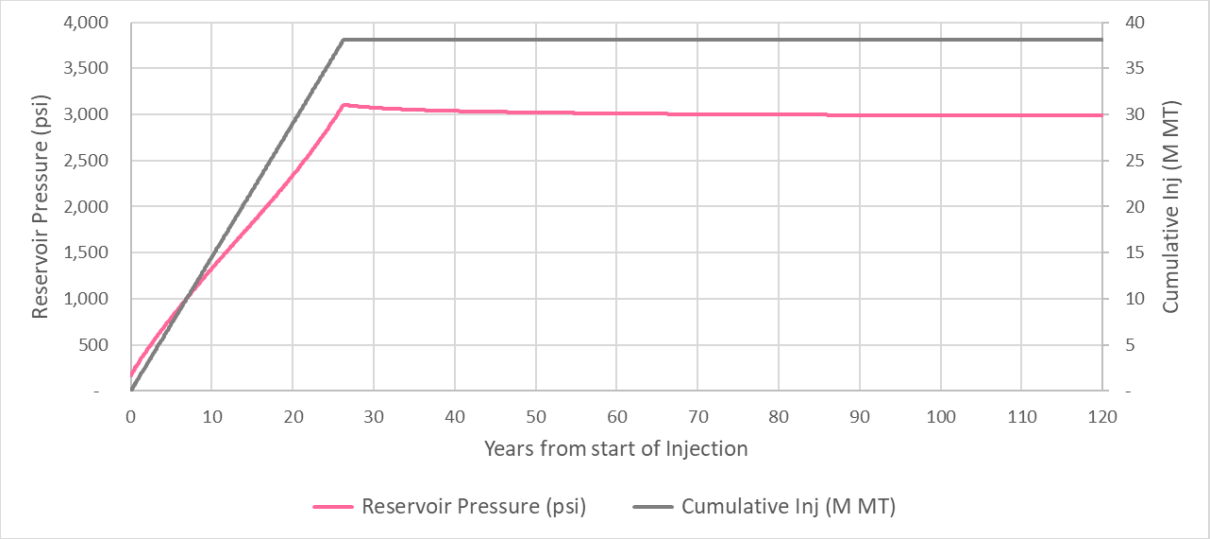


Figure 1: Reservoir pressure and Cumulative injection.

Pressure after 50 and 100 years post-injection are the same in monitoring well 328-25R (Figure 2) indicating plume stabilization. The low water saturation within the Monterey Formation 26R storage reservoir results in 72% of the CO_2 injectate remaining super-critical, minimizing the quantity of CO_2 dissolving in formation water through time.

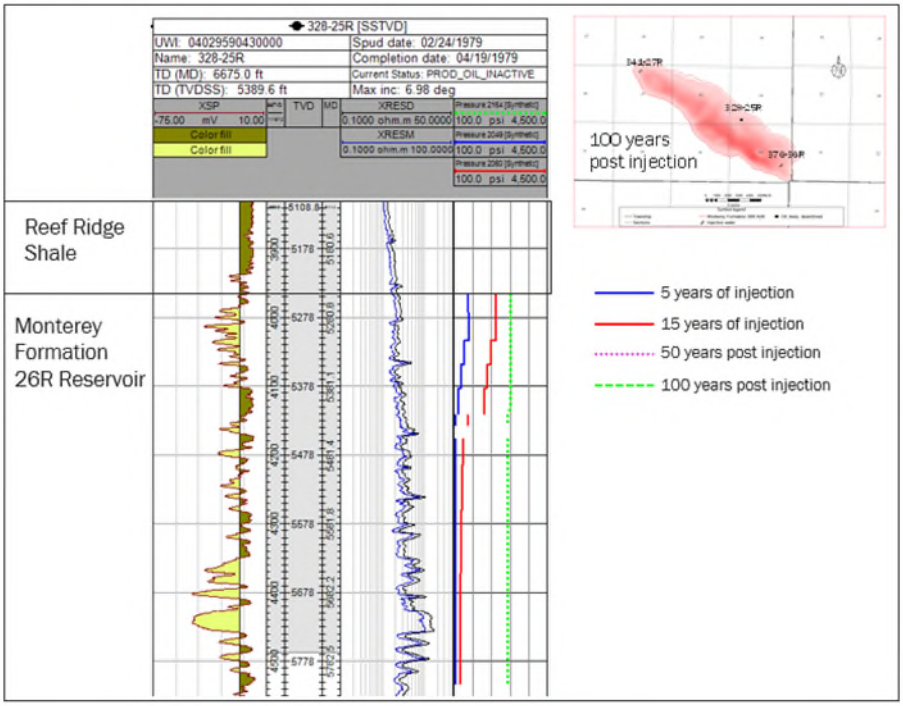


Figure 2: Pressure at the 328-25R monitoring well. Pressure after 50 and 100 years post-injection are the same indicating plume stabilization.

Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 3 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

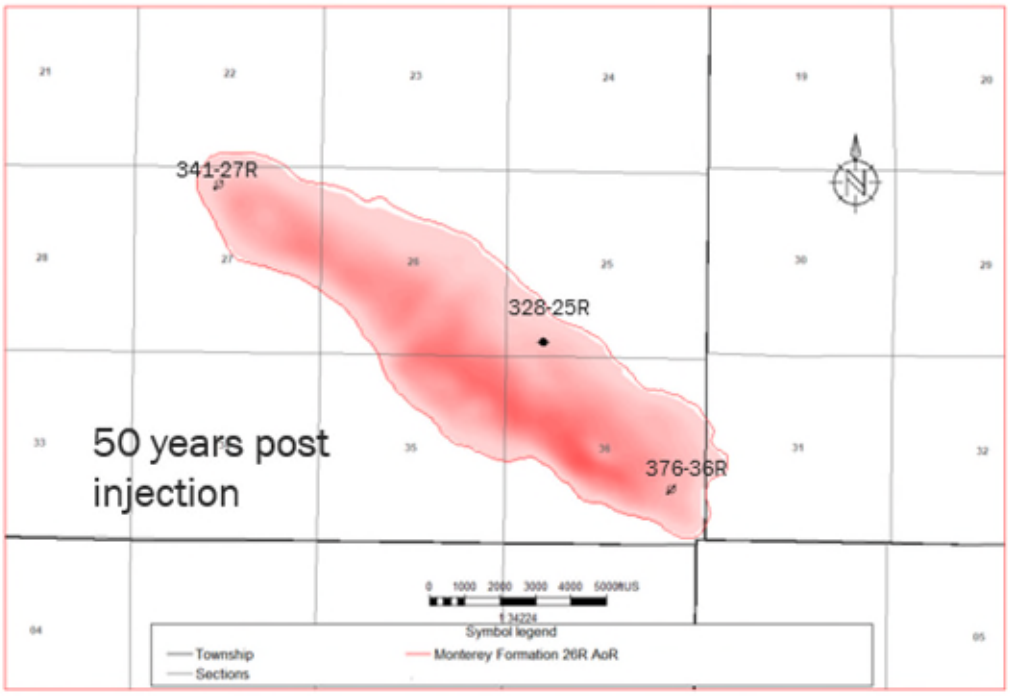


Figure 3: Map of the predicted extent of the CO_2 plume post-injection after 50 years with plume monitoring well locations . The pressure of the 26R reservoir will be at or beneath the initial pressure at the time of discovery.

Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include pressure monitoring and fluid composition monitoring in the storage reservoir and reservoirs above the injection zone. Post-injection monitoring, as described in the following sections, will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days of the anniversary date of final injection, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

The Testing and Monitoring Plan describes the monitoring strategies within the injection zone, above the injection zone, and within the USDW-containing reservoir. In addition to monitoring the zones above the injection zone for stabilized pressure and absence of CO2, the injection zone will be monitored for pressure stabilization as the best method to confirm confinement within the storage reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.

The Quality Assurance and Surveillance Plan (QASP) for all testing and monitoring activities during the injection and post-injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Throughout the AoR there is no USDW groundwater but a zone of unsaturated sands in the Upper Tulare. A shallow groundwater monitoring well will continuously assess reservoir pressure. Groundwater samples will be analyzed annually for indicators of CO_2 movement into the formation.

CTV own the mineral rights for the Monterey Formation 26R reservoir. Surface access is guaranteed for the life of the project as CTV is a wholly owned subsidiary of California Resources Corporation, owner of the surface rights.

Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ. Figure 4 shows the monitoring well locations. Table 3 shows the sampling and recording frequencies for continuous pressure monitoring in the shallow monitoring well. The pressures of these reservoirs may be affected by regional water recharge, injection, or withdrawal. For the Tulare Formation monitoring, CTV will compare these results to other groundwater monitoring wells in the Elk Hills Oil Field.

Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Post-Injection)
Tulare	Fluid Sampling	Shallow Water Monitoring Well	Pump	400’- 450' MD/VD	Annual
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’- 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’- 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	800' - 1100' MD/VD in each well	Continuous
Etchegoin	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Annual
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' MD/VD 4788' - 4811' MD/VD 4205' - 4226' MD/VD	Continuous

Table 2. Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn and T1)	ICP-MS EPA Method 6020
Cations (Ca, FE, K, Mg, Na, Si)	ICP-OEC EPA Method 6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300.0
Dissolved CO2	Coulometric Titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
Alkalinity	Method 2320B
δ13C	Isotope ratio mass spectrometry
pH	EPA 150.1
Total Dissolved Solids (TDS)	Gravimetry; Method 2540 C
Specific Conductance (field)	APHA 2510
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

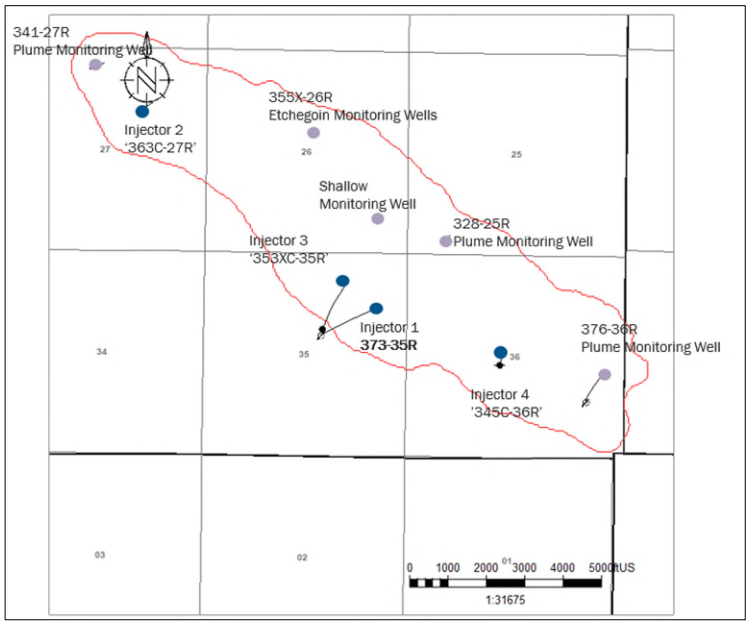


Figure 4: Map showing AoR and well locations for monitoring.

Table 3. Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
During active injection	Pressure Gauge	Shallow Monitoring Well	5 hours	5 hours
Post injection	Pressure Gauge	Shallow Monitoring Well	12 hours	12 hours

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the associated increase in pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the CO_2 plume, including the activities, locations, and frequencies CTV will employ. The parameters to be analyzed as part of fluid sampling in the Monterey Formation 26R (and associated analytical methods) are presented in Table 2.

Table 4. Post-injection phase plume monitoring.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Post-Injection Phase)
Plume Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm 26R	Fluid Sampling	341-27R	6981' - 7237' MD	Annual
		Pressure		6910' MD	Continuous
		Temperature		6910' MD	Continuous
	Monterey Fm 26R	Fluid Sampling	328-25R	5268' - 5800' MD	Annual
		Pressure		5188' MD	Continuous
		Temperature		5188' MD	Continuous
	Monterey Fm 26R	Fluid Sampling	376-36R	5832' - 6815' MD	Annual

		Pressure		5760' MD	Continuous
		Temperature		5760' MD	Continuous
Plume Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	Monterey Formation	Pulsed Neutron Log	341-27R	6981' - 7237' MD	Every 5 years
			328-25R	5268' - 5800' MD	
			376-36R	5832' - 6815' MD	

Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn and T1)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na and Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, and SO4)	Ion Chromatography: EPA Method 300.0
Dissolved CO2	Coulometric Titration ASTM D513-11
Dissolved CH4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
Alkalinity	Method 2320B
δ13C	Isotope ratio mass spectrometry
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Total Dissolved Solids (TDS)	Gravimetry; Method 2540 C
Specific Conductance (field)	APHA 2510
pH (field)	EPA 150.1
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

Fluid sampling will be performed as described in B.1. of the QASP. Sample handling and custody will be performed as described in B.3. of the QASP. Quality Control will be ensured using the methods described in B.5. of the QASP.

CTV will employ indirect and direct methods to monitor the pressure front. Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies. Direct monitoring will include pressure gauges to monitor the pressure of the CO_2 plume in the three Monterey Formation 26R monitoring wells. Additionally, seismic monitoring via installed surface and shallow borehole seismometers well will be utilized to detect micro-seismic events. Figures 4 and 5 show the location of the monitoring wells and the predicted extent of the CO_2 plume in map view and cross-section.

Table 6. Post-injection phase pressure-front monitoring.

Monitoring Category and Class VI Rule Citation	Target Formation	Monitoring Activity	Data Collection Location(s)	Spatial Coverage or Depth	Frequency (Post-Injection)
Pressure-Front Monitoring [40 CFR 146.90(g)] **DIRECT MONITORING**	Monterey Fm 26R	Pressure	341-27R	6981' - 7237' MD	Continuous
		Temperature			Continuous
	Monterey Fm 26R	Pressure	328-25R	5268' - 5800' MD	Continuous
		Temperature			Continuous
	Monterey Fm 26R	Pressure	376-36R	5832' - 6815' MD	Continuous
		Temperature			Continuous
Pressure-Front Monitoring [40 CFR 146.90(g)] **INDIRECT MONITORING**	All Formations	Seismicity	Seismic Monitoring Network	Full AOR	Continuous

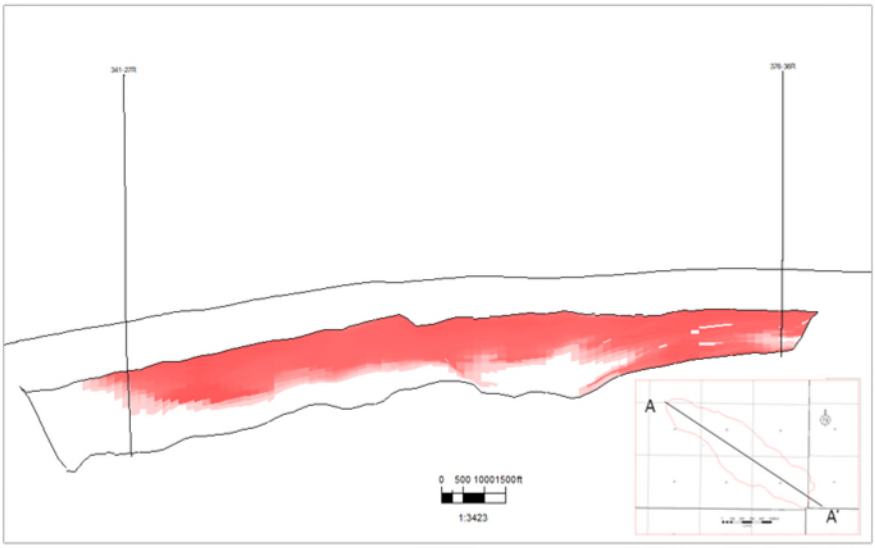


Figure 5: Cross-section showing plume CO2 plume 100 years post injection and 341-27R and 376-36R monitoring wells for post-injection monitoring.

Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period; i.e. well-based monitoring data, sample analysis, and the results from updated site models.

Non-Endangerment Demonstration Criteria [40 CFR 143.93(b)(2) or (3)]

Prior to authorization of site closure, CTV will submit a demonstration of non-endangerment of USDWs to the Director.

CTV will provide a report to the Director that demonstrated USDW non-endangerment based on the evaluation of site monitoring data. The report will detail how the non-endangerment determination is based on site-specific conditions, supported with the computational model. All relevant monitoring data and interpretations will be provided.

Summary of Monitoring Data

A summary of the site monitoring data, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project. Data submission will be in a format acceptable to the Director and will include:

1. A narrative that explains the monitoring activities,

2. Dates of all monitoring events,

3. Changes to the monitoring program over time,

4. An explanation of all monitoring information that has existed at the site,

5. Explanation of how the monitoring data from injection and PISC has varied from the baseline data during site characterization, and

6. Summary of any emergencies that occurred during the injection and post-injection phases of the project. Included will be a description of how any issues have been resolved and that there is no endangerment to the USDW.

Evaluation of the CO2 Plume and the AoR

Computational modeling results calibrated with monitoring data (e.g., pressure) will be used to support that the plume has stabilized and that the pressure change is negligible (less than 10 psi per year) and poses no risk for potential vertical migration. Computational modeling results calibrated with monitoring data from storage reservoir, USDW and above zone will be used to demonstrate:

1. the lack of CO2 leakage over the project timeframe,

2. the accuracy of the model to predict and represent the storage reservoir, and

3. the computational model adequately defined the AoR.

Evaluation of Reservoir Pressure

Monitoring data will be reviewed to ensure that the CO2 plume has stabilized post-injection and that the reservoir pressure change is negligible (less than 10 psi per year). This demonstration will be supported by the computational model that has been calibrated with the most recent monitoring data. The plume is trapped by structure and pinch-out of the reservoir sands. Plume migration is minimal, as such pressure stabilization will be used for non-endangerment assessment.

Evaluation of Potential Conduits for Fluid Movement

Wells that require corrective action will be reviewed and assessed prior to PISC and Site Closure, this includes monitoring wells, injection wells and other wells that penetrate within the AoR and the confining layer. Final demonstration will be made that natural and artificial conduits will not allow fluid migration from the storage reservoir.

Evaluation of Seismicity Monitoring

Demonstration will be made that the plume has stabilized and the pressure change is negligible (less than 10 psi per year), minimizing the risk for induced seismicity after site closure. Final review will be made with the seismicity monitoring to demonstrate seal integrity and that there is no further endangerment of to the USDW

Site Closure Plan [40 CFR 146.93(e)]

CTV will conduct site closure activities to meet the requirements of 40 CFR 146.93(e), with notification to the permitting agencies at least 120 days prior to its intent to close the site. Upon approval of the permitting agencies, CTV will plug the injection and monitoring wells, restore the site, and submit a site closure plan to the EPA. A site closure report will be prepared and submitted within 90 days following site closure supported by the following.

1. Verification of injector and monitoring well plugging,

2. Notifications to state and local authorities as per 40 CFR 146.93 (f)(2)

3. Composition and volume of the injected CO2, and

4. Post-injection monitoring records

CTV will record a notation to the property's deed that will indicate:

1. The property was used for CO2 sequestration, the period of injection and the volume of CO2 injected,

2. The formation that the fluid was injected, and

3. The name of the local agency to which a plat of survey with injection well locations was submitted.

ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(a)

CTV I: Elk Hills 26R Project

Facility Information

Facility name: CTV I: Elk Hills 26R

Facility contact: Travis Hurst / Geological Advisor
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date
Attachment F -ERR Plan	1	01/11/21
Attachment F -ERR Plan	2	05/31/22
Attachment F -ERR Plan	3	12/10/22

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault I LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

The Emergency and Remedial Response Plan would be implemented in response to events that could be detected in the course of monitoring pursuant to the Testing and Monitoring Plan, including exceedances of Actionable Testing limits described in the QASP (Table 7: Actionable Testing and Monitoring Outputs).

If CTV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.

3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in the individual Well Construction, Operating and Plugging details (COP) documents) is appropriate.

Local Resources and Infrastructure

Resources in the vicinity of the CTV I Elk Hills 26R Project that may be affected as a result of an emergency event at the project site include:

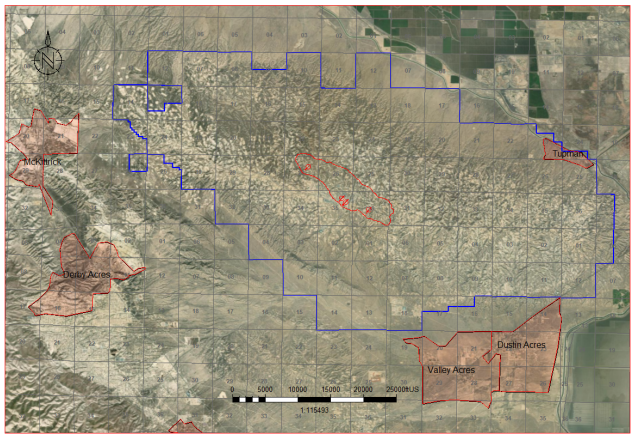
1. Elk Hills oil and gas production resources not associated with the CTV I Elk Hills 26R Project. These oil and gas operations are operated by California Resources Corporation (CRC) an owner of the CTV I Elk Hills 26R Project.
2. Upper Tulare USDW overlying the CO_2 plume. The USDW is not being utilized in the AoR and CTV does not expect usage in the foreseeable future.
3. The nearest census designated area is Valley Acres, 3.6 miles from the AoR. The population was 527 at the 2010 U.S. Census.

Infrastructure in the vicinity of the CTV I Elk Hills 26R Project that that may be affected as a result of an emergency at the project site include:

1. Elk Hills infrastructure owned and operated by CRC that is associated with oil and gas operations.

Resources and infrastructure addressed in this plan are shown in Figure 1.

Figure 1: Map of the site resources and infrastructure. The project is located 3.36 miles from the census designated area of Valley Acres.



Potential Risk Scenarios

The following events related to the CTV I Elk Hills 26R Project that could potentially result in an emergency response:

- Well integrity failure
- Injection well or monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- Potential Brine or CO2 Leakage to a USDW;
- A natural disaster (e.g. tornado, lightning strike); or
- Induced or natural seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

Well Integrity Failure

Integrity loss at the injection well and/or verification well may endanger USDWs. Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).

Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
    - Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

Severity: Low to moderate, dependent on the magnitude of the event.

Timing of event: Injection/Post-Injection

Avoidance measures: Well maintenance, monitoring and control of injection flow and pressure.

Detection methods: Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual (CO_2 at surface).

Potential response actions:

- Notify the plant superintendent and project manager.
- Limit access to wellhead to authorized personnel only.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (loss or increase of pressure or fluid volumes and/or loss of mechanical integrity during testing and maintenance):
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent CO_2 from surface facilities.
    - Communicate with CTV personnel and local authorities to initiate evacuation plans, as necessary.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
    - If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
    - Preform a well log/MIT to detect CO2 movement outside of the casing.
    - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).
- For a Minor emergency (downhole and surface sensor/monitoring equipment failure):
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Initiate shutdown plan.

- Shut-in injection well and vent CO_2 from surface facilities.
- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
- Perform a well log/MIT to detect CO2 movement outside of the casing.
- Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Injection Well or Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Severity: Low

Timing of event: Injection

Avoidance measures: Well maintenance, and careful monitoring and control of injection flow and pressure.

Detection methods: Anomalies in monitoring data, and visual failure of equipment.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (failure of sensors that will require shutdown of well to repair, requires extended repair time (>48 hours) and/or well intervention to remediate):
    - Contact security to restrict access to the Elk Hills 26R Storage site.

- Communicate with CTV personnel and local authorities to isolate the area and initiate evacuation plans, as necessary.
- Initiate shutdown plan.
- Shut-in injection well and vent CO_2 from surface facilities.
- Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
- Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
- Verify whether contamination has occurred via handheld CO_2 monitors.
- Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.

- For a Minor emergency (sensor or monitoring failure that does not require shutdown of the well to repair):
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan and refer to Major or Serious emergency guidelines.
  - Evaluate the cause of failure, and mitigate if necessary (i.e., repair equipment).
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response Personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Potential Brine or CO_2 Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) movement out of the injection zone or CO_2 leakage into a USDW. This may be identified through elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO2 leakage into a USDW. For example, a pressure increase of 50 PSI (not tied to seasonal changes) or a pH of 1.

Severity: Serious

Timing of event: Injection

Avoidance measures: CTV will operate the project to ensure containment of CO_2. Contamination to USDWs will be avoided by:

1. Ensuring injection well integrity through well maintenance and mechanical integrity testing
2. Maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer.
3. Reviewing monitoring well data to understand plume extent.
4. Monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

Detection methods: Pressure or water composition change in Etchegoin Formation or USDW monitoring well. Detection limits are 0.001 PSI for the pressure gauge and 0.2 for pH.

Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills 26R Storage site.
    - Shut-in all injection wells and vent CO_2 from surface facilities.
    - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
        - Remediate unacceptable impacts to the affected USDW.
    - Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
    - Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO_2 or "pump and treat" to aerate CO_2-laden water).
    - Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.
    - If there is a well integrity issue perform MITs, refer to the Mechanical Integrity Failure scenario.

- If the leak poses a risk to air quality a perimeter will be established vi hand-held air monitoring devices.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, groundwater remediation equipment, cement or casing and air and water testing equipment.

Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. Natural disasters (e.g. tornado or lightning strike) may disturb surface and/or subsurface facilities.

Severity: Minor to catastrophic

Timing of event: Pre-injection, injection, and/or post injection phases.

Avoidance measures: N/A

Detection methods: N/A

Potential response actions:

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
  - Initiate shutdown plan.
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Shut-in all injection wells and vent CO_2 from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - If contamination has occurred refer to the Potential Brine or CO_2 Leakage to USDW scenario.
  - Communicate with CTV personnel and local authorities to initiate evacuation procedures (if necessary).
  - If there is a well integrity issue for the injector or monitoring well, refer to the Mechanical Integrity Failure scenario.

- Perform MITs on the injection wells to identify if a loss of external mechanical integrity occurred.
- If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

- For a Minor emergency:
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan.
  - Contact security to restrict access to the Elk Hills 26R Storage site.
  - Shut-in all injection wells and vent CO_2 from surface facilities. Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

Induced or Natural Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a two-mile radius of the injection wells.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the Elk Hills 26R site for seismic activity. In addition to the CTV seismic monitoring, the Southern California Earthquake Data Center has deployed a network to monitor natural seismicity in the area.

Severity: Minor to Major

Timing of event: Injection / post injection

Avoidance measures: N/A

Detection methods: The seismic monitoring network.

Potential response Actions:

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table 2. Seismic monitoring system, for seismic events > M1.5 with an epicenter within a two-mile radius of the injection well.

Operating State	Threshold Condition[1,2]	Response Action[3]
Green	Seismic events less than or equal to M1.5	1. Continue normal operation within permitted levels. 2. Document the event in semiannual reports to the EPA.
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the injection wells if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. 5. Document the event in semiannual reports to the EPA.
Orange	Seismic event greater than M1.5 and local observation or felt report Seismic event greater than M2.0 and no felt report	1. Continue normal operation within permitted levels. 2. Initiate gradual shutdown of the injection wells if it is determined appropriate. 3. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 4. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 5. Report findings to the UIC Program Director and perform corrective actions. 6. Document the event in semiannual reports to the EPA

[1] Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition[1,2]	Response Action[3]
Magenta	Seismic event greater than M2.0 and local observation or report	1. Initiate gradual shutdown of the injection wells if it is determined appropriate. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well. 4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Determine if leaks to ground water or surface water occurred. 8. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 9. If USDW contamination is detected or endangerment, or CO2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and perform corrective actions. 12. Document the event in semiannual reports to the EPA.
Red	Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4]	1. Initiate shutdown plan for all injection wells. 2. Vent CO_2 from surface facilities. 3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

Operating State	Threshold Condition[1,2]	Response Action[3]
	Or Seismic event >M3.5	4. Limit access to wellhead to authorized personnel only. 5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary. 6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). 7. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event. 8. Determine if leaks to ground water or surface water occurred. 9. If USDW contamination or endangerment is detected, or CO_2 leaked: a. Notify the UIC Program Director within 24 hours of the determination. b. Contact environmental and geotechnical professionals for expertise and advice. 10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment. 11. Report findings to the UIC Program Director and perform corrective actions. 12. Document the event in semiannual reports to the EPA.

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Ken Haney (661- 763-6101)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director (24 hour contact)

Bill Blair (562-743-8336)

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	**Phone Number**
Local police	9-1-1 (Emergency) 661-861-3110 (Non-emergency)
California Governor's Office of Emergency Services (Cal OES)	(916) 845-8506
UIC Program Director (EPA Region 9)	David Albright (albright.david@epa.gov)
EPA National Response Center (24 hours)	800-424-8802
Kern County Fire Department	9-1-1 (Emergency) 661-324-6551 (Non-emergency)
California Air Resources Board (CARB)	800-242-4450
Poison Control Center	800-342-9293
California Office of Emergency Services (24 hours)	800-852-7550
State Water Quality Control Board (Central Valley)	916-255-3000
Kern Medical	661-326-2000

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

Emergency Communications Plan

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For

responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within 30 days, or other time prescribed by the EPA director, following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

Staff Training and Exercise Procedures

All CTV staff and contractors operating at the CO_2 sequestration facilities, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

CO_2 Facilities Training

Onsite and classroom training for facility and infrastructure security, maintenance, and operations.

CO_2 Safety Training

Carbon dioxide detection equipment: Operation and maintenance of personal monitors, portable multi-gas monitors and stationary monitors throughout the facility.

Carbon Dioxide Hazards: Accidental exposure, adverse health effects, workplace exposure limits and first aid.

Emergency Response: Training in the event of CO2 leakage and exercise and drills simulating potential emergency situations.

WELL CONSTRUCTION PLAN

CTV I ELK HILLS 26R PROJECT

Injection Well 363C-27R

Facility Information

Facility Name: Elk Hills 26R Storage Project

Facility Contact: Travis Hurst / CCS Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well Location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Version History

File Name	Version	Date	Description of Change
Attachment G – COP Details_363C-27R	1	05/31/22	Original document, combines well construction, operating procedures, and plugging plan into injection well narrative document.
Attachment G – COP Details_363C-27R_V2	2	12/21/22	Revisions made based on questions received from the EPA 09/23/22
Attachment G – COP Details_363C-27R_V3	3	01/11/23	Revisions made based on questions received from the EPA 01/11/23
Attachment G – COP Details_363C-27R_V4	4	05/14/2023	Revisions made based on questions received from the EPA 03/2023
Attachment G – COP Details_363C-27R_V5	5	11/29/2023	Separating Construction and Plugging Plans into Separate Attachments

Introduction

CTV requires four injection wells for the Elk Hills 26R Storage Project. CTV intends to drill three new CO_2 injection wells and repurpose one existing well for CO_2 injection. Figure 1 identifies the wells proposed for the project.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure protection of shallow formations. No USDW is present within the AoR. However, surface and intermediate casing strings will provide multiple barriers of protection for shallow formation. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of shallow formations using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

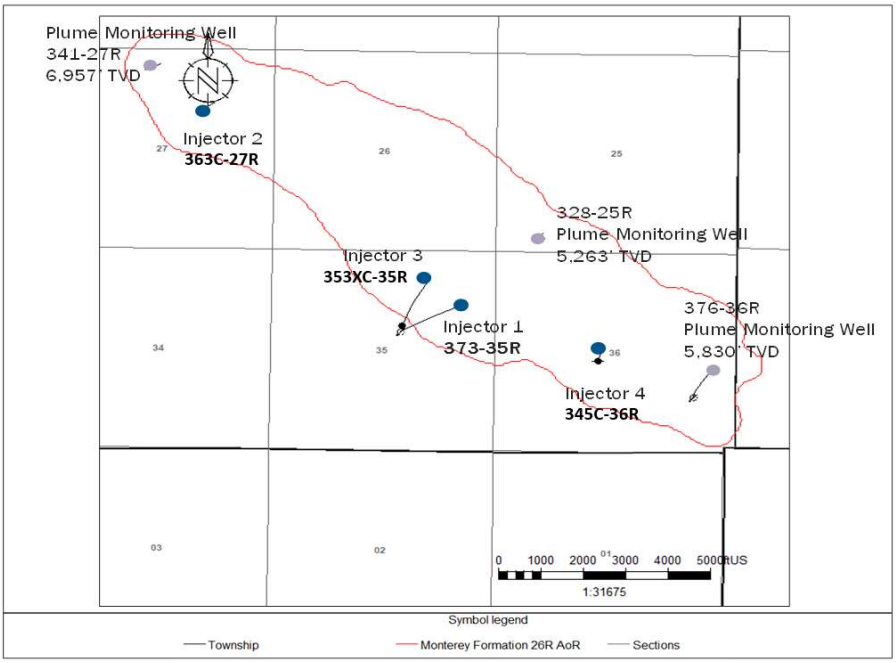


Figure 1: Map showing the location of injection wells and monitoring wells.

Figure 3 and *Appendix: 26R Injection and Monitoring Well Schematics* document provides casing diagram figures for all injection with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

Injection Well Construction

Construction of new injection and monitoring wells will occur during pre-operational testing. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO_2 injection rates: to prevent migration of fluids out of the injection zone, to protect the shallow formations, and to allow for monitoring, as described by the following.

- Well designs will be sufficient to withstand all anticipated load cases including safety factors
- Multiple cemented casing strings will protect shallow formations from contacting injection fluid
- All casing strings will be cemented in place with volume sufficient to place cement to surface using industry-proven recommended practices for slurry design and placement
- Cement bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer
- Mechanical integrity testing (MIT) will be performed on the tubing and the tubing/casing annulus
- Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired and MIT to be conducted
- All wellhead equipment and downhole tubulars will be designed to accommodate the dimensions necessary for deployment of monitoring equipment such as wireline-conveyed logging tools and sampling devices
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
- Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion.

- Wellhead – stainless steel or other material consistent with accepted industry practices for corrosion mitigation based on injected CO_2 specification
- Casing – 13Cr L-80 or other corrosion resistant alloy in specified sections of production string (ie. flow-wetted casing)
- Cement – Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 where good cement bond between formation and casing exists.
- Tubing – 13Cr L-80 or other corrosion resistant alloy
- Packer – corrosion resistant alloy and hardened elastomer

Well materials follow the following standards:

- API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
- API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
- API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

Casing and Cementing

The casing specifications in Table 1 are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure specified in the Operational Procedures section.

The 26R reservoir has been depleted and reservoir pressure is low. The temperature is approximately 210 degrees Fahrenheit. These conditions are not extreme, and CTV has extensive experience successfully constructing wells in depleted reservoirs. Standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement.

Operational parameters acquired throughout the cementing operation will be used to compare modeled versus actual pressure and rate. The presence of circulated cement at surface will also be a primary indicator of effective cement placement. Cement evaluation logging will be conducted to confirm cement placement and isolation.

Table 1: Casing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14' - 54'	20	19.124	94	H-40	Short	2.62	1530	520
Surface	14' - 2400'	9.625	8.835	40	L-80	Long	2.62	5750	3090
Long string	14' - 6200' 6200' - 6600'	7	6.276	26	L-80 L-80 CRA	Long	2.62	7240	5410
Liner	6300' - 8380'	4.5	3.92	13.5	L-80 CRA	Long	2.62	9020	8540

Subsidence in the San Joaquin Valley is largely attributed to groundwater extraction related to agricultural activities that has been exacerbated by recent drought conditions. There is no groundwater extraction within the area of the Elk Hills Oil Field. As shown in Figure 2, the ten-year subsidence map demonstrates no appreciable subsidence in the AoR. Therefore, subsidence does not pose a risk to well integrity within the storage project.

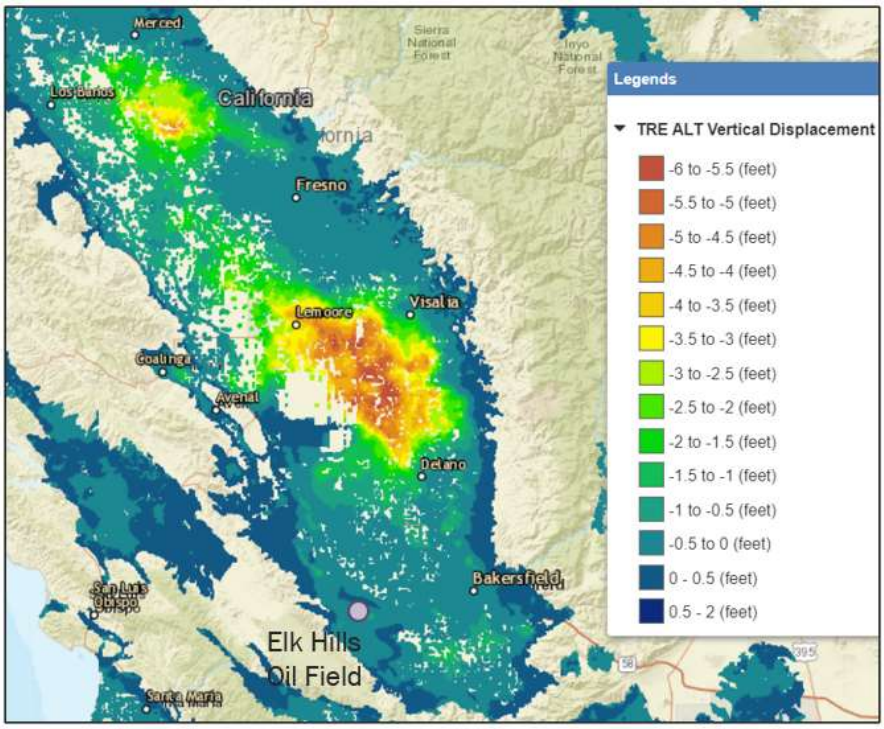


Figure 2: Subsidence in the Elk Hills Oil Field is -0.5 to 0 feet since 2015. Vertical displacement data for subsidence analysis is from the Sustainable Groundwater Management Act Data Viewer (https://sgma.water.ca.gov/).

Tubing and Packer

The information in the tables provided in the Tables 2 and 3 is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined prior to completion during pre-operational testing. A suitable corrosion-resistant alloy will be selected and installed once the CO_2 stream impurities and impurity concentrations have been determined. The packer setting depth refers to the center of the element, and the packer inner diameter refers to the ID of the packer mandrel.

At the beginning of CO_2 injection, CO_2 may be in direct contact with free phase water in the wellbore because of well work, until the free phase water is displaced into the formation. After initial displacement, no free phase water is expected in the wellbore. Tubing integrity is maintained with minimal and acceptable corrosive impact due to the CRA material selection and very limited duration of multi-phase injection.

Table 2: Tubing Specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	6,300	4.5	4.00	11.6	L-80 CRA	Premium	7,780	6,350

Table 3: Packer Specifications

Packer Type and Material	Packer Setting Depth (feet bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Sealbore Packer, CRA	6,300	30.3	26 - 32	5.875"	4.00"

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the 7" casing and external corrosion of the tubing.

Alarms and Shut-off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rates, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan detail the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The EPA Preamble to the Class VI Rule states (Federal Register Vol.75, No.237, p.77258): "EPA believes that requiring automatic surface shut-off devices instead of down-hole devices provides more flexibility to owners or operators when performing required mechanical integrity tests. Additionally, this requirement addresses concerns about risks associated with routine well workovers that may be complicated by the presence of down-hole devices while still maintaining USDW protection." For these reasons CTV will design 363C-27R with a surface shut-off valve at the wellhead and not a down-hole device.

Pre-Injection Testing Plan

The following tests and logs will be acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The testing activities described in this attachment are restricted to the pre-injection phase. Testing and

monitoring activities during the injection and post-injection phases are described in the Testing and Monitoring document.

Deviation Checks

Deviation measurements will be conducted approximately every 120' during construction of the well.

Tests and Logs

The following logs are expected to be acquired during the drilling or prior to the completion of 363C-27R:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Mud Log
- Acoustic Cement Bond Log

Demonstration of mechanical integrity

Table 4: Summary of tests to be performed prior to injection

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log. The mechanical integrity testing procedures are described in the Testing and Monitoring document.

Annulus Pressure Test Procedures

1. The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test.

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less equal to or greater than the highest annular pressure specified in the Operating Procedures document. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve.

4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals.

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

Injectivity and Pressure Fall-Off Testing for Injection Wells

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV will complete injectivity and pressure fall off testing prior to CO_2 injection, pursuant to 40 CFR §146.87(e).

CTV will consider pressure fall-off testing throughout the injection phase to complement reservoir monitoring if injection rate decreases along with a simultaneous injection pressure increase outside the results from computational modeling.

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

A surface gauge at the wellhead and a downhole gauge set above the packer with real-time surface readout capability will be used for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

Objectives for Pre-Operational Testing

Based on the site characterization, AoR delineation modeling, and testing and monitoring evaluations, EPA has identified the following objectives for the planned pre-operational testing to address data gaps identified during the reviews. This information is summarized below (along with the planned tests that will address each data need that was described in the initial permit application materials submitted in November 2021) for reference and to clarify EPA's expectations for the updated materials that CTV must submit pursuant to 40 CFR 146.82(c) and 146.87.

Regional Geology and Geologic Structure

• Perform pressure build-up testing (anticipated testing method: pressure build-up test).

• Confirm the fracture pressure of the injection and confining zones (anticipated testing method: step-rate test in each zone using a representative fluid).

Geochemistry/Geochemical Data

• Establish baseline geochemistry for the Monterey Formation, as well as the Tulare and Etchegoin Formations for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan (anticipated testing methods: various geochemical analyses).

Seismic History and Seismic Risk

• Establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

Facies Changes in the Injection or Confining Zones

• Determine if there are any heterogeneities within the Monterey 26R injection zone that could affect its suitability for injection, including facies changes that could facilitate preferential flow (anticipated testing methods: pressure build-up test; planned and completed core, log, and seismic analysis).

CO2 Stream Compatibility with Subsurface Fluids and Minerals

• Confirm the composition and water content of the CO2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses, benchtop studies).

• Confirm that the properties of the CO2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).

• Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of the geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).

Confining Zone Integrity

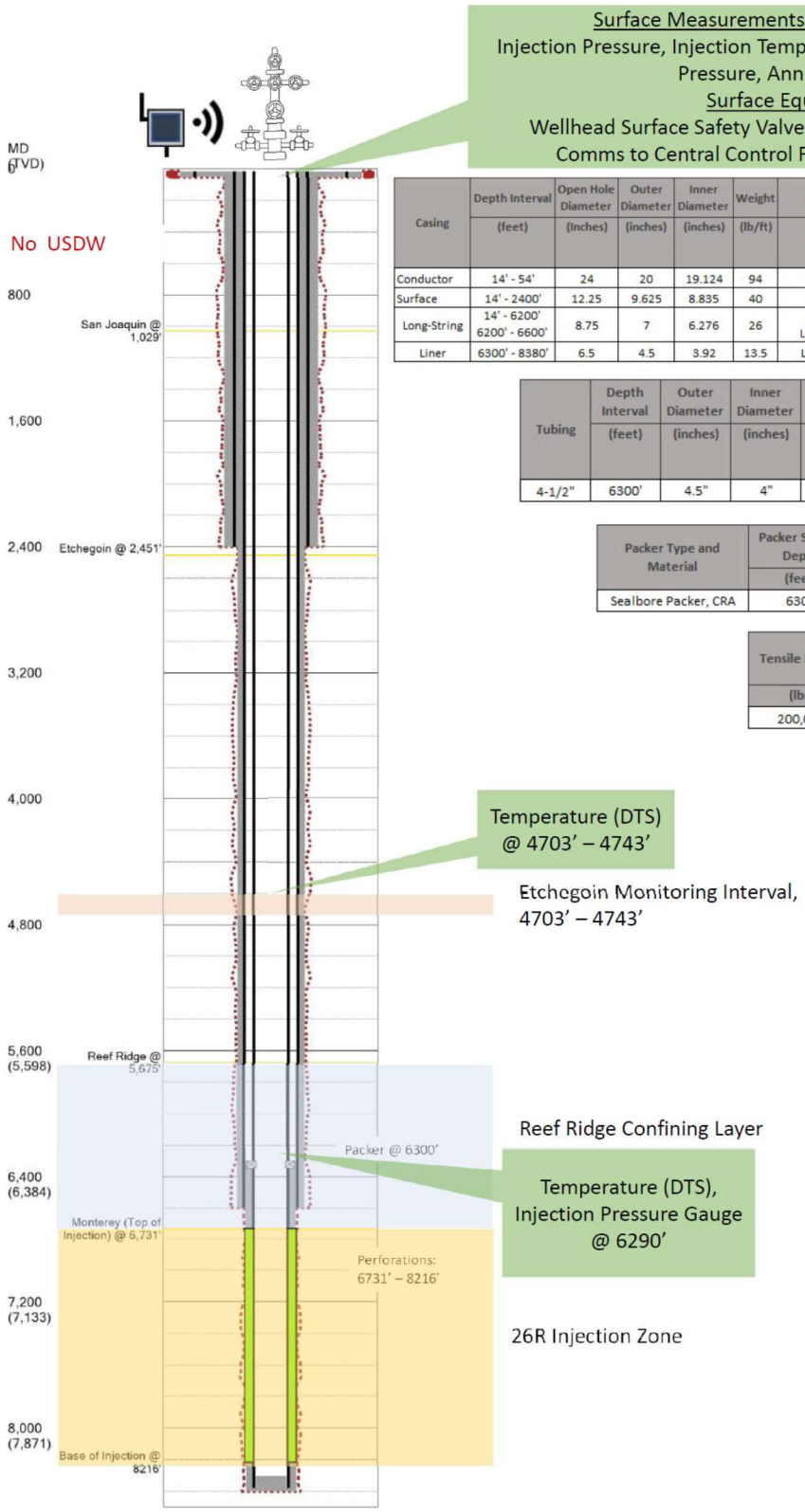
• Collect baseline pressure data in the Etchegoin Formation to support upward confinement between the Monterey and shallower formations (anticipated testing method: pressure build-up test).

• Determine the porosity and permeability of the Reef Ridge Shale at the location of each of the 26R project wells (anticipated testing methods: core and log data during well drilling).

• Test for changes in capillary entry pressure of the Reef Ridge Shale due to reaction of the shale with the injectate (anticipated testing method: mercury injection capillary pressure).

Injection Well Construction

• Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).



Casing	Depth Interval (feet)	Open Hole Diameter (inches)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)	Thermal Conductivity @ 77 °F (BTU/ft hr,°F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	14' - 54'	24	20	19.124	94	H-40	Short	2.62	1530	520
Surface	14' - 2400'	12.25	9.625	8.835	40	L-80	Long	2.62	5750	3090
Long-String	14' - 6200' 6200' - 6600'	8.75	7	6.276	26	L-80 L-80 CRA	Long	2.62	7240	5410
Liner	6300' - 8380'	6.5	4.5	3.92	13.5	L-80 CRA	Long	2.62	9020	8540

Tubing	Depth Interval (feet)	Outer Diameter (inches)	Inner Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (short or long threaded)	Burst Strength (psi)	Collapse Strength (psi)
4-1/2"	6300'	4.5"	4"	11.6	L-80 CRA	Premium	7780	6350

Packer Type and Material	Packer Setting Depth (feet)	Length (inches)	Nominal Casing Weight (lb/ft)	Outer Diameter (inches)	Inner diameter (inches)
Sealbore Packer, CRA	6300	30.3	26 - 32	5.875"	4.00"

Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max Casing Inner Diameter (inches)	Min Casing Inner Diameter (inches)
200,000	7,500	7,500	6.276	6.095

Figure 3: Injection Well 363C-27R, CO_2 Injection Schematic

ATTACHMENT H: FINANCIAL ASSURANCE DEMONSTRATION
40 CFR 146.85

CTV I: Elk Hills 26R Project

Document Version History

Version	Revision Date	File Name	Description of Change
1	9/29/2023	Att H_Financial Responsibility_26R	Compilation of financial responsibility documents in one attachment

Facility Information

Facility name: CTV I: Elk Hills 26R

Facility contact: Travis Hurst / Project Manager
28590 Highway 119
Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Financial Instruments

Carbon TerraVault (CTV) is providing financial responsibility information pursuant to 40 CFR 146.85. CTV is using the following financial instruments:

- Letter of Credit to cover the costs of corrective action, injection well plugging, post-injection site care, and site closure.
- Certificate of Insurance to cover costs of emergency and remedial response

The estimated costs of each of these activities, as provided by CTV, are presented in Table 1.

CTV has provided financial assurance for Emergency and Remedial Response by procuring an environmental insurance policy. If needed the limits will be re-determined by a reasonable estimate of the cost of these activities prior to the commencement of injection operations. The Elk Hills 26R project environmental insurance policy covers all emergency and remedial response activities arising from the assets. The selected insurance carrier has issued a financial assurance certificate in compliance with state and federal regulations that is provided below.

Table 1. Cost Estimates for Activities to be Covered by Financial Responsibility.

Activity	Instrument	Total Cost ($)
Corrective Action	Letter of Credit	111,320
Plugging Injection Wells	Letter of Credit	1,197,840
Post-Injection Site Care	Letter of Credit	6,790,750
Site Closure	Letter of Credit	994,750
Emergency and Remedial Response	Certificate of Insurance	24,578,125

The following supporting information is provided below to satisfy Financial Responsibility requirements:

- Daniel B. Stephens & Associates, Inc. (DBS&A) third party cost estimate
- Deutsche Bank AG Irrevocable Standby Letter of Credit
- Irrevocable Standby Letter of Credit Notification Letter
- Bank of New York Mellon Standby Trust
- Letter of Credit Cost Estimate and Funding Value Summary
- Ascot Certificate of Insurance
- Insurance Endorsement
- Financial Strength Demonstration

DBS&A THIRD PARTY COST ESTIMATE

CLASS VI FINANCIAL RESPONSIBILITY DEMONSTRATION

COST ESTIMATE

CTV I 26R

Carbon TerraVault (CTV) had the following cost estimate prepared by third party contractor, Daniel B. Stephens & Associates, Inc., completed on 9/5/2023.

Table 1. Financial Responsibility Cost Summary

Activity	Estimated Cost	Reference
Corrective Action	$ 111,320	Table 2
Injection Well Abandonment	$ 1,197,840	Table 3
Post-Injection Site Care	$ 6,790,750	Table 4
Site Closure	$ 994,750	Table 5
Emergency and Remedial Response	$ 24,578,125	Table 6
Total	**$**	**33,672,785**

All values in 2022 dollars

Table 2. Costs, Corrective Action Total

Activity	Unit		Unit Cost	Total	Reference
Revise Numerical Model	400	hrs	$ 220	$ 88,000	-
Review CalGEM Well Database	40	hrs	$ 220	$ 8,800	-
Plug Deficient Wells	0	wells	-	$ -	A
Project Management	1	each		$ 14,520	B
			Total	**$ 111,320**	

Notes

A: Per Attachment B, as required wells will be abandoned prior to injection as part of asset retirement obligations

B: 15% of project costs

Table 3. Costs, Injection Well Abandonment

Location	Unit Cost		Depth (ft)	Cost	Reference
Injector 4 345C-36R	30	$/ft	8,680	$ 260,400	A
Injector 1 373-35R	30	$/ft	8,680	$ 260,400	A
Injector 3 353XC-35R	30	$/ft	8,680	$ 260,400	A
Injector 2 363C-27R	30	$/ft	8,680	$ 260,400	A
Documentation, project management	1	each	-	$ 156,240	B
			TOTAL	**$ 1,197,840**	

Notes

A: Abandonment costs from Driltek, 2021; well construction from Attachment G 'Injection Well 1 353XC-35R', Table

B: 15% of project costs

Table 4. Post Injection Site Care Costs

Activity	Unit		Events, 50 years	Unit Cost	Total	Reference
USDW geochemical monitoring/fluid sampling	1	well	50	$ 6,000	$ 300,000	A
Above Confining zone geochemical, pressure monitoring	1	well	50	$ 5,600	$ 280,000	A
Injection zone geochemical, pressure monitoring	3	well	50	$ 5,600	$ 840,000	A
Monitoring well O&M, Above confining zone	1	well	3	$ 30,000	$ 90,000	B
Injection zone monitoring well O&M	3	wells	10	$ 84,000	$ 2,520,000	-
Indirect Plume Monitoring (Pulsed neutron)	1	survey	10	$ 37,500	$ 375,000	C
Mechanical Integrity Test, Injection zone	3	well	10	$ 50,000	$ 1,500,000	B
Reporting/Project Management	1	each	-	$ 885,750	$ 885,750	D
				Total	**$**	**6,790,750**

Notes:

A: Assumes 1 geochemical monitoring event per year per well and continuous pressure monitoring with automated gage; shallow groundwater well have a higher testing cost than the other monitoring wells due to the potential time required to obtain a stabilized sample from a reservoir with low water deliverability.

B: Patrick Engineering, 2013; assumes $2,000 base cost + $4.25/ft (+12%)

C: Zaluski et al., 2016; assumes 8 well survey (inflation adjusted); technology and frequency from PISC plan Table 4

D: 15% of project costs

Assumes:

1 USDW Monitoring Well (exempt or unsaturated)

1 Above Confining Zone Monitoring Well

3 Injection Zone Monitoring Wells

4 Injection wells

Table 5. Costs, Site Closure

Activity	Unit		Unit Cost	Total	Reference
Non-endangerment report	1	each	$ 45,000	$ 45,000	-
Injection zone monitoring well plugging	3	wells	$ 200,000	$ 600,000	A
Above-confining zone monitoring well plugging	1	wells	$ 170,000	$ 170,000	A
USDW Monitoring well plugging	1	well	$ 50,000	$ 50,000	
Plugging documentation, project management	1	each		$ 129,750	B
			Total	**$**	**994,750**

Notes
A: Abandonment costs from Driltek, 2021
B: 15% of project costs

Assumes:
1 USDW Monitoring Well (exempt or unsaturated)
1 Above Confining Zone Monitoring Well
3 Injection Zone Monitoring Wells
4 injection wells

Table 6. Emergency Response

Groundwater Contamination Causal Investigation

Activity	Unit		Unit Cost	Total	Reference
Planning/permitting	1	each	$ 1,381,875	$ 1,381,875	B
Monitoring wells, depth 1,000 ft	5	well	$ 385,000	$ 1,925,000	A
Monitoring wells, depth 5,000 ft	3	well	$ 1,925,000	$ 5,775,000	A
Abandoned well investigation	51	well	$ 27,500	$ 1,402,500	D
Former Injection Well Investigation	4	well	$ 27,500	$ 110,000	-
Reporting/Project Management	1	each	$ 921,250	$ 921,250	C
Total				**$**	**11,515,625**

Groundwater Contamination Remediation

Activity	Unit		Unit Cost	Total	Reference
Planning/permitting	1	each	$ 1,567,500	$ 1,567,500	B
Pumping well, depth 1,000 ft	4	well	$ 350,000	$ 1,400,000	A
Pumping well, depth 5,000 ft	4	well	$ 1,925,000	$ 7,700,000	A
Groundwater extraction	1	year	$ 300,000	$ 300,000	-
Above-ground CO_2 removal (aeration)	1	unit	$ 150,000	$ 150,000	-
Former injection well repair	4	well	$ 225,000	$ 900,000	-
Reporting/Project Management	1	each	$ 1,045,000	$ 1,045,000	C
Total				**$**	**13,062,500**

Total, Causal Investigation and Remediation	**$**	**24,578,125**

Notes

A: Assumes $385/ft for permitting, installation, field oversight, logging drilling, and waste

B: 15% of project costs

C: 10% of project costs separate from Planning/permitting

D: Assumes 25% of wellbores penetrating Reef Ridge Formation, Attachment B Table 9

References

Driltek, 2021: Personal communication with Driltek regarding well abandonment costs, California

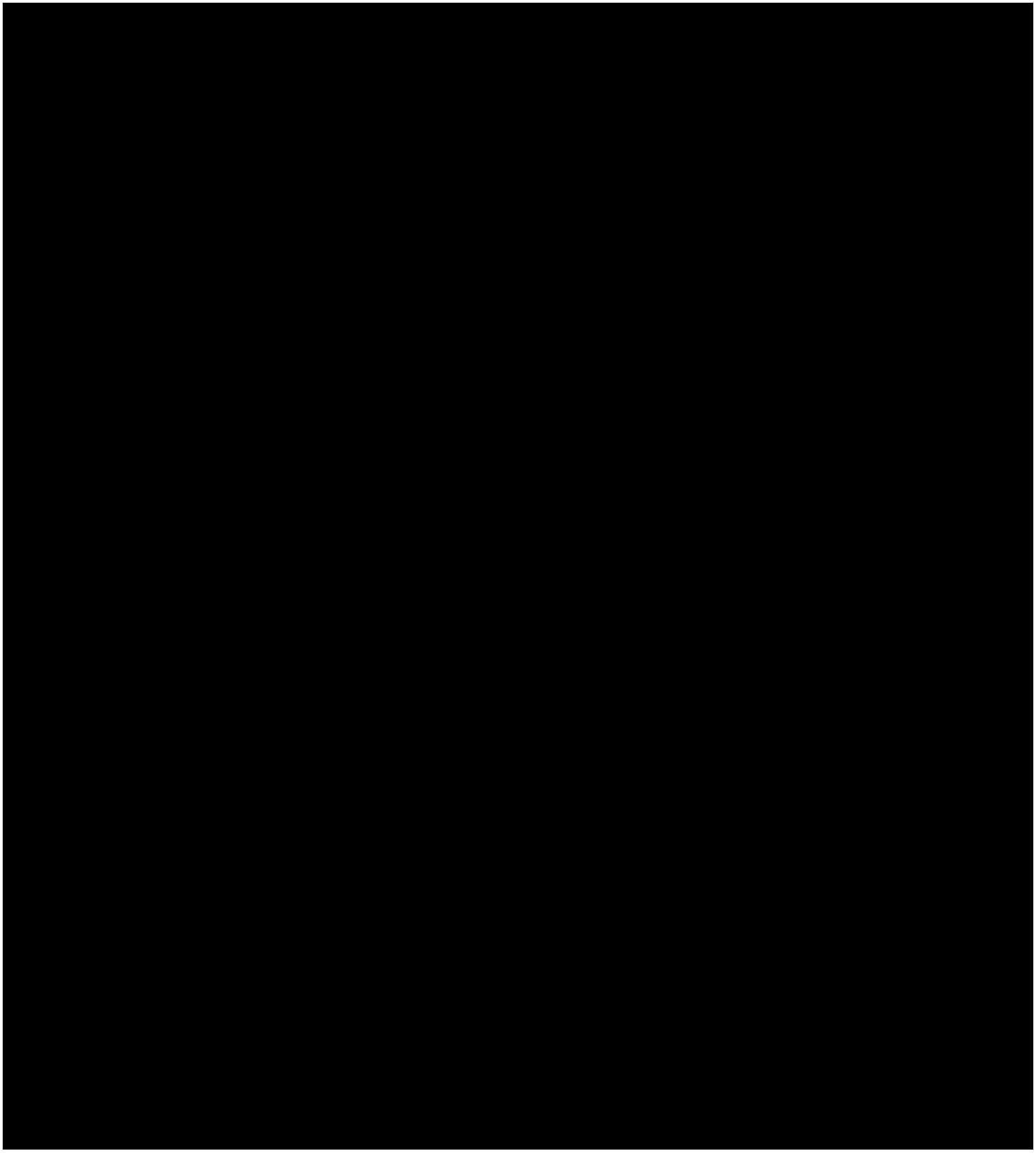
Patrick Engineering, 2013: Third Party Cost Estimate for FutureGen Alliance UIC Class VI Permit Application

Zaluski et al., 2016. Monitoring technology ranking methodology for CO2-EOR sites using the Weyburn-Midale Field as a case study, IJGGC v.54, p.466 - 478

DEUTSCHE BANK AG IRREVOCABLE STANDBY LETTER OF CREDIT

Deutsche Bank

Deutsche Bank AG New York Branch
Trade Finance & Lending
1 Columbus Circle, 17th Floor



Deutsche Bank AG New York Branch
Trade Finance & Lending
1 Columbus Circle, 17th Floor
New York, NY 10019



Very truly yours,
Deutsche Bank AG
New York Branch

[Signature(s) and title(s) of official(s) of issuing institution]

Chairman of the Supervisory Board: Alexander R. Wynaendts
Management Board: Christian Sewing (Chairman), James von Moltke, Karl von Rohr, Fabrizio Campelli, Bernd Leukert, Alexander von zur Mühlen, Christiana Riley, Rebecca Short, Stefan Simon, Olivier Vigneron
Deutsche Bank Aktiengesellschaft domiciled in Frankfurt am Main; Local Court of Frankfurt am Main, HRB No 30 000; VAT ID No DE114103379; www.db.com

IRREVOCABLE STANDBY LETTER OF CREDIT NOTIFICATION LETTER

September 6, 2023

United States Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, D.C. 20460
Attention: UIC Program Director

Re: EPA Identification Number: _____.

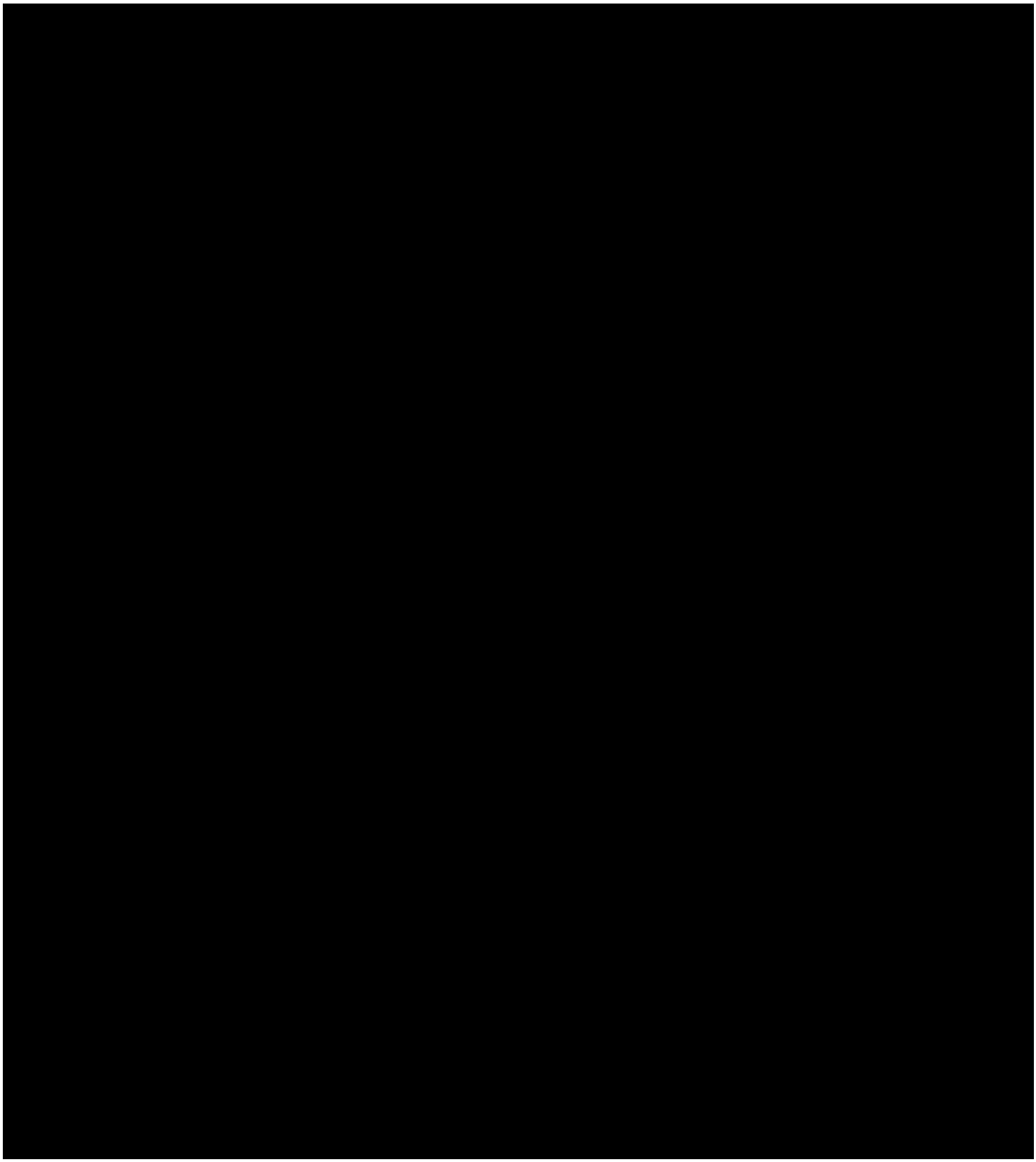
Dear UIC Program Director,

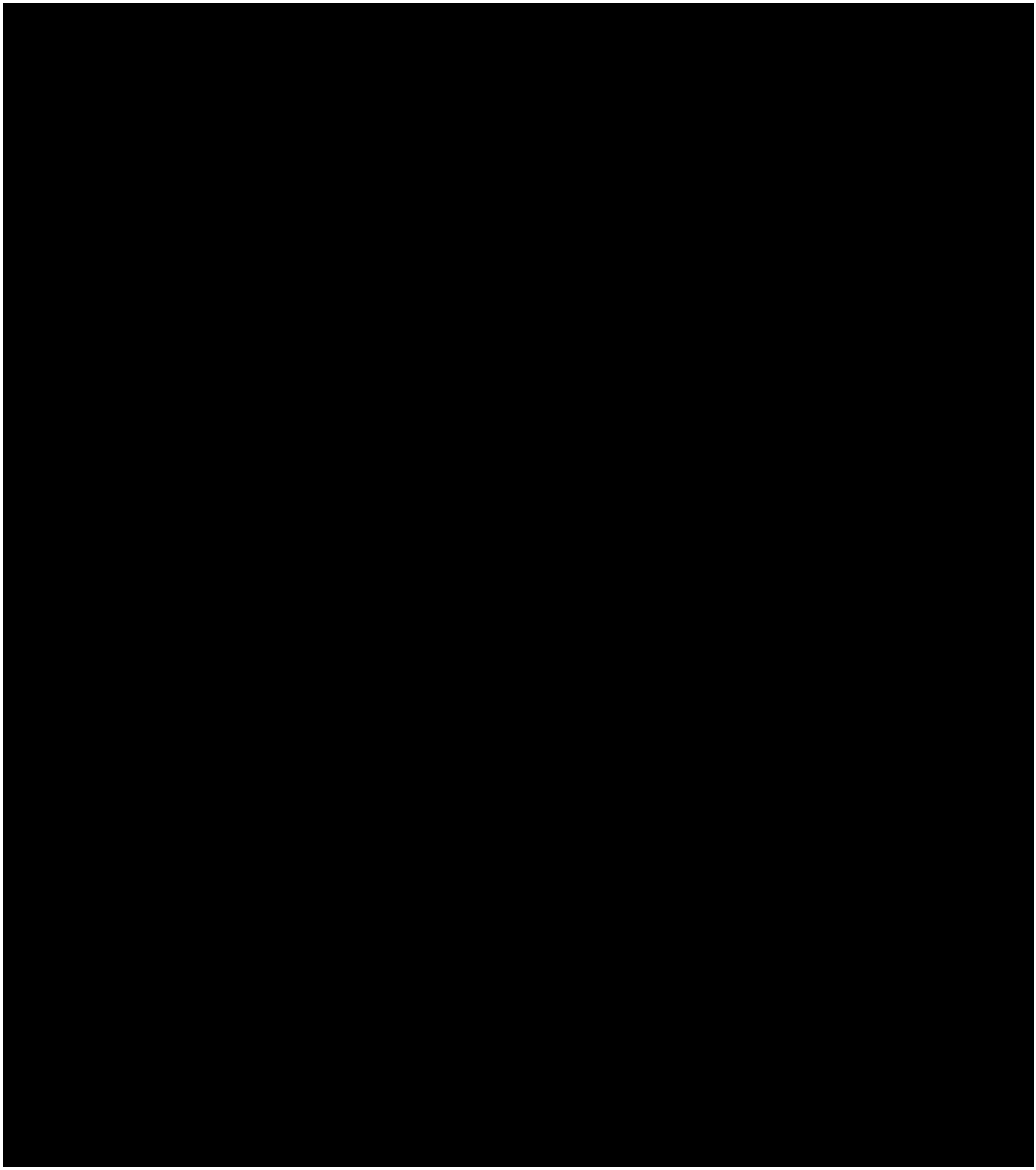
At our direction, effective _____, Deutsche Bank AG New York Branch issued a $_____ Irrevocable Standby Letter of Credit No. _____ in your favor.

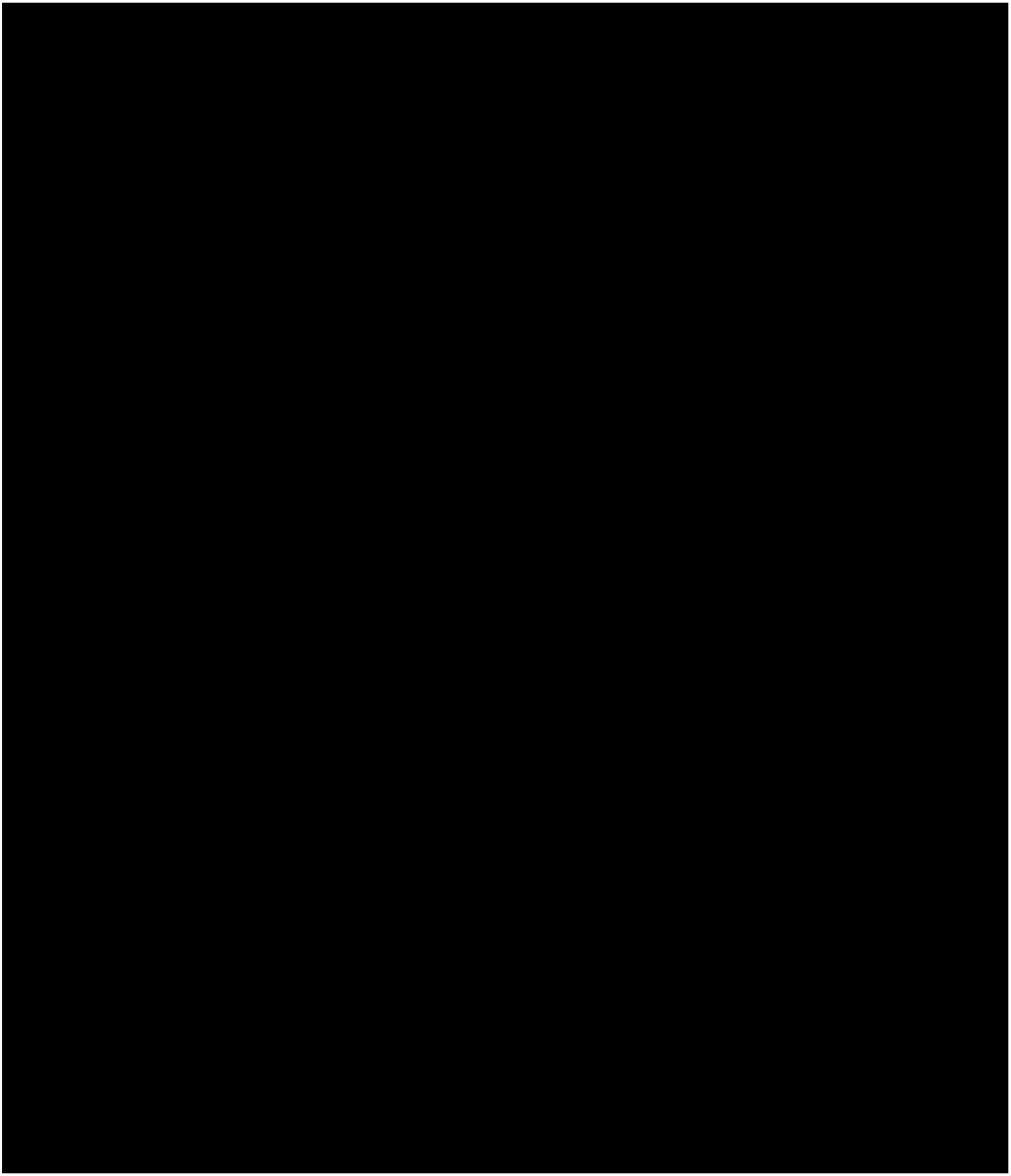
The Irrevocable Standby Letter of Credit was issued to meet the non-emergency response financial assurance requirements associated with the Elk Hills 26R Storage Project located at 28590 Highway 119, Tupman, CA 93276.

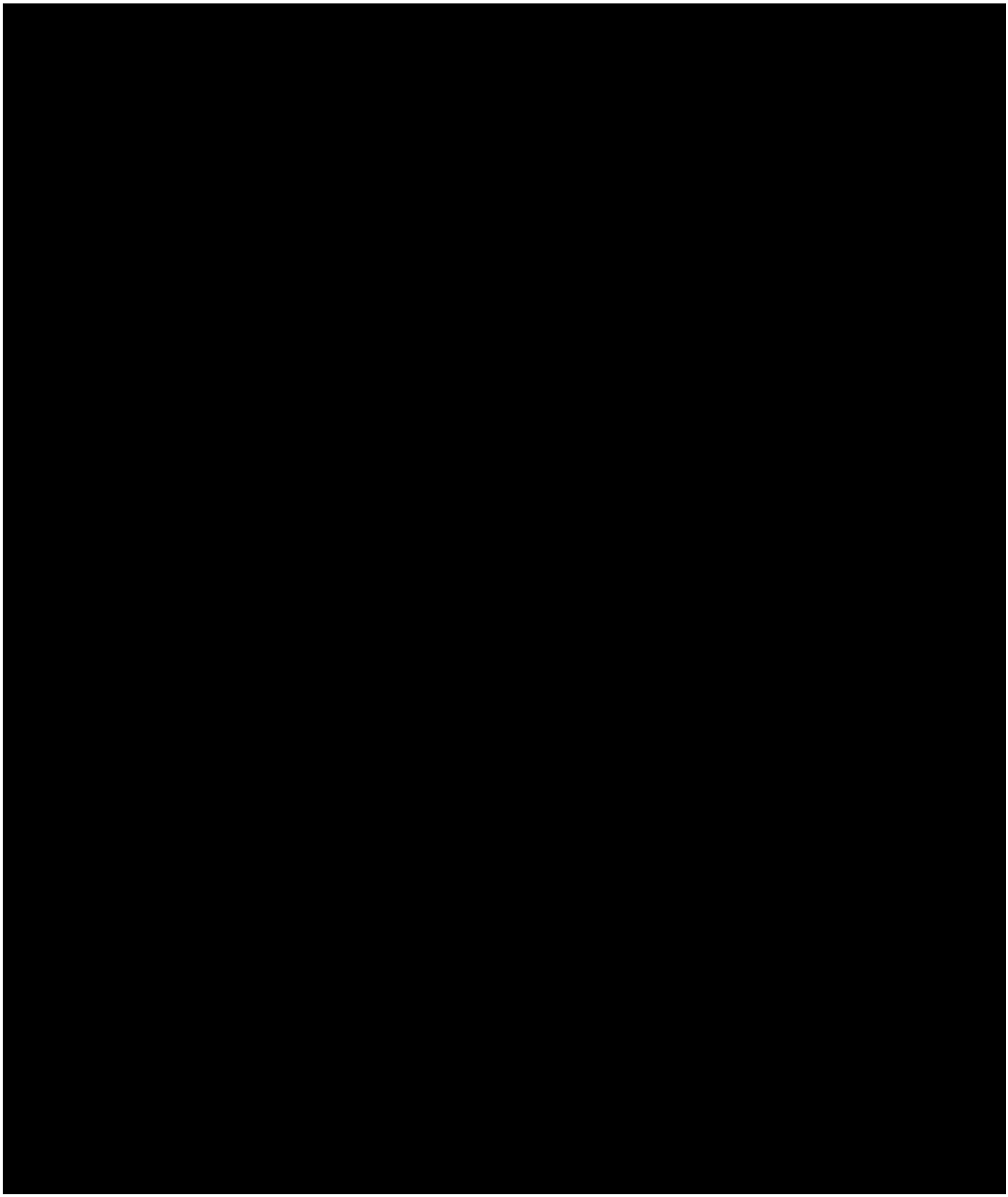
BANK OF NEW YORK MELLON STANDBY TRUST

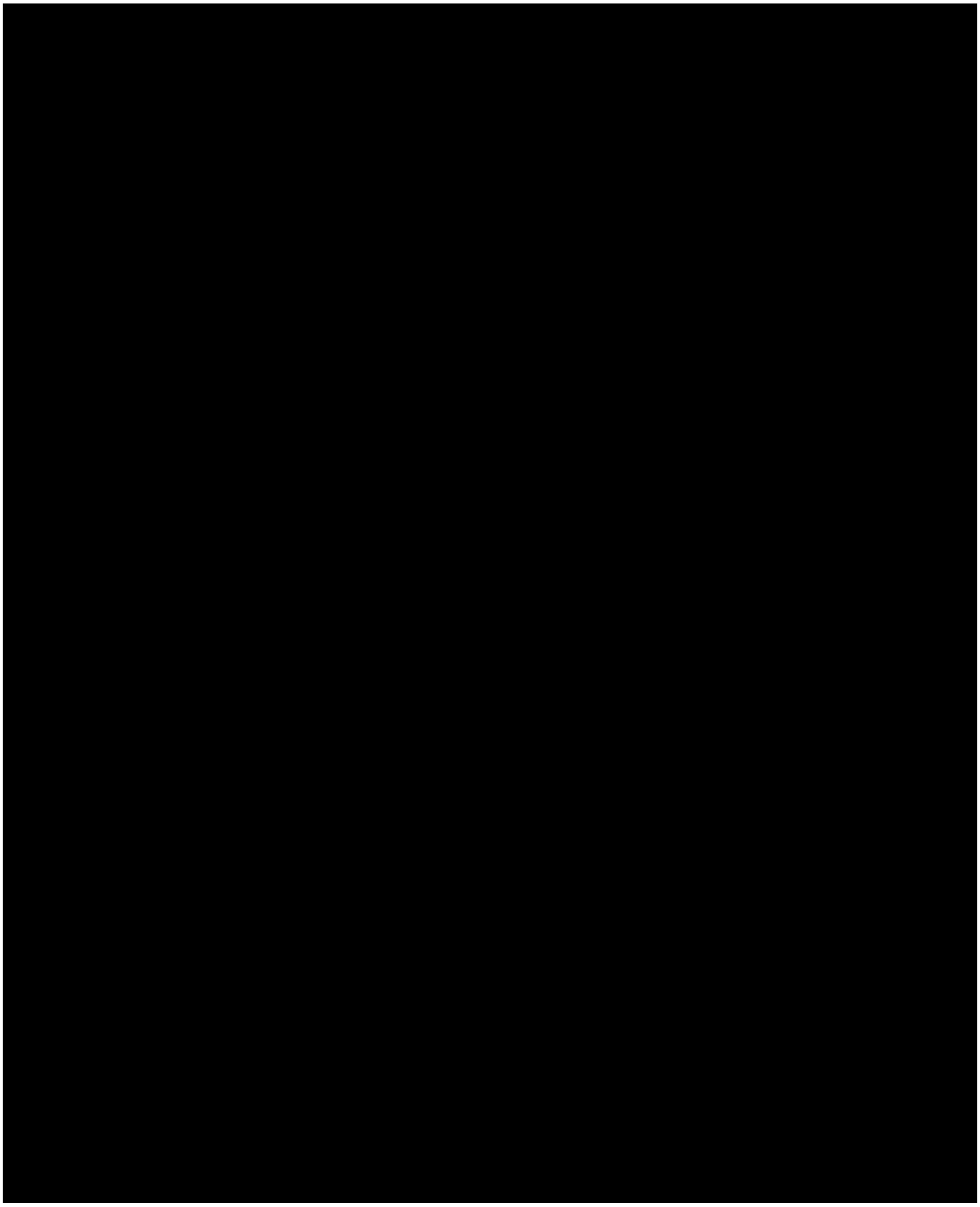
Trust Agreement

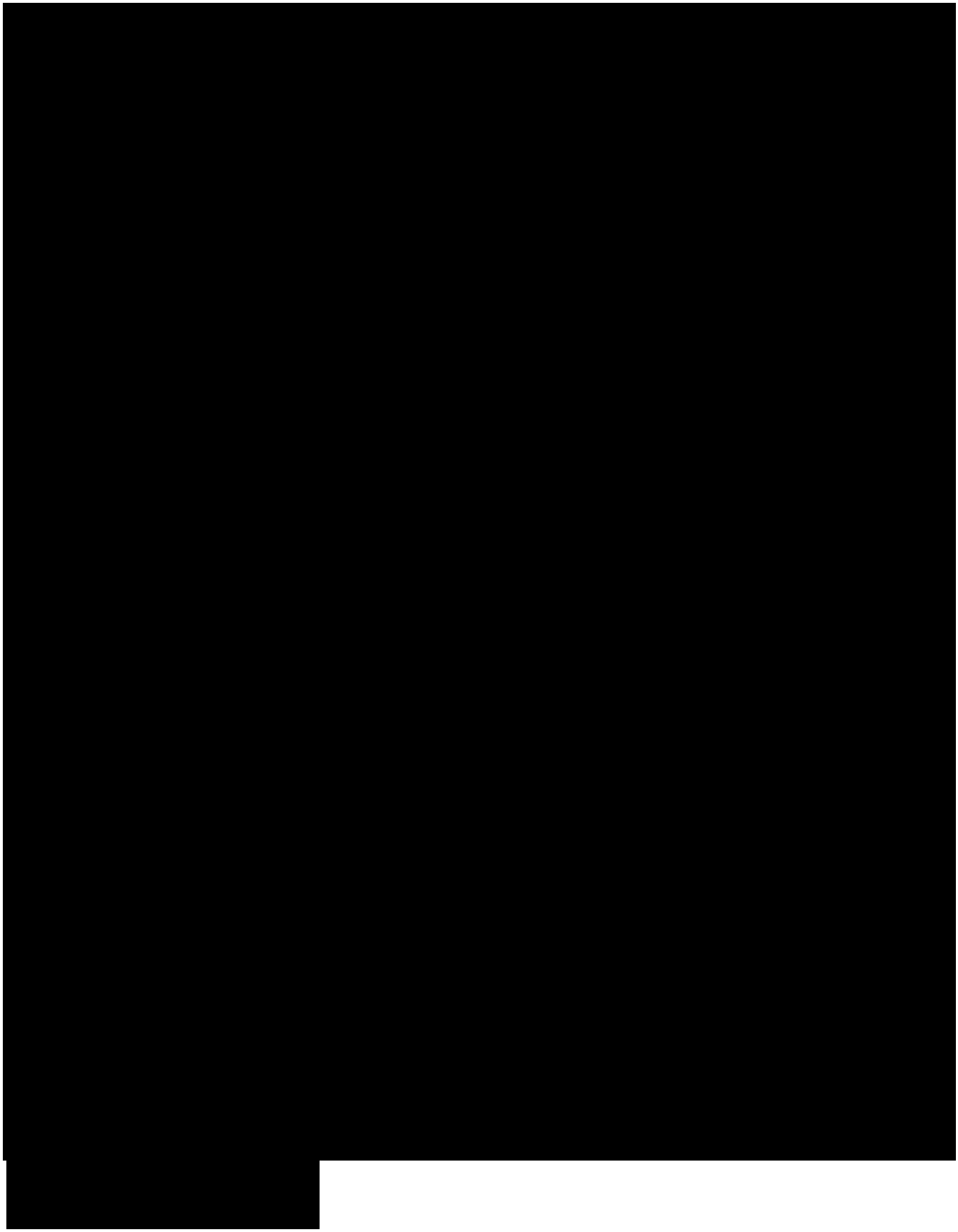














LETTER OF CREDIT COST ESTIMATE AND FUNDING VALUE SUMMARY

Schedule A

Facility	Cost Estimate		
	Corrective action	Injection well plugging	Post injection site care and site closure
EPA Identification number: Elk Hills 26R Storage Project 28590 Highway 119, Tupman, CA 93276	$111,320.00	$1,197,840.00	$7,785,500.00

Schedule B

Facility	Funding Value for Activities
EPA Identification number: Elk Hills 26R Storage Project 28590 Highway 119, Tupman, CA 93276	Irrevocable Standby Letter of Credit No. [839BGC2300XXX] issued by Deutsche Bank AG New York Branch in the amount of [$9,094,660.00].

ASCOT CERTIFICATE OF INSURANCE

55 West 46th Street,
26th Floor
New York, New York 10036

V. Certificate of Insurance

A certificate of insurance, as specified in this chapter, may be worded as follows, except that instructions in brackets are to be replaced with the relevant information and the brackets deleted:

Certificate of Insurance for [emergency and remedial response]

Name and Address of Insured (herein called the "insured"): Carbon TerraVault 1 LLC
1 World Trade Center, Suite 1500, Long Beach, CA 90831

Name and Address of Insurer (herein called the "insurer"): Ascot Specialty Insurance Company; 55 West 46th Street, 26th Floor, New York, New York 10036

Injection Wells covered: [list for each well: The EPA Identification Number, name, address, and the amount of insurance for [emergency and remedial response] (these amounts for all injection wells covered must total the face amount shown below).]

Underground Injection Control Class VI Permit Application Nos. R9UIC-CA6-FY22-1.1, R9UIC-CA6-FY22-1.2, R9UIC-CA6-FY22-1.3 and R9UIC-CA6-FY22-1.4

Face Amount: $25,000,000
Policy Number: ENPU2310001018-01
Effective Date: 05/18/2023

The insurer hereby certifies that it has issued to the Insured the policy of insurance identified above to provide financial assurance for [emergency and remedial response] for the injection wells identified above. The Insurer further warrants that such policy conforms in all respects with the requirements for the fulfillment of [emergency and remedial response] obligations described at 40 CFR 146.94, respectively, as applicable and as such regulations were constituted on the date shown immediately below. It is agreed that any provision of the policy inconsistent with such regulations is hereby amended to eliminate such inconsistency.

The insurer may cancel the policy only for failure to pay the premium and by sending notice of cancellation by certified mail to the owner or operator and to the UIC Program Director for the area in which the injection well(s) is (are) located. EPA requires that cancellation not become final for 120 days beginning on the date of receipt of the notice of cancellation by the UIC Program Director, as evidenced by the return receipts.

Whenever requested by the UIC Program Director, the Insurer agrees to furnish to the UIC Program Director a duplicate original of the policy listed above, including all endorsements thereon.

[Authorized signature of Insurer]



[Name of person signing] Ted Mavraganis
[Title of person signing] Senior Vice President

[Signature of witness or notary:]



[Date] 08/31/2023

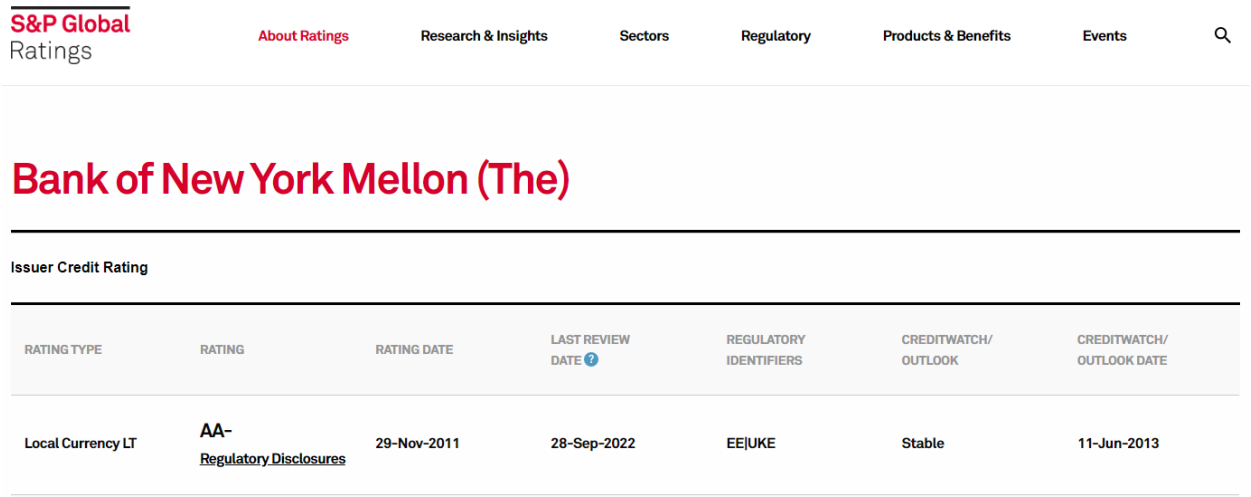
INSURANCE ENDORSEMENT

FINANCIAL STRENGTH DEMONSTRATION

Under 40 CFR 146.85(a)(6)(ii), EPA requires that the owner or operator submit proof of the third party's financial strength. EPA recommends that the owner or operator submit the third party's credit rating or, if the Director determines that the credit rating alone does not sufficiently meet the financial strength requirement, submit the third party's credit rating plus its most recent bond rating and calculated financial ratios. EPA recommends that owners or operators demonstrate that third party providers have a credit rating in the top four categories from either Standard & Poor's or Moody's (i.e., AAA, AA, A, or BBB for Standard & Poor's and Aaa, Aa, A, or Baa for Moody's)

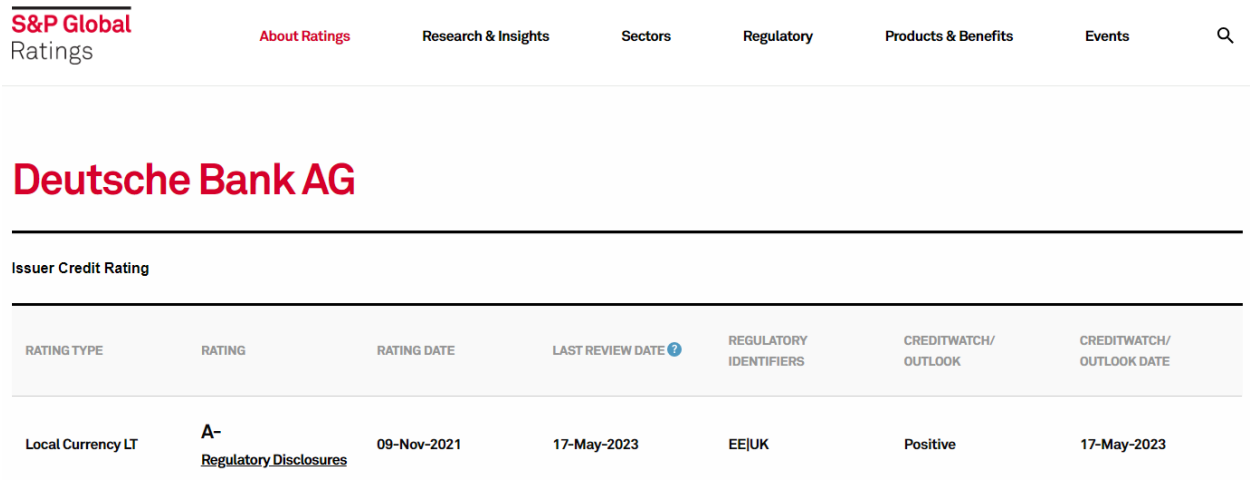
Bank of New York Mellon:

- Standard and Poor's rating: AA-



Deutsche Bank AG New York Branch:

- Standard and Poor's rating: A-



ATTACHMENT I: STIMULATION PLAN

Elk Hills 26R Storage Project

Facility Information

Facility name: CTV I Elk Hills 26R Project
357-7R and 355-7R

Facility contact: Travis Hurst / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 342-2409 / Travis.Hurst@crc.com

Well location: Elk Hills Oil Field, Kern County, CA

Version History

File Name	Version	Date	Description of Change
Att I – Stimulation Plan_v1	1	05/31/22	Original document

Stimulation Plan

The need for stimulation to enhance the injectivity potential of the Monterey Formation 26R reservoir is not anticipated at this time. If it is determined that stimulation techniques are needed, a stimulation plan will be developed and submitted to EPA Region 9 for review and approval prior to conducting any stimulation.

An official website of the United States government Here's how you know

EARTHQUAKE HAZARDS PROGRAM SCIENCE

M7.9 1857 Fort Tejon Earthquake

COMPLETED

By **Earthquake Hazards Program**

August 5, 2019

Overview

The Last "Big One" in Southern California.

Date/Time:	January 9, 1857 about 8:20am PST
Magnitude:	M_w 7.9*
Location/Depth:	35.72N 120.32W
Descriptive location:	45 miles NE of San Luis Obispo
Faulting type:	right-lateral strike-slip
Faults involved:	San Andreas Fault
Length of surface rupture:	about 225 miles (360 km)
Maximum surface offset:	about 30 ft (9 meters)

*Kerry Sieh



Sources/Usage: Public Domain. View Media Details

Map showing the San Andreas fault in green, which caused the 1857 Fort Tejon eathquake. (Public domain.)

This earthquake occurred on the San Andreas fault, which ruptured from near Parkfield (in the Cholame Valley) almost to Wrightwood (a distance of about 300 kilometers); horizontal displacement of as much as 9 meters was observed on the Carrizo Plain. It caused one fatality. A comparison of this shock to the San Francisco earthquake, which occurred on the San Andreas fault on April 18, 1906, shows that the fault break in 1906 was longer but that the maximum and average displacements in 1857 were larger.

Property loss was heavy at Fort Tejon, an Army post about 7 kilometers from the San Andreas fault. Two buildings were declared unsafe, three others were damaged extensively but were habitable, and still others sustained moderate damage. About 20 kilometers west of Fort Tejon, trees were uprooted, and buildings were destroyed between Fort Tejon and Elizabeth Lake. One person was killed in the collapse of an adobe house at Gorman. Strong shaking lasted from 1 to 3 minutes.

Instances of seiching, fissuring, sandblows andå hydrologic changes were reported from Sacramento to the Colorado River delta. Ground fissures were observed in the beds of the Los Angeles, Santa Ana, and Santa Clara Rivers and at Santa Barbara. Sandblows occurred at Santa Barbara and in the flood plain of the Santa Clara River. One report describes sunken trees, possibly associated with liquefaction, in the area between Stockton and Sacramento.

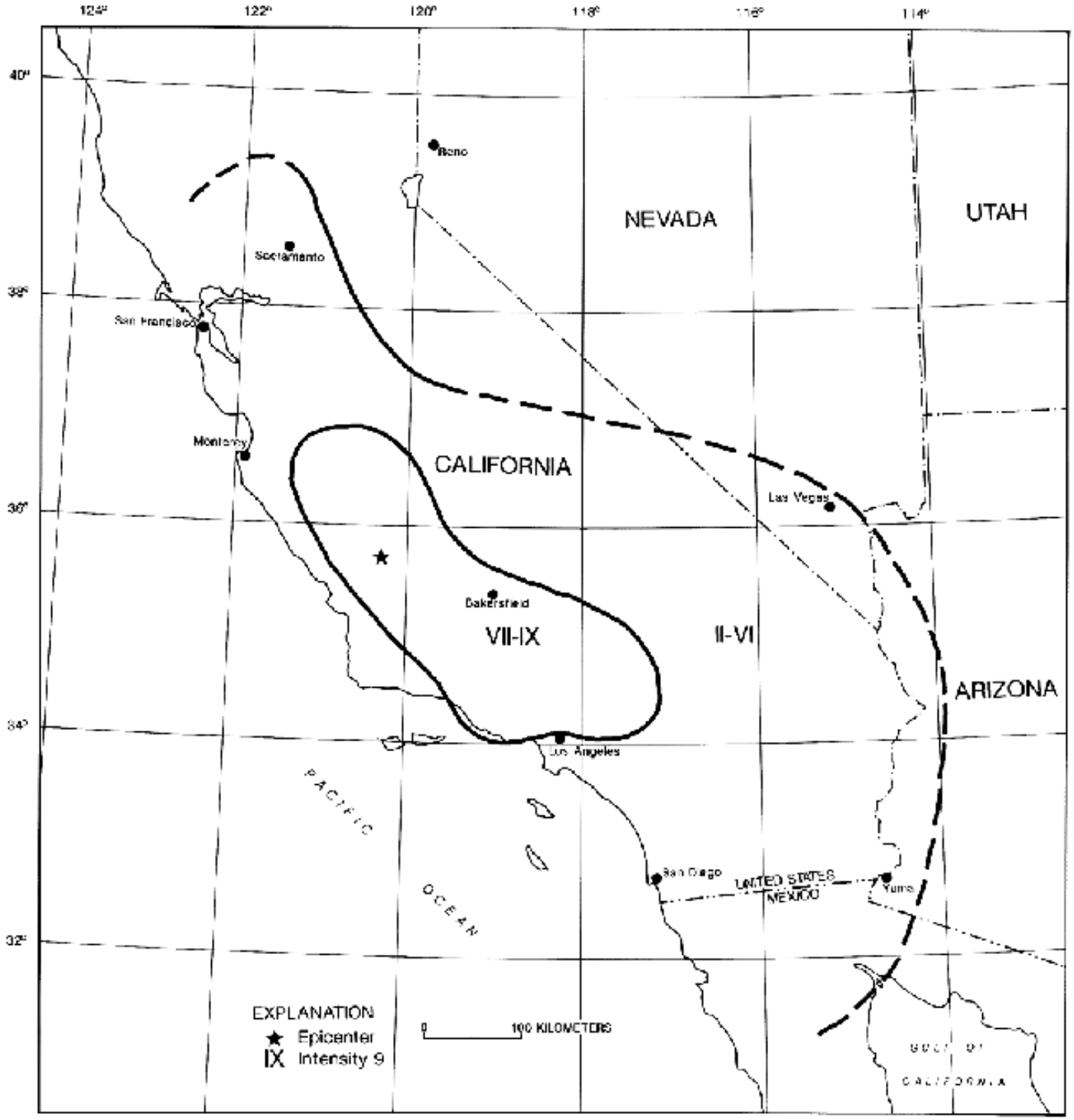
Changes in the flow of streams or springs were observed in the areas of San Diego, Santa Barbara, Isabella, and at the south end of San Joaquin Valley. The waters of the Kern, Lake, Los Angeles, and Mokulumme Rivers overflowed their banks. Changes in the flow of water in wells were reported from the Santa Clara Valley in northern California.

Felt from Marysville south to San Diego and east to Las Vegas, Nevada. Several slight to moderate foreshocks preceded the main shock by 1 to 9 hours. Many aftershocks occurred, and two (January 9 and 16) were large enough to have been widely felt.

Abridged from Seismicity of the United States, 1568-1989 (Revised), by Carl W. Stover and Jerry L. Coffman, U.S. Geological Survey Professional Paper 1527, United States Government Printing Office, Washington: 1993.

Isoseismal Map

Isoseismals are based on intensity estimates from data.



Sources/Usage: Public Domain. *View Media Details*

Isoseismal Map abridged from Seismicity of the United States, 1568-1989 (Revised), by Carl W. Stover and Jerry L. Coffman, U.S. Geological Survey Professional Paper 1527, United States Government Printing Office, Washington: 1993. (Public domain.)

For More Information:

- The Great 1857 "Fort Tejon" Earthquake: Shake, Rattle, and Roll! (Fort Tejon State Historic Park monthly newsletter)

- Eyewitness Accounts (*California Geology*)

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REPORTS

INDUCED SEISMICITY

High-rate injection is associated with the increase in U.S. mid-continent seismicity

M. Weingarten,[1]* S. Ge,[1] J. W. Godt,[2] B. A. Bekins,[3] J. L. Rubinstein[3]

An unprecedented increase in earthquakes in the U.S. mid-continent began in 2009. Many of these earthquakes have been documented as induced by wastewater injection. We examine the relationship between wastewater injection and U.S. mid-continent seismicity using a newly assembled injection well database for the central and eastern United States. We find that the entire increase in earthquake rate is associated with fluid injection wells. High-rate injection wells (>300,000 barrels per month) are much more likely to be associated with earthquakes than lower-rate wells. At the scale of our study, a well's cumulative injected volume, monthly wellhead pressure, depth, and proximity to crystalline basement do not strongly correlate with earthquake association. Managing injection rates may be a useful tool to minimize the likelihood of induced earthquakes.

The injection of fluids into the subsurface has been known to induce earthquakes since the mid-1960s (*1*–*3*). However, few additional cases of earthquakes induced by wastewater injection have been documented until 2009 (*4*). The hazard from these earthquakes was considered small because they were infrequent and not expected to be large (largest observed prior to 2011 was the M 4.9 Rocky Mountain Arsenal earthquake in 1967) (*4*–*6*). The central and eastern United States (CEUS) has seen an unprecedented increase in earthquake rate since 2009, and many of these earthquakes are believed to be induced (*7*). Along with the increased rate, several damaging earthquakes have occurred such as the 2011 magnitude (M) 5.6 Prague, Oklahoma, earthquake (*8*, *9*), the 2011 M 5.3 Trinidad, Colorado, earthquake (*10*), the 2012 M 4.8 Timpson, Texas, earthquake (*11*), and the 2011 M 4.7 Guy, Arkansas, earthquake (*12*). The increased earthquake rate and occurrence of multiple damaging earthquakes has prompted the scientific community to refocus efforts to understand the hazard posed by injection-induced earthquakes (*13*).

The sudden appearance of several large, potentially induced earthquakes led to many site-specific case studies (*4*). These case studies examined the operation of injection wells in close proximity to the earthquakes, showing a link between the timing and location of injection and seismicity (*12*, *14*–*18*). Though useful to understand the individual systems in which these earthquakes occurred, broader-scale studies are needed to understand the phenomenon as a whole. One previous study examined earthquakes in Texas's Barnett Shale region and found that earthquakes are commonly located near wells injecting more than 150,000 barrels per month (*19*). However, to fully understand the possibility of induced seismicity associated with a given injection well, we must analyze a range of geologic, hydrogeologic, and operational differences between injection wells that are potentially associated with earthquakes and those that are not.

We examined the location and timing of earthquakes and their relationship to the location and operation of injection wells across the CEUS (Fig. 1). We compiled a database from publicly available sources that documents the location and operational parameters of underground injection control class II injection wells in the CEUS (Fig. 1 and table S1). Class II injection wells inject fluids associated with oil and gas production and are distinct from hydraulically fractured production wells (*20*). The database contained 187,570 wells as of December 2014, with 56% actively injecting fluid (Fig. 1) and the remaining 44% being inactive or abandoned. About 75% of the active class II injection wells operated for the purposes of enhanced oil recovery (EOR), whereas nearly all of the remaining wells were designated as salt water disposal (SWD) wells (fig. S1). EOR wells inject fluid into depleted oil reservoirs to increase oil production. SWD wells inject to dispose of waste fluids produced by oil and gas production, which would otherwise be hazardous to surface waters or underground sources of drinking water. Injection wells are geographically clustered in the basins and regions of major oil and gas operations. Texas, Oklahoma, Kansas, and Wyoming contain ~85% of all class II injection wells in the CEUS. The spatial density of active SWD wells is highest (≥5 wells per 5 km^2) in the Forth Worth Basin of north-central Texas and the Mississippi Lime Play extending from north-central Oklahoma northward into central Kansas. The spatial density of active EOR wells is highest (≥5 wells per 5 km^2) in the Permian Basin of West Texas, the Fort Worth Basin, south-central Oklahoma, and southeastern Kansas (fig. S1).

We obtained earthquake location and magnitude data from the Advanced National Seismic System's comprehensive earthquake catalog (ANSS ComCat) (*21*). During the study period (1973 to 2014), we identified 7175 $M \geq 0.0$ events in the catalog in the CEUS region (Fig. 2). Although the catalog is not complete down to M 0.0 during the study period, we treated all earthquakes as potentially induced events to capture the most comprehensive data set of associated earthquakes and injection wells. We used a magnitude of completeness of 3.0 when comparing associated versus nonassociated earthquakes through time (*7*).

We used spatial and temporal filtering methods to discriminate injection wells that may be associated with earthquakes from those that are probably not. We considered any earthquake within 15 km of an active injection well to be associated with that well. This distance of association is based upon the sum of a 5-km radius within which earthquakes are traditionally considered as potentially induced (*22*) and a 10-km estimate of the spatial uncertainty in earthquake epicenter location in the CEUS (*23*). We designed the temporal filter to include only injection wells active at the time of the spatially associated earthquake. Both filters could be considered conservative, because induced seismicity has been found tens of kilometers from injection wells (*24*) and also after a well is shut-in (*25*) owing to the injection prior to the well becoming inactive (*4*, *5*). To analyze the sensitivity of our results to these filtering parameters, we also tested our analysis using spatial association distances of 5 and 10 km. This first-order analysis attempts to understand which basic well properties affect the likelihood of earthquake association.

We find 18,757 injection wells (~10% of all wells) associated with earthquakes in the CEUS after filtering, mostly in the states of Oklahoma and Texas (Fig. 1). The number of associated injection wells has tripled since the year 2000 (fig. S2). The spatiotemporal filter identifies every case of induced seismicity from class II injection wells documented in the literature for the CEUS region (table S2). We identify far more injection wells that are potentially related to earthquakes than those indicated by published cases. Of the wells that are associated with earthquakes, 66% are EOR wells. However, active SWD wells are more than 1.5 times as likely as active EOR wells to be associated with an earthquake, which accounts for their respective well totals (Fig. 1). The finding that SWD wells are preferentially associated with earthquakes likely resides with difference in well operation. SWD injection causes a net-positive reservoir pressure change, whereas EOR injection and extraction

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wells are typically operated in tandem with injection rates managed carefully to balance reservoir pressures (*7*).

Over the past four decades, more than 60% of all CEUS seismicity (*M* 3.0+) is associated with injection wells using our filtering criteria (Figs. 2 and 3). Varying the spatial distance of association by several kilometers only changes this percentage by ±5% (fig. S3). Before the year 2000, an average of ~20% of all CEUS seismicity was associated with injection wells. The yearly percentage of associated earthquakes has risen sharply to ~87% from 2011 to 2014 (Fig. 3 and fig. S4). The percentage increase of associated earthquakes, combined with the rising CEUS earthquake rate, implies that recent seismicity in the CEUS is preferentially occurring near injection wells. The number of nonassociated earthquakes during the same period has also remained stable (Fig. 3). This increase in associated earthquake rate does not correspond to an increase in the rate of wells completed; the well completion rate has remained constant over this period (fig. S5) (*26*). A portion of the increase in associated earthquakes may be due to increasing spatial coverage of wells, but we suggest that this effect is minimal, considering that the relative increase in spatial coverage was much more rapid between 1960 and 1980 than in recent years (fig. S5). Wells in central and north-central Oklahoma are the main contributors to the dramatic increase in associated seismicity. New production methods in these regions are generating large volumes of produced water, which are injected at high rates (fig. S6, A and B) (*27*). Regions such as west Texas, southern Colorado, central Arkansas, and southern Illinois also show concentrations of seismicity associated with injection wells (Fig. 2). However, several regions with large numbers of injection wells appear to be aseismic during the study period, including the Williston Basin of North Dakota (*28*), the Michigan Basin, and extensive areas of the Texas and Louisiana Gulf Coast (Figs. 1 and 2).

Several operational parameters are hypothesized to influence the likelihood of an induced seismic event: injection rate (*19*, *24*), cumulative injected volume (*29*, *30*), wellhead injection pressure (*31*), and injection in proximity to crystalline basement (*18*, *32*). Four states—Oklahoma, Arkansas, Colorado, and New Mexico—with both natural and induced earthquakes all have more than 15 years of injection data that include readily accessible information on monthly injection rate and pressure for a large proportion of operational wells. Using these data, we explore injection operational parameter control on the likelihood that SWD and EOR wells will be associated with earthquakes.

The maximum monthly injection rate of wells across these four states varies by several orders of magnitude, ranging from 100 barrels (~15.9 m^3) per month (bbl/month) up to 2 million bbl/month (~318,000 m^3) (Fig. 4A) (*33*). The average SWD well operates at a mean monthly rate of ~13,000 bbl/month. For each histogram bin in Fig. 4, A and B, we calculate the percentage of wells associated with earthquakes. The likelihood that an SWD well is associated with earthquakes increases as the maximum injection rate increases (Fig. 4C). To discern whether the association is random, we estimated upper (95%) and lower (5%) confidence bounds using a bootstrapped resampling method with 10,000 resamples (Fig. 4C) (*34*, *35*). Wells operating at maximum injection rates greater than 300,000 bbl/month fall outside the bootstrap resampling confidence bounds, suggesting a greater-than-expected likelihood of association with an earthquake at a statistical significance near 99%. This is contrasted with wells operating at maximum injection rates less than 100,000 bbl/month, which mostly fall within the bounds of random association. We confirmed this result using spatial distances of association of 5 and 10 km (fig. S7), as well as restricting our well associations to earthquakes greater than *M* 3.0 (fig. S8). Of the 413 wells operating at injection rates greater than 300,000 bbl/month, 253 (61%) are spatiotemporally associated compared with only 40% of wells operating at injection rates less than 10,000 bbl/month. Additionally, 34 (76%) of the 45 highest-rate SWD wells (injecting more than a million barrels per month) are associated with an earthquake. When SWD operations are examined state by state, the overall percentage associated varies, but the trend of increased earthquake association at higher rates is generally preserved (fig. S9A). Fewer data are available for EOR wells, but we do not observe a clear trend of increasing earthquake association with increasing injection rate for EOR wells (fig. S10A). Without considering geologic or hydrogeologic setting, the highest-rate SWD wells are nearly twice as likely to be near an earthquake as are low-rate SWD wells.

We next examine whether cumulative injected volume affects the likelihood of well association with earthquakes. For the four states examined during the period from 1973 to 2014, cumulative injected volume ranged from 1000 bbl to nearly 100 million bbl (Fig. 4B). Many large cumulative volume wells inject at moderate rates for decades, providing a contrasting data set from maximum injection rate. We do not observe a strong trend of increasing SWD well association as a function of increasing cumulative injected volume (Fig. 4D). The difference between the association rate of wells that have injected more than 1,000,000 bbl cumulatively (45%) and those which

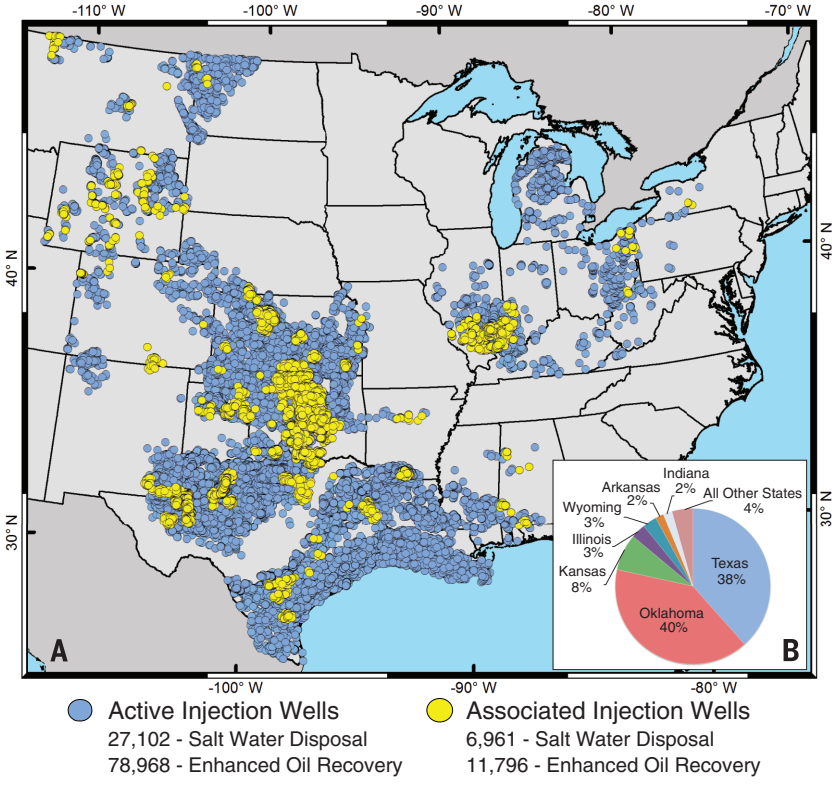


Fig. 1. Active and associated class II injection wells in the CEUS. (**A**) Map showing the location of active class II injection wells in the CEUS. Active injection wells from the database are shown as blue circles. Spatiotemporally associated injection wells, defined as those within a 15-km radius and active at the time of an earthquake, are shown as yellow circles. The CEUS region comprises all states intersected by 109°W longitude and eastward. The total number of wells, including inactive or abandoned wells in the CEUS, is 188,570. Of the 18,757 associated injection wells, >77% are currently active. (**B**) The inset pie diagram shows spatiotemporally associated injection wells by state. Only 8% of all injection wells are located in Oklahoma, but 40% of the associated injection wells in the CEUS are located in Oklahoma.

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have injected less than 10,000 bbl cumulatively (38%) is not statistically significant, as determined by a bootstrap resampling method (*35*). The percentage of wells associated with earthquakes at high cumulative injected volumes can be mostly explained by random variation given the total number of associated and nonassociated wells. EOR wells exhibit a trend of earthquake association similar to that of SWD wells as a function of cumulative injected volume (fig. S10B). If we instead calculate cumulative injected volume not for individual wells, but for all wells within 15 km of an associated earthquake, we observe a log-normal distribution of volumes without a clear threshold of increased earthquake association (fig. S11). We do not observe cumulative injected volume as strongly affecting the likelihood of an injection well's association with an earthquake.

The majority of class II injection wells operate at monthly wellhead injection pressures less than 500 pounds per square inch (psi). Reported wellhead pressures for both SWD and EOR wells ranged from 0 to 3000 psi (fig. S12, A and B). In the same four states studied, the proportion of SWD and EOR wells associated with earthquakes show no strong correlation toward increased monthly wellhead pressures (figs. S12 and S13). However, reported monthly wellhead pressure may not always be reliable because many wells report constant wellhead pressures despite changing injection rates. Wellhead injection pressure data may not reflect the pore-pressure conditions in the injection formation due to friction in the wellbore and other factors. In addition, wells reporting zero wellhead pressure still create bottomhole pressure from the hydrostatic fluid column in the well that could be large enough induce an earthquake. There are several hundred wells with zero wellhead pressures that are associated with earthquakes (fig. S12, A and B). This is consistent with field observations of earthquakes induced by wells with zero wellhead pressure (*10*, *36*). We do not consider the reported maximum wellhead pressure to be a controlling factor on injection well and earthquake association. This finding, together with the indication that SWD wells are preferentially associated with earthquakes, underscores the need to collect reservoir pressure data. Ideally, preinjection reservoir pore pressure and bottomhole formation pressure measurements during injection would prove more useful in determining whether a link exists between injection pressure and earthquakes.

Injection depth and proximity to crystalline basement have been hypothesized to affect the likelihood that wells are associated with earthquakes (*32*). Comparison of injection depths for most states in the CEUS, excluding Mississippi, Indiana, West Virginia, and Alabama, is possible, as these data are more readily available than injection rates and pressures (table S1). Class II injection wells are permitted over a wide range of injection depths from 300 to 4000 m (fig. S14). The majority of both SWD and EOR wells inject between 300 and 1500 m (fig. S14, B and E). Wells associated with earthquakes also inject over a similarly wide range of injection depths (fig. S14, A and D). We find no clear evidence that increasing injection depth increases the likelihood that a well will be associated with seismicity; the proportion of both SWD and EOR wells associated with earthquakes does not increase with increasing injection depth (fig. S14, C and F). However, comparison of injection depths neglects the large variations in sediment thickness across the CEUS.

Using a map of sediment thickness across the CEUS (*37*), we estimate injection proximity to basement for all wells by subtracting injection well depth from the sediment thickness at the closest sediment thickness data point. The

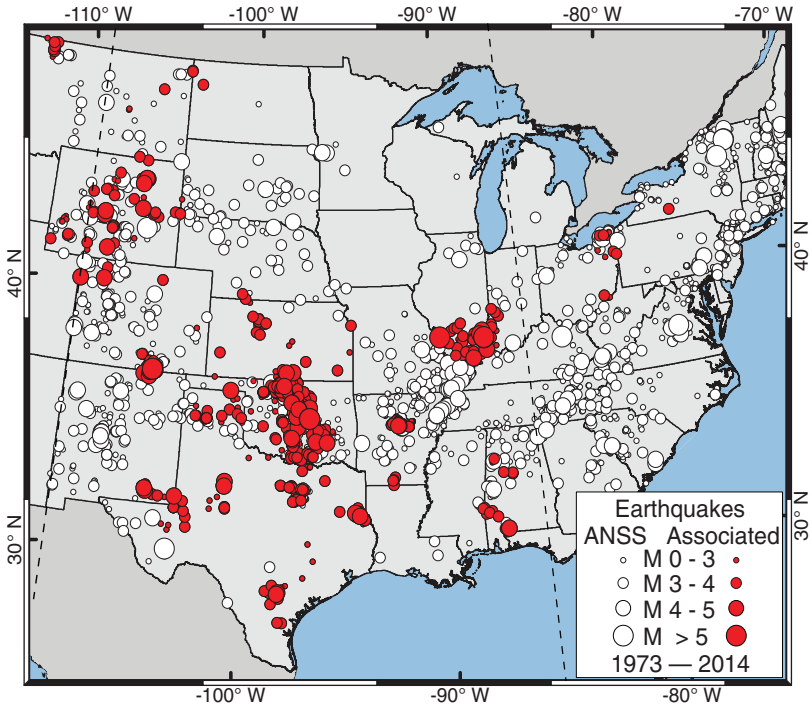


Fig. 2. Associated earthquakes in the CEUS from 1973 to 2014. Map showing the locations of $M \geq 0.0$ earthquakes in the ANSS ComCat earthquake catalog from 1 January 1973 through 31 December 2014. White dots denote earthquakes that are not spatiotemporally associated with injection wells. Red dots denote earthquakes that are spatiotemporally associated with injection wells. Following Ellsworth (*7*), the U.S. mid-continent is defined by the dashed lines inside of the greater CEUS.

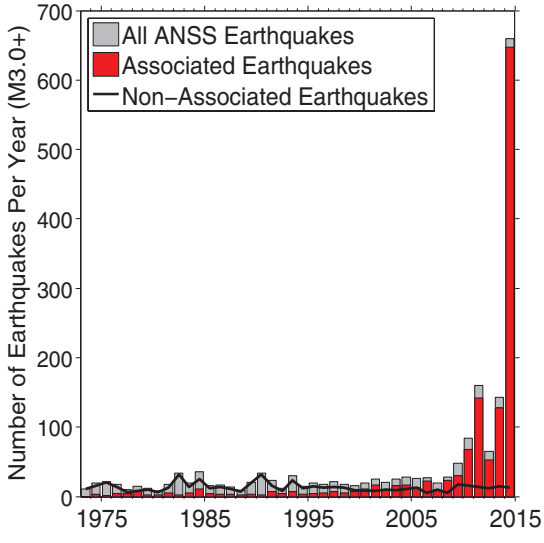


Fig. 3. Associated and nonassociated earthquakes per year in the U.S. mid-continent. The gray bars represent the number of $M \geq 3.0$ earthquakes per year in the U.S. mid-continent (Fig. 2) located by the networks of the ANSS ComCat earthquake catalog from 1 January 1973 to 31 December 2014. The red bars represent the number of earthquakes that are spatiotemporally associated with injection wells. The black line denotes the number of nonassociated earthquakes per year. Over the time period of the catalog, the number of nonassociated earthquakes per year has stayed roughly constant at 10 to 25 per year. Meanwhile, the number of associated earthquakes per year has risen from ~1 to 7 per year in the 1970s to 75 to 190 per year between 2011 and 2013 and >650 earthquakes in 2014.

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sediment thickness map was tested against known reference depths of crystalline basement and found to have errors in thickness up to ±15% (table S3). Thousands of wells in the CEUS inject fluid within 500 m of crystalline basement rock, but only a small proportion are associated with seismicity. When taking into account the error in basement depth over the CEUS region, we did not observe a significant correlation between a well's injecting near basement and earthquakes using a bootstrap resampling method (fig. S15). However, injection wells operating very far from basement, between 7 and 12 km vertically, exhibited an association rate near zero. We found similar results for both depth parameters using only well associations with earthquakes greater than *M* 3.0 (figs. S16 and S17). This finding supports the notion that detailed stratigraphic knowledge surrounding the injection interval is necessary to quantify the mechanistic linkage between injection and seismicity (*32*).

The lack of spatiotemporal association between injection and seismicity in several regions highlights the apparent influence of factors other than injection well operation. The San Juan Basin of New Mexico, the Williston Basin of North Dakota, the Michigan Basin, and extensive areas of the Texas and Louisiana Gulf Coast contain thousands of SWD and EOR wells that are not associated with seismicity (Fig. 1). In some of these regions, wells inject at rates similar to those in areas such as central Oklahoma, where large numbers of wells are associated with earthquakes. In the aseismic Michigan Basin, 30 wells operate at maximum injection rates greater than 200,000 bbl/month (fig. S18). Obviously, other factors in addition to high injection rate must play a role; the regional state of stress, fault size, fault orientation, the presence of fluid pathways between the injection point and faults, as well as other geologic factors must be examined to assess the potential for injection-induced seismicity (*4*).

Our analysis shows that injection rate is the most important well operational parameter affecting the likelihood of an induced seismic event in regions and basins potentially prone to induced seismicity. High-rate SWD wells are nearly twice as likely as low-rate wells to be near an earthquake. These high-rate wells perturb the ambient reservoir pressure by a larger magnitude and over a larger area than low-rate wells, thus increasing the likelihood that pressure changes will reach an optimally oriented, critically stressed fault. Previous studies have shown that high-rate wells exert greater influence on the extent and magnitude of reservoir and fault pressure perturbation (*24*). At the scale of our study, no other operational parameter was found to have a strong influence on the likelihood of association with an earthquake. The important distinction between operational parameters such as injection rate and cumulative injected volume shows the effect of the recent rise of new production methods and high-rate SWD wells. Thus, the oil and gas industry and regulatory bodies can use this operational parameter to lower the likelihood of earthquakes associated with injection wells.

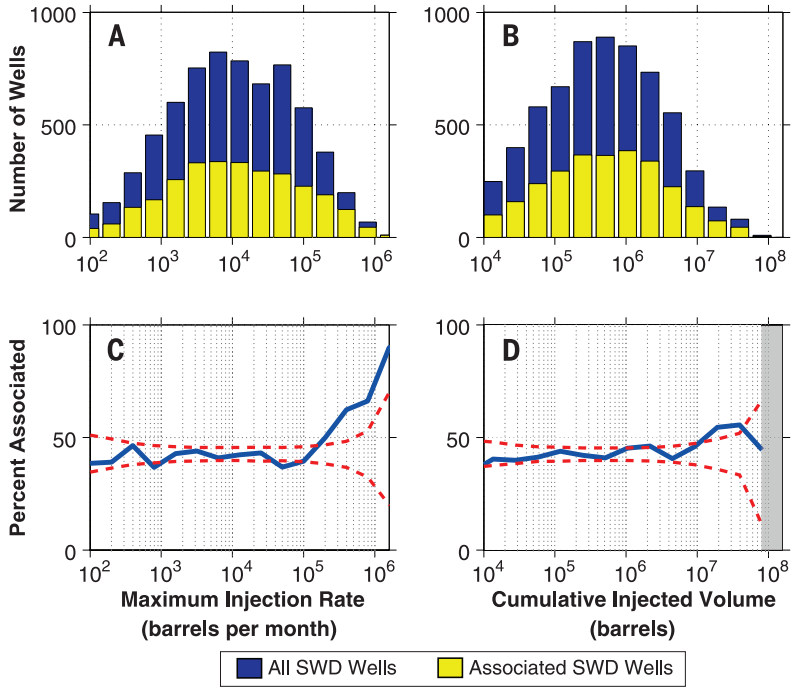


Fig. 4. Well operational parameter analysis. (**A**) Histogram showing the maximum monthly injection rate of salt water disposal (SWD) wells in Oklahoma, Arkansas, Colorado, and New Mexico. The blue and yellow bars show the number of wells operating at a given maximum monthly injection rate for all SWD wells (blue) and SWD wells spatiotemporally associated with an earthquake (yellow). (**B**) Histogram showing the cumulative injected volume at all wells in the same states as those in (A). The blue and yellow bars represent the number of wells operating at a given cumulative injected volume for all SWD wells (blue) spatiotemporally associated SWD wells (yellow). Injection data for Oklahoma were available from 1995 to 2013, for Arkansas from 1999 to 2013, for Colorado from 1999 to 2014, and for New Mexico from 1994 to 2014. (**C** and **D**) The percentage of all wells that are associated with an earthquake in each histogram bin is plotted as a function of (C) maximum monthly injection rate and (D) cumulative injected volume. The two dashed red lines represent the upper (95%) and lower (5%) confidence bounds in each bin generated by 10,000 bootstrap resamples and following the assumption that the rate of association is random. The shaded gray region of (D) indicates a lack of associated wells at the given volume. These data are also broken down state by state and for EOR wells in figs. S9 and S10.

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SUPPLEMENTARY MATERIALS

www.sciencemag.org/content/348/6241/1336/suppl/DC1
Materials and Methods
Figs. S1 to S18
Tables S1 to S4
References (*38*–*46*)

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POLARON DYNAMICS

Long-lived photoinduced polaron formation in conjugated polyelectrolyte-fullerene assemblies

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The efficiency of biological photosynthesis results from the exquisite organization of photoactive elements that promote rapid movement of charge carriers out of a critical recombination range. If synthetic organic photovoltaic materials could mimic this assembly, charge separation and collection could be markedly enhanced. We show that micelle-forming cationic semiconducting polymers can coassemble in water with cationic fullerene derivatives to create photoinduced electron-transfer cascades that lead to exceptionally long-lived polarons. The stability of the polarons depends on the organization of the polymer-fullerene assembly. Properly designed assemblies can produce separated polaronic charges that are stable for days or weeks in aqueous solution.

In biological photosynthetic systems, energy cascade structures promote the spatial separation of photogenerated charges created at the reaction center, preventing their recombination. These energy cascade structures require close proximity of the electron donors and acceptors, on the scale of ~1 nm, and the corresponding electron transfer (ET) processes take only a few picoseconds (*1*). Similarly, photoexcitation in artificial organic photovoltaic (OPV) cells generates dissociated charges at a donor-acceptor interface on subpicosecond time scales. However, OPVs suffer a large degree of recombination because they rely on phase separation of the conjugated polymer donor and fullerene acceptor into domains on the length scale of 10 to 20 nm to facilitate efficient exciton diffusion and charge transfer (*2*, *3*). The high charge densities present in OPVs, coupled with the low dielectric constant of organic materials, favor carrier recombination before the charges can be extracted through external electrodes. If OPVs could be designed to use ET cascade structures that are reminiscent of photosynthetic complexes, it should be possible to greatly improve charge separation and reduce recombination losses (*4*).

Here we describe how molecular self-assembly can enable dissolved OPV materials (conjugated polymers and fullerenes) in aqueous solution to mimic the ET cascade structures of biological complexes and allow us to "spatially" control photogenerated charges. We demonstrate efficient long-time charge separation following photoexcitation: The ET cascade produces separated polarons that are exceptionally stable for weeks, a lifetime that is unprecedented for OPV materials. Although long polaron lifetimes have been observed in covalently linked donor-acceptor dyads and triads (*5*) and micellar structures (*6*), our use of standard organic photovoltaic materials sets this work apart. In addition, our use of self-assembly provides potential future advantages in reproducibility and scalability, both of which are major hurdles for conventional OPVs with kinetically controlled structures (*7*–*9*). Finally, the photoinduced charge separation we achieve takes place in water, opening possibilities for the "green" production of artificial photosynthetic devices.

The particular materials used in this study are a combination of a conjugated polyelectrolyte, poly(fluorene-alt-thiophene) (PFT) (*10*), and several regioisomers of the charged fullerene derivatives C_{60}-*N*,*N*-dimethylpyrrolidinium iodide [$C_{60}(PI)_n$], where n is the number of charged pyrrolidinium iodide groups (*11*) (Fig. 1, A to C). PFT is a water-soluble semiconducting polyelectrolyte whose bis-alkylated sp^3-hybridized fluorenyl carbon forms a wedge-shaped monomer that facilitates the assembly of the charged polymer into rod-like micelles (Fig. 1B); details of how this polymer assembles have been published previously (*10*). Because of the charged nature of the polymer, the electron acceptor(s) must also carry cationic charges to avoid heterocoagulation. The synthesis of $C_{60}(PI)_n$, depending on the reaction conditions, produced multiadducts with n ranging from 2 to 5, including multiple regioisomers for each n. To avoid confusion, we will refer to $C_{60}(PI)_n$ with $n = 3$ to 5 as "higher" adducts and fullerenes with $n = 2$ as "mixed-bis" adducts.

We achieved control over the solution-phase aggregation of these materials by exploiting the different solubility properties of the conjugated polyelectrolyte and charged fullerene derivatives. Mixed-bis adducts show limited solubility (without PFT) in aqueous solution, whereas higher adducts are water soluble at high concentration. This difference suggests that the mixed-bis adducts should coassemble in aqueous solution with PFT, a result we confirmed by cryogenic electron microscopy (cryoEM), small-angle x-ray scattering (SAXS), and luminescence quenching studies. CryoEM images of pure PFT, PFT:mixed-bis adducts, and PFT:high adducts

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Science

High-rate injection is associated with the increase in U.S. mid-continent seismicity

M. Weingarten, S. Ge, J. W. Godt, B. A. Bekins and J. L. Rubinstein

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DOI: 10.1126/science.aab1345

Making quakes depends on injection rates

Wastewater injection wells induce earthquakes that garner much attention, especially in tectonically inactive regions. Weingarten *et al.* combined information from public injection-well databases from the eastern and central United States with the best earthquake catalog available over the past 30 years. The rate of fluid injection into a well appeared to be the most likely decisive triggering factor in regions prone to induced earthquakes. Along these lines, Walsh III and Zoback found a clear correlation between areas in Oklahoma where waste saltwater is being injected on a large scale and areas experiencing increased earthquake activity.

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Assessing induced seismicity risk at CO_2 storage projects: Recent progress and remaining challenges

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ABSTRACT

It is well established that fluid injection has the potential to induce earthquakes—from microseismicity to magnitude 5+ events—by altering state-of-stress conditions in the subsurface. This paper reviews recent lessons learned regarding induced seismicity at carbon storage sites. While similar to other subsurface injection practices, CO_2 injection has distinctive features that should be included in a discussion of its seismic hazard. Induced events have been observed at CO_2 injection projects, though to date it has not been a major operational issue. Nevertheless, the hazard exists and experience with this issue will likely grow as new storage operations come online. This review paper focuses on specific technical difficulties that can limit the effectiveness of current risk assessment and risk management approaches, and highlights recent research aimed at overcoming them. These challenges form the heart of the induced seismicity problem, and novel solutions to them will advance our ability to responsibly deploy large-scale CO_2 storage.

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1. Introduction

Geologic carbon storage is a valuable strategy to reduce atmospheric CO_2 emissions while minimizing the economic disruption of de-carbonizing the world's energy supply (International Energy Agency, 2010; Pacala and Socolow, 2004). Like all technologies, however, sequestration projects create a number of environmental and safety hazards that must be addressed. These include the potential for injection-induced earthquakes, which result from altering pore-pressure and state-of-stress conditions in the subsurface. To date, measured seismicity due to CO_2 injection has been limited to microseismicity and a few felt events (see Table 1). The hazard exists, however, and must be addressed. There are important similarities between CO_2 injection and fluid injection for other energy technologies that have induced significant events—e.g. geothermal systems, waste-fluid injection, hydrocarbon extraction, and others (National Research Council, 2012). There are also important distinctions among these technologies that should be considered in a discussion of inherent seismic risk (IEAGHG, 2013).

This paper discusses strategies for assessing induced seismicity risk during each phase of a geologic carbon storage (GCS) or CO_2-enhanced oil recover (CO_2-EOR) project. Before beginning, we note that *risk assessment* is only the first part of a broader *risk management* strategy. That is, the likelihood of inducing earthquakes and the ensuing risk at a given project are not fixed quantities, and can be lowered using a mix of mitigation and remediation strategies. To keep the discussion focused, however, we limit ourselves here to the assessment piece. A careful assessment of evolving risk at a site should inform all decision-making, and is therefore an essential first step towards effective management (Pawar et al., 2015; White and Foxall, 2014).

We employ the general notion that *risk* consists of three parts (Kaplan and Garrick, 1981):

1. one or more scenarios of concern;
2. the probability of a given scenario occurring;
3. and the damage that would result (i.e. the consequence of the scenario).

Thus a quantitative measure of risk must encompass both the probability of an event and the severity of its impacts. The term *hazard* is used to refer to components 1 and 2 alone—i.e. just the probability of occurrence, without the measure of damage.

The first step in a risk assessment is identifying all plausible scenarios that may lead to damage. For a CO_2-injection project, four

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Table 1
Summary of seismicity observations at recent CO_2 injection operations.

Project	Category	Monitoring design	Observations [a]	Seismicity Type[b]	References
Aneth USA	CO_2-EOR	Borehole Array	Magnitudes: **M**-1.2 to **M**0.8 Frequency: 3800 events over 1 year. Two fault-like clusters.	II	Rutledge (2010), Zhou et al. (2010), Soma and Rutledge (2013)
Cogdell USA	CO_2-EOR	Regional Network	One **M**4.4 event and 18 magnitude 3+ events over a 6 year period. No major seismicity at nearby, similar operations.	I	Gan and Frohlich (2013), Davis and Pennington (1989)
Weyburn Canada	CO_2-EOR	Borehole Array	Magnitudes: **M**-3 to **M**-1. Frequency: 100 events over 7 years. Diffuse locations.	II	Whittaker et al. (2011), White et al. (2011), Verdon et al. (2010, 2011)
Decatur USA	Dedicated Storage	Borehole Arrays Surface Stations	Magnitudes: **M**-2 to **M**1 Frequency: 10,123 events over 1.8 years. Multiple fault-like clusters.	I	Will et al. (2014), Couëslan et al. (2014), Kaven et al. (2014, 2015)
In Salah Algeria	Dedicated Storage	Borehole Array	Magnitudes: **M**-1 to **M**1. Frequency: 5500 events over 2 years. Indications of fracture stimulation.	I & II	Oye et al. (2013), Goertz-Allmann et al. (2014), White et al. (2014b), Verdon et al. (2015)

[a] **M** = moment magnitude.
[b] Type I = seismicity concentrated within overpressured zone. Type II = seismicity outside overpressured zone.

scenarios related to fault reactivation and induced seismicity are of primary concern. Induced slip on faults could potentially lead to:

1. property damage;
2. a public nuisance;
3. brine-contaminated drinking water;
4. and CO_2-contaminated drinking water.

The four scenarios lead to different types of damage: to property, to drinking water quality, or to the public well being. The first scenario (property damage) is analogous to the risk associated with natural seismicity, though here building and infrastructure damage results from induced events. The second scenario captures the notion that felt earthquakes will bother people in the local vicinity, even if there is no permanent damage. In this paper we use the common terminology "nuisance" for this risk, though unfortunately this word may convey the sense that it is a minor problem. The consequences should not be underestimated, however, as public backlash can lead to projects being shut down (Deichmann and Giardini, 2009) or skepticism of geologic carbon storage as a safe technology (Singleton et al., 2009). Scenarios 3 and 4 result from the observation that slip in a fault zone can alter its permeability structure, potentially creating or reactivating leakage pathways (Zoback and Gorelick, 2012, 2015; Juanes et al., 2012; Vilarrasa and Carrera, 2015a,b). It is helpful, however, to make a distinction between brine and CO_2 leakage. While they may occur together, they have different physical behavior, likelihoods of occurrence, and groundwater impacts. In the case that other in situ fluids are present—e.g. oil or gas—additional scenarios could be added. Indeed, the enumeration of risks above is not meant to be exhaustive, and additional risk scenarios may be important at a given site. The four listed here, though, are key priorities for all onshore storage operations. Also, while the intrinsic damage potential of offshore CO_2 storage may be much lower, significant fault reactivation and induced seismicity in an offshore project is also undesirable.

Given these four scenarios, this paper focuses on strategies for assessing their likelihoods of occurrence and the damage that may result. Ultimately, mitigation techniques can be applied to both aspects—i.e. safeguards can be put in place either to lower the likelihood of significant seismicity or to minimize damage should earthquakes occur. While it is desirable to avoid induced seismicity in the first place, the inherent complexity of subsurface systems make this a challenging task. Selection of sites having certain formation characteristics and operational procedures can be used to lower this likelihood, but an irreducible chance of inducing larger earthquakes will always remain. In light of this, it is pragmatic to always choose sites and engineering safeguards such that consequences will be low even if unwanted events occur.

The paper begins with a brief overview of the fundamental mechanisms behind induced seismicity, with a focus on the mechanics of CO_2 storage. We then review observations of induced earthquakes to date at recent CO_2 injection and comparable operations. This science basis—and its gaps—is crucial because it points to critical challenges in effectively implementing risk assessment approaches. The paper then presents a high-level overview of the key elements that inform a seismic risk assessment. We adopt one particular framework, Probabilistic Seismic Risk Assessment, but the underlying hazard and risk elements are universal and will be present in alternative assessment approaches.

The heart of the paper then describes key challenges in actually implementing such an assessment framework. In essence, geophysical characterization and monitoring limitations introduce very large uncertainties in the inputs to the risk assessment, and novel strategies are necessary for reducing and/or circumventing these uncertainties. We describe recent research by various groups that have made progress tackling these challenges, and also highlight open questions that remain. We conclude the paper with a list of research fronts that the authors feel will significantly advance our ability to assess and manage seismicity risk at CO_2 storage operations moving forward. The ultimate goal is to ensure we can deploy this valuable technology in a safe and responsible manner.

2. Mechanics of induced seismicity

Fig. 1 provides a conceptual illustration of the basic seismicity concern at a CO_2 storage site. Here, a well injects supercritical CO_2

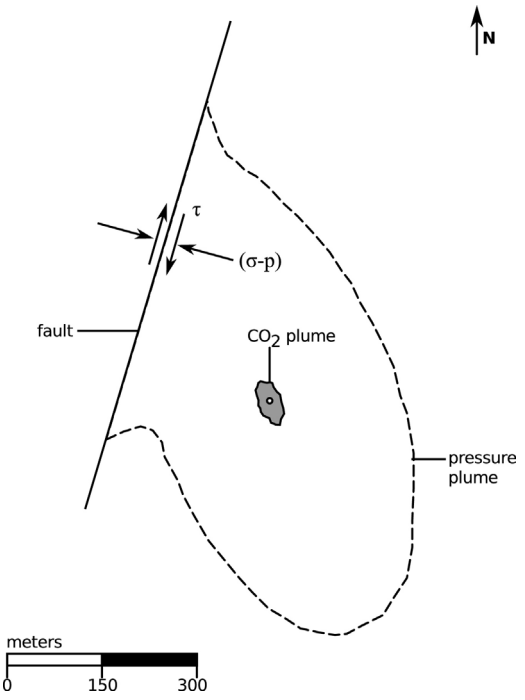


Fig. 1. Plan view of a CO_2 storage reservoir, showing pressure interaction between a vertical well and nearby fault.

into a storage reservoir. The reservoir is intersected by a moderately large, pre-existing fault. As injection begins, a CO_2-rich plume grows away from the injector, driven by pressure gradients and buoyancy forces. As the injected fluid displaces the in situ brine, a large overpressure plume also develops. Note that the extent of the pressure perturbation is typically much larger than the CO_2-rich plume. This pressure perturbation plume can interact with the fault, and potentially trigger seismic or aseismic slip.

A simple Coulomb criterion is often used to express the condition for fault stability (Scholz, 2002),

$$\tau \leq \mu(\sigma - p) \tag{1}$$

Here, τ and σ are the total shear and normal tractions applied on the fault, p is the pore fluid pressure, and μ is the static friction coefficient. The geomechanical convention is that positive stresses are compressive. The quantity $\sigma' = (\sigma - p)$ represents the *effective* normal traction on the fault, which is reduced by an increase in pore pressure or by a reduction in the in situ confining stress. The stability condition states that the fault will be stable as long as the shear traction is less than the current shear strength—i.e. the right hand side of Eq. (1). Here, we neglect any additional contribution to shear strength from fault cohesion, though this effect can be included as necessary.

We note that the deformation of the reservoir and density-change effects can create poromechanical stress perturbations that extend beyond the overpressured zone. These far-field stress perturbations can potentially reactivate well-oriented faults and fractures without substantially altering the local pore pressure p at the fault. For example, there are well known cases of production-induced seismicity, when net volume change in the reservoir is negative (Segall, 1989). As a convenient shorthand, we will refer to seismicity induced by direct pressure communication with faults as Type I seismicity, and seismicity induced outside of the overpressured zone as Type II.

The shear and normal tractions resolved on a fault plane will depend on the in situ state of stress in the formation, stress perturbations due to injection and/or production, and on the orientation

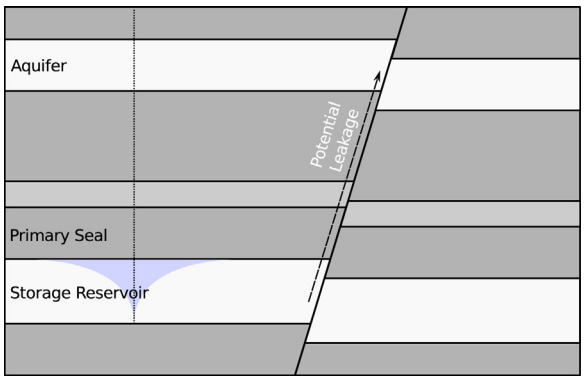


Fig. 2. Section view of a large fault intersecting a storage reservoir and shallow aquifer (not to scale). With this geometry, fault rupture could enhance the potential for leakage out of the storage zone.

of the fault with respect to this stress state. For a given state of stress, some faults may be favorably oriented for slip, while others may be poorly oriented. A simple measure of fault stability is therefore the critical pore pressure change Δp (or effective stress perturbation $\Delta\sigma'$) required to make condition (1) an equality. It is commonly observed that many faults are naturally in a state of critical equilibrium, in which the equality condition is nearly satisfied under in situ stresses and formation fluid pressures (Zoback and Townend, 2001). Very small perturbations in stress or pore pressure therefore can induce slip. It is these critically stressed faults that pose the greatest challenge for subsurface fluid injection (Zoback and Gorelick, 2012).

Eq. (1) is a useful simplification, though it masks some of the underlying complexity of fault reactivation. For example, this criterion is expressed as a point-wise condition, whereas in reality the stability of the fault will depend on a distribution of stresses, pressures, and friction strength across the whole structure. A variety of poromechanical and thermomechanical effects may substantially alter the state of stress in the reservoir and surrounding formations. Also, this condition only describes the behavior of the fault while it is in static equilibrium. Once slip is initiated, the fault may creep aseismically until it reaches a new stable configuration (quasi-static slip) or rupture dynamically in an earthquake (Dieterich, 1979; Ruina, 1983; Scholz, 2002). Strain accumulation during individual ruptures will also modify the state of the fault and nearby neighbor faults, potentially leading to complex foreshock/mainshock/aftershock cascades—e.g. (Sumy et al., 2014; Dieterich et al., 2015).

A related concern is that reactivation of a fault can create new permeable pathways, though the fault must penetrate the entire caprock seal (or seals) in order to create a leakage concern (Fig. 2). Given that the total area of the pressure perturbation plume is typically much larger than the mobile CO_2 plume, at many sites the risk of brine leakage may actually be much larger than CO_2 leakage risk, as mobile CO_2 may never come in contact with the reactivated fault. Both CO_2 and brine can cause groundwater degradation, and both types of leakage are a key project design factor. It is useful to distinguish them, however, as leak detection and management strategies for the two leakage types differ somewhat. Brine leakage requires a pressure differential to sustain it, while CO_2 leakage can rely on buoyancy drive alone. Also, the time periods of concern differ. Brine leakage can be effectively halted by reducing the driving pressure gradient. Removing pressure drive will also slow CO_2 leakage, but buoyancy drive may allow it to persist indefinitely until other trapping or remediation mechanisms come into play (Imbus et al., 2013; Zahasky and Benson, 2014).

Though the processes of fault reactivation, seismicity, and permeability change are closely related to each other, the occurrence

of one does not necessarily imply the occurrence of the others. For example, there could be fault reactivation with aseismic slip, fault reactivation with no substantial permeability change, and intrinsically permeable faults that have not experienced any reactivation. Faults that do not penetrate caprock seals may pose a seismicity hazard but will not create the same leakage hazard as a penetrating pathway. The depth, orientation, and lithologic composition of the fault is therefore crucial. In the event of rupture, the distribution of slip along the fault and any deformation in adjacent damage zones will control permeability modifications.

There are a number of CO_2-specific mechanisms that could potentially play a role in the seismic behavior of carbon storage operations, though direct observation of these mechanisms at field scale is challenging. For example, CO_2 can react chemically with certain fault minerals and potentially alter friction and permeability properties. Similarly, some clays may swell substantially in contact with supercritical CO_2, creating an additional stress perturbation. Given the relatively small size of the CO_2 plume in comparison to the pressurized brine volume, however, these additional effects—if they exist—would be confined to faults in closer proximity to the injection well.

3. Field experience

Field experience with CO_2 injection has grown in recent years, with new demonstration and commercial scale projects coming online. Specific studies on the seismic behavior at these fields, however, are more limited. Relatively few sites have deployed sensitive microseismic arrays capable of detecting smaller events. Table 1 summarizes seismicity observations at five CO_2 injection operations. The projects fall into two categories: CO_2-enhanced oil recovery projects (CO_2-EOR) and dedicated saline storage projects. Observed seismicity is denoted as Type I or Type II according to the broad classifications defined in Section 2.

The five projects summarized in Table 1 have shown a diverse range of seismic responses. We note that each site is unique and complex, and the brief notes given in Table 1 contain uncertainties and important caveats. The reader should consult the cited references for further details. Here, we briefly focus on three of these projects—Weyburn, Decatur, and Cogdell—as representative examples to highlight some unifying trends that have emerged in recent years.

The earliest CO_2-EOR project to deploy microseismic monitoring was the Weyburn–Midale CO_2 Monitoring and Storage Project in Saskatchewan, Canada (White et al., 2011). The Weyburn and Midale oil fields have a long history of EOR operations, with water flooding beginning in the 1960s. Starting in 2000, CO_2 has been injected to improve oil production. As of 2011, the total CO_2 injection rate reached 5.3 Mt/year through more than 100 wells (Whittaker et al., 2011). The net storage rate—i.e. excluding recycled CO_2—was 2.7 Mt/year. Injection rates for individual wells range from 50 to 500 tonnes/day. In August 2003, a deep borehole seismic monitoring array was deployed in an abandoned production well to study the behavior of one injection/production well pattern (Verdon et al., 2010, 2011). Between 2003 and 2010, approximately 100 locatable microseismic events were detected, with estimated moment magnitudes ranging from **M**-3 to **M**-1. The overall seismicity rate is therefore extremely low. While location uncertainties are large, most of these extremely small events appear to be diffusely located in the overburden and underburden, rather than localized to the reservoir interval. Geomechanical modeling suggests that the microseismicity is driven by stress perturbations due to reservoir deformation, rather than by direct pressure communication with the wells (Verdon et al., 2011). Many of these events are located in proximity to underpressured production wells, further supporting the Type II hypothesis. Similar indications of Type II seismicity have been associated with CO_2-EOR at the Aneth Oil Field in Utah (Rutledge, 2010; Zhou et al., 2010; Soma and Rutledge, 2013).

The Illinois Basin Decatur Project was the first large-scale dedicated storage demonstration in the U.S., injecting 1 Mt between 2011 and 2014 (Couëslan et al., 2014). CO_2 is stored in a 550 m thick, high-permeability sandstone unit at 2100 m depth. This saline aquifer (the Mt. Simon) is regionally extensive and has significant capacity for future storage operations. The pressurized storage zone directly overlies Precambrian granitic basement. Two independent groups have carried out microseismic monitoring at the site. The Decatur Project operates two deep borehole microseismic strings, one in the injection well and one in an offset monitoring well (Will et al., 2014; Couëslan et al., 2014). Separately, the U.S. Geological Survey (USGS) has installed a 12-station surface and shallow borehole array (Kaven et al., 2014, 2015). The deep borehole array has superior sensitivity to small events, while the surface array provides better spatial and focal sphere coverage. Both groups have observed clusters of microseismic events, several with linear trends and consistent Northeast strikes, near the bottom of the Mt. Simon and into the Precambrian basement. It appears that pressure from the storage operation has reactivated a number of small, well-oriented faults in the basement. No events have been seen in proximity to the upper seal, the Eau Claire Shale. The more sensitive downhole array has detected 10,123 events during 22 months of injection, with estimated magnitudes ranging from **M**-2 to **M**1. Location estimates for 2573 of these events reveal distinct microseismic clusters, with an expanding radius of seismic activity as injection proceeds. Several wastewater injection sites have observed similar microseismic clustering, notably the U.S. Bureau of Reclamation Paradox Valley Unit in Colorado (Ake et al., 2005; Block et al., 2012). Microseismic clusters that appear to define faults have also been observed at the Aneth Oil field, though these appear to have been activated in a Type II mode (Rutledge, 2010; Zhou et al., 2010; Soma and Rutledge, 2013).

The only case reported to date where earthquakes larger than **M**1 have been attributed to gas injection is at the Cogdell oilfield in Texas (Gan and Frohlich, 2013). A total of 38 earthquakes were recorded by the permanent regional seismic network and located within or close to the field during a period of high-rate gas injection between 2006 and 2011. Augmentation of the regional network coverage by stations of the Earthscope U.S. Temporary Array between 2009 and 2011 enabled a total of 105 events larger than about magnitude 1 to be located relatively accurately during this two-year period. Eighteen of the events detected by the permanent network had magnitudes between 3 and 4.4. If events within this range had occurred during the previous 20 years, most would have been detected by the network. Although previous earthquakes as large as magnitude 4.6 occurred in the vicinity of the Cogdell field during a period of waterflooding between 1956 and 1982 (Davis and Pennington, 1989), no seismicity was recorded in the area between 1983 and 2005.

Oil is produced at Cogdell from the Horseshoe Atoll limestone reef. Sustained CO_2 (and/or possibly methane) injection for EOR at a depth of about 2100 m began in 2001. The injection rate was increased sharply in 2003 to average about 350,000 m^3/month at the depth of injection until 2008. Five events ranging from magnitude 2 to 3.9 were recorded during this period, but almost all of the seismicity—including all but two of the magnitude 3+ events—was recorded during 2009 and 2010, when the injection rate peaked to average about 400,000 m^3/month. Seismicity continued to accompany injection at somewhat lower rates through 2011. Whereas water injection since 1976 has been approximately balanced by production, gas injection since 2001 has resulted in a net increase in reservoir fluid volume.

Most of the events located using US Array data occurred as five or six clusters, all of which are within four km of groups of injection wells. Three of the clusters define linear seismicity features having orientations that correspond to focal mechanism solutions for five larger events, which suggests that the seismicity occurred as triggered slip on previously unidentified faults. However, the network station spacing is too large to determine accurate earthquake focal depths, and hence the depths of the faults. It is pertinent to compare the apparent seismic response from gas injection at Cogdell with the lack of response at the Kelly-Synder field immediately to the southwest. Even though the Kelly-Synder field lies along the same structural trend as Cogdell and production is from the same limestone reservoir, no seismicity has been detected there despite closely similar trends in production and both water and gas injection histories at the two fields. The Kelly-Synder field was the site of the SACROC CO_2-EOR research project carried out by the DOE-sponsored Southwest Regional Partnership on Carbon Sequestration (Han et al., 2010). A detailed understanding of the key attributes leading to different seismic responses in these two fields is not yet available.

While the handful of case studies described above have improved our understanding of site-specific hazards, the overall empirical database of seismic events triggered by CO_2 injection is small. With limited data, it is difficult to make any overarching conclusions about the intrinsic seismic hazard associated with CO_2 storage. Further, even the examples described here display widely different responses. This is because hydromechanical behavior is highly site and operation-specific, as illustrated by the contrast between the Cogdell and Kelly-Synder fields. In this data-poor context, it would be valuable for future storage projects to deploy at least some baseline microseismic monitoring capability. This additional data can help identify and manage seismicity issues before they become a major operational problem.

4. Comparison with other injection technologies

The seismicity hazard associated with CO_2 injection is similar in many ways to that posed by subsurface injection for other purposes such as wastewater disposal, geothermal energy production, and reservoir stimulation by hydraulic fracturing or hydraulic shearing. Given limited experience so far with CO_2-induced events, it is important to learn as much as possible from these other practices. Clearly, however, there are features specific to each of these injection applications that will lead to differences in seismic hazard and risk; these include, for example, the hydromechanical properties of typical reservoir lithologies, injection rates and pressures, and net total volumes of injected fluid. Additional factors such as the degree of site characterization, the extent of site monitoring and permitting requirements also influence the way that seismic hazard assessments are carried out.

In its comprehensive review of induced seismicity related to energy technologies, the National Research Council (National Research Council, 2012) identified net fluid balance as the most important factor influencing the likelihood of induced seismicity—i.e. the net volume change resulting from both fluid injection and production. A more recent study (Weingarten et al., 2015) found that seismicity associated with wastewater disposal wells across the central U.S. is strongly correlated with the *rate* of fluid injection, rather than the accumulated net volume over decades-long time periods. Relatively sharp increases in net injection over time intervals shorter than the characteristic diffusion time scale will result in overpressure build-up, the primary driver of induced seismicity. Injection applications that result in low net fluid injected volumes, such as short-duration well stimulation and waterflood for EOR, typically create smaller and/or less intense overpressured zones, reducing the likelihood of Type I seismicity. The impact on Type II seismicity is less clear, however, because, as discussed in Section 2, any stress perturbation caused by injection and/or production can potentially reactivate well-oriented faults.

Consideration of net injected volume alone would imply that CO_2-EOR projects should have smaller seismic risk than dedicated storage. As Table 1 indicates, however, the largest earthquakes associated with CO_2 injection observed to date have occurred at the Cogdell CO_2-EOR field, suggesting that in this case the high injection rate (averaging about 400,000 m^3/month) during the seismicity sequence was the determining factor. This illustrates that multiple factors must be considered in a rigorous assessment of project risk. It is essential to investigate the likely spatial distribution, magnitude, and timing of stress perturbations that will be caused by injection and/or production operations. The stress perturbation field provides a more direct measure of reactivation potential. This detailed stress assessment is particularly important for fields that experience complex injection and production histories involving multiple wells and multiple fluids, such as CO_2-EOR operations.

Dedicated storage projects have raised concern because sequestering megatonnes (and ultimately, gigatonnes) of CO_2 in the subsurface will create large overpressured regions, increasing the likelihood that the overpressure will encounter larger faults capable of generating significant seismicity (Zoback and Gorelick, 2012, 2015; Juanes et al., 2012; Vilarrasa and Carrera, 2015a,b). The closest technology analog is waste-water disposal, which also involves injecting large volumes of fluid over significant time periods. In the U.S., a dramatic increase in the rate of seismicity has been observed in parts of the central and eastern U.S. since 2001, which is attributed to increased wastewater disposal activity resulting from the boom in unconventional shale oil and gas recovery enabled by hydrofracturing. The largest events to date that have been attributed to wastewater injection are **M**5.3 and **M**5.7 earthquakes that occurred in 2011 in Colorado and Oklahoma, respectively (Rubinstein et al., 2014; Keranen et al., 2013; Sumy et al., 2014).

According to Weingarten et al. (2015), induced events have been associated with only about 10% of the more than 180,000 Environmental Protection Agency (EPA) active or formerly active Class II (wastewater disposal and EOR) injection wells in the U.S. From a public engagement point of view, however, a handful of problematic projects has quickly gripped public attention. Given heightened scrutiny of CO_2 disposal as an unfamiliar technology, even one or two problematic projects may quickly create a public perception issue, even if the vast majority of storage operations experience no seismicity of concern whatsoever.

Weingarten et al. (2015) also point out that induced earthquakes are conspicuously absent in several regions in the central and eastern U.S., such as the San Juan Basin of New Mexico, the Williston Basin of North Dakota and large areas of the Gulf Coast, where thousands of wastewater and EOR wells are active. In California, Goebel et al. (2015, 2016) identified four earthquake sequences between 1975 and 2014 that were possibly associated with wastewater injection at oilfields in the southern San Joaquin Valley, but Goebel (2015) found no apparent large-scale correlation of seismicity with a marked overall increase in injected volumes since 2001. This is in contrast to Oklahoma, where average basin-wide injected volumes are roughly similar to those in California. While a great deal of further study is needed, these regional differences in seismic response might be due, at least in part, to fundamental differences in uppermost crustal stress states, geologic structure and hydraulic connectivity in different tectonic settings. Whatever the cause, it is fair to assume that there will be important regional differences in the hazard posed by induced seismicity.

Most industrial-scale dedicated storage projects currently under construction or in the planning stage have projected injection rates

between 1.0 and 3.5 Mt/year (or 1.4 and 5M m^3/year, assuming a density of 700 kg/m^3 for supercritical CO_2), injected through one or more wells. These rates are somewhat higher than typical high-volume wastewater injection rates—in the range of about 200,000–500,000 m^3/year—in areas of the central U.S. that have recently experienced induced seismicity. A few individual disposal wells in some of these areas inject at rates of 1–3M m^3/year. Furthermore, in some cases multiple nearby wells inject into the same target formation. For example, the cumulative injection rate in two adjacent injection wells within 2 km of an **M**4.7 foreshock of the 2011 **M**5.3 earthquake in Colorado was 63,100–76,100 m^3/mo (757,000–910,000 m^3/year) (Rubinstein et al., 2014), approaching the projected rates of planned CO_2 projects. Since wastewater disposal into some wells is continuous over time periods as long as decades, total reservoir volume changes can be of the same order (10–100M m^3) as the projected volumes of stored CO_2 of most of the planned GCS projects.

Most wastewater injection is into sedimentary formations in which pressure increases are moderated by relatively high permeabilities—similar to CO_2 storage. Although minor seismicity occurs within these units, in the documented cases to date the largest events (**M**3+) have occurred in the basement and/or lowermost sediments well below the injection interval. Pressure migration to deeper units with greater seismic potential is a key concern for CO_2 storage operations as well (Will et al., 2014).

One final factor controlling a project's seismic risk is the level of effort devoted to site selection, characterization, monitoring, and risk planning. Permit requirements under which the injection is carried out will therefore play an important role. In the U.S., for example, wastewater disposal and EOR operations require a Class II Underground Injection Control permit, while dedicated storage operations require a different Class VI permit (U.S. Environmental Protection Agency, 2012). The Class VI requirements are generally viewed as much more stringent. Given that only a few Class VI permits have been issued to date, however, the long term impact of different permitting and oversight requirements is as yet unclear.

5. Probabilistic Seismic Risk Assessment

Given the problem potentially posed by induced seismicity, an effective risk assessment and risk management framework is essential to project design. The two components—assessment and management—should go hand-in-hand in a closed-loop feedback cycle. This section gives an overview of the key elements that contribute to a project risk assessment. We describe a high-level workflow, setting the stage for a detailed discussion of challenges to implementing this workflow in Section 6. Risk assessment is a widely-studied field, with a significant body of practice to draw on to address the current problem. The true difficulty is ensuring the inputs to the chosen assessment workflow are meaningful. For induced seismicity applications, determining input parameters with acceptably narrow uncertainty bounds poses numerous hurdles.

A useful approach to assessing induced seismicity risk is to adapt the standard Probabilistic Seismic Risk Assessment (PSRA) approach widely used to estimate the risk of structural damage from naturally-occurring earthquakes. As certain regions are now dealing with both natural and induced events, a unified assessment framework is also desirable. PSRA involves coupling the probability of an event occurring with its societal consequences, which in the case of induced seismicity include nuisance caused by felt ground motion as well as building and infrastructure damage. PSRA is generally carried out using the following procedure:

1. *Source characterization*: Identify seismic sources, which may be individual faults or zones within which earthquake occurrence is assumed to be homogeneous.
2. *Earthquake occurrence rate*: Estimate the average frequencies of occurrence of earthquakes of different magnitudes for each source. These occurrence rates may contain time-dependencies and correlations between sources.
3. *Ground motion*: Calculate the ground shaking resulting from earthquakes on each source at sites of interest. Ground shaking measures include ground velocity and acceleration at specified frequencies, or seismic intensity. These are primarily functions of earthquake magnitude, source-to-site distance, and local site conditions.
4. *Hazard*: Derive a hazard curve representing the forecasted probability of exceeding each ground motion value, usually on an annual basis. This curve is derived by integrating the frequencies of occurrence of ground motions generated by all sources. In conventional PSRA, hazard constitutes a long-term forecast, typically over time periods of several decades. For induced seismicity, the hazard has an inherent time-dependency, and forecast windows must be adjusted accordingly.
5. *Vulnerability*: Develop a vulnerability function for each receptor (i.e. buildings, infrastructure, population centers) that expresses the probability of creating a certain level of damage or nuisance for a given ground motion value. Usually this involves structural analysis for buildings, or surveys asking people how they respond to given levels of shaking. Vulnerability functions are typically determined for different receptor "classes" (e.g. multi-story wood-framed homes). Custom vulnerability assessments are reserved for specialized assets.
6. *Risk*: Derive a risk curve representing the annual probability of a given consequence, such as a specified degree of structural damage. This is accomplished by convolving the hazard curve with the vulnerability function.

Steps 1–4 constitute a Probabilistic Seismic Hazard Assessment (PSHA), while Steps 5 and 6 add the damage component necessary for risk evaluation (PSRA). While we have adopted PSRA terminology here, these six elements are fundamental and will appear in one form or another in alternative assessment frameworks—whether they be quantitative, semi-quantitative, or qualitative.

Standard PSHA and PSRA methods require a number of modifications before they can be applied to induced seismicity. We will discuss these issues in more detail in Section 6, but two major changes are apparent:

First, source characterization and frequency-magnitude estimation (Steps 1 and 2) pose more of a challenge. For natural seismicity, there is often a long historical catalog of events we can use to identify sources and estimate long-term recurrence rates. Also, it is usually (though not always) assumed that these long-term rates are stationary in time. The hydromechanical processes responsible for induced seismicity, on the other hand, introduce strong time- and space-dependencies, and while in some instances background seismicity may aid in identifying sources near an injection site, obviously there cannot be a record of induced seismicity per se before injection begins. New methods are therefore required for evaluating the seismic potential of a given site and its relationship to injection. Any time- and space-dependencies that appear in Steps 1 and 2 must then be rigorously propagated through the entire assessment workflow.

Second, traditional PSRA has focused on building and infrastructure damage, and therefore is primarily concerned with larger events (usually, **M**4.5+). Experience with induced seismicity has extended the range of concern to lower magnitudes (say, **M**2+). The natural earthquake occurrence rate is essentially fixed by tectonic processes and is outside human control. Risk mitigation is

therefore mostly focused on site selection and structural design standards. In induced seismicity, the earthquake occurrence rate is controllable, conceivably, because it is linked to human activities. Therefore, the public has an expectation that the occurrence of *all* induced felt events be kept to a minimum. Frequent felt seismicity will create a community nuisance even if it does not cause damage, and these smaller magnitude events must be a key focus of an expanded risk assessment and management workflow. The inclusion of smaller magnitude events requires important alterations in Steps 3 and 5.

6. Fundamental challenges and recent progress

The previous section has presented a general framework for risk assessment, identifying the key elements that control the seismic hazard and resulting risk. Unfortunately, the inherent complexity of the induced seismicity process introduces technical hurdles that makes the actual implementation of this framework challenging. The next few sections describe several of these underlying challenges, and ongoing efforts aimed at addressing them. These challenges are at the heart of the induced seismicity problem, and novel solutions to them will significantly advance our ability to manage seismic risk during CO_2 injection. The same challenges are relevant to other types of fluid injection as well.

6.1. Fault identification

As described in Section 5, the first step in any seismic risk assessment is source characterization—i.e. identifying individual faults (or faulted zones) that are capable of generating seismicity of concern. Geophysical monitoring techniques have inherent limitations that make detecting faults—particularly smaller faults—difficult. In general, pre-existing faults in proximity to an injection project can be divided into two basic categories: observed and unobserved.

Known faults—such as those mapped at the surface or identified in seismic surveys—can be addressed early in the design phases of a project. The potential for reactivation can be assessed using in situ stress estimates and hydromechanical simulations (Chiaramonte et al., 2014), and hazardous faults can simply be avoided during site selection and project planning. Monitoring and mitigation plans can then be carefully designed around other, lower risk features. Indeed, several carbon storage projects have been sited in close proximity to larger faults—notably Snøhvit (Hansen et al., 2013; Chiaramonte et al., 2014) and Gorgon (Jenkins et al., 2012)—as these faults were deemed low risk. Faults are pervasive in the subsurface, however, and there will always be a population of faults about which little or no information is available prior to injection. A good example of this situation is the Illinois-Basin Decatur Project, where microseismicity has illuminated smaller faults that were not visible in 3D seismic surveys (Will et al., 2014; Couëslan et al., 2014). Assessing and managing the hazard from this unknown fault population is much less straightforward.

The key factor controlling the maximum magnitude event that a fault can produce is its area. At the same time, the likelihood of detecting a fault in the subsurface is also correlated with its size. To illustrate this notion, Fig. 3 plots a commonly-used relationship between rupture diameter, stress drop, and earthquake moment magnitude (Hanks, 1977; Scholz, 2002; Zoback and Gorelick, 2012). This relationship assumes an idealized circular rupture geometry—reasonable for modest earthquakes—so that fault length can be related to a maximum rupture area. This relationship indicates that a fault length of 1 km is potentially capable of generating a maximum earthquake in the **M**3 to **M**4 range. Such events would likely be felt by nearby populations and possibly cause minor damage to seismically fragile infrastructure in the immediate

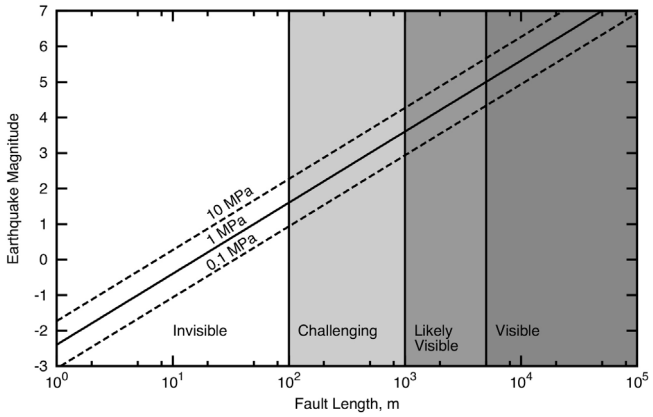


Fig. 3. Scaling relationship between fault rupture length and earthquake magnitude, supported by field observations (Hanks, 1977; Scholz, 2002). Dashed lines indicate a commonly observed range of stress drop, from 0.1 to 10 MPa. Vertical shaded regions indicate "typical" visibility of a given size fault using 3D seismic. Note that actual seismic resolution is highly site, survey, and fault specific, and the depicted thresholds are meant for conceptual illustration only.

vicinity. If the fault intersects the caprock, the rupture could potentially extend several hundred meters vertically through a seal.

A 3D seismic survey, combined with geological and well log data, can be used to detect faults and estimate the maximum magnitude earthquakes that may be expected. There are, however, limitations to fault detectability. For example, while the kilometer-long fault discussed above is large enough to produce seismicity of concern, it is also small enough that it could potentially be missed in seismic interpretation. Fig. 3 shows estimates of fault detectability that might be applicable to a "typical" seismic survey. The specific length ranges shown in Fig. 3 were chosen for illustrative purposes only, as the actual resolution achievable is not only site- and survey-specific, but is also highly dependent on the fault location, geometry and style. The visibility of a fault in a 3D seismic volume is primarily determined by its size and whether it creates detectable vertical offsets on reflecting horizons. Small offsets and steeply dipping faults are particularly difficult to see. Faults that are confined to the basement or to stratigraphic units having widely-spaced reflectors are challenging to detect, as are strike-slip faults, which may have substantial accumulated horizontal displacement but little or no vertical offset.

All carbon storage projects to date have used 3D (and often 4D) seismic as a key component of their site characterization and monitoring plans to provide a significant amount of information about subsurface structure. This is a key distinguishing feature of CO_2 injection compared to many wastewater disposal projects. However, it is critical to assess the resolution achieved with a given survey. A precise understanding of fault detectability will enable regions of lower and higher uncertainty to be distinguished. The injection operation can then be designed to avoid pressure migration into poorly characterized zones.

As mentioned earlier, known faults can be dealt with in the site selection and project design phases, and risk mitigation techniques can be applied. Thus, while the potential hazard from a large fault may be relatively high, the overall risk may be more easily managed. The most common way to obtain information about smaller faults that escape detection during the pre-injection phase is to carefully monitor microseismicity and its relation to pressure evolution in the reservoir as injection proceeds. This, however, creates an unusual situation: we must use the micro-earthquakes themselves to estimate the hazard on an ongoing basis and react rapidly to prevent larger events. We will discuss this issue further below.

While it is often difficult to detect individual faults, fault populations tend to follow well-established statistical distributions in

terms of their size and spatial density (Scholz, 2002). It is sometimes possible to constrain these distributions using available data. In particular, if a data set is available on the density distribution of larger faults—i.e. from geological mapping, 3D seismic, and well observations—it may be possible to extrapolate the observed distribution to estimate the likely density of smaller, unresolved faults. The inferred density can then be used within a probabilistic hazard assessment. Jordan et al. (2011) present an analysis along these lines, using fault density statistics to examine the probability that pressure and/or CO_2 might encounter faults during a previously-planned injection in the San Joaquin Basin. The same approach could be easily extended to assess the resulting seismicity hazard.

6.2. Microseismic event detection, location, and characterization

Microseismic monitoring during injection is the primary tool used to monitor the evolving seismic hazard posed by both known and previously undetected faults. Ideally, the monitoring array can precisely identify, locate, and characterize the micro-earthquakes, but in practice high-quality microseismic monitoring can be a demanding, and often expensive, task. Physical, technological, and budgetary constraints will inevitably limit the resolving power of the array, and introduce significant uncertainties into earthquake source characterization.

The first limitation is often one of cost. The ideal microseismic array would consist of multiple, deep borehole arrays—placing as many geophones as possible in close proximity to the seismic events while simultaneously providing the optimal spatial coverage necessary for accurate location and focal mechanism estimation. Deep borehole deployments are expensive, however, and during the design phases of a project it may not be clear if significant seismicity will even occur. Given budget constraints, project operators must decide whether the money may be better spent monitoring other potential hazards. To date, most projects have opted to deploy a relatively small number of instruments, often using a shallow or deep borehole string (see Table 1). The Illinois-Basin Decatur project is a good example of a monitoring approach in which the monitoring sophistication has adapted to increased understanding of the seismic hazard (White and Foxall, 2014). The initial design of the project began with a baseline microseismic monitoring system, which has subsequently expanded to include two deep borehole arrays (Will et al., 2014) and a separately operated surface network (Kaven et al., 2014, 2015). Recently, there has also been movement towards installing permanent, dual-purpose arrays—i.e. using the same array for both active and passive seismic monitoring. For example, the Aquistore project has deployed a dual-purpose array with 650 geophones spread over a 2.5 km × 2.5 km areal grid (Worth et al., 2014; White et al., 2014a). Looking to the future, significant research investment has focused on innovative technologies that will help lower monitoring cost. These include distributed acoustic sensing fiber-optic technology (Daley et al., 2013), "slimhole" drilling methods, and cheap, easily-deployable surface monitoring systems (Lin et al., 2013; Hutchings et al., 2015b).

Analysis of small-magnitude microseismic events is often plagued by low signal-to-noise ratio and significant uncertainties. Recent research has focused on improved signal processing algorithms in order to extract as much information as possible from recorded waveform data. For example, automated detection algorithms for identifying small magnitude events can extend the completeness of seismicity catalogs that constrain earthquake frequency-magnitude distributions used to estimate the likelihood of larger events. A large body of work on detection and phase arrival picking algorithms exists, e.g. Joswig (1990), Brown et al. (2008), Lomax et al. (2012), Skoumal et al. (2014, 2015) and Yoon et al. (2015). As one example, by applying a Matched Field Processing method (Harris and Kvaerna, 2010; Bucker, 1976; Baggeroer et al., 1993) to data from the Newberry Enhanced Geothermal Field, Templeton et al. (2014) were able to identify 399 microseismic events, compared with 235 detected by a traditional short-term-average/long-term-average method. Similarly, decision-making can be improved when precise event locations (Waldhauser and Ellsworth, 2000; Pujol, 2000; Zhang and Thurber, 2003; Gharti et al., 2010; Soma and Rutledge, 2013) and a good understanding of location uncertainty are available (Myers et al., 2007; Oye et al., 2013; Lomax et al., 2014). Given often non-ideal configurations of monitoring arrays, location uncertainty can be hundreds of meters laterally and vertically.

Additional research efforts are focused on reducing uncertainties in crustal velocity models. For example, Matzel et al. (2014) have recently applied Ambient Noise Correlation—a seismic interferometry technique typically used for imaging large-scale (regional to global) earth structure—to compute accurate 3D velocity and attenuation models beneath dense microseismic arrays. The same group has also applied the Virtual Seismometer Method—a related interferometry technique (Curtis et al., 2009; Hong and Menke, 2006)—to improve focal mechanism estimation based on cross-correlating waveforms recorded for pairs of microseismic events.

6.3. Estimating earthquake recurrence and the influence of injection

As discussed in Section 5, the growing subsurface pressure distribution resulting from injection introduces strong time- and space-dependencies into earthquake occurrence rates, which leads to the hazard evolving with time. New methods are therefore required for evaluating frequency–magnitude distributions in relation to injection. To date, there have been two primary approaches to this: empirically-based methods and simulation-based methods.

Empirically-based methods use a seismicity catalog compiled by microseismic monitoring of the injection to estimate the evolving seismic hazard (Shapiro et al., 2007, 2010; Bachmann et al., 2011; Mena et al., 2013). As the project proceeds, the growing catalog of events is used to continuously re-calibrate the parameters of an earthquake frequency–magnitude model. These empirical approaches typically use simplified models of the underlying physical processes, leading to a manageable number of free parameters to be fitted to observed data. The calibrated model may then be used to forecast the future seismic hazard within some forecast window (Bachmann et al., 2011; Mena et al., 2013). The quality of this forecast will depend on (1) the fidelity of the simplified model to the true system behavior, and (2) the availability of sufficient seismic observations to properly constrain future seismic occurrence. Both aspects of the problem are the subjects of ongoing research.

Most of the recent developments in empirical methods have been applied to reservoir stimulations for enhanced geothermal systems (Shapiro et al., 2007, 2010, 2011; Shapiro, 2015; Bachmann et al., 2011; Mena et al., 2013) where they have shown some promise. A key question, however, is to what extent the underlying physical models translate to geologic carbons storage operations, which operate in higher permeability reservoirs and over much longer time scales. The main limitation in testing these methods for carbon storage has been the lack of field data, though recent data acquisitions (Table 1) are improving this situation. Also, all of these methods make substantial simplifying assumptions that merit further investigation.

Recent work has also explored simulation-based approaches. Numerical simulation has been used to investigate induced seismicity at enhanced geothermal (Baisch et al., 2009; Baisch et al, 2010; McClure and Horne, 2011; Goertz-Allmann and Wiemer,

2013; Gischig and Wiemer, 2013), CO_2 sites (Cappa and Rutqvist, 2011, 2012; Rinaldi et al., 2014; Jha and Juanes, 2014), and wastewater injection systems (Keranen et al., 2014; Dieterich et al., 2015). These modeling approaches have been carried to varying levels of sophistication, but all simulate overpressure that can induce failure on fault elements according to a chosen friction/rupture model. In principle, simulation-based methods can include arbitrarily sophisticated models for the induced seismicity process, and thereby hew more closely to the underlying physics than the simplified empirical models above. In practice, however, obtaining the necessary characterization and calibration data necessary to make these model predictions accurate and useful remains an ongoing challenge.

The maximum magnitude ($\mathbf{M}_{max}$) at which frequency-magnitude distributions are truncated has a significant influence on forecasted hazard (Bachmann et al., 2011), but selection of $\mathbf{M}_{max}$ based on observed data remains an unsolved problem. If faults favorably oriented for failure have been identified intersecting the volume likely to be affected by stress perturbations, then $\mathbf{M}_{max}$ can be estimated from the dimensions of the largest fault. See the related discussion on fault detection in Section 6.1. Failing that, Shapiro et al. (2011) (see also Mena et al. (2013)) have proposed that the magnitude of the largest expected event can be empirically related to the dimensions of the perturbed pressure region. The underlying assumption is that that the maximum magnitude earthquake can occur on an undetected fault having dimensions approximately equal to the dimensions of this perturbed volume. This implicitly assumes that undetected faults of all sizes are pervasive in the vicinity of the injection well, and some are favorably oriented for slip. Since presumably that will not always be the case, it would perhaps be more accurate to say that this approach attempts to place an upper bound on $\mathbf{M}_{max}$ in the absence of more detailed information. McGarr (2014) has also proposed a simple relationship between the upper bound seismic moment and the net cumulative volume of injected fluid. The study notes, however, that the proposed relationship does not place an absolute physical limit on $\mathbf{M}_{max}$. These approaches downplay the possibility that failure of a fault patch within a pressure plume can result in a rupture that continues to propagate outside of it, leading to an event larger than the inferred $\mathbf{M}_{max}$ (Gischig, 2015). Stress transfer from foreshock ruptures and similar long-range perturbations could also promote slip on faults at significant distances from the injection well. An interesting case study here is the 2011 Prague, Oklahoma earthquake sequence attributed to wastewater injection—see Keranen et al. (2013) and Sumy et al. (2014). A **M**5.0 foreshock in close proximity to several wastewater injection wells triggered a complex earthquake cascade in the local fault network. Less than 24 h later, a **M**5.7 mainshock occurred on a fault approximately 2 km away. While the exact controls on this earthquake sequence remain unclear, static stress transfer between the faults may have played an important role.

Another important question from a risk management point of view is to what degree pre-cursor information may be available to identify hazardous situations before they become problematic. Ideally, microseismic observations could indicate a previously unknown fault has been encountered, and this information can be used to revise the seismic hazard estimate and potentially alter injection operations before larger events occur. It is also possible, however, that the largest events will occur very early in the earthquake sequence with little to no warning. In this latter case, "traffic light" systems and injection-rate control techniques may be rendered ineffective (Deichmann and Giardini, 2009; Majer et al., 2012a,b; Walters et al., 2015). As a result, it is important for operators and regulators to include damage mitigation strategies within the project design to ensure practical consequences will be low even if felt earthquakes cannot be prevented.

6.4. Ground motion prediction

A major difference between PSHA for induced and naturally-occurring seismicity is the need to calculate ground motions from small events that do not pose a risk of structural damage, but can be strongly felt at short distances. These events can cause annoyance and alarm, and possibly cosmetic damage. Depending on the distance to nearby communities, magnitudes as low as **M**1.5–**M**2 may need to be included in the hazard analysis.

Traditional PSHA employs empirical ground motion prediction equations (GMPEs) derived by regressions on worldwide strong motion data (Abrahamson and Shedlock, 1997; Abrahamson et al., 2008; Bozorgnia et al., 2014). The majority of existing GMPEs do not extend to magnitudes below **M**4.5, and even then are poorly constrained for smaller events and short distances (Bommer et al., 2006). The most recent GMPEs developed by the Pacific Earthquake Engineering Research Center Next Generation Attenuation (NGA) Working Group, NGA-West2, has been extended to **M**3.0 (Bozorgnia et al., 2014). However, the empirical fits are constrained by only minimal observed data from events smaller than **M**6 at distances less than 5 km. Douglas et al. (2013) recently developed GMPEs specifically for magnitudes less than **M**3.5 based on data from six geothermal areas worldwide, but the aleatory uncertainties on these generic relationships are quite large, owing primarily to site-to-site variability.

Microearthquake seismograms from small earthquakes can be used as empirical Green's functions (EGFs) for site-specific calculation of ground motion from larger events (e.g. Hutchings et al., 2007; Hutchings and Wu, 1990). The EGFs contain complete information about the point-source response (wave propagation) of the Earth along specific source-site paths. Larger events are modeled as a composite sequence of point-source sub-events on the fault plane that propagates at the earthquake rupture velocity. The ground motions at specific sites are calculated by convolving each point-source with the appropriate EGFs and summing the in-phase contributions from all of the sub-events.

Prior to injection, when in most cases recorded microearthquakes that could used as EGFs will not be available, it may be necessary to develop synthetic Green's functions. These are calculated by analytically or numerically modeling wave propagation from an array of synthetic point sources through the local seismic velocity and attenuation structure (Graves and Pitarka, 2010, 2015; Hutchings et al., 2015a). The accuracy of the synthetic functions will clearly depend on the quality of site characterization data available. Another method of deriving Green's functions and crustal velocity structure without microearthquake recordings is Ambient Noise Tomography, which has recently been applied in local-scale studies in (Matzel et al., 2014).

Ground acceleration and velocity amplitudes at a specific receiver site are strongly influenced by amplification effects that depend on the near-surface geology. Conventionally, amplification factors are applied to bedrock ground motions based on broad site classifications, often parameterized in terms of the average S-wave velocity above a depth of 30 m (VS30). Inversion methods have also been developed to obtain site response spectral amplifications from ambient noise recordings (Herak et al., 2008) and near-surface velocity profiles (Scherbaum et al., 2003). One approach is to use near-surface-velocity profiles to calculate analytic Green's functions, which are then convolved with site response functions to obtain site-specific Green's functions (Scognamiglio and Hutchings, 2009).

6.5. Structural and community vulnerability

The effects of ground-motion produced by medium to large earthquakes (**M**4.5+) on structures are usually modeled with a

fragility function that expresses the probability of structural damage as a function of ground-motion acceleration or velocity, or seismic intensity. These are combined with hazard curves to calculate damage risk; i.e. the probability of exceeding given damage levels at a site over a specified time period. Standard fragility functions can be applied to assess structural damage from either natural or induced earthquakes (e.g. U.S. Federal Emergency Management Agency, 2013).

Because smaller magnitude events are a key consideration for induced seismicity, an equivalent methodology must be developed to address the risk of nuisance and the attendant impact on public perception. The effects of felt but non-damaging ground motions have been extensively studied in the context of vibrations generated by mining and construction, which has led to the development of national (e.g. American National Standards Institute) and international (International Standards Organization) standards in the form of deterministic acceptability criteria (Dowding, 1996). These acceptability criteria form the basis for a U.S. Department of Energy protocol for assessing and mitigating nuisance risk created by enhanced geothermal systems (Majer et al., 2012a,b). These DOE guidelines could also generally be applied to CO_2-induced ground motions. Further work is needed to determine the most appropriate ground motion metric (acceleration, velocity, etc.) to relate to human response.

With regard to nuisance potential, an injection project's community outreach efforts (or lack there of) may have an important impact on how the local community reacts to seismicity. A project that is widely-perceived to provide tangible benefit to the community—e.g. by providing employment opportunities, economic stimulus, or environmental benefits—may be given more leeway than a project that is viewed with widespread skepticism. Similarly, a community's general familiarity with carbon storage technology is an important factor in the public perception of its riskiness (Singleton et al., 2009). A model case study in this context is the Geyser's Geothermal Project, which has a well-developed public education and outreach program aimed at local residents (Dobson, 2014; National Research Council, 2012). Clearly, however, building public trust and familiarity requires a focused and long-term commitment.

7. Conclusion

The goal of this paper has been to identify and describe specific technical difficulties that make seismic risk assessments for CO_2 storage operations inherently challenging. In our view, these issues lie at the heart of the induced seismicity problem, and focused research is required to address them. While promising progress has been made to date, a number of hurdles remain. These may be briefly summarized as follows:

1. Faults are pervasive in the subsurface, with a large range of scales, and our ability to identify and characterize them through geophysical techniques is inherently limited. Moderate-sized faults pose the greatest challenge, as they are both large enough to produce seismicity of concern but small enough to be often hard to detect via traditional means. Improved techniques for identifying and characterizing potential seismic sources are therefore needed. These techniques must be cost effective, practical to deploy, and allow for a quick turn-around time between data collection and interpretation.
2. The relationship between injection rate and seismic activity is complex, site-specific, and also constantly evolving in time and space. Project operators have limited time to understand and react to these evolving hazards. Better data analysis and modeling techniques, soundly based on the physics of induced seismicity, are therefore required to characterize earthquake occurrence relationships and their connection to injection operations.
3. Because felt events resulting from injection activities have the potential to alarm or annoy nearby communities, the lower bound magnitude of concern for induced seismicity (about **M**1.5–**M**2) is lower than that typically focused on for natural seismic risk assessment (usually ~**M**4.5). Conventional seismic risk assessment methods must therefore be updated to address smaller events, shorter distances, and the risk of nuisance in addition to property damage. Further, the intrinsic spatial- and time-dependencies introduced by the hydromechanical processes responsible for induced seismicity will have an important impact on the risk assessment workflow.
4. While not a focus of this paper, it should be recognized that risk management techniques for controlling seismicity and associated impacts have inherent limitations. There can also often be a significant delay before control measures take effect. As a simple example, drawing down the pressure in a reservoir can be effective at controlling seismicity, but will take time for pressure changes to propagate significant distances from injection or production wells. In this context, risk assessment techniques should ideally be predictive, allowing operators to assess how different operational decisions will impact forecasted seismic risk. This ability to look ahead is essential for proactive, rather than purely reactive, risk management.
5. Even though the overall number of CO_2 injection projects is growing, relatively few investigations have been undertaken on the seismic behavior of these fields. Moving forward, more observational data and field experience is clearly necessary. Further, it is important that this data be made broadly-accessible to independent research groups to solicit the best analysis and insight available.

Experience with induced seismicity at carbon storage sites is limited, and best practices will likely evolve as field experience grows. While seismicity is a serious concern and should be carefully addressed by all future projects, evidence to date at several successful projects suggests that good site selection and careful project design can lower seismic risk to acceptably low levels. Deploying CO_2 storage at sufficient scale to significantly impact global greenhouse gas emissions will require a dramatic scale-up in the number of storage projects, however, and well-focused research can help ensure we deploy this new infrastructure in a safe and responsible manner.

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Integrating induced seismicity for enhanced subsurface structural interpretation at the Decatur, Illinois Sequestration Site

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Abstract

Induced microseismic activity detected and located during and after injection of super-critical carbon dioxide ($scCO_2$) in the Illinois Basin – Decatur Project (IBDP) was used to help determine pathways the fluid took over time and to assess the risk of felt seismicity with injection. The microseismic activity at the site indicates locations where existing fractures and faults were reactivated but does not display a direct correlation with the locations of faults mapped in the seismic reflection volume. Most of the induced seismicity occurs below the reservoir in the fractured low porosity/permeability igneous basement rocks where fault identification proved problematic. Faults interpreted in the 2D and 3D seismic reflection data acquired are relatively small (a few 100s of m) and also have small interpretable displacements of up to 10 m on the largest faults. Temporal bursts of seismic activity define planar orientations of smaller structures within the individual clusters that are oriented oblique to the main trends. The poor correlation between the faults interpreted in the reservoir and the reactivated structures in the basement are indicative of their development in different tectonic regimes. Timing of the development of major structural trends around the Basin are consistent with the structural elements found at Decatur and help to explain the different orientations of faults. Combining the passive seismic results with the active seismic image interpretation enables an interpretation of the subsurface structure that is also consistent with the tectonic evolution of the basin.

Keywords: structural interpretation; reflection seismic, induced seismicity;fault reactivation; fractures; subsurface fluid flow Illinois

1. Introduction

The Illinois Basin – Decatur Project (IBDP) was a CO_2 capture and storage project in Illinois funded by the U.S. Department of Energy. The Illinois State Geological Survey (ISGS) partnered with the Archer Daniels Midland company to sequester the CO_2 produced as a byproduct from ethanol production. During the project 999,215 tonnes of supercritical carbon dioxide ($scCO_2$) was injected into the base of the 500 m thick Mt. Simon at a depth of 2140 m

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over three years from 2011 to 2014. The seismic monitoring program included active seismic acquisitions, with 2D lines through and near the injection site, a baseline and monitoring 3D survey, and timelapse 3D vertical seismic profiles, or VSPs [1]–[3]. The VSPs were acquired by a 31-level three-component permanent geophone array which also served as the primary acquisition array for the passive seismic data. Microseismic events were also detected by a 13-station seismic network comprised of mostly surface stations with four stations installed in 150 m deep boreholes that was installed by the U.S. Geological Survey 18 months after injection started [4]. An additional 5 surface seismometer stations were installed by the ISGS. Figure 1 shows the 3D seismic survey footprint and the locations of the seismometer stations of the USGS network at Decatur.

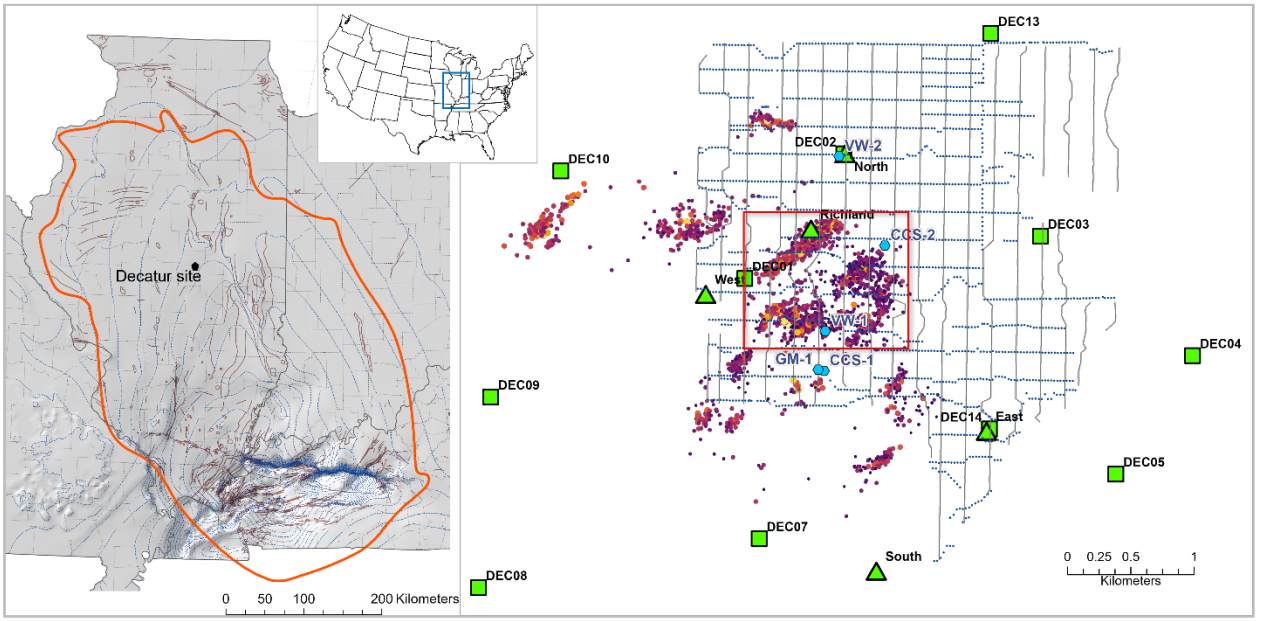


Figure 1. Seismic acquisition configuration at the Illinois Basin Decatur Project. Green squares indicate some of the USGS seismometer stations and the green triangles are ISGS stations. The blue and black lines of points are receiver and source locations of the active seismic acquisition survey. Induced events are shown by clusters of dots coloured and sized by magnitude. Open symbols show locations of the injection wells and the monitoring wells.

The primary injection target at the site is the Cambrian Mt. Simon Sandstone, an extensive formation that underlies much of the Midwestern United States which is also used regionally for geological storage of natural gas [5]. The basin is currently being assessed for the potential to store up to 50 MT of CO_2 from a variety of industrial sources, primarily in the Mt. Simon, but also in other units such as the St. Peter Sandstone, which also have favorable reservoir characteristics.

2. Seismic reflection interpretation

The 3D seismic data acquired in 2015 as a monitor survey to be used for time-lapse imaging and plume detection was reprocessed in 2019 using methods designed to enhance features that indicate subsurface faulting. The Cambrian Mt. Simon Sandstone reservoir in which most of the faults were interpreted has high porosity and permeability with much less common faulting and fracturing in the image logs that penetrate the formation. Because the resolution of the seismic data is close to the average dip-slip displacement on suspected faults, interpreting them in the reprocessed seismic data was still challenging, and only faults that could be interpreted on seismic slices for a minimum of 300 meters were considered to indicate features with low enough uncertainty to be included in the final model. Figure 2 shows the interpreted fault traces with lower interpretation uncertainty on two seismic cross sections extracted from the 3D volume, with event locations up to 50 meters to the west projected onto the section. Faults 1 and 2 are interpreted where a break in the seismic reflections are apparent, and their interpretation as faults is strongly supported by the highly fractured nature of the basement rock in this area. Both faults are small, and Fault 2 cannot be interpreted

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on inline 85 (see figure 3 for map view location of inline traces). Fault 3 appears to be the terminus for the adjacent NE-SW oriented induced seismicity cluster, demonstrating a geomechanical relationship between the faulting and induced failure, but not as the failure plane itself, as described in detail by [6]. Fault 5 on the figure is penetrated by the VW1 well, and its location coincides with a fault interpreted at that depth in the wellbore image log. This fault also is interpreted to tip out into the top of the Argenta at the same location as a small cluster of events. Several clusters of events occur where no fault was interpreted in the basement and faults are interpreted in the Mt. Simon where no events occur.

Sizes of the resulting interpreted faults range from about 90,000 m^2 (equivalent to a circular patch with a 300-meter diameter) to about 940,000 m^2 (equivalent to a circular patch with a 950-m diameter). This size range is much larger than the range of slip patch sizes calculated for the Decatur induced events calculated by [7] using the relationships derived by McGarr and Fletcher [8] and Thingbaijam et al [9]. Some microseismic events were large enough to determine focal mechanisms, but no felt seismicity was detected during or after CO_2 injection at the IBDP. About 90% of the detected events were M < 0 and the largest event detected with the downhole monitoring array to date was magnitude 1.6 [10]. The smallest interpreted faults are larger than the largest calculated slip patch size; 120 m diameter by McGarr (90% of source diameters are < 10 m), 440 m by Thingbaijam (90% of the source diameters are less than 80 m). The source radii are normally considered to be a smaller patch of failure on an existing fault plane. However, the orientations of subclusters of temporal seismicity bursts within the induced event clusters at Decatur consistently differ from the orientations of the clusters in which they occur, which could indicate failure of fault splays oblique to the main trend rather than a single fault, or of reactivation of a fracture corridor along the main cluster trend. A detailed analysis of one of the densest and earliest clusters to develop support an interpretation that the method of failure/reactivation is more likely reactivation of fractures with the optimal orientation for slip within basement fracture corridors.

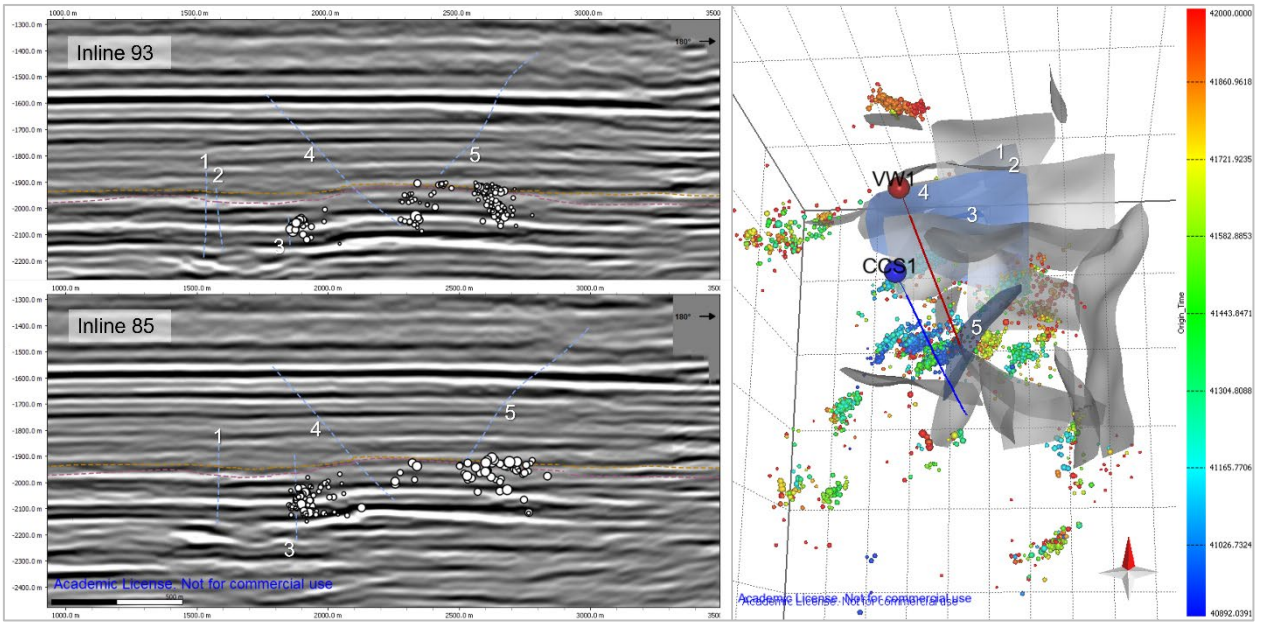


Figure 2. Intersection of 5 interpreted faults with seismic inline 93 (top left) and inline 85 (bottom left) with interpreted top Argenta horizon and top of basement (see Figure 3 for inline locations). Seismic events are projected from the west onto the seismic line from up to 50 m away. Right side of figure shows all the faults interpreted in the 3D seismic volume and their relationship in space to the seismic events with the faults that intersect the seismic lines shown in blue. Events are sized by magnitude and coloured by origin time where blue indicates the earliest events.

The temporal development of the microseismicity at the Decatur site suggests that the pressure front migrated largely to the north and west of the injection locations, indicated by development of clusters over time of events elongated in a NE-SW orientation that is close to azimuth of the maximum horizontal stress in this part of the Illinois

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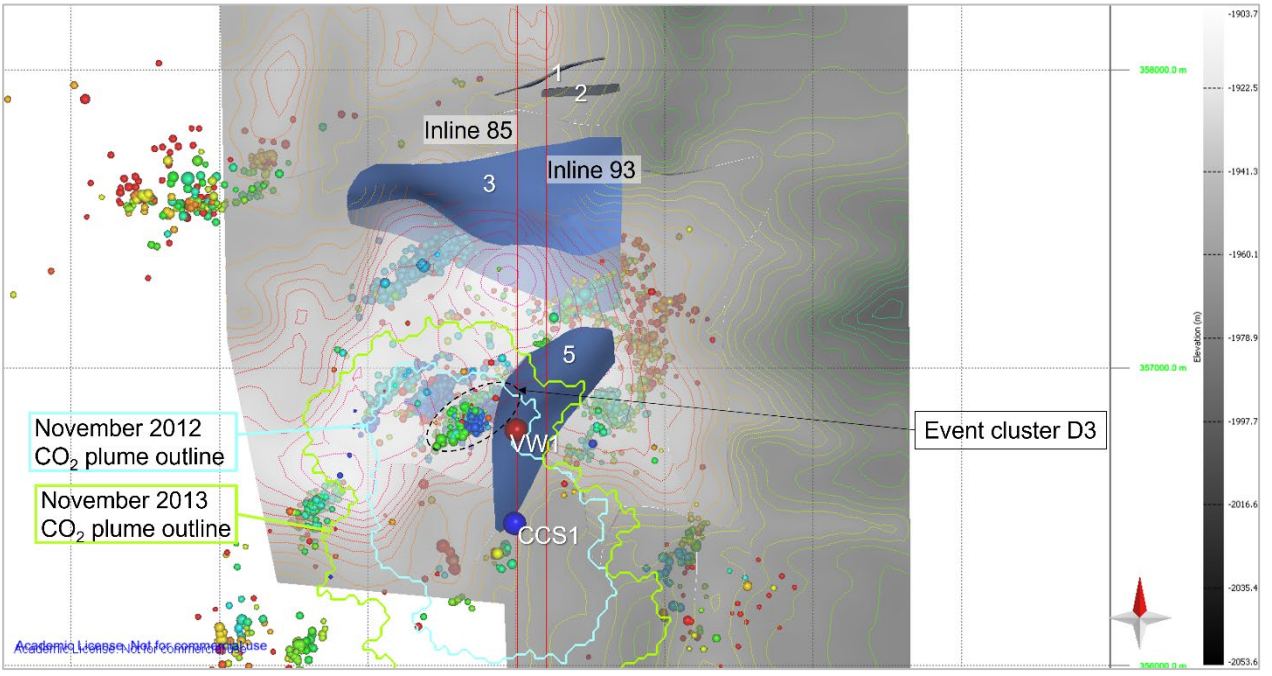


Figure 3. Map view of top of Precambrian basement showing topography of the surface. Only the 5 low-uncertainty faults interpreted from the active seismic are shown; Fault 4 is obscured beneath Fault 3. The locations of the two seismic cross sections shown in Figure 2 are indicated by the red lines. Induced events are coloured by time. Cluster D3 is encircled by a dotted black line. Some events in cluster D3 are above the basement where the Argenta is very thin, indicating the potential for hydraulic communication between the Mt. Simon reservoir and the fractured crystalline basement. The plume outlines indicate the edge of CO_2 gas saturation of 0.02 as modelled in history-matched dynamic simulation.

Basin, 68° azimuth. However, the extent of the plume edge of CO_2 saturation extracted from dynamic simulation models indicates significant migration to the south of the injection well. The plume is modelled primarily within the Mt. Simon reservoir, and its extent in the basement is unknown because no pressure gauges were installed in the basement. Hydraulic connection of pressure with the basement rock was most likely through fractures in the Argenta, especially where it is very thin above the basement high. This basement high also corresponds to a high density of seismicity clusters.

Dichiarante et al [6] analysed the spatial-temporal relationships of the clustering of events at Decatur. This paper focuses on additional details of cluster D3 (Figure 3). The source mechanisms of events occurring in cluster D3 are consistent with the stress state but show variability that supports multiple independent planes of failure rather than one large failure plane with an undulating topography. The temporal spatial bursts identified by Dichiarante et al [6] and discussed in this work have orientations that appear to be intersecting each other, which may be more indicative of fracture clusters or fracture corridors given the size of the event slip patches. Figure 4 shows coarse details of cluster D3 coloured by time from September 2012 to September 2013, where the colour groups indicate temporal development of subclusters in at least 4 different time periods. By separating smaller-period bursts and creating best fit planes to represent their orientation, 15 event subclusters were identified in cluster D3. The orientation of these subclusters is shown in Figure 4 (panel D) with their relationship to the Mohr-Coulomb failure criterion. The best fit planes derived by this method show good agreement with the burst plane orientations reported by [6]. The orientations of the interpreted failure planes are not parallel to the highest shear failure and should not fail as new fractures according to laboratory-derived values for the Argenta and Precambrian basement [11], supporting reactivation of mechanically weak existing fractures.

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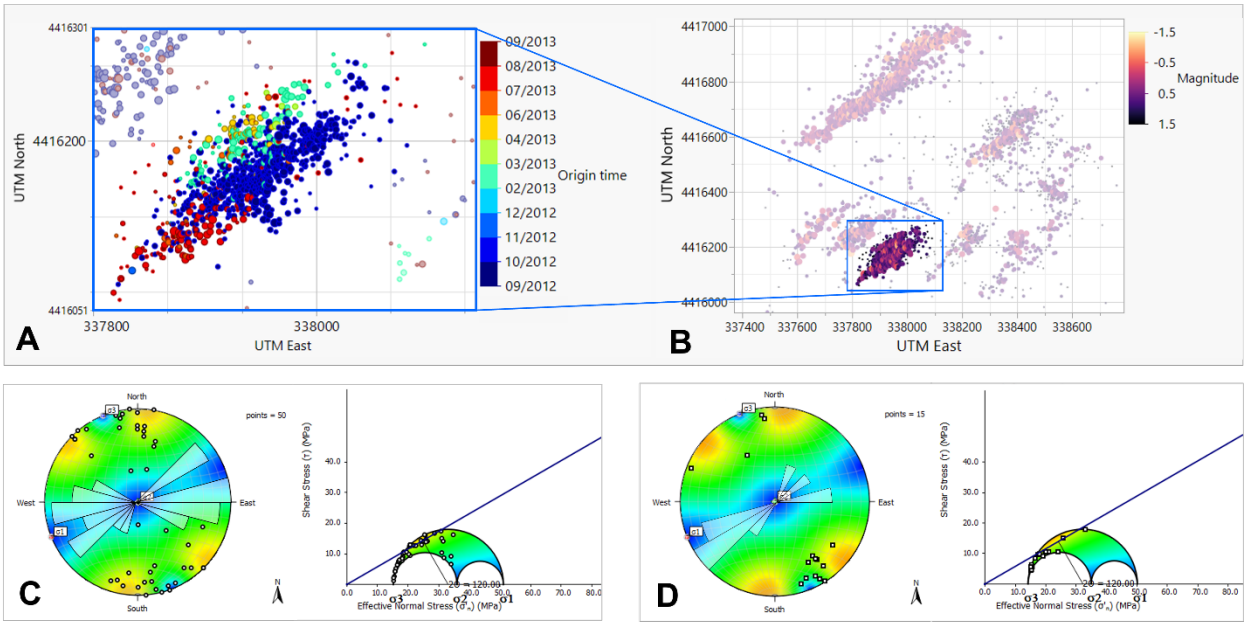


Figure 4. (A) Cluster D3 coloured by time to show temporal bursts that developed over one year. (B) Location of cluster D3 relative to the other subclusters in Region D (see Dichiarante et al. (2021) *for more details) and Region G. Most events in these regions formed prior to the first 18 months of injection at the Decatur site. (C) orientations of 50 source mechanisms chosen from the event catalogue, relative to the stress state and failure criteria. (D) Best fit planes of the 15 subclusters identified from short time-window bursts in cluster D3 relative to the stress state and failure criteria. Stress state shown for (C) and (D) is -2200 m depth.*

Figure 5 shows the timing of the bursts that define the 15 subclusters the developed in cluster D3, where the 3 to 4 burst development episodes are indicated by the intense clustering of events over relatively short time periods of a few days with additional clustering of event bursts lasting a few hours or less.

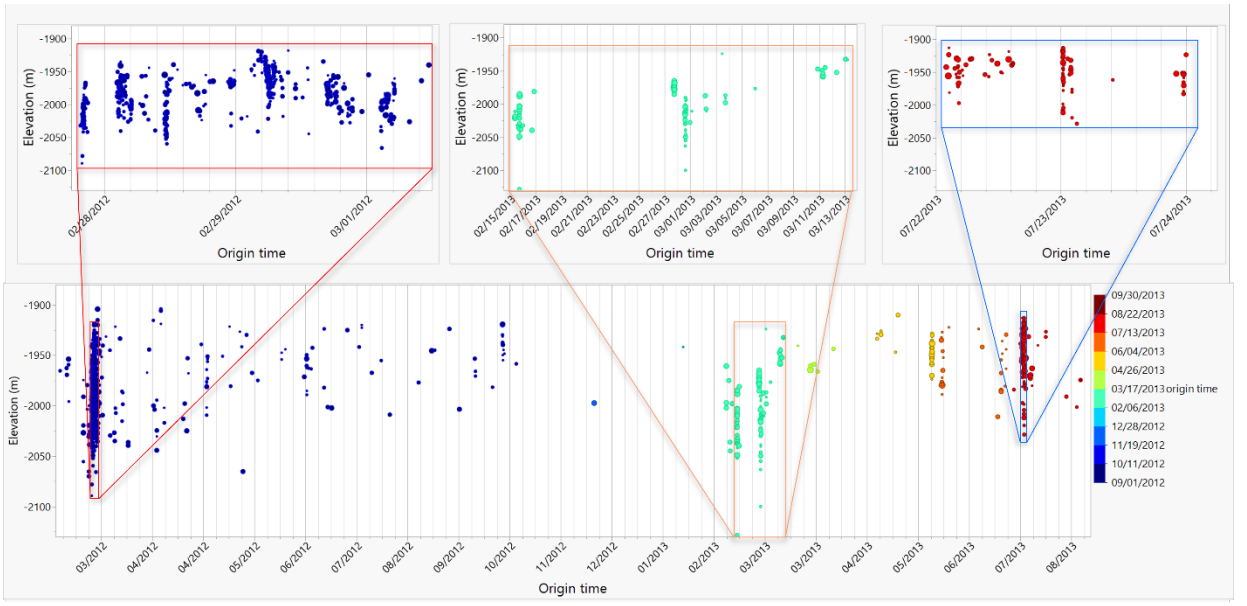


Figure 5. Timing of event bursts in cluster D3, expanded to show timing of the 15 subclusters bursts fit to fracture planes.

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3. Structural influences from the basement

The Illinois Basin is surrounded by several physiographic provinces where structural development could have impacted smaller scale features in the Basin like those interpreted at the IBDP site. The map in Figure 1 shows trends of structural features that are largely identified as gentle synclines and anticlines in central and northern Illinois, but interpretations of newer reflection seismic support the existence of faulting in the Precambrian basement beneath many of these structures that has been active at different times during the Phanerozoic, leading to a subtle structural overprint in the sedimentary overburden. Although the top of the basement is easily identified in seismic reflection profiles throughout the basement, the horizon lacks large vertical displacements possibly due to the depositional hiatus of more than 600 MY between the Grenville Orogeny and deposition of the Middle Cambrian sediments [12]. Large vertical displacements in the basement rocks in the Decatur area may also not be present. [13] interpreted the strong reflector at around 3000 m depth in the Decatur area as a bowl-shaped sill. Small disturbances in the reflector can be seen in some slices of the 3D seismic but without larger displacements that could be interpreted as faults, and the authors suggest that these structures indicate fractured zones. Semblance processing of depth slices through the 3D reflection seismic support these possible fracture corridors, showing discontinuities that trend very close to the average strike of the D3 subcluster trends and the source mechanism for the Decatur dataset [14].

4. Interpretation

The largest induced seismicity cluster developed prior to installation of a local array of 13 seismometers. Such a network is needed for reliable source mechanism inversions, but we were able to determine failure planes from 87 events detected after installation of the seismometer array. These indicate strike-slip along planes that are sub-parallel to parallel with the subcluster burst trends in the largest event cluster. For example, [15] analyzed data from the Hayward Fault in California, which has a mapped surface of about 100 km, but the total areas of slip patch for an earthquake of magnitude between 6 and 7 comprises half or less of the total fault area. Analysis of source mechanisms of seismicity along the Hayward Fault from 1967 to 1998 shows a significantly wide variation of both failure plane strike and slip sense for events that are nearly purely strike-slip to nearly pure reverse-slip failure [16]. In addition, the double-difference relocation distribution of events around the Hayward fault suggests failure of fault splays that intersect the main fault trace, similar to what is observed in some of the Decatur induced seismicity.

The poor spatial correlation of the microseismic cluster trends with the faults interpreted in the reflection seismic is only partly explained by the data resolution of the active seismic. The orientations of the faults in the Mt. Simon reservoir and in the Precambrian basement are not only poorly correlated by location but also by orientations, revealing a more complex structural history in the Central Illinois Basin than is indicated by the lack of large faults in this area. The temporal evolution of tectonic stresses indicated by the much more complex structure in the Southern Illinois Basin could be used to derive the timing of faults and fractures in the subsurface and build a conceptual history that explains the more subtle features in the Decatur area. Interpreting these structures in the central part of the Illinois Basin is problematic for the reasons identified above; where active seismic imaging is available, vertical displacement of faults can be too small to confidently identify them combined with the low impedance contrast between layers of igneous rocks.

5. Summary and conclusions

Fault and fracture development in the Precambrian basement likely developed prior to deposition of the overlying clastic rocks, during at least two different tectonic regimes, an extensional regime that formed E-W oriented grabens followed by a compression phase during which NW-SE strike-slip and transpressional deformation occurred. The structural trends present in the reservoir could be mostly disconnected from those in the basement due to the estimated more than 600 MY depositional hiatus prior to deposition of Cambrian sediments. Large scale faulting associated with major graben structures that were contemporaneous with clastic deposition, created structures that could be later reactivated as reverse or strike-slip faults as the stress tensor azimuth changed direction over time. The current maximum horizontal stress azimuth, ~68°, is optimal for slip on steeply dipping planes that strike east-west; the same orientation of many of the faults interpreted from seismic. The NE-SW striking seismicity trends, however, also show

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a connection to the basement deformation trends with their E-W trending temporal bursts and E-W source mechanism failure planes. This is particularly evident in the case where E-W faults interpreted in the seismic at the reservoir level cut across the microseismicity cluster at the same location and orientation as a temporal burst of events.

The source mechanism failure planes, the temporally distributed event clusters, and the best fit planes to the burst subclusters are not oriented parallel to the maximum resolved shear stress relative to S_{Hmax} in this area of the Illinois Basin. Nearly all the failure planes have a much smaller angle (12°) with respect to the maximum stress than Mohr-Coulomb failure criteria predicts. This smaller angle is evidence of reactivation of weak fractures. Rock mechanics experiments show that the friction angle of the basement grano-rhyolite with cohesionless fractures is 42° and would require an increase in pore pressure of 17 MPa to reach failure [17]. Combining the observed structural geology considerations like the ones in this paper and in Dichiarante et al [6] that suggest weak fractured rock when experimental parameters measure much stronger rock, indicates that additional factors are important for determining the rock response to CO_2 injection. Chemical interactions of fractured rock with CO_2 may have significant impact on failure [18]. Fully understanding which parameters are controlling failure and how they may change reservoir and basement response is critical to accurately assessing the risk of induced seismicity for geological carbon sequestration.

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A portrait of wellbore leakage in northeastern British Columbia, Canada

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Oil and gas well leakage is of public concern primarily due to the perceived risks of aquifer contamination and greenhouse gas (GHG) emissions. This study examined well leakage data from the British Columbia Oil and Gas Commission (BC OGC) to identify leakage pathways and initially quantify incident rates of leakage and GHG emissions from leaking wells. Three types of leakage are distinguished: "surface casing vent flow" (SCVF), "outside the surface casing leakage" (OSCL), and "cap leakage" (CL). In British Columbia (BC), the majority of reported incidents involve SCVF of gases, which does not pose a risk of aquifer contamination but does contribute to GHG emissions. Reported liquid leakage of brines and hydrocarbons is rarer. OSCL and CL of gas are more serious problems due to the risk of long-term leakage from abandoned wells; some were reported to be leaking gas several decades after they were permanently abandoned. According to the requirements of provincial regulation, 21,525 have been tested for leakage. In total, 2,329 wells in BC have had reported leakage during the lifetime of the well. This represents 10.8% of all wells in the assumed test population. However, it seems likely that wells drilled and/or abandoned before 2010 have unreported leakage. In BC, the total GHG emission from gas SCVF is estimated to reach about 75,000 t/y based on the existing inventory calculation; however, this number is likely higher due to underreporting.

shale gas | wellbore leakage | British Columbia | greenhouse gas emissions

All modern oil and gas wells are constructed in a drilled hole ("wellbore"), which may be vertical, deviated, or horizontal. The wellbore typically traverses numerous geologic layers variously containing brines and hydrocarbons. Pipe(s) ("casing") and surrounding sealants (typically Portland cement) are placed in the wellbore to maintain its stability, to protect against collapse and squeezing, and to prevent the movement of fluids between geologic layers. The resulting structure, including the wellbore, constitutes an oil and gas well. The inside of the well is hydraulically connected to the geologic layer targeted for fluid production or injection via holes through the casing. Well design thus allows fluids to be produced (hydrocarbons) or injected (waste disposal or fracking for instance) into the well at depth while preventing contamination of potable water sources close to the surface (1, 2).

In this study, the term "contaminants" refers to any substance located underground that may contaminate surface water, land, or air. This includes natural contaminants, such as gas, oil, and brines, as well as manmade contaminants (injected fluids). An inadvertent hydraulic connection between geologically isolated zones may be established along the well due to deficiencies in its design or construction and loss of integrity over time (2–7). This phenomenon is referred to as wellbore leakage. Wellbore leakage can occur along actively producing wells or wells that have been permanently abandoned after their productive life is over. There are 3 main consequences of wellbore leakage on the environment and public safety (1): 1) contamination of aquifers and surface waters from gases, brines, liquid hydrocarbons, and hydraulic fracturing fluids; 2) contribution to greenhouse gas (GHG) emissions, especially from venting methane; and 3) explosion of methane accumulated in poorly ventilated areas. Additionally, venting gases sometimes contain hydrogen sulfide gas, which is poisonous and deadly at high concentrations (8). Wellbore leakage incidents can be either chronic, occurring slowly over long periods, or acute, in which large volumes of fluids are released over a short period of time. An example of the latter case is an uncontrolled flow of fluids from a well that occurs at a rate that results in the immediate commencement of remedial action. Note that, for the purpose of this study, leakage will only refer to chronic leakage.

Oil and gas well integrity and wellbore leakage are not new issues to industry (3), but the shale gas sector has recently undergone significant growth made possible through the unconventional technique of horizontal drilling coupled with multistage slick water hydraulic fracturing. In consequence, increased attention and scrutiny have been brought to the issue of wellbore leakage.

Northeastern British Columbia (BC) has been a center of extensive conventional oil and gas production since the 1960s. The region also contains 4 shale gas basins that are increasingly being exploited (Fig. 1). Since 1995, well operators have been required to test for leakage prior to well abandonment (9). Additionally, since 2010, the Oil and Production Regulation of the province's Oil and Gas Activities Act has required operators to test for leakage after drilling, after recompletion, and during routine maintenance.

Significance

The possibility of leakage from oil and gas wells has raised environmental concerns. There are 2 major environmental consequences of wellbore leakage: 1) the risk of groundwater contamination from hydrocarbons and brines and 2) the risk of greenhouse gas (GHG) emissions. In this study, oil and gas wellbore leakage data from British Columbia (BC) were analyzed in order to quantify the occurrence and pathways of leakage as well as the contribution to GHG emissions. The key results summarize as follows. 1) In total, 2,329 wells in BC (of 21,525 that have been tested for leakage) have had reported leakage during the lifetime of the well. 2) In total, GHG emissions are estimated to reach about 75,000 metric t/y. The study also underlines that the values of leaky wells are likely underreported.

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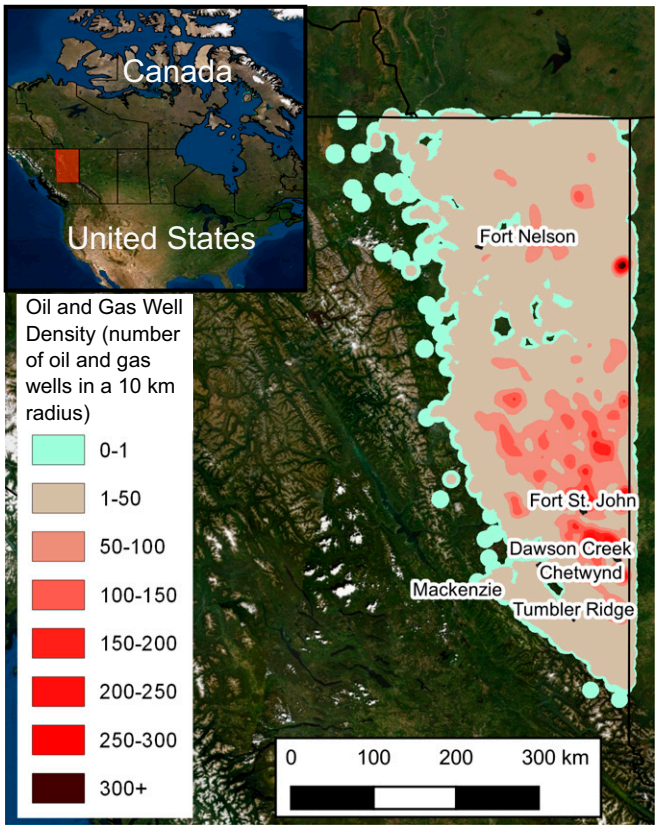


Fig. 1. Distribution of oil and gas wells and shale gas basins in northeastern BC.

To date, no study has attempted to establish wellbore leakage statistics for the entire region of northeastern BC. The goal of this study is to provide a first-glance portrait of wellbore leakage statistics in BC with the following objectives: 1) determine the percentage of leaky wells in BC classified by fluid type and environmental risk, 2) characterize and quantify well integrity issues and leakage pathways, 3) investigate the influence of well age on the frequency of reported leakage, and 4) quantify the contribution of wellbore leakage to GHG emissions.

Materials and Methods

Classification of Wellbore Leakage Types. The classification of wellbore leakage types is based on the requirements of oil and gas well construction in BC. These requirements are dictated by the province's Oil and Gas Activities Act and enforced by the provincial regulator of the oil and gas industry, the British Columbia Oil and Gas Commission (BC OGC). Although this study focuses on BC, it should be noted that drilling and completion operations are relatively similar for all modern oil and gas wells (1, 2).

The aim of oil and gas well design is to maintain wellbore stability and to prevent hydraulic communication between geologically isolated zones that are intercepted by the wellbore. This helps to protect shallow aquifers that could be contaminated by deep subsurface fluids. The standard design consists of an outer surface casing that is set and cemented in place below the depth of usable groundwater. Inside the surface casing lies the production casing, which conveys production or injection fluids between the target formation and the wellhead (Fig. 2). The production casing may be fully or partially cemented in place and is equipped with an additional replaceable inner production tubing. The wellhead includes a surface casing vent that allows any fluids entering the annular space between the surface and inner casings to vent at the surface rather than build up in or along the well. This type of leakage is referred to as a surface casing vent flow (SCVF) and is one of the possible exit points along a well for leakage of either gas or liquid (Fig. 2). Gases exiting the vent will enter into the atmosphere rather than entering into and possibly contaminating surrounding soils or groundwater. These gases are primarily composed of methane and contribute to atmospheric GHG emissions (1, 2, 10). Vented liquids, such as brines and liquid hydrocarbons, can spread at the surface and infiltrate the soil and the groundwater table below. When gases or fluids leak outside of the outermost surface casing, the contaminants may come into contact with aquifers. In the oil and gas industry, gas leaking around a well is commonly referred to as gas migration; however, the industry has no designated term for leakage of liquids around the casing. In this study, we designate all leakage occurring outside of the outermost surface casing, whether it be gaseous or liquid, as outside the surface casing leakage (OSCL). OSCL represents one of the possible exit points for wellbore leakage. Like SCVF of gas, OSCL of gas is considered a possible source of GHG emissions (11).

Wells are abandoned after their operating life comes to an end. The standard method of well decommissioning involves plugging the well, removing the wellhead, and then, cutting, capping, and burying the casing at least 1 m below the surface (Fig. 3). All perforated intervals of the well and all exposed porous geological zones of the well must be covered or isolated. This includes covering open-hole sections of porous zones and setting a cement retainer within 15 m above perforated zones. Additionally, sections of wells with uncemented liner must be cement squeezed in order to isolate porous zones. It should be noted that, in the past, abandonment procedures may have been less stringent. A more detailed explanation of abandonment procedures can be found in Directive 20 of the Alberta Energy Regulator, which also serves as the procedure for well abandonment in BC.

The wellhead assembly is replaced by a vented cap covering the production and surface casings. Any leakage that would manifest itself as SCVF on an active well will, in a decommissioned well, leak instead from the vented cap into the overlying soil rather than venting directly into the atmosphere. Similarly, fluids can leak out of the inner production casing through the vented cap and into the soil. In this study, we identify leakage through the vented cap of abandoned wells as a possible exit pathway for leakage. This exit pathway is referred to as cap leakage (CL). Depending on the depth of the buried vented cap relative to the groundwater table, CL could represent a source of groundwater contamination. Similar to active wells, abandoned wells can also emit OSCL. In general, we consider any leakage from an abandoned well as a possible source of groundwater contamination. Additionally, we consider any gas leaking from an abandoned well as a possible source of GHG emissions.

Wells that are no longer in operation but that have not yet been abandoned are considered suspended (or shut in). Suspended wells are similar to active wells in that their wellhead and vent remain in place; in other words, they are still intact. For this reason, suspended and active wells are considered a single well type; in this study, for reasons of brevity, they are referred to simply as active wells.

Occurrences of wellbore leakage in this study are described according to "entry" and "exit" pathways for active and abandoned wells as shown in Figs. 2 and 3, respectively. Entry refers to underground contaminants entering into the well. We have identified 7 possible entry pathways of contaminants along the well (Figs. 2 and 3).

1) Target formation that the well is drilled to exploit (either along or below the cement of the production casing)
2) Cemented intermediate formations above the target formation
3) Uncemented intermediate formations
4) Cemented shallow formations above the surface casing shoe
5) Production casing failure (this allows production fluids to enter directly into the outer surface casing)
6) Wellhead seal failure (these are integrity problems occurring at the wellhead and therefore, applicable only to active wells but not to abandoned wells)
7) Plug failure in abandoned wells

Exit pathways refer to the flow of fluids from the well outward to the environment into the atmosphere, shallow aquifers, surface waters, or soil. There are 3 exit pathways for contaminants: SCVF, OSCL, and CL. In all 3 cases, leakage can be either liquid leakage (brines and/or hydrocarbons) or gas leakage (principally methane).

Data Sources. All data analyzed in this study were extracted from databases maintained by the BC OGC. The BC OGC is the provincial regulator of the oil and gas industry; its data are publicly available on request. The BC OGC designates each well in the province by a unique Well Authorization Number (WAN), which can be used to search for data on that specific well among the 3 databases accessed for this study: Wellbore Leakage Database (*SI Appendix* and Datasets S1 and S2), Integrated Resource Information System (IRIS), and E-library.

Since 1995, oil and gas operators in BC have been required to submit to the BC OGC the results of all well tests that are positive for leakage. The BC OGC

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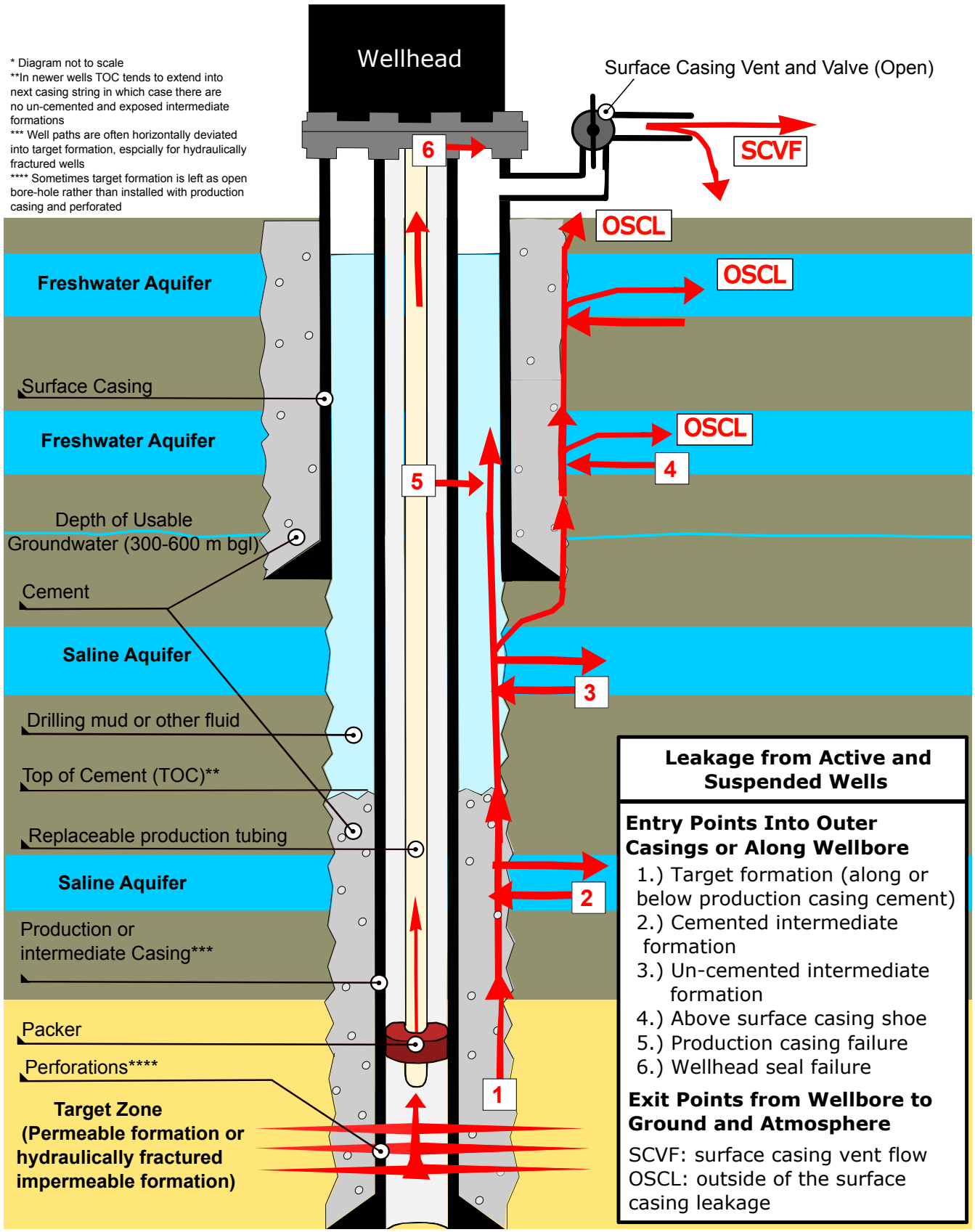


Fig. 2. Schematic of an active well with leakage pathways classified according to entry and exit points along the wellbore. Figure is not to scale.

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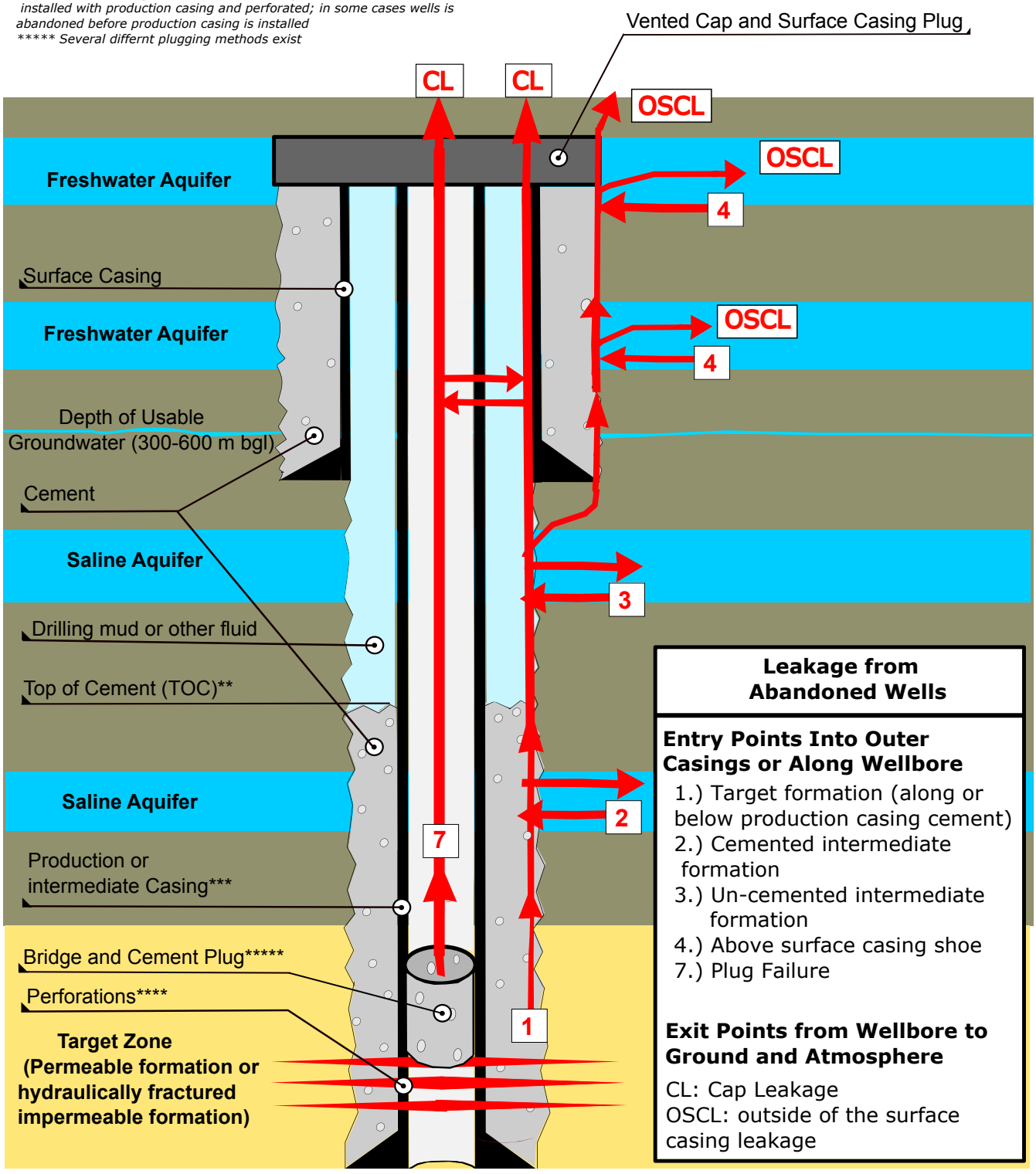


Fig. 3. Schematic of an abandoned well and leakage pathways classified according to entry and exit points along the wellbore. Figure is not to scale.

collects and summarizes the results of leakage testing in the Wellbore Leakage Database (which includes SCVF, OSCL, and CL). An extract of the Wellbore Leakage Database is shown in Table 1. It contains a column labeled "Flow type" to identify the type of fluid found to be leaking from the well: gas, hydrocarbon (hydrocarbon refers to liquid hydrocarbons), brines, or freshwater. The flow rate column corresponds uniquely to SCVF. The table

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Table 1. Sample data extracted from the Wellbore Leakage Database

WAN	Analysis date	Flow type	SCVF flow rate (m^3/d)	Gas migration
168	1 March 2012	Gas	9.5	
1220	7 February 2012	Salt water		
2183	12 June 2016			No
2249	23 September 2013	Gas	0	
2249	26 October 2016	Salt water		No
2283	7 July 2016			Yes
2287	30 March 2014	Gas	0.2	Yes
6136	13 November 2000	Hydrocarbon	22	Yes

also contains a separate column for the reporting of gas migration; in the industry, gas migration represents any leakage of gas that is detected in the soil around the well rather than issuing from the surface casing vent (SCVF). In the case of active wells, gas migration necessarily equates to OSCL; however, for abandoned wells, gas migration could be either OSCL or CL. Regarding liquid leakage, the database does not include a separate column corresponding to OSCL. In order to verify the exit points for all cases of liquid leakage or for abandoned wells with gas leakage, it was necessary to delve further into the database documents, most notably the completion workover reports of these wells available in the E-library database. Entries that had no reported fluid types were considered negative test results and therefore, were not considered to be leaking.

The completion workover reports analyzed in the E-library describe the remedial actions that were taken while reentering the well in order to repair the leakage. Analysis of the completion workover reports allowed us to determine the entry and exit points of leakage based on observations and the remedial steps that were taken to address the issue. One workover method for repairing leaking wells is to squeeze cement; this consists of perforating the leaky interval and injecting it with cement. These leaky intervals could have deficient cementing or be lacking cement altogether. We investigated the completion workover reports from a representative sample of leakage pathways for all active wells.

Lastly, an array of data on well location, construction, completion, production, and abandonment can be found in the BC OGC's IRIS. This study investigates all available data in the IRIS until the end of 2017.

The raw data from the Wellbore Leakage Database are presented in Dataset S1, whereas Dataset S2 presents the results and integration of all of the available datasets listed by WAN.

Results and Discussion

Wellbore Leakage Incident Rates. By the end of 2017 in BC, 25,119 wells had been drilled; 3,594 were drilled and abandoned before 1995 (Fig. 4). There are 2,322 cases of reported leakage from active wells and 7 reported instances from abandoned wells (Datasets S1 and S2). As previously stated, reporting of wellbore leakage in BC only goes as far back as 1995 (Fig. 4). This corresponds to the beginning of the database as well as the year that operators in BC were first required to test for SCVF leakage prior to abandonment. An increase in reported instances occurred in the late 2000s, potentially due to increased drilling activity and self-reporting from industry. This increase in reported leakage continued after 2010, the year of new regulations requiring leakage testing after drilling and during routine maintenance; 2010 is also the year that operators were

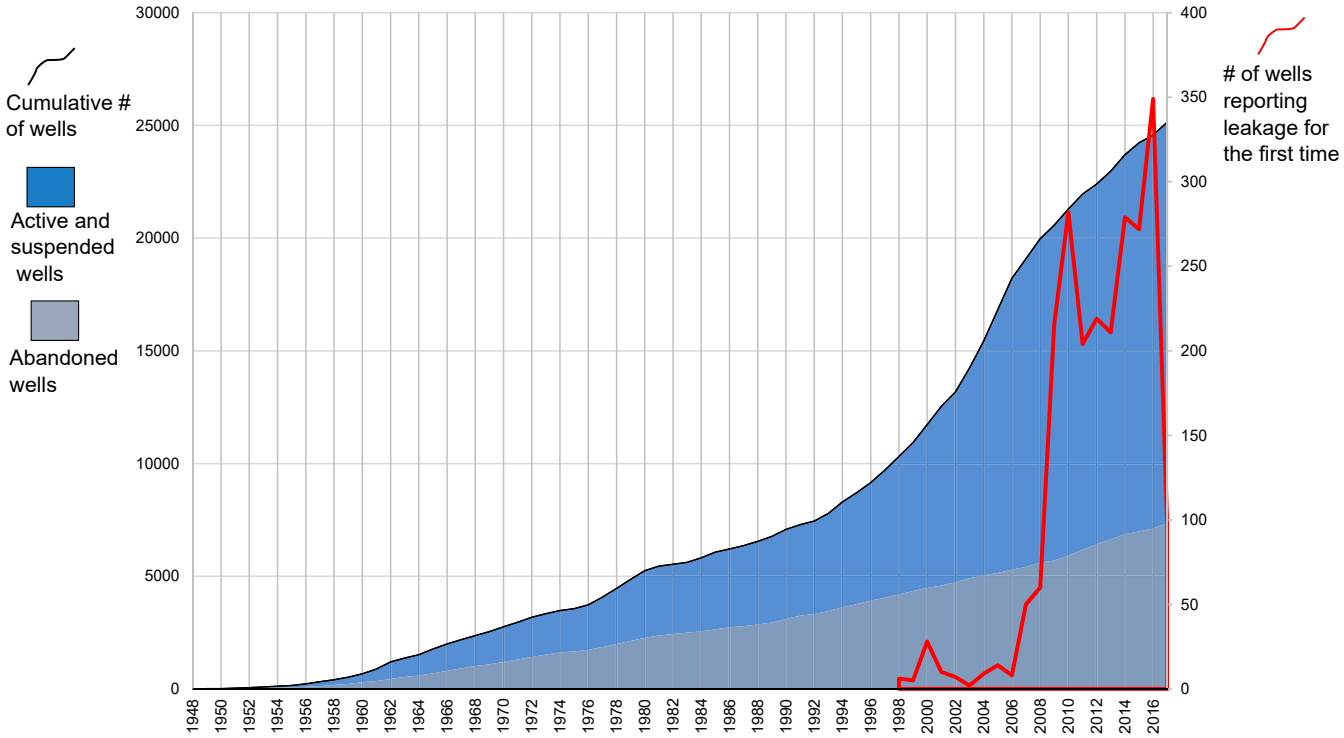


Fig. 4. Cumulative number of wells and number of reported leaky wells per year. The sharp increase in 2010 of the number of wells reporting leakage corresponds to stricter testing and reporting requirements.

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first required to report OSCL of gas. However, testing for OSCL of gas in BC is only required when there are visible signs, such as dead vegetation or bubbling in water around the wellhead (12). For abandoned wells, there is currently no requirement for leakage testing.

Leakage testing is generally self-reported by industry, and reporting is only required for positive test results. If we consider all wells in BC except those abandoned before 1995, the year when leakage reporting began in the province, this represents a total test population of 21,525 wells. The 2,322 reported cases of active wells with leakage, therefore, represent a leakage incident rate of 10.8%. This figure is more than 2 times higher than the leakage occurrence rate of 4.6% determined by other researchers for wells in the neighboring province of Alberta (4). These researchers also point out that their number could be influenced by less stringent testing and reporting requirements in the past. According to these authors, it is plausible that many wells in Alberta abandoned before 1995 could present unreported or undiscovered leakage (4), similar to what is observed in BC. In Alberta as in BC, leakage is self-reported by industry (4). For Alberta, however, it is unclear if the self-reporting by industry necessarily includes the submission of negative test results or if it is limited only to the submission of data for wells testing positive for leakage, as is the case in BC. This is an important point given that a comparison study between the leakage database in BC and the results of a field campaign have shown that approximately half of wells with detected leakage do not appear in the database (10, 13). This suggests that the true percentage of leaky wellbores in BC could be much higher than the 10.8% calculated from the theoretical test population. We will see in a subsequent section of this article that the rate of reported leakage could also be a function of the timing and frequency of testing, which are linked to drilling and abandonment dates.

Tables 2 and 3 summarize the wellbore leakage statistics for all active and abandoned wells in BC according to leakage fluid types and exit pathways, respectively. The majority of these leakage incidents (90.7%) involve SCVF of gas, which does not pose a risk of aquifer contamination but which does contribute to GHG emissions. OSCL of gas is rarer and is usually accompanied by SCVF of gas; 5.4% of cases involve a combination of SCVF and OSCL of gas, whereas ~0.5% involve only reported OSCL of gas.

Liquid leakage in active wells is rarer and is commonly accompanied by gas leakage. In total, 3.42% of leakage instances involve liquid leakage or a combination of gas and liquid, mostly in the form of SCVF (3.2%). Only 6 instances involving OCSL of liquid were discovered (including a combination of OSCL and SCVF as well as liquid and gas), representing 0.22% of active well leakage. The lesser number of instances of liquid leakage that are reported could be explained by the fact that liquid leakage is less likely to reach the surface where it can be detected. Indeed, liquid leakage requires a certain degree of hydraulic head in order to reach the surface; furthermore, liquid leaking along a wellbore will have a tendency to flow into a transmissive interval along the wellbore.

Table 2. Number and percentage of reported incidents by fluid types and exit pathways for active oil and gas wells in BC

	SCVF only, %	SCVF and OSCL, %	OSCL only, %	Total, %
Gas	90.7 (2,105)	5.4 (126)	0.5 (12)	96.6 (2,243)
Gas and liquid	1.3 (30)	0.1 (3)	0.04 (1)	1.5 (34)
Liquid	1.9 (43)	0.04 (1)	0.04 (1)	1.9 (45)
Total	93.8 (2,178)	5.6 (130)	0.6 (14)	100.0 (2,322)

Table 3. Number and percentage of reported incidents by fluid types and exit pathways for abandoned oil and gas wells in BC

	CL only, %	CL and OSCL, %	OSCL only, %	Total, %
Gas	57.1 (4)	42.9 (3)	0.0 (0)	100.0 (7)
Gas and liquid	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)
Liquid	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)
Total	57.1 (4)	42.9 (3)	0.0 (0)	100.0 (7)

Reported leakage of abandoned wells is rarer than that for active wells. At the end of 2017, there were 7,268 abandoned wells in BC. Of these, only 7 or 0.1% reported leakage after their abandonment date in the form of CL or OSCL of gas (Tables 3 and 4). No liquid leakage from abandoned wells was reported. It is difficult to determine if this low rate of leakage occurrence for abandoned wells is due to the fact that they actually leak less or that leakage from abandoned wells is simply less frequently discovered and reported. Although current regulations stipulate that all incidences of leakage must be repaired prior to well abandonment, there is no program in place in Canada for monitoring wellbore leakage in wells after permanently buried and abandoned (1). It is unclear why and how the 7 abandoned wells under investigation in this study were identified to be leaking. Furthermore, it is important to note that the majority (4 wells) of these 7 wells were abandoned after 1995, when leakage testing prior to abandonment became mandatory (Table 4). Therefore, either the leakage in these 4 wells was not properly identified and repaired prior to abandonment, or leakage developed along the well later after abandonment.

Several field investigations conducted in other study zones outside of BC indicate much higher incident rates of abandoned well leakage than those estimated in this study (6, 7, 14, 15). In general, field investigations tend to find that plugged abandoned wells, such as those in BC, leak far less than unplugged abandoned wells (7, 14). Still, the percentage of abandoned and plugged wells with detectable positive methane flow rates ranges from 0.8 (14) to 69% (7), which correspond to 8 and 700 times, respectively, the incident rate of 0.1% calculated in this study. The incident rate of leakage from abandoned wells could be even higher when considering that field investigations measuring methane fluxes at the surface may be unable to detect leakage due to oxidation and dispersion of methane in the subsurface (15, 16). In general, it is difficult to quantitatively compare the results of our inventory study with direct field measurements, as the database does not provide any information on testing methodology and detection limits. However, it is likely that the true percentage of abandoned and leaking wells in BC is higher than our inventory estimates considering the results of these field investigations and considering the absence of a monitoring program in BC.

Wellbore Leakage Pathways. Two subanalyses were conducted based on a sample of 29 active well leakage incidents and 7 abandoned well leakage incidents extracted from the databases; the 29 incidents occurring in active wells were chosen based on availability of completion workover reports containing sufficient detail. The goal was to obtain a preliminary idea of the proportion distribution of the various pathways for well leakage (i.e., how frequently one leakage pathway occurs vs. another). The percentage distributions of leakage incidents by type of pathway are shown in Table 5 for 29 active wells and in Table 6 for 7 abandoned wells.

Leakage Pathways in Active Wells. The completion workover reports of 29 active wells with leakage from the E-library were investigated. The most commonly reported entry pathway occurs through

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Table 4. Details of the 7 abandoned wells reporting leakage in BC

WAN	Reported initial abandonment date	Any leakage issues reported prior to abandonment?	Date of first reported leakage
2283	1968-03-07	No	2015-04-29
7858	1992-06-26	No	2009-07-10
8818	1996-01-14	No	2015-09-09
12307	2002-11-23	No	2016-12-08
2287	2005-02-24	No	2013-06-19
19071	2006-01-19	No	2013-10-10
5100	Unknown	No	2010-07-01

deficiencies in the production casing caused by corrosion or rupture of casing strings (44.8%). This typically resulted in SCVF; however, in 1 incident, leakage from deficiencies in the production casing exited in the form of OSCL. Chemical, electrochemical, and mechanical corrosion of steel casings in contact with highly saline and often acidic subsurface liquids is a common phenomenon (1). This corrosion can also occur in cemented sections of the wellbore, typically along, but not restricted to, zones of poor cement quality (4). These types of leaks were often detected by pressure testing of the production casing.

Leakage from uncemented intervals along the production casing occurred in 34.5% of the cases. Lack of cementing allows for intermediate subsurface fluids to enter unimpeded into the annular space. These always resulted in SCVF as an exit point. In these cases, leakage was repaired by squeeze cementing the unprotected intervals of the casing. Leakage due to the failure of wellhead seals accounted for 10.3% of reported incidents. In these cases, the leakage was remediated by replacing or repairing the wellhead.

Two cases of leakage originating above the surface casing shoe were reported (6.9% of reported incidents). In 1 of these 2 incidences, leakage was detected during drilling and completion operations before the production casing was installed (Well 2552). In the other incident, the surface casing was not completely cemented to the surface as required, which allowed freshwater from an aquifer located at a depth of 30 to 40 m to enter directly into the well's outer annulus (Well 22912).

Lastly, the type of pathway least frequently reported for leakage was through a production casing failure where the annulus was cemented. Only a single completion workover report among the 29 was found where SCVF was repaired by squeeze cementing an already cemented interval. Prior to remediation, this leakage exited the well in the form of SCVF.

Leakage Pathways in Abandoned Wells. Table 6 summarizes the observed leakage pathways for abandoned wells. As previously mentioned, all cases of abandoned well leakage involved gases rather than liquids. The majority of cases of abandoned well leakage originate from uncemented intervals below the surface casing (57.2%). The next most common entry points were cemented intervals below the surface casing (28.6%) and plug failure (14.3%). There were no reported cases of abandoned well leakage originating above the surface casing shoe. In all cases, leakage exited the well in the form of CL. In about half of these cases, leakage also exited the well in the form of OSCL in addition to CL.

Influence of Well Age on Leakage Occurrence

Table 7 shows the reported percentage and number of active well leakage occurrences as a function of age based on a matrix of drill and abandonment dates. An increase in well age can be noted by reading the table either vertically down or horizontally to the right along the matrix, where well age is calculated by subtracting the abandonment date by the drill date. Table 7 does not investigate the timing of first reported leakage, except for wells that were drilled and abandoned in the same date range, in which case we know that leakage occurred within the first 5 y of the well's existence. This table also shows the distribution of leakage occurrence by well age interpolated by drill date relative to the end of 2017 for nonabandoned wells. Nonabandoned wells are those wells that were active or suspended at the end of 2017 and that make up the majority of wells in the province (17,793 wells).

According to regulation, all wells in this table should have been tested for leakage at least once after drilling, during routine maintenance, during recompletion, or on abandonment. The requirement for testing after drilling and routine maintenance has been in effect since the beginning of 2010. As previously discussed, the leakage occurrence rate of the theoretical test population is, therefore, 10.8%; this percentage is calculated based on 2,322 wells with reported leakage of the 21,525 that were either abandoned after 1995 (3,732 wells) or are still active (17,793 wells). Note that this total of 2,322 does not include the 7 wells that were found to be leaking after abandonment, because Table 7 only deals with leakage detected on active wells.

If we consider only wells drilled after 2010, there is a relationship between well age and the reported incident rate of leakage reading in both the vertical and horizontal directions of the table. However, the relationship between well age and leakage occurrence is less clear in the remainder of the matrix (wells drilled before 2010). Instead, the occurrence of leakage seems more strongly correlated with regulatory changes implemented in 2010.

According to regulation, wells abandoned before 2010 were tested at least on abandonment; however, they were not necessarily tested during the lifetime of the well. Wells that were active or abandoned after 2010 have theoretically been tested during routine maintenance of the well, on recompletion of the well, and on abandonment where applicable. Wells drilled after 2010 were additionally tested after drilling. Table 7 reveals that there is a correlation between the leakage incident rates and the required frequency of testing according to regulation.

Table 5. Percentages and numbers of occurrences of leakage in different types of pathways for active wells as described in Fig. 2

Entry points	Exit points, %			
	SCVF only	SCVF and OSCL	OSCL only	Total
1. Target formation	0.0 (0)	0.0 (0)	0.0 (0)	0.0 (0)
2. Cemented intermediate formation	3.4 (1)	0.0 (0)	0.0 (0)	3.4 (1)
3. Uncemented intermediate formation	34.5 (10)	0.0 (0)	0.0 (0)	34.5 (10)
4. Above surface casing shoe	0.0 (0)	0.0 (0)	6.9 (2)	6.9 (2)
5. Production casing failure	41.4 (12)	3.4 (1)	0.0 (0)	44.8 (13)
6. Wellhead seal failure	10.3 (3)	0.0 (0)	0.0 (0)	10.3 (3)

Percentages are based on available reports from a sample of 29 studied wells.

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Table 6. Percentages and numbers of occurrence of leakage in different types of abandoned wells as described in Fig. 3

	Exit points, %			
Entry points	CL only	CL and OSCL	OSCL only	Total
1. Target formation	0.0 (0)	0.0 (0)	0.0 (0)	0 (0)
2. Cemented intermediate formation	14.3 (1)	14.3 (1)	0.0 (0)	28.6 (2)
3. Uncemented intermediate formation	42.9 (3)	14.3 (1)	0.0 (0)	57.2 (4)
4. Above surface casing shoe	0.0 (0)	0.0 (0)	0.0 (0)	0 (0)
7. Plug failure	0.0 (0)	14.3 (1)	0.0 (0)	14.3 (1)

Percentages are based on available reports from 7 studied wells.

The group of wells that report the least amount of leakage includes those abandoned prior to 2010 when routine testing and maintenance became mandatory. In general, Table 7 indicates that, regardless of drill date, wells abandoned before 2010 report less leakage than wells abandoned after 2010. This increase in reported leakage does not seem to be linked to well age, because the increase is only observed in a horizontal direction of the table.

Looking at wells that were abandoned after 2010 or never abandoned, there is no clear relationship between well age and leakage occurrence in either a horizontal or vertical sense, with the exception of wells drilled after 2010.

The group of wells that report the highest percentage of leakage includes those drilled after 2010, which are the newest wells in the province.

We feel that it should be questioned whether older wells have less leakage during their lifetime than newer and younger wells. The data seem to be strongly influenced by the different regulations making their appearance at different dates, casting doubt on the adequacy of well-testing practices and the accuracy of well-testing data for wells drilled before 2010.

Underreporting of wellbore leakage in BC is an issue that was raised in a previous study (13), which showed that approximately half of wells that tested positive for SCVF gas leakage did not appear in the BC OGC database; almost all of these wells that were missing from the leakage database were drilled before 2010.

Table 7 also suggests that wellbore leakage from wells abandoned before 2010 is underreported. This is supported by the observation that some wells have reported leakage after being abandoned, despite theoretically having been tested for leakage prior to their abandonment. All of the abandoned wells reporting leakage in Table 7 were abandoned prior to 2010. For all of these reasons, the true percentage of leaky wells is unknown but is likely higher than the 10.8% estimated in the total of this table. The figure of 10.8% should be considered a base minimum.

GHG Emissions

As mentioned, SCVF of gas is the most commonly reported type of leakage in the BC OGC database. Individual wells in the database often have multiple entries in the table listing gas leakage, referring to multiple testing events. In our calculations for this study, we used only the most recently reported value (and not an average of all of the reported rates for each well). Additionally, we have removed from our calculations all wells that have been remediated. We consider a well to be successfully remediated if the date of last remedial action postdates the last reported leakage.

The mean reported SCVF rate is 5.9 m^3/d; however, most vent flows are less than 1 m^3/d (Fig. 5). To provide some perspective, an average cow produces at least 0.25 m^3/d of methane (17). Therefore, the mean average leaky well in BC is equivalent to 24 head of cattle. An SCVF rate of 5.9 m^3/d and per well corresponds to a mass rate of 3.87 kg/d and per well or 1.4 t/y and per well for BC assuming that the exiting gas is composed entirely of methane and considering that the density of methane is 0.656 kg/m^3 (at standard conditions). This methane rate

Table 7. Percentage of intact wells reporting leakage in BC sorted by drill date and abandonment date

	Abandonment date						
	Intact wells tested on abandonment and found to be leaking, % (no. leaking/total)			Intact wells tested after drilling during routine maintenance and on abandonment and found to be leaking, % (no. leaking/total)			
Drill date	1995–1999	2000–2004	2005–2009	2010–2014	2015–2017	Not abandoned	Total
1945–1949	0.0 (0/1)						0.0 (0/1)
1950–1954	0.0 (0/1)	0.0 (0/4)	0.0 (0/3)	0.0 (0/2)		0.0 (0/17)	0.0 (0/27)
1955–1959	0.0 (0/11)	0.0 (0/3)	0.0 (0/13)	5.9 (1/17)	0.0 (0/4)	12.5 (18/144)	9.9 (19/192)
1960–1964	0.0 (0/20)	3.6 (1/28)	4.5 (1/22)	12.5 (5/40)	0.0 (0/4)	5.4 (26/480)	5.6 (33/594)
1965–1969	0.0 (0/25)	0.0 (0/13)	4.9 (2/41)	10.0 (6/60)	13.0 (3/23)	10.9 (35/322)	9.5 (46/484)
1970–1974	0.0 (0/26)	0.0 (0/28)	6.9 (2/29)	6.1 (2/33)	28.6 (6/21)	13.3 (35/264)	11.2 (45/401)
1975–1979	0.0 (0/29)	0.0 (0/33)	7.3 (4/55)	15.4 (14/91)	5.9 (1/17)	14.0 (74/529)	12.3 (93/754)
1980–1984	0.0 (0/34)	0.0 (0/21)	3.0 (1/33)	12.5 (6/48)	7.7 (1/13)	10.6 (40/378)	9.1 (48/527)
1985–1989	0.0 (0/22)	0.0 (0/19)	0.0 (0/25)	13.6 (6/44)	4.0 (1/25)	7.2 (34/469)	6.8 (41/604)
1990–1994	0.0 (0/47)	0.0 (0/39)	3.1 (1/32)	7.5 (7/93)	15.6 (5/32)	9.1 (77/848)	8.2 (90/1,091)
1995–1999	0.2 (1/505)	0.0 (0/96)	3.8 (3/79)	5.3 (11/208)	14.0 (6/43)	8.2 (139/1,697)	6.1 (160/2,628)
2000–2004		0.2 (1/411)	3.7 (5/135)	3.9 (12/307)	9.4 (13/139)	8.5 (300/3,526)	7.3 (331/4,518)
2005–2009			0.0 (0/197)	5.6 (11/195)	11.5 (16/139)	13.8 (637/4,600)	12.9 (664/5,131)
2010–2014				6.9 (2/29)	18.8 (3/16)	20.5 (633/3,083)	20.4 (638/3,128)
2015–2017					0.0 (0/9)	7.9 (114/1,436)	7.9 (114/1,445)
Total	0.1 (1/721)	0.3 (2/695)	2.9 (19/664)	7.1 (83/1,167)	11.3 (55/485)	12.2 (2,162/17,793)	10.8 (2,322/21,525)

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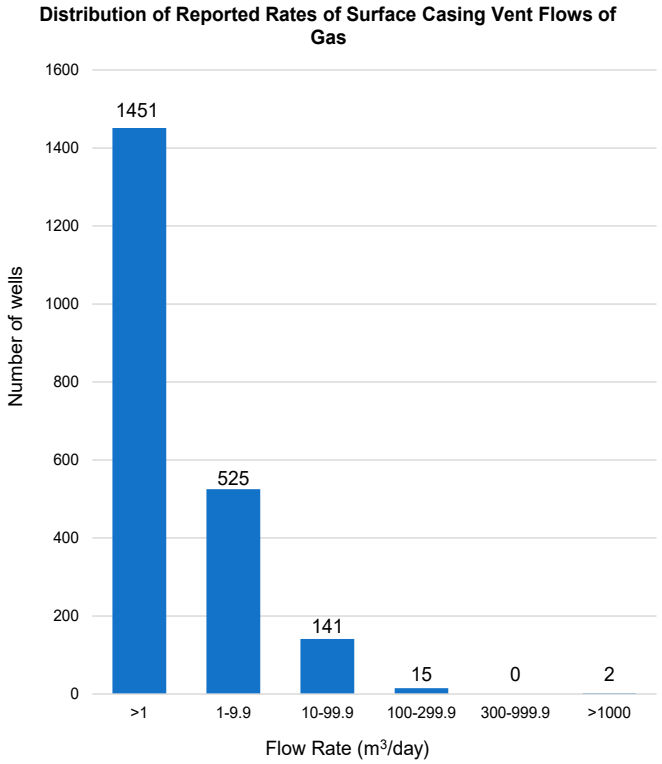


Fig. 5. Histogram of incidents of reported SCVF of gas in the Wellbore Leakage Database.

equates to 35 t of CO_2 equivalent per well and per year based on the Intergovernmental Panel on Climate Change's estimate of the global warming potential (GWP) of methane (18–21), which estimates that 1 kg of methane is equivalent to the GWP of 25 kg of carbon dioxide.

The BC OGC database records 2,134 wells with unremediated gas SCVF. Multiplying 2,134 wells by an average vent flow of 35 t of CO_2 equivalent per year and per well equates to a total GHG emission of 74,690 t of CO_2 equivalent per year emitted by wells with unremediated gas SCVF. This number can also be calculated by summing the total of all unremediated SCVFs.

In 2016, BC's provincial GHG inventory reported a total emission of 61,300,000 t of CO_2 equivalent per year for all human activity (19). Therefore, based on inventory calculations, emissions from SCVF account for 0.12% of the province's total GHG emissions. Considering that the per capita GHG emissions for Canada have been established at ~15 t of CO_2 per year, the GHG emission from wellbore leakage in BC is equivalent to that emitted by a Canadian town of 5,000 people. It should not be forgotten that these figures represent a base minimum, because as mentioned previously, the number of wells with SCVF is likely underreported. It should also be noted that wellbore leakage is not the only source of GHG emissions from upstream oil and gas activity; intentional release of gas from flaring and pneumatic devices also contributes significantly to total GHG emissions (10, 20).

Conclusions

A total of 2,329 oil and gas wells in northeastern BC have reported leakage. However, the actual number is likely higher due to underreporting.

Most reported leakage occurs in the form of gas SCVF, which does not pose a risk of aquifer contamination but does contribute to GHG emissions. Based on the data provided by the BC OGC, the total volume of GHG emissions from well leakage in BC is estimated to reach ~74,690 t/y CO_2 equivalent. This would make wellbore leakage a relatively minor contributor to the total GHG emissions in the province, keeping in mind that true emission rates and volumes could be higher due to underreporting of leakage. Reported liquid leakage of brines and hydrocarbons is rarer. In most cases, the risk would seem to be greatly reduced by fully cementing the production casing to the surface; however, full-length cementing increases the cost of constructing the well, and in some cases, the increased cement fluid pressure may decrease the quality of the cementing operation due to the lost circulation of cementing fluids during installation (21).

OSCL of gas from abandoned and active wells seems to be a more serious problem. Gas leakage is most readily identifiable when it manifests itself at the surface near the wellhead (2). However, gas leaking into aquifers could remain undetected. A recent 72-d methane gas injection experiment showed that, even if a significant portion of methane may vent to the atmosphere, an equal portion may remain in groundwater (22). Of particular concern is the risk of long-term development of leakage from wells that are cut and capped below the surface for permanent abandonment. For some wells, there have been reports of leaking gas several decades after they were permanently abandoned. Additionally, wells abandoned before 2010 report less leakage than those abandoned after 2010, which seems to indicate that existing leakage was either undetected or unreported prior to abandonment. In Canada, there is no requirement to monitor wells for leakage following their abandonment (2), despite the fact that gas leakage from abandoned wells in the province is a well-documented phenomenon (Table 5). It is possible and even probable that the number of abandoned wells leaking gas is much higher than the 7 documented cases mentioned in this study due to the number of untested abandoned wells. Unlike the field investigations conducted by other researchers (6, 7, 14, 15), there has been no field investigation carried out in BC directly monitoring leakage from abandoned wells. Further efforts should be dedicated to such monitoring of abandoned wells.

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A comprehensive review on the loss of wellbore integrity due to cement failure and available remedial methods

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ABSTRACT

With the recent abrupt fluctuations in oil pricing and the need of complying with environmental and social requirements, nowadays it is an urgent call for the oil and gas industry to produce the hydrocarbon without any loss as well as in a safe manner. Cements are placed in the annular space of casing to provide zonal isolation in between wellbore and surface during the operational life cycle of the well or even after the abandonment. But this is not what happens most of the time. Cement degrades or loses its integrity through debonding either from the casing or formation and generates cracks or fractures due to varied reasons throughout the life of the well.

Multiple causes contribute to the loss of wellbore integrity – either by physical, mechanical, or chemical processes. These failures lead to sustained casing pressure (SCP) and contamination of surrounding environment. To combat this issue or to restore the well integrity, multiple remedial actions have also been either implemented in the industry or proposed based on experimental research to prevent the damage or to seal the leakage in the cement sheath. This paper will provide an extensive review of the underlying reasons of cement failure and the available remedial actions to minimize the loss of well integrity issue. These information are not only useful to know about the different corrective options available for us to implement in industry but also it will provide us a knowledge base regarding how we can enhance the performance of the exiting systems to battle the cement integrity problem more efficiently.

1. Introduction

Cementing of oil and gas well is considered to be one of the most delicate jobs done during completion of the well. API Class G and H are the most widely used cement systems in this job. When cementing of a well is accomplished, it is expected that it would support the well and work as a barrier in between producing zone and surface or surrounding formations throughout its life and even after the abandonment. The safety of the working people in the field and safeguarding the environment are also considerably dependent on well integrity. But from spud-in to abandonment, a well experiences numerous events that can compromise the integrity of the well and thus result in loss of integrity via casing-cement or cement-formation debonding or by creation of cracks or fractures in the cement sheath. A de-bonded or fractured cement sheath permit the migration of formation fluid, which can reach the wellhead in the form of sustained casing pressure (SCP) or surface casing vent flow or can pollute the nearby strata and the water bearing formation. Additionally, loss of production, casing collapse, etc. are the other consequences that are caused by the annular flow. In such situations, the well needs to be shut-in, repaired or in worst-scenario case abandoned prior to the end of its productive life. Today, according to the US federal regulations, the wells having severe SCP problem need to be plugged and abandoned (Shadravan and Amani, 2015).

Researchers and experts have been working for decades to find the remedial action which would minimize the problem of well integrity loss. Many of their identified solutions have already been implemented in the industry. Some of which have been proved to be marginally successful whereas some failed to maintain the wellbore integrity in the long term. These applied solutions can be divided into two categories – pre and post remedial actions. Pre-remedial actions are the methods which have been applied before generation of any debonding or cracks e.g. proper cement design, expansive cement etc. Once the cement has failed to maintain its integrity during the operational phase of the well, post-remedial actions like cement squeezing, self-healing cement system, polymer gel, calcium carbonate precipitation, silica gel, etc. can be employed. Each of this solution has their own pros and cons in regard to their application and ability to offer assurance of long-term sealing capability that will be discussed in detail in the following sections of this

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paper.

2. Well integrity issues in countries

Loss of cement sheath integrity and thus having sustained casing pressure is a serious issue in the oil and gas industry. Although estimates of the number of leaking wells have fluctuated widely due to variation in reporting standards over time and from country to country. Events across the countries will buttress the notion that this is not a trifling issue anymore. It has been found that more than 50% wells which are 15 years old or older have at least one casing string with sustained casing pressure. On a survey conducted in Gulf of Mexico in 1991, it was found that nearly 11000 casing string of 8000 wells posed with SCP problem. Another report prepared by Minerals Management Service in 2004 where it was shown that around 33% SCP problem linked to cement leaking problem and the cost of removal was estimated at about $650 MM USD (Shadravan and Amani, 2015). Due to this problem, approximately 9000 wells in this region were either suspended or temporarily abandoned. (Frigaard and Pelipenko, 2003). In Western Canada, 142, 000 onshore wells were found with SCP problem and detailed reports of over 18,000 wells having surface casing vent flow that in some cases required them to be shut in and production halt (Watson and Bachu, 2009). Based on the field data about the shale gas wells in China, it was found that after hydraulic fracturing operation the percentage of wells with SCP was increased significantly from 23.01% to 55.80%, increased by 32.79%. And the percentage increase was 23.45% after one month and 6.13% after two months (Liu et al., 2018c). In 2006, it was determined that about 18% of wells on the Norwegian Continental Shelf and 34% of wells in North Sea, UK were suffering from well integrity issues (Shadravan and Amani, 2015). Looking back into the history, in the worst scenario cases some of the industry's largest blowout occurred due to the well integrity failure. For example, recently a blowout took place in a fracked natural gas well located in northwest Louisiana because of the wells' failure to maintain its integrity, the fire of which was in the air for months (Dermansky, 2019). Philips Petroleum's Bravo blowout in 1977, Saga Petroleum's blowout in 1989, PTT's Montara oil spill in 2009, and BP's deepwater horizon blowout in the Gulf of Mexico in 2010 – all these incidents happened just because of the inability of the wells to provide the required isolation between wellbore and surface and also people working there failed to identify the issue efficiently (Wilcox et al., 2016). From the statistics given above, we can perceive how severe the problem is for the industry and what consequences it may bring for us if the issue is not seriously taken care of.

3. Principal reasons of cement failure

A well loses its capability to provide expected integrity for various reasons among which debonding, and radial and longitudinal cracking are most common ones. The possible leakage pathways generated in wellbore casing-cement arrangement is depicted in Fig. 1. Casing mechanical failure like burst, collapse, or corrosion are the primary reasons for creation of leakage pathways (Fig. 1b) (Crow et al., 2010; Weideman and Nygaard, 2014). This is a common characteristic of Portland cement is that when sets, it tends to reduce its volume, and because of this reason debonding happens in the wellbore due to cement shrinkage either between cement-casing or cement-formation (Fig. 1a and e). Development of channels also contributes to the migration of gas through the cement (Fig. 1d). Radial and longitudinal crack generates due to fatigue loading or application of high pressure during stimulation operation like hydraulic fracturing or unwanted pressure-temperature changes during well lifecycle. Additionally, high casing internal pressure leading to casing expansion may also contribute to creation of cracks in the cement sheath (Fig. 1c) (Liu et al., 2018b; Goodwin and Crook, 1992). Figure 1f illustrates an annulus that was created due to inefficient cementing job where the entire annulus was not filled up with pumped cement. Poor bonding because of presence of mud cake is shown in Figure 1g. In specific geological conditions, if there is any reservoir compaction during production period, shear failure of formation and casing may take place which causes the hydrocarbon to flow through the created annular space (Fig. 1h). Below various significant causes of cement sheath failure, thus loss of well integrity will be discussed in details.

3.1. Poor cement design

One of the most critical completion jobs in petroleum industry is to design the well cement efficiently as multiple factors need to be considered during design period of it. Experts have recognized "poor

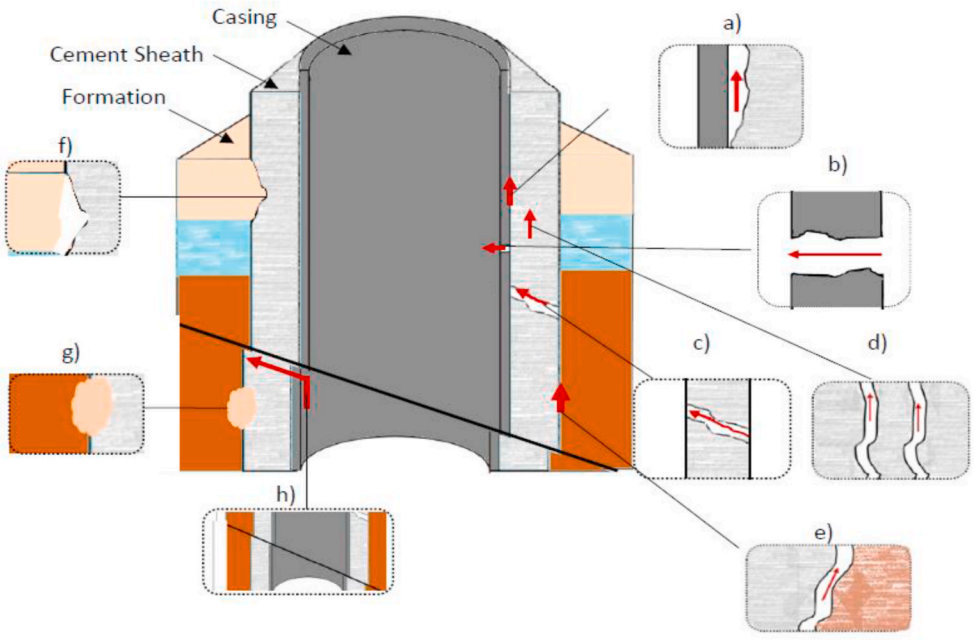


Fig. 1. Possible leakage pathways in a cased wellbore (Wu et al., 2020).

cement design" as the primary reason of cement sheath degradation (Turley, 2014; Visser, 2011; Wilcox et al., 2016; Garg and Gokavarapu, 2012). To ensure the durability and safety of a well, understanding the behavior of the cement prior to its downhole placement is one of the key issues in determining the success of cementing job. Usually, type G and H type portland cement are used in industry's cementing job. During the design phase of a cement, two design factors are required to be evaluated comprehensively: rheological aspect and mechanical aspect.

3.1.1. Cement slurry rheology

For successful cement run operation and proper downhole placement, understanding the rheological behavior of cement slurries is important in trying to prevent and eliminate the hydrocarbon migration-related problems in oil and gas wells. But usually cement slurries are reactive systems, changing continuously chemically and physically under different environmental conditions. Complex non-linear behavior like viscoelasticity, thixotropy, yield stress, shear-thinning effects, etc. are also exhibited by it (Tao et al., 2020). Design of these factors will determine the flowability and stability of the cement slurries; hence affect the successful well cementing job. It is quite significant to comprehend, and thus design the rheological characteristics like shear viscosity, yield stress, plastics viscosity, apparent viscosity as precise as possible. Therefore, it is desirable to understand these rheological properties of cement in order to examine the displacement efficiency as well as the flow rates for optimal mud removal and cement placement before setting (Lootens et al., 2004).

This is a well-known fact that visco-elastic behavior along with a yield stress, is demonstrated by the cement system. The Bingham plastic model and the power-law models are the two models that are most commonly used for designing cement slurries. The Bingham fluid model is largely used to illustrate the relationship between the shear stress and the shear rate for cement slurries at low shear rates. To portray the visco-plastic nature of some non-newtonian fluids, it is one of the most straightforward model. However, this is not always considered to be the accurate model as non-linear behavior of many cement slurries is not always fully covered (Atzeni et al., 1985). In some cases, direct relationship between the shear rate and the volumetric flow rate inside the pipe or annulus is found to be missing (Robertson and Stiff, 1976). To combat this issue Macosko and Krieger (1996) and Lootens et al. (2009) proposed a three-dimensional tensorial form of the Bingham model for cement slurries. Moreover, Herschel and Bulkley (1926) simplified the Bingham model where they introduced a three-parameter model for cement slurries. The power-law model, also known as the Ostwald model (Shapovalov, 2018) is one of the most popular models in characterizing the pseudoplastic fluids without yield stress. In this model, the consistency factor "k" and the flow behavior index "n" (the power-law exponent) measures the degree of non-Newtonian behavior.

In addition, few other models are available to design the cement slurry. But much care needs to be taken of while choosing a specific model for cement design. Because each of the model has their own pros and cons, and applicability restrictions. For example, The Eyring model (Eyring, 1936) is applicable for suspensions carrying dispersed particles. But, yield stress component is missing in this model and is more appropriate for non-Newtonian behavior at high shear rates. Yield stress term is discarded in Sisko's model (Sisko, 1958) which is later modified by Papo (1988) to cement pastes. Casson model is found to be one of the most errorless and handy models describing the rheological properties of cement slurries (Kok and Karakaya, 2018). Atzeni (Atzeni et al., 1985) and Banfill (2003) is not accurate when predicting the behavior of suspensions with high particle concentration. Therefore, this is quite crucial to select the appropriate model that will fit the purpose.

To provide more accuracy in above models, different methods to measure the yield stress have been suggested (Coussot et al., 2002). The yield stress, to a large extent, determines the transition between or the point at which the solid-like behavior changes to a fluid-like behavior. Poro-elastic solid behavior of fresh cement is shown below the yield stress. When the yield stress is reached, plastic strain behavior is shown by the slurry exhibits (Marrucci, 1999). According to the Perrot et al. (2012), yield stress is displayed by the cement slurry when the colloidal attractive forces dominate over the Brownian motion. If the Brownian motion rules over the colloidal attractive forces, no yield stress is observed. Michaux and Defosse (1986) stated that the yield stress of cement slurries demonstrated a peak value at the presence of low concentrated dispersant and decreased to zero at high concentration. The dispersant contributed to breaking the structure through interparticle attractive forces. Ivanov and Roshavelov (1990) claimed that water/cement ratio has also a great influence on the yield stress. It decreases with the increase of the water-to-cement ratio. Although pressure is seemed to have negligible effects on the flow of cement slurries, at the same time temperature has noteworthy effect on both the yield stress and the viscosity and they decrease when the temperature increases (Ravi and Sutton, 1990).

Shear viscosity is another critical cement rheological factor that can be a function of one or all of shear rate, volume fraction, temperature, pressure, thixotropic behavior, water to cement ratio, additives, mixing method, electric field, magnetic field. Viscosity is significant to evaluate the flow behavior of cement along the casing and annulus. Water viscosity usually decreases at higher temperatures. As a result, when the yield stress of the cement slurries increases, its effect on the viscosity is hardly understood due to dominating viscous behavior of the water (Ma and Kawashima, 2019; Aiad et al., 2018). With the increase of temperature in deep wells, the viscosity tends to drop due to thermal thinning behavior (Vipulanandan and Mohammed, 2015). With the increased water-cement ratio, the viscosity of cement slurries decreased at a noteworthy manner. Looking at Fig. 2, this can be understood that for pseudoplastic or shear-thinning fluids where $n < 1$, the viscosity seems to be decreased with the increased shear rate. In case of Newtonian fluids where $n = 1$, the viscosity is independent of the shear rate. For dilatant or shear-thickening fluids $n > 1$, the viscosity is found to be increased with the increase in shear rate.

Chemical additives are also an integral part of cement slurries and

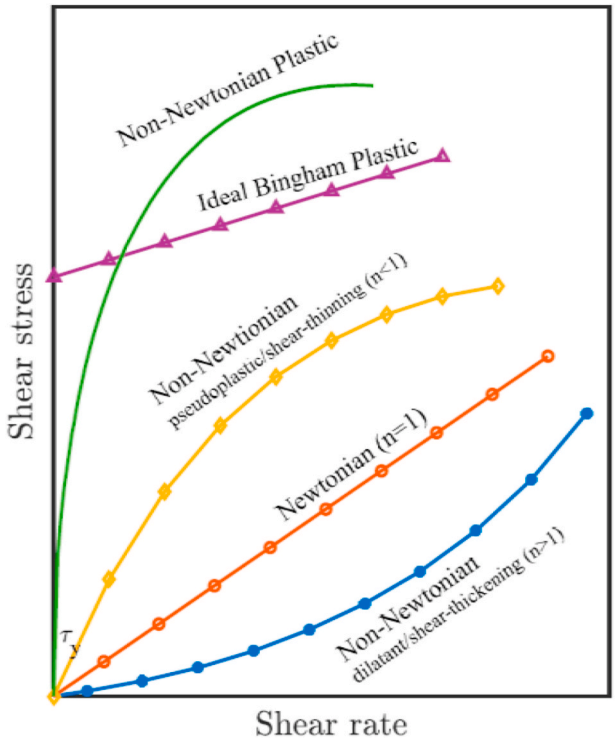


Fig. 2. Shear Stress vs. Shear Rate for different types of fluid (Tao et al., 2020; Daugherty, 1989).

have significant effects on its rheological properties. Additives are substances that are added with cement slurry to satisfy the desired properties (Banfill, 2003). This is why it is quite important to choose the right additive with right quantity. Because every different chemical additive has their own application condition as well as not every additive is applicable in all circumstances, and they have their own shortcomings too. Additives are mainly categorized as accelerators, retarders, extenders, dispersants, loss circulation control additives, fluid loss control additives, anti-foam agents etc. Accelerators are usually used to decrease the settling time of the cement and accelerate the development of compressive strength whereas retarders exhibit opposite behavior of accelerators. To cement the weak formations, extenders are used to reduce the cement density so that formation breakdown and loss circulation can be prevented. Dispersants reduce the cement slurry viscosity and confirms good mud removal during displacement (Michaux et al., 1989). Fluid loss and loss circulation additives are used to prevent loss of cement slurry and water into the formation from the cement paste. Likewise, there are many other types of additives that are added with oil and gas field cement to produce the expected cement slurry.In industry, there various types of additives of same category are available and each of them have their own unique functions, and they also influence the cement rheological properties to adjust with the requirement that are summarized below in Table 1:

3.1.2. Cement mechanical aspect

To maintain the long-term integrity of the set cement, design of mechanical properties like young's modulus, poisson's ratio, compressive strength, tensile strength etc. are extremely significant. Traditionally, the industry has given much emphasis on the short-term properties that are applicable when the cement is in slurry state. However, numerous cases have been identified where the cement was properly placed and initially provided a good hydraulic seal, but failed to provide wellbore integrity at the later stage of the well life (Goodwin and Crook, 1992; Jackson and Murphey, 1993). This failure might happen for various reasons and recent experiences have shown that operations such as completion, pressure testing, stimulating either by hydraulic fracturing or steam injection contribute to the loss of cement sheath. A laboratory test has revealed that during perforation of casing, an excess pressure of 6000 psi is exerted at the downhole. During hydraulic fracturing stimulation, high pressurized fluid injection usually lasts for hours which poses a significant threat to cement sheath. Cement fails from these operations mainly by stresses induced on it from the variation of downhole conditions (Thiercelin et al., 1998; Goodwin and Crook, 1992; Jackson and Murphey, 1993; Parcevaux and Sault, 1984; Jutten et al., 1987). This failure can create a path for fluid migration thought the annular space, resulting in pressurization of well and put the well in an unsafe condition to operate. According to the study conducted by Ravi et al. (2002), the integrity of the cement sheath could be lost due to either cracking of the cement sheath or by plastic deformation in the cement sheath.

Another study carried by Goodwin and Crook (1992) clearly demonstrated that stiff cements or cements that possess a high Young's modulus are more susceptible to damage caused by pressure and temperature change. Therefore, cement of high compressive strength is not always the best solution at the wellbore environment where pressure fluctuations may take place. In this case, flexible cements with lower Young's modulus are preferred to be employed.

Sudden increase of pressure and temperature during production or stimulation mainly contribute to the failure of cement sheath integrity. Pressure increment on the external surface of the cement poses a situation where the formation loads the wellbore because of creep. Far-field minimum stress changes can also take place following a redefined reservoir pore pressure or reservoir temperature.

While doing the mechanical design of the cement, experts should be aware of the future operation and behavior of the well in response to that. When downhole pressure increases due to any of the

Table 1
Pros and Cons of different additives used in Oil and Gas well's cement (Tao et al., 2020; Broni-Bediako et al., 2016).

Additive Name	Properties
Polycarboxylate superplasticizer	- Increase: Gelation threshold. - Decrease: Yield stress and the plastic viscosity by 70% when concentration <0.75% and Shear rate <128 rpm. - Seems to behave as a dilatant/ shear-thickening fluid with concentrations higher than 0.75%
Condensed silica fume	- Increase: Viscosity in the concentration range of 7.5–15%. - Increase: Packing density and the flowability in the lower ranges (<15%) and lower water cement ratio. - Decrease: Viscosity initially until a certain concentration value reaches. - Decrease: Packing density at concentration >15%
Pulverized fuel Ash (PFA)	- Increase: Packing density and flowability
Glycerin	- Increase: the viscosity and accelerate the hydration process at about 26% volume content - The effect of glycerin on viscosity is more obvious at larger shear rates.
Hydroxypropylmethylcellulose (HPMC)	- Increase: Plastic viscosity, Thickening time, Compressive strength - Decrease: fluid loss - Suitable for oil well cementing under high temperature conditions.
Limestone powder	- Increase: Fluidity - Decrease: Yield stress, Plastic viscosity
Nano-SiO_2 and Nano-TiO_2	- Increase: Yield stress, Plastic viscosity, Torque
Cellulose nanofibers (CNF)	- Increase: Yield stress, Degree of hydration, Flexural strength
Ultrafine admixtures (UA) [Blast Furnace Slag (BFS), Silica Fume (SF), Fly Ash (FA), Limestone (LS)]	- Decrease: Yield stress and viscosity. - The effect of ultra-fine slag is more obvious when the UA content is more than 15%. - Spherical shape of fly ash particles is found to reduce the viscosity and the yield stress of fresh cement pastes
Silica Flour	- Increase: Viscosity - Decrease: Thickening time - Suitable for oil well applications when the temperature exceeds 120 °C, in order to prevent decrease in the compressive strength.
Nano-Fe_2O_3	- Increase: Viscosity, Elastic properties, Suspending ability - Decrease: Free water, Fluid loss, Compressive strength, Thickening time
Calcium chloride ($CaCl_2$)	- An accelerator - Found in two grades: regular grade (77% Calcium Chloride) and anhydrous grade (96% Calcium Chloride). - Added in concentrations of 2%–4% - effective at temperatures between 40 °F and 120 °F (4 °C and 49 °C)

(*continued on next page*)

Table 1 (*continued*)

Additive Name	Properties
	- Higher concentration decreases thickening time and develops compressive strength faster.
Carboxymethyl Hydroxyethyl Cellulose (CMHEC)	- A Retarder - Functional up to approximately 230 °F BHCT - Provides good fluid-loss control
Hydroxycarboxylic acids (Citric acid, Tartaric acid, Gluconic acid, Glucoheptonate and Glucono-delta-lactone)	- A Retarder - Efficient to a temperature of 302 °F - Below 200 °F (93 °C) they can cause over retardation
Polynapthalene Sulfonate	- Most widely used dispersant - Available as a calcium and/or sodium salt, and can be obtained in both solid and liquid form - Improved rheological properties can be obtained, and slurries can be pumped with reduced frictional pressure.
Hydroxyethyl cellulose (HEC)	- A fluid loss additive - Used at temperatures up to approximately 180 °F (82 °C)
Gilsonite	- A loss circulation additive - effective at bottomhole temperatures between 60 °F and 230 °F - low specific gravity helps improve its ability to control lost circulation. This feature can also cause the additive to separate to the top of thin slurries. - Reduces slurry weight without loss of compressive strength
Polypropylene glycols	- An anti-foam additive - Typically, less than 0.1% by weight of water (BWOW) is used. - Modify the surface tension in the cement slurry
Calcium Lignosulfonate	- A Retarder - Effectiveness is limited in temperatures above 200 °F. - concentration range of 0.1% bwoc - 0.5% bwoc is more preferred. - Amounts above 1% bwoc do not add appreciably to slurry retardation. - Addition of the Lignosulfonate additive at concentrations higher than 0.2% bwoc resulted in a decrease in the compressive strength of the cement.
Bentonite	- An Extender, the most common type of additive - Used to prevent solids separation, reduce free water, reduce fluid loss, - and increase slurry yield. - lowers the slurry density. - concentrations of 2–16% by weight have been used. - able to hold water which is 16 times of its volume. - retrogression of strength in cements with time is promoted at temperatures above 230 °F (110 °C)
Sodium chloride (NaCl)	- An accelerator at low concentration - A retarder at high concentration. - Acts as an accelerator at concentrations from 1% to 10% - maximum acceleration of NaCl occurs at a concentration of about 5% for cements containing no bentonite - Saturated sodium chloride solutions tend to act as a retarder - NaCl, up to about 4% by weight of cement (4% bwoc), greatly accelerate the rate of setting, whereas larger quantities, from about 8% to 10%, do not have a very great effect upon setting times. - Most commonly used concentration of NaCl for cementing operation is 2%–2.5% bwoc

abovementioned issues, the stress applied on the cement behaves as linear function of the wellbore pressure which means for example, doubling the wellbore pressure results in doubling the value of the stresses in the cement. Usually, various forms of stresses act on the cement: radial stress, tangential stress, axial stress, shear stress. Among all these, tangential stress is the principal stress acting on the cement. As Fig. 3, radial stress acts radially along the wellbore center whereas tangential stress acts parallel to the well path. When pressure rises in a well, the radial stress is observed to be compressive, and the tangential stress is found to be tensile in nature. Usually, the highest tangential stress value takes place at the steel/cement interface and as a result the first point of failure occurs here.

If the wellbore pressure increases by a certain amount, the tensile strength needed to avoid the failure at the steel/cement interface depends on the tangential stress exists in that interface. An experiment of increasing the pressure by 1000 psi shows that the tensile strength requirement increases with an increase of cement Young's modulus and a decrease of rock Young's modulus (Thiercelin et al., 1998). The decrease of the tensile strength requirement with the increase of rock Young's modulus is caused by the increase of the support the rock provides to the cement. Additionally, it has been observed that the tangential stress in the cement is compressive, especially near the cement/rock interface. This increases the strength of cement sheath as cement is stronger in compression than in tension; therefore, it is advantageous to use a low Young's modulus cement to take advantages of rock mechanical support. To evaluate whether the cement will fail or not under a wellbore pressure increase, one must know the tensile strength and elastic properties of the cement as well as that of the rock.

3.2. *Hydraulic fracturing*

Operation like hydraulic fracturing has helped significantly to unveil

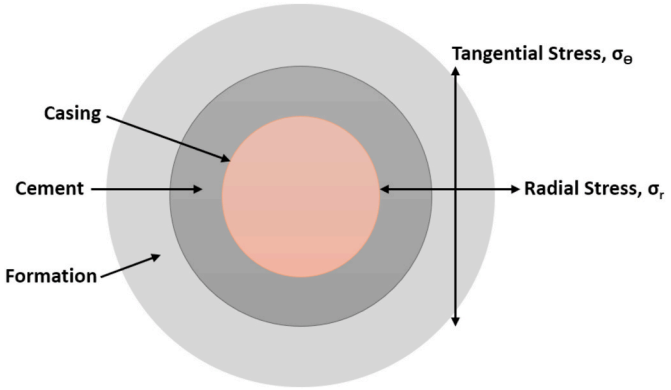


Fig. 3. Radial stress "σ_r" and tangential stress "σ_Θ"

the mystery of unconventional reservoir like shale. As the operation came into play, the industry has seen a noteworthy growth in hydrocarbon supply that has enabled us to experience a momentum shift in recent years. Although the production has vastly increased due to implementation of techniques like fracking and horizontal well (Li et al., 2017, 2019; Chen et al., 2017), in most of the cases this has put the issue of well integrity into a vulnerable condition. During fracking operation, fracturing fluid is pumped into the wellbore at a high pressure in order to generate fractures within hydrocarbon bearing formation (Huang et al., 2012; Heathman and Beck, 2006; Lu et al., 2016). This acting high wellbore pressure put stress on the casing-cement-formation system because of which stress-strain response of cement and its surrounding system also gets affected and sometimes leads to loss of wellbore integrity due to generation of crack and annulus in cement column (Liu et al., 2018a). From previous studies, it has been observed in most of the cases that cement sheath at shallow stratum could suffer tensile failure while in deep formation, it might undergo interface bonding failure (Wang et al., 2019). During the fracturing process, the casing internal pressure ranges from 65 MPã90 MPa (Liu et al., 2018a) and various types of fracture mechanism takes place in the cement system when influenced by this magnitude of pressure. To analyze the cement failure behavior, different types of scientific study have been done. Many experts used finite element methods to examine the effect of properties and geometries on cement sheath integrity (De Andrade and Sangesland, 2016; Lian et al., 2015; Feng and Gray., 2017a; Rodriguez et al., 2003). While others used the numerical simulation method to study cement stress and failure criterion (Yan et al., 2018, 2019, 2020; Feng et al., 2017; Reddy et al., 2007; Boukhelifa et al., 2005). Experimental studies have also been conducted to characterize the cement inability to provide zonal isolation (Lu et al., 2016; Liu et al., 2018b; Wang et al., 2019). Usually, two major cyclical changed load is found to be acting upon casing-cement structure. Firstly during loading phase, casing internal pressure rises too much that causes high compressive stress on the surrounding system. In response to this increased stress, plastic deformation may occur inside the cement column (Li et al., 2019). Further increase in casing internal pressure may lead to generation of micro-annulus or cracks or fractures in cement (Wei et al., 2015; Taleghani and Klimenko, 2015). Experimental evidence showed that cement-shale interface could fail to provide zonal isolation under triaxial compression during pressurization period. In this regard, the underlying reason is that cement is an elasto-plastic material in nature and its plastic strain is greater than that of casing and formation under the condition of the same compressive stress (Wang et al., 2019). On the other hand, when fracturing pump is stopped, there is a sudden drop in casing internal pressure that lowers the radial stress on the interfaces. As the casing pressure drops, reversed deformation occurs in casing, cement sheath and surrounding rock, and the contact force at the first and second interfaces turns down in response to that. During Pressurizing period, the interfacial contact force is at compression state which turns into tension state when depressurized. If the interfacial tension is exceeded by the interfacial cementing force, the interface gets detached, and micro-annulus would form. Subsequently as the pressure continues to drop, the micro-annulus would extend gradually. This type of varying stress can severely degrade the cement sheath ability to hold its integrity in the long run (Liu et al., 2018a).

Radial and shear crack may also develop by the fracturing fluid which may later propagate in transverse and longitudinal direction (Wang and Dahi Taleghani, 2014) when the pressure applied in fracturing treatment exceeds the ultimate compressive strength value of the cement. The casing pressure usually reaches tens of megapascal, which exerts a compression effect on the cement sheath. Therefore, this acting casing pressure plays a significant role in propagation of radial crack length. Once a crack is initiated at the fracture tip, this has been observed from one of the experiments done by kangxing et al. (2015) that these generated cracks swerve along the interface layer of horizontal principal stress. Also, hydraulic fracture is easy to swerve if friction coefficient and tensile strength of the cement are low. In some cases, this pressure drives not only propagation of fracture, but also casing collapse at the wellbore which may lead the well to be abandoned. Usually, cement sheath failure follows the Mohr-Coulomb failure criterion. But experiments indicate that Mohr-Coulomb failure criterion may fail in a high pressure and high temperature condition (Zhang et al., 2013; Wang and Dahi Taleghani, 2014; Lu et al., 2016). At high confining pressure the Triaxial Compressive Strength starts to drop with the increase of confining pressure, which is violation of Mohr-Coulomb failure criterion (Lu et al., 2016). Therefore, the fracturing operating pressure must be controlled under a certain value, which is called maximum wellbore pressure. The maximum wellbore pressure would be an important guideline for the design of fracturing operation. This is also a significant observation that cement sheath with higher Young's modulus (Thiercelin et al., 1998) and lower Poisson's ratio will damage more easily to affect the fracturing operation. Therefore, to prevent the damage during fracking operation, mechanical design of the cement is quite crucial in maintaining the well integrity of a well.

3.3. Cement shrinkage

Shrinkage of oil field cement is a volume-change phenomenon that involves the removal of free water from the cement mixture (Chenevert and Shrestha, 1991). The underlying mechanism is that when cement clinkers come in contact with water, they undergo hydration reaction due to which the paste gets hardened and tends to shrink (Kosmatka and Wilson, 2011; Powers, 1935; Dusseault et al., 2000; Aitcin et al., 1997). As the cement reacts with water, there forms a calcium silicate crystal named as "ettringite" which during hardening adsorbs water within its crystal structure. As a result, the net volume of the cement decreases. Experiments on pure silica using magnetic resonance and dielectric permittivity, conducted by Dusseault et al. (2000) has revealed that there exist at least 9 to 11 layers of water that can be adsorbed on the cement particle surface, and the closest layers are the most tightly bound. Bulk shrinkage initiates only after particle-to-particle contact is established (percolation threshold) in the hydrating slurry (Sun et al., 2005; Voigt et al., 2005; Sabins and Sutton, 1991; B.R. Reddy et al., 2007). Presence of dissolved gas and early (flash) set are also responsible for shrinkage (Dusseault et al., 2000). Cement shrinkage mechanism is found to be accelerated significantly at high temperature and pressure borehole environment as particle-to-particle contact is established sooner by application of high pressure and temperature (Olvera et al., 2019; Reddy et al., 2005). It can be exacerbated in presence of mudcake if the annulus is not cleaned appropriately before placing the cement. Most of the time, this leaving mudcake gets dehydrated due to interaction with cement that drives the cement to shrink more. According to several studies, rapid shrinkage rate has been observed between 8 and 24 h, followed by a slower shrinkage rate (Reddy et al., 2005; Backe et al., 1998; Chenevert and Shrestha, 1991).

Cement shrinkage behavior to date, has mostly been evaluated on laboratory scale and various shrinkage values have been observed due to varied setup and provided conditions. Sometimes different shrinkage values are obtained for the same slurry e.g., results found in balloon test and sleeve test and this discrepancy usually happens due to varied experimental setup, procedure and the methods used to measure the shrinkage (Reddy et al., 2007). But in most of the cases, chemical shrinkage was reported varying from 0.6 to 6 vol%, while most results are found to be in the range of 1.5–3 vol% (Backe et al., 1998; Sabins and Sutton, 1991; Justnes et al., 1995). The measurement of cement shrinkage behavior of oil field cement was first done by Le Chatelier in 1900 and is still applied today that measures water uptake by curing cement slurry placed in a flask as a thin layer and covered with water (Justnes et al., 1995, 1996bib_Justnes_et_al_1995, 1996; Ravi et al., 2006; Holt, 2005; Bentz et al., 2001). Experimental studies carried out by Le Chatelier concluded that Portland cement shrinks by 4.6% shrinkage when it sets. Complying with Le Chatelier, Ravi and Bosma

(2002) did another experimental study where they claimed that cement reduction volume is usually about 4%. To simulate the downhole condition, a variety of specially assembled equipment has been used for measuring shrinkage under downhole conditions (Beirute and Tragesser, 1973; Chenevert and Shrestha, 1991; Jennings, 2005). Moreover, several studies have put emphasize on measuring shrinkage under downhole conditions in presence of water so that the results can comply to field use. (Reddy et al., 2007; Parcevaux and Sault, 1984; Moran et al., 1991; Ghofrani and Plack, 1993; Baumgarte et al., 1999; Backe et al., 1999; Goboncan and Dillenbeck, 2003; Jennings, 2005).

When the cement shrinks, the hydrocarbon migration starts to take place as the radial contact stress between cement and formation falls below the formation pore pressure. The effective radial stress drop can be approximated using a simple first-order calculation, and a way of calculating that is proposed by Dusseault et al. (2000). This situation will be exacerbated if the surrounding rock is stiff as this will hold the formation to move inward to adjust the physical contact stress as a result of which annulus will be generated. Moreover, a more critical case will arise if the casing is highly eccentric. Because more radial shrinkage will take place on the thickest side of the cement sheath.

3.4. Chemical degradation

Cement degrades chemically when they come in contact with aggressive fluids like carbonic acid, sulfuric acid, hydrochloric acid, Hydrogen sulfide etc. Chemical reaction like carbonation, leaching, sulfidation are carried out when cement encounters these acidic substances (Omosebi et al., 2017a, b). But among all, cement experiences the most vulnerable condition in CCS (Carbon capture and Storage) and CO_2-EOR reservoir due to a chemical mechanism named carbonation and bi-carbonation. In this process, at first CO_2 dissolved in water or brine reacts with water to form carbonic acid as in equation (1). Usually, high alkaline nature is maintained in cement and the most significant alkaline component of the cement system is $Ca(OH)_2$ which reacts with carbonic acid to form precipitation of $CaCO_3$ according to reaction (2) (Han et al., 2012). The process of formation of $CaCO_3$ is found to be accelerated at higher temperatures (Garnier et al., 2012). This generated $CaCO_3$ fills the cement pore space and reduce permeability due to which further penetration of the carbonic acid into the cement pores slows down (Duguid et al., 2007). $CaCO_3$ also enhances the compressive and shear bond of cement; as a result, mechanical strength of the cement gets improved in this process (Srivastava et al., 2019). Cement has other component such as $C_{3.4}$-S_2-H_8 that reacts with carbonic acid, but this has been found that $Ca(OH)_2$ in the cement reacts earlier than $C_{3.4}$-S_2-H_8 (Duguid, 2008).

Generation of H_2CO_3 within the reservoir:

$$CO_2 + H_2O \leftrightarrow H_2CO_3 \leftrightarrow H^+ + HCO_3^- \leftrightarrow 2H^+ + CO_3^{2-} \quad (1)$$

Reaction of H_2CO_3 with cement to form $CaCO_3$ precipitation:

$$Ca(OH)_2(s) + 2H^+ + CO_3^{2-} \rightarrow CaCO_3(s) + 2H_2O \quad (2)$$

Although cement's strength is improved due to initial carbonation, however, this is a chain reaction and the further bi-carbonation reaction continues to take place. The previous reaction product, calcium carbonate ($CaCO_3$) also degrades due to exposure to carbonic acid. If they are in contact with each other for a long period of time, the calcium carbonate will eventually break down and release Ca^{2+} according to process named leaching (reaction 3). The decrease of calcium content in the cement matrix contributes to increase of porosity and permeability of the cement (Carde et al., 1996; Carde and Frangois, 1997, 1999; Carey et al., 2007; Duguid et al., 2007; Duguid, 2008; Crow et al., 2010; Revertegat et al., 1992) and create a path for migration of CO_2 stored in the reservoir. The degree of occurrence of these reactions are influenced by temperature, CO_2 gas composition, pressure, slurry composition and brine concentration (Omosebi et al., 2017b). Also existence of other acids like H_2SO_4, HCl and HPHT conditions accelerate carbonation and leaching of cement (Srivastava et al., 2019).

Calcium carbonate dissolution:

$$CO_2 + H_2O + CaCO_3(s) \leftrightarrow Ca^{2+} + 2HCO_3^- \quad (3)$$

Leaching of Portland cement has also been observed due to sulfidation reaction on exposure to H_2S. Sulfidation takes place when ferrites components of cement react with H_2S to form sulfides as a result of which Ca^{2+} leaches out from the cement system (Jacquemet et al., 2008, 2011). In sulfate environment, cement degrades due to formation of pyrite, ettringite and gypsum. Although calcium leaching kinetics in presence of sulfates is not that much faster compared to carbonation, yet the reaction of sulfate ions with Tri-calcium aluminate ($3CaO.Al_2O_3$) and Tetra-calcium aluminoferrite ($4CaO.Al_2O_3.Fe_2O_3$) leads to cement deterioration (Omosebi et al., 2017b; Schmidt et al., 2009; Planel et al., 2006; Irassar et al., 2003; Wang, 1994). At higher temperature, twofold characteristic has been found in presence of H_2S – the solubility of H_2S decreases as the temperature goes up whereas the ions diffuse faster at higher temperature. Co-existence of both CO_2 and H_2S pose much threat to cement structure as all the above-mentioned reactions go on when they encounter the cement surface.

4. Leak detection and monitoring methods/techniques

On simple understanding, when there is a rise in the casing pressure which is recorded at the wellhead or during subsurface water production, increased oil-water ratio, it is believed that leakage has taken place either in cementing or casing through which oil or gas is flowing through the casing instead of production tubing. In such scenario, it is necessary to take prompt action as early as possible to prevent the situation getting worsen. There are few leak detection and monitoring techniques are available in the industry that help to evaluate whether the cement is well integrated or there is generation of any leakage.

During production and after a well has been plugged and abandoned, continuous monitoring and assessment techniques to check cement integrity are needed. One of the most common techniques for monitoring the output of wellbores is wireline logging that records data periodically. Cement bond logs (CBL), variable density logs (VDL), ultrasonic casing imagers (UCI), and corrosion log et al. are some of the wireline instruments that are widely known to examine the current cement integrity conditions based on basic downhole requirements (Kiran et al., 2017; Froelich et al., 1982; Griston, 1990; Crow et al., 2010; Alaref et al., 2016). CBL and VDL have been implemented to assess the cement consistency behind casing to evaluate the separation between reservoir units. The loss of acoustic energy is proportional to the fraction of the casing perimeter protected by cement, as measured by CBL. The ratio of CBL and VDL gives an average volumetric assessment of cement in the annular space between the casing and the formation (Kiran et al., 2017). UCI logs include a high-resolution scan of the casing's state, cement bond, and casing consistency in real time (Van Kuijk et al., 2005). The conclusion is focused on the differences in acoustic impedance thresholds between different materials. However, there are some drawbacks to ultrasonic log recordings, such as the fact that they are vulnerable to errors in some situations, such as gas leakage in cement. The volume of entrained gas or a mixed gas of cement affects the acoustic impedance of gas contaminated cement. In most cases, an ultrasonic log does not provide enough contrast to differentiate polluted cement from gas or fluid acoustic impedance (Coelho de Souza Padilha and da Silva Araujo, 1997; Johns et al., 2011). Furthermore, without explicitly measuring the strength, the ultrasonic log provides post-operational assessments. Corrosion log is a short, high-energy electromagnetic pulse from a transmitter coil to produce a charge in the surrounding concentric pipes. A receiver coil tests the collapsing eddy currents after the excitation pulse. This decay is characterized by a complex signature based on the pipe structure and electromagnetic

properties. To determine current casing thicknesses, an inversion technique is used, which offers information about the corrosion or defects that have affected the casing or tubular since its installation (Brill et al., 2011; Garcia et al., 2013). Furthermore, other techniques such as the noise log (spectral noise logging) is an acoustic noise measuring technique that records acoustic noise produced by fluid or gas flow through the reservoir or leaks in downhole well components, output logging, and temperature log can provide insight into complex well conditions (Jalan et al., 2013).

Some well testing methods are also deployed to determine the well integrity. Standard annular pressure test (SAPT) involves applying pressure to a closed structure, such as the annulus between casing and cement, and then measuring pressure depletion to detect possible leaks once the pressure is removed. The inability of SAPT to detect defective cement jobs and/or leaks through the casing shoe is its key flaw (Kiran et al., 2017). Vacuum insulated tubing test is based on perforating two distinct downhole intervals and isolating them with casing packers (Nordbotten et al., 2005). In this test, the upper zone's downhole pressure is set to some extent, while the lower zone's pressure is controlled. This pressure monitoring might give you an idea of how fluids are moving in general, but it can't tell you whether the flow you're seeing is coming from microchannels (Gasda et al., 2008). Radioactive tracer survey test involves the introduction of radioactive tracers into the fluid, followed by the use of a radioactive detector to identify the tracer elements in the device (Griston, 1990). Leaks cause anomalies in the sensor and noise of varying frequencies.

5. Cement fractures remedial methods

Once cement is degraded by any of the above-explained issues and path for hydrocarbon migration is created, number of techniques have been applied in the industry for cement repair with varying degree of success. If the problem of well integrity loss is not handled carefully, this may lead us to disaster like blowouts or leaks that may result in resource damage, personnel injuries, loss of production, and environmental damages. These losses are so significant that sometimes they exceed well repair cost. Experts have been working for years to provide efficacious cement sealing solution that would be convenient and efficient to apply.

5.1. Cement squeezing

Cement squeezing refers to the process of injecting a cement slurry at pressurized condition into the annulus or cracks generated in the wellbore cement system. Among all other cement remedial techniques, cement squeezing is the most common and popular process in field level application as the operation is quite similar to primary cementing job and the materials are easily available in the field. Yet, there are some differences in slurry properties used for squeezing jobs compared to conventional cementing jobs. The viscosity of squeezing cement slurry is typically lower than the conventional cement, and usually the density remains in between 1380 and 1500 kg/m^3 (11.5–12.5 lbm/gal) (Meek and Harris, 1993). On higher density, it usually becomes difficult for the slurry to penetrate through the fractures. Once the slurry is prepared, it is pumped at a high pressure to squeeze through the annulus or fractures. Later a shut-in time – usually ranges from 48 to 72 h – is provided to allow the cement to solidify. But the problem with this conventional cement slurry is that they can hardly pass through the restrictive opening; hence hinder the penetrating capability of the cement. To confront this issue, there have been use of small particle size cement which are even distinguished in between fine and ultrafine particle cement. Fine cement is well grounded cement with an average particle size of 8 μm and maximum size can reach up to 15 μm (Lizak et el., 1992). The fineness of this type of cement allows them to be more reactive, but provides a better penetration capabilities. The effectiveness of fine and ultrafine cements has been proven in number of jobs where it was required to seal a casing collar leak or other very narrow area (Lizak et el., 1992). The squeezing operation is categorized into two different ways: continuous squeeze and hesitation squeeze (Nasional, 2002). Continuous squeeze method is a technique where the cement slurry is continuously injected into the zone of interest (repair zone) until the desired squeeze pressure is obtained. When the operation terminates, the final squeeze pressure is monitored and recorded. But when the pressure falls, there is need for additional slurry to be squeezed to increase the pressure back to the final squeeze value. This intermittent pressurization is repeated until final squeeze is obtained. However, Hesitation squeeze cementing is a technique used in squeezing operation whereby a portion of cement slurry is pumped, then suddenly stopped in order to expose the slurry to differential pressure against the zone of interest over a period of time (hours). This simply means that the pressure forces the cement slurry into the area requiring repair. This procedure is called a stage process which is done continuously until the cement slurry is finally placed into the treatment zone. The cement in this treatment zone develops an effective hydraulic seal with a high compressive strength.

The injectivity Test in cement squeezing is performed to capture the character of the reservoir formation, and to obtain the value of injectivity factor. The injectivity factor, which is expressed as the ratio between injection pressure and injection rate can be used to determine the type of cement to be used for squeeze operation. For instance, if the injectivity factor is less than 2000, normal class G type of cement may be used. But if injectivity factor is greater than 2000, microfine cement should be used for squeeze operation. In other words, the value of injectivity factor dictates the ability of cement to penetrate the zone of repair (Asyri and Mulia, 2018).

Although cement squeezing technique is favored in field application, but the success rate of this method is relatively low, and the operation often needs to be repeated several times for achieving complete sealing. It was reported that cement squeezing operation using conventional oilfield cements has successfully been applied to repair the defect in primary cement jobs but proved to be ineffective in sealing microfractures/micro-annuli which often have an aperture size less than 150 μm (Wu et al., 2020). In New Hope Field in United States, it took 5.33 squeeze jobs on an average to seal an unproductive perforation, yet some of the zone failed to provide isolation after consequent squeezing jobs. Laboratory injectivity test on sand packs was conducted by Ewert et al. (1990) where it was demonstrated that the micro-cement slurry could penetrate and seal a 40/60 gravel pack whereas the conventional oilfield cement slurry failed to do so. In addition, an experiment reported by Meek and Harris (1993) showed that micro-cement slurry with lower density could penetrate a slot width of 0.01" (250 μm) without bridging or forming a filter cake at the slot.

Cost of each squeezing operation was estimated about 30,000 USD including all other costs like rig, manpower, materials. In this manner, each well could contribute to expenditure around $100,000 for each squeezing job (Farkas et al., 1999; Roth et al., 2008). Investing this amount of money is a wastage, if it does not provide expected performance. Moreover, it has also failed to perform efficiently in sealing tight or micro leaks. Air bridging may also happen while injecting the slurry at a high pressure which causes loss of cement strength. Another big problem associated with cement squeezing is the fluid loss of the cement slurry. When the slurry is injected against a permeable formation, the aqueous phase of the slurry escapes into the formation, leaving the cement particle attached to the formation face as cake forms (Slater et al., 2001); hence fails to offer effective sealing. Due to above difficulty experienced in this method, experts and researchers were looking for a better option.

5.2. Self-healing cement

Although industry has progressed much in innovation of better cementing solution, yet the problem of SCP in wells remains persistent. Sometimes it is quite difficult to predict all the wellbore processes, and

events that will take place during the life of the well or even after the abandonment to ensure that no failure of the cement sheath will ever take place that will allow reservoir fluid to pass through it. It is a rule of thumb in industry that if the fracture aperture is greater than 10 μm, this is sufficient to allow the hydrocarbon flow through it, especially gas (Johnson et al., 2019). Therefore, a cementing solution named "self--healing cement (SHC)" is in practice for over last few decades. Self-healing cement is a material where self-responsive additives are blended with cement clinker and other additives. The cement triggers its self-healing or swelling mechanism as it comes in contact with hydrocarbon as a consequence of failure of cement sheath integrity (Cavanagh et al., 2007).

Flowing hydrocarbon in cement fracture or annulus would activate the self-healing material whenever the integrity is compromised (cracks and/or debonding), and then efficiently seal the leak path automatically by swelling (Taoutaou et al., 2011). Reaction rate and degree of swelling will depend upon the concentration of self-responsive material, and well conditions such as temperature, pressure and the type of hydrocarbon to which it is exposed (Khattak et al., 2015). If the SHC system is not exposed to hydrocarbons, it will remain inert in place and act as conventional portland cement. Nowadays, commercially available SHC slurries have densities ranging from 1440 to 1920 kg/m^3 (12–16 lbm/gal) and their temperature application ranging from 20 to 138 °C (68–280 °F) (Roy-Delage et al., 2010).

Laboratory experiments showed that a reduction or termination of hydrocarbon flow can be achieved within 24–48 h after the fluid initiates to flow (Shadravan and Amani, 2015). Full or partial sealing time can be calculated by recording the increase in pressure differential across the sample while flowing hydrocarbon through the fractured cement sample (Roy-Delage et al., 2010). Also, Johnson et al. (2007) demonstrated that self-healing mechanism of such cement is repetitive in nature. If the seal is broken for any reason, it restores its self-healing mechanism to shut the leakage path again (Johnson et al., 2019). Brandl et al. (2016) and Sevilla Dieguez et al. (2016) utilized a multifunction test cell to examine the self-sealing effectiveness of a cementing system under in-situ downhole conditions either through the cement matrix or a micro annulus (Saeed et al., 2017). Conducting 5 times experiments on the same specimen, this has been observed that the self-sealing material has the capability to break and seal multiple times. For CO_2 storage reservoir, cement usually breaks down due to carbonation reaction that has been discussed in detail earlier of this paper, and there is similar solution available for this kind of reservoir or where there is presence of sour solution like H_2S. To validate this, Engelke et al. (2017) carried out an experimental study on a cement sample that contains additives responsive to CO_2. In 10 h testing upon contact with CO_2 containing fluid, this has been found that the fissure size decreased from 40 μm to approximately 3 μm, a reduction of 92.5% and also experienced 99.9% reduction in flow rate through the fissure. Similar behavior is observed while doing the experiment with fluid composition that includes significant (18% mole) concentration of H_2S (Sozonov et al., 2020).

Although most of the SHC is hydrocarbon reactive, Reddy et al. (2010) has showed that self-sealing cement system could heal without any dependence on fluid contact, and thermal healing can be achieved if there is presence of fracture in cement. To activate the thermal healing, they have used elastomeric polymer materials of 4% by cement weight that will seal the fractures. The results clearly showed a decrease in fluid flow with temperature, suggesting that higher temperatures may accelerate the self-healing process. At comparatively lower temperature, the effect could be vice-versa. Another special type of self-healing system has been proposed by Bu and Liu (2016) where they have demonstrated that fracture will heal in presence of water instead of hydrocarbon or corrosive liquid. But to implement this in field, there are some challenges that are needed to be overcome to prove it successful. For this, they have introduced a polymer named "superabsorbent polymer". But the shortcomings of this polymer are that they cannot be used in cement blend directly because addition of this polymer will result in substantial increase in slurry viscosity which will make it difficult to pump the cement.

From operational perspective, the main advantage of all above-mentioned SHC is that the system can be treated the same way as the conventional Portland cement, and blending and pumping arrangement are pretty similar to conventional one. Additionally, addition of self-healing additive in the cement blend has been proved to improve the mechanical properties of the cement. To see the difference, Shadravan and Amani (2015) examined two slurries with and without self-healing additive. The noteworthy observation is the slurry with the self-sealing material increased compressive strength by 10%, tensile strength by 48% and Poisson's Ratio by 66% and decreased Young's Modulus by 56%. This translates to the fact that the cement design with the optimal percentage of self-sealing materials suggests more cement sheath durability that can withstand fluctuating stresses applied on the cement sheath during well operations. Also cement bond log (CBL), variable density log (VDL), ultra-sonic imaging tool (USIT) confirms that good bonding can be achieved in casing-cement-formation interfaces. This claim is supported by other studies conducted by different researchers, though the amount of mechanical improvement might be different. To date, most of the fields where SHC has been used, showed a favorable result. In Denver-Julesburg Basin, implementation of SHC over 250 wells resulted in reduction of SCP from 20% to 2% (Langley et al., 2018). Very effective zonal isolation was achieved in UGS well of Cortemaggiore 155 in Italy by using the SHC material (Johnson et al., 2007). In addition, the solution is seemed to be effective in other fields too - Western Colorado field, Stolberg field in the Central Alberta, Le Houga field and Lussagnet field in the south of France, Algeria field etc.- where the wells showed no sign of pressure buildup in the annulus or at surface after using SHC in these wells (Roy-Delage et al., 2010).

Johnson et al. (2019) in their study claim that the maximum swelling capacity of the set SHC cement is of the order of 100 μm. To comply with this, other studies also conducted their experiment on fracture width less than 100 μm. Therefore, whether SHC can seal the fracture width greater than 100 μm is yet to be verified. Also, Self-Healing Cement can never provide complete sealing of the induced fracture. It might minimize the fracture width, but absolute closing of fissure is not possible. In case of gas reservoir, sometimes a tiny microlevel of fracture is enough to allow gas to pass through it. This system is a good candidate when the well operating envelope is well known, outside this envelope the cement system may not perform as well, leading the cement to fail (Al-Suwaidi et al., 2008; Taoutaou et al., 2011). Flawless execution of self-healing system is significant and requires close observation during slurry preparation to avoid potential contamination, which can eliminate the self-healing properties of the blend; hence may fail to serve its purpose.

5.3. Polymer gel

In plugging the narrow fractures in cement, a low viscosity sealant is desirable that can be easily placed into these fractures easily while providing a long-term robust durability. In this manner, an acidic polymer solution is proposed that will meet the above criteria. This low pH poly-acrylic acid polymer solution will turn into gel upon neutralization reaction with the cement. Usually, the Portland cement used in the oil and gas wells is highly alkaline in nature. When the polymer solution is injected into the cement fractures, the cement surface and the solution come in contact with each other, and a neutralization reaction occurs instantaneously in between low-pH polymer solution and high-pH cement. As a result, pH-sensitive microgels viscosify and form highly swollen gels with substantial yield stress that can prevent fluid flow through it. Fig. 4 schematically illustrates the process of pH triggered polymer gel for cement fracture repairment. Although this pH-triggered gelation exhibits simple mechanism and rheology measurements of the polymer gel shows promising results, but there is a crucial shortcoming too. When the solid gel forms, they go through a syneresis reaction with calcium cation released from the cement surface and cause

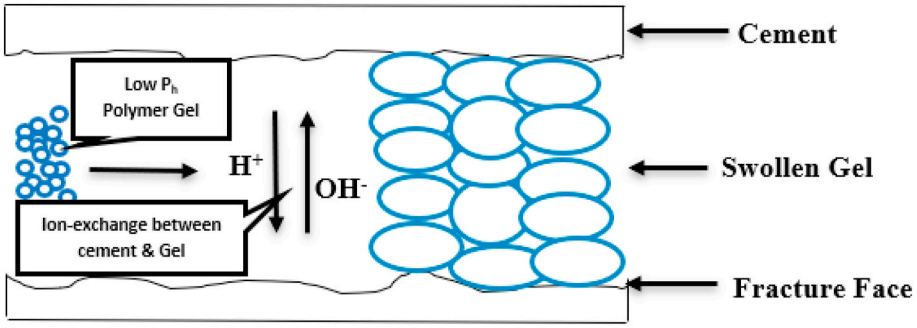


Fig. 4. Formation of pH-triggered Polymer gel in cement fracture.

the polymer structure to collapse physically. Due to occurrence of this reaction, an unwanted calcium precipitation byproduct is formed which hampers the strength and stability of the gel severely. As a result, the gel system fails to resist holdback pressure, and at one point it tends to fail; hence again permits the formation fluid to migrate through it. But this problem can be bypassed through doing the pretreatment of the cement surface with chemicals, called chelating agent. A chemical named Sodium Triphosphate ($Na_5P_3O_{10}$) is found to be successful in eliminating the syneresis while pretreatment was done with it. When pretreatment is carried out and polymer solution is injected into the fractures, a shut-in time is provided to allow the gel to solidify completely. To determine the polymer gel strength, a liquid breakthrough test is done after various periods of pre-treatment and polymer shut-in time. It has been found that cores pre-treated with $Na_5P_3O_{10}$, is able to resist an average pressure gradient of 80 psi/ft, which is remarkably greater than the range of pressure gradients expected in reservoir applications (Ho et al., 2016). Though this pH-triggered polymer gel is a good candidate in microfractures, the efficiency of them in sealing the larger fractures is yet to be proved. Because in this mechanism, the gel formed on the surface side of the cement would be stronger in near surface area, because the solution comes in contact with the cement first. But the polymer solution that will be in the mid region of the fracture, they may not be able to go through the total neutralization because of their distance from cement surface. Therefore, the central part of the gel may be weaker than the circumferential part which may lead to migration of hydrocarbon fluid through it. Moreover, the pretreatment required to prevent the syneresis reaction is one of the most significant drawbacks of this process. Firstly, it will take time to do the pretreatment which may lead to additional production loss. Doing the pretreatment at laboratory scale and in real field is completely different thing. In field application, operators must ensure that the pretreating chemical will travel all through the fracture path. If the pretreatment is not done efficiently, then there is always a risk of occurring that degradation reaction again.

The polymer gel system has been widely used in oil/gas industry to control the fluid flow conformance and prevent leakage near wellbores. There are different types of polymer gel that can be applied for wellbore integrity treatment. Syed (Syed et al., 2014) reported a PAM-based polymer gel composed of PAM and chromium (III) acetate. Their results indicated the polymer gel could reduce the CO_2 relative permeability by more than 99% in brine and can be applied to remediate wellbore fractures in carbon storage wells. Li (Li et al., 2016) studied the CO_2 leakage migration with phenolic resin cross-linked polymer gel. They observed that high-strength polymer gel was formed and blocked CO_2 leakage path as the solution was in contact with CO_2. Polymer gel systems usually have good injectivity and controllable cross-lining time. However, they normally require the addition chemicals such as chromium (III) to initiate the gelation process. In addition, the polymer gel thermostability is a concern for high temperature wells.

5.4. Silica gel

Colloidal silica solution is a stable inorganic aqueous dispersion of amorphous silicon dioxide (SiO_2) particles which exist in anionic form in the suspension. The environmental benignity and easy handling of the substance has made it unique compared to other organic solution. In ambient condition, the solution exists as a low viscosity fluid like water which is favorable for easy pumping. Particle collision, bonding, and aggregation into long-chain networks are believed to cause colloidal silica to gel (Jurinak and Summers, 1991). Particle's gelation can be triggered by adding salts or cations into the solution, by increasing particle concentration, by increasing temperature, or by adjusting the pH of the solution.

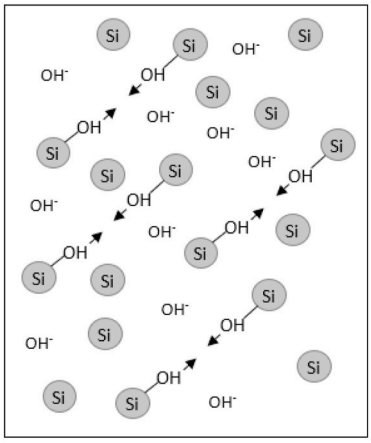
In aqueous solution, hydroxyl ion (OH^-) is attracted by silica surface and form silanol (Si–OH) group as shown in Fig. 5a. During gelation process the added salt solution acts as an activator or accelerating agent. With the presence of an activator, the formed SiO^- group starts bonding with Si–OH to initiate the formation of siloxane bond as in Fig. 5b. Finally, silica gelation can be envisioned to occur via formation of long chain siloxane bonds (Fig. 5c and d) (Krumrine and Boyce, 1985).

Gelation occurs when particle aggregation ultimately forms a uniform 3D structural network of long, bead-like strings of silica particles. Gelation time of colloidal silica depends on various factors, among which most governing factors are silica concentration, type of salt used, cation concentration, pH, temperature. Depending on the type of colloidal silica solution, pH effect may provide varied gelation behavior. Additionally, use of $CaCl_2$ rather than NaCl and Na_2CO_3 seems to shorten the gelation time due to bi-valency nature of the salt.

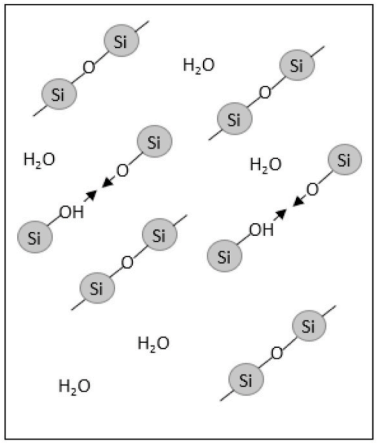
When fracture is induced in the well cement due to fracturing operation or other reason, it may generate either macro or micro sized fracture depending on the degree of fracturing effect. Regardless of the fracture size, nano-silica dispersion has the ability penetrate through the any size of fracture because of its initial low viscosity.

In the laboratory core flooding test, fully cured silica gels were found to withstand applied pressure gradients in the range between 2500 psi/ft depending on the silica and salt concentration which is much more than applied borehole pressure gradient (Jurinak et al., 1991b). These data strongly support the fact that colloidal silica gel has enough strength to resist holdback pressure of reservoir fluid to escape through the fracture.

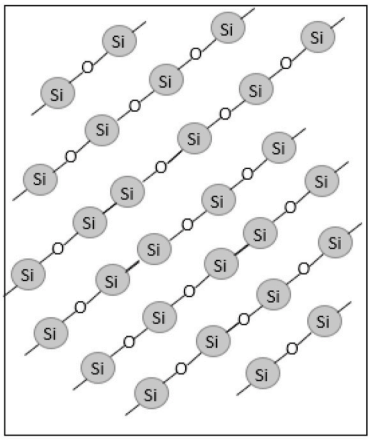
Unlike polymer gel, colloidal silica does not undergo syneresis reaction. Moreover, this gel system is immune to bacterial action, hydrolysis, and thermal decay mechanisms that can degrade the gel strength. But the one of the most significant advantages of nano-Si solution in maintaining well integrity is that under downhole condition, usually at higher temperature, the gelation mechanism expedites. Also, we all are aware that one of the main constituents of cement is Ca^{2+}. When the solution will enter the fracture aperture and come in contact with cement surface, bivalent Ca^{2+} may leach out from cement and result in acceleration of formation of gel. Moreover, inside the fracture, high pH of cement surface would somewhat alter the pH of penetrated nano-silica solution. Therefore, it is necessary to adjust the pH in such a



(a) Hydroxyl groups (Si-OH) on the surface of Si particles



(b) Hydroxyl groups reaction [In presence of activator. e.g., NaCl]



(c) Siloxane bonds (-Si-O-Si-)



(d) Image of Silica Gel

Fig. 5. Gelation mechanism of Nano-Si.

way that it will accelerate the gelation time after penetrating into the fracture aperture. Therefore, choosing optimum silica and salt concentration as well as combined effect of higher downhole temperature, presence of Ca^{2+} in cement, presence of multi-ions from the formation and tuned pH will help nano-Si solution to form the gel immediately after entering into the fracture.

5.5. Expansive cement

This is a well-known fact that cement shrinks during the later plastic and hardening phase of its setting period due to hydration reaction taking place over it and this shrinkage happens as reaction between water and cementous material results in lower volume than when they were mixed (Geiker, 2015). In the course of setting period, pore structure in the cement-water mixture gets somewhat emptied; The process is termed as self-desiccation because of which there is generation of capillary forces and an under pressure in the pore structure of the water. The pressure is transmitted to the solid portion of the cement as a result of which contraction in the cement takes place that leads to creation of microannular aperture either in between cement-casing or cement-formation and leads to loss of zonal isolation (Lura et al., 2003). To overcome the problem, expansive additives have been introduced with conventional oil and gas well cement system and together the mixture is called “Expansive cement”. Industrially, Expansive cement is one of the most popular cementing solutions and in use for almost over 50 years (Thomas et al., 2014).

In field application, there are over 40 types of expansive additives available, although all of them are not so popular (Bourgoyne et al., 1991). Yet, the number is on the rise as extensive research is going on to provide more efficient additives that will fit for every purpose. There usually four types of expansion mechanism have been practiced: Crystal expansion, Gas expansion, Expansion through metal oxides hydration and Salt crystallization expansion. In crystal expansion, a crystal named “ettringite” is formed due to reaction between sulfates and tri-calcium aluminate of the cement. Due to its larger size, the lattice structure of the tri-calcium aluminate is replaced by ettringite that induce internal stress to expand the cement (Seidel and Greene, 1985). The reaction rate and product stabilization under downhole condition are significant while considering crystal expansion. For example: Sulfoaluminate type additive loses its stability as the temperature goes beyond 76 °C (Nelson and Guillot, 2006). When zinc, magnesium, iron, aluminum powder or gaseous nitrogen are added with cement, gas expansion takes place due to generation of small hydrogen bubbles because of reaction among compounds. But in case of gas expansion, much care should be adopted, especially in high temperature environment, to make sure that the produced gas has stabilized uniformly within the system. Otherwise, gas

may escape from the system through channeling that may exacerbate the problem more instead of solving. The hydration of metal oxides is the most practiced expansion option adopted by the industry. Metal oxides like MgO, CaO when mixed with cement slurry and as the cement sets, it provides a larger volume of cement than usual (Jafariesfad et al., 2016). High concentration of salts like NaCl and Na_2SO_4, as they are mixed with cement paste, they can expand due to crystallization of added salt within the cement matrix. All these expansive additives may account for 0.2–0.4% expansion of cured cement (Sutama et al., 2013; Williams et al., 2011). There is formula available to measure the degree of expansion at 24 h interval while the cement paste is placed inside a curing machine to simulate the downhole temperature and pressure condition (Gupta et al., 2020). But when the specimen curing temperature goes beyond than 170 °F, a correction factor should be introduced to have the accurate expansion result. The value of correction factor will depend on the considered temperature scale.

Although expansive cement seems to be an effective solution to provide long term zonal isolation, yet the design of such type of cement should be done with significant care. Also, the liner expansion must be restricted up to 2% (Tanoto et al., 2016). If the expansion goes beyond this level, cement mechanical integrity will be affected severely. Also how much expansive additive should be added to the cement that should be identified cautiously as too much additives will result in bond failure (Jennings and Siddiqui, 2004). In a Saudi Aramco gas well drilling program, Al Hammad and Altameimi (2002) identified cement cracks during initial life of the well as excessive amount of additive was used (Shafqat et al., 2018). From an experimental study, Baumgarte et al. (1999) claimed that to obtain the best output, expansive cement should be placed in a fit for purpose formation that is capable of resisting expansive force acted by the cement. If the cement set against a soft formation, expansion may go outwards and thus create leakage path on the inner interface of cement. Moreover, most of the expansion test of oil and gas well cement on laboratory scale is conducted by following API RP 10B-5 or ASTM C1608-17. In case of gas expansion, if the measurement is done in ambient condition the gas generated in the cement may escape from the system that may account for inaccurate expansion calculation (Olvera et al., 2019). Therefore, a comprehensive procedure needs to be developed so that such kind of flaw during cement design can be avoided.

5.6. Biofilm-induced calcium carbonate precipitation

The technology of Biofilm-induced calcium carbonate precipitation has the potential to improve the long-term security of geologically stored carbon dioxide (CO_2) by sealing fractures in cap rocks or to mitigate leakage pathways to prevent contamination of overlying aquifers from hydraulic fracturing fluids. Sealing technologies using low-viscosity fluids are advantageous since they potentially reduce the necessary injection pressures and increase the radius of influence around injection wells (Phillips et al., 2015b, 2016).

Aqueous solutions and suspensions are used to promote microbially-induced mineral precipitation which can be applied in subsurface environments. A leakage reduction through biofilm-induced calcium carbonate precipitation was reported by Philips (Phillips et al., 2015a,b). A strategy was developed to twice seal a hydraulically fractured 74 cm (2.4′) diameter Boyles Sandstone core, collected in North-Central Alabama. As the microorganisms were injected into the core, they could hydrolyze urea enzymatically, which could influence the saturation state of surrounding fluids in the presence of calcium to favor precipitation of $CaCO_3$. The results indicated that the fractured core permeability decreased 2 to 4 orders of magnitude after the treatment.

Microbially-induced calcite precipitation commonly abbreviated as MICP is attracting significant recognition as the emerging technology for solving subsurface engineering sealing defects in wellbore cement. The Technology involves hydrolyzing urea to produce carbonate and then carbonate react with calcium ions to form calcium carbonate as depicted in reactions 4 and 5 (Mitchell and Ferris, 2006; Mitchell et al., 2010). This formed Calcium carbonate precipitation is later controlled to form seals capable of bridging small fluid migration pathways.

$$(NH_2)_2CO + 2H2O \xrightarrow{bacteria} 2NH_4^+ + CO_3^{2-} \quad (4)$$

$$CO_3^{2-} + Ca^{2+} \rightarrow CaCO_3 \quad (5)$$

Microbes can be used to stimulate the chemistry of their surrounding environments, which lead to supersaturation and precipitation of calcium carbonate. Biofilms produce the Urease enzyme which catalyzes the hydrolysis of urea to produce precipitation of calcium carbonate ($CaCO_3$). The advantage is that MICP can be pumped further into the formation compared to higher viscosity fluids, such as cements.

This investigative research focused on method of using the MICP concept to develop leakage mitigation strategies in fractured and unfractured porous media based on controlling the activity of ureolytic microorganisms notably Sporosarcina pasteurii. These microorganisms have the possibility of increasing the pH value in the presence of calcium and saturations conditions. In addition, this technology requires the maintenance of established barriers; microbial biofilms will degrade over time without nutrient supply.

5.7. Considerations when adopting a remedial method

From the above analysis, this is evident that although there are multiple methods available to seal the fractures in cement or restore the well integrity, yet there is hardly any comprehensive method that can seal all type of fractures. In fact, most of the methods are application based and each of them has their own success criteria. For example: the most popular method “cement squeezing” has been found to be successful in sealing the larger fractures. Where there exists micro or nano scale fracture, this technique does not seem to be effective. Instead from previous experience, this is observed that several squeezing operations were required to achieve the effective sealing which contributed to both loss of production hours and increasing operating cost. Whereas polymer gel, silica gel, biofilm induced calcium carbonate precipitation - all these methods have been quite successful in sealing tiny fractures, but they have their own limitations too. In case of polymer gel, an additional pretreatment of the fracture surface is required prior to injecting polymer solution to avoid the gel breakdown through syneresis as well as their ability to block the larger fracture is yet to be examined. Biofilm induced calcium carbonate precipitation is only applicable for narrow fractures because they have an issue of homogeneous distribution along the fracture length. If the fracture is larger than usual, this may not be effective due to ununiform distribution. Moreover, this method takes quite a longer period to have an effective sealing. Experiment conducted by Philips et al. (2012) showed that 24 h biomineralization stages were performed before injecting the calcium growth medium which means the well required to do this operation will be out of production for more than this amount of time. Self-healing cement system is an good option too as it is helpful to make the fracture narrower as well as it improves the cement mechanical strength too. But complete closure of the fissure is not possible. There still may nano scale of fracture exist which is not expected regarding carbon capture and storage reservoir. Control of expansion mechanism of expansive cement is quite crucial in employing this method. But in case of nano-silica gel, it can seal both nano level to macro level fractures and gelation time can be controlled quite conveniently. But the cost and their performance under reservoir conditions need further investigated.

6. Conclusion

From our review study, this is evident that cement design, placement, initial chemical changes, stimulating operation, wellbore environment and thus cement response to changed environment are crucial

for cement ability to maintain its integrity. Selection of cement formulation model and post placement alteration play a significant role and need to be identified in advance as precise as possible. Moreover, high pressure applied during hydraulic fracturing operation or carbonation reaction in CO_2-EOR reservoir could severely affect the physical integrity of the cement and lead it to breakdown if proper measures were not taken earlier.

The available remedial methods are mostly case sensitive, there is hardly any method that will restore the well integrity comprehensively. For example, cement squeezing method is primarily successful in sealing comparatively larger fractures. It can hardly penetrate the smaller fractures due to cement particle size and high density and viscosity. To seal the nano or micro level fractures, either polymer gel or nano-silica gel or biofilm induced calcium carbonate precipitation could be the selected, though each of the method has their own shortcomings. The efficacy of self-healing system to seal the larger fractures yet to be examined. To sum up, before sealing the fractures in cementing, it is necessary to evaluate whether the applied method would be fit for purpose or has the ability to restore the well integrity effectively.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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RESEARCH LETTER
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Elevated Seismic Hazard in Kansas Due to High-Volume Injections in Oklahoma

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Key Points:
- Unified hydromechanical model to reproduce and forecast induced seismicity for western Oklahoma and southern Kansas
- The state of stress and seismicity rate in Kansas are modulated by injection in Oklahoma
- The probability of large earthquakes in Kansas is exacerbated by the hydromechanical interaction with fluid injection in Oklahoma

Supporting Information:
- Supporting Information S1

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Abstract Induced seismicity has expanded into south-central Kansas, an area with rare damaging natural earthquakes, leading to the second-highest seismicity rate in the central United States after Oklahoma. Here we assess the mechanical effects of large-scale injection in the combined area of western Oklahoma and southern Kansas during 2010–2018 and its link to the observed seismicity using physics-based hydromechanical and seismicity rate models. Such models link injection operations to seismic hazards and allow solving for the spatially variable distribution of background seismic productivity that yields an acceptable match between the observed and modeled seismicity. We show that injection in Oklahoma amplifies the total Coulomb stress change and seismicity rate by 1.5-fold and threefold, respectively, in south-central Kansas. This cross-border interaction modulates the annual earthquake probability in Kansas. We conclude that the issue of induced seismicity is not a local problem due to the far-reaching effects of fluid diffusion.

1. Introduction

A large body of evidence suggests that the sharp increase in the number of earthquakes in the eastern and central United States over the past decade is linked to the large volume of deep waste fluid disposal (Ellsworth, 2013; Rubinstein & Mahani, 2015). States experiencing the issue of induced seismicity include Oklahoma (Keranen et al., 2014), Texas (Frohlich, 2012), Colorado (Ake et al., 2005; Block et al., 2014; Yeck et al., 2014; Yeck et al., 2016), Arkansas (Horton, 2012), Ohio (Kim, 2013), New Mexico (Rubinstein et al., 2014), and California (Goebel et al., 2016). This issue has extended to Kansas, an area with a low risk of damaging natural earthquakes with a historical average of one M3.0+ earthquake every 1 to 2years (Peterie et al., 2018; Rubinstein et al., 2018). The rapid increase of seismicity since 2014 in south-central Kansas correlates with the regional growth of fluid injection into the Cambrian-Ordovician Arbuckle Group (Peterie et al., 2018). This seismic activity makes Kansas the state with the second-highest seismicity rate in the central United States. The Milan M_w4.9 earthquake in 2014 highlights the elevated seismic hazard in Kansas due to fluid injection (Choy et al., 2016; Hearn et al., 2018).

The underlying mechanism of injection-induced seismicity is well known. Fluid injected into the disposal formation diffuses in the medium and increases the pore pressure and creates poroelastic stresses, reducing frictional strength on faults and bringing them closer to failure (Healy et al., 1968; Raleigh et al., 1976). Although direct observation of subsurface pressure change is limited, this mechanism is supported by numerical simulations (Fan et al., 2016; Keranen et al., 2014; Shirzaei et al., 2016). Monitoring of Arbuckle formation pressure provides strong evidence linking the fluid injection and induced seismicity within the U.S. midcontinent through pore pressure changes (Ansari et al., 2019; Barbour et al., 2019; Kroll et al., 2017; Peterie et al., 2018). However, the relationship between fluid injection and pore pressure evolution is complex in time and space (Zhai et al., 2019; Zhai & Shirzaei, 2018). The spatiotemporal evolution of pore pressure and poroelastic stresses depends on several factors including the location, depth, and volume of injection wells as well as hydrogeological properties of the permeable reservoir (Zhai et al., 2019; Zhai & Shirzaei, 2018), which can be estimated using seismic and geodetic observations (Shirzaei et al., 2019).

Peterie et al. (2018) investigated bottom-hole pressure data in southern Kansas and showed that starting in 2011, formation pressures begin to increase suddenly despite the near-steady rate of injection. They also

noticed a northward propagation of seismicity. These observations suggest that the pressure rise may not be solely due to local injection and may be influenced by fluid migration from the distant, high-volume injection wells located near the Oklahoma-Kansas border region, nearly 90 km away (Peterie et al., 2018). Kansas thus provides an opportunity for studying the impact of distant fluid injection on regional induced seismicity.

Previous studies have focused on the pore pressure and poroelastic stress perturbations within 40 km of injection wells, resolving the first-order correlation between pore pressure and stress changes and the occurrence of isolated earthquake swarms or sequences (Goebel et al., 2017; Keranen et al., 2014). However, a quantitative study of the impact of distant injections on the local induced seismic hazard is needed. Here, we compile the injection, seismicity, and hydrogeological data for the combined area of western Oklahoma and southern Kansas during 2010–2018. We apply a physics-based induced seismicity forecasting framework to construct a unified hydromechanical model to simulate the seismicity rate within the study area caused by fluid injection. Using this model, we evaluate the impact of the far-field injections in western Oklahoma on seismic hazard in south-central Kansas.

2. Data Sets

2.1. Fluid Injection

We compile reported wastewater injection data for 668 Class II injection wells within western Oklahoma and southern Kansas, distributed by the Oklahoma Corporation Commission and the Kansas Corporation Commission. A large amount of saltwater, coproduced from oil and gas production, was injected into the Cambrian-Ordovician Arbuckle formation during 2010–2018 with a total volume of 5.87×10^8 m^3. Figure 1a shows the Arbuckle well locations, with 325 and 343 wells within Oklahoma and Kansas, respectively. The injection rate shows substantial spatiotemporal variability (Figures 1a and 1b). Note that most high-volume injection wells are within Oklahoma rather than Kansas (Figure 1a). The total injection volume in Oklahoma is ~2.8 times that in Kansas for the period of 2010–2018, while that value is ~3.3 for 2014–2016, during which seismicity peaks in Kansas (Figure 1b). The injection rate starts to increase in 2012 and peaks in early 2015. It then decreases to a level determined by the injection reduction plan in response to increased seismicity in both Oklahoma and Kansas. The coincidence of injection and seismicity increase suggests a causal link (Peterie et al., 2018).

We note that the injection volume is reported monthly in Oklahoma, while that in Kansas before 2015 is accessible online as yearly. To construct a unified hydrogeological model due to fluid injection within the combined region, as a first-order approximation, we calculate the average monthly injection rate from the yearly reported values in Kansas during 2010–2014.

2.2. Seismicity

The seismicity catalogs are obtained from the Kansas Geological Survey (KGS) and Oklahoma Geological Survey (OGS) from 2010 to 2018. Both Kansas Geological Survey and Oklahoma Geological Survey catalogs have the same magnitude of completeness of ~M2.0 (Supporting Information Figure S2). Despite the fact that different earthquake catalogs may use different magnitude scales, the empirical scaling indicates that such differences are small (Al-Ismail et al., 2019).

The recorded seismicity contains both injection-induced earthquakes as well as their aftershocks. To focus on earthquakes linked directly to injection operations, we use the algorithm of Reasenberg (1985) for earthquake catalog declustering to remove dependent earthquakes (Figure S1). Due to the spatial proximity of Kansas and Oklahoma, the parameters associated with the declustering algorithm are chosen following the previous study of induced seismicity in Oklahoma (Zhai et al., 2019). The declustering procedure reduces the total earthquake counts and seismic moment in Kansas and Oklahoma by ~63% and 40%, respectively, but the earthquake magnitude of completeness remains unchanged and is ~ M2.0 (Figures S2). Thus, we only use declustered M2.0+ earthquakes for further analysis. In Kansas, most induced earthquakes occur within the south-central region (Peterie et al., 2018). Figure 1c shows the distribution of declustered seismicity in this region with a focus on Sumner and Harper counties. Noteworthy, during the study period is the 2014 M_w4.9 Milan earthquake.

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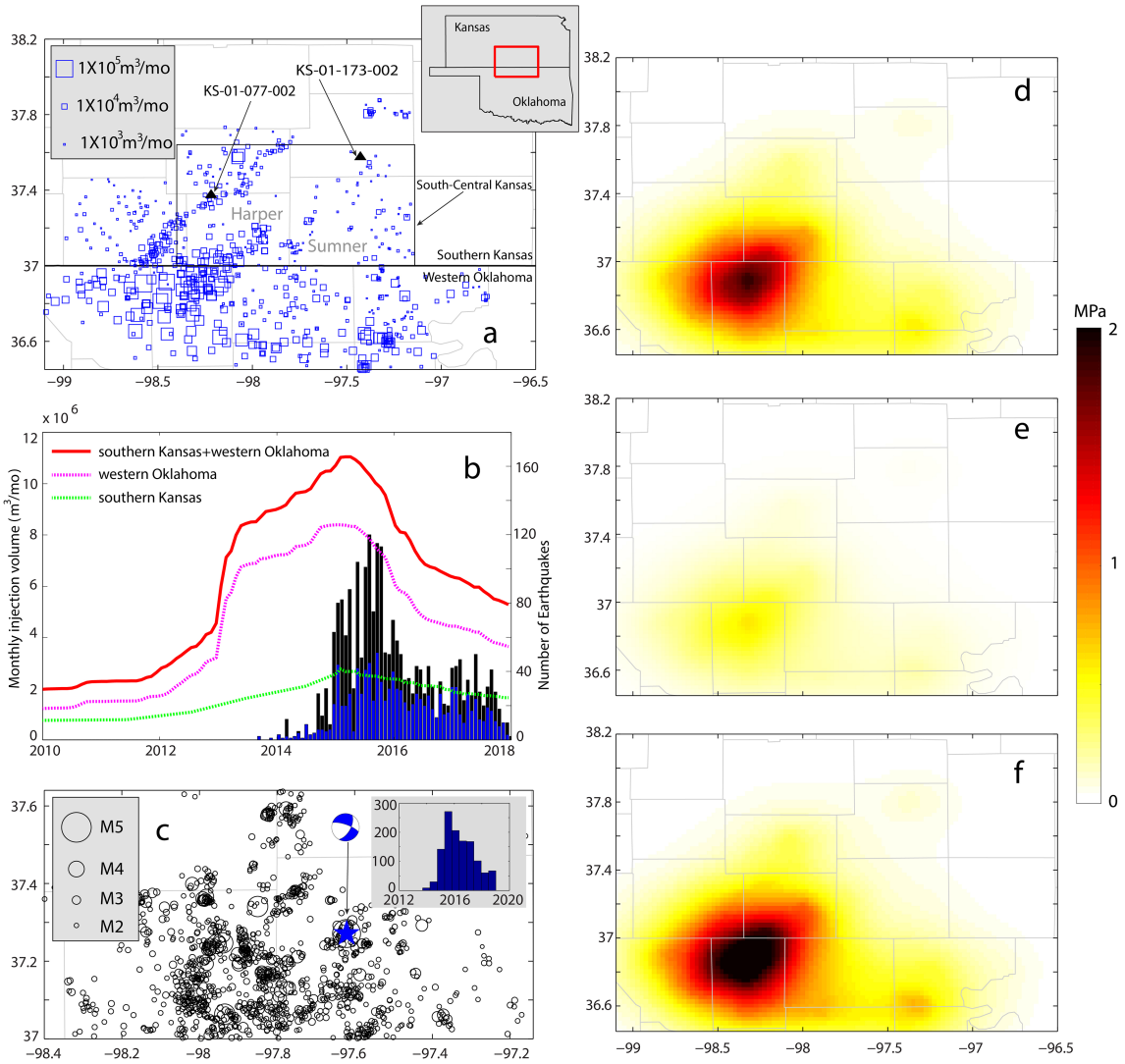


Figure 1. (a) Spatial distribution of Class II injection wells (blue squares) scaled with average monthly injection volume. Black triangles indicate the two Class I well locations that monitor bottom-hole pressure. Black rectangle indicates the area of south-central Kansas. Red rectangle in the inset shows the combined area of western Oklahoma and southern Kansas. (b) Time series of monthly M2+ earthquake number (black: original catalog from Oklahoma and Kansas Geological Survey; and blue: declustered catalog) in south-central Kansas and monthly injection volume for southern Kansas wells, western Oklahoma wells, and their addition. Kansas injection time series prior to 2015 is downsampled and reported as annual averages. (c) Spatial distribution of declustered M2+ earthquakes in south-central Kansas. Blue star shows the 2014 Milan Mw4.9 earthquake. Inset shows semiannual number of declustered M2+ earthquakes within south-central Kansas. (d) Distribution of pore pressure change scaled with friction coefficient (Table S2) during 2010–2018. (e) Coulomb stress change due to poroelastic stresses during 2010–2018. (f) Total Coulomb stress change due to both pore pressure change and poroelastic stress change. The detailed spatial and temporal evolution of pore pressure and poroelastic stress is shown in Figures S5 and S6.

3. Hydromechanical and Seismicity Rate Models

To establish the link between injection operations and seismicity, we use a physics-based induced earthquake forecasting framework, which has been used to investigate induced seismicity in Texas and Oklahoma and to evaluate the time-dependent seismic hazards due to fluid injection (Zhai et al., 2019; Zhai & Shirzaei, 2018). In this approach, the process of fluid diffusion in a poroelastic medium is linked to the mechanism of earthquake nucleation on a prestressed fault.

3.1. Hydromechanical Model

Based on the regional hydrogeological setting within the combined area of western Oklahoma and southern Kansas, we set up a poroelastic Earth model with four significant layers, including a shallow aquifer, shale,

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the Arbuckle formation, and a granite basement (Text S1 and Figure S3). Each layer is characterized by five hydrogeological parameters shown in Table S1. The associated parameter values are constrained based on rock properties (Perilla-Castillo, 2017; Wang, 2000), seismic velocity (Chen, 2016; Christensen, 1996), and seismicity migration (Peterie et al., 2018). The relative distance between injection depth and the basement interface is a crucial factor controlling induced seismicity (Hincks et al., 2018) and is calculated using Arbuckle well log, depth, and isopach information (Campbell & Weber, 2006; Franseen et al., 2004; Franseen & Byrnes, 2012). The unified, curved Arbuckle-basement interface within Oklahoma and Kansas is approximated using a polynomial function (Figure S4). The relative distance between injection well-bottom depth and basement interface is used to determine the injection depth within the layered poroelastic model (Figure S3). We use the numerical solution provided by Wang and Kümpel (2003) to simulate the spatial and temporal evolution of poroelastic stresses and pore pressure due to fluid injected into the isotropic, layered poroelastic half-space. Since we use a linear poroelastic model, we can superimpose the solutions from all injection wells. Considering that the basement faults penetrate into the overlying permeable Arbuckle formation (Kolawole et al., 2019) and host fast fluid flow (Chang & Yoon, 2018; Hearn et al., 2018; Scibek et al., 2016), we estimate the changes of pore pressure and poroelastic stresses due to fluid injection at the Arbuckle-basement boundary. More information is provided in Text S1.

3.2. Earthquake Nucleation Model

We employ a rate-and-state earthquake nucleation model to simulate the evolution of seismicity rate along faults in response to Coulomb stress changes (Dieterich, 1994; Heimisson & Segall, 2018; Segall & Lu, 2015). This model calculates the expected number of earthquakes relative to the background rate as a function of time due to stress perturbations on a given fault:

$$\frac{dR}{dt} = \frac{R}{t_a}\left(\frac{\dot{\tau}}{\dot{\tau}_0} - R\right), \tag{1}$$

where R is the seismicity rate relative to the background rate; $\dot{\tau}_0$ is the background stressing rate; $t_a = \frac{A\overline{\sigma}}{\dot{\tau}_0}$ is the characteristic relaxation time; A is a constitutive parameter in the rate-and-state-dependent friction law (Dieterich, 1994); $\overline{\sigma}$ is the background effective normal stress; and $\dot{\tau}$ is the Coulomb stressing rate time series. In addition, we include a critical time t_{crit} to account for the Arbuckle pressure deficit prior to the observed seismicity increase following Zhai et al. (2019).

The Coulomb stressing rate is computed using the stress and fluid pressure from the poroelastic model, which are spatially and temporally variable (see section 3.1). To calculate the normal and shear components of the stress tensor on faults, we use a receiver fault geometry consistent with that of the 2014 M_w4.9 Milan earthquake, which is also compatible with the regional tectonic stress field and mapped fault distribution (Schoenball & Ellsworth, 2017). The background stressing rate $\dot{\tau}_0$ is based on the geodetic study of strain within the Northern American Plate (Calais et al., 2006). The value of $A\overline{\sigma}$ is set following that proposed by Segall and Lu (2015). The model parameters are provided in Table S2.

3.3. Earthquake Magnitude-Time Simulation

Combining the seismicity rate model and Gutenburg-Richter law, we simulate an earthquake magnitude-time distribution over a particular area and then compare it with observations. The earthquake count per unit area, per unit time, t, per unit magnitude, M, at a specific location $\boldsymbol{x}$ is given by

$$R(\boldsymbol{x}, t, M) = \ln(10)k(\boldsymbol{x})b10^{-bM}R(\boldsymbol{x}, t), \tag{2}$$

where a and b are two parameters associated with the Gutenberg-Richter frequency-magnitude distribution and $k(x)$ is the background seismicity rate defined as $\frac{10^a}{S \times t}$, where S is area. Here, a is location dependent, and we assume spatially constant b value, which is set to 0.93, supported by declustered seismic catalog of the study area (Figure S2). The total number of earthquakes per unit time per unit magnitude is given by integrating over area, S:

$$R(t, M) = \int_S R(\boldsymbol{x}, t, M)d\boldsymbol{x}. \tag{3}$$

Next, we simulate the magnitude-time distribution governed by the function $R(t,M)$. To this end, we discretize the interval, t, into N_t bins of length Δt. We also define the minimum and maximum magnitudes of M_{min}

and M_{max} to mimic a probability distribution. We set M_{min} to 0 and M_{max} to 10 and for each period $[t_i\ t_{i+1}]$, we calculate the total number of earthquakes:

$$N(t_i) = \int_{M_{min}}^{M_{max}} \int_{t_i}^{t_{i+1}} R(t, M) dt dM. \quad (4)$$

We next define a cumulative probability distribution as a function of earthquake magnitude:

$$P(M; t_i) = 1 - \frac{\int_{M}^{M_{max}} \int_{t_i}^{t_{i+1}} R(t, M) dt dM}{\int_{M_{min}}^{M_{max}} \int_{t_i}^{t_{i+1}} R(t, M) dt dM}. \quad (5)$$

We randomly sample this distribution over each interval $[t_i\ t_{i+1}]$ for $N(t_i)$ earthquakes and iterate over the entire observation period to determine the magnitude-time distribution.

4. Results

4.1. Hydromechanical Modeling and Seismicity Rate

We use the records of saltwater injection volume at 668 wells within western Oklahoma and southern Kansas as input to the poroelastic model. We simulate the spatial and temporal evolution of pore pressure and poroelastic stresses for the period 2010–2018. The obtained pore pressure and poroelastic stress models are then used to calculate the time series of changes in the Coulomb failure stress. Next, we apply the rate-and-state-dependent earthquake nucleation model (equation (1)) to estimate the time-dependent seismicity rate changes. The model parameters are listed in Tables S1 and S2. Figures 1d–1f show the cumulative changes in pore pressure, poroelastic stresses, and Coulomb failure stress within the combined area of western Oklahoma and southern Kansas during 2010–2018. The snapshots of annual changes are shown in Figure S5. They show an increasing rate that peaks in 2017, followed by a decaying trend (Figure S6). The contribution of pore pressure change dominates the change of Coulomb failure stress. Also, two Class I wells in the study area (Figure 1a) measure the well-bottom pore pressure (Ansari et al., 2019), which can be used to validate the simulated pore pressure changes. We find a reasonable agreement at well KS-01-077-002 (Figure S7a). However, at well KS-01-173-002 (Figure S7b), the magnitude of simulated pore pressure change is about eight times smaller than that observed. These observations are further discussed in section 5.1. The computed seismicity rate, informed by the Coulomb stressing rate (equation (1)), peaks in mid-2015 (Figures S5 and S6), consistent with the temporal pattern of injection volume (Figure 1b). The seismicity rate snapshots show outward propagation with a decreasing amplitude following large injection rate reduction at high-volume wells.

4.2. Calibration of *k* Value

As seen in Figure 2a, there is a correlation between the location of observed seismicity and that predicted from the seismicity rate model. However, there are zones with a predicted seismicity rate increase but no observed seismicity. To simulate an earthquake catalog, our model requires an estimate of background seismicity rate and predicted seismicity rate change. For the study area, we can assume that the background stressing rate is uniform (Levandowski et al., 2018). Therefore, we suggest that the apparent discrepancy between the simulated relative seismicity rate and observed seismicity is due to spatially variable background seismicity. We can use this discrepancy to estimate the spatially variable k value across the study region, mapped on to the grid used for hydromechanical modeling (section 3.1). We consider the area within a 10-km radius from the center point of each grid cell and compare the number of observed and simulated earthquakes. We assume an unknown k for each circular zone and integrate the right side of equation (2) over its area and the entire observation period of 2010–2018 for magnitudes larger than M2.0, namely, the magnitude completeness of seismic catalog (see Figure S2). This operation ensures that the simulated relative earthquake rate times the unknown k equals the number of observed earthquakes and thus the k value can be estimated for that zone. Figure 2b shows the spatial distribution of the log-transformed k value, which can be used to simulate the earthquake magnitude-time distribution.

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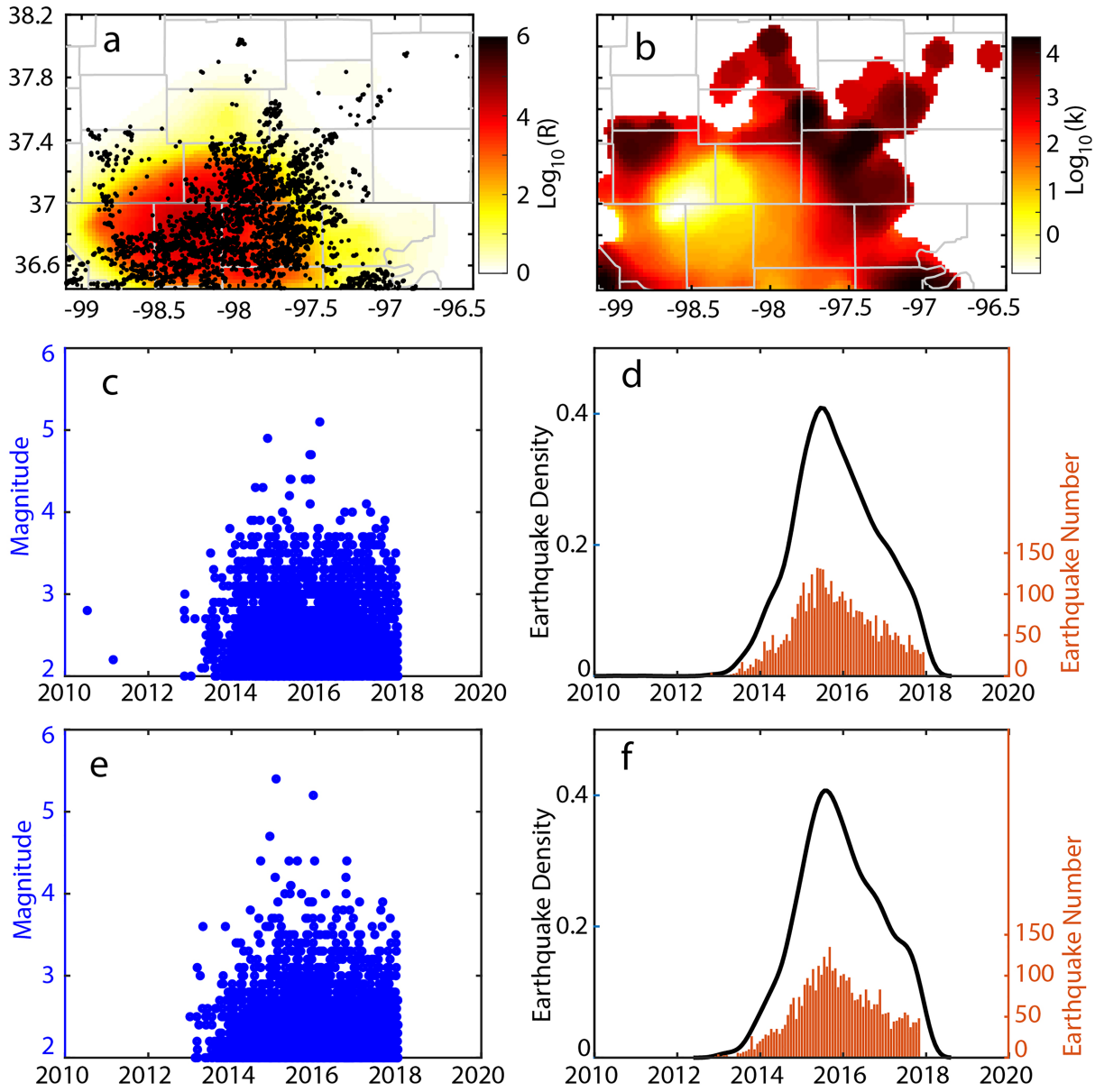


Figure 2. (a) Spatial distribution of observed declustered M2+ earthquakes and temporally average simulated relative seismicity rate for western Oklahoma and southern Kansas. (b) *k*-value distribution obtained by comparing the observed and simulated seismicity rate for western Oklahoma and southern Kansas. (c, e) The observed (panel c) and simulated (panel e) earthquake magnitude-time distributions for the combined area. (d, f) The observed (panel d) and simulated (panel f) earthquake histogram and earthquake count probability density for the combined area. The black curves are probability densities of earthquake number calculated from the earthquake histograms.

4.3. Earthquake Magnitude-Time Distribution

The Gutenberg-Richter law that characterizes background seismicity before fluid injection and the relative seismicity rate change obtained from hydromechanical simulations allow us to simulate the earthquake magnitude-time distribution. In addition to induced earthquake frequency, our method (see section 3.3) can reproduce the time dependence of earthquake magnitude, which is the starting point for time-varying induced earthquake hazard assessment. Figures 2c and 2e show the observed earthquake-time distribution and that simulated using the distributed *k* values and relative seismicity rate. The temporal evolution of seismicity in terms of earthquake magnitude and frequency is reproduced (Figures 2c–2f), and the total number of earthquakes is similar. A peak in 2015 characterizes both observed and simulated magnitude-time distributions.

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5. Discussion

To assess future seismic hazard, we need to understand the sensitivity of our results to model parameters, evaluate the role of distant injection, and compute the expected magnitude of induced earthquakes. Seismic hazard is a forecast of seismic ground shaking intensity at a specified site during an interval of time, which is linked to earthquake probability and ground motion equations (Baker, 2015). Thus, earthquake probability can be a first-order manifestation of seismic hazard, whose conversion to the ground motion probability is straightforward (Baker, 2015).

5.1. Model Uncertainties

Although our model successfully reproduces the time series of pore pressure change during 2010–2018 at Class I well KS-01-077-002 (Figure S7a), the simulated pore pressure change at Class I well KS-01-173-002 is eight times smaller than that observed (Figure S7b). This underestimate can be due to several factors. In addition to monitoring well-bottom pressure, Class I wells also inject fluid into the Arbuckle formation, which can locally increase pore pressure. This effect is more significant at KS-01-173-002 because the injection volume at KS-01-173-002 is one order of magnitude larger than that at KS-01-077-002 (Ansari et al., 2019). However, the depths of Class I wells are not available, which prevent us from including Class I well injection in the hydromechanical simulation. Also, the simulated pore pressure change from our model is at the Arbuckle-basement interface, while Class I well-bottom pressure record can have shallower depths. The different simulation and observation depths can result in a significant difference in pore pressure because pore pressure decays exponentially in space (Segall & Lu, 2015). To assess this effect, we implemented simulations using the published injection volumes at KS-01-173-002 during 2010–2016 (Ansari et al., 2019), assuming a range of well depths. Figure S8 shows that the well-bottom pressure is larger than that at the Arbuckle-basement interface if the well depth is shallower. However, the observed well-bottom pressure falls within the range of simulated well-bottom pressure (Figures S7 and S8), suggesting that the observed well-bottom pressure is largely due to Class I well injection at KS-01-173-002.

Besides heterogeneous background seismic productivity, the other possibilities to explain the apparent discrepancy between simulated and observed seismicity rate include heterogeneous background tectonic stress and diffusivity. However, the regional stress map indicates that tectonic stress is relatively uniform within our study area (Levandowski et al., 2018). While diffusivity is likely not uniform (Ansari et al., 2019; Zhai et al., 2019), it has only a second-order effect because injection wells are located within the zone with no observed seismicity (Figures 1a and S1), and the bottom of injection wells is close to the Arbuckle-basement interface (Figure S4).

The triggering mechanisms for injection-induced seismicity include pore pressure diffusion, poroelastic stresses, and static Coulomb stress transfer. In this work, we only focus on pore pressure and poroelastic stresses and decluster the earthquake catalog to eliminate earthquake sequences. Other studies suggest that earthquakes can be caused in part by previous induced events or aseismic slip through static Coulomb stress transfer (Bhattacharya & Viesca, 2019; Brown & Ge, 2018; Qin et al., 2018) in addition to the direct effect of fluid injection. More effort is needed to incorporate the static Coulomb stress transfer into seismicity rate forecasting.

5.2. The Effect of Cross-Border Injection

Many induced earthquakes occur near injection wells, and the seismicity is preceded by high-volume fluid injection over months to years. However, some studies also show that earthquakes occur beyond zones of high-volume injection, suggesting mechanical interaction between distant injection operations and seismicity. Keranen et al. (2014) show that pore pressure changes caused by high-volume injections near Oklahoma City can propagate ~35 km to explain the 2011 Jones earthquake swarm. The Fairview earthquake sequence may have been triggered by clustered fluid injection 40 km away near the Oklahoma-Kansas border; however, instead of pore pressure propagation, poroelastic stresses were proposed to be the driver of the seismicity (Goebel et al., 2017). Regardless of the mechanisms, these observations indicate that the stress field perturbation due to fluid injection can reach as far as 40 km. The present study provides another example of the far-reaching impact of fluid injection in south-central Kansas that possibly acts over distances of up to 90 km (Peterie et al., 2018). Although geospatial analysis of fluid injection and seismicity in Oklahoma implies that this far-reaching triggering is possible, the

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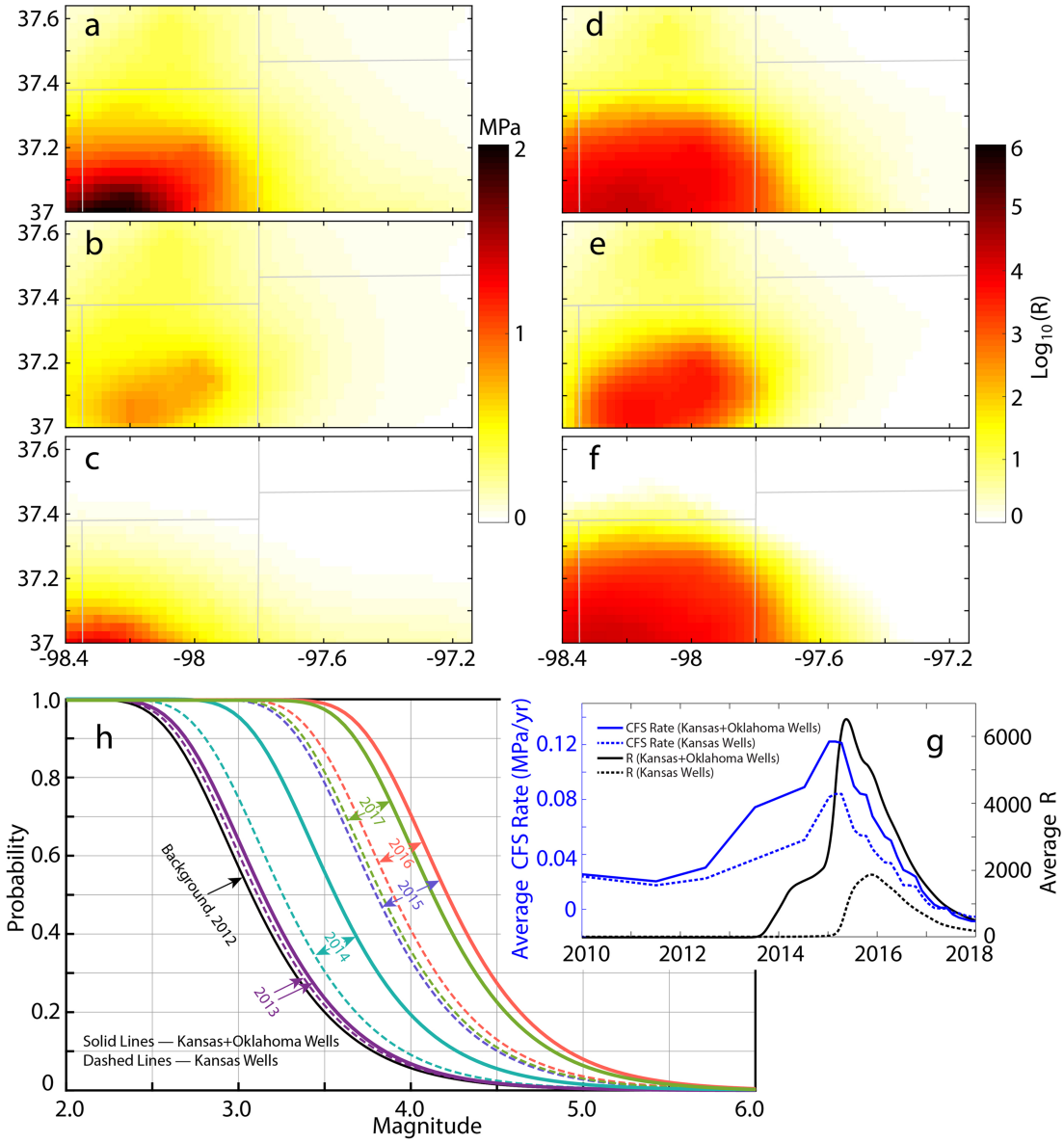


Figure 3. (a) Cumulative Coulomb failure stress during 2010–2018 in south-central Kansas due to both western Oklahoma and southern Kansas wells. (b) Same as panel a but only considering Kansas wells. (c) The difference between that shown in panels a and b. (d, e) The distribution of average simulated seismicity rate in logarithmic scale during 2010–2018 corresponding with stress change shown in panels a and b, respectively. (f) The difference of *R* between panels d and e. (g) Time series of average Coulomb failure stressing rate and seismicity rate within south-central Kansas with and without western Oklahoma wells. The stressing rate prior to 2015 is downsampled to an annual average. (h) Annual earthquake magnitude exceedance probability in south-central Kansas with (solid lines) and without (dashed lines) western Oklahoma wells. Note that the 2015 and 2016 solid curves overlap.

importance of geological complexities are not considered (Pollyea et al., 2018). The northward propagation of seismicity in Kansas indicates that fluid diffusion from the south is the main driver (Peterie et al., 2018). Our unified hydromechanical model allows us to examine the far-reaching effect of injection in Western Oklahoma on the stress field (Figures 3a–3c) and the associated seismicity rate (Figures 3d–3f) in south-central Kansas. The western Oklahoma wells can affect spatial patterns of Coulomb stress change and seismicity rate distribution with the highest effect in the southern part of south-central Kansas that diminishes northward (Figures 3c and 3f). Including western Oklahoma wells, in addition to southern Kansas wells, increases Coulomb stressing rate by a factor of 1.5 in south-central Kansas, which advances the seismicity increases by 1–2 years and amplifies seismicity rate by approximately threefold (Figure 3g).

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5.3. Probabilistic Seismic Hazard

A crucial component of probabilistic seismic hazard analysis is an estimate of the spatiotemporal distribution of seismicity (Cornell, 1968). Generally, the seismicity distribution is modeled through smoothing the recorded earthquakes to obtain a grid of Gutenberg-Richter sources. Applying probabilistic seismic hazard analysis to estimate future seismic hazard due to anthropogenic processes, such as injection-induced earthquakes (Petersen et al., 2016; Petersen et al., 2017; Petersen et al., 2018), is challenging because injection operations and thus subsequent seismicity show substantial spatial and temporal variations, which cannot be captured robustly using conventional methods of spatial smoothing and temporal extrapolation.

Our method considers the physical processes of fluid diffusion and rate-and-state earthquake nucleation to simulate relative seismicity rate, which is scaled with background seismicity rate to obtain absolute seismicity rate. Due to limited seismic activity before 2012, estimating the k-value distribution, which characterizes the background seismicity rate distribution, is not possible. However, fluid injection operations can relate background seismicity to observations through physical models, allowing us to estimate background seismicity indirectly. Assuming that the background tectonic loading, and thus the background seismicity rate, is steady, then we can reasonably use the mapped k value to forecast expected future earthquake probability due to stress evolution under specifically designed injection scenarios. For combined western Oklahoma and southern Kansas, the injection data are collected through December 2017. Therefore, we focus on the retrospective investigation of earthquake probability until the end of 2017. We estimate earthquake magnitude exceedance probability ($P_{\geq M}$) considering the Poisson process:

$$P_{\geq M} = 1 - \exp(N_{\geq M}), \tag{6}$$

where $N_{\geq M}$ is the estimated number of earthquakes with magnitude larger than or equal to M through the integration of equation (2). The value of exceedance probability depends on time and space scales considered. Here, we show the annual earthquake exceedance probability over the area of south-central Kansas (Figure 3h). The annual exceedance probability is time dependent, and the annual probability for exceeding M4 increases from 7% in 2013 to 70% in 2015 and 2016, followed by a decrease to 63% in 2017. Also, we calculated the exceedance probability by ignoring Oklahoma injection, which results in a consistent probability decrease for each year with a maximum reduction of 36 % in 2015 for exceeding M4.

6. Conclusions

We construct a unified hydromechanical and induced seismicity rate model in the combined area of western Oklahoma and southern Kansas. This physics-based model, combined with seismic observations, can be used to map background earthquake productivity. It also allows us to examine and quantify the long-distance mechanical interactions between injection practices and induced seismicity. We demonstrate that injection in Oklahoma can change the spatiotemporal patterns and amplitudes of Coulomb failure stress and seismicity rate in Kansas. Ignoring these interactions results in systematic underestimates of annual earthquake magnitude exceedance probability in Kansas. These results highlight that the far-reaching effect due to fluid diffusion is crucial in understanding induced earthquake nucleation and assessing the associated seismic hazard. Since fluid pressure and stress changes do not respect state or county borders, regulation and management should be coordinated across agencies to mitigate induced seismicity.

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Review

Review of integrity of existing wells in relation to CO_2 geological storage: What do we know?

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ABSTRACT

Carbon dioxide storage in geological media is a climate change mitigation technology that is based on the ability of certain geological media to retain CO_2 in supercritical phase or dissolved in formation water and to prevent its return to the atmosphere for very long periods of time. However, in certain cases there are flow pathways, natural or manmade, conducive to CO_2 leakage. Depending on their condition, existing oil and gas wells may provide such leakage pathways due to either mechanical defects developed during well drilling, completion and/or abandonment, or to chemical degradation of well cements and/or casing. In the case of CO_2 storage, there is a concern that well cement in existing wells will degrade in the presence of water-saturated CO_2 and/or CO_2 saturated formation water/brine, thus creating new leakage pathways and compromising the integrity and security of CO_2 storage. In this paper we review the status of knowledge in regard to the failure of existing wells, with special attention to the laboratory experiments, field investigations and numerical simulations carried out in the last several years in attempts to elucidate the behavior of well cements in the presence of CO_2. Extensive carbonation has been observed in well cements in both laboratory and field studies. However, in CO_2-rich environments, severe cement degradation is associated with the dissolution of calcite from the carbonated cement. This is not expected under typical geological storage conditions because CO_2-saturated brine is likely in equilibrium with carbonate minerals that are present in virtually all formation rocks.

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1. Introduction

Warming of the climate system is evidenced by observations of increases in global air and ocean temperatures, widespread melting of glaciers and ice caps, and raising global average sea level (IPCC, 2007). This climate warming is attributed to human activity since the beginning of the industrial revolution that led to corresponding increases in the concentration of carbon dioxide (CO_2), methane and nitrous oxide in the atmosphere, which have a greenhouse effect (IPCC, 2007). A major challenge in mitigating climate change effects is the reduction of CO_2 emissions to the atmosphere, which can be achieved through a portfolio of measures that include energy efficiency and conservation, switching from carbon-heavy fuels like coal to carbon-light fuels like natural gas, switching power generation from fossil energy to nuclear energy, increasing use of renewable forms of energy, and carbon capture and storage (CCS) (IEA, 2004, 2010). The latter entails CO_2 capture from large industrial processes, mainly power generation based on fossil fuels, and injection into deep geological formations in sedimentary basins, mainly hydrocarbon reservoirs and deep saline aquifers (IPCC, 2005).

For CCS to be successful, three fundamental conditions have to be met by the storage medium: (1) capacity, (2) injectivity, and (3) confinement (Bachu, 2003, 2010; IPCC, 2005). The last condition is critical because CO_2 leakage poses local risks to other resources, potable groundwater, vegetation and animal life, and to human health (IPCC, 2005), notwithstanding the global aspect of the return of CO_2 to the atmosphere, even if it is at acceptable levels (Celia and Bachu, 2003; Pacala, 2003; IPCC, 2005). Pathways for CO_2 leakage are natural (e.g., active or reactivated faults, open fractures, interruptions and breaches through the confining strata) and man-made, mainly wells (Bachu and Celia, 2009). The potential for CO_2 leakage through existing wells, either active or abandoned, is particularly important in mature sedimentary basins with a history of oil and gas exploration and production. Well integrity may be compromised as a result of poor completion or abandonment, and of well operation. Crow et al. (2010) defined "wellbore integrity" as a condition that maintains isolation of geological formations and prevents vertical migration of fluids. In this review, we refer to the defects that are developed during these operations as "mechanical", and discuss first the processes leading to mechanical failures of existing wells that are not CO_2 injectors. In regard to cement degradation processes, these mechanical failures may be considered as pre-existing conditions.

Of special concern in the case of CO_2 storage in geological media is the effect of CO_2 on well cements, the concern being that reaction of supercritical CO_2 and/or CO_2-saturated formation water with well cements could potentially cause cement degradation. This concern has been supported by early laboratory experiments conducted to understand the durability of well cements for CO_2-EOR and acid gas injection operations (Onan, 1984; Bruckdorfer, 1986; Krilov et al., 2000; Jacquemet et al., 2005). Recently, more laboratory studies have been performed under conditions relevant specifically to CCS applications. Rapid degradation was observed in cement samples undergoing a continuous flush of CO_2-saturated brine (Duguid et al., 2004, 2005). Under different experimental conditions, however, much slower carbonation rates were measured (e.g., Kutchko et al., 2007, 2008; Barlet-Gouédard et al., 2009; Duguid and Scherer, 2010). The latter findings are comparable to the analysis of cement cores recovered from a well in Texas that had been exposed to CO_2 for 30 years (Carey et al., 2007) and from another 30-year old production well in a natural CO_2 reservoir in Colorado (Crow et al., 2009, 2010). These works consistently suggest that Portland cement based wellbore systems, if properly completed and abandoned, can prevent significant migration of CO_2 from reservoirs for long period of time. A review of the literature on the integrity of well cements in contact with CO_2 and CO_2-saturated formation water is the focus of this study. We have summarized the knowledge to date and addressed important aspects in cement degradation studies relevant to CO_2 geological storage.

2. Mechanical well failure

Following drilling, all wells are completed by running a steel casing pipe in the borehole and cementing the casing in place by circulating a cement slurry down the casing and up the annular space between the casing and the surrounding rock (Nelson and Guillot, 2006). This cement should shield the steel casing from contact with subsurface fluids and should prevent these fluids from migrating vertically through the wellbore annular space to reach other zones. Leakage in the annulus is often detected as a sustained casing pressure (SCP) or as surface casing vent flow (SCVF), depending if the surface casing vent is closed (SCP) or open (SCVF). The Minerals Management Service (MMS, 2000) defines SCP as a pressure measurable at the casinghead of a casing annulus that rebuilds when bled down and that is not due solely to temperature fluctuations and is not a pressure that has been deliberately applied (see, e.g., Watson and Bachu, 2009, for a diagram of the main well components, including the well head and surface casing vent, and a picture of the latter in the field).

2.1. Factors affecting the potential for well leakage

Watson and Bachu (2009) ascribed well leakage to poorly cemented casing/hole annulus, casing failure, and abandonment failure. Interfaces between cement and formation rock and/or casing, and casing and plug were identified as the preferential pathways for fluid flow (Gasda et al., 2004). In the cement annulus, migration of fluid could also occur through fractures, channels, or through the pore space. In the latter case, fluid flow would occur only when cement was degraded or did not form properly during the emplacement process.

The analysis by Watson and Bachu (2009) of 315,000 oil, gas and injection wells in Alberta, Canada, has shown that wellbore deviation, well type, abandonment method, whether or not cement is present, and the quality of cement are the key factors that may contribute to, and may be indicative of potential well leakage in the shallower part of wells. No correlation was found between leakage and well age, operational mode, completion interval, and the presence of acid gas (H_2S and CO_2) in the produced fluids. Although not found through data analysis, well age was expected to have an impact on wellbore leakage due to poorer quality of materials and less advanced techniques used in well construction and to

more relaxed or no regulatory requirements in earlier times. This hypothesis is supported by Nicot et al. (2006) who documented that salinization of shallow groundwater and surface water in West Texas was most likely due to formation water migration through leaking wells from 1920 to 1930s.

Watson and Bachu (2008) evaluated the potential leakage from the deep regions of a wellbore by considering well stimulation treatment methods (hydraulic fracturing and acidizing), multiple completions (perforation intervals), and abandonment methods. In addition to these factors, the authors also discussed various cement types, especially cement additives, in terms of their ability to withstand CO_2 attack. Cement additives, such as bentonite (or other gel additives) and gypsum, were considered to have a negative impact on cement durability. Bachu and Watson (2009) also studied the 79 wells used for CO_2 injection in CO_2-EOR operations and acid gas (a mixture of H_2S and CO_2) disposal in Alberta, Canada. They found that the percentage of well failures is higher for the converted wells than for those drilled and completed specifically for injection, and that most failures are not caused by injection per se. The results also showed that the introduction of more stringent regulatory requirements in Alberta in 1994 reduced the incidence of well failure (Bachu and Watson, 2006, 2009).

2.2. Well completion and operation: impact on well integrity

The failure of cement seals is caused primarily by poor bonding of cement to the formation rock, the creation of gas channels and micro fractures in cement sheath, or by the development of a micro annulus between cement and casing (Wojtanowicz, 2008). If a substantial thickness of mud cake develops during the drilling process and is not removed prior to cementing, the formation/cement bond may not form properly (Bittleston and Guillot, 1991). During the cement setting process, gas can invade the cement and form channels. Gas migration that occurs during cementing is related to slurry characteristics, displacement mechanism, and hydrostatic pressure (Bol et al., 1991; Bonett and Pafitis, 1996). After the cement sets, cyclic pressure and temperature variations during production may lead to debonding, tensile failure or stress crushing of the cement (Khandka, 2007). Mechanical shocking can also play a certain role in weakening the casing–cement bond. In addition to variations in temperature and pressure, the formation of circumferential fractures due to cement shrinkage was proposed as an alternative mechanism to explain gas accumulation in wellbores after cement sets (Dusseault et al., 2000).

Bachu and Bennion (2009) measured permeability of cement–casing pairs in four tests. In the case of perfect bonding between cement and casing, an effective permeability of less than 10^{-6} mD (10^{-21} m^2) was measured for the combined casing–cement sample. When poor bonding between cement and casing was created intentionally and radial cracks and micro annuli were induced by applying torsion, the effective permeability was determined to be five to six orders of magnitude higher than in the case of perfect bonding. With micro cracks of 3–5 μm and a micro annulus of 10–15 μm, fluid flow was observed in the tests conducted under reservoir conditions. These tests emphasize the important effects of mechanical defects on well integrity. Nagelhout et al. (2005) tested the sealing ability of two different cement systems for use in plug-and-abandon operations. The flow of gas was measured across the cement plug at various differential pressures. The results showed that the system of higher flexibility was capable of withstanding large differential pressures, illustrating the importance of cement slurry design.

Mechanical causes for generating leakage pathways at different stages of well completion and production are discussed below.

2.2.1. Mud displacement

If channels of mud remain in the annulus, the lower yield stresses of drilling fluids may provide a preferential route for gas migration (Bonett and Pafitis, 1996). A mud filter cake that has not been removed from the formation could dehydrate after the cement sets, resulting in an annulus at the formation–cement interface. Incomplete mud removal often occurs in deviated wellbores (Keller et al., 1987), where a continuous mud channel may remain along the narrow section of the cemented annulus. Effective mud displacement is a primary requisite to prevent sustained casing pressure from occurring, with the main objective being to provide a relatively clean pipe and formation surface to which the cement slurry can bond (Watson et al., 2002). Before primary cementing, the wellbore must be properly conditioned by breaking the gel strength and by removing as much as possible of the filter cake (Ravi et al., 1992). Circulation of at least one annular volume is recommended (Bittleston and Guillot, 1991). In addition to mud conditioning, casing centralization is regarded as an important preparation for a cement job. Chemical washes/spacers are often pumped ahead of the cement slurry and act as a buffer between the mud and cement slurry, helping to thin and remove the mud (Nelson and Guillot, 2006). It is preferred for spacer and cement slurry to be in turbulent flow, if possible, to enhance mud removal and to minimize fluid channeling. If turbulent flow cannot be achieved for various reasons, effective laminar flow displacement may also be quite successful (Brady et al., 1992). In addition, the displacing cement density should be significantly higher than that of the mud that it is displacing.

2.2.2. Gas migration during cement setting

Gas invasion into the cement-filled annulus could occur during the cement setting process, resulting in gas channeling (Wojtanowicz, 2008). Various mechanisms have been proposed to account for gas migration during the cement setting process. Among them, fluid loss, slurry gelation, and bulk shrinkage are of primary importance (Bonett and Pafitis, 1996; Bol et al., 1991). Sedimentation, i.e., separation of free water from cement particles, was also thought to be responsible for creating gas migration channels in deviated wells (Bol et al., 1991). Slurry density is a factor that needs to be considered in cement design for preventing gas flow during cement placement. The density of cement slurry must be high enough to generate a hydrostatic pressure that exceeds the formation gas pressure in order to prevent gas from entering the annulus. On the other hand, when the annular hydrostatic pressure exceeds the formation pressure, fluid loss of the slurry to the formation could take place, which leads to a volume reduction.

When cement pumping stops, the cement slurry in the annulus is a dense, granular fluid that transmits full hydrostatic pressure (Bonett and Pafitis, 1996; Bol et al., 1991). However, even for a properly-designed cement slurry that initially provides sufficient hydrostatic pressure, the pressure within the annulus begins to fall as a result of cement gelation (Bonett and Pafitis, 1996; Wojtanowicz, 2008). This is because the reduction in hydrostatic pressure is proportional to the static gel strength, whose value increases constantly as the cement sets. Depending on the state of the slurry, gas could potentially migrate by micropercolation, bubbles, or through fractures. As setting continues and hydration accelerates, pressure (pore pressure at this stage) decreases due to the consumption of water by cement hydration. There are two mechanisms for gas invasion at this stage. Early in the setting process, when the cement still has a weak solid structure, fingers or viscoelastic fractures may be created. During the late setting process, a significant and rapid decrease in pore pressure occurs as water is further consumed by hydration. If this occurs while the pore structure is still inter-

connected, gas may invade and flow rapidly through this pore space.

2.2.3. Cement sheath stress failure

Even if the cement was properly placed and initially provided a good hydraulic seal, gas migration could still occur during the life of a well (Bellabarba et al., 2008). Changes in downhole conditions can induce sufficient stresses to damage the integrity of the cement sheath. Changes in casing pressure and temperature lead to stresses in casing and may cause casing displacement. The casing displacement and stress changes could cause the cement to fail in tension or compression, or to debond from the casing or formation, creating microannuli and radial cracks (Boukhelifa et al., 2004).

Goodwin and Crook (1992) measured casing expansion as a function of internal casing pressure or temperature in a flowing well. It was observed that loss of annular zonal isolation occurred due to radial stress cracks in the cement sheath, which were created by casing expansion. Similarly, Jackson and Murphey (1993) detected gas flow through the annulus after the casing pressure was reduced from 69 MPa to 14 MPa. Cyclic pressure fluctuation along wellbore boundaries may also cause fatigue fractures within the cement or generation of a microannulus (Marlow, 1989). The most damaging wellbore pressure increases often occur during hydraulic testing (Bellabarba et al., 2008). Casing perforation or a hydraulic fracturing treatment can also generate large wellbore pressure increases (Thiercelin et al., 1997). A pressure decrease occurs in the wellbore during normal well production operations, which causes stress redistribution in casing and cement. This may lead to the failure of the wellbore structure, especially in the perforation section. Loading from far-field formation stresses, such as tectonic stress, subsidence and formation creep, could cause pressure increase on the external surface of the cement. A change of pore pressure or temperature during reservoir production can also result in a change in formation stress (Dusseault et al., 2001).

A variation in temperature that is applied to the casing inner wall consequently produces thermal gradients cross the wellbore structure (Wong and Yeung, 2006), which in turn induces dilation of casing and cement. Due to the differences in thermal expansion coefficients between casing steel, cement and formation rock, stresses are induced across these materials (Philippacopoulos and Berndt, 2002). Thermal casing expansion causes a longitudinal shearing stress at the cement/casing interface or radial fracturing in the cement sheath. The failure mechanism is more complex owing to heat diffusion and differences in thermal properties between cement and casing steel (Nelson and Guillot, 2006). The complexity also lies in the fact that the thermally-induced expansion is cubical, so stress cracks induced in the cement are tensional rather than compressional (Goodwin and Crook, 1992). The phase transition of injecting or producing fluids, such as CO_2, could also bring about temperature changes (Pruess and Spycher, 2006).

Cement shrinkage leads to circumferential fractures behind the casing (Dusseault et al., 2000). Within the fracture, formation gas will slowly accumulate and transmit pressure from depth. Thus the fracture will propagate upward. Cement shrinkage can gradually cause gas leakage along casing years after production has ceased and the well has been plugged and abandoned. Small radial strains brought by shrinkage will cause relaxation of the radial stress and an increase in the tangential stress between cement and rock. Once the condition under which pore pressure is greater than the radial stress is reached, the bond between cement and rock may be lost. As a result, one or a pair of circumferential hydraulic fractures, typically perpendicular to the minimum stress direction, could be initiated and then propagate upwards. Thus, well leakage may occur through fractures induced by long-term shrinkage after well abandonment.

2.3. Well abandonment

In mature sedimentary basins, abandoned wells account for a high percentage of existing wells, e.g., about 50% of the wells penetrating the Viking formation in the Alberta Basin are abandoned wells (Gasda et al., 2004). The main objective of well abandonment operations or well plugging is to prevent cross-flow between different horizons and, in particular, contamination of groundwater resources (Nicot, 2009). However, as pointed out by Nicot (2009), materials such as wooden plugs were used in the early times in Texas (and elsewhere) before regulation started to take hold in 1934 in Texas, and in 1939 in Alberta (Bachu and Watson, 2006). As rules, regulations and requirements evolved with time, these authors suggest that there is a high probability that wells abandoned after more stringent abandonment regulations were introduced are properly plugged. Inadequate bonding has been detected at the interface between cement and formation/casing by bond logs and other tools (Nicot, 2009). The quality of execution of the plugging operation was considered to be more of a problem than the quality of the materials used. Watson and Bachu (2009) ascribed the type of abandonment method as one of the key factors that could potentially cause well leakage.

In summary, the key factors that may contribute to potential well leakage include wellbore deviation, well type, abandonment method, whether or not cement is present, and the quality of cement. Leakage pathways can be created at different stages of well construction, completion, production, and abandonment. They result primarily from poor mud displacement prior to primary cementing, gas migration during cement setting, and stress crack and micro-annulus formation during well operation. Incomplete mud removal results in poor bonding of cement to the formation rock. Loss of hydrostatic pressure due to the development of static gel strength during the transition of cement slurry from liquid to solid is the most important process responsible for gas migration in unset cement. After the cement sets, changes in downhole conditions can induce sufficient stresses to damage the integrity of the cement sheath. These stress changes could cause the cement to fail in tension or compression, or to debond from the casing or the formation. Alternatively, these cracks and micro annuli may result from cement shrinkage.

3. Chemistry of cement and cement carbonation

Portland cement clinker consists primarily of four principal phases: tricalcium silicate (Ca_3SiO_5, or C_3S in cement chemistry notation), dicalcium silicate (Ca_2SiO_4, or C_2S), tricalcium aluminate ($Ca_3Al_2O_6$, or C_3A) and tetracalcium aluminoferrite ($Ca_4Al_2Fe_2O_{10}$, or C_4AF) (Taylor, 1997). Gypsum is commonly added during the grinding of the clinker to produce Portland cement. Based on chemical compositions and/or fineness, well cements are categorized into eight classes (from A to H) by the American Petroleum Institute (API) (Nelson and Guillot, 2006) and used in different applications. Of these, classes G and H well cements are most commonly used. Due to the wide range of downhole conditions being encountered, more than 100 cement additives have been developed to adapt Portland cement to these conditions. There are eight categories of cement additives, including accelerators, retarders, extenders, weighing agents, dispersants, fluid-loss control agents, lost-circulation control agents, and special additives (Michaux et al., 1989).

3.1. Cement hydration

Hydration of C_3S and C_2S begins with the dissolution of these phases into water, where the dissolved species combine to form

calcium silicate hydrate (CSH, expressed here as $Ca_3Si_2O_7{\cdot}3H_2O$) and portlandite ($Ca(OH)_2$) as described by the following reactions (MacLaren and White, 2003):

$$2Ca_3SiO_5 + 6H_2O \rightarrow Ca_3Si_2O_7{\cdot}3H_2O + 3Ca(OH)_2 \quad (1)$$

$$2Ca_2SiO_4 + 4H_2O \rightarrow Ca_3Si_2O_7{\cdot}3H_2O + Ca(OH)_2 \quad (2)$$

CSH is amorphous, with the Ca/Si ratio ranging from 1.5 to 2.0 and various amounts of water (Neville, 1995; Taylor, 1997). CSH is the main binding phase and comprises about 65% of fully hydrated Portland cement at ambient conditions, whereas portlandite accounts for 15–20% in hardened cement (Nelson and Guillot, 2006). Portlandite is crystalline, occurring in a hexagonal form. On a mass basis, C_3S produces more than twice as much portlandite as is formed by the hydration of C_2S (Neville, 1995). Therefore, the proportion of C_3S to C_2S in cement will determine the quantity of portlandite produced.

Hydration reactions of C_4AF are similar to those of C_3A. In the presence of gypsum, C_3A reacts with gypsum to form needle-like ettringite crystals (Nelson and Guillot, 2006):

$$Ca_3Al_2O_6 + 3CaSO_4{\cdot}2H_2O + 26H_2O \rightarrow Ca_6Al_2O_6(SO_4)_3{\cdot}32H_2O \quad (3)$$

Gypsum is gradually consumed as more ettringite precipitates. When the supply of gypsum is exhausted, the sulfate concentration in solution drops. Ettringite becomes unstable and converts to platey monosulfate (Nelson and Guillot, 2006):

$$Ca_6Al_2O_6(SO_4)_3{\cdot}32H_2O + 2Ca_3Al_2O_6 + 4H_2O \rightarrow 3Ca_4Al_2O_6(SO_4){\cdot}12H_2O \quad (4)$$

The hydration rate of C_3S is much faster than that of C_2S. Therefore, hydration of C_3S is responsible for the early strength development of cement paste, whereas the strength development at later time is controlled by C_2S (Nelson and Guillot, 2006). The rate for the reaction between C_3A and gypsum is in between, although initially the reaction rate is higher than that of C_3S. The reactivity of cement is also controlled by temperature and the surface area of cement particles (fineness). As temperature increases, the rate of cement hydration generally increases. Higher hydration rates are associated with finer cements. MacLaren and White (2003) further point out that cement hydration is controlled by other factors such as impurities present in the clinker, water/cement (w/c) ratio, and the presence of additives.

3.2. Carbonation research conducted in cement and concrete

Cement carbonation is a phenomenon commonly observed in concrete and cement paste, and has been studied extensively using laboratory experiments conducted under both natural (atmospheric P_{CO_2}) and accelerated (higher P_{CO_2}) conditions. Although carbonation experiments carried out in cement and concrete research employed parameters (e.g., T, P_{CO_2}, amount of water) that are significantly different from those encountered in geological storage (see Section 4), these studies provided useful information regarding reaction products and mechanisms, as well as factors controlling the carbonation rate.

The process of cement carbonation involves the dissolution of carbon dioxide into the pore water of cement paste, which then reacts with calcium and hydroxyl ions to form calcium carbonate. The overall reaction can be described as follows (Papadakis et al., 1989):

$$Ca(OH)_{2(s)} + CO_{2(g)} \rightarrow CaCO_{3(s)} + H_2O \quad (5)$$

In addition to $Ca(OH)_2$, principal phases and other hydration products of Portland cement are also susceptible to carbonation in the presence of moisture (Papadakis et al., 1989). The reactions of CO_2 with the hydrated and unhydrated silicate phases produce calcium carbonate and amorphous silica (Richardson, 1988; Papadakis et al., 1989):

$$Ca_3Si_2O_7{\cdot}3H_2O + 3CO_{2(g)} \rightarrow 3CaCO_{3(s)} + 2SiO_2 + 3H_2O \quad (6)$$

$$Ca_3SiO_5 + 3CO_2 + nH_2O \rightarrow 3CaCO_3 + SiO_2{\cdot}nH_2O \quad (7)$$

$$Ca_2SiO_4 + 2CO_2 + nH_2O \rightarrow 2CaCO_3 + SiO_2{\cdot}nH_2O \quad (8)$$

Groves et al. (1991) monitored the progress of carbonation in C_3S pastes that were reacted with pure CO_2 for 1–16 h. It was observed that calcium was gradually leached from the CSH, resulting in a decrease in the Ca/Si ratio. This process accompanied silicate polymerization, and silica gel formed in the later stages of carbonation. At the end of the experiment, the paste became rather heterogeneous, with regions of Ca-modified silica gel, CSH of reduced Ca/Si ratio, and regions of gel with unknown composition infiltrated by extremely small carbonate crystals.

Under CO_2 attack, calcium aluminates/ferrite hydrates are decomposed to produce calcium carbonate, hydrated alumina/ferric oxide, and gypsum. An example of such reactions is shown below (Venhuis and Reardon, 2001):

$$Ca_6Al_2O_6(SO_4)_3{\cdot}32H_2O + 3CO_2 \rightarrow 3CaCO_3 + 3CaSO_4{\cdot}2H_2O + Al_2O_3{\cdot}3H_2O + 23H_2O \quad (9)$$

Calcium carbonate is the most important product of cement carbonation and could occur as three polymorphs (calcite, aragonite, and vaterite), and calcite is the ultimate form of calcium carbonate found in the cement paste (Richardson, 1988). Water is produced when the hydration phases react with CO_2, and blocks the cement pores. Cement carbonation is controlled by a diffusion-dominated process. The water produced hinders the diffusion of CO_2 through the pores, and therefore reduces the rate of carbonation, which is defined as the depth of carbonation per exposure time (Richardson, 1988). The impact of water content on the carbonation rate has been demonstrated experimentally by Reardon et al. (1989), whose results showed that the rate of carbonation increased as the water was removed from the pores through vacuum dry to allow the access of CO_2. However, water is required to catalyze the reaction. It was found that carbonation proceeded very slowly in samples subjected to extreme conditions of drying.

Richardson (1988) described three reaction zones for carbonation occurring under natural conditions. Calcium hydroxide exists in the inner non-carbonated zone. Calcium carbonate precipitates in the carbonated zone, and the outer layer is characterized by the dissolution of $CaCO_3$. Dissolution of $CaCO_3$ occurs only where abundant amounts of CO_2 and water are available.

The carbonation rate is affected by a variety of factors such as cement type, additives, water/cement ratio and curing conditions (Richardson, 1988; Thomas and Mattews, 1992; Loo et al., 1994). These factors have a substantial impact on the physical and chemical properties of cement pastes, including the content of calcium hydroxide, porosity and permeability. In general, the rate of carbonation decreases as the $Ca(OH)_2$ content increases and the cement permeability decreases. Conditions under which the carbonation reaction occurs, such as temperature, CO_2 concentration, relative humidity (RH), and exposure time also affect the carbonation rate (Richardson, 1988).

In summary, Portland cement clinker consists of four principal phases: tricalcium silicate (C_3S), dicalcium silicate (C_2S), tricalcium aluminate (C_3A) and tetracalcium aluminoferrite (C_4AF). The reaction between calcium silicates and water produces CSH and portlandite. Tricalcium silicate hydrates much faster than C_2S, and also produces more than twice as much portlandite. Both C_3A and C_4AF hydrate in a similar manner. They react with gypsum to pre-

cipitate ettringite, which converts to monosulfate as gypsum is consumed.

Calcium carbonate is the main carbonation product, which can occur as three polymorphs (calcite, aragonite and vaterite). The composition of CSH evolves with the progress of carbonation. Calcium is gradually leached out from CSH, leading to highly heterogeneous CSH with various Ca/Si ratios. Silica gel forms at late stages. Carbonation is controlled by a diffusion-dominant process. The rate of carbonation is affected by a variety of factors that control the physical and chemical properties of cement pastes. Important factors include cement types, additives, water/cement ratio, and curing conditions. Conditions under which the carbonation reaction occurs are also crucial to the rate of carbonation. These conditions include temperature, P_{CO_2}, and the amount of water present.

4. In-situ conditions for CO_2 geological storage

Temperature, pressure, composition of formation water and rocks, the CO_2 state (phase), and CO_2 and/or formation water flow rate are among the most important parameters affecting cement carbonation at the conditions encountered in CO_2 geological storage. It is recommended to store CO_2 at depths greater than 800 m where it will be in supercritical state, i.e., at pressures greater than 7.38 MPa and temperatures greater than 31.1 °C (IPCC, 2005). Regulatory agencies require injection at depths where formation water has salinity greater than that of protected groundwater (e.g., 10,000 mg/L in the U.S., EPA, 2008). These represent the lower limits of pressure, temperature and formation water salinity that will be encountered in CO_2 storage. However, conditions more likely to be encountered in CO_2 storage, at least in the near-to-medium term, are characteristic of depths up to 2500–3000 m, which would translate into pressured of 30 MPa and temperatures of 100–150 °C. This depth range will likely be extended in later stages of CCS deployment.

Four different chemical environments are expected when supercritical CO_2 is injected into deep saline aquifers and hydrocarbon reservoirs: (1) dry supercritical CO_2 near the injection well (Pruess and Müller, 2009); (2) a CO_2 plume containing supercritical CO_2 that is likely in equilibrium with the formation water (water content on the order of a few mole percent), otherwise known as wet supercritical CO_2; (3) CO_2-rich water whose composition varies with the proximity to the CO_2 plume; and (4) original saline water (brackish water or brine) that contains a negligible amount of dissolved CO_2. Existing vertical wells in the area of impact of a CCS operation will likely be contacted, depending on the distance to the injection well, first by formation water driven by pressure build-up, then by CO_2-saturated formation water, then possibly by the CO_2 plume itself, and in some cases by dry CO_2. Of these, the two most important scenarios in studying cement carbonation in wells that are not CO_2 injectors are (1) the interaction between cement and wet supercritical CO_2; and (2) the interaction between cement and CO_2-saturated formation water.

Due to the low permeability of the consolidated sediments that form deep saline aquifers, the flow velocity of formation water is typically on the order of millimeters to centimeters per year (e.g., Bachu et al., 1994). For such slow flow rates, the reactions between cement and the CO_2-saturated brine can be largely regarded as similar to those that occur under static conditions.

Water salinity may reach more than 400 g/L even at shallow depths if the storage aquifer is adjacent to salt beds or if deep basinal brines are approaching the surface, like in the Alberta and Williston basins in North America (e.g., Hitchon and Friedman, 1969; Jensen et al., 2006). Carbon dioxide solubility in water generally increases with increasing pressure and decreasing temperature (Kohl and Nielsen, 1997), and decreases with increasing water salinity (Enick and Klara, 1990). In addition, the water content in CO_2 also decreases with an increase in salinity, particularly when CO_2 is in supercritical state (Spycher and Pruess, 2005).

The dissolution of supercritical CO_2 into pure water could reduce the pH to about 3 (Toews et al., 1995). In a storage reservoir or an aquifer, CO_2-saturated brine is likely in equilibrium with the formation rock before reaching existing wells. The effect of formation rock on cement carbonation is mainly through the rock pH buffer capacity. Scherer et al. (2005) calculated that there would be about a 2 pH unit difference between limestone and a quartzitic sandstone over the range of depth relevant to CO_2 storage. However, calcite cement is commonly present in sandstones, generally at levels in excess of 1% by volume (Milliken, 2004). In addition to the cement–CO_2 interactions in the storage reservoir or aquifer, reactions between well cements and CO_2 may also occur in the caprock (shale or evaporites) when: (1) CO_2 migrates along the interface between cement and formation rocks (e.g., Carey et al., 2007); and (2) CO_2 diffuses from CO_2-rich pore waters in the shale (Scherer and Huet, 2009).

5. Determination of carbonation rates relevant to CO_2 geological storage

Various experimental, field and numerical studies have been performed in the last few years to gain an understanding of the behavior of well cements specifically for CO_2 geological storage applications.

5.1. Laboratory experiments

Both static and dynamic flow conditions have been used in laboratory experiments to determine the rate of carbonation, to characterize reaction products, and to measure the changes in physical and hydrological properties. The effect of additives, curing conditions, water salinity and rock composition on the rate of carbonation has also been examined. In laboratory studies, the depth of carbonation (or penetration depth) was defined as the distance from the surface of the cement sample to the boundary where no alteration occurred. Based on the depth measured, the rate of carbonation was determined. Table 1 provides detailed information on these experiments, discussed more thoroughly below.

Duguid et al. (2004, 2005) and Duguid and Scherer (2010) studied the degradation of well cement under dynamic flow conditions at two temperatures (~20 and 50 °C) using a flow-though reactor. The flow rates were maintained between 8.2 and 8.7 cm^3/min (flow velocities around 0.16 cm/min, i.e., 2.3 m/day). Two leaching solutions with pH of 3.7 and 2.4 were used. The solution at pH 3.7 was prepared by bubbling CO_2 into 0.5 M NaCl brine. The second solution was prepared by adding HCl to the first one to bring the pH to 2.4. In the first set of experiments, Duguid et al. (2004) determined the reaction rate, porosity, and thickness of the reacted layers. In addition to the neat cement, they also prepared samples containing 6% bentonite. The experiments were allowed to proceed for 1.3–7.2 days, during which the pH of the effluent was monitored. The reaction rates were determined based on the initial and steady state pH values, assuming that the reaction was governed by the dissolution of portlandite. Compared to the original samples, the porosity of the reacted neat cements increased 10–45%. Multi layers with various $Ca(OH)_2$ contents were observed in the reacted samples, where the outermost layer showed a complete depletion of $Ca(OH)_2$. Based on the experimental results, the authors concluded that a short exposure to carbonated brines could damage the sealing properties of the well cement. Relative to neat cement, the reaction rate is higher for bentonite-containing cement.

Table 1
Summary of laboratory determination on the rate of cement carbonation.

Study	Sample preparation	Curing conditions	Experimental conditions	Determined carbonation rate	Predicted 30-year carbonation depth
Duguid et al. (2004)	• Cement samples: (1) Class H cement + DI water, w/c = 0.38 (2) Class H cement + 6% bentonite + DI water, w/s = 0.70 • Size: 7.3–7.7 mm × 140–260 mm (dia. × h)	• Cured in 0.5 M NaCl • Room temp. • 28 days or older	• Leachants: CO_2-sat. brine (1) pH 3.7: bubble CO_2 to 0.5 M NaCl (2) pH 2.4: bubble CO_2 to 0.5 M NaCl + HCl • Flow: 8.2–8.3 cm^3/min • Temperature (1) 23 °C (2) 50 °C • Duration: 1.3–7.2 days		
Duguid et al. (2005)	• Cement samples: Class H cement, w/c = 0.38 • Size: 7.5 mm × 200 mm (dia. × h)	• Cured in 0.5 M NaCl • Temperature: 20 or 50 °C • 12-month old	• Leachants: CO_2-sat. brine (1) pH 3.7: bubble CO_2 to 0.5 M NaCl (2) pH 2.4: bubble CO_2 to 0.5 M NaCl + HCl • Flow: 8.3–8.7 cm^3/min (velocity: 230–245 cm/day) • Temperature (1) 20 °C (2) 50 °C • Duration: up to 31 days	• 0.24 mm/day (pH 2.4, 50 °C) • 0.066 mm/day (pH 3.7, 20 °C)	• 2630 mm (pH 2.4, 50 °C) • 723 mm (pH 3.7, 20 °C)
Duguid and Scherer (2010)	• Cement samples: same as Duguid et al. (2004) • Size: same as Duguid et al. (2005)	• Same as Duguid et al. (2005)	• Leachants: same as Duguid et al. (2005), but with an additional one (3) pH 5: $CaCO_3$-saturated NaCl brine equilibrated with a 100% CO_2 atmosphere • Flow: same as Duguid et al. (2005) • Temperature for (3): 50 °C • Duration for (3): up to 26 days	• No carbonation for reaction with leachant (3) (pH 5.0, 50 °C)	
Duguid (2008)	• Composite sample: cast cement (Class H, w/c 0.38) into a hole (25 mm) of sandstone cylinder (55 mm)	• Cured in brine for 7 months	• Leachants: CO_2-sat. brine (1) pH 3: bubble CO_2 to 0.5 M NaCl + HCl (2) pH 4: bubble CO_2 to 0.5 M NaCl + NaOH (3) pH 5: bubble CO_2 to 0.5 M NaCl + NaOH • Diffuse through sandstone • Temperature: 20 or 50 °C • Duration: 1, 2, 3, 6, 12 months	• $L = 0.0395t^{1/2} + 0.184$ (pH 3, 20 °C) • $L = 0.00848t^{1/2} + 0.241$ (pH 5, 20 °C) • $L = 0.0429t^{1/2} + 0.401$ (pH 3, 50 °C) L – mm t – month	• 0.93 mm (pH 3, 20 °C) • 0.40 mm (pH 5, 20 °C) • 1.21 mm (pH 3, 50 °C)
Barlet-Gouédard et al. (2006, 2007)	• Cement samples: Portland cement + antifoam agent + dispersant + retarder fresh water • Size: cored from cubic samples to obtain (1) 12.7 (dia.) × 25.4 mm (2) 25.4 (dia.) × 50.8 mm	• Cured at 20.68 MPa and 90 °C for 72 h	• CO_2 Fluids: (1) Wet supercritical CO_2 (2) CO_2-saturated water, • Static • Temperature: 90 °C • P_{CO_2}: 28 MPa • Duration: 0.5 days, 2 days, 4 days, 1 week, 3 weeks, 6 weeks, 3 months, 6 months	(1) Supercritical CO_2: L (mm) = $0.26t^{1/2}$ (2) CO_2-saturated water: L (mm) = $0.22t^{1/2}$ t – hour	(1) Supercritical CO_2: 133 mm (2) CO_2-saturated water: 113 mm
Barlet-Gouédard et al. (2009)	Same as above	Same as above	• Additional CO_2 fluids: (3) CO_2-saturated brine (salinity of 220 g/L) • Static • Duration: 2 days	(3) CO_2-saturated brine: 10 times less than (2)	(3) CO_2-saturated brine: 11 mm
Kutchko et al. (2007)	• Cement samples: Class H cement, w/c = 0.38 • Size: 12 mm × 130 mm (dia. × h)	• Cured in 1% NaCl for 28 days at (1) 22 °C, 0.1 MPa (2) 22 °C, 30.3 MPa (3) 50 °C, 0.1 MPa (4) 50 °C, 30.3 MPa	• CO_2 Fluids: (1) Wet supercritical CO_2 (2) CO_2-saturated 1% NaCl • Static • Temperature: 50 °C • P_{CO_2}: 30.3 MPa • Duration: 9 days	(2) CO_2-saturated brine: 0.2 mm in 9 days under curing condition (4)	

Table 1 (*Continued*)

Study	Sample preparation	Curing conditions	Experimental conditions	Determined carbonation rate	Predicted 30-year carbonation depth
Kutchko et al. (2008)	• Cement samples: Class H cement, w/c = 0.38	• Cured in 1% NaCl for 28 days at 50 °C, 30.3 MPa	• Fluids: (1) Wet supercritical CO_2 (2) CO_2-saturated 1% NaCl • Static • Temperature: 50 °C • P_{CO_2}: 30.3 MPa • Duration: up to 1 y	(1) Supercritical CO_2: L (mm) = $0.016t^{1/2}$ (2) CO_2-saturated brine: L (mm) = 0.09 ln(t) + 0.17 t – day	(1) Supercritical CO_2: 1.7 mm (2) CO_2-saturated water: 1 mm
Kutchko et al. (2009)	• Cement samples: Class H cement + fly ash + 2% bentonite (1) Fly ash/cement = 35:65, w/s = 0.51 (2) Fly ash/cement = 65:35, w/s = 0.56	• Cured in 1% NaCl for 28 days at 50 °C, 15 MPa	• CO_2 Fluids: (1) Wet supercritical CO_2 (2) CO_2-saturated 1% NaCl • Static • Temperature: 50 °C • P_{CO_2}: 15 MPa • Duration: 5, 7, 9, 14, 31 days		• Fly ash/cement: 35:65 (1) Supercritical CO_2 and (2) CO_2-saturated brine: 170–180 mm • Fly ash/cement: 65:35 (2) CO_2-saturated brine: 520 mm
Pratt et al. (2009)	• Cement samples: Portland cement • Size: 7.5 mm × 200 mm (dia. × h)	• Cured at room temperature and 100% RH for 1 month	• CO_2 Fluids: (1) Wet supercritical CO_2 • Static • Temperature: 50 °C • P_{CO_2}: 10 MPa • Duration: 12 weeks	(1) Supercritical CO_2: 0.2 mm in 12 weeks	
Sweatman et al. (2009)	• Cement samples: Class G cement, density of 15.8 ppg • Size: 25.4 × 63.5 mm (dia. × h) • Composite sample: cast cement slurry into sandstone cores	• Cured in water at 60 °C and 13.8 MPa for 28 days	• CO_2 Fluids: (1) Wet (40% R.H.) supercritical CO_2 (2) CO_2-saturated water • Static • Temperature: 60 °C • P_{CO_2}: 13.8 MPa • Duration: 15, 90 days	(1) Supercritical CO_2: 0.2 mm in 12 weeks	

In their second set of experiments, which proceeded for 31 days, Duguid et al. (2005) focused on the characterization of the reaction products. As many as five reaction zones showing various colors were observed in the cement sample reacted at 50 °C and pH 2.4. The outermost orange zone contained iron oxide, and the next brown zone contained brownmillerite (Ca_2AlFeO_5, i.e., C_4AF). Three $CaCO_3$ polymorphs (calcite, aragonite and vaterite) were identified in the white layer. The light gray zone contained both portlandite and calcite, whereas in the dark gray core, brownmillerite was present in addition to portlandite and calcite. The authors suggested that calcium was dissolved in the gray zones and deposited in the white zones, and that the cement degradation rate was likely controlled by the dissolution rate of the white zone. Based on the change in the diameter of the cement core, carbonation rates between 0.07 and 0.24 mm/day were estimated for the conditions used in this study.

In addition to the experiments described above, Duguid and Scherer (2010) reported a parallel set of experiments conducted under conditions similar to those used in their previous studies, with a different leaching solution. In this case, CO_2 was bubbled into a Ca–Na–Cl solution, which was then pumped through a column of crushed calcite. The solution was saturated with $CaCO_3$ and had a pH around 5. In contrast to the observations made in the previous experiments where significant degradation was evident, the samples reacted with $CaCO_3$-saturated solution showed no apparent damage after 26 days of reaction. The mineral phases identified at the end of the experiment were essentially the same as in the pristine cement. These results suggest that well cement is resistant to CO_2 attack in a $CaCO_3$-saturated solution.

Duguid (2008) further designed laboratory experiments to allow carbonate species to diffuse through the pores of the formation rock before reacting with the cement. A composite sample was prepared by pouring the cement slurry into a hole that was drilled off-center through a sandstone cylinder. Three sets of solutions containing 0.5 M NaCl were used in the experiments, with pH values of 3, 4 and 5. The pH was adjusted by adding HCl or NaOH to the solution that was in equilibrium with 1 atm of CO_2. The depth of reaction was measured over a time period of 12 months and plotted against the square root of time. Because the transport of carbonate species was controlled by diffusion, a straight line was expected on the plot. However, a breakdown of the slope was observed between 2 and 3 months. The second segment of the slope was thought to control the rate of cement degradation, and was used to estimate the time to degrade a 25 mm thick cement sheath. The author concluded that in a diffusion-dominated system, it would take between 30,000 and 70,000 years to degrade 25 mm of neat cement in a sandstone reservoir.

Barlet-Gouédard et al. (2006, 2007) argued that subsurface flow conditions are relatively static, and examined the reaction between cement and supercritical CO_2 as well as CO_2-saturated brine at 90 °C and P_{CO_2} of 28 MPa. Cement samples were stacked in a reaction vessel, where the bottom half was filled with water while the top half was pressurized with supercritical CO_2. As a result, the samples at the bottom were in contact with CO_2-saturated water, and the top ones were reacted with wet supercritical CO_2. The samples in the middle were exposed to both fluids. A sharp alteration was observed after half a day of reaction, with the thickness of the alteration front increasing from 1–2 mm to 5–6 mm between 2 days and 3 weeks (Barlet-Gouédard et al., 2006, 2007). After 6 weeks, the front reached the core for the sample size of $0.5'' \times 1''$ (1.27×2.54 cm, diameter × height). For the larger samples ($1'' \times 2''$, i.e., 2.54×5.08 cm), the depth of carbonation was 8 mm after 3 months in CO_2-saturated water whereas it reached the core (12 mm) in supercritical CO_2. After 6 months, spalling was seen in the sample which was located at the interface between supercritical CO_2 and CO_2-saturated water (Barlet-Gouédard et al., 2007).

Four different concentric zones were observed in samples reacted with supercritical CO_2 or CO_2-saturated water. From the center to the rim of the cement samples, these were (1) non-carbonated zone; (2) dissolution front of high porosity; (3) carbonation front of low porosity; and (4) carbonated zone (or dissolution back–front) (Barlet-Gouédard et al., 2006, 2007). The outermost carbonated zone contained calcium carbonate, silica gel and calcium-depleted CSH phase. This zone showed strong degradation of the cement as a result of the dissolution of newly-formed carbonates. Portlandite and CSH dissolved in the dissolution front and calcium carbonate precipitated in the carbonation front. The inner part of the sample contained primarily unreacted cement phases. In fully carbonated samples, the concentric reaction zones were no longer visible. The alteration process followed the diffusion law, and could be described by $L = 0.26t^{1/2}$ and $L = 0.22t^{1/2}$ (L in mm; t in hour) for wet supercritical CO_2 and CO_2-saturated water, respectively. Using these equations, the thickness of carbonation was predicted to reach 90 mm in CO_2-saturated water and 110 mm in wet supercritical CO_2 after 20 years of exposure.

The authors also compared the change in physical properties for cement samples before and after exposure to CO_2 (Barlet-Gouédard et al., 2006, 2007). A rapid increase in cement density was observed within 4 days. Following the early increase, the density increased slightly in wet supercritical CO_2 within 6 weeks but stabilized in CO_2-saturated water. A larger decrease in compressive strength was measured in samples reacted with CO_2-saturated water compared to those reacted with supercritical CO_2 (a loss of 65% vs. 30% after 6 weeks). Permeability remained below the detection limit of 8 μD before and after exposure to CO_2. Porosity decreased from 33% to 15% after the cement reacted with supercritical CO_2 for 6 weeks, and then increased to 27% after 3 months of exposure. This value remained unchanged until the end of the experiment (6 months) (Rimmelé et al., 2008). In CO_2-saturated water, porosity decreased from 33% to 9% in the first 3 weeks, during which the carbonation front had almost reached the core. Porosity then showed an increase to 28% after 3 months and to 30% after 6 months. Rimmelé et al. (2008) proposed a two-stage evolution of the porous network of cement samples. The precipitation of calcium carbonate was thought to be responsible for the initial sealing stage, whereas an increase in porosity observed in the second stage was attributed to the dissolution of calcium carbonate. The dissolution stage occurred earlier in CO_2-saturated water than in wet supercritical CO_2.

Barlet-Gouédard et al. (2009) carried out an additional experiment under conditions similar to those used in their previous studies, except that a brine of 4 M (salinity of 220 g/L) was used instead of pure water. After 2 days of reaction with CO_2-saturated brine, the alteration front was only a tenth of what was observed in the reaction with CO_2-saturated water (200 μm vs. 2 mm). The authors attributed the reduced alteration to the fact that the solubility of CO_2 is much lower in brine (0.6 mol/kg) compared to fresh water (1.3 mol/kg).

Kutchko et al. (2007) examined the effect of curing conditions on carbonation using laboratory experiments, in which cement samples were partially immersed in a 1% NaCl solution and pressurized with supercritical CO_2 at 50 °C and 30.3 MPa. The cement cylinders were cured under four sets of conditions: (1) 22 °C and 0.1 MPa; (2) 22 °C and 30.3 MPa; (3) 50 °C and 0.1 MPa; and (4) 50 °C and 30.3 MPa. Three well-defined alteration zones were identified in samples reacted with CO_2-saturated brine for 9 days. Relative to the pristine cement, the innermost altered zone showed a slight increase in porosity, resulting from the dissolution of portlandite. The decreased porosity in the middle zone was related to the precipitation of calcite. The outermost zone had a significantly increased porosity, which was caused by the dissolution of calcite. Degradation of less than 1 mm was measured after 9 days of reaction for all the curing conditions employed. The extent of car-

bonation was lowest (0.25 mm) in the sample cured under storage conditions (50 °C and 30.3 MPa), which showed a slight increase in the degree of hydration. Relative to those samples cured at 22 °C, it was observed that portlandite particles were smaller in size and were more evenly distributed in samples cured at 50 °C. The smaller depth of carbonation was related to the increase in hydration and the change in the microstructure of portlandite.

Kutchko et al. (2008) further determined the carbonation rate in similar laboratory experiments that lasted up to 1 year for cement samples cured at 50 °C and 30.3 MPa. A total of 6 samples were reacted in a single vessel, from which they were removed at various time intervals. As a result, the vessel was depressurized and re-pressurized several times. Differences were observed between the cement samples that reacted with CO_2-saturated brine and those with supercritical CO_2, as shown by the appearance, development of reaction zones, and the extent of alteration. The outer surface of the samples submerged in the CO_2-saturated solution was orange with a smooth texture, whereas samples reacted with supercritical CO_2 had a light gray color and a rough surface. Cement samples exposed to CO_2-saturated brine showed an initial rapid alteration, followed by a rate decrease with time. Well-defined reaction zones were shown in these samples compared to a single reaction front observed in those exposed to supercritical CO_2. In the absence of the dense carbonate barrier, the carbonation occurring in supercritical CO_2 was likely controlled by diffusion as described by the equation $L = 0.016t^{1/2}$, where L is the depth of carbonation (mm) and t is time of exposure (day). In CO_2-saturated brine cement alteration is more complex than a simple diffusion process, for which an empirical relation was derived, $L = 0.09\ln(t) + 0.17$. Based on these equations, penetration depths after 30 years of exposure were predicted to be 1.7 and 1.0 mm for the reactions with supercritical CO_2 and CO_2-saturated brine, respectively.

Kutchko et al. (2009) studied also the effect of fly ash on cement carbonation. Two sets of samples were prepared by mixing Class H cement with Type F fly ash at fly ash/cement volumetric ratios of 35:65 and 65:35. The samples were exposed to both supercritical CO_2 and CO_2-saturated solution (1% NaCl) at 50 °C and 15 MPa. For samples with a fly ash/cement ratio of 35:65, carbonation reached full extent within 14 days. The penetration depths in both supercritical CO_2 and CO_2-saturated brine were similar and followed Fick's second law of diffusion. A penetration depth of 170–180 mm was predicted after 30 years of exposure. For a fly ash/cement ratio of 65:35, complete carbonation was achieved after exposed to supercritical CO_2 for 2 days and to CO_2-saturated brine for 8 days. The carbonation rate in CO_2-saturated brine was estimated to be 2.9 times greater than those measured for the 35:65 samples. Compared to the carbonation of neat cement, it was found that the leaching of calcium was more gradual in the carbonated fly ash–cement samples.

Pratt et al. (2009) used a suite of analytical techniques to characterize cement samples exposed to wet supercritical CO_2 at 50 °C and 10 MPa. The depth of carbonation was measured to be approximately 200 μm after 12 weeks of reaction. Various reaction zones were observed in the carbonated samples. In the outermost carbonated zone, only a few relics of C_3S were recognized. The surrounding CSH phase was completely decomposed, where an intergrowth of calcium carbonate and hydrated silicate phases was observed.

Sweatman et al. (2009) reacted neat cement and cement–sandstone composite samples with CO_2-saturated water and wet supercritical CO_2. In their first test, the samples were fully immersed in water and CO_2 was applied at 60 °C and 13.8 MPa. The second test involved only supercritical CO_2 (with a humidity of 40%). After 15 days, the penetration depth was found to be slightly greater in neat cements reacted with wet supercritical CO_2 than in those immersed in CO_2-saturated water. It was also observed that the sandstone core acted as barrier for CO_2 diffusion. Santra and Sweatman (2010) compared carbonation of cement and fly ash mixtures (16–50%) with that of neat cement, both of which were reacted with CO_2 at 93 °C and 13.8 MPa. It was observed that compared to the neat cement carbonation was more extensive in cement samples containing fly ash and that the penetration depth increased with an increase in the content of fly ash.

Verba and O'Connor (2010) determined the rate of carbonation (at 50 °C and 29 MPa) in four different brines with composition comparable to those found at four storage sites. These brines were of Na–Cl type with various amounts of Ca and Mg. Salinity ranged from 1 to 2.2 M. The alteration rates were higher in brines with lower salinity, likely due to the higher solubility of CO_2 in the lower salinity brines.

Core flood experiments have been carried out to examine cement carbonation as a result of CO_2 flow through interfaces or pre-existing fractures. Carey et al. (2010) investigated cement carbonation and steel corrosion induced by flow through a cement–casing micro-annulus. A mixture of 50:50 supercritical CO_2 and brine was used, which was equilibrated with a limestone. After being flushed with 59,000 pore volumes, the cement did not show mass loss as a result of cement carbonation, but steel casing reacted to form calcium and iron carbonate precipitates. Wigand et al. (2009) simulated fluid flow through shale (caprock) into fractured cement. The fracture was created along the longitudinal axis of the cement cylinder. After both shale and cement were saturated with 1.65 M brine, supercritical CO_2 was injected. The reaction produced abundant calcite crystals on both surfaces of the fracture. As a result, the fracture was enlarged in some places and partially healed in others. Sweatman et al. (2009) also conducted a CO_2 flow test with a pre-cracked cement core specimen to study the self-healing effect of CO_2. After establishing flow with fresh water, CO_2-saturated water was passed through the pre-cracked sample. No flow of water was detected after 57 min. Micro cracks were found to be self-sealed upon exposure to CO_2.

Large variations in cement carbonation rates have been determined using laboratory experiments conducted under simulated geological storage conditions. The rate depends on the cement–water–rock system defined as well as the experimental conditions employed. High carbonation rates are related to high temperatures and CO_2 pressures, large water/rock ratios (or dynamic flow), reactions with dilute waters, and the absence of carbonates in the laboratory simulations. The conditions that define the low end of carbonation rates include low temperatures and CO_2 pressures, very low water/rock ratios, and waters of high salinity and saturated with carbonates.

Where possible, rate expressions were derived based on the depth of penetration measured at different time intervals. The derived relationships are often used to extrapolate the carbonation depth to a period of decades; this is chosen for the convenience of comparison with field data (see Table 1). The predicted carbonation depth varies from less than 1 mm to over 2500 mm after 30 years of exposure to CO_2. To a certain extent, these variations reflect the fact that there is a wide range associated with the in-situ conditions encountered in CO_2 geological storage. On the other hand, some parameters used in laboratory experiments are not representative of field conditions.

In these laboratory studies, the temperature ranged generally from 50 to 90 °C and CO_2 pressure from 10 MPa to over 30 MPa. The upper values (90 °C and 30 MPa) correspond to a depth of approximately 3000 m. The variation in temperature and pressure covers the depth range for the majority of currently existing and planned CO_2 storage operations. However, a number of experiments were carried out at room temperature, atmospheric pressure and in pure water, and these results should not be applied indiscriminately to geological storage. More critically, no effort was made to equilibrate the solutions introduced into the carbonation reaction to a

specific formation rock type in most of the reported experiments. In addition, high flow rated used in experimental studies can rapidly remove ions dissolved from the cement, exposing new surface for reaction. This process results in high carbonation rates. Given the low velocity of formation water associated with CO_2 storage, it seems more reasonable to assume that cement carbonation occurs under quasi-static conditions, where a rock-dominated environment is likely involved (low water/rock ratio). However, most of the experiments reported were conducted in a water-dominated system, generating higher carbonation rates than would be expected in the field.

5.2. Field studies

Carey et al. (2007) studied a core sample recovered from a well that had been exposed to CO_2 for 30 years. The well penetrates an oil reservoir in Texas (SACROC Unit) undergoing CO_2 enhanced oil recovery. The reservoir is located at about 2100 m depth in a limestone reef (temperature of 54 °C and pressure of 18 MPa), and the overlying shale forms the caprock. The limestone is composed of calcite and ankerite, with minor amounts of quartz and illite. The shale consists predominantly of illite and quartz, with less than 5% carbonate minerals. Portland cement was used in primary cementing, and no additives were applied at depths below 534 m.

A side-track core sample including casing, cement and shale caprock was retrieved from 6 to 4 m above the reservoir–caprock contact. At the casing–cement interface, a dark rind was observed, forming a vein-filling deposit (1–3 mm). Adjacent to this deposit is gray cement, in which there are a set of fractures filled with calcium carbonate. An intensely carbonated orange zone (1–10 mm) was observed between the gray cement and the shale. The interface between the orange zone and the caprock consists of a shale-fragment-zone (SFZ) containing regions of high porosity. The dark rind formed at the casing–cement interface consists of aragonite, calcite and halite, indicating an extensive interaction with CO_2. However, the formation of this dark rind appears to limit fluid flow. The gray cement was almost fully hydrated as no C_3S and C_2S phases were identified. Portlandite (5%) was present in the gray cement, implying that the gray cement has not experienced an extensive carbonation. The orange zone was dominated by three $CaCO_3$ polymorphs (calcite, aragonite and vaterite) and amorphous alumino-silica. The gray cement and the orange zone were separated by a narrow (<1 mm) deposit of amorphous silica, silicate–carbonates, and carbonates. This interface is denser than both the adjacent gray cement and the orange zone, likely forming a continuous barrier limiting CO_2 migration into the gray zone.

The porosity of the gray cement was measured to be 33.5%, typical for Portland cement. The permeability of air-dried gray cement was 0.1 mD. The low extent of carbonation observed in the gray cement was thought to be the result of CO_2 diffusion from the cement–casing and/or cement–formation interfaces. The permeability of the orange zone sample was similar to that of the gray cement (0.2 vs. 0.1 mD), suggesting that the extensive carbonation occurred in the orange zone had not compromised the durability of the cement. The authors concluded that Portland cement based wellbore systems, if properly completed, can prevent significant migration of CO_2 from reservoirs for long period of time (at least decades).

Crow et al. (2009, 2010) conducted an investigation of a 30-year old well from a natural CO_2 production reservoir. The produced fluid contains 96% CO_2, which occurs as a supercritical fluid. Class H Portland cement mixed with 50% fly ash was used in primary cementing, to which 3% bentonite was added. The well was completed in the Dakota Sandstone Formation at a depth of 1390 m (at 58 °C and 10 MPa pressure). The formation rock consists of 69% quartz and less than 10% carbonate, with a water saturation of 20%. Confining the sandstone are the Graneros shale and Greenhorn shale/limestone formations.

In this study, 10 sidewall cores of casing, cement and formation samples were recovered at depths ranging from within the CO_2 reservoir to 70 m above the reservoir in the caprock. Cement samples taken near the CO_2 reservoir have a permeability ranging from 5 to 32 μD and porosity from 38% to 45%, whereas the samples collected higher up in the caprock have a permeability of 0.3–2.31 μD and porosity of 18–29%. This is consistent with the observed extent of cement alteration, which decreases with distance from the reservoir. The original cement phases almost completely converted to calcium carbonate in cement samples taken near the reservoir, whereas samples at the top of the caprock had a minimal alteration. Although permeability and porosity increased as a result of cement alteration, these properties are still adequate to provide an effective hydraulic barrier and resistance to CO_2 migration.

Unlike the observations made on cement samples recovered at the SACROC Unit, where different reaction zones were identified, carbonate minerals were found to be distributed evenly in the cement samples. In addition, no calcium carbonate deposit was observed along the casing–cement interface, and the casing was in very good condition. It was also observed that cement was tightly contacted with the formation without significant calcium carbonate deposition.

Two potential sources of CO_2 were proposed to be responsible for the cement carbonation occurring in the caprock: (1) CO_2-bearing formation water present in the caprock, and (2) migration of CO_2 from the reservoir. In the second hypothesis, defects in the wellbore such as interfaces between cement and formation rocks and high porosity channels within the cement were considered as the possible pathways for CO_2 migration. It was concluded that conventional cement–fly ash systems could be used effectively in creating suitable barriers to CO_2 migration in long-term CO_2 storage operations.

Scherer et al. (in press) characterized cement samples recovered from a 19-year old well at the Teapot Dome oil field to provide an understanding of the properties of aging cements before CO_2 injection. A mixture of 50% Class G cement and 50% fly ash was used for primary cementing. The cement samples were taken from two different depths, showing different microstructure and mineralogy. Adjacent to the Tensleep dolomite reservoir (88 °C and 16.2 MPa), the cement sample was depleted in Ca (with no portlandite) and enriched in Mg. This was related to the reaction between calcium hydroxide in the cement and dolomite in the formation rock. The cement sample from the higher-up Wall Creek sandstone is characterized by the formation of large quantities of ettringite and increased porosity. Ettringite forms as the cement reacts with sulfate-rich formation water. This study demonstrates that aging cements will not retain their original properties and that downhole conditions have a significant effect on cement alteration.

5.3. Modeling

The interaction between cement and CO_2 or CO_2-saturated brine has been numerically simulated using reactive transport models, based on either experimental results or field observations. The development of predictive models for cement degradation is very important in assessing well integrity and well performance, particularly for existing wells, in the selection, permitting, operation and abandonment of CO_2 geological storage sites. This is because, together with statistical analysis of well characteristics, models are the only predictive tool that may help in identifying wells susceptible to degradation and failure within the area of impact of a CO_2 storage operation.

Huet et al. (2007, 2010) simulated the reaction between cement and CO_2-saturated brine, with an emphasis on predicting the changes in geochemical and physical properties of the cement. The experimental results of Duguid et al. (2005) were used as a benchmark, and diffusion was assumed to be responsible for the transport of aqueous species in cement pore network. The experiments that were chosen for modeling were conducted at pH 3.7 and 25 °C, in which four reaction zones were identified (Duguid et al., 2005). As initial conditions, the cement was assumed to be fully hydrated, where portlandite, CSH, ettringite, and monosulfate were the major hydration phases. The amorphous CSH was represented by crystalline jennite and tobermorite in the simulations. The model calculated the changes in mineralogical composition across four reaction zones. Variations in the concentrations of aqueous species in pore water were predicted, and transport properties such as porosity and effective diffusion coefficient were calculated for each alteration zone.

The leakage of CO_2 along the interfaces was thought to be responsible for cement carbonation observed in samples recovered adjacent to the caprock (e.g., Carey et al., 2007; Crow et al., 2009, 2010). Scherer and Huet (2009) used a modeling approach to demonstrate the possibility of an alternative mechanism, which attributes the carbonation to the reaction of cement with CO_2 dissolved in the pore water of the caprock. This modeling work was based on the field study of Crow et al. (2010). Using parameters collected in the field, Scherer and Huet (2009) estimated the concentration of dissolved CO_2 to be 1 M at the bottom surface of the confining Granerous shale and to be close to zero at the boundary with the Greenhorn formation (upper surface). Assuming a linear distribution of dissolved CO_2 in the pore water of the Granerous shale, the authors further calculated the depth of cement carbonation after being contacted with the shale for 30 years. This modeling exercise allowed them to conclude that cement carbonation could result from diffusion of CO_2 dissolved in the shale.

Carey et al. (2007) simulate the interaction between cement and CO_2 based on their field study conducted at the SACROC site. A conceptual model was built, in which CO_2-saturated brine was assumed to migrate along the cement–shale interface and to diffuse into the cement matrix. The brine was in equilibrium with the shale before reacting with the cement. A column including both cement (5 cm, porosity 30%) and the shale-fragment-zone (SFZ) (20 cm, porosity 70%) was defined. The cement paste was fully hydrated, consisting of CSH (Ca/Si = 1.78), portlandite, monosulfate, and hydrogarnet. The shale contained 1.4% carbonate minerals. The brine present in the SFZ was saturated with 18 MPa CO_2 at 25 °C. All these parameters were defined as the initial conditions and the model was based on a diffusion mechanism. The modeling results are comparable to the field observations in terms of the extent of carbonation, interface alteration and compositional variation. In a 5 mm region adjacent to the cement–formation interface, all cement hydration phases were converted to calcium carbonate, amorphous silica and alumina. This was reproduced by adjusting the tortuosity of the cement and the reaction rates of the minerals.

Carey and Lichtner (2009) argued that the extent of CO_2 penetration in the cement is likely controlled by the difference in capillary properties between cement and the formation rock that contains CO_2. Using properties measured at the SACROC site, they demonstrated that in rocks with reservoir-like properties, CO_2 can only penetrate through the unaltered cement via diffusion. However, if CO_2 were present in the caprock and there was a good bond between caprock and cement, it would be possible for CO_2 to penetrate the cement due to the similarity in their capillary properties. Distinct reaction zones were predicted in a diffusion-dominant system compared to the uniform carbonation pattern for cement in contact with shale.

6. Summary and remarks

6.1. Summary

This study reviewed both mechanical and chemical processes that could potentially cause well integrity failure, focusing primarily on well cements. In a typically abandoned well, leakage can take place in the annulus, along casing, and along/through plugs, where the interfaces between cement and formation rock, cement and casing, and casing and plugs have been identified as preferential pathways for fluid flow. In the cement matrix, fluid may migrate either through fractures or within the pore space. In the latter case, fluid flow would occur only when cement is degraded or not properly formed during the emplacement process.

Leakage pathways may be generated in the well annulus during well construction, completion and operation. Incomplete mud removal results in poor bonding of cement to the formation rock. During the cement setting process, gas may invade the cement to form gas channels due to mechanisms such as fluid loss, slurry gelation, and bulk shrinkage. After cement setting, changes in downhole conditions can induce sufficient stresses to damage the integrity of the cement sheath. Cyclic pressure and temperature variations during production and injection can lead to debonding between cement and casing, as well as the development of stress cracks in the cement sheath.

Carbonation studies conducted in cement and concrete research have shown that calcium carbonates are the major reaction products and that the composition of CSH evolves during the reaction. The carbonation progresses through a diffusion-controlled process; both water and calcium carbonates resulting from the reaction block the pore structure further hindering diffusion of CO_2 through the pore spaces. Compared to surface conditions that are commonly used in cement and concrete research, much higher CO_2 pressure and temperature are encountered at depths envisaged for CO_2 storage. Temperatures and pressures could range from the critical point of CO_2 (31.1 °C and 7.38 MPa) to over 100 °C and 30 MPa. The salinity of formation water may reach more than 400 g/L. Cement carbonation could take place in sandstone or carbonates, two major rock types found in storage reservoirs and in deep saline aquifers, or in shale and evaporites which are the most common caprocks.

Laboratory experiments have been conducted under various geological storage conditions to estimate the rate of cement carbonation, characterize carbonation reaction products and to determine the physical properties of well cements reacted with supercritical CO_2 or CO_2-saturated brine. The results show that the rate of carbonation increases with temperature, CO_2 pressure and flow rate, and decreases with water salinity. In addition to water composition, rock mineralogy has a profound impact on the extent of carbonation. In a cement–water system containing no carbonate minerals, the extent of carbonation is much larger than would be observed in a cement–carbonate–water system. In laboratory experiments, these parameters varied greatly, leading to a large variation in the carbonation rate determined. It is noted that some parameters used in laboratory studies are not representative of in-situ conditions encountered in geological storage. Based on the experimental measurements, carbonation depths from less than 1 mm to more than 2500 mm were predicted after 30 years of exposure to CO_2.

Reaction zones were commonly observed in cement samples subjected to the carbonation reaction. These reaction zones can be distinguished by variations in chemical and mineralogical composition, which are often accompanied by a change in physical properties such as porosity and permeability. The development of reaction zones reflects the fact that different processes operate during different stages of the reaction. These processes are characterized initially by the dissolution of portlandite, followed by the precipitation of calcite and further dissolution of the precipitated

calcite. The conversion of portlandite to calcite improves, from a storage security viewpoint, the physical and hydrological properties of the cement, as shown by an increase in density and hardness as well as a decrease in porosity and permeability. However, any subsequent dissolution of calcite from the carbonated cement leads to an increase in porosity and permeability.

In field studies, core samples of casing, cement and formation rock were recovered from wells that had been in contact with CO_2 for 30 years. Substantial carbonation with various reaction zones was observed in cement samples retrieved a few meters above the oil reservoir at the SACROC CO_2-EOR site. The cement–casing and cement–formation interfaces were identified as major pathways for CO_2 migration. In the field study involving natural CO_2 deposits, significant carbonation was also observed in well cement located within or near the reservoir. The extent of carbonation, however, decreased with the vertical distance from the reservoir. It was noted that well integrity was retained in both cases, even though porosity and permeability increased as a result of the reaction between cement and CO_2.

Reactive transport models have been used to simulate reactions between cement and CO_2 or CO_2-saturated brine under different conditions. Various assumptions and models were used to represent chemical and physical changes associated with cement carbonation. The simulations were able to produce mineralogical profiles across reaction zones that were comparable to experimental or field results. Through history matching of field or experimental results, porosity and CO_2 diffusivity in the reacted cement were generated. However, it is critical to evaluate the conditions employed in laboratory experiments and to understand the mechanism through which cement degrades in order to predict the rate of cement degradation in geological storage environments.

6.2. Critical overview

The following sections address key considerations regarding processes responsible for cement carbonation and degradation, chemical environments encountered in geological storage units, and the importance of mechanical defects on potential cement degradation in caprock. It is intended to provide some insights in whether or not well integrity will be compromised as a result of the interaction between well cements and CO_2 in geological storage environments.

6.2.1. Carbonation vs. degradation

Cement carbonation involves initially the dissolution of CO_2 into the pore water of cement pastes, followed by reaction with portlandite to form calcium carbonate (mainly as calcite). Calcite is more stable than portlandite in hydrogeological systems due to its lower solubility. The conversion of portlandite to calcite also results in a decrease in porosity and permeability. Therefore, cement carbonation is beneficial to the storage process due to the improved chemical stability and physical properties of the reacted cement. Under certain conditions, however, the precipitated calcite may dissolve from the carbonated cement. This process is sometimes described as "bicarbonation". The dissolution of calcite could lead to an increase in porosity and even disintegration of well cement. It is the "bicarbonation" that contributes primarily to cement degradation. Given that "cement carbonation" and "cement degradation" result from two different processes, these two terms should not be used interchangeably as has been done in some previous studies.

In laboratory experiments, the depth of carbonation (or penetration depth) was measured from the surface of cement samples to the boundary where no alteration occurred. Next to this non-carbonated cement, reaction zones with various mineralogical compositions and physical properties are often present. Degradation as a result of calcite dissolution (bicarbonation) only occurs in the zone near the surface. This depth of bicarbonation is much less than the depth of carbonation measured in the experiments. Therefore, the rate of carbonation determined based on the measured depth of carbonation is much greater than the rate of cement degradation. Even for the degraded cement, its ability to prevent fluid flow may still be retained if calcite has not been leached substantially. This was shown in cement samples retrieved from the 30-year old well penetrated into natural CO_2 deposits (Crow et al., 2010) where well cements have undergone extensive carbonation, but only a limited degree of bicarbonation. The increased porosity and permeability have not reached to the extent to compromise the integrity of the well.

6.2.2. Dissolution of calcite from carbonated cement

When CO_2 is injected into subsurface, a portion of CO_2 dissolves in the formation water, resulting in a reduction in pH. Calcite present in the formation rock will dissolve along the flow path of CO_2-saturated brine. Under conditions typical of CO_2 geological storage, there is a need of less than 0.1% of calcite to be present in the formation rock to saturate the first pore volume of the fluid flow. Carbonate minerals are present ubiquitously in sedimentary rocks. For instance, calcite cement usually accounts for a few percent of the total sandstone volume (1–3%) on a formation-wide basis (Milliken, 2004). The flow velocity of formation water is typically on the order of millimeters to centimeters per year in deep saline aquifer (Bachu et al., 1994). Under these conditions, it is reasonable to assume that virtually all CO_2-saturated brines will be in equilibrium with calcite before it reaches an existing well. The dissolution of calcite from the carbonated cement will not occur in these formation waters because they have already been in equilibrium with calcite. In other words, substantial degradation of well cements is not expected under conditions commonly encountered in geological storage. However, extensive flushing with CO_2-rich water, as might be expected in CO_2-EOR operation, could potentially exhaust carbonate minerals if their contents in the formation rock are very low. Under these circumstances, well integrity may be compromised due to cement degradation.

6.2.3. Cement degradation in caprock

We have addressed the dependence of the stability of the carbonated cements on the chemical environment in which the cement is located. The chemical composition of formation water and the mineralogy of formation rock are primary determinants. In the previous section, we have focused on the storage unit (reservoir or aquifer) to examine the stability of calcium carbonate precipitated during cement carbonation. However, well integrity is more significantly affected by cement degradation occurring in the caprock since the leakage is through conduits in the caprock rather than within the storage unit. Even if severe degradation of cement had taken place in the reservoir or aquifer, well integrity would be retained as long as the cement in the well adjacent to the caprock does not degrade substantially. Therefore, aspects relevant to cement degradation in shale and evaporites, two commonly-found caprock types, should be the focus of future studies.

To trigger carbonation in cements adjacent to the caprock, a pathway for flow of CO_2-rich fluids must exist. At the SACROC CO_2-EOR site, the shale-fragment-zone next to the cement likely acted as a conduit for these fluids (Carey et al. (2007). In addition to the cement–shale interface, CO_2-rich fluid can also migrate through pre-existing mechanical defects that are created during well construction, completion, operation, and abandonment. When such a conduit is present, well cements adjacent to the caprock will be carbonated, and may even be degraded. This emphasizes the important role that primary cementing and well abandonment practices play in well integrity relevant to CO_2 geological storage.

6.3. Some considerations for regulatory agencies

This review of the current status of knowledge regarding wellbore integrity in relation to CO_2 geological storage may serve as guidance to regulatory agencies in various jurisdictions in developing appropriate regulations for permitting CO_2 geological storage.

- Although this review focused on existing wells rather than CO_2 injection wells, the results of one study reviewed here indicate that CO_2 injection wells should be built for purpose, meeting stringent zonal isolation requirements, rather than converting existing wells into CO_2 injection wells.
- The integrity of a well may be compromised by reactions of CO_2 with cements adjacent to the caprock. Mechanical defects developed during well construction, completion, and abandonment could provide a pathway for CO_2-rich fluids. Wells with high likelihood of leakage due to pre-existing mechanical defects should be identified early on and remediated or properly monitored.
- Generally, regulations for drilling, completion and abandonment of wells, regardless of their purpose, should be improved and tightened up; experience has shown that the occurrence of well leakage decreases when regulations for well construction, operation and monitoring are improved.
- The area of impact in CO_2 storage operations should be defined both in terms of spread and migration of the stored CO_2, and in terms of pressure build-up as a result of injection. In the former case, wells with high likelihood of leakage that may come in contact with CO_2 should be checked, monitored, and, if need be, remediated, since the contact of CO_2 with well cement may lead to further cement degradation and enhanced leakage. In the latter case, although this subject was not addressed in this paper, upwell brine leakage may occur.

These are only a few observations directly flowing from this review, and a more thorough review of regulatory requirements for the permitting, operation and abandonment of CO_2 storage sites, including well integrity, is needed, which is beyond the scope of this paper.

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Earthquake triggering and large-scale geologic storage of carbon dioxide

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Despite its enormous cost, large-scale carbon capture and storage (CCS) is considered a viable strategy for significantly reducing CO_2 emissions associated with coal-based electrical power generation and other industrial sources of CO_2 [Intergovernmental Panel on Climate Change (2005) IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change, eds Metz B, et al. (Cambridge Univ Press, Cambridge, UK); Szulczewski ML, et al. (2012) *Proc Natl Acad Sci USA* 109:5185–5189]. We argue here that there is a high probability that earthquakes will be triggered by injection of large volumes of CO_2 into the brittle rocks commonly found in continental interiors. Because even small- to moderate-sized earthquakes threaten the seal integrity of CO_2 repositories, in this context, large-scale CCS is a risky, and likely unsuccessful, strategy for significantly reducing greenhouse gas emissions.

carbon sequestration | climate change | triggered earthquakes

The combustion of coal for electrical power generation in the United States generates approximately 2.1 billion metric tons of CO_2 per year, ~36% of all US emissions. In 2011, China generated more than three times that much CO_2 by burning coal for electricity, which accounted for ~80% of its total emissions. (According to the Energy Information Agency of the US Department of Energy, total CO_2 emissions in China were 8.38 billion metric tonnes in 2011, with 6.95 billion tons from coal burning, nearly all of which is used electrical power generation.) From a global perspective, if large-scale carbon capture and storage (CCS) is to significantly contribute to reducing the accumulation of greenhouse gases, it must operate at a massive scale, on the order of 3.5 billion tons (1) of CO_2 per year, a volume roughly equivalent (2) to the ~27 billion barrels of oil currently produced annually around the world. (Under reservoir conditions, one billion tons of CO_2 occupies a volume of ~1.3 billion cubic meters, equivalent to 8.18 billion barrels. Thus, 3.5 billion tons of carbon dioxide would correspond to a volume of approximately 28.6 billion barrels. There are currently ~850,000 wells producing oil around the world.) Moreover, a leak rate from underground CO_2 storage reservoirs of less than 1% per thousand years is required for CCS to achieve the same climate benefits as renewable energy sources (3).

Before embarking on projects to inject enormous volumes of CO_2 at numerous sites around the world, it is important to note that over time periods of just a few decades, modern seismic networks have shown that earthquakes occur nearly everywhere in continental interiors. Fig. 1, *Upper* shows instrumentally recorded earthquakes in the central and eastern United States and southeastern Canada. Fig. 1, *Lower* shows instrumentally recorded intraplate earthquakes in south and east Asia (4). The seismicity catalogs are complete to magnitude (M) 3. The occurrence of these earthquakes means that nearly everywhere in continental interiors a subset of the preexisting faults in the crust is potentially active in the current stress field (5, 6). This is sometimes referred to as the *critically stressed* nature of the brittle crust (7). It should also be noted that despite the overall low rate of earthquake occurrence in continental interiors, some of the most devastating earthquakes in history occurred in these regions. In eastern China, the M 7.8, 1976 Tangshan earthquake, approximately 200 km east of Beijing, killed several hundred thousand people. In the central United States, three M 7+ earthquakes in 1811 and 1812 occurred in the New Madrid seismic zone in southeast Missouri.

Because of the critically stressed nature of the crust, fluid injection in deep wells can trigger earthquakes when the injection increases pore pressure in the vicinity of preexisting potentially active faults. The increased pore pressure reduces the frictional resistance to fault slip, allowing elastic energy already stored in the surrounding rocks to be released in earthquakes that would occur someday as the result of natural geologic processes (8). This effect was first documented in the 1960s in Denver, Colorado when injection into a 3-km-deep well at the nearby Rocky Mountain Arsenal triggered earthquakes (9). Soon thereafter it was shown experimentally (10) at the Rangely oil field in western Colorado that earthquakes could be turned on and off by varying the rate at which water was injected and thus modulating reservoir pressure. In 2011 alone, a number of small to moderate earthquakes in the United States seem to have been triggered by injection of wastewater (11). These include earthquakes near Guy, Arkansas that occurred in February and March, where the largest earthquake was M 4.7. In the Trinidad/Raton area near the border of Colorado and New Mexico, injection of produced water associated with coalbed methane production seems to have triggered a number of earthquakes, the largest being a M 5.3 event that occurred in August. Earthquakes seem to have been triggered by wastewater injection near Youngstown, Ohio on Christmas Eve and New Year's Eve, the largest of which was M 4.0. Although the risks associated with wastewater injection are minimal and can be reduced even further with proper planning (11), the situation would be far more problematic if similar-sized earthquakes were triggered in formations intended to sequester CO_2 for hundreds to thousands of years.

Deep borehole stress measurements confirm the critically stressed nature of the crust in continental interiors (12), in some cases at sites directly relevant to the feasibility of large-scale CCS. For example, deep borehole stress measurements at the Mountaineer coal-burning power plant on the Ohio River in West Virginia indicate a severe limitation on the rate at which CO_2 could be injected without the resulting pressure build-up initiating slip on preexisting faults (13). Because of the low permeability of the formations at depth, pore pressure increases would be expected to trigger slip on preexisting faults if CO_2 injection rates exceed approximately 1% of the 7 million tons of CO_2 emitted by the Mountaineer plant each year. Similarly, stress measurements at Teapot Dome, Wyoming, the US government-owned oil field where pilot CO_2

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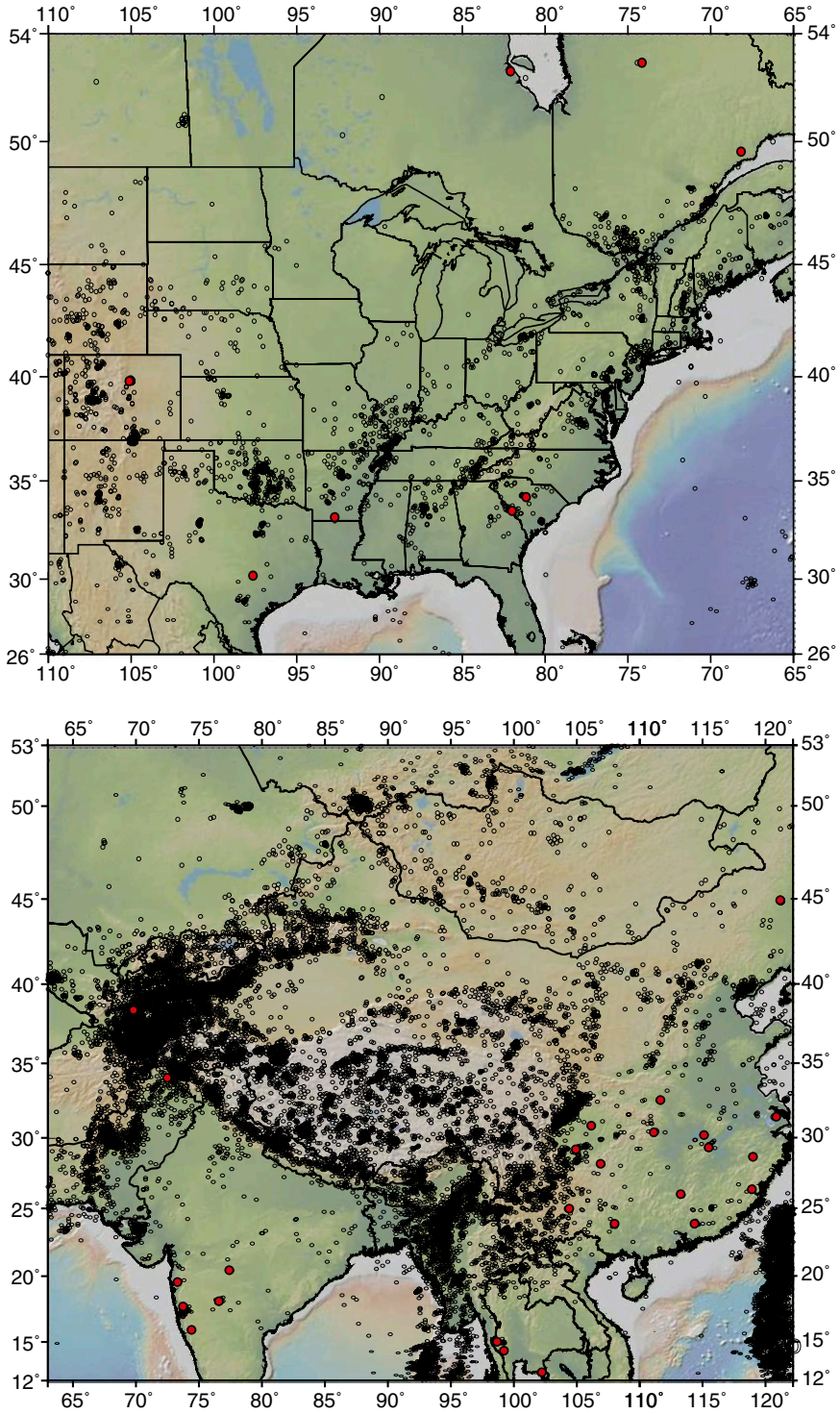


Fig. 1. *Upper*: Instrumentally recorded seismicity and damaging historical earthquakes in the central and eastern United States and southeastern Canada. Red dots indicate sites of reservoir-induced seismicity. *Lower*: Seismicity of south and east Asia and sites of reservoir-induced seismicity. Both data sets are available from the US Geological Survey (4).

injection projects have been considered, show that very small pressure buildups are capable of triggering slip on some preexisting faults (14).

Dam construction and water reservoir impoundment produce much smaller pore pressure changes at depth than are likely to occur with CO_2 sequestration, but many have triggered earthquakes at various sites around the world (15) (red dots in Fig. 1). Except for the much smaller pore pressure increases at depth, reservoir-triggered earthquakes are a good analog for the potential for seismicity to be triggered by CO_2 injection. Both activities cause pore pressure increases that act over large areas and are persistent for long periods. Three reservoir impoundments in eastern Canada (located in the ancient, stable core of the North American continent) triggered earthquakes as large as M 4.1 and M 5 at the two sites (Fig. 1), despite the fact that the pore pressure increases at depth were extremely small.

Triggered Earthquakes and Seal Integrity

Our principal concern is not that injection associated with CCS projects is likely to trigger large earthquakes; the problem is that even small to moderate earthquakes threaten the seal integrity of a CO_2 repository. In parts of the world with good construction practices, it is unusual for earthquakes smaller than approximately M 6 to cause significant human harm or property damage. Fig. 2 uses well-established seismological relationships to show how the magnitude of an earthquake is related to the size of the fault that slipped and the amount of fault slip that occurred (16). As shown, faults capable of producing M ~6 earthquakes are at least tens of kilometers in extent. (The fault size indicated along the abscissa is a lower bound of fault size as it refers to the size of the fault segment that slips in a given earthquake. The fault on which an earthquake occurs is larger than the part of the fault that slips in an individual event.) In most cases, such faults should be easily identified during geophysical site characterization studies and thus should be avoided at any site chosen for a CO_2 repository. (Faults in crystalline basement rocks might be difficult to recognize in geophysical data. We assume, however, that any site chosen as a potential CO_2 repository would be carefully selected, avoiding the possibility of pressure changes in the CO_2 repository from affecting faults in crystalline basement.) The problem is that site characterization studies can easily miss the much smaller faults associated with small to moderate earthquakes.

Although the ground shaking from small- to moderate-sized earthquakes is inconsequential, their impact on a CO_2 repository would not be. Most of the geologic formations to be used for long-term storage of CO_2 are likely to be at depths of approximately 2 km—deep enough for there to be adequate sealing formations to isolate the CO_2 from the biosphere but not so deep as to encounter formations with very low permeability. Given large volumes of CO_2 injected into selected formations for many decades, if a small to moderate earth-

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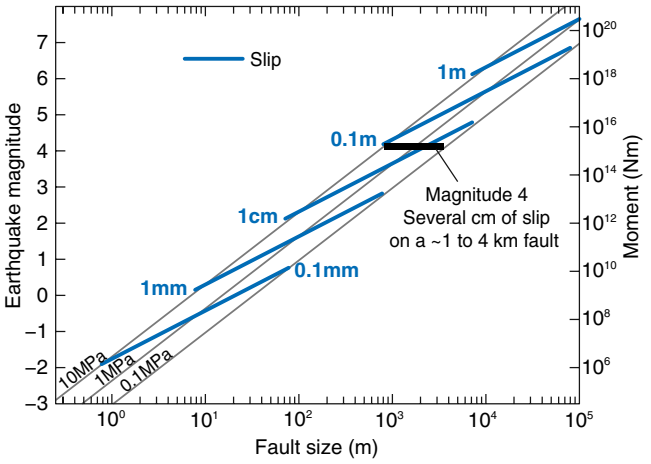


Fig. 2. Relationships among various scaling parameters for earthquakes. The larger the earthquake, the larger the fault and amount of slip, depending on the stress drop in a particular earthquake. Observational data indicate that earthquake stress drops range between 0.1 and 10 MPa.

quake were to be triggered in a geologic formation at approximately 2 km depth, it could jeopardize the seal integrity of the storage formation. For example, if a M ~4 earthquake were to be triggered by CO_2 sequestration (17)—an event that would be widely felt in a populated area but for which shaking would be unlikely to cause harm or damage—it would be associated with several centimeters of slip on a fault several kilometers in size. Because laboratory studies show that just a few millimeters of shear displacement are capable of enhancing fracture and joint permeability (18), several centimeters of slip would be capable of creating a permeable hydraulic pathway that could compromise the seal integrity of the CO_2 reservoir and potentially reach the near surface.

Safe Sequestration

It is important to emphasize that CCS can be valuable and useful for reducing greenhouse gas emissions in specific situations. A good example is the injection of CO_2 into the Utsira formation (19) at the Sleipner gas field in the North Sea, where a significant amount of CO_2 is coproduced with natural gas. After separating the CO_2 from the produced gas, approximately 1 million tons of CO_2 per year has been injected over the past 15 y without triggering seismicity. Assuming isolation from the near surface, injection into highly porous and permeable reservoirs that are laterally extensive would produce small increases in pressure in response to CO_2 injection. Moreover, weak, poorly cemented sandstones are expected to deform slowly in response to applied geologic forces. In such reservoirs, the stresses *relax* over time, and such formations are not prone to faulting (20). In this regard, the Utsira formation is ideal for CO_2 sequestration. It is isolated from vertical migration by impermeable shale formations, and it is highly porous, permeable, laterally extensive, and weakly cemented.

To contribute significantly to greenhouse gas emission reductions (2), roughly 3,500 sites similar to the Utsira formation would have to be found at convenient locations around the world, assuming comparable injection rates of approximately 1 million tons of CO_2 per year. In fact, it would take approximately 85 such sites coming on line each year to reach a goal of storing approximately 1 billion tons of CO_2 by midcentury. Clearly this is an extraordinarily difficult, if not impossible, task if only highly porous and permeable and weakly cemented formations are to be used.

Of course, rather than using potentially problematic geologic formations close to coal-burning power plants for sequestration (as illustrated by the Mountaineer case study cited above), relatively ideal formations for CO_2 storage could be sought on a regional basis to accommodate emissions from a number of plants. One example of this is the potential use of the Mt. Simon sandstone in the Illinois basin. The Mt. Simon is porous, permeable, and regionally extensive. However, models of injection of 100 million tons of CO_2 per year for 40 y predicts (21) increases in pore pressure of several megapascals over a region of ~40,000 km^2. The approximate area of significantly increased pore pressure resulting from injection is shown as the blue-shaded area in Fig. 3, essentially adjacent to the Wabash fault zone, where a series of moderate natural earthquakes occurred in the spring of 2008, the largest being M 5.2. Paleoseismic data indicate the occurrence of much larger nearby earthquakes (some greater than M ~7) in the recent geologic past (22). Importantly, the 100 million ton annual CO_2 injection rate used in the

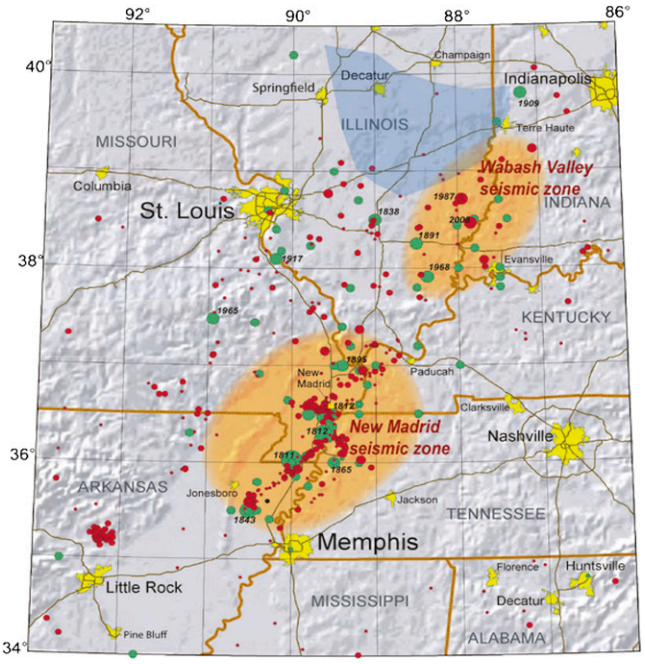


Fig. 3. Instrumentally recorded seismicity in the New Madrid and Wabash Valley seismic zones (modified from ref. 23). Red circles indicate earthquakes that occurred from 1974 to 2002 with magnitudes larger than 2.5 located using modern instruments. Green circles denote earthquakes that occurred before 1974. Larger earthquakes are represented by larger circles. The area shown in blue corresponds to the area where a pressure increase of several megapascals would result from injecting 100 million tons per year of CO_2 into the Mt. Simon sandstone in the Illinois Basin for 40 y (19).

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modeling only represents approximately one seventh of the CO_2 generated by the coal-burning power plants in the Ohio River Valley alone.

Because of the need to carefully monitor CO_2 repositories with observation wells, geophysical and geochemical monitoring systems, etc., it is likely that most sites will have to be located on land or very near shore. Otherwise, highly porous reservoirs located offshore, like those adjacent to salt domes along the US Gulf Coast, would be relatively ideal sites because salt formations are known to be excellent seals for hydrocarbons.

Depleted oil and gas reservoirs are potentially suitable for CO_2 storage for a variety of reasons—an infrastructure of wells and pipelines exist, and there is a great deal of geologic and subsurface property data available to characterize the subsurface from decades of study. In addition, from an earthquake-triggering perspective, depleted reservoirs are attractive because at the time injection of CO_2 might start, the pore pressure would be below the value that existed before petroleum production. Thus, there could be significant injection of CO_2 before pressures increase to preproduction values, thereby reducing the potential for triggering earthquakes.

There are a number of potential issues to consider before using depleted oil and gas reservoirs for CO_2 storage, the most important of which are capacity and geographic distribution. The reasons that there is such interest in using saline aquifers for CO_2 storage is that they are potentially well distributed with respect to likely sources of CO_2, and they could presumably accommodate the enormous volumes of CO_2 that need to be stored. If one were only to consider the United States, storing the 2.1 billion tons of CO_2 currently generated annually by coal-burning power plants in depleted oil and gas reservoirs would require injection of CO_2 at a rate of approximately 17 billion barrels per year; a rate equivalent to eight times current US annual oil production and more than four times US peak annual oil production that occurred in the early 1970s. In addition, it is important to make sure that production-related activities, such as water flooding during secondary recovery, did not compromise the seal capacity of the reservoirs. There also needs to be careful study of the wells in the depleted oil or gas field to make sure that poorly cemented well casings, especially in older wells, will not be pathways for release of stored CO_2 (23). Finally, there are likely to be complicated legal questions concerning ownership and liability that will need to be worked out on a case-by-case basis.

Although enhanced oil recovery (EOR) using CO_2 (in which CO_2 is injected to dissolve in oil and reduce its viscosity) would be a beneficial use of CO_2, it is important not to confuse this with CCS. In CCS the goal is to inject large quantities of CO_2 into available pore space and store it there for hundreds to thousands of years. When CO_2 is used for EOR, the CO_2 dissolved in the oil is separated and captured from produced oil and then reinjected. Thus, smaller volumes of CO_2 are used, and the long-term storage capacity of the reservoir is not an issue.

Many CCS research projects are currently underway around the world. Much of this work involves characterization and testing of potential storage formations and includes a number of small-scale pilot injection projects. Because the storage capacity/pressure build-up issue is critical to assess the potential for triggered seismicity, small-scale pilot injection projects do not reflect how pressures are likely to change (increase) once full-scale injection is implemented. Moreover, even though limitations on pressure build-up are among the many factors that are evaluated when potential formations are considered as sequestration sites, this is usually done in the context of not allowing pressures to exceed the pressure at which hydraulic fractures would be initiated in the storage formation or caprock. In the context of a critically stressed crust, slip on preexisting, unidentified faults could trigger small- to moderate-sized earthquakes at pressures far below that at which hydraulic fractures would form.

As mentioned above, sequences of small to moderate earthquakes were apparently induced by injection of waste water near Guy, Arkansas, Trinidad, Colorado, and Youngstown, Ohio in 2011 and on the Dallas-Ft. Worth airport, Texas. Although these earthquakes were widely felt, they caused no injury, and only the Trinidad earthquake resulted in any significant damage. However, had similar earthquakes been triggered at sites where CO_2 was being injected, the impacts would have raised pressing and important questions: Had the seal been breached? Was it still safe to leave previously injected CO_2 in place?

In summary, multiple lines of evidence indicate that preexisting faults found in brittle rocks almost everywhere in the earth's crust are subject to failure, often in response to very small increases in pore pressure. In light of the risk posed to a CO_2 repository by even small- to moderate-sized earthquakes, formations suitable for large-scale injection of CO_2 must be carefully chosen. In addition to being well sealed by impermeable overlaying strata, they should also be weakly cemented (so as not to fail through brittle faulting) and porous, permeable, and laterally extensive to accommodate large volumes of CO_2 with minimal pressure increases. Thus, the issue is not whether CO_2 can be safely stored at a given site; the issue is whether the capacity exists for sufficient volumes of CO_2 to be stored geologically for it to have the desired beneficial effect on climate change. In this context, it must be recognized that large-scale CCS will be an extremely expensive and risky strategy for achieving significant reductions in greenhouse gas emissions.

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Charging of Elk Hills reservoirs as determined by oil geochemistry

John E. Zumberge, Judy A. Russell, and Stephen A. Reid

ABSTRACT

Crude oils from Miocene and Pliocene reservoirs from the Elk Hills field in California's San Joaquin basin were analyzed for stable carbon isotopes and biomarkers. Cluster analysis of geochemical variables defines five principal oil families, all derived from different organic-rich facies of the Miocene Monterey Formation. Carbon isotope analysis indicates no contribution from the basin's other major source rock, the Eocene Kreyenhagen Formation. Oil families show a strong correspondence to stratigraphic intervals. Oils from pre-Monterey reservoirs were probably generated from the lowermost organic-rich facies of the Monterey and are the most thermally mature. Upper Miocene Stevens zone turbidite reservoirs contain oils of various thermal-maturity stages, but mature light ends are abundant and are likely generated from the floors of the adjacent subbasins located north and south of Elk Hills. The relatively minor presence of low-thermal-maturity biomarkers that are typically characteristic of Monterey oils may indicate that Stevens traps did not form until after the source intervals were at a higher level of thermal maturity. All oils in Stevens porcelanite reservoirs contain a higher concentration of low-maturity biomarkers, which may indicate derivation from more localized areas on the flanks of the Elk Hills anticlines. The shallow Pliocene oils have suffered biodegradation to different degrees, and the lowest API gravities occur on the flanks of the anticline. The carbon isotopic composition of these oils suggests yet another Monterey source facies that charged the Pliocene reservoirs and is not simply the result of vertical leakage from the older Miocene reservoirs.

INTRODUCTION

Oils from California's San Joaquin basin are derived from Eocene and Miocene source intervals (Zieglar and Spotts, 1978; Kruge 1986; Peters et al., 1994; Kaplan, 2000). Expulsion and migration

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of oil from the deeper, thermally mature areas of the basin began in the Pliocene and is coincident with the initiation of deformation that forms many of the basin's structural traps. Other than the general relationship of oils to source rocks, little additional information has been published for the basin documenting specifics of expulsion timing, migration pathways, and filling (or charging) of traps. This study presents a detailed look at oils from the Elk Hills field and nearby fields and indicates that oil families differ by reservoir composition, depth, and location. These subtle distinctions reflect a complex expulsion and migration history at Elk Hills and provide clues on the timing of trap formation and the filling sequence of oil reservoirs.

This study presents geochemical data and interpretations for 66 oils from the Elk Hills field, San Joaquin Valley, California. Most of the samples are from turbidite sandstone and porcelanite reservoirs of the upper Miocene Monterey Formation. Pre-Monterey and Pliocene reservoirs are also incorporated. In addition, 10 oils from other southern San Joaquin fields, mostly from pre-Monterey reservoirs, were included for comparison. The purpose of this study is to determine the origin and potential migration pathways for Elk Hills oils, including those produced from the older reservoirs as well as the shallow Pliocene zones. Whether pre-Monterey source units are present in Elk Hills (e.g., Eocene Kreyenhagen or lower Miocene Temblor) is important, considering not only the deep potential in Elk Hills, but also other deep targets in the southern San Joaquin Valley.

Based only on a limited oil sample data set, Peters et al. (1994) distinguished San Joaquin oils derived from the Miocene Monterey and the Eocene Kreyenhagen source rocks using primarily stable carbon isotopic compositions. Typical of marine Miocene-derived oils worldwide, oils derived from the Monterey are isotopically heavy (more positive), whereas the Eocene oils are 4–5 ‰ lighter (more negative). These petroleum system assignments were confirmed by source rock analyses (Peters et al., 1994). With this limited data set, Peters et al. (1994) determined that Eocene oils are present in the northern San Joaquin basin and extend as far south as the Belgian Anticline field, which is located just to the west and northwest of Elk Hills (Figure 1). Oils in the central and southern San Joaquin basin are derived from Miocene source rocks.

In 1999, the first 15 oils from Elk Hills were analyzed for this study. Two of these oils were from pre-Monterey reservoirs (Temblor Formation) and differed in their biomarker chemistry (molecular fossils) from most of the oils produced from various Stevens sandstone units. The stable carbon isotopic composition of the C_{15+} fractions still indicated a Monterey source for these Temblor oils, at least for the heavy-oil fraction. These first studied Elk Hills oils were also compared to other Monterey oils from the Santa Maria, Santa Barbara Channel, and Los Angeles basins. The lower phosphatic and carbonate-rich facies of the Monterey generated much of the oil found in the Santa Maria and Los Angeles basins (e.g., Isaacs and Rullkötter, 2001), whereas Elk

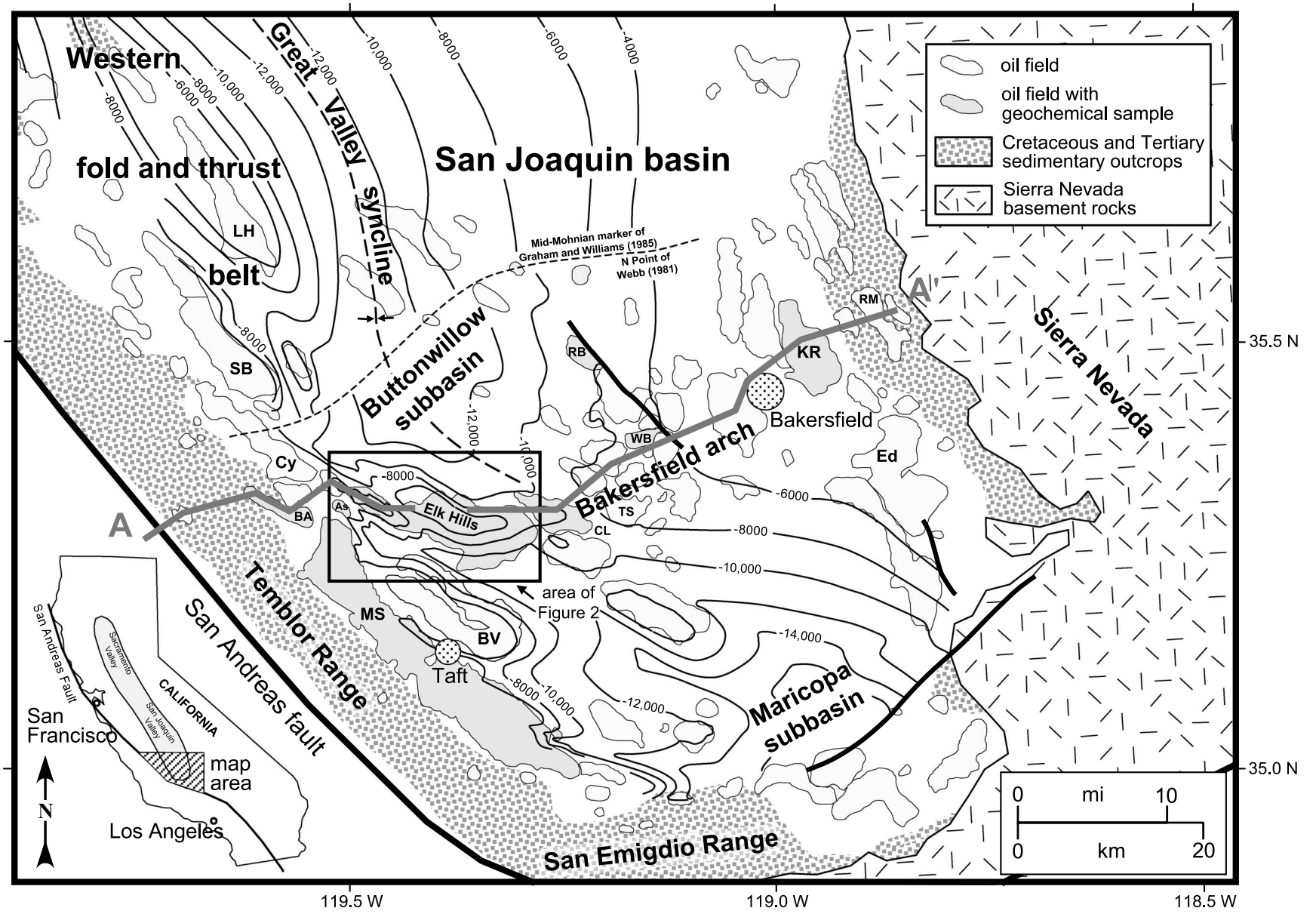


Figure 1. Index map of the southern San Joaquin basin, showing the major structural features and significant oil fields. Simplified structural contours are of Graham and Williams' (1985) mid-Mohnian marker and Webb's (1981) N Point. Key to field names: As = Asphalto; BA = Belgium Anticline; BV = Buena Vista; CL = Coles Levee; Cy = Cymric; Ed = Edison; KR = Kern River; LH = Lost Hills; MS = Midway-Sunset; RB = Rio Bravo; RM = Round Mountain; SB = South Belridge; TS = Ten Section; and WB = West Bellevue.

Hills Monterey oil biomarkers appear to originate primarily from more siliceous Monterey facies based on biomarker distributions. Subsequently, 51 additional Elk Hills oils were analyzed to include additional pre-Monterey reservoirs as well as porcelanite and shallow oil zone samples. Ten oils from other southern San Joaquin fields, including Eocene Kreyenhagen-derived oils, were also analyzed. The pedigrees of all oils are listed in Table 1.

REGIONAL GEOLOGIC SETTING, SOURCE ROCKS, AND RESERVOIRS

Elk Hills is located in the southern San Joaquin basin, about 40 mi (65 km) southwest of Bakersfield, California (Figure 1). The basin is a prolific hydrocarbon region and has produced more than 12 billion bbl oil and 3.5 tcf gas (California Division of Oil, Gas, and Geothermal Resources, 2003). The basin is asymmetrical along a north-south–trending axis (the Great Valley syncline) and is filled with sediments of late Mesozoic and Cenozoic age. On the east side of the basin, the basin fill thins as it onlaps Mesozoic igneous basement and forms a homoclinal limb that is locally broken by Miocene and Pliocene extensional faulting. The stratigraphic section thickens westward and is more than 25,000 ft (7620 m) thick west of the axis. The west side of the basin, which terminates at the San Andreas fault, is strongly deformed because of Pliocene to Holocene compression, and parts of the Cretaceous to Miocene section are exposed in outcrop. Several large anticlines, including Buena Vista, Belridge, and Lost Hills, are part of Bartow's (1991) western fold and thrust belt and formed during this period of compression. A broad northeast-trending basement ridge, the Bakersfield arch, divides the southern San Joaquin basin into the Maricopa and Buttonwillow subbasins. The Elk Hills field lies between the two subbasins southwest and along trend with the arch and merges westward into the western fold and thrust belt.

The principal petroleum source facies of the basin are the middle to upper Eocene Kreyenhagen Formation and the middle and upper Miocene Monterey Formation (Figure 2). The Kreyenhagen Formation is present in the subsurface throughout the Buttonwillow subbasin and extends at least as far south as Elk Hills and the Bakersfield arch. The Kreyenhagen consists of shale and siliceous shale and is up to 1000 ft (305 m) thick in the Buttonwillow subbasin (Church and Krammes, 1957; Villanueva and Kappeler, 1989). It was deposited under restricted marine conditions when the basin was partially closed along its western margin (T. H. Nilsen, S. A. Reid, D. R. D. Boote, 2005, personal communication). Along the west side of the basin, submarine-fan deposits of the Point of Rocks Sandstone Member are encased within the Kreyenhagen (Nilsen, 1987). Total Kreyenhagen and Point of Rocks thickness west of Elk Hills is about 6500 ft (2000 m) (Dunwoody, 1986) (Figure 3). Organic content is moderate to high (Kaplan, 2000) and consists of marine kerogen. The Kreyenhagen is a good source rock and is the source of oils in most of the fields in the northern Buttonwillow subbasin (Peters et al., 1994; Kaplan, 2000).

The Monterey Formation is present in the subsurface in the central and western areas of the Buttonwillow and Maricopa subbasins as well as across the Bakersfield arch. West of the basin axis and east of the outcrop belt, the formation is more than 5000 ft (1524 m) thick (Graham and Williams, 1985) (Figure 3). A complex lithologic suite is present that includes diatomite, porcelanite, siliceous shale, chert, clay-shale, and dolomite. In the Elk Hills area, the Monterey was deposited in a dynamic setting of evolving subsea structures in a deep-water setting (~2000–4000 ft; ~600–1200 m; Bandy and Arnal, 1969). Deposition of the Monterey occurred after the development of the San Andreas fault and the transformation of the San Joaquin basin from a convergent to a transform margin setting (Graham et al., 1989). By the late Miocene, wrench tectonism caused several San Joaquin structures to begin growing, including those at Buena Vista Hills, Elk Hills, and Lost Hills (Harding, 1976). Based on paleogeographic reconstructions by Graham (1978) and Graham et al. (1989) that include restoration of 165 mi (265 km) of post-Miocene offset on the San Andreas fault, emergent granitic basement of the Salinian block lay west of the basin and resulted in the basin's partial closure. The deep-marine setting became ideal for the preservation of organic-rich diatomaceous source rocks (Graham and Williams, 1985). Organic-rich shales collected in abundance in areas removed from coarse-grained deposition, including on the crests of the growing subsea anticlines. Thick turbidite sandstones, collectively referred to informally as the Stevens sand (and by numerous local names), are derived from highlands on the west, south, and east sides of the basin (MacPherson, 1978; Webb, 1981) and are interbedded within the Monterey, mostly in the upper half of the formation. Organic material from the Monterey Formation is established as the source of oil

in oil fields in the Maricopa and southern Buttonwillow basins (Peters et al., 1994; Kaplan, 2000).

Although the Miocene and Pliocene part of the stratigraphic section in the Elk Hills area and the central San Joaquin basin is composed primarily of mudstone, claystone, and siliceous shale, at five distinct time intervals, depositional systems brought reservoir-quality sands to the basin center (Figures 2, 3): (1) early Miocene western-sourced Santos and Carneros fans; (2) late Miocene eastern-derived Stevens submarine fan; (3) late Miocene western-derived Stevens turbidites; (4) early Pliocene Etchegoin–San Joaquin tidal system; and (5) late Pliocene Mya tidal channels (Reid, 1995).

The oldest and deepest reservoir sandstones are the Santos and Carneros sandstone members of the Temblor Formation. Both sandstones are submarine-fan deposits that are derived from highlands originally located west of the field but now positioned in the Santa Cruz area of coastal California, having been moved northward long the San Andreas fault system (Graham et al., 1989). Deeper sandstone units are present at Elk Hills, including the Eocene Point of Rocks Sandstone Member of the Kreyenhagen Formation, but have failed to produce commercial quantities of oil or gas.

The Monterey Formation contains several productive sandstone units of late Miocene age that are derived from highlands at the eastern and western margins of the basin. The Western 31S and Main Body B sandstones (W31S-MBB; Figure 2) are within the B unit of the Monterey and are part of the much larger Stevens submarine-fan system that extends across much of the Bakersfield arch, northern Maricopa subbasin, and southern Buttonwillow subbasin (MacPherson, 1978; Webb, 1981). The fan was the deep-water extension of the Kern River delta, which was the principal site of deposition of clastics derived from the southern Sierra Nevada. At Elk Hills, the western limit of the Stevens submarine fan falls about midway across the field.

Sands derived from smaller turbidite systems are present at Elk Hills in the A and N units of the Monterey (Figure 2). The 26R and 24Z sand bodies are derived from highlands once present west of Elk Hills but, because of right-lateral faulting on the San Andreas fault, are now located in the Gabilan Range in the central Coast Ranges (Graham, 1978). Both sand bodies were deposited in a slope setting that was disrupted by contemporaneous structural folding. The turbidite systems generally prograded northeastward, but were deflected by growing anticlines and were locally ponded in small synclinal basins before reaching the floor of the Buttonwillow subbasin (Webb, 1981; Reid, 1990). The result was the deposition of sand bodies along narrow and sinuous fairways in the western area of the field.

Intervals of porcelanite and chert are interbedded with and adjacent to the Stevens sandstone reservoirs. Porcelanite is a diagenetic product derived from deposits of diatom debris. The diagenetic process that forms porcelanite and chert begins with the burial of diatomite and the conversion of unstable amorphous opal (opal A) to cristobalite and tridymite (opal-CT) and, ultimately, to quartz and the formation of porcelaneous and cherty textures (see Isaacs, 1981, for a review of the process). Through this process, porosity is reduced, but even in the quartz phase, is still significant (average 20–25% at Elk Hills; Reid and McIntyre, 2001). Permeability improves during the transition from opal-CT to quartz because the mineral lining the walls of pore throats simplifies, resulting in reduced tortuosity (Reid and McIntyre, 2001; Schwalbach et al., 2001). The CT-quartz transition depth is affected by clay content but occurs at Elk Hills at about 4500 ft (1375 m) subsea.

Pliocene reservoirs of the Elk Hills area consist of sandstone units for the Etchegoin and San Joaquin formations that were deposited in shallow-marine, nearshore, and deltaic-channel environments and represent the final filling of the San Joaquin basin (Reid, 1995). The Calitroleum and Wilhelm sandstone units are poorly sorted, fine-grained sandstones deposited in a lower delta-front environment and are productive in the western area of the field. The Sub-Scalez-1 (SS-1) sandstone is the most significant of the Pliocene reservoirs and consists of coarse-grained sandstone deposited in tidal channels and tidal sand sheets and is present only in eastern Elk Hills. The shallowest and youngest of the Pliocene reservoirs, the Mya interval, consists of numerous narrow sandstone channels that cross the field in a north-south orientation. The Mya channels were deposited by deltas that prograded across the field at the end of the Pliocene.

ELK HILLS FIELD

At the depth of the Stevens reservoirs (~5000–10,000 ft; ~1500–3000 m subsea), the Elk Hills field contains three elongated domes with steep limbs: the 31S, 29R, and Northwest Stevens anticlines (Figure 4). The overall structural trend is northwest-southeast in the western part of the field and bend to east-west at the east side of the field. Major thrust faults

Table 1. List of Elk Hills Oils Analyzed with Corresponding Reservoir Formation, Age, and Depth as well as Family Designation*

Sample ID	Family**	Field	Well	Formation	Age	Depth (ft)	$<C_{15}$
CA230	SOZ	Elk Hills	37-35R	Wilhelm 1A, 1B	Pliocene	2794	37.6
CA231	SOZ	Elk Hills	153H-36R-RD2	CAL 1	Pliocene	4701	65.1
CA232	SOZ	Elk Hills	38H-31S	Gusher 4	Pliocene	2530	82.0
CA233	SOZ	Elk Hills	3-56-24Z	Sub Mulinia	Pliocene	2423	71.6
CA234	SOZ	Elk Hills	28-35R	Sub Mulinia	Pliocene	2530	46.0
CA235	SOZ	Elk Hills	86-24R	Sub Mulinia	Pliocene	2915	49.8
CA236	SOZ	Elk Hills	43-24Z	Wilhelm	Pliocene	2257	65.0
CA237	SOZ	Elk Hills	37-28R	Gusher 4	Pliocene	2999	60.2
CA238	SOZ	Elk Hills	34S-36R	CAL 2	Pliocene	4098	63.5
CA239	SOZ	Elk Hills	357XH-30S	Above bitumen (2)	Pliocene	2589	31.1
CA240	SOZ	Elk Hills	57-28R	Wilhelm 1A, 1B, 2	Pliocene	2387	67.0
CA258	SOZ	Elk Hills	312-31S	C4D-CT Phase	Pliocene	3692	58.5
CA260	SOZ	Elk Hills	376-24Z	Mid Reefridge-CT/Qtz	Upper Miocene–Pliocene	5145	50.4
CA197	SOZ	Elk Hills	58A-25R	Reef Ridge/C4D	Upper Miocene–Pliocene	3600	57.7
CA263	SOZ		35NE-6G				42.5
CA021	B1	Elk Hills	583L-30R	Lower Santos	Lower Miocene	9500	24.1
CA210	B1	Elk Hills	584-26Z	Carneros	Lower Miocene	8700	77.7
CA212	B1	Elk Hills	583L-30R	Santos	Lower Miocene		25.8
CA213	B1	Elk Hills	934H-29R RD4	Santos	Lower Miocene	9600	22.4
CA223	B1	Elk Hills	578-24Z	Carneros	Lower Miocene	9100	60.0
CA224	B1	Elk Hills	542-30R	Carneros	Lower Miocene	8500	59.9
CA015	B1+	Elk Hills	18-14Z	Temblor (+?)	Middle Miocene	8000	40.4
CA022	C	Elk Hills	362H-7R	Stevens NWS	Upper Miocene	9100	36.0
CA203	C	Elk Hills	331H-18R	A-1	Upper Miocene	9400	40.2
CA204	C	Elk Hills	373AH-7R	A-2	Upper Miocene	9160	33.7
CA205	C	Elk Hills	324H-7R	A1/A2	Upper Miocene	6100	58.3
CA206	C	Elk Hills	318-8R	A4/5	Upper Miocene	8900	31.8
CA011	A1	Elk Hills	372-17R	Stevens NWS	Upper Miocene	8900	41.8
CA016	A1	Elk Hills	362-24Z	Stevens 24Z	Upper Miocene	5800	42.4
CA017	A1	Elk Hills	362-16R	Stevens NWS	Upper Miocene	8600	41.9
CA025	A1	Elk Hills	312H-26R	Stevens 26R	Upper Miocene	6500	49.6
CA207	A1	Elk Hills	313H-16H	A5/6	Upper Miocene	8540	44.8
CA208	A1	Elk Hills	372-17R	A5/6	Upper Miocene	8850	43.9
CA214	A1	Elk Hills	324-15R	Stevens NWS (T3/4)	Upper Miocene	8800	50.8
CA215	A1	Elk Hills	334-15R	Stevens NWS (T3/4)	Upper Miocene	8800	47.8
CA217	A1	Elk Hills	328-35R-RD1	Stevens 2B	Upper Miocene	6300	53.5
CA218	A1	Elk Hills	317X-13Z	Stevens N Shale	Upper Miocene	5500	44.7
CA198	A2	Elk Hills	381-36S	UMBB	Upper Miocene	8600	98.3
CA199	A2	Elk Hills	383H-36S RD2	UMBB	Upper Miocene	8750	42.0
CA200	A2	Elk Hills	333-35S	UMBB	Upper Miocene	7350	44.8
CA202	A2	Elk Hills	315-35S	UMBB	Upper Miocene	7000	45.0
CA209	A2	Elk Hills	384H-25R	NA/ND	Upper Miocene	5250	58.4
CA216	A2	Elk Hills	346-35R	Stevens 2B	Upper Miocene	6500	48.7
CA219	A2	Elk Hills	383-26Z	Stevens	Upper Miocene	5500	38.9
CA220	A2	Elk Hills	352-26Z	Stevens	Upper Miocene	5800	32.4
CA012	SH	Elk Hills	361-25S	Stevens MBB	Upper Miocene	9700	40.4
CA013	SH	Elk Hills	343-29R	Stevens D Shale	Middle Miocene	6000	42.2
CA014	SH	Elk Hills	324-4G	Stevens A	Upper Miocene	6400	44.1

API	% S	Ni/V	% Sat	% Aro	% Asph	S/A	$^{13}C_s$†	$^{13}C_a$†	$^{13}C_{wo}$†	^{13}C LE††	^{13}C HE††
27.2	1.12	4.5	28.4	38.7	3.5	0.73	−25.12	−24.37	−24.27	−23.75	−24.58
39.1	0.68	4.3	30.7	35.1	5.2	0.87	−25.40	−24.43	−24.10	−23.76	−24.73
48.2	0.40	1.8	33.0	34.0	5.7	0.97	−25.24	−24.68	−23.85	−23.63	−24.86
36.4	0.58	2.6	30.6	37.5	5.5	0.82	−25.27	−24.43	−24.13	−23.91	−24.69
28.1	1.04	4.7	28.3	39.4	3.1	0.72	−25.18	−24.34	−24.04	−23.41	−24.58
15.8	0.80	3.1	24.0	41.9	6.1	0.57	−24.97	−24.34	−24.09	−23.69	−24.49
39.4	0.72	4.9	32.3	35.5	2.9	0.91	−25.26	−24.50	−24.13	−23.80	−24.75
36.7	0.84	3.8	31.7	34.9	4.3	0.91	−25.49	−24.53	−24.29	−23.93	−24.83
39.0	0.65	3.6	31.8	35.1	6.4	0.91	−25.35	−24.33	−24.03	−23.67	−24.65
14.3	1.10	5.0	27.6	38.0	4.5	0.73	−25.24	−24.41	−24.30	−23.55	−24.64
38.1	0.69	3.7	30.4	35.1	3.2	0.87	−25.46	−24.41	−24.18	−23.91	−24.73
36.3	0.73	2.1	33.1	38.6	3.3	0.86	−25.55	−24.45	−24.26	−23.87	−24.81
35.5	0.91	2.3	32.9	38.7	2.1	0.85	−25.19	−24.39	−24.07	−23.50	−24.65
38.6	0.74	5.8	33.3	38.4	2.1	0.87	−25.41	−24.30			−24.67
28.8	1.04	4.8	26.0	39.6	4.8	0.66	−25.14	−24.32	−24.22	−23.80	−24.53
27.6	0.48	3.2	34.2	39.2	5.6	0.87	−24.62	−23.56	−24.04	−24.41	−23.92
50.0	0.20	3.5	45.7	35.7	1.9	1.28	−24.82	−23.68	−23.53	−23.34	−24.20
27.6	0.45	3.3	31.6	39.2	7.1	0.81	−24.68	−23.56	−23.76	−23.32	−23.91
	0.65	2.8	7.5	11.4	28.9	0.66	−24.13	−23.12	−23.27	−23.53	−23.20
35.9	0.34	5.0	40.6	36.6	6.6	1.11	−24.95	−23.64	−23.84	−23.62	−24.17
36.3	0.32	7.8	41.8	35.1	5.9	1.19	−25.11	−23.65	−23.84	−23.56	−24.26
35.2	0.92	1.8	38.8	33.8	4.2	1.15	−25.11	−23.82	−24.10	−23.77	−24.32
37.7	1.51	1.0	29.6	38.9	5.7	0.76	−24.96	−23.63	−23.58	−23.33	−24.02
26.7	1.39	0.5	24.5	38.8	15.5	0.63	−24.87	−23.57	−23.54	−23.31	−23.89
14.0	0.65	0.3	22.2	33.1	22.5	0.67	−24.94	−23.52	−23.25	−22.95	−23.84
24.5	0.79	0.4	25.5	37.6	12.4	0.68	−24.98	−23.62	−23.59	−23.06	−23.97
	1.00	0.7	33.1	38.5	8.6	0.86	−24.54	−23.24	−23.32	−23.16	−23.67
35.4	0.70	0.3	39.6	33.1	3.8	1.20	−24.15	−22.78	−23.04	−22.65	−23.32
35.0	0.68	0.6	50.9	31.4	1.7	1.62	−24.75	−23.12	−23.45	−22.77	−23.95
36.8	0.53	0.3	38.3	33.4	6.3	1.15	−24.38	−23.08	−23.22	−22.72	−23.58
40.8	0.62	0.6	40.5	35.3	7.0	1.15	−24.28	−23.12	−23.34	−23.09	−23.59
33.4	0.59	0.7	43.4	36.5	4.2	1.19	−24.02	−22.78	−22.98	−22.56	−23.32
34.8	0.71	0.6	41.4	37.0	4.7	1.12	−24.14	−22.80	−23.02	−22.59	−23.35
38.0	0.43	5.3	47.5	32.0	5.4	1.48	−24.14	−22.76	−23.21	−23.01	−23.42
33.1	0.54	0.4	43.7	34.9	4.1	1.25	−24.20	−22.84	−23.13	−22.80	−23.43
38.1	0.41	16.0	49.5	30.8	1.3	1.61	−24.49	−23.15	−23.55	−23.32	−23.81
30.8	1.17	2.2	32.1	34.0	5.8	0.94	−24.65	−23.59	−23.57	−23.12	−23.93
60	0.02	1.8	40.4	35.9	0.0	1.13	−24.73	−23.54	−20.28	−20.22	−24.02
33.5	0.68	1.8	39.4	37.3	4.0	1.06	−24.79	−23.45	−23.84	−23.65	−23.98
33.0	0.62	1.4	42.5	35.5	3.3	1.20	−24.74	−23.35	−23.71	−23.43	−23.94
34.0	0.47	1.9	44.8	36.0	3.2	1.24	−24.61	−23.31	−23.70	−23.46	−23.89
39.7	0.65	4.4	38.8	33.0	2.2	1.18	−25.04	−23.97	−23.91	−23.57	−24.39
32.8	0.49	13.5	42.2	35.2	5.2	1.20	−24.48	−23.30	−23.54	−23.27	−23.80
32.9	0.64	2.6	41.6	34.6	3.0	1.20	−24.47	−23.39	−23.56	−23.12	−23.84
30.6	0.76	0.9	43.4	32.4	3.3	1.34	−24.45	−23.29	−23.62	−23.26	−23.79
32.7	0.73	1.1	32.9	35.2	4.7	0.93	−24.69	−23.36	−23.41	−22.84	−23.80
38.4	0.48	0.8	46.1	31.4	3.7	1.47	−24.47	−23.18	−23.99	−24.28	−23.77
39.0	0.49	1.0	48.3	34.1	1.4	1.42	−24.93	−23.36	−23.67	−23.10	−24.12

Table 1. Continued

Sample ID	Family**	Field	Well	Formation	Age	Depth (ft)	$<C_{15}$
CA018	SH	Elk Hills	347-33S	Stevens MBB	Upper Miocene	6600	45.8
CA019	SH	Elk Hills	388-28R	Stevens B	Upper Miocene	6500	46.4
CA020	SH	Elk Hills	337HA-33S	Stevens MBB	Upper Miocene	6600	45.5
CA023	SH	Elk Hills	325H-30S	Stevens D Shale	Middle Miocene	6900	52.4
CA024	SH	Elk Hills	348A-23R	Stevens W.31S	Upper Miocene	6400	45.9
CA201	SH	Elk Hills	347-35S	UMBB	Upper Miocene	7300	55.8
CA246	SH	Elk Hills	322H-32S	A-Sand	Upper Miocene	5094	50.8
CA247	SH	Elk Hills	371X-32R	N-CT Phase	Upper Miocene	5457	45.8
CA248	SH	Elk Hills	314-5G	N-Qtz Phase	Upper Miocene	6345	48.4
CA249	SH	Elk Hills	326-19R	N-Qtz Phase	Upper Miocene	5690	51.6
CA250	SH	Elk Hills	326-29R	N-Qtz Phase	Upper Miocene	5600	46.8
CA251	SH	Elk Hills	382H-5G	A-Sand	Upper Miocene	6306	48.8
CA252	SH	Elk Hills	314-3G	N-Qtz Phase	Upper Miocene	6660	44.8
CA253	SH	Elk Hills	368H-19R	N-CT Phase	Upper Miocene	5250	47.1
CA254	SH	Elk Hills	357-35S	N-Qtz Phase	Upper Miocene	5695	67.7
CA255	SH	Elk Hills	386XH-33S	A-Sand	Upper Miocene	6849	46.0
CA256	SH	Elk Hills	321XH-33R	B-Qtz Phase	Upper Miocene	5398	45.0
CA257	SH	Elk Hills	382-25Z	Olig/C4D-CT?	Upper Miocene	4910	49.7
CA259	SH	Elk Hills	325-28R	B-Qtz Phase	Upper Miocene	5550	48.5
CA225	KH	Kettleman N. Dome	E72-33J	Kreyenhagen	Eocene	9400	47.1
CA226	KH	Kettleman N. Dome	341-11P	Kreyenhagen	Eocene	8850	47.5
CA228	KH	Belgian Anticline	75-17Y	Point of Rocks III	Eocene	2300	86.3
CA227	~A1	West Bellevue	Lovegren 62X-32	Lower Stevens	Miocene	8815	39.9
CA229	High mat.	Ekho	1	Temblor	Oligocene	18,015	63.9
CA221	Biodeg.	Deer Creek	Community lease		Miocene	800	7.2
CA245	Biodeg.	Midway-Sunset					41.3
OXCA001	~SOZ	Kern River	Apollo-CP-Revenue	Vedder Sands	Oligocene	4800	44.1
OXCA002	~B1	Rio Bravo	Mandell 2 (RD1)	Freeman-Jewette Fm.	Miocene	11,260	47.1
OXCA003	~SOZ	Kern River	Revenue 4X	Vedder Sands	Oligocene	4700	43.7

*Column definitions: $<C_{15}$ = % less than C_{15} (light ends); S/A = C_{15+} saturated hydrocarbons/C_{15+} aromatic hydrocarbons; $^{13}C_s$ = carbon isotope composition of C_{15+} saturated hydrocarbons; $^{13}C_a$ = carbon isotope composition of C_{15+} aromatic hydrocarbons; $^{13}C_{wo}$ = carbon isotope composition of whole oil; ^{13}C LE = calculated carbon isotope composition of light-end components; ^{13}C HE = calculated carbon isotope composition of heavy ends.

**For explanation see text section titled Oil Families Description.

†Measured.

††Calculated.

are present on the flanks of all the anticlines and generally parallel to the fold axes (Imperato, 1995; Fiore et al., 2004). Most thrust faults terminate upward in the thick shale sequence that separates the Monterey and Etchegoin reservoirs. At the depth of the Pliocene sandstone section (about 2000–5000 ft [600–1500 m] subsea), the 29R and 31S anticlines merge to form a single large structure that generally has an east-west trend. The Northwest Stevens anticline did not have significant activity following the end of the Miocene and does not make a major contribution to the Pliocene structure. The Pliocene section in eastern Elk Hills is broken by numerous northeast-southwest–trending normal faults. The Elk Hills anticlinal complex is most likely a fault propagation fold formed by north- and northeast-directed compression (Imperato, 1995; Fiore et al., 2004). Like many of the west-side anticlines, folding began at Elk Hills in late Miocene, accelerated in the Pliocene, and continues today (Harding, 1976).

Elk Hills has produced more than 1.2 billion bbl oil and 1.6 tcf gas (California Division of Oil, Gas, and Geothermal Resources, 2003) from four petroleum zones. The Carneros zone includes the Santos

API	% S	Ni/V	% Sat	% Aro	% Asph	S/A	$^{13}C_s$†	$^{13}C_a$†	$^{13}C_{wo}$†	^{13}C LE††	^{13}C HE††
38.5	0.42	0.9	46.7	33.8	2.1	1.38	−24.57	−23.30	−23.70	−23.47	−23.89
37.7	0.40	0.8	49.5	30.4	1.8	1.63	−24.35	−23.08	−23.55	−23.37	−23.71
39.2	0.39	1.0	47.7	32.0	1.8	1.49	−24.55	−23.26	−23.71	−23.51	−23.88
33.6	0.44	1.6	45.1	32.9	2.4	1.37	−24.77	−23.50	−24.00	−23.93	−24.07
38.8	0.42	0.9	48.9	32.0	2.8	1.53	−24.43	−23.18	−23.61	−23.40	−23.79
21.1	0.47	1.7	24.2	25.8	8.7	0.94	−24.71	−23.41	−23.80	−23.86	−23.72
34.5	0.78	1.8	37.0	36.7	3.3	1.01	−24.95	−23.83	−23.97	−23.70	−24.24
30.6	0.54	1.6	45.6	35.7	2.8	1.28	−24.53	−23.30	−23.67	−23.44	−23.86
36.0	0.61	1.7	41.6	37.5	3.0	1.11	−24.66	−23.36	−23.67	−23.42	−23.90
37.7	0.52	1.4	43.4	34.7	3.3	1.25	−24.53	−23.38	−23.64	−23.42	−23.88
37.8	0.56	1.6	44.5	33.8	2.5	1.32	−24.49	−23.28	−23.63	−23.42	−23.82
37.7	0.55	1.4	44.6	35.7	2.9	1.25	−24.63	−23.49	−23.77	−23.53	−24.00
34.2	0.92	1.8	32.2	36.7	6.2	0.88	−24.62	−23.42	−23.41	−22.92	−23.81
36.0	0.70	1.5	41.3	33.7	3.1	1.23	−24.57	−23.54	−23.70	−23.40	−23.97
40.9	0.40	1.4	46.8	30.0	9.8	1.56	−24.60	−23.50	−23.50	−23.25	−24.01
35.1	0.47	1.4	49.5	33.8	2.6	1.46	−24.83	−23.35	−23.69	−23.23	−24.08
34.2	0.46	1.0	47.5	34.2	2.3	1.39	−24.41	−23.15	−23.53	−23.26	−23.75
36.3	0.79	1.8	38.4	37.5	1.9	1.02	−24.91	−23.87	−23.85	−23.42	−24.27
36.9	0.44	1.0	49.4	34.6	1.9	1.43	−24.47	−23.22	−23.58	−23.31	−23.84
36.6	0.39	3.2	45.7	37.0	1.6	1.23	−29.07	−28.19	−28.64	−28.68	−28.59
37.8	0.37	3.8	45.6	37.3	1.8	1.22	−28.83	−27.94	−28.45	−28.54	−28.35
41.7	0.06	9.0	51.2	36.8	0.0	1.39	−28.03	−25.97	−26.56	−23.64	−27.02
35.7	0.72	1.9	42.8	35.4	3.9	1.21	−24.64	−23.45	−23.82	−23.73	−23.96
37.7	0.19	3.0	50.5	38.0	0.3	1.33	−23.75	−22.40	−23.19	−23.38	−23.08
13.0	0.43	3.5	43.3	41.5	0.9	1.04	−26.49	−25.55	−25.94	−25.94	−25.96
13.9	0.92	0.8	16.0	35.8	6.9	0.45	−24.44	−23.52			−23.67
30.2	0.70	5.7	39.8	36.8	6.0	1.08	−25.08	−23.64	−23.70	−23.30	−24.21
35.1	0.33	5.5	46.5	37.6	2.7	1.24	−24.67	−23.47	−23.96	−23.88	−24.03
31.9	0.71	9.2	40.0	36.6	6.1	1.09	−25.02	−23.61	−23.78	−23.47	−24.17

and Carneros sandstones and contains light-gravity oil, condensate, and gas and is productive only on the 29R anticline at depths of about 10,000 ft (3048 m). The Stevens oil zone contains several major pools in structural and stratigraphic traps on each of the large anticlines. Drill depth of pools ranges from 5000 to 10,000 ft (1500 to 3000 m), with many wells completed in oil columns originally 500–1000 ft (152–305 m) thick. Produced oil from all Stevens pools averages 35° API, with abundant associated produced gas. The shallow oil zone produces from drill depths of 2000–4000 ft (610–1220 m) and produces light-gravity oil and gas from the Calitroleum and Wilhelm reservoirs in western Elk Hills and 25–30° API oil in the SS-1 reservoir on the east side of the field. The dry gas zone, as its name implies, produces only methane from the Pliocene Mya interval at drill depths of 1000–2000 ft (305–610 m).

EXPERIMENTAL METHODS

Standard laboratory procedures were followed in obtaining the geochemical results used in the multivariate statistical analysis and are summarized here.

The weight of the light ends lost from each oil sample under a stream of nitrogen was determined gravimetrically ($<C_{15+}$). The amount of asphaltenes was measured by precipitation using n-hexane (overnight at room temperature). The C_{15+} deasphalted fractions were separated into saturated hydrocarbon, aromatic hydrocarbon, and nitrogen-sulfur-oxygen compounds or resin fractions using gravity-flow column chromatography employing a 100–200 mesh silica gel support activated at 400°C prior to use. Hexane was used to elute the saturated hydrocarbons; dichloromethane was used to elute the aromatic hydrocarbons; and dichloromethane/methanol (50:50) was used to elute the nitrogen-sulfur-oxygen fraction. Following solvent

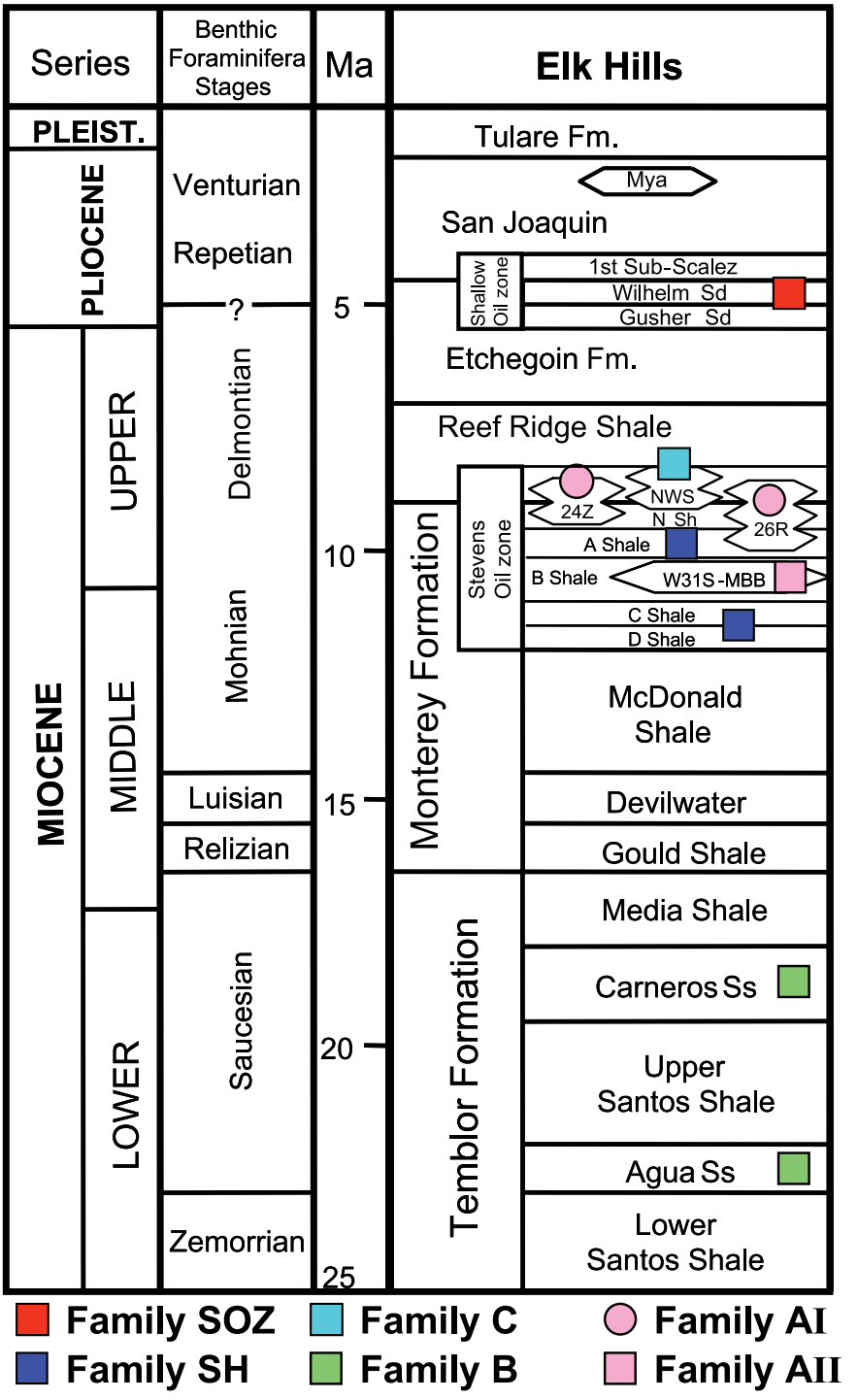


Figure 2. Stratigraphic section and oil families at Elk Hills. For explanation of oil families, see text section titled Oil Families Description.

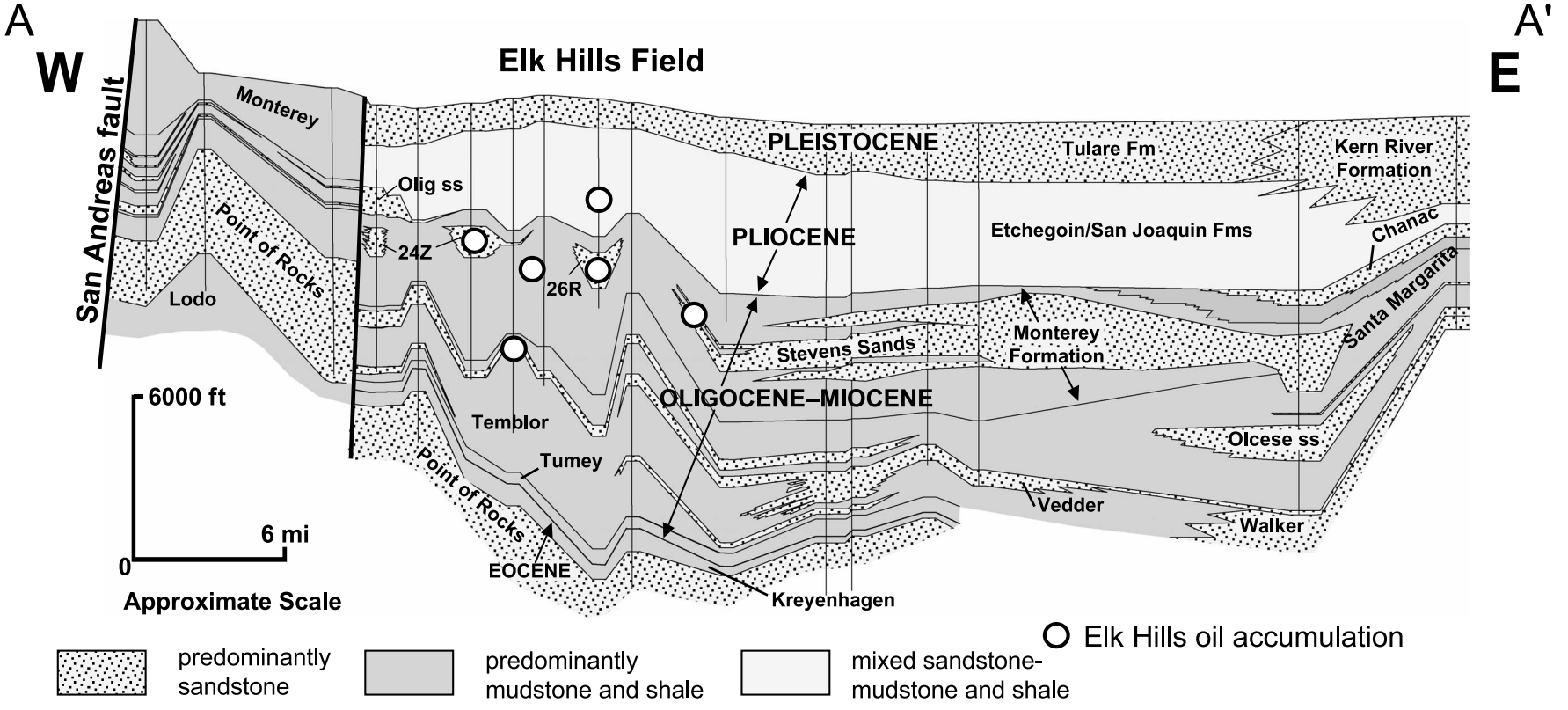


Figure 3. Cross section of the southern San Joaquin basin from the San Andreas fault through Elk Hills to the Sierra Nevada. Modified from Dunwoody (1986).

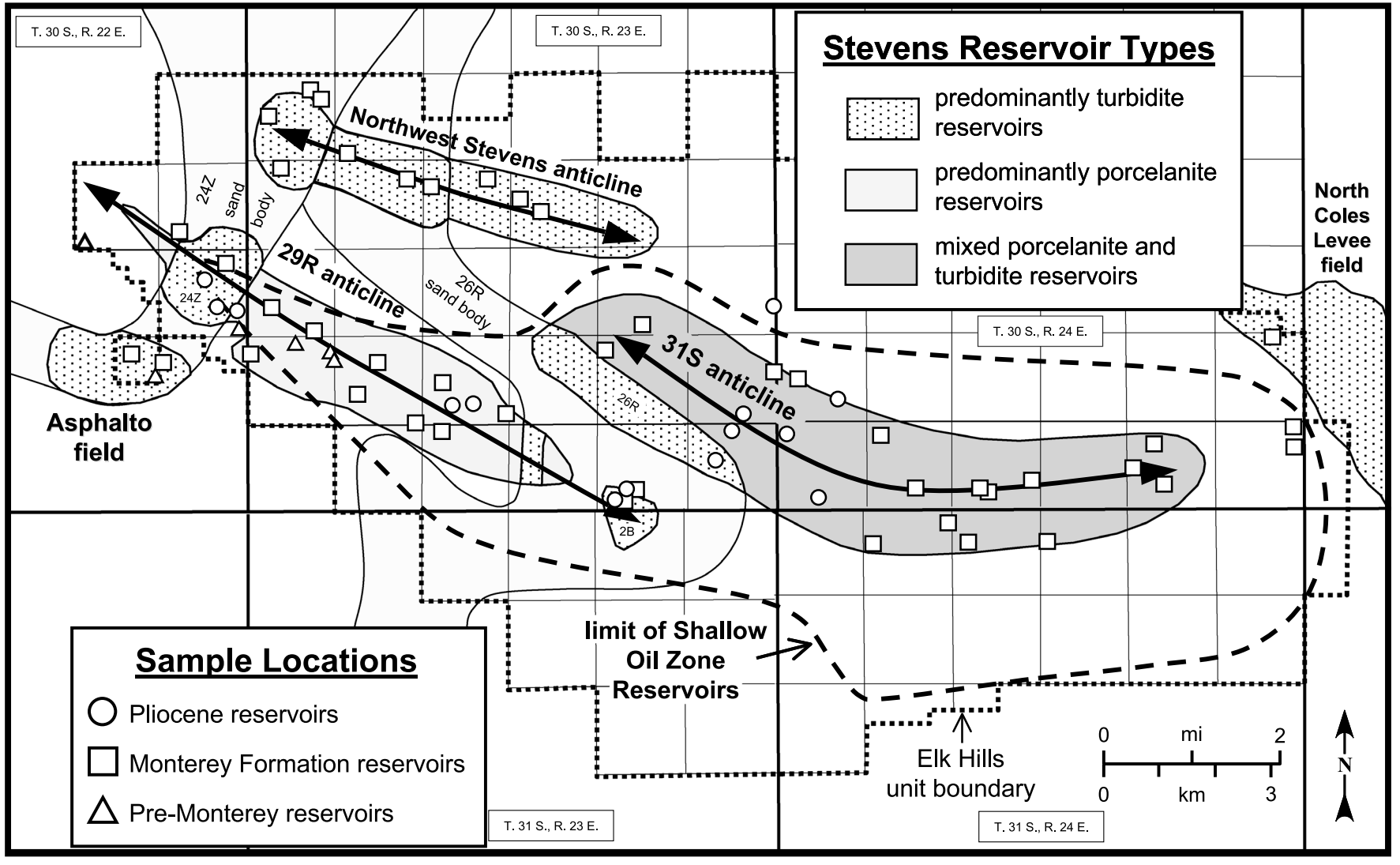


Figure 4. Detailed map of the Elk Hills field showing location of geochemical samples, location of the major Stevens reservoirs, and a general outline of the shallow oil zone. Some samples are from minor reservoirs that have unmapped aerial distributions.

evaporation, the recovered fractions were quantified gravimetrically. The C_{15+} saturated hydrocarbon fraction was subjected to molecular sieve filtration (Union Carbide S-115 powder) after the technique described by West et al. (1990) to concentrate the branched and cyclic biomarker fractions. Stable carbon isotopic compositions of the whole oil as well as the C_{15+} saturated and aromatic hydrocarbon fractions were determined using the combustion technique of Sofer (1980) and a Finnigan delta E isotope ratio mass spectrometer. Results are reported relative to the Peedee belemnite standard.

Whole crude oils were injected (split mode 70:1) on a 30-m × 0.32-mm (100-ft × 0.012-in.) J&W DB-5 column (0.2-μm film thickness) and temperature programmed from −60 to 350°C at 12°C/min using a Hewlett Packard 5890 gas chromatograph. Helium was used as the carrier gas. Gas chromatographic and mass spectrometric analyses of C_{15+} branched/cyclic and aromatic hydrocarbon fractions (to determine sterane and terpane biomarker distributions and quantities) were performed using a Hewlett Packard 5890 gas chromatograph (split injection) interfaced to a HP 5971 mass spectrometer. The HP-2 column (50 m × 0.2 mm [164 ft × 0.0078 in.]; 0.11-μm film thickness) was temperature programmed from 150 to 325°C at 2°C/min for branched and cyclic hydrocarbons and 100 to 325°C at 3°C/min for aromatics. The mass spectrometer was run in the selected ion mode, monitoring ion mass-to-charge ratio (*m/z*) 177, 191, 205, 217, 218, 221, 231, and 259 (branched/cyclic) and *m/z* 133, 178, 184, 192, 198, 231, 245, and 253 (aromatics). To determine absolute concentrations of individual biomarkers, a deuterated internal standard (d4-C29 20R sterane; Chiron Laboratories, Norway) was added to the C_{15+} branched and cyclic hydrocarbon fraction. Response factors (RF) were determined by comparing the mass spectral response at *m/z* 221 for the deuterated standard to hopane (*m/z* 191) and sterane (*m/z* 217) authentic standards. These response factors were found to be approximately 1.4 for terpanes and 1.0 for steranes. Concentrations of individual biomarkers in the branched and cyclic fraction were determined using the following equation:

$$\begin{aligned}\text{Concentration(ppm)} &= [(\text{peak height of biomarker})(\text{nanograms of standard})] \\ &\quad /[(\text{peak height of standard})(\text{RF}) \\ &\quad \times (\text{milligrams of branched and cyclic fraction})]\end{aligned}$$

OIL FAMILIES DESCRIPTION

Table 1 lists the Elk Hills wells that produced the 66 oils used in this study and provides reservoir identification and depth, as well as bulk properties such as API gravity and stable carbon isotope compositions. Figure 4 shows a map locating the samples, highlighting the Elk Hills oils from pre-Monterey reservoirs (7 samples) as well as 14 samples from the Pliocene shallow oil zone. A total of 32 samples come from the various Stevens turbidites, and 13 samples are from porcelanite reservoirs (Elk Hills Shale Member of the Monterey Formation). The Elk Hills samples are evenly distributed between the two main producing anticlines: 31S (eastern Elk Hills) and 29R (western Elk Hills), with 10 oils from the Northwest Stevens anticline. Complete analytical results of all the oils used in this study, including whole oil chromatograms and terpane and sterane biomarker distributions and concentrations, can be accessed from the GeoMark Research Reservoir Fluid Database (www.RFDbase.com) using the demo-user password.

Also shown in Table 1 are the results of the oil classification or groupings (oil families), which will be described in detail below. Family member oils generally share a common source organofacies, albeit at different levels of thermal maturity. Most remarkably, Elk Hills oil families strongly correlate to reservoir horizon (see stratigraphic section, Figure 2), although all Elk Hills oils were generated from the Monterey, even family B oils that produce from pre-Monterey horizons.

Statistical Analyses

The two statistical treatments used in the present study to delineate the different oil families are termed principal component analysis and hierarchical cluster analysis and were performed using computer programs from Infometrix (Pirouette™). In principal component analysis, new independent variables are created (i.e., principal components) that are linear combinations of the original variables (i.e., geochemical parameters). The primary objective of the principal component analysis is to reduce the dimensionality of the data to a few important components that best explain the variation in the data. Oil samples can be plotted in a principal component space, for example, PC1 (factor 1) versus PC2 (factor 2), like any other *x-y* plot. This is called a scores plot. The geochemical variables

responsible for the PC axes can be viewed as a loadings plot. Hierarchical cluster analysis is an ancillary technique to principal component analysis where a distance matrix is created from the scaled data. A resulting dendrogram is the output of a cluster analysis and shows groups or clusters of related oils. The distance between any two samples on a hierarchical cluster analysis is a measure of their similarity. (This distance is similar to a linear correlation coefficient; perfect correlation would have a value of 1.0, whereas poor correlation would have values less than 0.5.)

The geochemical variables used to correlate oils are various source-dependent biomarker ratios and stable carbon isotopic compositions. Biomarkers (biological markers) are geochemical fossils and are defined as organic compounds found in sedimentary rocks or oils in which a sufficient part of the carbon skeleton has been preserved. These compounds, including terpanes and steranes, can be correlated with the original biochemical precursor after having undergone accumulation, diagenesis, and catagenesis (i.e., oil generation). Thus, biomarkers can be indicators of source rock depositional environments in the same manner that the physical remains of organisms can describe depositional systems. Biomarkers are also useful as thermal-maturity indicators. A good review of biomarkers and their applications in petroleum geochemistry can be found in Peters et al. (2005).

The level of statistical correlation between the 66 oils included in the Elk Hills data set is shown in the hierarchical cluster analysis dendrogram presented in Figure 5. Eighteen isotope and biomarker variables (identified in Figure 6) were used to construct the cluster analysis dendrogram. Five compositional clusters are identified on the dendrogram:

family A: Stevens turbidites; includes closely related subfamilies AI and AII
family B: oils in pre-Monterey reservoirs
family C: limited to the Stevens zone in the 7R area of the Northwest Stevens anticline
family SH: oils from the Stevens porcelanite reservoirs
family SOZ: oils from the Pliocene shallow oil zone

The analytical variation in the data set is minimal. For example, oil samples CA011 and CA208 (well 372-17R; family AI) as well as CA021 and CA212 (well 583L-30R; family B) represent duplicate pairs. Although samples CA208 and CA212 were analyzed 1.5 yr after samples CA011 and CA021, both duplicate pairs are highly correlative, remaining within their respective oil family. This indicates little variation caused by analytical techniques. Temblor oil sample CA015 (well 18-14Z) is probably a member of both families B and A (instead of the family SOZ) because it is likely a comingled oil, representing both pre-Monterey and Stevens reservoirs (B. Countryman, 2000, personal communication).

Figure 6 shows the results of the principal component analysis using the heavy-end carbon isotope composition of the saturated and aromatic hydrocarbon fractions and key source-related biomarker ratios shown on the variable (loadings) plot. These are the same geochemical variables used in the cluster analysis. The five families defined in the cluster analysis are labeled on the principal component plot (A, B, C, SOZ, and SH) using the same color code. By comparing the scores and loadings plot, the geochemical variables responsible for the groupings become apparent. For example, the SOZ oils have high negative factor 1 values, meaning that they have the highest $\%C_{29}$ variable (steranes mostly from green algae) and the lightest (i.e., most negative) carbon isotope values ($^{13}C_s$ and $^{13}C_a$). Family B oils, from pre-Monterey reservoirs, have high S1/S6 (rearranged to regular steranes) and low C_{28}/H (bisnorhopane to hopane) ratios, whereas family C oils from the Northwest Stevens anticline have reversed values. These two parameters are most affected by thermal maturity, suggesting that the C_{15+} oil components in family B come from more deeply buried Monterey facies than family C oils. Families A and SH are not readily distinguished using only factors 1 and 2. These two families, which represent most of the oil produced from Elk Hills, are also most closely related based on the cluster analysis (Figure 5). By rotating the principal component axis (Figure 6), family A is better separated from family SH. Not surprisingly, the porcelanite-reservoired oils (SH) contain slightly more C_{28} steranes ($\%C_{28}$), many of which originate from diatoms.

Oils from Other Fields

Table 1 also lists 10 oils from southern San Joaquin fields other than Elk Hills. Three of these oils (CA225, CA226, and CA228) are from Eocene reservoirs (Kettleman N. Dome and Belgian Anticline fields) and have very light carbon isotopic compositions highly suggestive of Kreyenhagen source rocks (Peters et al., 1994). The two Kern River oils (CA269 and CA271) statistically most resemble the Elk Hills SOZ family,

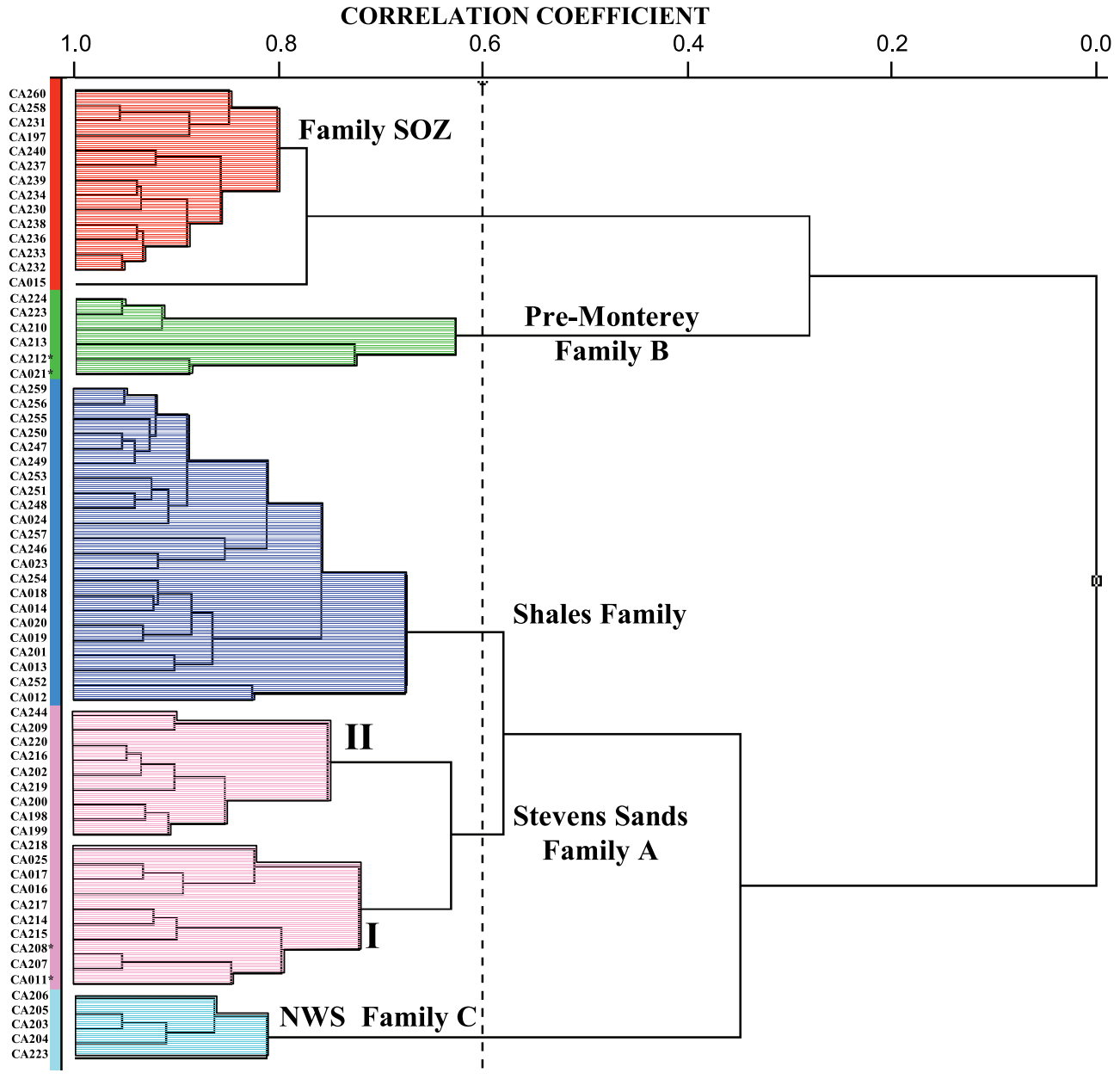


Figure 5. Cluster analysis dendrogram showing the five principal Elk Hills oil families. The geochemical variables used to construct this dendrogram are defined in Figure 6. Oils CA212 and CA021 as well as CA208 and CA011 represent duplicate sample pairs, collected and analyzed 18 months apart; the high correlations indicate little variation caused by sampling or analytical technique.

although they are produced from the Oligocene Vedder sandstone. The Stevens oil from West Bellevue (CA227) correlates best with family AI (same as Elk Hills Stevens oils), whereas the Rio Bravo oil (CA270) appears to be a member of family B. Heavily biodegraded oils from Midway-Sunset (CA245) and Deer Creek (CA221) fields preclude accurate correlation with Elk Hills families because the steranes have been degraded. The carbon isotopes, however, suggest a Monterey origin for oil from the Midway-Sunset field and perhaps a mixed Miocene–Eocene origin for Deer Creek oil. The deep Temblor test from exploratory well Ekho 1 (CA229) is too mature (the terpanes and steranes have been thermally degraded) to correlate successfully with Elk Hills oils. Again, the carbon isotopes strongly suggest a Monterey-equivalent source for this oil recovered at 18,015 ft (5491 m).

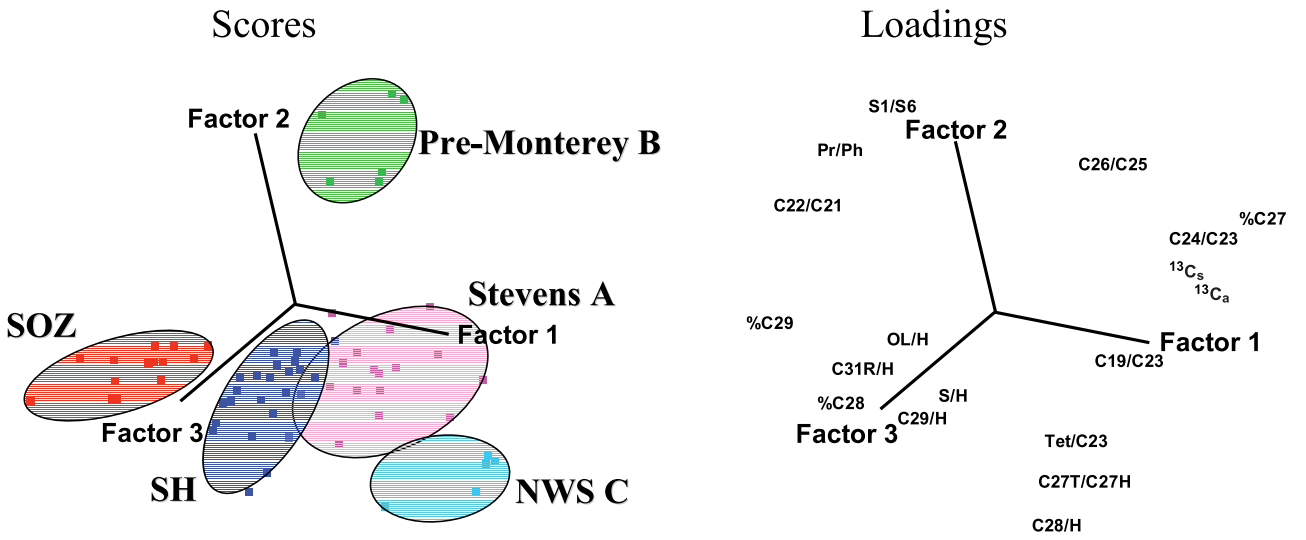


Figure 6. Principal component analysis showing the five Elk Hills oil families (scores) and geochemical variables (loadings) employed. S1/S6 = 13β,17α-diacholestane (20S)/5α-cholestane (20R); Pr/Ph = pristane/phytane from whole crude GC; %C27, %C28, and %C29 = relative percent 5α,14β,17β-cholestane (20S), 5α,14β,17β-ergostane (20S), and 5α,14β,17β-stigmastane (20S) based on *m/z* 218; C19/C23, C22/C21, C24/C23, and C26/C25 = various tricyclic terpane ratios; Tet/C23 = C24 teteracyclic terpane/C23 tricyclic terpane; C28/H = 17α,18α,21β-28,30-bisnorhopane/17α,21β-hopane; C29/H = 17α,21β-30-norhopane/17α,21β-hopane; OL/H = oleanane/17α,21β-hopane; C31R/H = 17α,21β-30-homohopane (22R)/17α,21b-hopane; C27T/C27H = 17α,18α,21β-25,28,30-trisnorhopane/(18α,21β-22,29,30-trisnorhopane + 17α,21β-22,29,30-trisnorhopane); S/H = sum of 15 steranes/16 hopanes; $^{13}C_s$ and $^{13}C_a$ = stable carbon isotopic composition of the C_{15+} saturate and aromatic hydrocarbons, respectively.

Stable Carbon Isotopes

The Elk Hills C_{15+} saturated and aromatic hydrocarbon fractions ($^{13}C_s$ and $^{13}C_a$, respectively; Table 1) have distinctive heavy isotopic compositions, characteristic of other marine-derived Miocene oils globally. In Figure 7, the Elk Hills oil families plot well to the marine side of the best separating line (marine versus nonmarine-sourced oils; Sofer, 1984), and the SOZ family is clearly distinguished, strongly suggesting a different Monterey source facies.

Based on the whole oil carbon isotope compositions ($^{13}C_{wo}$; Table 1), the less than C_{15+} fraction (% < C_{15} or light-ends) carbon isotopic ratios can be calculated using mass-balance considerations and are given in Table 1 (^{13}C LE). If the light hydrocarbons originated from the Eocene Kreyenhagen Formation, then they would likely have much more negative carbon isotopic compositions, approximately −28 to −29‰, instead of the −23 to −24‰ of the Miocene. In fact, the light hydrocarbons of most of the Elk Hills oils are isotopically more positive than the C_{15+} fractions (heavy-end ^{13}C HE), strongly suggesting that the Monterey generated both the light- and heavy-end components. This is illustrated in Figure 8, which is a plot of the light-end versus heavy-end carbon isotopic composition. Increasing thermal maturity results in more positive C_{15+} carbon isotope values (Sofer, 1984).

DISCUSSION

Thermal Maturity

The Elk Hills oils represent a wide range of Monterey source rock thermal maturities. Low-maturity indicators are common in the Monterey. Certain key biomarker ratios, in which one of the two related compounds is thermodynamically less stable, represent the maturity ranges of the heavy ends, and the least mature, local sources dominate (local to the reservoir; i.e., see figures 12 and 13 of Reid and McIntyre, 2001). Conversion of Monterey kerogen (1–7 wt.% and about 2–20 vol.% total organic carbon) to fluids involves a volume increase resulting in local overpressure zones, which allows primary oil migration and concentration. At present-day depths of about 5000–7000 ft (1524–2134 m), ongoing, early oil generation from

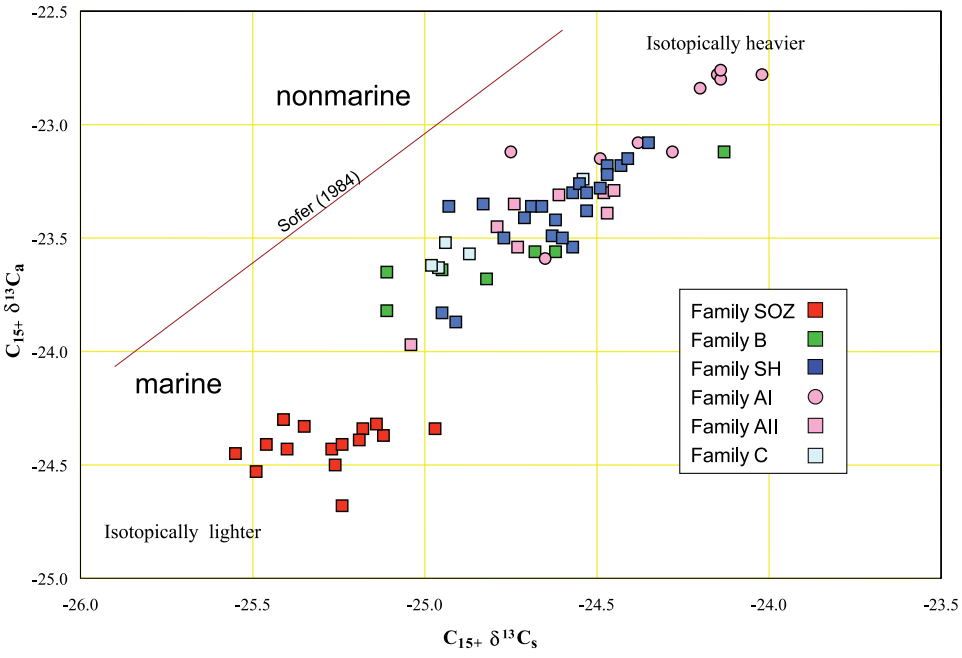


Figure 7. Stable carbon isotope composition of C_{15+} saturated and aromatic hydrocarbons. Shallow oil zone samples (family SOZ) are isotopically distinct, although they are still in the isotopic range of oils generated from the Monterey Formation. Biodegradation generally results in isotopically heavier values (Sofer, 1984).

labile, relatively sulfur-rich kerogen of Monterey source rocks maybe of sufficient magnitude to open microfractures, increasing porcelanite permeability. Paleodepths were likely greater with corresponding higher temperatures.

Figure 9 is a plot of the thermally sensitive terpane biomarkers C_{27} T_s to T_m and a triaromatic sterane ratio (TAS3), with higher ratios suggesting generation from more mature source rocks. The T_s/T_m ratio is also source dependent, so that maturity differences are valid only for oils in the same family. For example, Kern River Vedder oils are slightly more mature than Elk Hills SOZ samples, but they may or may not be of equivalent maturity to family C. Again, these terpane ratios reflect weighted maturity of the source rocks that generated the heavy ends, with the least mature horizons weighted more because they contain higher absolute concentrations of biomarkers. The triaromatic

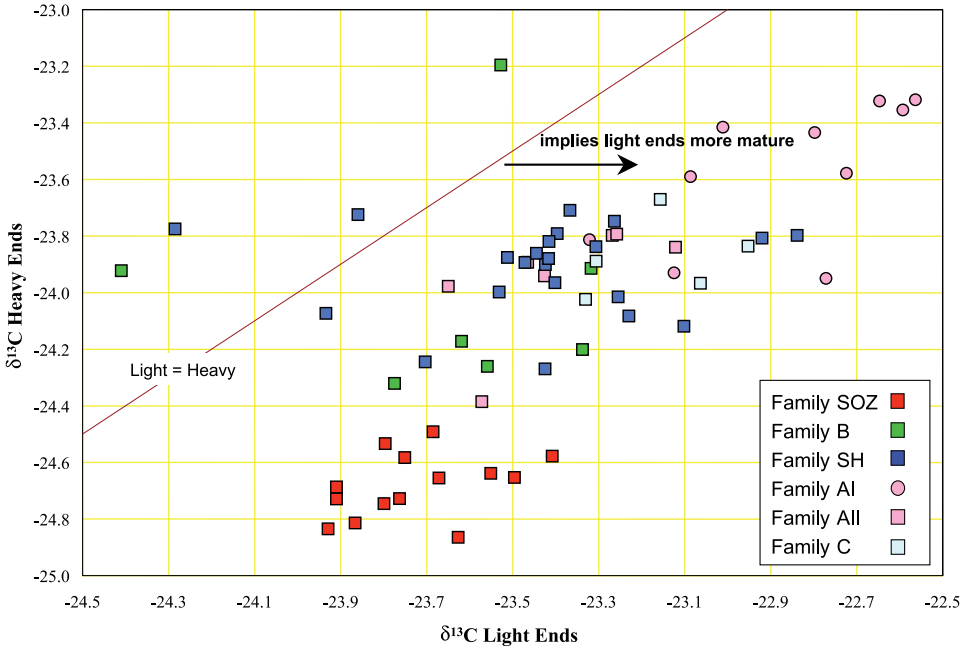


Figure 8. Stable carbon isotope composition of light-end versus heavy-end Elk Hills hydrocarbons. The light-end isotopic values were calculated from the measured heavy ends (C_{15+}) and whole crude isotopic values based on the amount of light ends lost from evaporation ($<C_{15}$; Table 1). The light-end hydrocarbons are isotopically heavier than the heavy ends, suggesting a Monterey source for both the light and heavy ends with the light ends from a more mature Monterey.

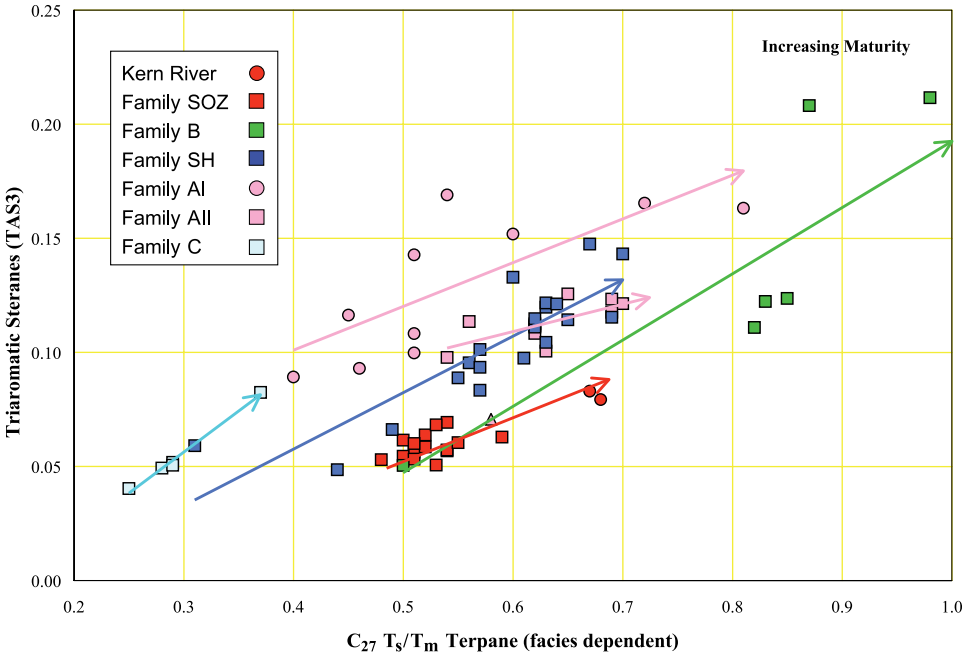


Figure 9. Heavy-end biomarker maturity indicators showing thermal-maturity trends in each oil family. Kern River field oils are related to Elk Hills family SOZ oils but appear slightly more mature. C_{27} T_s/T_m = 18α,21β-22,29,30-trisnorhopane/17α,21β-22,29,30-trisnorhopane; TAS3 = $[C_{20} + C_{21}]/[\Sigma C_{20} - C_{28}]$ triaromatic steranes (*m/z* 231).

sterane TAS3 ratio ($[C_{20} + C_{21}]/[\Sigma C_{20} - C_{28}]$; *m/z* = 231) appears to be a more universal indicator of maturity, with much less dependence on source. The C_{15+} fraction of SOZ and family C oils both contain the least mature TAS3 ratios.

The range of maturity indicated by family AI samples, which are from the Northwest Stevens and western 29R anticlines, suggests multiple pulses of oil generated from a source rock that is maturing over time. In contrast, family AII oils, which are mostly from the 31S Stevens turbidite reservoirs, have a more concentrated distribution, suggesting oils are derived from a source rock of consistent maturity.

A graph of the absolute concentrations of two terpane biomarkers (hopane [C_{30}] and bisnorhopane [C_{28}]) relative to the whole crude oil, including light ends, is given in Figure 10. As source rocks mature, fewer heavy-end biomarkers are generated relative to

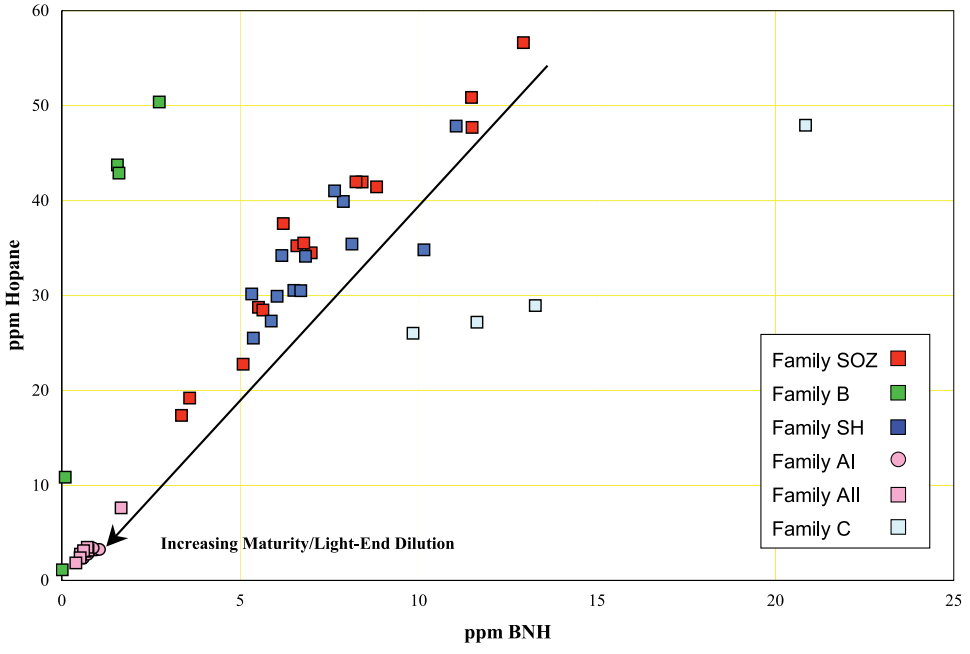


Figure 10. Absolute biomarker concentrations in whole crude oils: C_{28} bisnorhopane (17α,18α,21β-28,30-bisnorhopane) versus C_{30} hopane (17α,21β-hopane). The different trends between families B and C oils versus family A, shales (SH), and SOZ members correspond to different Monterey organic-rich facies. The absolute concentrations of these biomarkers are also a function of thermal maturity.

light-end hydrocarbons ($<C_{15}$). If the reservoir or trap is charged and intermixed with local low-maturity oil in addition to oils from various levels of increasing maturity (toward and including subbasin depocenters), then the oil should contain lower absolute concentrations of biomarkers with increasing charge of more mature, downdip generated oil. (Sample CA201, an oil from the upper Main Body B sandstone in well 347-35S, was not included in the figure because it has an anomalous resin content with a low API gravity, inconsistent with the $\% < C_{15}$; this sample also appears to have been misclassified and is likely a member of family AII instead of SH.)

Families B and C oils show different trends in Figure 10 because of their abundance of bisnorhopane relative to hopane, both a source and maturity indicator (see Figure 6). The oils from families A, SH, and SOZ all have about the same bisnorhopane/hopane ratio. However, what is probably the most significant aspect of Figure 10 is the low absolute biomarker concentration of family A oils from the Stevens turbidites. Of course, these are, by far, the main oil producers in Elk Hills, and they contain the greatest proportion (or dilution) of more mature light hydrocarbons from the subbasin depocenters by a factor of about 10 or more (3–4 ppm hopane for Stevens turbidite oils versus 30–40+ ppm for the other oil families).

The relationship between the absolute hopane concentrations and the TAS3 maturity ratio for the heavy ends is illustrated in Figure 11. Again, family A oils have constant low amounts of biomarkers, although family AI appears to contain more mature heavy-end components than family AII. In contrast, family SOZ oils have the least mature heavy ends (along with family C) but have a threefold variation in hopane concentration. Much of the biomarker concentration variance in SOZ oils is caused by different degrees of biodegradation, which will be discussed below. In addition, some the SOZ oils may contain water and/or de-emulsifier, which can affect the measurement of $\% < C_{15}$ (light ends), resulting in incorrect values for biomarker concentrations.

Families B and SH show maturity trends in the whole crude and heavy ends. Regarding family B, the lower Miocene Carneros oils appear to contain less mature oil than the older Santos samples. Both reservoirs contain Monterey-sourced oil migrating updip, but downsection, probably along faults. For SH oil family samples, an interesting trend is evident in Figure 11, at least for samples from the 29R anticline. The three opal-CT samples contain oil that is clearly less mature than the oil in the porcelanites that have undergone the opal-CT to quartz transition (four 29R wells). This suggests two pulses of oil charging: an initial wave of oil generated from a less mature source rock into the opal-CT reservoir and a second migration event from a similar but more mature source rock, but occurring after opal-CT porcelanite is converted to quartz phase. The 31S anticline oil in quartz porcelanite reservoirs appears less mature than the 29R anticline oil in corresponding quartz porcelanites. Perhaps the 29R reservoirs received a greater proportion of downdip oil than the 31S reservoirs.

Biodegradation of SOZ Oils

Family SOZ (all of the Reef Ridge and post-Miocene oils in Table 1) comprises a distinctly different type of Monterey oil than that seen in the Stevens turbidites. Because they occur in the youngest reservoirs, they probably originated from the uppermost organic-rich facies of the Monterey (similar to the Monterey facies that generated the Kern River field oil). Many of the SOZ oils have suffered biodegradation because of the low reservoir temperatures. The rate of biodegradation intensifies below reservoir temperatures of about 140°F (60°C). Biodegradation is evident from the whole crude gas chromatograms because the bacteria preferentially consume the n-paraffins, resulting in a lower quality oil (e.g., reduced API gravity and increased sulfur content). The isoprenoids pristane and phytane are more resistant to biodegradation than the n-paraffins (Figure 12), whereas the sterane and terpane biomarkers are the most resistant within the saturated hydrocarbon fraction. Most of the SOZ oils are only mildly degraded, although SOZ oil CA235 is extensively biodegraded (almost no n-paraffins and sterane biomarkers are altered). Other more degraded SOZ oils include CA239, CA230, CA233, and CA234. The API gravities have been significantly lowered in these more extensively degraded oils (Table 1).

However, reservoir temperature is not the only factor relating to the degree of biodegradation. Because oil-degrading bacteria live and reproduce in the aqueous phase, the oil must also be in contact with ground water in order for extensive biodegradation to occur. The most biodegraded SOZ oils occur on the flanks of the 31S anticline, likely corresponding to increased oil-water interaction. Many of the slightly biodegraded SOZ oils have abundant light ends, which is incompatible with biodegradation because bacteria use

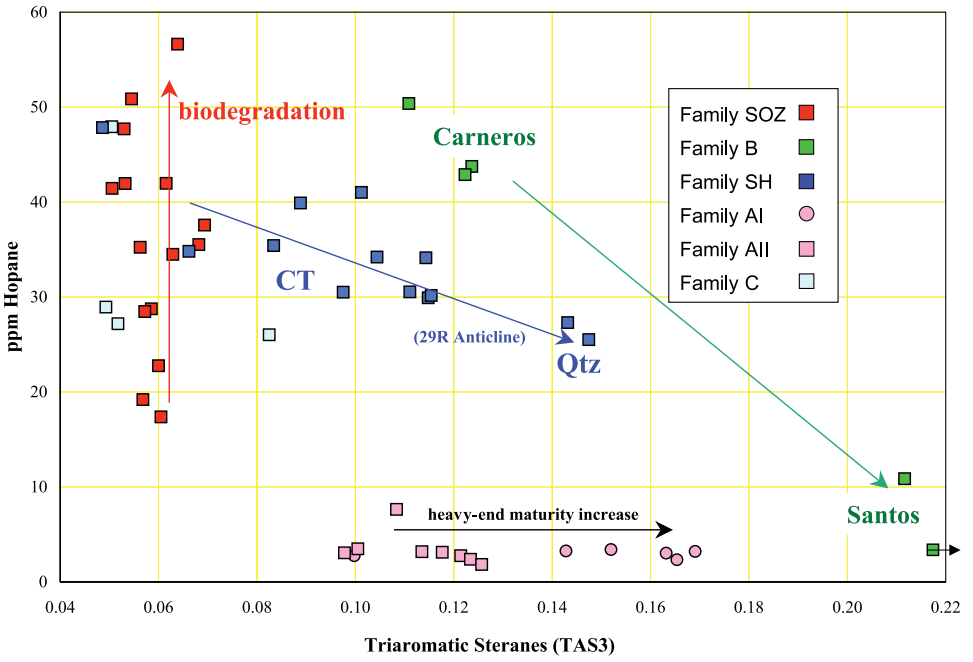


Figure 11. Absolute hopane concentrations versus triaromatic sterane maturity indicator. Family SOZ oils are of equivalent maturity but vary in hopane concentration because of different degrees of biodegradation. The heavy-end components of subfamily AI appear to have originated from more mature source rocks than subfamily AII. The pre-Monterey reservoired oils of family B show an increase in maturity for the older and deeper Santos oils compared to the younger Carneros oils; family B oils were likely generated from the lowermost organic-rich facies of the Monterey. Porcelanite reservoirs in the 29R anticline (western Elk Hills; family Shales) contain more thermally mature oil in the higher temperature microcrystalline quartz phase than in the opal-CT phase reservoirs, perhaps suggesting localized oil generation.

the lighter n-paraffins in preference to C_{15+} n-paraffins. This implies that the SOZ reservoirs have been charged with mature oil, which mixes with the biodegraded initial in-place oil. The quality of these polyhistory oils is determined by the rate of biodegradation versus the rate of recharging.

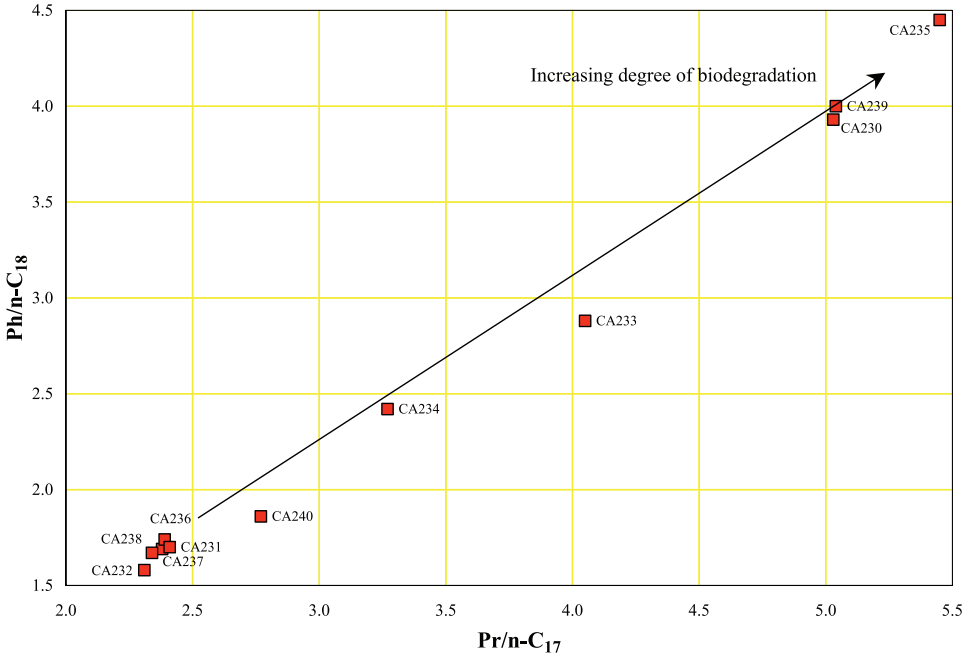


Figure 12. Pristane to n-C_{17} versus phytane to n-C_{18} plot representing various degrees of family SOZ (shallow oil zone) biodegradation. Bacteria preferentially degrade the n-paraffins relative to the isoprenoid hydrocarbons. The most degraded oils occur on the flanks of the 31R anticline.

Sequence of Filling Stevens Reservoirs

The geochemical data presented here provide a basis to speculate on the sequence of filling of the Elk Hills reservoirs. On the Northwest Stevens anticline, analysis of the oils (families AI and C) indicates multiple pulses for migration. The initial pulse may have consisted of low-maturity oil derived from the first phase of generation from the Monterey Formation (Figure 13A). Family C oil is restricted to the west end of the anticline and predominantly in a structural-stratigraphic trap. The trap is unique for Stevens reservoirs at Elk Hills in that it was fully formed before all the other traps (Imperato, 1995). The presence of low-maturity oil is consistent with the early trap formation, indicating that this trap had the geometry necessary to accept the initial oil expelled from the Monterey. This oil was generated from the Buttonwillow subbasin, which is structurally adjacent to and downdip of the Northwest Stevens anticline.

The remaining accumulations on the Northwest Stevens anticline contain family AI oils. Although family AI oils have a substantial high-maturity component (Figure 10), these oils have the widest distribution of all Stevens oils on a crossplot of maturity biomarkers (Figure 9). This distribution indicates that oil was derived from a source rock of consistent composition that became increasingly mature. Once the A4–A6 trap formed (probably by middle Pliocene), a continuous stream entered the trap from the Buttonwillow subbasin as the source rock matured and expelled oil (Figure 13B).

The Northwest Stevens anticline and the western 29R structure share some of the same turbidite sand bodies (Figure 4). Sandstone reservoirs on the two structures also share the same oil family (family AI). After filling of the Northwest Stevens anticline reservoirs, oil appears to have spilled into and filled the 24Z trap (Figure 13B). Family AI oil may also have reached the 2B trap on the east nose of the 29R anticline and the 26R reservoir at the west end of the 31S anticline, again moving within turbidite sand bodies from the Northwest Stevens structure.

Oil from Stevens sandstone reservoirs of the 31S anticline belong to family AII. This includes the Main Body B, Western 31S and 26R, and the 2B reservoirs on the eastern nose of the 29R anticline (Figure 13C). The 31S anticline is positioned on a structural high between the Maricopa and Buttonwillow subbasins and is favorably positioned to be charged from either. If family AII oil is derived from both areas, then the source facies must be extremely similar and at the same point of maturity when oil was expelled. Alternatively, only one of the subbasins supplied oil to the 31S sandstone reservoirs and the migration route from the other subbasin was somehow blocked. Maturity biomarkers (Figure 9) show a small maturity band for the AII oils, indicating that the source rock underwent minimal evolution during the period it charged 31S reservoirs. This charge history would be consistent with migration along a newly formed route, such as a developing fault zone on the flanks of the 31S anticline and the quick flooding of the reservoir zones in the late Pliocene or Pleistocene.

The 2B reservoir on the eastern nose of the 29R anticline also contains family AII oil (Figure 13C). The reservoir is a combination structural-stratigraphic trap that has an updip lateral seal formed by the abrupt pinch-out of the 26R sand body. Oil likely migrated from the adjacent 26R reservoir, which is filled to its spillpoint. The 2B reservoir is not filled to its spillpoint, and Reid (1990) speculated that leakage may have occurred through a lower sand body into the updip porcelanite interval. However, family AII oil is not present in the adjacent updip reservoir (as discussed below), indicating that the trap has not leaked and is instead underfilled, possibly because of rerouting of the oil-migration path away from the 31S anticline.

All the Stevens porcelanite reservoirs contain family SH oils (Figure 13D). The distinction between family A and SH oils is remarkable given the close proximity of the reservoir types and clearly indicates a strong segregation of migration routes or histories. A possible explanation is tied to the diagenesis of porcelanite. During migration of family A oils into Stevens sand reservoirs, the adjacent porcelanite intervals may have been at the opal-CT phase of the diagenetic process and had matrix permeabilities too low to permit significant oil to accumulate (Reid and McIntyre, 2001; Schwalbach et al., 2001). Migration into fractures may have occurred, thus accounting for the lower maturity oil present in the opal-CT interval (Figure 9). At some later point, after the sand reservoirs were filled, opal-CT converted to quartz phase and acquired sufficient matrix permeability to become an effective reservoir. Porcelanite reservoirs are the last of the Steven traps to be charged and occurred at a time when the Monterey oil-generating window is the closest to the Elk Hills anticlines. The differences in characteristics between families A and SH oils may reflect compositional variations between distal, basin-floor source rocks that charge the sand reservoir and

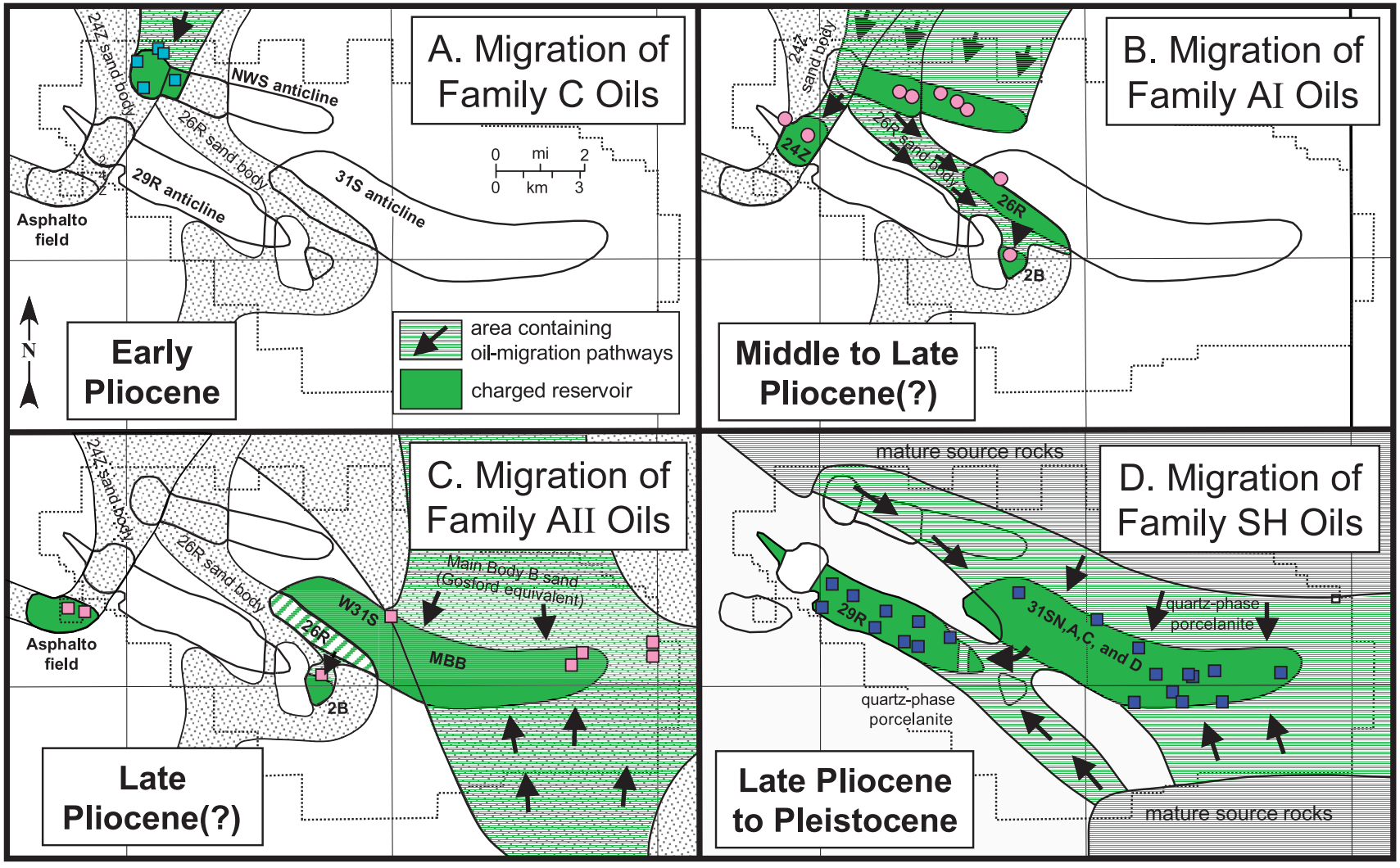


Figure 13. Migration of oil into major Stevens turbidite and porcelanite reservoirs at Elk Hills. (A) Family C oils are restricted to the western end of the Northwest Stevens anticline and are the least mature of the sampled oils. They may have migrated into the earliest formed traps in the Northwest Stevens anticline along turbidite sand bodies updip from the Buttonwillow subbasin. (B) Oils of family AI are likely derived from the Buttonwillow subbasin and filled reservoirs in the central and eastern Northwest Stevens anticline. Oil spilled from the Northwest Stevens traps and followed turbidite sand bodies updip into the 26R, 2B, and 24Z reservoirs. (C) Family AII oils probably are from both the Buttonwillow and Maricopa subbasins and migrated into the 31S reservoirs following the Main Body B submarine-fan complex. Oil possibly leaked into the 26R sand body and spilled into the 2B trap. The occurrence of family AII oil in the Asphalto field remains a dilemma. (D) Family SH oils occur in porcelanite reservoirs across the entire field and are sandwiched stratigraphically between families AI and AII reservoirs. Migration likely occurred after filling of the turbidite reservoirs and after development of more favorable porosity because of transition of porcelanite from opal-CT to quartz phase.

more proximal (lower slope?) areas where organic material was deposited on the flanks of actively growing structures.

The presence of family AII oil in the Asphalto field west of Elk Hills presents a migration dilemma because obvious migration routes are not supported by the geochemical data. Low-permeability opal-CT phase porcelanite on the 29R anticline should have blocked oil migration from the 2B area into 24Z or Asphalto. The other option of migration from the 24Z and Northwest Stevens anticline reservoirs seems unlikely because of the absence of family AII samples on this trend. This problem demonstrates that the distinction between family AI and AII is very subtle, and there may be limits to the extent oil families should be used to interpret migration history.

CONCLUSIONS

Five principal oil families, all generated from different organofacies of the Monterey, were determined to exist at Elk Hills based on multivariate statistical analyses of genetically important biomarker distributions and bulk carbon isotope compositions. Family C oil at the west end of the Northwest Stevens anticline contains the least mature oil and was the first to migrate into the Elk Hills areas. The remaining Stevens sandstone reservoirs have family A oil. These oils contain the most light-end hydrocarbons and were likely generated from organic-rich facies of the Monterey, stratigraphically adjacent to the turbidite sand bodies in location on or near the basin floor. Family SH oils, in porcelanite reservoirs, are widespread across the entire field and were derived from similar, albeit more local Monterey facies interbedded with quartz porcelanite. The pre-Monterey oils of family B appear to have been generated from lowermost, organic-rich Monterey facies. These have different biomarker distributions and are the most thermally mature, but also have the distinct isotopic signature of the Monterey. Family SOZ oils are commonly biodegraded, occur in shallow post-Monterey reservoirs, and were probably generated from uppermost organic-rich Monterey facies.

The aerial distribution of Stevens oil families (Figure 13) represents the development of source areas and oil-migration routes. Entrapment of the Monterey's initially generated and expelled low-maturity oil is very limited because migration routes to Elk Hills were not established and few traps had formed. By the time most of the Stevens structures form, the source areas located on or near the basin floors are generating high-maturity oil and expelling into the Stevens sand bodies. Migration routes may have altered over time, especially on the 31S anticline, where family AII oil was possibly diverted after charging the 31S reservoirs. Through the late Pliocene and Pleistocene, the thermally mature areas of the Buttonwillow and Maricopa subbasins expanded and approached the flanks of the Elk Hills anticlines. By the time quartz-phase porcelanite reservoirs developed sufficient permeability to accumulate oil, areas downdip on the anticlinal limbs were mature and expelling high-maturity oil.

The results of the carbon isotopic analyses suggest that both the heavy- and light-end components of Elk Hills reservoirs originated from the Monterey (no Eocene Kreyenhagen component). Oil was generated at various thermal-maturity stages (at different times and different depths in the subbasins) and mixed in the reservoir. Family A oils, from Stevens turbidites, by far the main oil producers at Elk Hills, contain a factor of 10 or more of the mature light hydrocarbons from the subbasin depocenters than the other families.

One conspicuous dichotomy noticed early in interpreting the chemistry of the Elk Hills Monterey oils was that the biomarkers indicate a low thermal maturity for the source, almost immature. However, the API gravities of most Elk Hills oils are between 30 and 40° with 40–50% light ends. These abundant lighter hydrocarbons and relatively high gravities indicate at least moderate thermal maturity for the source. Most biomarkers occur in the heavy C_{15+} fraction and are concentrated in low-maturity, early-generated oil. Subsequent oil expelled from deeper, more thermally mature source horizons contains more mature biomarker distributions, but at much lower absolute concentrations. Most of the Elk Hills oils produced from the Stevens sandstones appear to be the result of mixing, with small quantities of biomarker-rich low-maturity Monterey oil (migrating through the reservoirs prior to trap formation) being progressively diluted by increasingly mature oil from downdip source rocks containing abundant light ends. The question as to the source of these mature, light-end hydrocarbons, both in the Stevens and pre-Monterey reservoirs, has been answered based on carbon isotope compositions; the Monterey also generated the light-end hydrocarbons instead of the older Eocene Kreyenhagen.

What is remarkable about the Elk Hills oil families is the strong correlation with the reservoir interval (Table 1; Figure 2). The different oil families, generated from stratigraphic and geographic variations in the Monterey organic-rich facies, correspond to reservoir horizons. This suggests minimal upsection, cross-stratigraphic migration from the basin depocenters to Elk Hills; specific inter-Monterey source-reservoir packages extend downdip into the basin with good intervening seals. However, the pre-Monterey reservoired oils (family B) in the Carneros and Santos formations also contain Monterey oils, albeit at higher thermal maturities. It appears that the older Monterey source horizons can charge even older reservoir units as updip, but downsection migration occurs.

The Pliocene SOZ oils, which are isotopically distinct from other Elk Hills oils, have been biodegraded to different degrees. The most biodegraded oils have the lowest API gravities and occur on the flanks of the 31S anticline. Although slightly more positive (not caused by biodegradation), the carbon isotopic composition of SOZ oils suggests yet another Monterey source facies (perhaps the youngest) with charging of Pliocene reservoirs. The SOZ oils are not simply the result of vertical leakage in the Elk Hills area from any of the older Miocene reservoirs.

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by
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March 23, 2022

This report is developed from information clearly in the public domain. The views expressed in this document represent the opinion of the author.

I. Introduction

Accufacts Inc. ("Accufacts") was asked to review and comment on various aspects related to carbon dioxide transmission pipeline safety and federal pipeline safety regulations within the U.S. In recent years there has been considerable discussion about how to address carbon dioxide emissions and global warming through carbon capture, utilization, and sequestration (aka "CCUS" or "CCS"). CCS efforts are intended to help mitigate climate change by capturing carbon dioxide emissions both before and after they are released to the atmosphere and permanently storing such material deep in underground geological structures.

The federal Pipeline Safety Act ("PSA") directs the U.S. Department of Transportation ("DOT") to issue detailed safety standards with regard to the design, construction, operation, and maintenance of CO_2 pipelines.[1, 2] In turn, the DOT has delegated its authority to the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). The PSA's broad mandate is supplemented by detailed federal regulations.[3] The PSA expressly prohibits state and local regulation that interferes with or supplements federal safety standards for interstate pipelines.[4] States meeting certain conditions may supplement federal pipeline safety regulation on their intrastate pipelines as long as such state regulations are not in conflict with federal pipeline safety regulations.

The U.S. has the most mileage of CO_2 transmission pipelines in the world, consisting of approximately 5,150 miles, out of a total 229,287 miles of hazardous liquid transmission pipelines within the U.S.[5] The vast majority, if not all, of these CO_2 existing pipelines are driven by enhanced oil recovery ("EOR") efforts that increase oil production utilizing CO_2 in a supercritical state. Most of this supercritical state CO_2 comes from high pressure higher purity natural underground source domes. It is an excellent solvent for EOR efforts, but the CO_2 must be injected into oil fields as a supercritical fluid.

CCS efforts are driven by an entirely different purpose such that CO_2 used for CCS could be shipped as a gas or a non-supercritical liquid. However, current federal safety regulations regulate only pipelines that transport supercritical CO_2 containing over 90% carbon dioxide molecules, and not pipelines that ship CO_2 in these other lower concentrations or forms, leaving a large regulatory gap. Moreover, even the regulations for supercritical CO_2 pipelines are incomplete or inadequate and place the public at

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[1] 49 U.S.C. § 60101 *et seq*.
[2] 49 U.S.C. § 60102(a) and (i).
[3] 49 C.F.R. Part 195.
[4] 49 U.S.C. § 60104(c) ("A State authority may not adopt or continue in force safety standards for interstate pipeline facilities or interstate pipeline transportation.")
[5] PHMSA reporting database, "Hazardous Liquid Pipeline Miles and Tanks," as of January 31, 2022 for CO_2 commodity at: https://portal.phmsa.dot.gov/analytics/saw.dll?Portalpages&PortalPath=%2Fshared%2FPDM%20Public%20Website%2F_portal%2FPublic%20Reports&Page=Infrastructure.

great risk, especially from the tens of thousands of miles of CO_2 pipelines that may be driven by CCS efforts.[6]

A flurry of multibillion dollar CO_2 pipeline proposals have recently been announced, likely driven by enhanced tax credit incentives provided by Internal Revenue Code § 45Q.[7, 8, 9] Congress provided these enhancements in the Bipartisan Budget Act of 2018, and expanded by the Infrastructure Investment and Jobs Act of 2021 ("Acts of 2018 and 2021").[10] As intended, these laws accelerated CCS and CO_2 pipeline development efforts, because they make such credits more available and valuable to certain generators of CO_2 emissions and require projects to start construction by January 1, 2026.[11] Since most carbon dioxide emitters are likely considerable distances from suitable deep, permanent underground storage sites, it is understandable that CO_2 transmission pipelines may be needed between emitters and these storage sites. If CO_2 pipeline mileage increases as projected, the CO_2 pipeline network could soon rival the existing oil and natural gas pipeline networks in size and complexity. PHMSA would be faced with the greatest and fastest pipeline expansion in the history of the U.S. pipeline industry, and many of these pipelines could threaten the safety of countless individuals and communities.

This report is intended to increase regulator and public awareness of the regulatory challenges posed by this proposed massive expansion in CO_2 pipeline mileage and the unique safety risks of transporting CO_2, especially in its supercritical state. It focuses on a higher-level review of the more technical pipeline safety matters, based on decades of pipeline safety experience including pipeline failure investigations, process engineering and process safety management practice, as well as years of experience in processing and handling many tons of liquid CO_2. This report also makes specific recommendations for improvements in federal pipeline safety regulations needed to fill regulatory gaps and ensure public safety. The proposed CO_2 pipeline boom presents

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[6] For one perspective see what I would call a planning study from Princeton University, "Net-Zero America - Potential Pathways, Infrastructure, and Impacts," Final Report, October 29, 2021, pp. 212 – 219 of 348, indicating a possible need of over 60,000 new miles of CO_2 pipelines by 2050.

[7] Des Moines Register, "What we know about two carbon capture pipelines proposed in Iowa," https://www.desmoinesregister.com/story/money/business/2021/11/28/what-is-carbon-capture-pipeline-proposals-iowa-ag-ethanol-emissions/8717904002/, Nov. 28, 2021.

[8] Agweek, "World's largest carbon capture pipeline aims to connect 31 ethanol plants, cut across Upper Midwest," https://www.agweek.com/business/worlds-largest-carbon-capture-pipeline-aims-to-connect-31-ethanol-plants-cut-across-upper-midwest 12/6/2021.

[9] S&P Global Platts, "Oil producer Denbury plans CO_2 storage hub in southern Alabama." https://www.spglobal.com/platts/en/market-insights/latest-news/energy-transition/020822-oil-producer-denbury-plans-co2-storage-hub-in-southern-alabama, 2/8/2022.

[10] 26 U.S.C. § 45Q.

[11] I.R.C. § 45Q.

PHMSA with an unprecedented challenge; hopefully, this report will help PHMSA rise to this challenge.

II. A brief history of U.S. federal CO_2 pipeline safety regulation

PHMSA and its predecessor agencies, such as the Office of Pipeline Safety, have historically relied on more prescriptive minimum safety approaches. In the past several decades federal minimum pipeline safety regulations have, by the industry's lobbying, shifted to more "performance-based" approaches that rely heavily on certain industry standards or recommended practices, some of which are incorporated by reference into federal pipeline safety regulation.[12] This industry driven shift can result in changes in pipeline safety regulations without proper public input. A prime example may be in the development of CO_2 transmission pipeline safety regulations that historically have been a very small percentage of overall transmission pipeline mileage in the U.S. This country may be facing a significant increase in CO_2 transmission pipeline mileage without appropriate pipeline safety regulatory development or enactment, leaving the country and the public ill prepared for a tsunami of CO_2 pipeline construction.

Congress, in Section 211 of the Pipeline Safety Reauthorization Act of 1988, required that the DOT regulate carbon dioxide transported by pipeline facilities. Part of this concern was driven by a 1986 natural carbon dioxide release event in Lake Nyos, Cameroon spanning many miles with over 1,700 fatalities, underscoring the dangers and possible consequences of CO_2 releases.[13] On July 12, 1991, federal regulators issued a minimalist final rule that mainly added the words "and carbon dioxide" to existing federal minimum pipeline safety regulations developed for hazardous liquid petroleum pipelines (49CFR§195). It opted to not issue standards specifically applicable to supercritical CO_2 pipelines due to the small number of already existing and anticipated CO_2 pipelines. Even though the situation is about to change dramatically, PHMSA has not proposed to review and overhaul its CO_2 pipeline standards, such that these limited regulations are still in effect today.[14] As a result, many of PHMSA's regulations no longer are adequate to protect public safety.

For example, under federal regulations "carbon dioxide" is defined as follows:

> "Carbon Dioxide means a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state."[15]

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[12] 49CFR§195.3 What documents are incorporated by reference partly or wholly in this part?

[13] Federal Register / Vol. 56, No. 113 / Wednesday, June 12, 1991/Rules and Regulations, Research and Special Programs Administration (RSPA), DOT, Docket No. PS-112, Amendment 195-45, RIN 2137-AB72, 49CFR Part 195, "Transportation of Carbon Dioxide by Pipeline," final rule.

[14] *Ibid*, p. 26924.

[15] 49CFR§195.2 Definitions.

The above definition is clearly not appropriate to deal with CCS CO_2 pipelines, nor is that its intent as demonstrated further in this report.

Existing U.S. CO_2 transmission pipelines are primarily located in sparsely developed or more rural locations and, as mentioned previously, involve approximately 5,150 miles moving CO_2 mostly from natural underground sources/domes to EOR projects. The current definition of "carbon dioxide" does not include pipelines that transport supercritical carbon dioxide streams in which CO_2 makes up less than 90 percent of the stream. It also excludes pipelines that transport CO_2 as a non-supercritical liquid or gas. In 1991, there were only a very limited number of pipelines transporting CO_2 in these other forms that apparently didn't justify the need for federal regulation, which is not the case now.

In 2011, Congress, in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Section 15, mandated that the Secretary of Transportation "prescribe minimum safety standards for the transportation of carbon dioxide by pipeline in a gaseous state." As a result, PHMSA issued a report in early 2015 entitled "Background for Regulating the Transportation of Carbon Dioxide in a Gaseous State."[16] Unfortunately, PHMSA never issued new regulations for transportation of CO_2 as a gas.

Thus, PHMSA currently has no regulations applicable to pipelines transporting CO_2 as a gas, liquid, or in a supercritical state at concentrations of CO_2 less than 90 percent. This regulatory gap means that current federal pipeline safety regulations are clearly inadequate because CO_2 pipeline companies could develop CO_2 gas and liquid pipelines that fall outside of this narrow federal rule. The definition of "carbon dioxide" should be modified so that all CO_2 transmission pipelines are regulated by federal law and held to appropriate minimum safety standards. Otherwise, CO_2 pipelines could be designed, constructed, operated, and maintained with no federal or state oversight.

III. CO_2 transmission pipelines can take on three basic forms

CO_2 transmission pipelines can be designed to transport carbon dioxide either as a supercritical state fluid, a liquid (aka in a subcritical or chilled state), or as a gas. Within the industry the term "dense phase" is often used to label CO_2 pipelines operating in either a supercritical state fluid or in a liquid phase as explained below. It is odd that the proposed new CO_2 transmission pipeline applications recently reviewed have not clearly stated in what phase they are designed to operate, their temperature ranges, nor their quality requirements.[17] The key characteristics of supercritical, liquid, and gaseous CO_2 transmission pipelines are summarized below.

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[16] PHMSA report dated February 2015, posted to the 2016 docket under PHMSA-2016-0049-001 at www.regulations.gov.

[17] For example, see Summit Carbon Solutions, "Application to the South Dakota Public Utilities Commission for a Permit for the SCS Carbon Transport LLC (SCS) Pipeline Under the Energy Conversion and Transmission Facility Act – Document Number: SCS-0700-ENV-05-PE-009-A," dated February 7, 2022.

i. Supercritical state CO_2 transmission pipelines

Pure CO_2 has a critical temperature of about 88 ºF (33 ºC) and a critical pressure of approximately 1070 psia, or pounds force per square inch absolute (73 atm). At temperatures and pressures above these critical values, CO_2 is not technically a liquid and instead is in a supercritical state as a dense phase "fluid" or vapor with properties between that of a liquid and a gas. This supercritical fluid will not condense to liquid within the pipeline, as long as the temperature remains above the critical temperature, no matter how high the pressure is increased above the critical pressure. If the temperature along a supercritical state pipeline drops below the critical temperature, part of the fluid will condense to liquid with a higher density than the fluid. If the pressure along a supercritical state pipeline drops below 1070 psia, part of the CO_2 will convert to a gas/liquid mixture depending on the temperature.

The primary reason that the existing 5,000 or so miles of CO_2 pipelines transport CO_2 in a supercritical state is because CO_2 in this state is an excellent solvent having no liquid surface tension. It readily dissolves oil trapped in porous rock. In contrast, CO_2 destined for sequestration could be transported as a gas or liquid, because sequestration does not, as a practical matter, need the CO_2 to be in a supercritical state, and federal law does not require transportation in a supercritical state. In fact, a clever pipeline operator could employ loopholes to avoid federal pipeline safety oversight by PHMSA. Clearly the sources and needs of CO_2 for EOR are not the same as those for the CCS objective, which is to remove CO_2 from the atmosphere.

CO_2 supercritical fluid transmission pipeline operating pressures usually range from 1,200 to 2,200 pounds force per square inch gauge, or psig. The higher pressure is set based on the maximum operating pressure ("MOP") usually related to a pipe specification limit.[18] There are a minor number of CO_2 supercritical state pipelines that have been designed to operate at much higher MOPs (*e.g.*, 3200 psig). Moving CO_2 as a dense phase supercritical state fluid permits the use of pumps along a pipeline instead of compressors that would be needed to move the material if it were a gas. For pipelines, the use of pumps to move higher density fluids requires smaller, less complex, equipment that is more efficient in moving mass along a pipeline than compressors (*i.e.*, pumps are cheaper to build, install, maintain, and operate than compressors). In addition, the higher MOPs of supercritical state CO_2 pipelines permit them to utilize smaller diameter pipe, albeit much stronger pipe, to move the same tonnage of CO_2 as compared to shipment as a gas. In contrast, gas pipelines require larger diameter pipe to move the same tonnage, because they must usually operate at pressures lower than the supercritical pressure (1070 psig), otherwise some of the CO_2 could convert to a liquid

[18] MOP stands for maximum operating pressure for liquid pipelines and is defined in federal minimum pipeline safety regulations that provide conditions for "normal" operation of pipelines. Pipelines are permitted to exceed MOP within certain limits, under certain situations.

(depending on the temperature along the pipeline) and such liquid slugs would severely damage/destroy the compressors used in gas pipelines.

While there are many cost/efficiency advantages to moving CO_2 in a supercritical state, there is one well known threat associated with supercritical state operation. A CO_2 pipeline operating in a supercritical state can be more prone to pipe running ductile fractures than hazardous liquids or natural gas pipelines. Running ductile fractures are unusual and particularly dangerous fractures that can "unzip" a CO_2 transmission pipeline for extended distances exposing great lengths of the buried pipeline. These extreme rupture forces throw tons of pipe, pipe shrapnel, and ground covering, generating large craters along the failed pipeline. It is well known that CO_2 pipelines operating in dense phase, either supercritical or as a liquid, are particularly susceptible to such running ductile fractures. Although current federal regulations recognize this risk, they do not contain any detailed requirements that specifically identify how to address fracture propagation threats. Though there are various approaches well known in the industry (*i.e.*, pipe steel fracture toughness parameters, usually for new pipe, and/or mechanical arrestors such as valves, thicker/tougher pipe transitions) such approaches should be specifically mentioned in safety regulation.[19] To address this risk, PHMSA should revise federal regulations, especially for supercritical CO_2 pipelines, to specifically mitigate the effects of these fracture propagation forces. The current regulations do not adequately address these CO_2 fracture risks.

ii. Liquid CO_2 transmission pipelines

Subcooled or subcritical state means to transport CO_2 as a liquid that usually requires chilling and/or cooling of the stream slightly below ambient temperatures to assure the pipeline is operated in one phase, that of a liquid. For new pipelines this also may require the use of pipeline insulation, though not always, to reduce temperature increase of the CO_2 along the pipeline, assuring it stays as a liquid. It is important that cooling stay well above the pipe carbon steel brittle transition temperature of approximately - 20 ºF to avoid the threat of catastrophic pipeline rupture. Despite these obstacles, transporting CO_2 as a liquid, basically at its highest density, which is typically about double the density of CO_2 fluid in its supercritical state, allows the pipeline transportation of more tonnage of carbon dioxide with even smaller diameter pipe than a supercritical state operation, as well as lower MOPs. Because the liquid phase operation also has a lower viscosity, a liquid CO_2 pipeline system for a given length can utilize a fewer number of pump stations that can have major advantages over supercritical state or gas pipeline approaches needed to move similar tonnage of CO_2. For CCS objectives, liquid phase CO_2 transmission pipelines additional efficiency over their supercritical state or gas counterparts may justify the additional cooling infrastructure along such

[19] 49 CFR§195.111 Fracture propagation. The regulation states in full: "A carbon dioxide pipeline system must be designed to mitigate the effects of fracture propagation." Thus, pipeline safety law contains no detailed standards to prevent running ductile fractures leaving much room for misinterpretation.

pipelines. It is worth emphasizing that PHMSA chose to not issue regulations for CO_2 pipelines designed to operate as a liquid, so such pipelines are currently unregulated.

iii. CO_2 gas transmission pipelines

New pipelines designed to move CO_2 as a gas in a transmission pipeline is not likely, given that the system must be operated at lower pressures. For a CO_2 gas pipeline, the MAOP must not exceed approximately 1,000 psig at normal operating temperatures, so that the CO_2 is maintained as a gas and does not convert to a liquid as this could be disastrous for the pipeline's compressors.[20] For an equivalent daily CO_2 tonnage pipeline capacity, the requirement to keep design pressure lower drives such new gas pipeline approaches to much higher pipe diameters than their liquid or supercritical state pipeline alternatives. However, specific situations may exist where existing liquid or larger diameter natural gas pipelines could be "repurposed" into primarily CO_2 gas service.[21] Such change in service, will most likely be highly limited in its pipeline mileage and, in my opinion, should exceed the requirements identified in ADB-2014-04, addressing repurposing of natural gas pipelines or liquid pipelines. For example, an Advisory Bulletin, or ADB, does not carry the force of promulgated pipeline safety regulation but is issued to more quickly alert pipeline operators of PHMSA concerns on certain issues. ADB-2014-04 does not address, nor was it intended to address, the specific additional challenges associated with unique fracture propagation risks associated with CO_2 transmission pipelines as previous discussed. While there are unique situations where nonoperating or underutilized pipelines exist, there are several factors that can make repurposing of such pipelines to CO_2 gas service economically attractive, given the billions of dollars in tax credit incentives associated with CCS under the Acts of 2018 and 2021, and the associated start construction deadline. The critical deadlines to meet tax credit triggers could make timing of such conversions more favorable than routing and construction of new CO_2 pipelines for CCS. Such pipeline conversions would be at much greater risk of failure from CO_2 service than conventional hydrocarbon or new construction CO_2 pipelines, given the unique and increased potential for CO_2 pipeline ruptures from various risks associated with CO_2 operation. Only time will tell, given the economic temptations and timing thresholds, whether such repurposing of an existing transmission pipeline to CO_2 service will prove practical for CCS utilization.

[20] MAOP stands for maximum allowable operating pressure, which is the standard for gas pipelines and is defined in federal minimum pipeline safety regulations that provide conditions for "normal" operation of pipelines. Pipelines are permitted to exceed MAOP within certain limits, under certain situations.

[21] See DOT PHMSA, Advisory Bulletin, ADB-2014—04, "Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes and Conversion to Service," Docket No. PHMSA–2014–0040, Sept 12, 2014.

IV. CO_2 transmission pipelines pose different risks than traditional hydrocarbon transmission pipelines

Carbon dioxide gas is odorless, colorless, doesn't burn, is heavier than air, and is an asphyxiant and intoxicant, making CO_2 pipeline releases harder to observe and avoid especially as a released plume spreads and migrates well off the pipeline right-of-way. CO_2 properties differ from those for materials moved in hazardous hydrocarbon liquid or natural gas transmission pipelines. CO_2 pipeline releases significantly increase the possible "affected" or "potential impact" area identified in federal regulations addressing hydrocarbon transmission pipelines upon pipeline rupture release, and CO_2 pipeline ruptures have a greater potential to endanger the public. Current federal pipeline safety regulations do not incorporate these important CO_2 differences to assure safety to the public. Federal pipeline safety regulatory changes are warranted if CO_2 pipeline mileage is to be increased dramatically in the U.S., especially under CCS. CO_2 transmission pipelines have many unique failure dynamics such that a rupture may impact significantly greater geographic areas than hydrocarbon pipelines. In particular, a combination of CO_2 phase/temperature changes may result in explosive pipe release forces as the CO_2 converts to gas. Moreover, CO_2's lack of odor and invisibility means that it may not be possible for citizens and first responders to determine if they are in a hazard area before they are harmed, unless they have access to a CO_2 detection meter. It is important that anyone using such CO_2 detection meters assure that such equipment has been properly calibrated/maintained and users properly trained in their use and limitations. Once a CO_2 pipeline release has been warmed by the surrounding environment, it travels unseen influenced by gravity, terrain, and the wind, preferentially settling in low spots, displacing air and providing no warning to persons and animals caught in the invisible release plume. Hydrocarbon pipeline releases that haven't ignited, can usually be detected by unusual smell or sight, which makes CO_2 pipeline releases different and harder to detect by emergency responders or the public.

During a CO_2 pipeline rupture release, multiple phase changes can result not only in the significant lowering of temperature near the pipe failure site, but also the likelihood of solid CO_2 formation (i.e., dry ice). Dry ice particles within the fluid can contribute to fogging in the air and ground around the pipeline release, as well as the formation of dry ice within the pipeline upstream/downstream of the pipe failure site that can impact the rate of release out of a pipe failure. Such dry ice blockage can result in temporary restriction/blockage within the pipe, affecting release rate, especially for smaller diameter transmission pipelines experiencing rupture fracture.

In CO_2 pipelines experiencing smaller, slower rate releases, often called leaks, such as through minor holes or cracks, the resulting lower rate CO_2 rich clouds may disperse/dissipate after a short time. In much larger rate releases, such as pipeline rupture fractures caused from various anomalies or pipeline threats, the resulting release of cold gas and dry ice solid mixtures can be quite dangerous (see video of

DNV rupture failure test of an CO_2 8-inch diameter pipeline).[22] The CO_2 released from a pipeline will be heavier than air, and the high-rate release from a pipe rupture will form cold dense gas fog clouds comprised of dry ice particles and visible water vapor as the humidity in the air condenses from the extreme cooling. Such high-rate releases can produce areas of low visibility from "fog," both from dry ice particles and water condensation. The CO_2 pipeline rupture fog becomes transparent when eventually warmed by the surrounding environment. Upon warming, the CO_2 plume can flow considerable distances from the pipeline unobserved, traveling over terrain, displacing oxygen while settling or filling in low spots. Oxygen displacement can starve gasoline or diesel powered equipment, such as first responder and private vehicles, causing such equipment to malfunction or even shut off, and cause pilot lights on furnaces, stoves, and natural gas fireplaces to go out. Oxygen displacement by CO_2 gas can cause asphyxiation of humans and animals, that can lead to death. Further, CO_2 gas can cause disorientation, confusion, and unconsciousness, which can be dangerous for persons caught in the plume, especially those who are driving, using power equipment, or exposed to cold weather. Cooling of a CO_2 release can also impact the rate of release and exacerbate pipe fracture propagation during rupture. Clearly, dispersion modeling for analyzing potential impact areas for CO_2 pipeline failures and their related released gas plumes, must consider the propensity of heavier than air CO_2 gas to displace oxygen and to follow the terrain as terrain factors can play a critical role in evaluating a potential area and receptors that could be affected by a CO_2 pipeline release. It is vitally important to not underestimate the potential distance that a CO_2 pipeline rupture plume can reach and affect, especially in nonlevel terrain. Additional safety margins should be employed in populated areas when using dispersion modeling results for CO_2 pipeline releases.

Before the U.S. is blanketed with a major increase in CO_2 transmission pipeline mileage driven by CCS efforts, substantial changes need to be implemented in federal pipeline safety regulations specifically addressing the unique dangers of CO_2 in transmission pipelines in any phase. CO_2 is not flammable. It doesn't burn or explode/detonate from ignition, so heat radiation is not an issue of concern as in conventional hydrocarbon pipelines. CO_2 can, however, generate similar overpressure "blast" forces upon pipeline rupture (from the high-rate releases associated with pipeline fracture failure, see previous referenced 8-inch CO_2 pipeline rupture test). CO_2 pipeline rupture and resulting rapid "blast like" expansion forces dissipate quickly with distance from the pipeline but can easily extend well beyond the pipeline right of way. The areas potentially impacted by ruptures of oil and gas transmission pipelines are well defined in current federal regulations, which estimate how far liquid hydrocarbon will spread and the blast or burn radius resulting from a natural gas pipeline rupture. The danger zone for human life for hazardous hydrocarbon liquid and natural gas pipeline releases is generally measured in feet, albeit many thousands of feet for larger diameter higher pressure pipelines.

[22] Video of 2013 DNV Spadeadam Research and Testing test experiment of dense phase CO_2 8-inch buried pipeline rupture, https://www.dnv.com/oilgas/laboratories-test-sites/dense-phase-spadeadam-video.html.

In contrast, a CO_2 pipeline's impact area may be measured in miles, not feet. This is likely because:

- CO_2 pipeline ruptures can release many tons of CO_2,
- the compressed CO_2 will expand into gas phase upon pipeline rupture and fill a much larger volume that it did inside the pipe, and
- the CO_2 may not disperse quickly because it is heavier than air, meaning that it will tend to flow toward and settle in low lying areas including ravines, valleys, and basements.

Current federal pipeline safety regulations do not provide any methodology for assessing the hazard zone for CO_2 pipelines or require that pipeline operators adequately address this risk.

V. Impact of impurities on CO_2 pipelines

The amounts and types of impurities in a CO_2 stream can have an impact on pipeline design and approaches. Current CO_2 pipeline regulations, which only address CO_2 pipelines greater than 90% CO_2 concentration compressed to a supercritical state, make no mention as to the level of non-CO_2 impurities such as H_2S, which can be lethal even in very low parts per million concentrations. Also, impurities can affect the range of safe operating pressures. Most of the natural sources of CO_2 for existing pipelines contain CO_2 well above 90%, but this may not be the case for all CO_2 streams captured from industrial facilities. Federal regulation should be modified to adequately regulate CO_2 pipelines used for CCS, and subsequent transportation by transmission pipeline, especially because CCS pipelines may operate differently from those used for EOR. Such federal regulatory improvements should focus on public safety for all forms/phases of CO_2 transmission pipelines. There are some very pure sources of CO_2 emitters, such as ethanol plants and some hydrogen reformers, that emit very high concentrations of CO_2 to the atmosphere that require very little, if any, impurity treatment to prepare for pipeline transportation for CCS.[23] Unlike most of the currently existing CO_2 pipelines whose sources are underground natural gas domes or reservoirs, CSS pipelines may be supplied from various sources where the concentration of CO_2 is quite low and needing concentration, processing, and treatment for contaminant removal before it may be safely transported by pipeline.

There appears to be no transmission pipeline in the U.S. that transports pure CO_2, although there are pipelines that move very high concentrations of CO_2, well above 90%, containing only small levels, of impurities, especially those from natural sources of CO_2. Such CO_2 rich sources can still contain impurities, such as hydrogen sulfide, methane, carbon monoxide, oxygen, nitrogen oxide, sulphur oxide, hydrogen, or

[23] My experience is that purity from such CO_2 specialized emitters can exceed 99.9 % with trace impurities.

water.[24] The types and amounts of impurities in a CO_2 rich pipeline is largely driven by the source of CO_2, and proper operation of associated upstream treatment equipment to assure the material meets pipeline quality specifications, which is not always assured. At relatively low levels of impurities, such as at trace or levels in the lower parts per million, the specific effects of the impurities on the overall stream critical thermodynamic properties (such as enthalpy, entropy, density, and viscosity), are not significantly impacted. However, higher impurity concentrations, such as impurities measured in percentage concentrations should not be ignored as they can impact the critical pressure, but more importantly the critical temperature, such that even a percent or two change in impurity levels can result in unexpected phase change from dense phase fluid to other phases. Such phase changes may impact the system hydraulics, and to some extent the rupture release dynamics should the pipeline fail.

Two impurities that might be possible in CO_2 pipelines merit mention given their unique dangers to pipelines and the public: water and H_2S. CO_2 pipelines are usually made from carbon steel and require special maximum water quality specifications typically measured in the part per million, or its equivalent, that prevents the possibility of free water forming anywhere in the pipeline system. The presence of free water in a CO_2 stream permits the formation of carbonic acid in the pipeline, an acid that has a ferocious appetite for carbon steel. Given the rapidity and unpredictability at which carbonic acid can attack pipelines, prudent CO_2 pipeline operators have voluntarily established maximum water quality limitations for their input streams. Given the risks associated with carbonic acid attack, PHMSA should not leave this critical factor to company discretion, but instead should adopt federal regulations that specify a maximum water quality limitation for CO_2 pipelines.

Hydrogen sulfide, or H_2S, is mentioned here because of a curious item identified in an article related to a supercritical state CO_2 pipeline rupture failure in Mississippi in early 2020.[25] The observations noted in the article by responders of a "green cloud" from the pipeline release, is a possible indication of high levels of H_2S. Further investigation indicates that the source of the CO_2 (Jackson Dome) has levels of H_2S at 5 percent, or 50,000 ppm. In contrast, the Centers for Disease Control and Prevention states that a level of 300 parts per million is "immediately dangerous to life or health."[26] While the H_2S level that transitions into "sour" gas is not defined in federal

[24] For example, see Suoton P. Peletire, Nejat Rahmanian, Iqbal M. Mujtaba, "Effects of Impurities on CO_2 Pipeline Performance, Chemical Engineering Transactions," Vol. 57, 2017.

[25] Dan Zegart Huffpost article, "The Gassing of Satartia," August 26, 2021 at https://www.huffpost.com/entry/gassing-satartia-mississippi-co2-pipeline_n_60ddea9fe4b0ddef8b0ddc8f,

[26] https://www.cdc.gov/niosh/idlh/7783064.html. It is my understanding that while a few states have attempted to impose H_2S limits on intrastate pipelines, there is no such federal pipeline safety regulation limiting H_2S on transmission pipelines, even though there are OSHA H_2S limits on workplace workers, much lower than 300 ppm.

pipeline safety regulations, serious questions need to be raised about this specific CO_2 pipeline operation.

For CCS generated CO_2, from fuel combustion emission, an expected source for CCS, H_2S is not a likely contaminant of the stream with trace levels of H_2S in the less than 1 ppm to be expected. Treatment for the removal of water and water quality enforcement control limitations, however, are critical for CCS pipelines transporting CO_2 from combustion sources. Yet, current federal pipeline safety regulations also do not require that this risk be addressed.

VI. Areas needing additional federal pipeline safety focus for CO_2 pipelines

Based on my experiences, the following are my preliminary observations on specific areas where CO_2 pipeline safety regulation improvement efforts should focus.

1. **PHMSA should update the definition of carbon dioxide in current regulation.**
   The current "carbon dioxide" definition incorporated into pipeline safety regulation is driven by EOR and does not or may not apply to all CO_2 pipelines that may be developed for CCS projects. Federal regulations need to be modified to assure that federal standards apply to all CO_2 transmission pipelines that transport CO_2 for CCS projects, including all supercritical, gas, and liquid CO_2 transmission pipelines.

2. **PHMSA needs to identify in regulation the potential impact areas for CO_2 pipeline ruptures.**
   The unique, and potentially very large impact areas for CO_2 pipeline ruptures need to be developed, defined, and promulgated into pipeline regulations. As mentioned previously, these areas are most likely to be measured in miles, not feet.

3. **Specific CO_2 pipeline federal regulations should not be based solely on industry Recommended Practices.**
   Changes in the CO_2 pipeline safety regulation are needed and should be prescribed to avoid misinterpretation or misuse. Recent efforts by many in the industry to rely on more performance-based standards, even those incorporated by reference, have proven ineffective and disastrous. Such industry efforts also remove an important party to pipeline safety regulatory development, the public. Ironically, it is the public that has the most to lose from inadequate pipeline safety regulation if such referenced citations are not clear, relevant, effective, and cannot be enforced in assuring pipeline safety.

4. **PHMSA should specifically identify how to incorporate fracture propagation protection on CO_2 transmission pipelines.**
   Given the differential propensity for CO_2 pipelines to propagate fractures along the pipeline upon rupture, regulations should specifically list pipeline design methods to arrest CO_2 fracture propagation.

5. **PHMSA should mandate the use of odorant injection into CO_2 transmission pipelines.**
   Given the inability to detect or observe a CO_2 pipeline release, it is time to require the use of odorant injection in such pipelines, especially those pipelines that are not in unpopulated areas, to assist the public in identifying dangerous releases.

6. **PHMSA should require CO_2 pipeline operators to update their required procedural manuals related to coordination with local emergency response agencies for CO_2 pipeline ruptures.**
   The major differences and uniqueness of CO_2 pipeline releases compared to hydrocarbon pipelines require that pipeline operators improve the sections of their federally mandated operation, maintenance, and emergencies procedural manuals for emergency response to CO_2 pipeline ruptures.[27] In particular, operators must be required to periodically and fully inform, train, and equip key local officials and emergency responders with regard to special response actions unique to CO_2 pipeline releases. Moreover, upon a rupture, pipeline operators must inform state and local emergency personnel so that they can quickly and adequately protect impacted citizens and themselves.

7. **PHMSA should establish regulations setting specific maximum contaminant impurities for CO_2 pipelines.**
   Given the various sources and the unique risk associated with the introduction of water into a CO_2 pipeline, PHMSA should prescribe the maximum concentration of water allowed in them. This requirement goes well beyond a quality specification given the ability of water to rapidly cause CO_2 pipeline failures in unpredictable ways. Given the wide range of impurity sources for CO_2 streams for CCS, PHMSA should review a full range of limits for all common impurities and consider establishing maximum levels for all impurities that pose a safety risk in federal pipeline safety regulations.

8. **PHMSA should strengthen federal regulations for conversion of existing pipelines to CO_2 pipeline service.**
   It is not clear whether the public interest is best served by CO_2 shipment in existing transmission pipelines converted to CO_2 service. Further, the general conditions of PHMSA's advisory bulletin are not adequate for conversion to CO_2 pipelines. PHMSA should fully investigate the risks of such conversions and issue regulations appropriate to the serious risks that could result from repurposing a pipeline for CO_2 service.

VII. Conclusions

Current federal minimum pipeline safety regulations focus on higher concentration CO_2 pipelines transporting CO_2 in a supercritical state for use in oil production. Such

[27] 49CFR§195.402 and 49CFR§192.605 Procedural manual for operations, maintenance, and emergencies.

regulations are incomplete or in conflict with the intent of CCS, to reduce CO_2 content in the atmosphere to address global warming. Federal pipeline safety regulation concerning CO_2 pipelines need specific changes to address the likely expansion of CO_2 transmission pipeline mileage expected by CCS efforts enhanced by the Acts of 2018 and 2021.

Certain manufacturing processes, such as ethanol and some hydrogen reforming refinery units, produce CO_2 emission that are very pure CO_2, with only trace amounts of contaminants, that are higher priority choices for CCS and associated pipelines, most likely new liquid transmission pipelines, especially under the immense tax credits associated with the Acts of 2018 and 2021. Current federal pipeline safety regulations, however, are not adequate to deal with the additional pipeline risks associated with the expected significant increase in associated CO_2 transmission pipelines under CCS.

The country is ill prepared for the increase of CO_2 pipeline mileage being driven by federal CCS policy. Federal pipeline safety regulations need to be quickly changed to rise to this new challenge, and to assure that the public has confidence in the federal pipeline safety regulations.[28]

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[28] Disclosure: The author prepared this report for the Pipeline Safety Trust but retained full editorial control. The author received compensation from the Pipeline Safety Trust and the Bold Alliance for the preparation of this report.

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TITLE 5. LOCAL AGENCIES [50001 - 57607] *(Title 5 added by Stats. 1949, Ch. 81.)*

DIVISION 1. CITIES AND COUNTIES [50001 - 52203] *(Division 1 added by Stats. 1949, Ch. 81.)*

PART 1. POWERS AND DUTIES COMMON TO CITIES AND COUNTIES [50001 - 51298.5] *(Part 1 added by Stats. 1949, Ch. 81.)*

CHAPTER 5.5. The Elder California Pipeline Safety Act Of 1981 [51010 - 51019.1] *(Heading of Chapter 5.5 amended by Stats. 1992, Ch. 855, Sec. 1.)*

51010. It is the intent of the Legislature, in enacting this chapter, that the State Fire Marshal shall exercise exclusive safety regulatory and enforcement authority over intrastate hazardous liquid pipelines and, to the extent authorized by agreement between the State Fire Marshal and the United States Secretary of Transportation, may act as agent for the United States Secretary of Transportation to implement the federal Hazardous Liquid Pipeline Safety Act of 1979 (49 U.S.C. Sec. 60101 et seq.) and federal pipeline safety regulations as to those portions of interstate pipelines located within this state, as necessary to obtain annual federal certification.

(Amended by Stats. 2023, Ch. 131, Sec. 86. (AB 1754) Effective January 1, 2024.)

51010.5. As used in this chapter, the following definitions apply:

(a) "Pipeline" includes every intrastate pipeline used for the transportation of hazardous liquid substances or highly volatile liquid substances, including a common carrier pipeline, and all piping containing those substances located within a refined products bulk loading facility that is owned by a common carrier and is served by a pipeline of that common carrier, and the common carrier owns and serves by pipeline at least five of these facilities in the state. "Pipeline" does not include the following:

(1) An interstate pipeline subject to Part 195 of Title 49 of the Code of Federal Regulations.

(2) A pipeline for the transportation of a hazardous liquid substance in a gaseous state.

(3) Transportation of petroleum in onshore gathering lines located in rural areas.

(4) A pipeline for the transportation of a hazardous liquid substance offshore located upstream from the outlet flange of each facility on the Outer Continental Shelf where hydrocarbons are produced or where produced hydrocarbons are first separated, dehydrated, or otherwise processed, whichever facility is farther downstream.

(5) Transportation of a hazardous liquid by a flow line.

(6) A pipeline for the transportation of a hazardous liquid substance through an onshore production, refining, or manufacturing facility, including a storage or inplant piping system associated with that facility.

(7) Transportation of a hazardous liquid substance by vessel, aircraft, tank truck, tank car, or other vehicle or terminal facilities used exclusively to transfer hazardous liquids between those modes of transportation.

(b) "Flow line" means a pipeline that transports hazardous liquid substances from the well head to a treating facility or production storage facility.

(c) "Hydrostatic testing" means the application of internal pressure above the normal or maximum operating pressure to a segment of pipeline, under no-flow conditions for a fixed period of time, utilizing a liquid test medium.

(d) "Local agency" means a city, county, or fire protection district.

(e) "Rural area" means a location that lies outside the limits of any incorporated or unincorporated city or city and county, or other residential or commercial area, such as a subdivision, a business, a shopping center, or a community development.

(f) "Gathering line" means a pipeline eight inches or less in nominal diameter that transports petroleum from a production facility.

(g) "Production facility" means piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation, or treatment of petroleum or associated storage or measurement. To be a production facility under this definition, piping or equipment must be used in the process of extracting petroleum from the ground and transporting it by pipeline.

(h) "Public drinking water well" means a wellhead that provides drinking water to a public water system as defined in Section 116275 of the Health and Safety Code, that is regulated by the State Department of Public Health and that is subject to Section 116455 of the Health and Safety Code.

(i) "GIS mapping system" means a geographical information system that will collect, store, retrieve, analyze, and display environmental geographical data in a database that is accessible to the public.

(j) "Motor vehicle fuel" includes gasoline, natural gasoline, blends of gasoline and alcohol, or gasoline and oxygenates, and any inflammable liquid, by whatever name the liquid may be known or sold, which is used or is usable for propelling motor vehicles operated by the explosion type engine. It does not include kerosene, liquefied petroleum gas, or natural gas in liquid or gaseous form.

(k) "Oxygenate" means an organic compound containing oxygen that has been approved by the United States Environmental Protection Agency as a gasoline additive to meet the requirements for an "oxygenated fuel" pursuant to Section 7545 of Title 42 of the United States Code.

(Amended by Stats. 2022, Ch. 536, Sec. 2. (AB 2931) Effective January 1, 2023.)

51010.6. Notwithstanding Section 51010.5, that portion of an interstate pipeline that is located within this state and is subject to an agreement between the United States Secretary of Transportation and the State Fire Marshal is subject to the federal Hazardous Liquid Pipeline Safety Act of 1979 (49 U.S.C. Sec. 60101 et seq.).

(Amended by Stats. 2022, Ch. 536, Sec. 3. (AB 2931) Effective January 1, 2023.)

51011. (a) The State Fire Marshal shall adopt hazardous liquid pipeline safety regulations in compliance with the

federal law relating to hazardous liquid pipeline safety, including, but not limited to, compliance orders, penalties, and inspection and maintenance provisions, and including amendments to those laws and regulations that may be hereafter enacted and adopted. Regulations adopting the minimum standards for hazardous liquid pipelines contained in the federal Hazardous Liquid Pipeline Safety Act of 1979 (49 U.S.C. Sec. 60101 et seq.), and Title 49 of the Code of Federal Regulations, by the State Fire Marshal are exempt from the procedures specified in Article 5 (commencing with Section 11346) of Chapter 3.5 of Part 1 of Division 3 of Title 2, except that those regulations shall be submitted to the Office of Administrative Law for filing with the Secretary of State and publication in the California Code of Regulations.

(b) The State Fire Marshal may exempt the application of regulations adopted pursuant to this section to any pipeline, or portion thereof, when it is determined that the risk to public safety is slight and the probability of injury or damage remote.

(c) Notification of exemptions shall be written, and shall include a discussion of those factors that the State Fire Marshal considers significant to the granting of the exemption.

(Amended by Stats. 2022, Ch. 536, Sec. 4. (AB 2931) Effective January 1, 2023.)

51012. The State Fire Marshal shall establish a Pipeline Safety Advisory Committee for purposes of informing local agencies and every pipeline operator of changes in applicable laws and regulations affecting the operations of pipelines and reviewing proposed hazardous liquid pipeline safety regulations adopted pursuant to Section 51011.

The committee shall be composed of eight members of whom two shall represent pipeline operators, three shall represent local agencies, one shall be a fire chief, and two shall be public members. The committee shall meet when requested by the State Fire Marshal, but not less than once a year. The members shall be paid expenses and one hundred dollars ($100) per diem for each meeting.

(Amended by Stats. 1989, Ch. 1252, Sec. 1.)

51012.4. (a) Notwithstanding any other provision of this chapter, including, but not limited to, Section 51012.3, each pipeline operator shall file with the State Fire Marshal, on or before July 1, 2000, an inspection, maintenance, improvement, or replacement assessment for the following:

(1) Any pipeline or pipeline segments built before January 1, 1960.

(2) Any pipeline installed on or after January 1, 1960, for which regular internal inspections cannot be conducted, or which shows diminished integrity due to corrosion or inadequate cathodic protection.

(b) When preparing any assessment required by subdivision (a), the operator shall give priority to older pipelines located in densely populated areas, pipelines with a high-leak history, pipelines located near existing seismic fault lines, or, pipelines in areas with identified ground formations.

(c) On or before January 1, 1998, the State Fire Marshal, in consultation with the Pipeline Safety Advisory Committee and pipeline operators, shall establish evaluation criteria for use by a pipeline operator when conducting any assessment required by subdivision (a).

(d) A pipeline inspection, maintenance, improvement, or replacement assessment developed pursuant to this section may incorporate any information on regulatory requirements or existing public policies that could act as barriers to the inspection, maintenance, improvement, or replacement of pipelines, including, but not limited to, findings from the studies required pursuant to Section 51015.05.

(e) Nothing in this section is intended to require the replacement of a pipeline.

(Added by Stats. 1996, Ch. 973, Sec. 2. Effective January 1, 1997.)

51013. (a) Any new pipeline constructed after January 1, 1984, and which normally operates under conditions of constant flow and pressure, shall be designed and constructed in accordance with Subparts C and D of Part 195 of Title 49 of the Code of Federal Regulations, and shall include a means of leak detection and cathodic protection which the State Fire Marshal determines is acceptable, except that any pipeline which transports by gravity or operates at a stress level of 20 percent or less of the specified minimum yield strength of the pipe shall meet these design and construction requirements on or before January 1, 1991.

(b) Any new pipeline on which construction begins after January 1, 1990, shall be designed to accommodate the passage of instrumented internal inspection devices, and shall have leak mitigation and emergency response plans and equipment as the State Fire Marshal may require. Any repairs to existing pipelines which can accommodate instrumented internal inspection devices shall be done in a manner not to interfere with the passage of these devices.

(c) Subdivision (a) does not apply to the replacement of valves and the relocation or replacement of portions of pipelines.

(d) For pipelines which cannot accommodate internal inspection devices, replacements of portions of the pipe shall be done in a manner consistent, to the extent practicable, with the eventual accommodation of instrumented internal inspection devices.

(Amended by Stats. 1989, Ch. 1277, Sec. 3.)

51013.1. (a) By January 1, 2018, any new or replacement pipeline near environmentally and ecologically sensitive areas in the coastal zone shall use best available technology, including, but not limited to, the installation of leak detection technology, automatic shutoff systems, or remote controlled sectionalized block valves, or any combination of these technologies, based on a risk analysis conducted by the operator, to reduce the amount of oil released in an oil spill to protect state waters and wildlife.

(b) (1) By July 1, 2018, an operator of an existing pipeline near environmentally and ecologically sensitive areas in the coastal zone shall submit a plan to retrofit, by January 1, 2020, existing pipelines near environmentally and ecologically sensitive areas in the coastal zone with the best available technology, including, but not limited to, installation of leak detection technologies, automatic shutoff systems, or remote controlled sectionalized block valves, or any combination of these technologies, based on a risk analysis conducted by the operator to reduce the amount of oil released in an oil spill to protect state waters and wildlife.

(2) An operator may request confidential treatment of information submitted in the plan required by paragraph (1) or contained in any documents associated with the risk analysis described in this section, including, but not limited to, information regarding the proposed location of automatic shutoff valves or remote controlled sectionalized block valves.

(c) The State Fire Marshal shall adopt regulations pursuant to this section by July 1, 2017. The regulations shall include, but not be limited to, all of the following:

(1) A definition of automatic shutoff systems.

(2) A process to assess the adequacy of the operator's risk analysis.

(3) A process by which an operator may request confidential treatment of information submitted in the plan required by paragraph (1) of subdivision (b) or contained in any documents associated with the risk analysis described in this section.

(4) A determination of how near to an environmentally and ecologically sensitive area a pipeline must be to be subject to the requirements of this section based on the likelihood of the pipeline impacting those areas.

(d) An operator of a pipeline near environmentally and ecologically sensitive areas in the coastal zone shall notify the Office of the State Fire Marshal of any new construction or retrofit of pipeline in these waters.

(e) For purposes of implementing this section, the State Fire Marshal shall consult with the Office of Spill Prevention and Response about the potential impacts to state water and wildlife.

(f) For purposes of this section, "environmentally and ecologically sensitive areas" is the same term as described in subdivision (d) of Section 8574.7.

(g) (1) For purposes of this section, "best available technology" means technology that provides the greatest degree of protection by limiting the quantity of release in the event of a spill, taking into consideration whether the processes are currently in use and could be purchased anywhere in the world.

(2) The State Fire Marshal shall determine what is the best available technology and shall consider the effectiveness and engineering feasibility of the technology when making this determination.

(h) For the purposes of this section, "oil" means hazardous liquid as defined in Section 195.2 of Title 49 of the Code of Federal Regulations.

(Amended by Stats. 2016, Ch. 341, Sec. 1. (SB 840) Effective September 13, 2016.)

51013.5. (a) Every newly constructed pipeline, existing pipeline, or part of a pipeline system that has been relocated or replaced, and every pipeline that transports a hazardous liquid substance or highly volatile liquid substance, shall be tested in accordance with Subpart E (commencing with Section 195.300) of Part 195 of Title 49 of the Code of Federal Regulations.

(b) Every pipeline not provided with properly sized automatic pressure relief devices or properly designed pressure limiting devices shall be hydrostatically tested annually.

(c) Every pipeline over 10 years of age and not provided with effective cathodic protection shall be hydrostatically tested every three years, except for those on the State Fire Marshal's list of higher risk pipelines, which shall be hydrostatically tested annually.

(d) Every pipeline over 10 years of age and provided with effective cathodic protection shall be hydrostatically tested every five years, except for those on the State Fire Marshal's list of higher risk pipelines which shall be hydrostatically tested every two years.

(e) Piping within a refined products bulk loading facility served by pipeline shall be tested hydrostatically at 125 percent of maximum allowable operating pressure utilizing the product ordinarily transported in that piping if that piping is operated at a stress level of 20 percent or less of the specified minimum yield strength of the pipe. The frequency for pressure testing these pipelines shall be every five years for those pipelines with effective cathodic protection and every three years for those pipelines without effective cathodic protection. If that piping is observable, visual inspection may be the method of testing.

(f) Beginning on July 1, 1990, and continuing until the regulations adopted by the State Fire Marshal pursuant to subdivision (g) take effect, each pipeline within the State Fire Marshal's jurisdiction which satisfies any of the following sets of criteria shall be placed on the State Fire Marshal's list of higher risk pipelines until five years pass without a reportable leak due to corrosion or defect on that pipeline. Initially, pipelines on that list shall be tested by the next scheduled test date, or within two years of being placed on the list, whichever is first. On July 1, 1990, pipeline operators shall provide the State Fire Marshal with a list of all their pipelines which satisfy the criteria in this subdivision as of July 1, 1990. If any pipeline becomes eligible for the list of higher risk pipelines after that date, the pipeline company shall report that fact to the State Fire Marshal within 30 days, and the pipeline shall be placed on the list retroactively to the date on which it became eligible for listing. Pipelines which are found to belong on the list, but are not so reported by the operator to the State Fire Marshal, shall be placed on the list retroactively. Operators failing to properly report their pipelines shall be subject to penalties under Section 51018.6. Pipelines not covered under the risk criteria developed pursuant to subdivision (g) shall be deleted from the list when regulations are adopted pursuant to that subdivision. For purposes of this subdivision, a leak which is traceable to an external force, but for which corrosion is partly responsible, shall be deemed caused by corrosion, "defect" refers to manufacturing or construction defects, and "leak" or "reportable leak" means a rupture required to be reported pursuant to Section 51018. As long as all pipelines are tested in their entirety at least as frequently as standard risk pipelines under subdivisions (c) and (d), it shall suffice for additional tests on higher risk pipelines to cover 20 pipeline miles in all directions along an operator's pipeline from the position of the leak or leaks which led to the inclusion or retention of that pipeline on the higher risk list. The interim list shall include pipelines which meet any of the following criteria:

(1) Have suffered two or more reportable leaks, not including leaks during a certified hydrostatic pressure test, due to corrosion or defect in the prior three years.

(2) Have suffered three or more reportable leaks, not including leaks during a certified hydrostatic pressure test, due to corrosion, defects, or external forces, but not all due to external forces, in the prior three years.

(3) Have suffered a reportable leak, except during a certified hydrostatic pressure test, due to corrosion or defect of more than 50,000 gallons, or 10,000 gallons in a standard metropolitan statistical area, in the prior three years; or have suffered a leak due to corrosion or defect which the State Fire Marshal finds has resulted in more than 42 gallons of a hazardous liquid within the State Fire Marshal's jurisdiction entering a waterway in the prior three years; or have suffered a reportable leak of a hazardous liquid with a flashpoint of less than 140 degrees Fahrenheit, or 60 degrees centigrade, in the prior three years.

(4) Are less than 50 miles long, and have experienced a reportable leak, except during a certified hydrostatic pressure test, due to corrosion or a defect in the prior three years. For the purposes of this paragraph, the length of a pipeline with more than two termini shall be the longest distance between two termini along the pipeline.

(5) Have experienced a reportable leak in the prior five years due to corrosion or defect, except during a certified hydrostatic pressure test, on a section of pipe more than 50 years old. For pipelines which fall in this category, and no other category of higher risk pipeline, additional tests required by this subdivision shall be required only on segments of the pipe more than 50 years old as long as all pipe more than 50 years old which is within 20 pipeline miles from the leak in all directions along an operator's pipeline is tested.

(g) The State Fire Marshal shall study indicators and precursors of serious pipeline accidents, and, in consultation with the Pipeline Safety Advisory Committee, shall develop criteria for identifying which hazardous liquid pipelines pose the greatest risk to people and the environment due to the likelihood of, and likely seriousness of, an accident due to corrosion or defect. The study shall give due consideration to research done by the industry, the federal government, academia, and to any other information which the State Fire Marshal shall deem relevant, including,

but not limited to, recent leak history, pipeline location, and materials transported. Beginning January 1, 1992, using the criteria identified in that study, the State Fire Marshal shall maintain a list of higher risk pipelines, which exceed a standard of risk to be determined by the State Fire Marshal, and which shall be tested as required in subdivisions (c) and (d) as long as they remain on the list. By January 1, 1992, after public hearings, the State Fire Marshal shall adopt regulations to implement this subdivision.

(h) In addition to the requirements of subdivisions (a) to (e), inclusive, the State Fire Marshal may require any pipeline subject to this chapter to be subjected to a pressure test, or any other test or inspection, at any time, in the interest of public safety.

(i) Test methods other than the hydrostatic tests required by subdivisions (b), (c), (d), and (e), including inspection by instrumented internal inspection devices, may be approved by the State Fire Marshal on an individual basis. If the State Fire Marshal approves an alternative to a pressure test in an individual case, the State Fire Marshal may require that the alternative test be given more frequently than the testing frequencies specified in subdivisions (b), (c), (d), and (e).

(j) The State Fire Marshal shall adopt regulations before January 1, 1992, to establish what the State Fire Marshal deems to be an appropriate frequency for tests and inspections, including instrumented internal inspections, which, when permitted as a substitute for tests required under subdivisions (b), (c), and (d), do not damage pipelines or require them to be shut down for the testing period. That testing shall in no event be less frequent than is required by subdivisions (b), (c), and (d). Each time one of these tests is required on a pipeline, it shall be approved on the same individual basis as under subdivision (i). If it is not approved, a hydrostatic test shall be carried out at the time the alternative test would have been carried out, and subsequent tests shall be carried out in accordance with the time intervals prescribed by subdivision (b), (c), or (d), as applicable.

(Amended by Stats. 1991, Ch. 395, Sec. 2.)

51014. (a) The pressure tests required by subdivisions (b), (c), and (d) of Section 51013.5 shall be conducted in accordance with Subpart E (commencing with Section 195.300) of Part 195 of Title 49 of the Code of Federal Regulations, except that an additional four-hour leak test, as specified in Section 195.302(c) of Title 49 of the Code of Federal Regulations, shall not be required under subdivisions (b), (c), and (d) of Section 51013.5. The State Fire Marshal may authorize the use of liquid petroleum having a flashpoint over 140 degrees Fahrenheit or 60 degrees Centigrade as the test medium. The State Fire Marshal shall make these authorizations in writing.

(b) Test pressure shall be at least 125 percent of the actual pipeline operating pressure.

(Amended by Stats. 2022, Ch. 536, Sec. 6. (AB 2931) Effective January 1, 2023.)

51014.3. (a) Each pipeline operator shall notify the State Fire Marshal and the local fire department having fire suppression responsibilities at least three working days prior to conducting a hydrostatic test which is required by this chapter. The notification shall include all of the following information:

(1) The name, address, and telephone number of the pipeline operator.

(2) The specific location of the pipeline section to be tested and the location of the test equipment.

(3) The date and time the test is to be conducted.

(4) An invitation and a telephone number for local fire departments to call for further information on what they should do in the event of a leak during testing.

(5) The test medium.

(6) The name and telephone number of the independent testing firm or person responsible for certification of the test results.

(b) The State Fire Marshal may observe tests conducted pursuant to this chapter.

(Amended by Stats. 1989, Ch. 1277, Sec. 5.5.)

51014.5. (a) When hydrostatic testing is required by Section 51013.5, the test results shall be certified by an independent testing firm or person who is selected from a list, provided by the State Fire Marshal, of independent testing firms or persons approved annually by the State Fire Marshal. The State Fire Marshal may charge a fee for consideration and approval of an independent testing firm or person pursuant to this subdivision, not to exceed the reasonable costs of that consideration and approval.

(b) The results of the tests required by Section 51013.5 shall be submitted by the independent testing firm or person within 30 days after completion of the test to the State Fire Marshal, who may review the results. The report

shall show all of the following information:

(1) The date of the test.

(2) A description of the pipeline tested including a map of suitable scale showing the route of the pipeline.

(3) The results of the test.

(4) Any other test information that may be specifically requested by the State Fire Marshal.

(c) The State Fire Marshal shall not supervise, control, or otherwise direct the testing.

(Amended by Stats. 1988, Ch. 995, Sec. 3.)

51014.6. (a) Effective January 1, 1987, no person, other than the pipeline operator, shall do any of the following with respect to any pipeline easement:

(1) Build, erect, or create a structure or improvement within the pipeline easement or permit the building, erection, or creation thereof.

(2) Build, erect, or create a structure, fence, wall, or obstruction adjacent to any pipeline easement which would prevent complete and unimpaired surface access to the easement, or permit the building, erection, or creation thereof.

(b) No shrubbery or shielding shall be installed on the pipeline easement which would impair aerial observation of the pipeline easement. This subdivision does not prevent the revegetation of any landscape disturbed within a pipeline easement as a result of constructing the pipeline and does not prevent the holder of the underlying fee interest or the holder's tenant from planting and harvesting seasonal agricultural crops on a pipeline easement.

(c) This section does not prohibit a pipeline operator from performing any necessary activities within a pipeline easement, including, but not limited to, the construction, replacement, relocation, repair, or operation of the pipeline.

(Amended by Stats. 1986, Ch. 1401, Sec. 5.)

51015. (a) A pipeline operator shall provide to the fire department having fire suppression responsibilities a map or suitable diagram showing the location of the pipeline, a description of all products transported within the pipeline, and a contingency plan for pipeline emergencies that shall include, but not be limited to, any reasonable information that the State Fire Marshal may require.

(b) The State Fire Marshal, for purposes of carrying out the requirements of state or federal law relating to hazardous liquid pipeline safety, including, but not limited to, developing or assisting in the development of pipeline standards or regulations, determining compliance with this chapter, or carrying out any requirement of this chapter, may require the owner or operator of a pipeline to do the following:

(1) Establish and maintain records specified by the State Fire Marshal.

(2) Make reports pursuant to methods and in a manner specified by the State Fire Marshal.

(3) Provide any information that the State Fire Marshal may reasonably require, including, but not limited to, maps, written procedures, accident reporting, or information on design, construction, testing, or operation and maintenance.

(c) The State Fire Marshal, or an officer or employee authorized by the State Fire Marshal, at any reasonable time, upon presentation of credentials, shall have a right of entry to, upon, or through any premises on which records, reports, or any other information required to be maintained pursuant to this chapter are located and may access and copy those records, reports, or other information.

(d) The State Fire Marshal may disclose records, reports, or other information required to be maintained pursuant to this chapter to an officer, employee, or authorized representative of the state or the United States for purposes of carrying out the requirements of this chapter or the federal Hazardous Liquid Pipeline Safety Act of 1979 (49 U.S.C. Sec. 60101 et seq.), or when relevant to a proceeding pursuant to this chapter.

(e) A pipeline operator shall offer to meet with the local fire department having fire suppression responsibilities at least once each calendar year to discuss and review contingency plans for pipeline emergencies.

(Amended by Stats. 2022, Ch. 536, Sec. 7. (AB 2931) Effective January 1, 2023.)

51015.05. (a) The State Fire Marshal shall establish and maintain a centralized database containing information and

data regarding the following intrastate pipelines:

(1) Pipelines used for the transportation of crude oil that operate by gravity or at a stress level of 20 percent or less of the specified minimum yield strength of the pipe.

(2) Pipelines used for the transportation of petroleum in onshore gathering lines located in rural areas.

(b) The database shall include, but is not limited to, an inventory of the pipelines described in subdivision (a), including pipeline locations, ownership, ages, and inspection histories, that are in the possession of the owner or operator of the oil field or other gas facility.

(c) The State Fire Marshal shall regularly update the database and shall make the information in the database available to the public, and to all local, state, and federal agencies.

(d) A state or local governmental agency that regulates, supervises, or exerts authority over a pipeline described in subdivision (a) shall report any information or data specified in subdivision (b) in its possession to the State Fire Marshal. That information shall be submitted to the State Fire Marshal in a computer compatible format.

(e) The State Fire Marshal shall conduct a study of the fitness and safety of all pipelines described in subdivision (a), and investigate incentive options that would encourage pipeline replacement or improvements, including, but not limited to, a review of existing regulatory, permit, and environmental impact report requirements and other existing public policies, as may be identified by the Pipeline Safety Advisory Committee and adopted by the State Fire Marshal, that could act as barriers to the replacement or improvement of those pipelines.

(Amended by Stats. 2022, Ch. 536, Sec. 8. (AB 2931) Effective January 1, 2023.)

51015.1. (a) Commencing January 1, 2017, the State Fire Marshal, or an officer or employee authorized by the State Fire Marshal, shall annually inspect all intrastate pipelines and operators of intrastate pipelines under the jurisdiction of the State Fire Marshal to ensure compliance with applicable laws and regulations. By January 1, 2017, the State Fire Marshal shall adopt regulations implementing this subdivision.

(b) For portions of interstate pipelines that are not under the jurisdiction of the State Fire Marshal pursuant to Section 51010.6, the State Fire Marshal shall not become an inspection agent for those pipelines unless all regulatory and enforcement authority over those pipelines is transferred to the State Fire Marshal from the federal Pipeline and Hazardous Materials Safety Administration.

(c) The State Fire Marshal shall revise the fee assessed pursuant to Section 51019 to a level sufficient to cover the costs associated with the implementation of this section.

(Added by Stats. 2015, Ch. 607, Sec. 1. (SB 295) Effective January 1, 2016.)

51015.2. (a) The Legislature recognizes that hazardous liquid pipelines are often located alongside and in the immediate proximity of rail lines. In the event of a derailment, these pipelines may be damaged in such a fashion that their integrity is lost, making a rupture or leak more likely.

(b) In an effort to better protect public safety, the State Fire Marshal shall adopt regulations governing the construction, testing, operations, periodic inspection, and emergency operations of intrastate hazardous liquid pipelines located within 500 feet of any rail line. These regulations shall, at a minimum, include provisions dealing with the following:

(1) Minimum depth of cover for newly constructed or reconstructed pipelines.

(2) Minimum hydrostatic testing requirements for newly constructed pipelines.

(3) Minimum requirements for testing existing pipelines which may have been affected by a derailment.

(4) Minimum requirements for periodic inspections.

(5) Minimum requirements for installation and operation of safety or check valves.

(6) Procedures for developing, testing, approving, and implementing coordinated emergency contingency plans prepared by pipeline and rail operators. These procedures shall also provide for consultation with local affected agencies, and require pipeline and rail operations to develop and implement emergency training for their employees approved by the State Fire Marshal.

(Added by Stats. 1989, Ch. 1252, Sec. 3.)

51015.3. The State Fire Marshal may, in the interest of public safety, adopt emergency regulations which govern intrastate pipeline emergencies involving railroad car derailments. Any hazardous liquid pipeline located in a rural

area shall be exempt from these regulations. Notwithstanding any other provision of law, these emergency regulations shall remain in effect until permanent regulations provided for in Section 51015.2 are adopted, but in no case beyond January 1, 1995.

(Added by Stats. 1989, Ch. 1252, Sec. 4.)

51015.4. (a) Each operator shall, as specified in regulations provided for in subdivision (c), maintain each valve and check valve that is necessary for the safe operation of its pipeline systems in good working order at all times.

(b) Each operator shall provide protection for each valve and check valve from unauthorized operation and from vandalism.

(c) The State Fire Marshal shall adopt regulations, not later than June 30, 1991, which establish procedures for maintaining, testing, and inspecting mainline valves and check valves on intrastate hazardous liquid pipelines.

(Added by Stats. 1989, Ch. 1252, Sec. 5.)

51015.5. (a) In the event of an intrastate pipeline rupture, leak, or other incident which could affect safe pipeline operation, any person who performs or intends to perform nonemergency site cleanup, repair, reconstruction, or any other alteration shall obtain prior approval from the State Fire Marshal.

(b) Approval by the State Fire Marshal of a repair plan, submitted by a pipeline operator in conformance with contingency plan requirements established by the State Fire Marshal, shall constitute prior approval to perform repairs as specified in subdivision (a).

(c) The State Fire Marshal may adopt regulations to implement subdivisions (a) and (b).

(Added by Stats. 1989, Ch. 1252, Sec. 6.)

51015.6. (a) On or before January 31, 2017, and on or before January 31 annually thereafter, the State Fire Marshal shall submit a report to the Legislature containing information, including, but not limited to, all of the following:

(1) The number of annual inspections conducted pursuant to Section 51015.1.

(2) The status of the installation of automatic shutoff systems pursuant to Section 51013.1, including a summary of the types of shutoff systems installed, and the number of miles of pipeline covered by an automatic shutoff system.

(3) The status of Line 901 and Line 903 in the County of Santa Barbara.

(b) (1) A report required to be submitted pursuant to subdivision (a) shall be submitted in compliance with Section 9795.

(2) Pursuant to Section 10231.5, this section is inoperative on January 31, 2021.

(Added by Stats. 2016, Ch. 341, Sec. 2. (SB 840) Effective September 13, 2016. Inoperative January 31, 2021, by its own provisions.)

51016. The State Fire Marshal shall study the spacing of valves which would limit spillage into standard metropolitan statistical areas and environmentally sensitive areas from surrounding higher ground. If any existing pipeline system's valve spacing is deemed insufficient to protect California's uniquely situated population centers and environmental resources, the State Fire Marshal shall adopt regulations to require the addition of valves on existing pipelines. If the study indicates that guidelines for valve spacing do not, in the State Fire Marshal's opinion, adequately protect these population centers and environmental resources, the State Fire Marshal may adopt regulations to require new valves on new, existing, or replacement pipelines as necessary to protect the public interest.

(Added by Stats. 1989, Ch. 1277, Sec. 6.5.)

51017. The State Fire Marshal shall develop a comprehensive database of pipeline information that can be used for emergency response and program operational purposes. The database shall include information on pipeline location, age, reported leak incidences, and inspection history, and shall have the capability of mapping pipeline locations throughout the state. The data collection format shall be compatible with any pipeline mapping project implemented by the United States Department of Transportation's Office of Pipeline Safety and shall be compatible with GIS mapping and data management required by Article 12 (commencing with Section 25299.97) of Chapter 6.75 of Division 20 of the Health and Safety Code.

(Amended by Stats. 2022, Ch. 536, Sec. 9. (AB 2931) Effective January 1, 2023.)

51017.1. (a) Utilizing GIS-based location information furnished by the State Department of Health Services and the State Water Resources Control Board, at least once every two years the State Fire Marshal shall determine the identity of each pipeline or pipeline segment that is regulated by the State Fire Marshal pursuant to this chapter that transports petroleum product when that pipeline is located within 1,000 feet of a public drinking water well.

(b) With assistance from the State Department of Health Services and the State Water Resources Control Board, the State Fire Marshal shall notify the operator of the pipelines identified in subdivision (a) of the following information:

(1) That the specific pipeline or pipeline segment has been identified as being located within 1,000 feet of a public drinking water well.

(2) The name of the water purveyor and the location of the public drinking water well affected. With advice from the GIS mapping advisory committee, created pursuant to subdivision (b) of Section 25299.97 of the Health and Safety Code, the identification of the pipelines and notification of pipeline owners by the State Fire Marshal pursuant to subdivision (a) and this subdivision shall begin once the GIS mapping system created by Section 25299.97 of the Health and Safety Code is able to provide accurate and useful information on pipeline and wellhead locations.

(c) Each pipeline operator notified pursuant to subdivision (b) shall prepare a pipeline wellhead protection plan as required by Section 51017.2 and submit the plan to the State Fire Marshal within 180 days from the date of either receiving the notification specified in subdivision (b), or adoption of regulations by the State Fire Marshal pursuant to Section 51017.2, whichever is later.

(d) With the advice of the State Department of Health Services, the State Water Resources Control Board, appropriate California regional water quality control boards, and local water purveyors, the State Fire Marshal shall review each wellhead protection plan submitted by a pipeline operator, and approve those plans that meet the criteria of the regulations adopted by the State Fire Marshal pursuant to Section 51017.2. The State Fire Marshal shall have discretion to allow a wellhead protection plan to address multiple wellheads where the conditions creating the risk to the wellheads are substantially similar. The pipeline operator shall implement the wellhead protection plan within 180 days from the date of receiving approval from the State Fire Marshal.

(e) Each pipeline operator having a wellhead protection plan approved by the State Fire Marshal pursuant to subdivision (d) shall evaluate that plan at least once every five years to ensure that the plan is in compliance with the current regulations established by the State Fire Marshal pursuant to Section 51017.2. The pipeline operator shall provide either written documentation to the State Fire Marshal that the previously approved wellhead protection plan has been evaluated and that no changes are warranted, or submit a new wellhead protection plan to remain in compliance with existing regulations or to meet the requirements of regulations adopted since the plan was approved.

(f) The pipeline operator subject to subdivision (c) may petition the State Fire Marshal in writing for an exemption from the requirements of subdivision (c). With advice from the State Water Resources Control Board, the State Department of Health Services, the California regional water quality control boards, and local water purveyors, the State Fire Marshal may approve the exemption if the petition demonstrates that the pipeline either does not transport motor vehicle fuel, or does not pose a significant threat to the public drinking water well based upon, but not limited to, the following criteria:

(1) Pipeline parameters, such as operation pressure, operating temperature, age, design, fabrication materials, construction, corrosive nature of the surrounding soil, cathodic protection, and feasibility of internal inspection or evaluation tools (smart pigs).

(2) Hydrogeologic parameters, such as soil permeability, direction and velocity of groundwater flow, aquifer location or depth, and hydrogeologic barriers or conduits.

(3) Water well parameters, such as depth of well and well construction.

(4) The nature of the fuel and its ability to migrate to public drinking water wells.

(5) The impact of human activity that may elevate or reduce the risk to the drinking water well.

(Amended by Stats. 1998, Ch. 485, Sec. 91. Effective January 1, 1999.)

51017.2. (a) With advice from the Pipeline Safety Advisory Committee, the State Water Resources Control Board, the California regional water quality control boards, and local water purveyors, the State Fire Marshal shall adopt regulations for wellhead protection plans that provide guidelines to be used by the pipeline operator as specified in Section 51017.1 to protect the public drinking water well from contamination should a pipeline rupture or leak pose a significant threat to a public drinking water well, taking into account the nature of the fuel and its ability to

migrate to a public drinking water well. The regulations adopted by the State Fire Marshal shall require each plan to contain adequate and effective measures that are technologically feasible, practical, and operationally sound that protect public drinking water wells. At a minimum, the wellhead protection plan shall contain the following:

(1) Operational activities that provide the pipeline operator with sufficient information to adequately ensure the integrity of the pipeline. These may include internal inspection or evaluation tools (smart pigs), substructure excavation (potholing), well monitoring, additional or more frequent pressure tests, cathodic protection surveys or visual inspections, or other technologies as appropriate.

(2) Response measures that will enhance the pipeline operator's response to an emergency, such as a pipeline rupture, fire, earthquake, or flood. These measures may include activities, such as additional training for operator staff or improved coordination with emergency response agencies.

(b) At least once every five years, the State Fire Marshal, with the advice of the Pipeline Safety Advisory Committee, the State Water Resources Control Board, the California regional water quality control boards, and local water purveyors, shall review the regulations adopted pursuant to subdivision (a) to determine if new measures that have been proven to be technologically feasible, practical, and operationally sound should be included in the regulations. The State Fire Marshal shall adopt new regulations if such new measures are identified.

(Added by Stats. 1997, Ch. 814, Sec. 5. Effective January 1, 1998.)

51018. (a) Every rupture, explosion, or fire involving a pipeline, including a pipeline system otherwise exempted by subdivision (a) of Section 51010.5, and including a pipeline undergoing testing, shall be immediately reported by the pipeline operator to the fire department having fire suppression responsibilities and to the Office of Emergency Services.

(b) (1) The Office of Emergency Services shall immediately notify the State Fire Marshal of the incident, who shall immediately dispatch State Fire Marshal employees to the scene. The State Fire Marshal or the employees, upon arrival, shall provide technical expertise and advise the operator and all public agencies on activities needed to mitigate the hazard.

(2) For purposes of this subdivision, the Legislature does not intend to hinder or disrupt the workings of the "incident commander system," but does intend to establish a recognized element of expertise and direction for the incident command to consult and acknowledge as an authority on the subject of pipeline incident mitigation. Furthermore, it is expected that the State Fire Marshal will recognize the expertise of the pipeline operator and any other emergency agency personnel who may be familiar with the particular location of the incident and respect their knowledgeable input regarding the mitigation of the incident.

(c) For purposes of this section, "rupture" includes every unintentional liquid leak, including any leak that occurs during hydrostatic testing, except that a crude oil leak of less than five barrels from a pipeline or flow line in a rural area, or any crude oil or petroleum product leak in any in-plant piping system of less than five barrels, when no fire, explosion, or bodily injury results or no waterway is contaminated thereby, does not constitute a rupture for purposes of the reporting requirements of subdivision (a).

(d) This section does not preempt any other applicable federal or state reporting requirement.

(e) Except as otherwise provided in this section and Section 8589.7, a notification made pursuant to this section shall satisfy any immediate notification requirement contained in any permit issued by a permitting agency.

(f) This section does not apply to pipeline ruptures involving nonreportable crude oil spills under Section 3233 of the Public Resources Code, unless the spill involves a fire or explosion.

(Amended by Stats. 2022, Ch. 536, Sec. 10. (AB 2931) Effective January 1, 2023.)

51018.6. (a) The State Fire Marshal shall adopt regulations for conducting enforcement proceedings pursuant to this section. These regulations shall include provisions for the service and the content of the notice of probable violation, response options, conduct of hearings, issuing of the final order, amended final order, and petitions for reconsideration and compromise of penalties, and shall be consistent with the procedures specified in Subpart B (commencing with Section 190.201) of Part 190 of Title 49 of the Code of Federal Regulations.

(b) If the State Fire Marshal determines, pursuant to the regulations adopted pursuant to subdivision (a), that a person has violated this chapter or any regulation adopted pursuant thereto, that person is subject to a civil penalty not to exceed the amount specified in Section 190.223(a) of Title 49 of the Code of Federal Regulations.

(c) The amount of the penalty shall be assessed by the State Fire Marshal pursuant to the regulations adopted pursuant to subdivision (a). In determining the amount of the penalty, the State Fire Marshal shall consider the nature, circumstances, and gravity of the violation and, with respect to the person found to have committed the

violation, the degree of culpability, any history of prior violations, the effect on ability to continue to do business, any good faith attempts to achieve compliance, ability to pay the penalty, and any other matters as justice may require.

(d) A civil penalty assessed under subdivision (b) may be recovered in an action brought by the Attorney General on behalf of the state. Prior to referring the penalty action to the Attorney General, the State Fire Marshal may accept an offer to compromise the amount of the assessed penalty pursuant to the regulations adopted pursuant to subdivision (a).

(e) The State Fire Marshal shall deposit all civil penalties assessed pursuant to this section in the Local Training Account in the California Hazardous Liquid Pipeline Safety Fund. The money in the Local Training Account is available, upon appropriation by the Legislature, to the State Fire Marshal, who shall use the money for providing hazardous liquid fire suppression training to local fire departments.

(Amended by Stats. 2022, Ch. 536, Sec. 11. (AB 2931) Effective January 1, 2023.)

51018.7. (a) Any person who willfully and knowingly violates any provision of this chapter or a regulation issued pursuant thereto shall, upon conviction, be subject, for each offense, to a fine of not more than twenty-five thousand dollars ($25,000), imprisonment in a county jail for not more than one year, imprisonment pursuant to subdivision (h) of Section 1170 of the Penal Code, or by both that fine and imprisonment.

(b) Any person who willfully and knowingly defaces, damages, removes, or destroys any pipeline sign or right-of-way marker required by federal or state law or regulation shall, upon conviction, be subject, for each offense, to a fine of not more than five thousand dollars ($5,000), imprisonment in a county jail for not more than one year, or by both that fine and imprisonment.

(Amended by Stats. 2011, Ch. 15, Sec. 134. (AB 109) Effective April 4, 2011. Operative October 1, 2011, by Sec. 636 of Ch. 15, as amended by Stats. 2011, Ch. 39, Sec. 68.)

51018.8. The State Fire Marshal may issue orders directing compliance with this chapter or any regulations adopted pursuant thereto. The State Fire Marshal shall specify in the order the particular action which is required of the person issued the order.

(Added by Stats. 1983, Ch. 1222, Sec. 18. Effective September 30, 1983.)

51019. The State Fire Marshal may assess and collect from every pipeline operator an annual fee for the purpose of carrying out this chapter. The State Fire Marshal may assess this fee for expenses which will be incurred during the following year. A pipeline operator shall pay this fee when billed by the State Fire Marshal. The State Fire Marshal may impose a delinquency fee of 10 percent of the annual fee if the pipeline operator does not pay the fee within 60 days after receipt of the bill, and, in addition, the pipeline operator shall pay interest on that portion of its annual fee not paid within 60 days at the rate of 15 percent per annum from the date of receipt of the bill until paid. The total amount of the fee collected shall not exceed the actual expenses incurred, or the estimated expenses which will be incurred, by the State Fire Marshal in carrying out this chapter.

(Amended by Stats. 1988, Ch. 995, Sec. 9.)

51019.05. If the agreement specified in Section 51010.6 is entered into, the State Fire Marshal may assess and collect, from every operator of an interstate pipeline having a portion thereof located within this state, as described in the agreement, an annual fee for the purpose of carrying out this chapter. The State Fire Marshal may assess this fee for expenses which will be incurred during the following year. The pipeline operator shall pay this fee when billed by the State Fire Marshal.

The State Fire Marshal may impose a delinquency fee of 10 percent of the annual fee if the interstate pipeline operator does not pay the fee within 60 days after receipt of the bill, and, in addition, the interstate pipeline operator shall pay interest on that portion of its annual fee not paid within 60 days at the rate of 15 percent per annum from the date of receipt of the bill until paid.

The total amount of the fee collected pursuant to this section and Section 51019 shall not exceed the actual expenses incurred, or the estimated expenses which will be incurred, by the State Fire Marshal in carrying out this chapter.

(Added by Stats. 1986, Ch. 863, Sec. 3.)

51019.1. (a) There is hereby created the California Hazardous Liquid Pipeline Safety Fund, consisting of the Local Training Account and the Pipeline Operations Account.

(b) All fees collected pursuant to Sections 51019 and 51019.05 shall be deposited in the Pipeline Operations

Account. The money in the account is available, upon appropriation by the Legislature, to the State Fire Marshal for the purpose of carrying out this chapter.

(Amended by Stats. 1991, Ch. 395, Sec. 3.)

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- Federal Register - Pipeline Safety: Potential for Damage to Pipeline Facilities...

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- PHMSA Notice of Proposed Violation, Proposed Civil Penalty and Proposed Compliance Order to Denbury Gulf Coast Pipeline
- PHMSA Failure Investigation Report - Denbury Gulf Coast Pipelines, LLC

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PHMSA Announces New Safety Measures to Protect Americans From Carbon Dioxide Pipeline Failures After Satartia, MS Leak

Thursday, May 26, 2022

PHMSA 05-22
Contact: PHMSAPublicAffairs@dot.gov

WASHINGTON - The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) today announced it is taking steps to implement new measures to strengthen its safety oversight of carbon dioxide (CO_2) pipelines around the country and protect communities from dangerous pipeline failures. The new measures, as well as an enforcement action taken today are a result of PHMSA's investigation into a CO_2 pipeline failure in Satartia, Mississippi in 2020 that resulted in local evacuations and caused almost 50 people to seek medical attention.

To strengthen CO_2 pipeline safety, PHMSA is undertaking the following:

- initiating a new rulemaking to update standards for CO_2 pipelines, including requirements related to emergency preparedness, and response;
- issuing a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (NOPV) to Denbury Gulf Coast Pipeline, LLC for multiple probable violations of Federal pipeline safety regulations (PSRs). The proposed civil penalties amount to $3,866,734.
- completing a failure investigation report for the 2020 pipeline failure in Satartia, Mississippi;
- issuing an updated nationwide advisory bulletin to all pipeline operators underscoring the need to plan for and mitigate risks related to land-movements and geohazards that pose risks to pipeline integrity like the 2020 incident in Satartia, Mississippi; and
- conducting research solicitations to strengthen pipeline safety of CO_2 pipelines.

"I recently visited with the first responders in Satartia to hear firsthand of the pipeline failure so that we can improve safety and environmental protections for CO_2 pipelines and work to protect communities from experiences like this," said PHMSA Deputy Administrator Tristan Brown. "The safety of the American people is paramount and we're taking action to strengthen CO_2 pipeline safety standards to better protect communities, our first responders, and our environment."

PHMSA's investigation identified a number of probable violations in connection with the 2020 accident, including the following alleged failures:

- the lack of timely notification to the National Response Center to ensure the nearby communities were informed of the threat;
- the absence of written procedures for conducting normal operations, as well as those that would allow the operator to appropriately respond to emergencies, such as guidelines for communicating with emergency responders; and
- a failure to conduct routine inspections of its rights-of-way, which would have fostered a better understanding of the environmental conditions surrounding its facilities that could pose a threat to the safe operation of the pipeline.

PHMSA has longstanding and comprehensive guidance on its enforcement of PSRs as well as its civil penalties, which are calculated using a range of criteria and based on statutory limitations. Under the authorities granted by Congress, PHMSA may propose civil penalties, with the recipient of the NOPV being able to contest, contest in part, or accept them. A pipeline operator that receives a proposed civil penalty may also request and receive an informal hearing before a presiding official of the agency and prior to a proposed civil penalty being finalized. PHMSA publishes its entire history of enforcement actions online for public consumption, available here.

###

The Pipeline and Hazardous Materials Safety Administration develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's 2.8-million-mile pipeline transportation system and the nearly 1.2 million daily shipments of hazardous materials by land, sea, and air. Please visit https://www.phmsa.dot.gov for more information.

U.S. DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

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○ Are FTA's methods of stakeholder engagement sufficient? What other methods should FTA consider?

6. Workforce

Automation will not replace transit bus operators in the foreseeable future, nonetheless, transit bus automation and automated features will impact the transit workforce, including bus operators, maintenance workers, and the domestic supply chain, including bus manufacturers.

FTA seeks information from stakeholders on:

○ What activities have agencies undertaken to understand and prepare for the impacts of automation on their workforce? Please be specific and include examples where possible.

○ What types of new skills, training, and resources may be required for transit workforce development and transition?

○ What specific areas of workforce-related research should FTA consider?

○ What types of resources could FTA provide to help agencies and their workers adopt transit bus automation?

Please note, this RFI will serve as a planning document. The RFI should not be interpreted as policy, a solicitation for applications, or an obligation on the part of the Government.

Nuria I. Fernandez,

Administrator.

[FR Doc. 2022–11782 Filed 6–1–22; 8:45 am]

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DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

[Docket No. PHMSA–2022–0063]

Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), DOT.

ACTION: Notice; issuance of updated advisory bulletin.

SUMMARY: PHMSA is issuing this updated advisory bulletin to remind owners and operators of gas and hazardous liquid pipelines, including supercritical carbon dioxide pipelines, of the potential for damage to those pipeline facilities caused by earth movement in variable, steep, and rugged terrain and terrain with varied or changing subsurface geological conditions. Additionally, changing weather patterns due to climate change, including increased rainfall and higher temperatures, may impact soil stability in areas that have historically been stable. These phenomena can pose a threat to the integrity of pipeline facilities if those threats are not identified and mitigated. Owners and operators should consider monitoring geological and environmental conditions, including changing weather patterns, in proximity to their facilities.

FOR FURTHER INFORMATION CONTACT: Mary McDaniel at 202–366–4595 or *Mary.McDaniel@dot.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

The purpose of this updated advisory bulletin is to remind owners and operators of gas and hazardous liquid pipelines, particularly those with facilities located onshore or in inland waters, about the serious safety-related issues that can result from earth movement and other geological hazards. Additionally, changing weather patterns due to climate change may result in heavier than normal rainfall and increased temperatures causing soil saturation and flooding or soil erosion. Either phenomenon may adversely impact the stability of soil surrounding or supporting nearby pipeline facilities. The United States Geological Survey (USGS) is a resource for pipeline owners and operators in evaluating earth movement vulnerabilities of pipeline facilities.

Gas and hazardous liquid pipelines are required to be designed to withstand external loads including those that may be imposed by geological forces. Specifically, gas pipelines must be designed in accordance with 49 CFR 192.103 and hazardous liquid pipelines must be designed in accordance with 49 CFR 195.110. To comply with these regulations, the design of new pipelines, including repairs or replacement, must consider the load that may be imposed by geological forces.

Once operational, § 192.317(a) states that for gas transmission and part 192-regulated gathering pipelines ''[t]he operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mudslides, water currents, hurricanes, ship anchors, and fishing operations.'' This advisory bulletin addresses those protective requirements associated with damage caused by geological factors.

In addition, § 192.705 requires operators of gas transmission lines, and applicable gas gathering lines, to have a patrol program to observe surface conditions on and adjacent to the pipeline right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation. The frequency of these patrols must be based upon the size of the line, operating pressures, class locations, terrain, seasonal weather conditions, and other relevant factors. One of the primary reasons for this patrol requirement is to monitor geological movement, both slowly occurring and acute changes, which may affect the current or future safe operation of the pipeline.

Furthermore, for applicable gas pipelines § 192.613(a) states that ''each operator shall have a procedure for continuing surveillance of its facilities to determine and take appropriate action concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions.'' Section 192.613(b) further states that ''[i]f a segment of pipeline is determined to be in unsatisfactory condition but no immediate hazard exists, the operator shall initiate a program to recondition or phase out the segment involved, or, if the segment cannot be reconditioned or phased out, reduce the maximum allowable operating pressure in accordance with § 192.619(a) and (b).''

For hazardous liquid pipelines, § 195.401(b)(1) states that ''[w]henever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition.'' Section 195.401(b)(2) further states that ''[w]hen an operator discovers a condition on a pipeline covered under [the integrity management requirements in] § 195.452, the operator must correct the condition as prescribed in § 195.452(h).'' Land movement, soil instability due to saturation, severe flooding, river scour, and river channel migration are the types of conditions that can adversely affect the safe operation of a pipeline and require corrective action under §§ 192.613(a) and 195.401(b). Additional guidance for identifying risk factors and mitigating natural force

hazards on pipeline segments that could affect high consequence areas, are outlined in Appendix C, section I, subsection B, to part 195.

PHMSA integrity management regulations require operators to take additional preventative and mitigative measures to prevent, and to mitigate the consequences of, failures on gas transmission lines in high consequence areas (§ 192.935) and hazardous liquid pipelines that are in or which could affect a high consequence area (§ 195.452(i)). An operator must base the additional measures on the threats the operator has identified for each pipeline segment. If an operator determines there is a threat to the pipeline, such as outside force damage (*e.g.,* earth movement or floods), the operator must take steps to prevent a failure and to minimize the consequences of a failure under these regulations.

PHMSA is aware of recent earth movement and other geological-related incidents and accidents and safety-related conditions throughout the country. Some of the more notable events, including those discussed in a prior advisory bulletin (ADB–2019–02; 84 FR 18919, 05/02/2019) are briefly described below:

- On March 11, 2022, a 22-inch hazardous liquid pipeline spilled 3,900 barrels of crude oil adjacent to the Cahokia Creek approximately 15 miles east of St. Louis, Missouri. Preliminary information indicates land movement may have contributed to this failure. The National Transportation Safety Board (NTSB) investigation into the cause continues as of the date of this notice.
- On May 30, 2021, a hazardous liquid pipeline spilled 640 barrels of gasoline in Greens Bayou affecting high consequence areas near Houston, Texas. The operator's reported cause indicated earth movement/progressive ground movement over time on a bayou bank.
- On February 19, 2021, 22,318 one thousand cubic feet [1] (Mcf) of natural gas was released from a Type A gathering pipeline system in Belmont, Ohio. A third-party subject matter expert determined the proximate cause of this incident was land movement, or slip, that exerted force on the pipe causing a circumferential crack in an area where evidence of stress corrosion cracking and general corrosion were found.
- On December 23, 2020, 4,450 Mcf natural gas was released from a gas distribution main line in the City of Newport News, Virginia. The operator report indicated that the apparent cause was pipe stress created by ground settlement which caused misalignment of a flange resulting in a pinhole leak on gasket.
- On November 19, 2020, a pipeline spilled 17.50 barrels of crude oil east of I–5 in Kern, California during routine start-up. A metallurgical analysis determined the root cause to be related to external factors (*i.e.,* historical land movement, terrain, and cyclic weather patterns around this pipeline segment). There is a history of land movement in the area, all of which contributed to unintentional bending of the pipeline causing the circumferential cracking found at the leak site.
- On October 4, 2020, an intrastate gas transmission pipeline in Goodrich, Texas released 118,724 Mcf of natural gas below the Trinity River. While no definitive root cause was determined, the operator used the geological, meteorological, site-gathered information and historical data in its computer modeling and identified earth movement of the soil surrounding the pipe as the most plausible cause of the rupture. Circumferential stress corrosion cracking may have been a contributing factor to the failure.
- On May 19, 2020, 447 Mcf was released from a gas distribution main pipeline in Edenville Township, Michigan due to heavy rain fall. An investigation confirmed a 4-inch steel pipeline was severed when significant flooding in the area caused a road washout/scouring.
- On May 4, 2020, a 30-inch natural gas pipeline ruptured and ignited near Hillsboro, Kentucky. Preliminary information indicates land movement may have contributed to this failure. The NTSB investigation into the cause continues as of the date of this notice.
- On February 22, 2020, a carbon dioxide pipeline failed approximately one mile southeast of Satartia, Mississippi, releasing approximately 30,000 barrels of liquid carbon dioxide that immediately began to vaporize at atmospheric conditions. The pipeline failed on a steep embankment which had subsided adjacent to a local highway. Heavy rains are believed to have triggered a landslide, which created axial strain on the pipeline and resulted in a full circumferential girth weld failure.
- On January 29, 2019, a pipeline ruptured near the town of Lumberport in Harrison County, West Virginia. The rupture was located at a girth weld of an elbow on the 12-inch interstate pipeline. The root cause investigation concluded that a landslide about 150 yards from the rupture moved the pipeline approximately 10 feet from its original location causing excessive stress on the pipe resulting in the rupture.
- On January 21, 2019, a 30-inch natural gas pipeline ruptured and ignited near Summerfield, Ohio. A metallurgical analysis indicates a girth weld failed due to ductile overload from a longitudinal tensile or bending force, likely from land movement.
- On June 7, 2018, a 36-inch pipeline ruptured in a rural, mountainous area near Moundsville, West Virginia, resulting in the release of approximately 165,000 Mcf of natural gas. According to a metallurgical analysis, the rupture was caused by earth movement on the right-of-way due to a single overload event. Overloading of the pipeline likely resulted from a series of lateral displacements with accompanying bending.
- On April 30, 2018, an 8-inch intrastate pipeline failed in a remote mountainous region of Marshall County, West Virginia resulting in the release of 2,658 barrels of propane. The failure was caused by lateral movement of the pipeline due to earth movement along the right-of-way.
- On January 31, 2018, a 24-inch interstate pipeline ruptured near the city of Summerfield, Ohio releasing approximately 23,500 Mcf of natural gas in a rural forested area. A root cause analysis concluded that the girth weld failure was caused by axial stress due to movement of the pipe that exceeded the cross-sectional tensile strength of the net section weld zone surrounding the crack initiation location.
- On January 9, 2018, a 22-inch transmission pipeline failed in Montecito, California. The incident resulted in a fire and explosion and the release of an estimated 12,000 Mcf of natural gas. Heavy rains and localized flooding contributed to the pipe failure.
- On December 5, 2016, approximately 14,400 barrels of crude oil were spilled into an unnamed tributary to Ash Coulee Creek, Ash Coulee Creek itself, the Little Missouri River, and their adjoining shorelines in Billings County, North Dakota. The metallurgical and root cause failure analysis indicated the failure was caused by compressive and bending forces due to a landslide impacting the pipeline. The landslide was the result of excessive moisture within the hillside creating unstable soil conditions.
- On October 21, 2016, a pipeline release of over 1,238 barrels of gasoline spilled into the Loyalsock Creek in Lycoming County, Pennsylvania. The release was caused by extreme localized flooding and soil erosion.

[1] Mcf stands for one thousand cubic feet. The ''M'' is representative of the roman numeral for one thousand.

Within its rulemaking entitled ''Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments'' (RIN 2137–AF39), PHMSA notes that it is considering adopting revisions to § 192.613 that would oblige operators of gas transmission pipelines to conduct inspections on their facilities following an extreme weather event to ensure timely identification and remediation of damage to those facilities. In addition, the Council on Environmental Quality (CEQ) recently issued interim guidance underscoring the importance of the evaluation of, and emergency planning for, geohazards for safe operation of carbon dioxide and other pipeline facilities.[2]

II. Advisory Bulletin (ADB–2022–01)

Advisory: All owners and operators of gas and hazardous liquid pipelines, including supercritical carbon dioxide pipelines, are reminded that earth movement, particularly in variable, steep, and rugged terrain and terrain with varied or changing subsurface geological conditions, can pose a threat to the integrity of a pipeline if those threats are not identified and mitigated. Additionally, changing weather patterns due to climate change may result in heavier than normal rainfall and higher temperatures, resulting in soil saturation and flooding or soil erosion, each of which may adversely impact soil stability surrounding or supporting nearby pipeline facilities.

Pipeline operators should consider taking the following actions to ensure pipeline safety:

1. Identify areas surrounding the pipeline that may be prone to large earth movement, including but not limited to slope instability, subsidence, frost heave, soil settlement, erosion, earthquakes, and other dynamic geologic conditions that may pose a safety risk.

2. Use geotechnical engineers during the design, construction, and ongoing operation of a pipeline system to ensure that sufficient information is available to avoid or minimize the impact of earth movement on the integrity of the pipeline system. At a minimum, operators should consider soil strength characteristics, ground and surface water conditions, propensity for erosion or scour of underlying soils, and the propensity of earthquakes or frost heave.

3. Develop design, construction, and monitoring plans and procedures for each identified location, based on the site-specific hazards identified. When constructing new pipelines, develop and implement procedures for pipe and girth weld designs to increase their effectiveness for taking loads, either stresses or strains, exerted from pipe movement in areas where geological subsurface conditions and movement are a hazard to pipeline integrity.

4. Monitoring plans may include provisions related to the following:

- Ensuring during construction of new pipelines that excavators do not steepen, load (including changing the groundwater levels) or undercut slopes which may cause excessive ground movement during construction or after operations commence.
- Conducting periodic visits and site inspections. Increased patrolling may be necessary due to potential hazards identified and existing/pending weather conditions. Right-of-way patrol staff must be trained on how to detect and report conditions that may lead to or exhibit ground movement to appropriate staff.
- Identifying geodetic monitoring points (*i.e.,* survey benchmarks) to track potential ground movement.
- Installing slope inclinometers to track ground movement at depth which may otherwise not be detectable during right-of-way patrols.
- Installing standpipe piezometers to track changes in groundwater conditions that may affect slope stability.
- Evaluating the accumulation of strain on the pipeline by installing strain gauges.
- Conducting stress/strain analysis utilizing in-line inspection tools equipped with inertia mapping unit technology and high resolution deformation in-line inspection for pipe bending and denting from movement.
- Utilizing aerial mapping light detection and ranging or other technology to track changes in ground conditions.

5. Develop mitigation measures to remediate the identified locations.

6. Monitor environmental conditions and changing weather patterns in proximity to their facilities and evaluate soil stability that may have been adversely impacted.

- The National Oceanic and Atmospheric Administration's National Centers for Environmental Information has excellent information publicly available. For example, see the National Temperature and Precipitation Maps at the National Centers for Environmental Information (*https://www.ncdc.noaa.gov/temp-and-precip/us-maps/*).

7. Use available data and information resources to assess pipeline facility vulnerability relative to landslides and other types of earth movement.

- The USGS has excellent information publicly available regarding land movement. For example, see the Landslide Hazards Maps at the USGS website (*https://www.usgs.gov/programs/landslide-hazards/maps*).

8. Consider the findings and recommendations of pertinent research projects, studies, and reports on the impact of changing weather patterns on soil stability.[3] PHMSA also notes that industry and academic materials could be informative regarding relevant considerations and strategies for ensuring pipeline integrity in areas of land movement or soil subsidence.

9. Mitigation measures should be based on site-specific conditions and may include:

- Re-routing the pipeline right-of-way prior to construction to avoid areas prone to large ground movement such as unstable slope areas, earthquake fault zones, permafrost movement, or scour.
- Utilize properly designed horizontal directional drilling to go below areas of potential land movement.
- Installation of drainage measures in the trench to mitigate subsurface flows and enhance surface water draining at the site including streams, creeks, runs, gullies, or other sources of surface run-off that may be contributing surface water to the site or changing groundwater levels that may exacerbate earth movement.
- Reducing the steepness of potentially unstable slopes, including installing retaining walls, soldier piles, sheet piles, wire mesh systems, mechanically stabilized earth systems and other mechanical structures.
- Installing trench breakers and slope breakers to mitigate trench seepage and divert trench flows along the surface to safe discharge points off the site or right-of-way.
- Building retaining walls and/or installing steel piling or concrete caissons to stabilize steep slope areas as

[2] CEQ, ''Carbon Capture, Utilization, and Sequestration Guidance,'' 87 FR 8808, 8810 (Feb. 16, 2022).

[3] For example, PHMSA has funded the following research and development projects on the impact of soil movement and pipeline monitoring: *Pipeline Integrity Management for Ground Movement Hazards* (*https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=202); Combined Vibration, Ground Movement, and Pipe Current Detector* (*https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=655); Definition of Geotechnical and Operational Load Effects on Pipeline Anomalies* (*https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=561*); and *Fiber Optic Sensors for Direct Pipeline Monitoring Under Geohazard Conditions* (*https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=889).*

long as the corrosion control systems are not compromised.

• Reducing the loading on the site by removing and/or reducing the excess backfill materials to off-site locations. Soil placement should be carefully planned to avoid triggering earth movement in other locations.

• Compacting backfill materials at the site to increase strength, reduce water infiltration, and achieve optimal moisture content.

• Drying the soil using special additives such as lime-kiln dust or cement-kiln to allow the materials to be re-used and worked at the site. Over-saturated materials may require an extensive amount of time and space to dry.

• Regrading the pipeline right-of-way to minimize scour and erosion.

• Bringing the pipeline above ground and placing it on supports that can accommodate large ground movements (*e.g.,* transitions across earthquake fault zones or unstable slopes, without putting excessive stress or strain on the pipeline).

• Reducing the operating pressure temporarily or shutting-in the affected pipeline segment completely.

• Re-routing the pipeline when other appropriate mitigation measures cannot be effectively implemented to maintain safety.

Pipeline safety regulations require reporting of certain conditions that impair the serviceability of a pipeline, as noted in §§ 191.23 and 195.55.

PHMSA encourages pipeline operators to enhance their preparations and procedures beyond the minimum Federal standards and to address the unique threats, vulnerabilities, and challenges of each individual pipeline facility. Pipeline operators, Federal and state regulators, and the public have a common goal of no damage and no releases from pipeline infrastructure. Working together will better achieve our goal of zero incidents and releases.

Issued in Washington, DC, on May 26, 2022, under authority delegated in 49 CFR 1.97.

Alan K. Mayberry,

Associate Administrator for Pipeline Safety.

[FR Doc. 2022–11791 Filed 6–1–22; 8:45 am]

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DEPARTMENT OF TRANSPORTATION

Office of the Secretary

[Docket No. OST 2022–0014]

Agency Information Collection Activities: Notice of Request for New Information Collection

AGENCY: Office of the Secretary of Transportation (OST), DOT.

ACTION: Notice and request for comments.

SUMMARY: The OST invites public comments about our intention to request the Office of Management and Budget's (OMB) approval to submit one information collection, which is summarized below under **SUPPLEMENTARY INFORMATION**. We are required to publish this notice in the **Federal Register** by the Paperwork Reduction Act of 1995.

DATES: Please submit comments by August 1, 2022.

ADDRESSES: You may submit comments identified by Docket ID OST 2022–0014 by any of the following methods:

Website: For access to the docket to read background documents or comments received go to the *Federal eRulemaking Portal:* Go to *http://www.regulations.gov.* Follow the online instructions for submitting comments.

Fax: 1–202–493–2251.

Mail: Docket Management Facility, U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590–0001.

Hand Delivery or Courier: U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE, Washington, DC 20590, between 9 a.m. and 5 p.m. ET, Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: Tara Lanigan (*tara.lanigan@dot.gov*), Department of Transportation, Office of the Secretary of Transportation, 1200 New Jersey Avenue SE, Washington, DC 20590. Office hours are from 7 a.m. to 4:30 p.m., Monday through Friday, except Federal holidays.

SUPPLEMENTARY INFORMATION:

Title: Strengthening Mobility and Revolutionizing Transportation (SMART) Grant Program.

OMB Control Number: Not applicable; this is a new collection.

Summary: The Bipartisan Infrastructure Law (BIL, also known as the Infrastructure Investment and Jobs Act), enacted on November 15, 2021 provides for significant investments in America's transportation infrastructure. A key program of the legislation is the Strengthening and Revolutionizing Transportation (SMART) Grant Program ($100 million per year), under which ''the Secretary shall provide grants to eligible entities to conduct demonstration projects focused on advanced smart city or community technologies and systems in a variety of communities to improve transportation efficiency and safety'' (BIL § 25005; 23 U.S.C. 502(b)). More specifically, SMART Grants may be used to carry out a project that demonstrates at least one of the following:

- Coordinated Automation
- Connected Vehicles
- Systems Integration
- Commerce Delivery and Logistics
- Leveraging Use of Innovative Aviation Technology
- Smart Grid
- Smart Technology Traffic Signals

For this competitive grant program, the Office of the Secretary will issue a Notice of Funding Opportunity (NOFO) that describes the requirements of the SMART Grant program, including the criteria that will be used to evaluate applications. The NOFO will provide a description of the application requirements. All eligible entities must submit a completed application in order to be considered for a grant award.

The applicants who are selected for a grant (*i.e.,* the grantees) will have additional reporting requirements associated with their SMART grant, outlined below.

• *Annual Implementation Reports.* These annual reports document project progress in meeting its goals. The first report is submitted not later than 2 years after the date on which the SMART grant is received and annually thereafter until the date on which the SMART grant is expended.

○ The Final Implementation Report will demonstrate how the deployment and operational costs of the project compared to the benefits and savings; the means by which each project has met its original expectation, including data findings on the impacts of the project (*e.g.,* safety, mobility, access, system efficiency, etc.) and lessons learned.

• *Evaluation Plan.* The evaluation plan describes how the project will be evaluated, including the anticipated impacts of the project (*e.g.,* goals), the methods that will be used to measure those impacts, and the performance measures.

• *Data Management Plan.* The data management plan provides more detailed information on the types of data being collected by the grantee and

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EPA Proposes to Strengthen Air Quality Standards to Protect the Public from Harmful Effects of Soot

New Standards Demonstrate President Biden's Leadership to Reduce Air Pollution that Threatens Communities

January 6, 2023

Contact Information
EPA Press Office (press@epa.gov)

WASHINGTON — Today, the U.S. Environmental Protection Agency (EPA) is announcing a proposal to strengthen a key national ambient air quality standard (NAAQS) for fine particle pollution, also known as $PM_{2.5}$, to better protect communities, including those most overburdened by pollution. Fine particles, sometimes called soot, can penetrate deep into the lungs and can result in serious health effects that include asthma attacks, heart attacks and premature death – disproportionately affecting vulnerable populations including children, older adults, those with heart or lung conditions, as well as communities of color and low-income communities throughout the United States. These particles may be emitted directly from a source, such as construction sites, unpaved roads, fields, smokestacks, or fires; other particles form in the atmosphere as a result of complex reactions of chemicals such as sulfur dioxide and nitrogen oxides, which are pollutants emitted from power plants, industrial facilities, and vehicles.

EPA's proposal will specifically take comment on strengthening the primary (health-based) annual $PM_{2.5}$ standard from a level of 12 micrograms per cubic meter to a level between 9 and 10 micrograms per cubic meter, reflecting the latest health data and scientific evidence; the Agency is also taking comment on the full range (between 8 and 11 micrograms per cubic meter) included in the Clean Air Scientific Advisory Committee's (CASAC) latest report.

"Our work to deliver clean, breathable air for everyone is a top priority at EPA, and this proposal will help ensure that all communities, especially the most vulnerable among us, are protected from exposure to harmful pollution," **said EPA Administrator Michael S. Regan**. "This proposal to deliver stronger health

protections against particulate matter is grounded in the best available science, advancing the Biden-Harris Administration's commitment to scientific integrity and a rigorous scientific process."

"As a physician who's passionate about oncology and dedicated to enhancing the health equity that's so often needed in Black communities and other communities of color, I am grateful for the Biden Administration's commitment to advancing equity and justice for all," **said Dr. Doris Browne, former President of the National Medical Association**. "No one should be sickened by the environment they live in, and EPA's proposal marks the start of changes that will have lasting impacts in communities all over, especially Black and brown communities that often experience increased PM pollution. Harmful air pollution can have lasting and devastating impacts on people's health, but by strengthening air quality standards, we can ensure healthier, more sustainable communities across this country."

Since EPA completed its last review of the PM NAAQS in 2012, thousands of new scientific studies have demonstrated the dangers of soot exposure. Strengthening the primary annual $PM_{2.5}$ standard is expected to address disparities and would result in significant public health benefits. EPA estimates that if finalized, a strengthened primary annual $PM_{2.5}$ standard at a level of 9 micrograms per cubic meter, the lower end of the proposed range, would prevent:

- up to 4,200 premature deaths per year;
- 270,000 lost workdays per year;
- result in as much as $43 billion in net health benefits in 2032.

EPA will work closely with state, local, and Tribal air agencies to implement the revised primary annual $PM_{2.5}$ standard when finalized. Today's proposal is the latest in a broader suite of programs under President Biden's leadership to reduce air pollution that threatens communities. These programs include the proposed Good Neighbor Plan to address smog that affects downwind states, rules to address air pollution from oil and gas operations, including methane pollution, and other critical rules to reduce emissions from power plants and the transportation sector, such as the recently finalized Clean Trucks Rule that will slash smog- and soot-forming pollution from heavy-duty trucks. Additionally, funding from the President's Bipartisan Infrastructure Law and the Inflation Reduction Act aimed at cutting pollution from school buses and trucks, port operations, and electricity generation are also expected to reduce soot and other harmful air pollutants.

EPA is also proposing to revise other aspects related to the PM standards – such as monitoring requirements and the Air Quality Index (AQI) – that will help states and Tribal Nations meet the revised standards while making significant strides toward protecting the health of all people, including at-risk populations. The Agency is proposing to retain the primary 24-hour $PM_{2.5}$ standard of 35 micrograms per cubic meter, while taking comment on revising this level to as low as 25 micrograms per cubic meter.

In June 2021, EPA announced it would reconsider the previous administration's December 2020 decision to retain the 2012 $PM_{2.5}$ standards, because available scientific evidence and technical information indicated that the standards may not be adequate to protect public health and welfare. In developing today's proposal, EPA considered the best available science and technical information, including an Integrated

Science Assessment and updated Policy Assessment that were made available for public comment and for expert review by the Agency's Clean Air Scientific Advisory Committee (CASAC) and CASAC PM expert panel. EPA carefully evaluated the recommendations of the CASAC in developing the proposed rule.

EPA will accept public comment for 60 days after the proposal is published in the Federal Register. EPA will also conduct a virtual public hearing over several days for this proposed rulemaking, with the hearing beginning at 11:00 am Eastern Time and concluding at 7:00 pm ET each day. EPA will begin pre-registering speakers for the hearing upon publication of the announcement of the public hearings in the Federal Register. Additional information will also be made available on the National Ambient Air Quality Standards (NAAQS) for PM webpage <https://epa.gov/pm-pollution/national-ambient-air-quality-standards-naaqs-pm>.

After reviewing comments, the Agency plans to issue final standards later this year.

More information on particulate matter <https://epa.gov/pm-pollution>.

More information on the NAAQS review process and other documents related to this reconsideration <https://epa.gov/naaqs/particulate-matter-pm-air-quality-standards>.

Background

The Clean Air Act requires EPA to set two types of NAAQS: health-based standards, called *primary standards*, and standards to protect public welfare, called *secondary standards*. Based on the scientific evidence and technical information, EPA has set two primary standards for $PM_{2.5}$, which work together to protect public health: the annual standard, which EPA is proposing to revise, and a 24-hour standard, which the Agency is proposing to retain. EPA also is proposing to retain the current primary 24-hour standard for PM_{10}, which provides protection against coarse particles. In addition, the Agency is proposing to retain the secondary standards for both $PM_{2.5}$ and PM_{10} at this time.

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Kern County
Daily Average Ozone Data
Seven Day Display Ending 12/31/2022
Parts Per Million (ppm)

Bas	Cnty	Site Name	7 Day Max	12/25/2022	12/26/2022	12/27/2022	12/28/2022	12/29/2022	12/30/2022	12/31/2022	GraphIt
MD	KER	Mojave-CA 58 Business	0.039	0.024	0.017	0.033	0.039	0.034	0.025	0.022	☐
SJV	KER	Arvin-Di Giorgio	0.022	0.005	0.005		0.022	0.017	0.015	0.013	☐
SJV	KER	Bakersfield-5558 California Avenue	0.017	0.005	0.005	0.004	0.017	0.010	0.010	0.009	☐
SJV	KER	Bakersfield-Municipal Airport	0.017	0.003	0.003	0.002	0.017	0.011	0.012	0.008	☐
SJV	KER	Edison	0.020	0.007	0.004	0.009	0.020	0.017	0.015	0.014	☐
SJV	KER	Maricopa-Stanislaus Street	0.030	0.012	0.012	0.021	0.030	0.024	0.020	0.024	☐
SJV	KER	Oildale-3311 Manor Street	0.007	0.007	0.004						☐
SJV	KER	Shafter-Walker Street	0.022	0.005	0.002	0.004	0.022	0.010	0.012	0.009	☐

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Asterisk (*) indicates 25% or more hourly values are missing.
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202 | December | 31

Ozone | ppm

Daily Average

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