CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR §146.82(a)

Brown Pelican CO_2 Sequestration Project

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1.0 Project Background and Contact Information

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS1, CCS2 and CCS3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

The Brown Pelican CO_2 Sequestration Project (BRP Project or Project) is part of the Oxy Low Carbon Ventures, LLC (OLCV), whose objective is to demonstrate technical feasibility of Carbon Capture and Storage (CCS) utilizing CO_2 from Direct Air Capture (DAC). The advancement of CCS technology is critically important in addressing CO_2 emissions and global climate change concerns. The BRP Project is designed to demonstrate utility-scale integration of transport and permanent storage of captured CO_2 into a deep geologic formation (i.e., geologic sequestration). A commercial-scale CCS system is currently being constructed and will be operated to provide safe, long-duration subsurface storage of CO_2.

The BRP Project will demonstrate that the geologic sequestration process can be done safely, ensuring that the injected CO_2 will be retained within the intended storage reservoir. By using safe and proven pipeline technology, the CO_2 will be transported to a storage site located near Penwell, Texas. The pipeline will be designed and installed according to all applicable standards and codes and will adhere to strict mechanical integrity testing schedules to ensure long-term reliability. The CO_2 will be injected into the Lower San Andres Formation at a proposed rate of 0.385 Million Metric Tons per Annum (MMTPA) for approximately two years followed by CO_2 injection at a rate of 0.77 MMTPA for an additional 10 years. A total of 8.5 Million Metric Tons (MMT) is estimated to be stored during the injection period.

The proposed Area of Review (AoR) has no known cultural sites or sites of archaeological significance. There is one known place of worship and one known cemetery within a 1-mile buffer zone surrounding the AoR. There are no known schools, hospitals, or nursing homes within the AoR or buffer zone surrounding the AoR.

GSDT Submission – Project Background and Contact Information
GSDT Module: Project Information Tracking ***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Required project and facility details ***[40 CFR §146.82(a)(1)]***

2.0 Site Characterization [40 CFR §146.82(c)(2)]

A detailed geologic evaluation was conducted both regionally and locally for the area pertaining to the BRP Project site using geologic, geophysical, and petrophysical data obtained from public literature and Oxy-licensed data. A detailed discussion of the geologic features, geochemistry, geomechanics, seismic history, Injection and Confining Zone details, and Area of Review (AoR) site suitability is described in the Area of Review and Corrective Action document of this application. Below are some highlights summarized from the detailed discussion.

2.1 Stratigraphic Framework [40 CFR §146.82(a)(3)(iii), §146.83]

Two stratigraphic test wells, Shoe Bar 1 and Shoe Bar 1AZ, were drilled in 2023 to provide site-specific data. A suite of ~10 wireline logs, and more than 700 ft of whole core, and fluid samples from three depths were acquired in each of the two wells. The Shoe Bar 1 is located in an area observed to have a different seismic facies characterization than the Shoe Bar 1AZ. Between these two wells, it is possible to provide a robust geologic and petrophysical characterization of the Injection Zone, Upper and Lower Confining Zones, and Upper Confining System. Step rate tests and injectivity tests were conducted in these wells to constrain dynamic simulation modeling parameters. In addition to the data from Shoe Bar 1 and Shoe Bar 1AZ, the stratigraphic framework is defined by 359 well logs and 624 well tops.

The CO_2 Storage Complex in the proposed Project consists of four main elements shown in Figure 1:

1. Injection Zone (Lower San Andres Formation);
2. Upper Confining Zone (Upper San Andres and Grayburg Formations)
3. Regional Seal / Upper Confining System (Queen through Rustler Formations); and
4. Lower Confining Zone (Upper Glorieta Formation) (Figure 1).

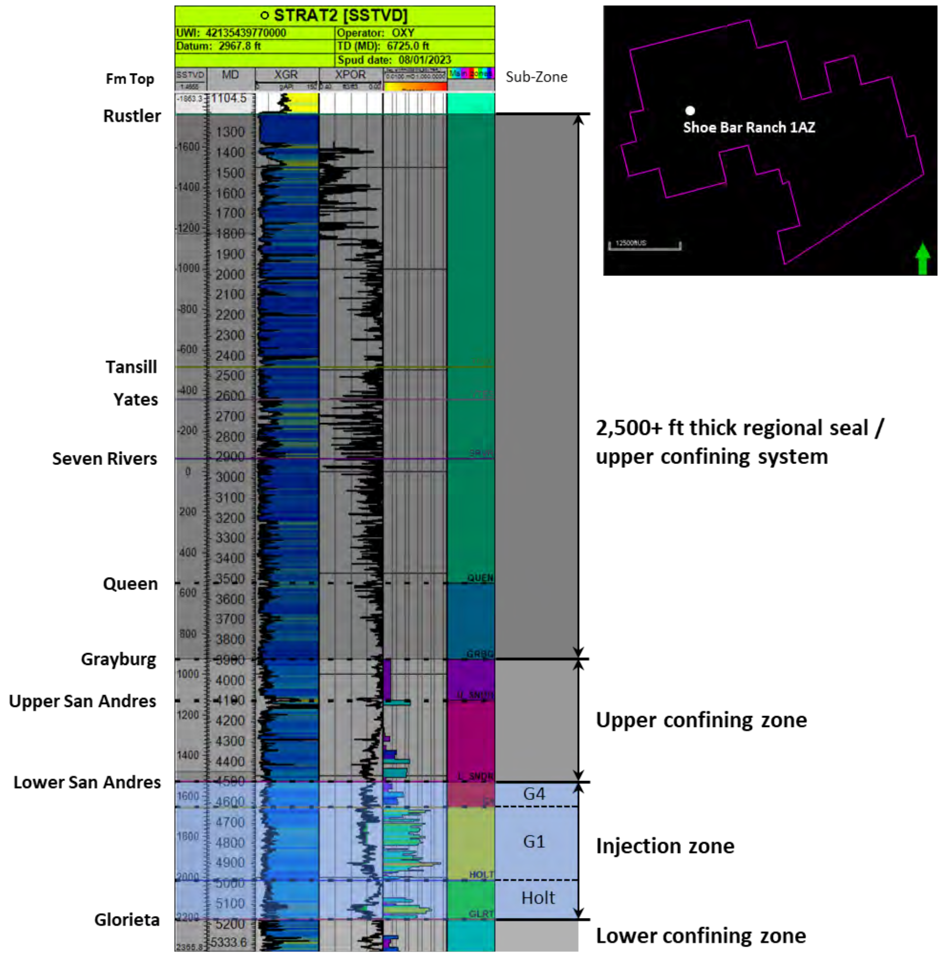

Figure 1— Stratigraphic column covering the Injection Zone, Upper Confining Zone, and Upper Confining System. UWI = Unique Well Identifier; SSTVD = True vertical depth subsea; MD = Measured depth; XGR = Gamma Ray log QCd by Oxy or OLCV petrophysicist; XPOR = porosity log QCd by Oxy or OLCV petrophysicist; K = Permeability

The Lower San Andres Formation is divided into three sub-zones that comprise the proposed Injection Zone. The G4 sub-subzone has average porosity = 9.7 % and average permeability = 1.2 mD. The G1 sub-zone has average porosity = 11.2 % and average permeability = 12 mD. The Holt sub-zone has average porosity = 9.4 % and average permeability = 18.8 mD. Core facies encountered in Shoe Bar 1 and Shoe Bar 1AZ in sub-zones G4 and G1 are dominated by stacked grain-dominated and mud-dominated dolo-packstones. Core facies encountered in the Holt sub-zone of Shoe Bar 1 are dominated by extensively leached and burrowed dolo-wackestones, whereas core facies in the Holt sub-zone of Shoe Bar 1AZ comprise a 70 ft thick tight calcite interval overlying grain-dominated dolo-packstones to dolo-wackestones. Data from the Shoe Bar 1 and Shoe Bar 1AZ wells are sufficient to adequately characterize the AoR because the rock and fluid properties from these wells were calibrated to seismic facies and extrapolated beyond the wellbores.

OLCV confirmed the Upper San Andres Formation and the Grayburg formations as the Upper Confining Zone with log and core data from Shoe Bar 1 and Shoe Bar 1AZ. The Upper San Andres has average porosity of 6.1 % and average permeability of < 0.1 mD. The Grayburg formation has average porosity of 4.1 % and average permeability of < 0.1 mD.

The Queen through Rustler Formations form the Regional Seal / Upper Confining System and consist of regionally extensive, lateral continuous evaporites (anhydrite, halite), shale, and tight silt. These units form the Permian regional seal complex that is ~2,500 ft thick (Figure 1) and is demonstrated to trap hydrocarbon accumulations throughout the Permian Basin. These deposits are some of the most extensively studied evaporite systems in the world (Beauheim and Roberts 2002; Anderson et al. 1972; Espinoza and Santamarina 2017; Kendall and Harwood 1989; Dean et al. 2000). Evaporite formations are interbedded with clay and siltstone marker beds that are traceable across much of the western Permian Basin (Anderson et al. 1972).

The Upper Glorieta Formation is confirmed to be the Lower Confining Zone with log and core data from the Shoe Bar 1 and Shoe Bar 1AZ stratigraphic wells. The Upper Glorieta Formation exhibits a porosity of <1% and <0.1 mD of permeability.

2.2 Structural Framework [40 CFR §146.82(a)(3)(ii), §146.82(a)(3)(v), §146.82(a)(3)(vi)]

OLCV acquired a high-density, 20.5 mi^2 3D seismic survey over the Project site in late 2022. Two orthogonal 2D lines totaling 10 line-miles were acquired in addition to the 3D survey. These data were used in conjunction with seismic data licensed from vendors and data from the BEG to construct the structural framework.

The subsurface geologic structure of the Lower Confining Zone through the Upper Confining Zone dips gently towards the West at 0.7° (170 ft vertically over 12,500 ft laterally) across the Project area. Based on recently acquired site-specific 3D seismic data, the Injection Zone, the Upper Confining and Lower Confining Zones are not faulted. Devonian and older strata are faulted. The Devonian strata are separated ~1800 ft from the Permian-age Lower San Andres Injection Zone.

The proposed Project site is situated in an area of West Texas that has historically exhibited low seismic activity, based on catalogs from both USGS[1] (up to and including December 2016, Figure 2) and TexNet[2] (January 2017 to present). The risk to the Project from seismic events is considered minimal because the proposed Injection Zone is vertically separated from deeper faulted strata by approximately 1,800 ft, as observed on 2D and 3D seismic images, providing sufficient vertical separation to prevent any interaction between injection pressures and the faults. Additionally, OLCV proposes to manage pressure by producing brine from the Injection Zone, further reducing

[1] https://earthquake.usgs.gov/earthquakes/search/
[2] https://www.beg.utexas.edu/texnet-cisr/texnet

the risk of seismicity from the proposed Project. The USGS predicts this site to have low future seismic hazard. Because of these factors, the site low risk of induced seismicity due to Project operations.

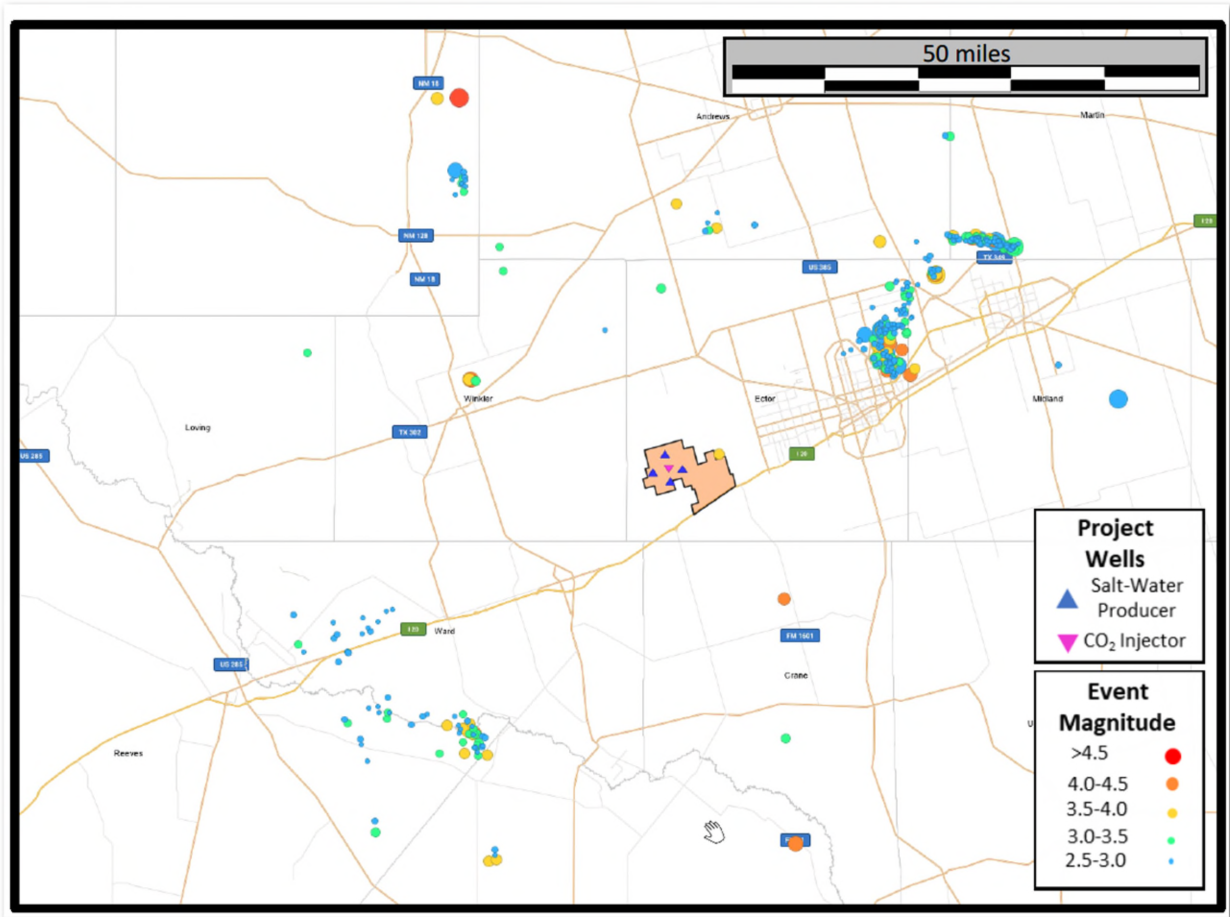

Figure 2— Seismic activity map showing a 50-mile radius around the Shoe Bar Ranch (shaded outline). The closest seismic event observed was 5 miles east of the proposed site in 2001. The seismic cluster 25 miles NE of the proposed Project site is currently attributed to SWD operations in deeper strata close to critically-stressed faults.

2.3 Underground Sources of Drinking Water [40 CFR §146.82(a)(3)(vi), §146.82(a)(5)]

Southeast Ector County has two sources of groundwater in the extent of the Project that meet the formal definition of a Underground Source of Drinking Water (USDW) by EPA Class VI standard (40 CFR §144.3): the Pecos Valley major aquifer (surface to ~250 ft below ground level); and the Dockum minor aquifer / Santa Rosa Formation (~600 to 1,150 ft below ground level) (Bradley and Kalaswad, 2001; Mace et al., 2006; George et al., 2011).

Drainage of the Pecos Valley and Dockum aquifers from the study area is directed southeast toward the Pecos River, following the Monument Draw Trough (Boghici, 1999). The Dewey Lake

Formation separates the base USDW from the Regional Seal and consists of red siltstone and shale (Meyer et al., 2012; and Figure 1).

2.4. Geochemistry [40 CFR §146.82(a)(6)]

The main reactive transport phenomenon of interest in carbonate reservoir CO_2 storage projects is mineral dissolution by weak carbonic. The dissolution of the mineral can alter the porosity and the permeability of the reservoir rock, affecting sequestration storage capacity, well injectivity, and integrity of confining zones. For the BRP Project, dolomite is the dominant mineral in the Injection Zone and anhydrite is the dominate mineral in the Upper Confining Zones. Oxy's operational experience in San Andres reservoirs has shown that the effect of reactive transport on reservoir performance is insignificant.

Geochemical and reactive transport modeling were conducted to evaluate the impact of the proposed CO_2 injectate stream on the Injection Zone and the Upper Confining Zone. The Upper Confining Zone shows negligible reactivity as anhydrite does not dissolve and it is chemically compatible with CO_2 at reservoir pressure and temperature.

Overall, the porosity change in the Injection Zone at the BRP Project is modeled to be insignificant. Considering the total pore volume estimated to be in contact with CO_2 (2.98 billion ft^3) and the maximum volume change in the reservoir due to mineral dissolution/precipitation (1.36 million ft^3 in 2087), the change in pore volume is about 0.046%. Thus, the results support that the changes in reservoir storage volume due to injection is negligible. The differences in injection are negligible because the permeability change is directly related to porosity alteration. Thus, wells injectivity is considered unchanged due mineral dissolution and precipitation.

2.5 Geocellular and Dynamic Model Construction

The static geocellular framework was constructed by first modeling large-scale stratigraphic and structural features, and then modeling the petrophysical properties of these geologic features. Four zones in the geocellular model were created from stratigraphic surfaces based on well log correlations of formation tops: the Grayburg with mean average thickness of 237 ft, the Upper San Andres with 355 ft, the Lower San Andres with 652 ft, and the Glorieta with 341 ft. Proportional layering was applied to each model zone, and the number of layers within each model zone division was based on the upscaled thickness of each interpreted zone.

Core-measured porosity data were used to guide and calibrate the porosity model for deriving log-based porosity estimates as an input to the geocellular model. In addition, core-measured permeability data were used to construct a permeability model of Lucia Rock Fabric Number (RFN) for the Injection Zone.

The BRP Project dynamic reservoir simulation followed a method developed by Ghomian (2008), who had successfully matched the results of a 2004 Frio pilot injection test, described in detail by Sakurai et al. (2006). OLCV adopted these established processes for petrophysical evaluations, geocellular model construction, and equation-of-state (EOS) modeling for CO_2 properties and solubility. Further, all simulation runs were executed using the GEM simulator, as used by Ghomian (2008).

The grid properties of porosity and horizontal permeability (k_h) were imported directly from the static geocellular model. The base vertical permeability (k_v) for each grid cell was calculated using a multiplier of 0.1 to the horizontal permeability, based on Oxy's 30 years of experience in building simulation models for more than 20 San Andres reservoirs in the Permian Basin. The initial conditions of the model are based on data from Shoe Bar 1 and Shoe Bar 1AZ.

The Project is modeled to include three CO_2 injection wells. The BRP CCS1 and BRP CCS2 commence injection in January 2025. The third injector, BRP CCS3 commences injection in January 2027. The BRP CCS1 and BRP CCS3 are slanted injectors that are completed in the G4 and G1 sub-zones. The BRP CCS2 is a horizontal well completed in the Holt sub-zone. To manage pressure in the Injection Zone and restrict the size of the pressure plume, the Project drilled four brine producer wells that are expected to commence production in the summer of 2024. The produced brine will primarily be used in Oxy's Enhanced Oil Recovery Operations and may be injected into future UIC Class 1 wells. Brine produced from the Project will not be injected into Class II Saltwater Disposal Wells.

Geomechanical modeling of the AoR using Mohr-Coulomb analysis was conducted using the hydrostatic pore pressure in the Lower San Andres Formation. The stress model is constrained by the geological interpretation that the area is in a normal faulting/strike-slip transitional failure mode that is consistent with the larger Permian Basin. Estimated operating pressures during CO_2 injection are expected to be less than 90% of the 1,100 psi required to initiate tensile failure. Therefore, risk of containment failure during CO_2 injection operations is low.

2.6 Site Storage Capacity

An initial estimation of the site storage capacity was performed using the CO_2 Screen tool by the U.S. DOE authored by Sanguinito et al. (2020) for estimating storage in saline formations, described by Equation 1:

$$G_{CO_2} = A_t h_g \phi_{tot} \rho_{CO_2} E_{saline} \qquad \textit{Equation 1}$$

where G_{CO_2} is the CO_2 storage capacity, A_t is the total area being assessed for CO_2 storage, h_g is the average gross thickness of the formation, ϕ_{tot} is the average total porosity of the formation, and E_{saline} is the CO_2 storage efficiency factor that reflects a fraction of the total pore volume filled by CO_2. The efficiency factors for area, volumetric, and microscopic displacement were assigned default values using the CO_2 Screen tool based on lithology and depositional environment. The rest of the inputs were obtained from the geocellular model. The storage capacity was evaluated on a per-square-mile basis. Table 1 below describes the inputs used to estimate the storage capacity in million metric tons (MMT) per square mile.

Table 1—Inputs Used to Estimate Storage Capacity

Formation	TVD (ft)	Pressure (psi)	Net Thickness (ft)	Total Porosity	G_{CO_2}, (MMT/sq mile)		
					P10	P50	P90
Lower San Andres, Injection Zone	4,755	2378	400	0.09	2.14	3.13	4.32

Notes:
ρ_{CO2} =50.40 lb/ft3
E_{saline} = (0.09, 0.13, 0.18)

Using a conservative estimate of the total available pore-space acreage at 6,400 acres (10 sq miles), the total storage capacity of the BRP Project site in the Lower San Andres interval is between 21.4 and 43.2 MMT CO_2. The DOE methodology provides a wide variation in the storage capacity estimate and is considered a high-level estimate to assess the site's potential. Even considering a conservative P10 case, the storage amounts to 21 MMT, which is more than twice the volume of CO_2 planned to be injected. The main limitation of this methodology is the lack of dynamic information in the analysis, such as the impact on storage caused by a lack of good permeability pathways or the impact of exceeding the fracture gradient.

The dynamic simulation model is a more advanced method for determining storage capacity. Details of the construction and physics of the base case dynamic model are described in detail in the Area of Review and Corrective Action Plan. The base case model includes structural and stratigraphic (supercritical), dissolved in the aqueous phase, and residual trapped CO_2. There is no trapping due to mineralization because of the overall carbonate dissolution as shown in the reactive-transport simulations. Figure 3 shows the change in storage capacity and CO_2 plume area over time from the dynamic simulation, forecast to run for 100 years after injection ends. The maximum CO_2 plume area is 4.8 mi^2 at the end of the injection period with a storage capacity of 1.77 MMT/mi^2. The plume shrinks after the injection stops from Year 12 to Year 50 and stabilizes in the following years. The plume area is based on CO_2 global mole fraction with a 0.1% cutoff. The change in plume size is negligible 50 years after injection, which is the proposed site closure time.

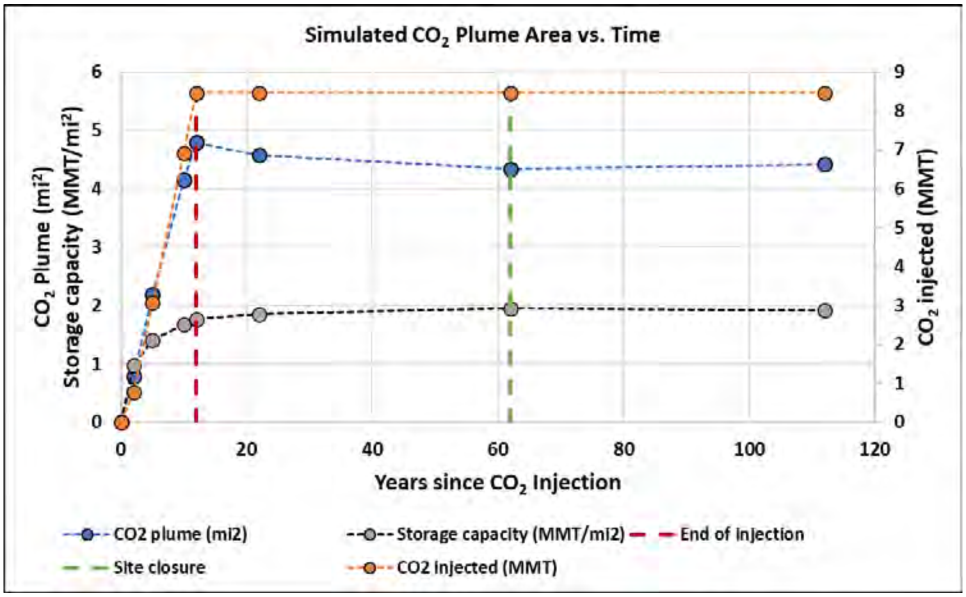

Figure 3—Dynamically simulated CO_2 plume area (blue dots), CO_2 injected mass (orange dots), and storage capacity (gray dots) from start of injection to 100 years post-injection. Plume area is based on the saturation extent of CO_2 in the reservoir.

3.0 AoR and Corrective Action [40 CFR §146.82]

OLCV determined the critical pressure, i.e., threshold at which the increase in pore pressure is high enough to overcome the hydraulic head of the fluid in a hypothetical wellbore and enter the USDW. Then, OLCV calculated the critical pressure front by following the method proposed by Birkholzer et al. (2011) and Oldenburg et al. (2014) where reservoir simulation (as multiphase numerical tool) can be used to model the leakage through single well. The Injection Zone is observed to be overpressured prior to Project operations, therefore method of Birkholzer et al. (2011) and Oldenburg et al. (2014) is appropriate to use.

In total, 28 hypothetical wells were positioned at different locations (i.e., 28 simulation runs). In addition, nine Artificial Penetrations (APs) within and adjacent to the AoR were considered as potential leak points. If left unmitigated, the following APs could potentially leak small volumes of brine or CO_2 to the USDW: Eidson E-1 (API 4213531130) with maximum about 0.00022 bbl/day; Eidson-Scharbauer-1 (API 4213506139) with maximum about 0.00024 bbl/day, and Scharbauer Eidson-1 (API 4213510667) with maximum about 0.00023 bbl/day.

Simulation results were used to determine the time at which the pressure and CO_2 plumes reach the APs with leak potential. The pressure plume is modeled to intersect the Eidson E-1 after approximately two years following the commencement of CO_2 injection operations. The pressure plume is modeled to intersect the Eidson-Scharbauer-1 and the Scharbauer Eidson-1 within four to five years following the commencement of injection activities. To conservatively protect the

USDW, OLCV will perform corrective action on these three wells prior to commencement of CO_2 injection operations.

At a fixed frequency specified in the Area of Review and Corrective Action Plan, or more frequently when monitoring and operational conditions warrant, OLCV will re-evaluate the AoR and perform any required corrective action in the manner specified in 40 CFR §146.84. As part of this reevaluation process, OLCV must also update the Area of Review and Corrective Action Plan or demonstrate to the UIC Program Director that no update is needed.

Following each Area of Review and Corrective Action Plan re-evaluation or demonstration showing that no new evaluation is needed, OLCV shall submit the resultant information in an electronic format to the Program Director for review and approval of the results. Once approved by the Program Director, the revised Area of Review and Corrective Action Plan will become an enforceable condition of this permit.

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR §146.82(a)(4)]*** ☒ AoR and Corrective Action Plan ***[40 CFR §146.82(a)(13) and §146.84(b)]*** ☒ Computational modeling details ***[40 CFR §146.84(c)]***

4.0 Financial Responsibility

OLCV 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 approved financial assurance mechanisms are found in the Financial Assurance Plan document of this permit. The financial instrument(s) must be sufficient to cover the cost of:

- Corrective action (per 40 CFR §146.84);
- Injection well plugging (meeting the requirements of 40 CFR §146.92);
- Post-injection site care and site closure (meeting the requirements of 40 CFR §146.93);
- Emergency and remedial response (meeting the requirements of 40 CFR §146.94).

During the active life of the geologic sequestration project, OLCV 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 Program Director in an electronic format. OLCV must also provide to the Program Director written updates of adjustments to the cost estimate in an electronic format within 60 days of any amendments to the project plans that address the cost items covered in the Financial Assurance Plan.

OLCV shall provide notifications to meet the requirements of 40 CFR §146.85 and the conditions of this permit and shall take the following actions:

- Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, OLCV, 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 an increase to the Program Director, or obtain other financial responsibility instruments to cover the increase. 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 OLCV has received written approval from the Program Director.

- OLCV must notify the Program Director by certified mail and in an electronic format of any adverse financial conditions, such as bankruptcy, which may affect the ability to carry out injection well plugging, post-injection site care and site closure, and any applicable ongoing actions under the Corrective Action and/or Emergency and Remedial Response Plan.

    - If OLCV or a third-party provider of a financial responsibility instrument is going through a bankruptcy, OLCV must notify the Program Director by certified mail and in an electronic format of the commencement of voluntary or involuntary proceedings under Title 11 US Code (Bankruptcy), which names OLCV as the debtor, within 10 days after commencement of the proceeding.

    - A guarantor of a corporate guarantee must make such a notification if he or she is named as debtor, as required under the terms of the guarantee.

    - A permittee who fulfills the requirements of financial assurance 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 suspension/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.

OLCV must establish other financial assurance or liability coverage, acceptable to the Program Director, within 60 days of a change to the Area of Review and Corrective Action Plan.

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Demonstration of financial responsibility ***[40 CFR §146.82(a)(14) and §146.85]***

5.0 Injection Well Construction [40 CFR §146.82(c)(5), §146.82(a)(12)]]

The CO_2 injection wells are designed with the highest standards and best practices for drilling and well construction (see Figure 4). The operational parameters were designed, and materials were selected to ensure mechanical integrity in the system and to optimize the operation during the life of the project.

5.1 Well design and Construction: BRP CCS1

The BRP CCS1 well design includes three main casing sections: 1) surface casing to cover the USDW and provide integrity while drilling to the Injection Zone, 2) intermediate section, and 3) a long string section to acquire formation data and isolate the target formation while running the upper completion equipment. The orientation of this well will be slanted to maximize the length of the completion in the Injection Zone. This well will be completed in the G4 and G1 sub-zones of the Lower San Andres formation.

Surface Section

The 20-inch conductor pipe will be pre-set at 120 ft prior starting drilling operations. A 26-inch hole will be drilled with auger and cemented before drilling rig arrives on location. The 17 ½ inch surface section will be drilled vertical to 1,800 ft measured depth (MD)/ true vertical depth (TVD) below the base of the underground source of drinking water (USDW) while taking deviation surveys every 200 ft. Once total depth (TD) for the surface section is reached, the well will be circulated and conditioned to run open hole electric logs according to the testing program. Then, 13 3/8 -inch casing will be run and cemented to the surface with Class C cement slurry. If there are no cement returns to the surface, the Project Manager will inform the Program Director, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Program Director.

After the cement job, Section A of the wellhead and the blowout preventor (BOP) equipment will be installed. The rig crew will then test the BOP, test the casing, and pick up the drilling assembly.

Intermediate Section

Make up the 12 ¼ inch drilling assembly and run in hole (RIH). Drill out shoe track and ten (10) ft new formation. Perform a formation integrity test (FIT) to a minimum equivalent mud weight (EMW) of 13 ppg. A 12-1/4-inch hole for the intermediate string will be drilled vertically from 1,800 ft to the kickoff point (KOP) at 3,500 ft MD, and then directionally drilled to 3,800 ft measured depth MD. At the section total depth (TD), the hole will be circulated, and the mud will be conditioned to run open hole electric logs according to the testing program. Then, the 9 5/8-inch casing will be run and cemented to the surface with Class C cement slurry. If there are no cement returns to the surface, the Project Manager will inform the Program Director, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Program Director.

Injection Section

An 8-1/2-inch hole will be drilled vertically from 3,800 ft MD to 4,700 ft MD. The rat hole will extend to 6,270 ft MD. Once TD is reached, the well will be circulated and conditioned to run openhole electric logs as per the testing program. A cement bond log (CBL) and variable density log (VDL) will be acquired. Then, the long string of 5-1/2-inch casing will be deployed with a DTS/DAS fiber optic cable attached to the exterior of the casing. The 5 1/2-inch casing will be cemented to the surface with a combination of CO_2-resistant class C reduced Portland with additives (1st stage slurry) and Class C (2nd stage slurry) cement slurries with DV tool.

Completion

During the completion operations, the rig will test the casing to 500 psi, condition the long string casing with a bit and scraper, run a CBL-VDL-USIT-CCL log to evaluate cement bonding and casing conditions, perforate the Injection Zone, and run the upper completion equipment. The 2 7/8-inch tubing and packer completion will be run to approximately 4,100 ft, in conjunction with an electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid, and the packer will be set. Once the packer is set, an annular pressure test will be performed to 500 psi to validate the mechanical seal. A leak-off test followed by a pressure fall-off test will be performed before starting injection.

Specific details on the proposed casing properties and cementing program are found in Section 5.0 of the Injection Well Construction Plan document of this permit.

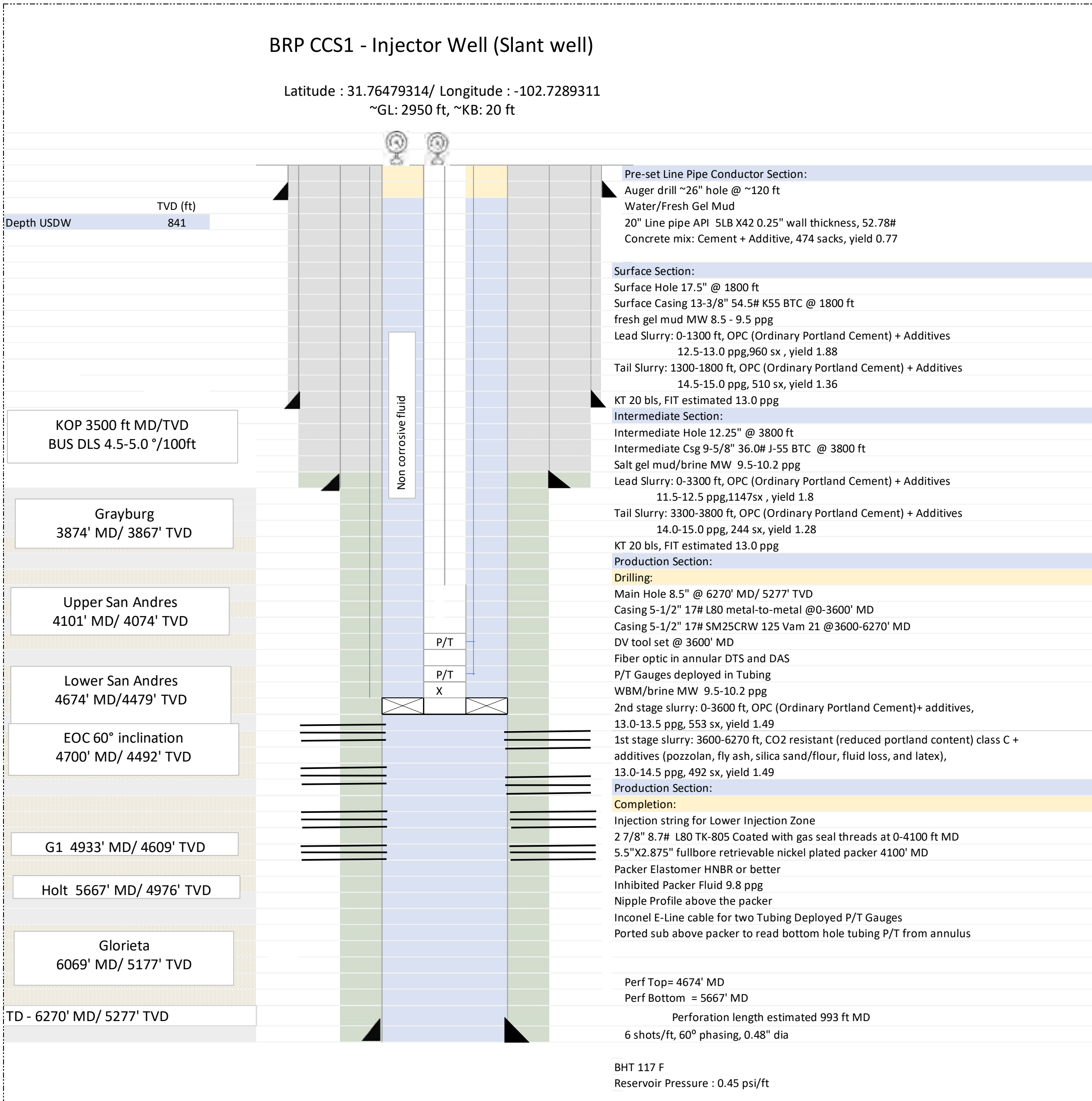

Figure 4—BRP CCS1 well proposed schematic

5.2. Well Design and Construction: BRP CCS2

The BRP CCS2 well design includes three main casing sections: 1) surface casing to cover the USDW and provide integrity while drilling to the Injection Zone, 2) intermediate section, and 3) a long string section to acquire formation data and isolate the target formation while running the upper completion equipment. The orientation of this well will be horizontal, completed in the Holt sub-zone of the Lower San Andres formation.

Surface Section

The 20-inch conductor pipe will be pre-set at 120 ft prior starting drilling operations. A 26-inch hole will be drilled with auger and cemented before drilling rig arrives on location. The 17 ½ inch surface section will be drilled vertical to 1,800 ft measured depth (MD)/ true vertical depth (TVD) below the base of the underground source of drinking water (USDW) while taking deviation surveys every 200 ft. At the section total depth (TD), the hole will be circulated, and the mud will be conditioned to run open hole electric logs according to the testing program. The 13 3/8-inch surface casing will be cement to the surface with Class C cement slurry and additives. After the cement job, section A of the wellhead and the blowout preventor (BOP) equipment will be installed. If there are no cement returns to the surface, the Project Manager will inform the Program Director, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Program Director.

Intermediate Section

The 12 ¼ inch intermediate hole will be drilled vertical from 1,800 ft MD to the section TD at 3,800 ft MD. At the section total depth (TD), the hole will be circulated, and the mud will be conditioned to run open hole electric logs according to the testing program. The 9 5/8-inch intermediate casing will be run to section TD. The 9 5/8-inch intermediate casing will be cement to the surface with Class C cement slurry and additives. If there are no cement returns to the surface, the Project Manager will inform the Program Director, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Program Director.

Injection Section

Make up the 8 ½ inch drilling assembly and RIH. Drill out shoe track and ten (10) ft new formation. Perform a FIT to a minimum EMW of 13 ppg. The 8 ½ inch production hole will be drilled vertical from 3,800 ft MD to the kickoff point (KOP) at 3,885 ft MD. Drill directional to landing point (LP) at 5,835 ft MD. Drill lateral section directional holding inclination to 9,260 ft MD/ 5,083 ft TVD in Holt formation, 200 ft will be used for casing shoe track and completion perforation guns rat hole. At the well TD, the hole will be circulated, and the mud will be conditioned to run open hole electric logs according to the testing program. The long string of 5 ½ inch casing will be deployed with a DTS/DAS fiber optic cable attached to the exterior of the 5 1/2-inch production casing and will be run to section TD. The 5 ½ in casing will be cemented to the surface with a combination of CO_2-resistant class C reduced Portland with additives (1st stage slurry) and Class C (2nd stage slurry) cement slurries with DV tool.

Completion

During the completion operations, the rig will test the casing to 500 psi, condition the long string casing with a bit and scraper, run a CBL-VDL-USIT-CCL log to evaluate cement bonding and casing conditions, perforate the Injection Zone, and run the upper completion equipment. The 2 7/8 in. tubing and packer completion will be run to approximately 4,500 ft, in conjunction with an electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid, and the packer will be set. Once the packer is set, an annular pressure test will be performed to 500 psi to validate the mechanical seal. A leak-off test followed by a pressure fall-off test will be performed before starting injection.

The proposed schematics is shown in Figure 5.

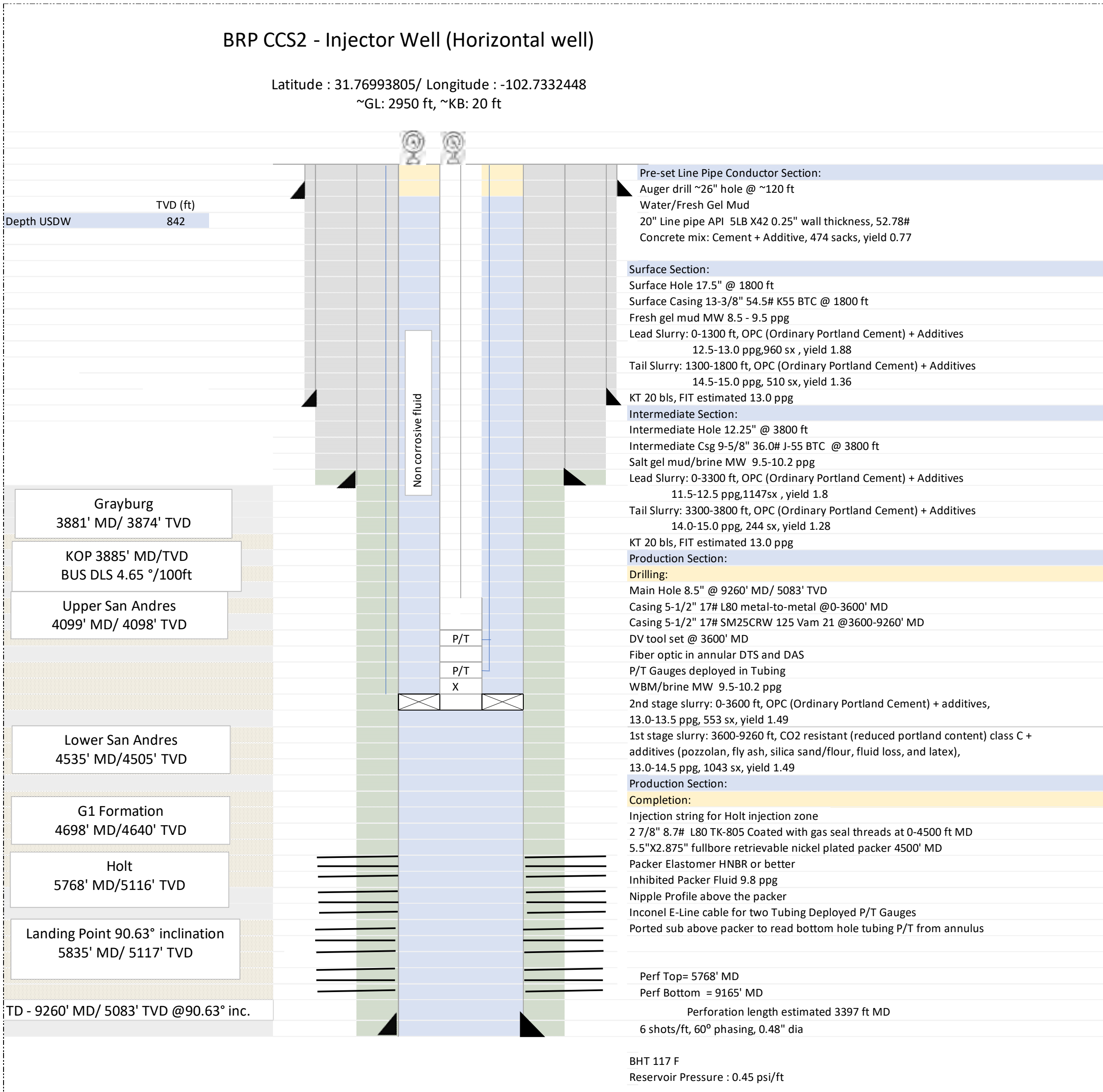

Figure 5—BRP CCS2 well proposed schematic

5.3. Well Design and Construction: BRP CCS3

The BRP CCS3 well design includes three main casing sections: 1) surface casing to cover the USDW and provide integrity while drilling to the injection zone, 2) intermediate section, and 3) a long string section to acquire formation data and isolate the target formation while running the upper completion equipment. The orientation of this well will be slanted to maximize the length of the completion in the Injection Zone. This well will be completed in the G4 and G1 sub-zones of the Lower San Andres formation.

Surface Section

The 20-inch conductor pipe will be pre-set at 120 ft prior starting drilling operations. A 26-inch hole will be drilled with auger and cemented before drilling rig arrives on location. The 17 ½ inch surface section will be drilled vertical to 1,800 ft measured depth (MD)/ true vertical depth (TVD) below the base of the underground source of drinking water (USDW) while taking deviation surveys every 200 ft. At the section total depth (TD), the hole will be circulated, and the mud will be conditioned to run open hole electric logs according to the testing program. The 13 3/8-inch surface casing will be cement to the surface with Class C cement slurry and additives. After the cement job, section A of the wellhead and the blowout preventor (BOP) equipment will be installed. If there are no cement returns to the surface, the Project Manager will inform the Program Director, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Program Director.

Intermediate Section

The 12 ¼ inch intermediate hole will be drilled vertical from 1,800 ft MD / TVD and will start to kickoff (KOP) from the same depth (1,800 ft MD/TVD). Drill directional to 3,800 ft MD. At the section total depth (TD), the hole will be circulated, and the mud will be conditioned to run open hole electric logs according to the testing program. The 9 5/8-inch intermediate casing will be run to section TD. The 9 5/8-inch intermediate casing will be cement to the surface with Class C cement slurry and additives. If there are no cement returns to the surface, the Project Manager will inform the Program Director, determine the top of cement with a temperature log or equivalent, and complete the annular cement program with a top job procedure after approval by the Program Director.

Injection Section

Make up the 8 ½ inch drilling assembly and RIH. Drill out shoe track and ten (10) ft new formation. Perform a FIT to a minimum EMW of 13 ppg. The 8 ½ inch production hole will be drilled directional from 3,800 ft MD to the end of curve point (EOC) at 4,511 ft MD. Drill tangent section directional holding inclination to 6,578 ft MD, 200 ft below Glorieta formation for wire line rat hole, casing shoe track and completion perforation guns rat hole. At the well TD, the hole will be circulated, and the mud will be conditioned to run open hole electric logs according to the testing program. The long string of 5 ½ inch casing will be deployed with a DTS/DAS fiber optic cable attached to the exterior of the 5 1/2-inch production casing and will be run to section TD. The 5 ½ in casing will be cemented to the surface with a combination of CO_2-resistant class C reduced Portland with additives (1st stage slurry) and Class C (2nd stage slurry) cement slurries with DV tool.

Completion

During the completion operations, the rig will test the casing to 500 psi, condition the long string casing with a bit and scraper, run a CBL-VDL-USIT-CCL log to evaluate cement bonding and casing conditions, perforate the Injection Zone, and run the upper completion equipment. The 2 7/8 in. tubing and packer completion will be run to approximately 3,680 ft, in conjunction with an electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid, and the packer will be set. Once the packer is set, an annular pressure test will be performed to 500 psi to validate the mechanical seal. A leak-off test followed by a pressure fall-off test will be performed before starting injection.

The proposed schematics is shown in Figure 6.

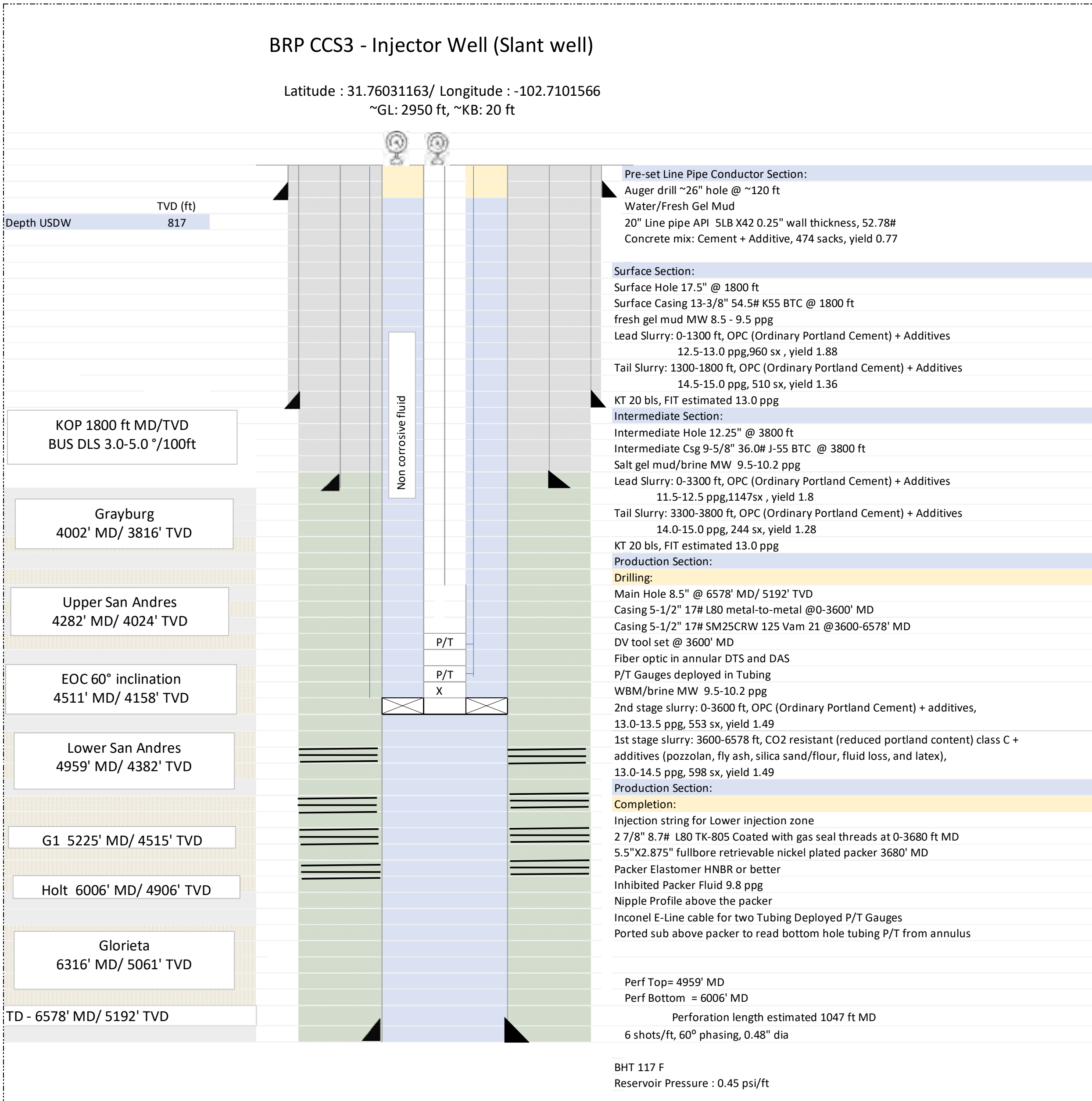

Figure 6—BRP CCS3 well proposed schematic

<u>6.0 Pre-Operational Logging and Testing [40 CFR §146.82(c)(4), (7) and §146.87]</u>

The Shoe Bar 1 and Shoe Bar 1AZ stratigraphic wells were drilled in 2023 to provide site-specific characterization data for the BRP site. The Shoe Bar 1AZ is located within the proposed AoR, close to the locations in proposed Injector wells. Core data collected in the Shoe Bar 1AZ is representative of the subsurface at the locations of proposed future injectors BRP CCS1 and BRP CCS2, which will be located less than 2,000 ft from Shoe Bar 1AZ (see additional details in Pre-Operational Plan Appendix A). Shoe Bar 1 is located in the easternmost extent of the modeled AoR, approximately 1.5 miles East of Shoe Bar 1AZ.

The Project acquired a comprehensive suite of basic and advanced geophysical logs, whole core through the injection interval, sidewall cores, reservoir pressure data and fluid samples in the stratigraphic test wells. After each well was constructed, the BRP team conducted step-rate tests in the injection and confining intervals.

The BRP Project will construct three new wells for CO_2 injection. An extensive suite of tests and logs will be acquired during drilling, casing installation, and post-casing installation in the injector wells in accordance with the testing required under 40 CFR §146.87(a), (b), (c), and (d). Because of close proximity and stratigraphic and structural conformance demonstrated by seismic data of the BRP CCS1 and BRP CCS2 to the Shoe Bar 1AZ, the Project does not intend to re-collect core in the BRP CCS1 or BRP CCS2. The BRP CCS3 will be located in close proximity to the Shoe Bar 1, but additional sidewall core will be collected in the BRP CCS3, because seismic data indicate that its rock properties may be different than what was encountered in the Shoe Bar 1.

The Project has constructed a well to monitor the lowermost USDW and four wells to withdraw brine from the Injection Zone for pressure maintenance. In the future, the Project will construct two additional wells to monitor the Injection Zone. These wells will be logged, and fluid samples will be collected for characterization and future monitoring efforts.

Specific details on the proposed pre-operational logging and testing program are found in the Pre-Operational Testing Plan document that is part of this application.

Pre-Operational Logging and Testing GSDT Submissions
GSDT Module: Pre-Operational Testing ***Tab(s):*** Welcome tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Proposed pre-operational testing program ***[40 CFR §146.82(a)(8) and §146.87]***

7.0 Proposed Stimulation Program [40 CFR §146.82(a)(9)]

OLCV may stimulate the Injection Zone for the BRP Project to enhance the injectivity potential of CO_2 injection wells and the productivity of water withdrawal wells. Stimulation may involve, but is not limited to, flowing fluids into or out of the CO_2 injection wells, increasing or connecting pore spaces in the injection/production formation, or other activities that are intended to allow CO_2

to move more readily into the Injection Zone and for the brine to be more efficiently produced by water withdrawal wells.

8.0 Well Operation [40 CFR §146.88]

The CO_2 Injection wells are designed to maximize the rate of injection as well as reduce the surface pressure and friction alongside the tubing, while maintaining the bottomhole pressure below 90% of the fracture pressure. The selected design provides enough clearance to deploy the pressure and temperature gauges on tubing and to ensure continuous surveillance of external integrity and conformance through the external fiber optic cable. The design allows for other logs to be periodically run, e.g., temperature logs.

8.1 Operational Procedures [40 CFR §146.82(a)(10)]

The operational procedures summarized below describe how OLCV will initiate injection and conduct startup-specific monitoring of the CO_2 injector wells.

The multistage (step-rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the full injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

During the startup period, OLCV will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, OLCV may be required to schedule a daily conference call to discuss this information. A multistage (step-rate) startup procedure will initially be applied to the well. At no point during the start-up procedure will the injection pressure be allowed to exceed the maximum injection pressure of 1,100 psig for BRP CCS 1 and CCS3 and 1,800 for BRP CCS 2, which is measured at the wellhead. The injection rate will be measured and recorded using an orifice flowmeter.

A spinner log will be conducted during each change (step) in rate, and the project team will look for any evidence of anomalous pressure behavior. If during the startup period any anomalous pressure behavior is observed, the project team may conduct additional logging and modify the injection rate program to characterize the anomaly better.

Additional operational parameters are detailed in the Summary of Operating Conditions document of this permit.

Operating conditions are summarized in Table 2 below.

Table 2—Operating conditions for CO_2 Injector wells

Parameter/Condition	Limitation or Permitted Value	Units
Daily group maximum injection mass	2,116	Metric tons per day
Daily group average injection mass	1,931	Metric tons per day
Daily maximum injection mass BRP CCS1	600	Metric tons per day
Daily average injection mass BRP CCS1	450	Metric tons per day
Daily maximum injection rate BRP CCS1	8.24	Million standard cubic feet per day
Daily average injection rate BRP CCS1	7.88	Million standard cubic feet per day
Total mass BRP CCS1	1.83	Million metric tons
Maximum surface wellhead injection pressure BRP CCS1	1,100	psig
Maximum bottomhole injection pressure BRP CCS1	2,625.3	psig
Average bottomhole injection pressure BRP CCS1	2,600.3	psig
Daily maximum injection mass BRP CCS2	1,500	Metric tons per day
Daily average injection mass BRP CCS2	1,112	Metric tons per day
Daily maximum injection rate BRP CCS2	25.0	Million standard cubic feet per day
Daily average injection rate BRP CCS2	21.9	Million standard cubic feet per day
Total mass BRP CCS2	4.87	Million metric tons
Maximum surface wellhead injection pressure BRP CCS2	1,800	psig
Maximum bottomhole injection pressure BRP CCS2	3,391.8	psig
Average bottomhole injection pressure BRP CCS2	3,300	psig
Daily maximum injection mass BRP CCS3	600	Metric tons per day
Daily average injection mass BRP CCS3	450	Metric tons per day
Daily maximum injection rate BRP CCS3	9.02	Million standard cubic feet per day
Daily average injection rate BRP CCS3	8.10	Million standard cubic feet per day
Total mass BRP CCS3	1.77	Million metric tons
Maximum surface wellhead injection pressure BRP CCS3	1,100	psig
Maximum bottomhole injection pressure BRP CCS3	2,625.3	psig
Average bottomhole injection pressure BRP CCS3	2,600.3	psig
Minimum annulus pressure	100	psig
Minimum annulus pressure/tubing differential	100	psig

Automatic alarms and automatic shutoff systems will be installed and maintained. Successful function of the alarm system and shutoff system will be demonstrated prior to injection and once annually thereafter.

At all times, pressure will be maintained on the well to prevent the return of the injection fluid to the surface. The wellbore must be filled with a high-specific-gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed that 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.

- OLVC shall cease injection should it appear that the well is lacking mechanical integrity or that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW.

Permittee will cease injection according to the guidelines provided below:

- OLCV must shut in the well by gradual reduction of the injection pressure as outlined in the Summary of Operating Conditions document of this permit; or
- OLCV must immediately cease injection and shut in the well as outlined in the Emergency and Remedial Response Plan document of this permit.

8.2 Proposed Carbon Dioxide Stream [40 CFR §146.82(a)(7)(iii) and (iv)]

The CO_2 stream composition is shown below in Table 3. No injectant other than those identified in this permit shall be injected into the well except fluids used for stimulation, rework, and well tests as approved by the Program Director.

Table 3—CO_2 Stream Composition

Component	Specification
CO_2 content	>95 mol% (>96.5 mass%)
Water	<30 lbm/MMscf
Nitrogen	<4 mol%
Sulphur	<35 ppm by weight
Oxygen	<5 mol%
Glycol	<0.3 gal/MMscf
Carbon Monoxide	<4,250 ppm by weight
NOx	<6 ppm by weight
SOx	<1 ppm by weight

Component	Specification
Particulates ($CaCO_3$)	<1 ppm by weight
Argon	<1 mol%
Surface pressure	>1,600 psig
Surface temperature	>65°F and <120°F

8.3 Reporting and Recordkeeping

Electronic reports, submittals, notifications, and records made and maintained by OLCV under this permit must be in an electronic format approved by EPA. OLCV shall submit all required reports electronically to the Program Director.

OLCV shall submit semi-annual reports containing:

- Any changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from the proposed operating data;
- Monthly average, maximum, and minimum values for injection pressure, flow rate, daily volume, temperature, and annular pressure;
- A description of any event that exceeds operating parameters for the annulus or injection pressure specified in the permit;
- A description of any event that triggers the required shutoff systems and the responses taken;
- The monthly volume and/or mass of the CO_2 stream injected over the reporting period and volume and/or mass injected cumulatively over the life of the project;
- Monthly annulus fluid volume added or produced; and
- Results of the continuous monitoring required, including:
    - A tabulation of the (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.
    - Graph(s) of the continuous monitoring required or of daily average values of the above parameters. The injection pressure, injection volume and flow rate, annulus fluid level, annulus pressure, and temperature shall be submitted as one or more graphs, using contrasting symbols or colors, or in another manner approved by the Program Director; and

- Results of any additional monitoring prescribed under 40 CFR §146.90 and implemented pursuant to the Testing and Monitoring Plan.

Any permit noncompliance shall be reported to the Program Director as described below:

- OLCV shall report to the Program Director any permit noncompliance that may endanger human health or the environment, and/or any events that require implementation of actions in the Emergency and Remedial Response Plan. Any information shall be provided orally within 24 hours from the time OLCV becomes aware of the circumstances. Such verbal reports shall include, but not be limited to, the following information:
    - Any evidence that the injected CO_2 stream or associated pressure front may cause an endangerment to a USDW or any monitoring or other information that indicates that any contaminant may have caused endangerment to a USDW;
    - Any noncompliance with a permit condition or malfunction of the injection system that may cause fluid migration into or between USDWs;
    - Any triggering of the shutoff system;
    - Any failure to maintain mechanical integrity; and
    - 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 Program Director, any release of CO_2 to the atmosphere or biosphere.
- A written submission shall be provided to the Program Director in an electronic format within five (5) days of the time OLCV becomes aware of the circumstances. The submission shall contain a description of the noncompliance and its cause; the period of noncompliance (including the exact dates and times); and if the noncompliance has not been corrected, then 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 document of this permit. This submission should also include the steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

Within 30 days, OLCV will report to the Program Director the results of periodic tests of mechanical integrity; any well workover, including stimulation; any other test of the injection well conducted by OLCV, if required by the Program Director.

The following items require advance notification from OLCV to the Program Director:

- **Well Tests.** OLCV shall give at least 30 days' advance written notice to the Program Director in an electronic format of any planned workover, stimulation, or other well test.

- **Planned Changes.** OLCV shall give written notice to the Program 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.
- **Anticipated Noncompliance.** OLCV shall give the Director advance notice of any planned changes in the facility or activity that may result in noncompliance with the permit requirements.

The following include other reporting requirements:

- **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 OLCV no later than 30 days after each schedule date.
- **Transfer of Permits.** This permit is not transferable to any person except after notice is sent to the Program Director in an electronic format at least 30 days before the transfer and requirements of 40 CFR §144.38(a) have been met. Pursuant to the requirements of 40 CFR §144.38(a), the Program Director will require modification or revocation and reissuance of the permit to change the name of OLCV and incorporate such other requirements as may be necessary under the Safe Drinking Water Act (SDWA).
- **Other Noncompliance.** OLCV 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 40 CFR §144.51(l)(6).
- **Other Information.** When OLCV becomes aware of a failure to submit any relevant facts in the permit application or incorrect information has been submitted in a permit application or in any report to the Program Director, OLCV shall submit such facts or corrected information in an electronic format within 10 days in accordance with 40 CFR §144.51(l)(8).
- **Report on Permit Review.** Within 30 days of receipt of this permit, OLCV shall certify to the Program Director in an electronic format that he or she has read and is personally familiar with all terms and conditions of this permit.

The following guidelines are provided for record keeping:

- OLCV shall retain records of all monitoring data collected for 10 years after it is collected.
- OLCV 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 re-evaluations and 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.

- OLCV shall retain records concerning the nature and composition of all injected fluids for 10 years after site closure.
- The retention periods may be extended at any time by a request of the Program Director. OLCV shall continue to retain records after the specified retention period of this permit, or any requested extension thereof expires, unless OLCV delivers the records to the Program Director or obtains written approval from the Program Director to discard the records.
- Records of monitoring information shall include:
  - The date, exact place, and time of sampling or measurements;
  - The name(s) of the individual(s) who performed the sampling or measurements;
  - A precise description of both the sampling methodology and handling of samples;
  - The date(s) analyses were performed;
  - The name(s) of the individual(s) who performed the analyses;
  - The analytical techniques or methods used; and
  - The results of such analyses.

9.0 Testing and Monitoring [40 CFR §146.82(c)(9) and §146.90]

Testing and monitoring data will be used to demonstrate that the CO_2 Injection wells are operating as planned, the CO_2 plume and pressure front are behaving as predicted, and that there is no endangerment to Underground Sources of Drinking Water (USDW). In addition, the testing and monitoring data will be used to validate and adjust the geocellular and simulation models used to predict the distribution of the CO_2 within the Injection Zone to support Area of Review (AoR) re-evaluations and a non-endangerment demonstration at site closure.

The Testing and Monitoring Plan was designed to monitor and mitigate the key risks identified for this project that are described in the Emergency and Remedial Response Plan. During the Injection and Post-injection periods, those risks include the potential for: well integrity failure, leakage to USDW, natural disasters, induced seismicity or critical surface impacts.

The methodology and frequency of testing and monitoring methods is expected to change throughout the life of the project. Pre-injection monitoring and testing will focus on establishing baselines and ensuring that the site is ready to receive injected CO_2. Injection phase monitoring will be focused on collecting data that will be used to calibrate models and ensure containment of CO_2. Post-injection phase monitoring and testing is designed to demonstrate CO_2 plume stabilization and ensure containment. The testing and monitoring plan will be reviewed at least once every five years and will be amended, if necessary, to ensure monitoring and storage performance is achieved and new technologies are appropriately incorporated.

OLVC plans to install two Single Reservoir-level (SLR) wells in the Injection Zone, and has already installed a well to monitor the first permeable zone above the confining zone, which is coincident with the lowermost Underground Source of Drinking Water Aquifer (USDW). Prior to initial startup of CO_2 injection operations, OLCV will install the SLR2 well. One additional SLR well is planned to be constructed. In addition, the Injection Zone will be monitored with data collected in Water Withdrawal wells (WW). The WW wells will extract brine to manage pressure in the Injection Zone. The need for additional monitoring wells will be evaluated as needed, and at least annually during the injection period and until plume stabilization.

In addition to utilizing a well-based network to monitor pressure, temperature, and fluid and dissolved gas chemistry of the subsurface, OLCV will also utilize surface and near-surface methods to monitor CO_2 containment. Additional details on geophysical monitoring methods are described in Sections 11 and 12 of the Testing and Monitoring Plan document. Near-surface soil and soil gas monitoring are described in Section 8.2 of the Testing and Monitoring Plan.

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Updated Testing and Monitoring Plan ***[40 CFR §146.82(c)(9) and §146.90]*** ☐ NO UPDATES NECESSARY

9.1 Mechanical Integrity

OLCV will conduct tests to verify the internal and external mechanical integrity of the Injector Wells before and during the injection phase pursuant to 40 CFR §146.89(c), 40 CFR §146.90(e), 40 CFR §146.87 (a)(2)(ii), and 40 CFR §146.87 (a)(3)(ii)]. Other than during periods of well workover or maintenance approved by the Program 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.

The purpose of internal mechanical integrity testing is to confirm the absence of significant leakage within the injection tubing, casing, or packers [40 CFR §146.89(a)(1)]. Continuous monitoring of injection pressure, injection rate, injected volume and annulus pressure will be used to ensure internal mechanical integrity. In addition, annulus pressure tests will be periodically conducted to confirm gauge measurements.

The purpose of external mechanical integrity testing is to confirm the absence of significant leakage outside of the casing [(40 CFR §146.89(a)(2))]. OLCV proposes to conduct temperature logging in the Injector wells on an annual basis to demonstrate external mechanical integrity. In addition, OLCV plans to collect continuous temperature profiles above the Injection Zone in Injector wells, using DTS fiber.

Additional details regarding demonstrations of mechanical integrity are found in the Construction Plan, the Testing and Monitoring Plan, and the Injection Well Plugging Plan.

OLCV will observe the following reporting guidelines:

- OLCV shall notify the Program Director in an electronic format of his or her intent to demonstrate mechanical integrity at least 30 days before such demonstration. However, at the discretion of the Program Director, a shorter time may be allowed.
- Reports of mechanical integrity demonstrations that contain logs must include an interpretation of the results by a knowledgeable log analyst. OLCV shall report in an electronic format the results of a mechanical integrity demonstration.
- OLCV shall calibrate all gauges used in mechanical integrity demonstrations and other required monitoring to an accuracy of not less than 0.5% 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 Program Director in an electronic format with the report of the test. Pressure gauge resolution shall be no greater than five (5) psi. Certain mechanical integrity and other testing may require greater accuracy and shall be identified in the procedure submitted to the Program Director before the test.

OLCV must adhere to the following guidelines regarding failure to maintain mechanical integrity:

- If OLCV or Program Director finds that the well fails to demonstrate mechanical integrity during a test, is unable 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), OLCV must:
    - Immediately cease injection;
    - Take all steps reasonably necessary to determine whether there may have been a release of the injected CO_2 stream or formation fluids into any unauthorized zone. If there is evidence of USDW endangerment, OLCV shall implement the Emergency and Remedial Response Plan included in this permit;

  - Follow the reporting requirements as directed in the Emergency and Remedial Response Plan;
  - Restore and demonstrate mechanical integrity to the satisfaction of the Program Director and receive written approval from the Program Director before resuming injection; and
  - Notify the Program Director in an electronic format when injection is expected to resume.
- If a shutdown is triggered, either downhole or at the surface, OLCV must immediately investigate and identify the cause of the shutdown as expeditiously as possible. If, upon such investigation, the well appears to be lacking mechanical integrity or if the monitoring required indicates that the well may be lacking mechanical integrity, OLCV must take the actions described in the Emergency and Remedial Response Plan.
- If the well loses mechanical integrity before the next scheduled test date, then the well must be either plugged or repaired and retested within 30 days of losing mechanical integrity. OLCV shall not resume injection until the mechanical integrity is demonstrated and the Program Director gives written approval to recommence injection in cases where the well has lost mechanical integrity.

OLCV shall demonstrate mechanical integrity at any time upon written notice from the Program Director.

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Testing and Monitoring Plan ***[40 CFR §146.82(a)(15) and §146.90]***

10.0 Injection Well Plugging

The CO_2 Injection wells will be plugged and abandoned (P&A'd) consistent with the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of carbon dioxide (CO_2) with water mixtures, and protect any underground sources of drinking water (USDWs).

Detailed plugging procedures and diagrams are presented in the Well Plugging Plan that is submitted as part of this application.

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Well Plugging Plan ***[40 CFR §146.82(a)(16) and §146.92(b)]***

11.0 Post-Injection Site Care and Site Closure Plan

The Post-Injection Site Care and Site Closure (PISC) Plan describes the activities that OLCV will perform to meet the requirements of 40 CFR §146.93. OLCV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years, or a shorter period should OLCV make a demonstration under 40 CFR §146.93(b)(2) that the geologic sequestration project no longer poses a risk of endangerment to USDWs. OLCV may 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, OLCV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ PISC and Site Closure Plan ***[40 CFR §146.82(a)(17) and §146.93(a)]***
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Alternative PISC timeframe demonstration ***[40 CFR §146.82(a)(18) and §146.93(c)]***

12.0 Emergency and Remedial Response

The Emergency and Remedial Response Plan (ERRP) document of this permit describes actions OLCV 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.

If OLCV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause endangerment to a USDW, OLCV will initiate a shutdown plan for the injection well, take all steps reasonably necessary to identify and characterize any release, notify the permitting agency (UIC Program Director) of the emergency event within 24 hours, and implement applicable portions of the approved ERRP.

Emergency and Remedial Response GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Emergency and Remedial Response tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Emergency and Remedial Response Plan ***[40 CFR §146.82(a)(19) and §146.94(a)]***

13.0 Injection Depth Waiver and Aquifer Exemption Expansion

Injection depth waivers are not requested in this permit application.

Injection Depth Waiver and Aquifer Exemption Expansion GSDT Submissions
GSDT Module: Injection Depth Waivers and Aquifer Exemption Expansions ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Injection Depth Waiver supplemental report ***[40 CFR §146.82(d) and §146.95(a)]*** ☐ Aquifer exemption expansion request and data ***[40 CFR §146.4(d) and §144.7(d)]***

14.0 References

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SUMMARY OF OPERATING CONDITIONS
40 CFR §146.82 (a)(7) and (10) and §146.88 (e)

Brown Pelican CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Injection Well Operating Conditions 1
3.0 Reporting Frequencies 3
4.0 Startup Monitoring and Reporting Procedures 4
5.0. Operations after startup 6

1.0 Facility Information

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS1 Well

Facility contact: [redacted]

Well location: Penwell, Texas
31.76479314, 102.7289311

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements for the Brown Pelican CO_2 Sequestration Project (BRP Project or Project) are specified in this document and summarized below in Table 1.

Table 1—Injection Well Operating Conditions

Parameter/Condition	Limitation or Permitted Value	Units
Daily group maximum injection mass	2,116	Metric tons per day
Daily group average injection mass	1,931	Metric tons per day
Daily maximum injection mass BRP CCS1	600	Metric tons per day
Daily average injection mass BRP CCS1	450	Metric tons per day
Daily maximum injection rate BRP CCS1	8.24	Million standard cubic feet per day
Daily average injection rate BRP CCS1	7.88	Million standard cubic feet per day
Total mass BRP CCS1	1.83	Million metric tons
Group maximum injection rate	773,000	Metric tons per year
Group average injection rate	705,000	Metric tons per year
Maximum injection rate BRP CCS1	166,000	Metric tons per year
Average injection rate BRP CCS1	153,000	Metric tons per year
Maximum surface wellhead injection pressure BRP CCS1	1,100	psig
Maximum bottomhole injection pressure BRP CCS1	2,625.3	psig
Average bottomhole injection pressure BRP CCS1	2,600.3	psig
Minimum annulus pressure	100	psig
Minimum annulus pressure/tubing differential	100	psig

Limitations or permitted values for the maximum surface wellhead injection pressure, maximum bottomhole injection pressure, minimum annulus pressure, and minimum annulus pressure/tubing differential limitation are set as follows:

- **Maximum Surface Wellhead Injection Pressure:** CO_2 will be supplied by a dehydration and compression facility located approximately four miles northeast of the CO_2 Injector well location. The pressure at the facility discharge will be 2,500 psig. The CO_2 will then be routed via pipeline to valve stations near the injection well. Here the pressure will be reduced to 1,100 psig prior to reaching the wellhead. Pressure at the well will be controlled via control valves with shutdown protocols in place to protect the well in the event of a high-pressure scenario**.** Wellbore tubing pressure curves representative of the CO_2 Injector well will be created and calibrated after well construction.
- **Maximum Bottomhole Injection Pressure:** To meet EPA requirements in 40 CFR §146.88(a), the maximum pressure considered for the CO_2 Injector well is 90% of the

fracture opening pressure of the Injection Zone, measured using a downhole pressure gauge. The fracture pressure of the Injection Zone is determined from Step Rate Test data collected in the Shoe Bar 1AZ well that was drilled for the purposes of this Project. Reservoir modeling indicates the pore pressure required to move the effective stress state into tensile failure is near 2933 psi at a depth of 4,609 ft below the ground surface. Maximum downhole injection pressure is therefore set to be less than 90% of that 2,933 psi threshold, calculated as follows:

$$0.9 \times 2{,}933 = 2{,}640 \text{ psia} - 14.7 \text{ psi} = 2{,}625.3 \text{ psig} \quad \textit{Equation 1}$$

The maximum bottomhole injection pressure will be re-calculated based on logs and well information from the CO_2 Injection well after it is constructed.

- **Minimum Annulus Pressure:** As necessary to prevent "burst" or "collapse" of the tubing, the minimum annulus pressure is calculated as follows:

$$\text{Collapse Pressure} = \text{depth} \times [(\text{pressure gradient of formation}) + (\text{pressure gradient of cement}) - (\text{pressure gradient of water})] \quad \textit{Equation 2}$$

$$\text{Burst Pressure} = \text{depth} \times (\text{pressure gradient of injectant}) + \text{surface pressure} \quad \textit{Equation 3}$$

- **Minimum Annulus Pressure/Tubing Differential:** The annulus pressure/tubing differential is measured directly above and across the injection packer and is set to be a minimum of 100 psi above the surface wellhead injection pressure.

  If the downhole pressure gauge fails to function properly, then the maximum injection pressure shall immediately be limited by the maximum surface wellhead injection pressure until the downhole pressure gauge can be repaired or replaced.

3.0 Reporting Frequencies

Oxy Low Carbon Ventures, LLC (OLCV) will maintain the reporting frequencies as summarized below in Table 2.

Table 2—Class VI Reporting Frequencies

Activity	Minimum Reporting Frequency
Change to the CO_2 stream characterization	Semi-annually
Monthly injection pressure, flow rate, volume, pressure on the annulus, annulus fluid level, and temperature (Min, Max, and Avg.)	Semi-annually
Corrosion monitoring	Semi-annually
Monthly and cumulative volume and mass of the carbon dioxide stream injected	Semi-annually

Activity	Minimum Reporting Frequency
Monthly annulus fluid volume added	Semi-annually
Results and reports for the monitoring systems proposed: plume tracking, above confining zone monitoring, surface monitoring	Semi-annually
Description of any event that triggers a shutoff device and the response taken	Semi-annually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semi-annually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT*	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results 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: The reporting frequency for MIT will comply with TAC Title 16 Chapter 5.206(e)(1): "The operator of an anthropogenic CO2 injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone."

All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document of this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR §146.91 reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

The procedures related to the startup of operations, as well as monitoring and reporting during startup, are specified in this section. The injection rates will be gradually increased to the planned rate over a period of six (6) days.

The procedures detailed below describe how OLCV will initiate injection and conduct startup-specific monitoring of the CO_2 Injector well, pursuant to 40 CFR §146.90.

The multistage (step-rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the full injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 Injector well.
(2) During the startup period, the permittee will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.
(3) A series of successively higher injection rates will be applied, as shown in Table 3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 1,100 psig, which is measured at the wellhead.
(4) The planned injection rates are shown in Table 3.

Table 3—Planned Injection Rates During Startup

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Pressure (%)
202	24	40
253	24	50
303	24	60
354	24	70
404	24	80
455	24	90

(5) The injection rates will be controlled with variable frequency drive pumps.
(6) The injection rates will be measured and recorded using an orifice flowmeter.
(7) Surface and downhole pressures and temperatures will be measured and recorded.
(8) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented, and the project team will look for any evidence of anomalous pressure behavior.
(9) If during the startup period any anomalous pressure behavior is observed, additional logging and modification of the injection rate program may be conducted to characterize the anomaly better. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and the line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:
    (a) The instantaneous shut-in pressure (ISIP) will be measured.
    (b) The permittee will notify the agency within 24 hours of the determination.

(c) The permittee will consult with the agency before initiating any further injection.

5.0. Operations after startup

Automatic alarms and automatic shutoff systems will be installed and maintained. Successful function of the alarm system and shutoff system will be demonstrated prior to injection and once annually thereafter.

At all times, pressure will be maintained on the well to prevent the return of the injection fluid to the surface. The wellbore must be filled with a high-specific-gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed that 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.

- OLVC shall cease injection should it appear that the well is lacking mechanical integrity or that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW.

Permittee will cease injection according to the guidelines provided below:

- OLCV must shut in the well by gradual reduction of the injection pressure as outlined in the Summary of Operating Conditions document of this permit; or
- OLCV must immediately cease injection and shut in the well as outlined in the Emergency and Remedial Response Plan document of this permit.

SUMMARY OF OPERATING CONDITIONS: BRP CCS2
40 CFR §146.82 (a)(7) and (10) and §146.88 (e)

Brown Pelican CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Injection Well Operating Conditions 1
3.0 Reporting Frequencies 3
4.0 Startup Monitoring and Reporting Procedures 4
5.0. Operations after startup 6

1.0 Facility Information

Facility name:	Brown Pelican CO_2 Sequestration Project BRP CCS2 Well
Facility contact:	[redacted]
Well location:	Penwell, Texas 31.76993805, -102.7332448

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements for the Brown Pelican CO_2 Sequestration Project (BRP Project or Project) are specified in this document and summarized below in Table 1.

Table 1—Injection Well Operating Conditions

Parameter/Condition	Limitation or Permitted Value	Units
Daily group maximum injection mass	2,116	Metric tons per day
Daily group average injection mass	1,931	Metric tons per day
Daily maximum injection mass BRP CCS2	1,500	Metric tons per day
Daily average injection mass BRP CCS2	1,112	Metric tons per day
Daily maximum injection rate BRP CCS2	25.0	Million standard cubic feet per day
Daily average injection rate BRP CCS2	21.9	Million standard cubic feet per day
Total mass BRP CCS2	4.87	Million metric tons
Group maximum injection rate	773,000	Metric tons per year
Group average injection rate	705,000	Metric tons per year
Maximum injection rate BRP CCS2	481,000	Metric tons per year
Average injection rate BRP CCS2	406,000	Metric tons per year
Maximum surface wellhead injection pressure BRP CCS2	1,800	psig
Maximum bottomhole injection pressure BRP CCS2	3,391.8	psig
Average bottomhole injection pressure BRP CCS2	3,300	psig
Minimum annulus pressure	100	psig
Minimum annulus pressure/tubing differential	100	psig

Limitations or permitted values for the maximum surface wellhead injection pressure, maximum bottomhole injection pressure, minimum annulus pressure, and minimum annulus pressure/tubing differential limitation are set as follows:

- **Maximum Surface Wellhead Injection Pressure:** CO_2 will be supplied by a dehydration and compression facility located approximately four miles northeast of the CO_2 Injector well location. The pressure at the facility discharge will be 2,500 psig. The CO_2 will then be routed via pipeline to valve stations near the injection well. Here the pressure will be reduced to 1,800 psig prior to reaching the wellhead. Pressure at the well will be controlled via control valves with shutdown protocols in place to protect the well in the event of a high-pressure scenario. Wellbore tubing pressure curves representative of the CO_2 Injector well will be created and calibrated after well construction.
- **Maximum Bottomhole Injection Pressure:** To meet EPA requirements in 40 CFR §146.88(a), the maximum pressure considered for the CO_2 Injector well is 90% of the

fracture opening pressure of the Injection Zone, measured using a downhole pressure gauge. The fracture pressure of the Injection Zone is determined from Step Rate Test data collected in the Shoe Bar 1AZ well that was drilled for the purposes of this Project. Reservoir modeling indicates the pore pressure required to move the effective stress state into tensile failure is near 3,785 psi at a depth of 5,115 ft below the ground surface. Maximum downhole injection pressure is therefore set to be less than 90% of that 3,785 psi threshold, calculated as follows:

$$0.9 \times 3{,}785 = 3{,}406.5 \text{ psia} - 14.7 \text{ psi} = 3{,}391.8 \text{ psig} \qquad \textit{Equation 1}$$

The maximum bottomhole injection pressure will be re-calculated based on logs and well information from the CO_2 Injection well after it is constructed.

- **Minimum Annulus Pressure:** As necessary to prevent "burst" or "collapse" of the tubing, the minimum annulus pressure is calculated as follows:

$$\text{Collapse Pressure} = \text{depth} \times [(\text{pressure gradient of formation}) + (\text{pressure gradient of cement}) - (\text{pressure gradient of water})] \qquad \textit{Equation 2}$$

$$\text{Burst Pressure} = \text{depth} \times (\text{pressure gradient of injectant}) + \text{surface pressure} \qquad \textit{Equation 3}$$

- **Minimum Annulus Pressure/Tubing Differential:** The annulus pressure/tubing differential is measured directly above and across the injection packer and is set to be a minimum of 100 psi above the surface wellhead injection pressure.

  If the downhole pressure gauge fails to function properly, then the maximum injection pressure shall immediately be limited by the maximum surface wellhead injection pressure until the downhole pressure gauge can be repaired or replaced.

3.0 Reporting Frequencies

Oxy Low Carbon Ventures, LLC (OLCV) will maintain the reporting frequencies as summarized below in Table 2.

Table 2—Class VI Reporting Frequencies

Activity	Minimum Reporting Frequency
Change to the CO_2 stream characterization	Semi-annually
Monthly injection pressure, flow rate, volume, pressure on the annulus, annulus fluid level, and temperature (Min, Max, and Avg.)	Semi-annually
Corrosion monitoring	Semi-annually
Monthly and cumulative volume and mass of the carbon dioxide stream injected	Semi-annually

Activity	Minimum Reporting Frequency
Monthly annulus fluid volume added	Semi-annually
Results and reports for the monitoring systems proposed: plume tracking, above confining zone monitoring, surface monitoring	Semi-annually
Description of any event that triggers a shutoff device and the response taken	Semi-annually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semi-annually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT*	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results 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: The reporting frequency for MIT will comply with TAC Title 16 Chapter 5.206(e)(1): "The operator of an anthropogenic CO2 injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone."

All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document of this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR §146.91 reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

The procedures related to the startup of operations, as well as monitoring and reporting during startup, are specified in this section. The injection rates will be gradually increased to the planned rate over a period of six (6) days.

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(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 Injector well.

(2) During the startup period, the permittee will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.

(3) A series of successively higher injection rates will be applied, as shown in Table 3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 1,800 psig, which is measured at the wellhead.

(4) The planned injection rates are shown in Table 3.

Table 3—Planned Injection Rates During Startup

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Pressure (%)
493	24	40
617	24	50
740	24	60
863	24	70
986	24	80
1,110	24	90

(5) The injection rates will be controlled with variable frequency drive pumps.

(6) The injection rates will be measured and recorded using an orifice flowmeter.

(7) Surface and downhole pressures and temperatures will be measured and recorded.

(8) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented, and the project team will look for any evidence of anomalous pressure behavior.

(9) If during the startup period any anomalous pressure behavior is observed, additional logging and modification of the injection rate program may be conducted to characterize the anomaly better. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and the line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

(a) The instantaneous shut-in pressure (ISIP) will be measured.

(b) The permittee will notify the agency within 24 hours of the determination.

(c) The permittee will consult with the agency before initiating any further injection.

5.0. Operations after startup

Automatic alarms and automatic shutoff systems will be installed and maintained. Successful function of the alarm system and shutoff system will be demonstrated prior to injection and once annually thereafter.

At all times, pressure will be maintained on the well to prevent the return of the injection fluid to the surface. The wellbore must be filled with a high-specific-gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed that 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.

- OLVC shall cease injection should it appear that the well is lacking mechanical integrity or that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW.

Permittee will cease injection according to the guidelines provided below:

- OLCV must shut in the well by gradual reduction of the injection pressure as outlined in the Summary of Operating Conditions document of this permit; or
- OLCV must immediately cease injection and shut in the well as outlined in the Emergency and Remedial Response Plan document of this permit.

SUMMARY OF OPERATING CONDITIONS: BRP CCS3
40 CFR §146.82 (a)(7) and (10) and §146.88 (e)

Brown Pelican CO_2 Sequestration Project

1.0 Facility Information 1
2.0 Injection Well Operating Conditions 1
3.0 Reporting Frequencies 3
4.0 Startup Monitoring and Reporting Procedures 4
5.0. Operations after startup 6

1.0 Facility Information

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS3Well

Facility contact: [redacted]

Well location: Penwell, Texas
31.76031163, -102.7101566

2.0 Injection Well Operating Conditions

Key injection well operating and project reporting requirements for the Brown Pelican CO_2 Sequestration Project (BRP Project or Project) are specified in this document and summarized below in Table 1.

Table 1—Injection Well Operating Conditions

Parameter/Condition	Limitation or Permitted Value	Units
Daily group maximum injection mass	2,116	Metric tons per day
Daily group average injection mass	1,931	Metric tons per day
Daily maximum injection mass BRP CCS3	600	Metric tons per day
Daily average injection mass BRP CCS3	450	Metric tons per day
Daily maximum injection rate BRP CCS3	9.02	Million standard cubic feet per day
Daily average injection rate BRP CCS3	8.10	Million standard cubic feet per day
Total mass BRP CCS3	1.77	Million metric tons
Group maximum injection rate	773,000	Metric tons per year
Group average injection rate	705,000	Metric tons per year
Maximum injection rate BRP CCS3	166,000	Metric tons per year
Average injection rate BRP CCS3	153,000	Metric tons per year
Maximum surface wellhead injection pressure BRP CCS3	1,100	psig
Maximum bottomhole injection pressure BRP CCS3	2,625.3	psig
Average bottomhole injection pressure BRP CCS3	2,600.3	psig
Minimum annulus pressure	100	psig
Minimum annulus pressure/tubing differential	100	psig

Limitations or permitted values for the maximum surface wellhead injection pressure, maximum bottomhole injection pressure, minimum annulus pressure, and minimum annulus pressure/tubing differential limitation are set as follows:

- **Maximum Surface Wellhead Injection Pressure:** CO_2 will be supplied by a dehydration and compression facility located approximately four miles northeast of the CO_2 Injector well location. The pressure at the facility discharge will be 2,500 psig. The CO_2 will then be routed via pipeline to valve stations near the injection well. Here the pressure will be reduced to 1,100 psig prior to reaching the wellhead. Pressure at the well will be controlled via control valves with shutdown protocols in place to protect the well in the event of a high-pressure scenario. Wellbore tubing pressure curves representative of the CO_2 Injector well will be created and calibrated after well construction.
- **Maximum Bottomhole Injection Pressure:** To meet EPA requirements in 40 CFR §146.88(a), the maximum pressure considered for the CO_2 Injector well is 90% of the

fracture opening pressure of the Injection Zone, measured using a downhole pressure gauge. The fracture pressure of the Injection Zone is determined from Step Rate Test data collected in the Shoe Bar 1AZ well that was drilled for the purposes of this Project. Reservoir modeling indicates the pore pressure required to move the effective stress state into tensile failure is near 2933 psi at a depth of 4,609 ft below the ground surface. Maximum downhole injection pressure is therefore set to be less than 90% of that 2,933 psi threshold, calculated as follows:

$$0.9 \times 2{,}933 = 2{,}640 \text{ psia} - 14.7 \text{ psi} = 2{,}625.3 \text{ psig} \qquad \textit{Equation 1}$$

The maximum bottomhole injection pressure will be re-calculated based on logs and well information from the CO_2 Injection well after it is constructed.

- **Minimum Annulus Pressure:** As necessary to prevent “burst” or “collapse” of the tubing, the minimum annulus pressure is calculated as follows:

$$\text{Collapse Pressure} = \text{depth} \times [(\text{pressure gradient of formation}) + (\text{pressure gradient of cement}) - (\text{pressure gradient of water})] \qquad \textit{Equation 2}$$

$$\text{Burst Pressure} = \text{depth} \times (\text{pressure gradient of injectant}) + \text{surface pressure} \qquad \textit{Equation 3}$$

- **Minimum Annulus Pressure/Tubing Differential:** The annulus pressure/tubing differential is measured directly above and across the injection packer and is set to be a minimum of 100 psi above the surface wellhead injection pressure.

  If the downhole pressure gauge fails to function properly, then the maximum injection pressure shall immediately be limited by the maximum surface wellhead injection pressure until the downhole pressure gauge can be repaired or replaced.

3.0 Reporting Frequencies

Oxy Low Carbon Ventures, LLC (OLCV) will maintain the reporting frequencies as summarized below in Table 2.

Table 2—Class VI Reporting Frequencies

Activity	Minimum Reporting Frequency
Change to the CO_2 stream characterization	Semi-annually
Monthly injection pressure, flow rate, volume, pressure on the annulus, annulus fluid level, and temperature (Min, Max, and Avg.)	Semi-annually
Corrosion monitoring	Semi-annually
Monthly and cumulative volume and mass of the carbon dioxide stream injected	Semi-annually

Activity	Minimum Reporting Frequency
Monthly annulus fluid volume added	Semi-annually
Results and reports for the monitoring systems proposed: plume tracking, above confining zone monitoring, surface monitoring	Semi-annually
Description of any event that triggers a shutoff device and the response taken	Semi-annually
Description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit	Semi-annually
Any injectivity test performed in the well	Notification 30 days before and results within 30 days of completion of test
External Mechanical Integrity Test (MIT) and internal MIT*	Notification 30 days before and results within 30 days of completion of test
Pressure falloff testing	Notification 30 days before and results within 30 days of completion of test
Planned workover or well stimulation	Notification 30 days before and results within 30 days of completion of test
Monitoring well MITs	Notification 30 days before and results 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: The reporting frequency for MIT will comply with TAC Title 16 Chapter 5.206(e)(1): “The operator of an anthropogenic CO2 injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone.”

All testing and monitoring frequencies as well as methodologies are included in the Testing and Monitoring Plan document of this permit.

The events that trigger an immediate emergency response should be reported within 24 hours, according to the 40 CFR §146.91 reporting requirements.

4.0 Startup Monitoring and Reporting Procedures

The procedures related to the startup of operations, as well as monitoring and reporting during startup, are specified in this section. The injection rates will be gradually increased to the planned rate over a period of six (6) days.

The procedures detailed below describe how OLCV will initiate injection and conduct startup-specific monitoring of the CO_2 Injector well, pursuant to 40 CFR §146.90.

The multistage (step-rate) startup procedure and period only apply to the initial start of injection operations until the well reaches the full injection rate. Monitoring frequencies and methodologies after the initial startup will follow the Testing and Monitoring Plan document of this permit.

(1) This procedure will be performed using the existing surface and downhole pressure and temperature gauges in the CO_2 Injector well.

(2) During the startup period, the permittee will submit a daily report summarizing and interpreting the operational data. At the request of the EPA, the permittee may be required to schedule a daily conference call to discuss this information.

(3) A series of successively higher injection rates will be applied, as shown in Table 3 below in Step 4. The elapsed time and pressure values will be read and recorded for each rate and timestep. At no point during the procedure will the injection pressure be allowed to exceed the maximum injection pressure of 1,100 psig, which is measured at the wellhead.

(4) The planned injection rates are shown in Table 3.

Table 3—Planned Injection Rates During Startup

Rate (tonnes per day)	Duration (hours)	Percent of Permit Maximum Injection Pressure (%)
202	24	40
253	24	50
303	24	60
354	24	70
404	24	80
455	24	90

(5) The injection rates will be controlled with variable frequency drive pumps.

(6) The injection rates will be measured and recorded using an orifice flowmeter.

(7) Surface and downhole pressures and temperatures will be measured and recorded.

(8) During the startup period, a plot of injection rates and their corresponding stabilized pressure values will be graphically represented, and the project team will look for any evidence of anomalous pressure behavior.

(9) If during the startup period any anomalous pressure behavior is observed, additional logging and modification of the injection rate program may be conducted to characterize the anomaly better. The project team will also determine if the observed anomalous pressure behavior indicates formation fracturing, which will cause the injection to cease and the line valve to be closed, allowing the pressure to bleed off into the injection zone, as discussed below:

    (a) The instantaneous shut-in pressure (ISIP) will be measured.

    (b) The permittee will notify the agency within 24 hours of the determination.

(c) The permittee will consult with the agency before initiating any further injection.

5.0. Operations after startup

Automatic alarms and automatic shutoff systems will be installed and maintained. Successful function of the alarm system and shutoff system will be demonstrated prior to injection and once annually thereafter.

At all times, pressure will be maintained on the well to prevent the return of the injection fluid to the surface. The wellbore must be filled with a high-specific-gravity fluid during workovers to maintain a positive (downward) gradient and/or a plug shall be installed that 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.

- OLVC shall cease injection should it appear that the well is lacking mechanical integrity or that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW.

Permittee will cease injection according to the guidelines provided below:

- OLCV must shut in the well by gradual reduction of the injection pressure as outlined in the Summary of Operating Conditions document of this permit; or
- OLCV must immediately cease injection and shut in the well as outlined in the Emergency and Remedial Response Plan document of this permit.

AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR §146.84(b)

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1.0 Facility Information

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS1, CCS2 and CCS3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

2.0 Computational Modeling Approach

Pursuant to 40 CFR §146.86, this plan delineates the Area of Review (AoR) and describes the corrective action plans for wells that require corrective action. Delineation of the AoR is one of the key elements of the Class VI Rule to ensure Underground Sources of Drinking Water (USDW) in the region surrounding the geologic sequestration project may not be endangered by the injection activity.

The AoR is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The AoR is delineated using multiphase CO_2-brine transport computational modeling, constructed from a geocellular model that accounts for the site-specific hydrogeology and the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids. The AoR delineation is based on available site characterization, monitoring, and operational data as set forth in §146.84. The methods and approaches for developing this complex multiphase simulation model and delineating the AoR are provided below.

2.1 Simulation Model Background

2.1.1 Geocellular Model Introduction

The characterization effort and geocellular modeling workflow undertaken for the Brown Pelican CO_2 Sequestration Project (BRP Project or Project) follows the industry-accepted best practices of Kerans and Tinker (1997). The geocellular model was constructed using Schlumberger's Petrel (v2021) geostatistical modeling software, which is a "reliable technology" for reserve estimation, as defined by the US Securities and Exchange Commission (Society of Petroleum Engineers 2018). Application of this software has been reliably demonstrated in numerous peer-reviewed journals (e.g., Palermo et al. 2010; Rush and Rankey 2017; He et al. 2019) and from Carbon Capture and Sequestration investigations (e.g., Hosseini et al. 2012; Holubnyak et al. 2014).

2.1.2 Simulation Model Name and Authors

The model was created using the GEM (v2022.10) reservoir simulator with the Greenhouse Gas (GHG) module, from Computer Modeling Group Ltd. (CMG).

2.1.3 Description of the Simulation Model

GEM is a commercially available, compositional, finite-difference simulator that is commonly used to model hydrocarbon production, enhanced oil recovery, and other thermodynamic and fluid flow reservoir processes. GEM has also been used to model carbon capture and storage projects. The GEM's Greenhouse Gas (GHG) module accounts for the thermodynamic interactions between three phases: a H_2O-rich phase (liquid), CO_2-rich phase (gas), and a solid phase, which may include several minerals. Physical properties (e.g., density, viscosity, enthalpy) of the H_2O and CO_2 phases and CO_2 solubility in H_2O are calculated from a correlation suitable for a wide range of typical CO_2 storage formation conditions, including temperature ranges between 54°F and 300°F and pressures up to 16,000 psi. Details of this method can be found in Collins et al. (1992), Thomas and Thurnau (1983), and Nghiem and Li (1989).

The phase interactions throughout the simulations are governed as follows:

- The CO_2-rich phase (gas) density is obtained using the Peng-Robinson equation of state. The model was calibrated and modified as described in *Equation 1* (Peng and Robinson 1976).
- The CO_2 dissolution in brine is calculated from Henry's Law Constant Correlation using Harvey's method (Harvey 1996).
- The brine density is specified at a reference pressure of 2,200 psi. The brine viscosity is calculated using the Kestin et al. (1981) correlation.
- The CO_2 gas viscosity is calculated per the methods described by Pedersen et al. (1984).

The Peng-Robinson equation of state, as described above, takes this form:

$$p = \frac{RT}{v - b_{mix}} - \frac{a_{mix}}{v^2 + 2vb_{mix} - b^2} \qquad \textit{Equation 1}$$

Where, v is the molar volume, p is the pressure, T is the temperature in Kelvin, R is the universal gas constant, and a_{mix} and b_{mix} are the mixture-specific functions of temperature and composition calculated from the critical properties and acentric factors of the components. The CMG WinProp software used with GEM has a built-in library for the properties of CO_2 and CH_4, based on Reid et al. (1977). No changes were made to the library components.

The transition between liquid and gaseous CO_2 can lead to rapid density changes in the gas phase. The simulator uses a narrow transition interval between the liquid and gaseous density to represent the two-phase CO_2 region.

The compression facility controls the CO_2 delivery temperature to the injection well, keeping it between 70°F and 110°F. Consequently, the temperature of the injectant will be comparable to the reservoir formation temperature at the injection interval. Therefore, the simulations were based on isothermal operating conditions with a linear initial reservoir temperature gradient of 0.0072°F/ft and a surface temperature of 70°F.

With respect to the timestep selection, the software algorithm optimizes the timestep duration based on the specific convergence criteria designed to minimize numerical artifacts. For these simulations, the timestep size ranged from 0.001 days to 30 days. In all cases, the maximum solution change over a timestep is monitored and compared to a specified target. Convergence is achieved once the model reaches the maximum tolerance where small changes of the temperature and pressure calculation results occur on successive iterations. Timesteps are chosen so that the predicted solution change is less than the specified target.

2.2 Site Characteristics

2.2.1 Site Overview

A detailed regional and local geologic evaluation of the area around the BRP Project was conducted using geological, geophysical, and petrophysical data obtained from public literature, licensed data, and site-specific data collected for this project. These data are described in the following sections.

The BRP Project is located approximately 20 miles southwest of Odessa, Texas on the Shoe Bar Ranch. Part of the surface acreage is owned by OLCV, and the remaining acreage is leased by OLCV. OLCV conducted a surface assessment of the site to determine its suitability for CO_2 sequestration. The surface assessment included a review of high-resolution satellite imagery and high-resolution drone imagery to determine the presence or absence of surface water, springs, mines, or quarries. The United States Geological Survey (USGS) maintains a database of historical, current and prospective mines. The following sources were consulted to identify surface and near-surface features:

- USGS Mineral Resources Data System[1]
- High-resolution satellite imagery (licensed from Maxar)
- High-resolution drone imagery acquired in July 2023 for this Project

Based on review of these data, there are no springs, mines, or quarries in the BRP AoR. Two small ephemeral ponds are located outside of the AoR, but within the Shoe Bar Ranch.

Environmental Protection Agency (EPA), Texas Commission on Environmental Quality (TCEQ), and the Texas Railroad Commission (TRRC) databases were consulted to determine if the site contained groundwater contamination, industrial or hazardous waste facilities, petroleum tanks, superfund sites or brownfields.

- TCEQ Groundwater Contamination Viewer[2]
- TCEQ Industrial and Hazardous Waste Facility Viewer[3]
- TCEQ Petroleum Storage Tank Viewer[4]
- TCEQ Brownfields Viewer[5]
- TCEQ Superfund Sites Viewer[6]
- EPA Superfund Sites Viewer[7]
- TRRC Data (Including Brownfields) Viewer[8]

Based on a review of these data, there is no groundwater contamination, no industrial or hazardous waste sites, no petroleum storage tanks, no brownfields, and no superfund sites in the BRP AoR. Figure 1 shows surface features of the BRP Project site.

[1] https://mrdata.usgs.gov/mrds/map-commodity.html

[2] https://www.tceq.texas.gov/gis/groundwater-contamination-viewer

[3] https://www.tceq.texas.gov/gis/ihw-viewer

[4] https://www.tceq.texas.gov/gis/petroleum-storage-tanks-pst-viewer

[5] https://gis-tceq.opendata.arcgis.com/datasets/brownfields-points/explore?location=31.691297%2C-102.767404%2C9.63

[6] https://www.tceq.texas.gov/remediation/superfund/sites/county/ector.html

[7]https://www.arcgis.com/apps/webappviewer/index.html?id=b3d2408f1fb24a03bb68157c91c446b2&extent=-21022431.7148%2C1332394.4297%2C-7843465.046%2C8787756.4205%2C102100

[8] https://gis.rrc.texas.gov/GISViewer/

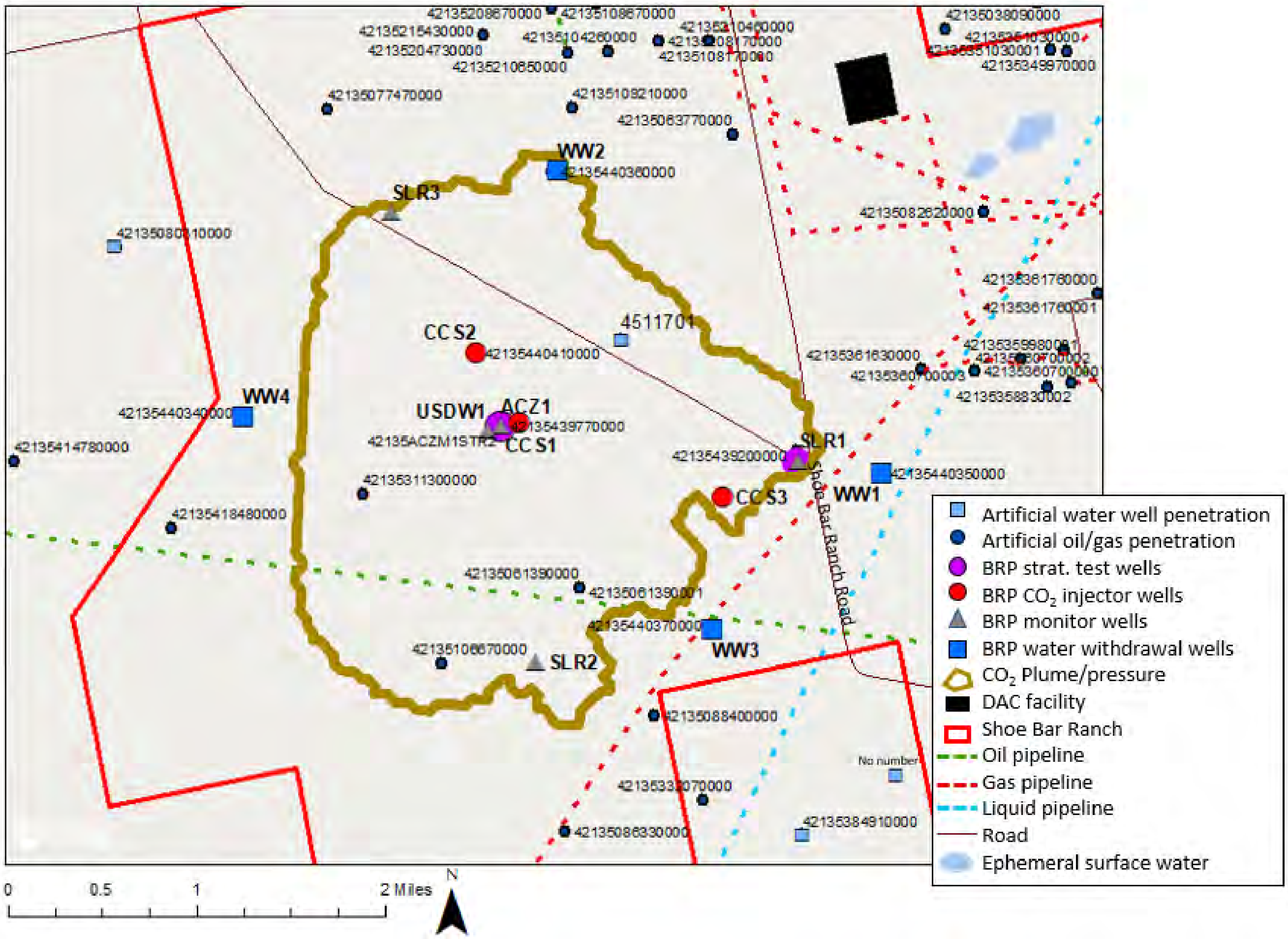

Figure 1—Overview of the BRP Project site AoR

For purposes of this application, the Project site encompasses the areas depicted in Figure 1 and 2 and include: (1) the AoR, (2) the Area of Interest (AoI), which is the area surrounding the AoR in the western half of the Shoe Bar Ranch (SBR) boundary; (3) the Shoe Bar Ranch (SBR), which is the surface land on which the Project is located; and (4) the simulation model outline that encompasses the area of SBR with an approximately one-mile buffer (Figure 2). The Project site includes the total extent of these four areas. The AoR in Figures 1 and 2 represents the combination of maximum extent of CO_2 plume at 50 years post-injection and the pressure plume at the stop of injection in January 2037.

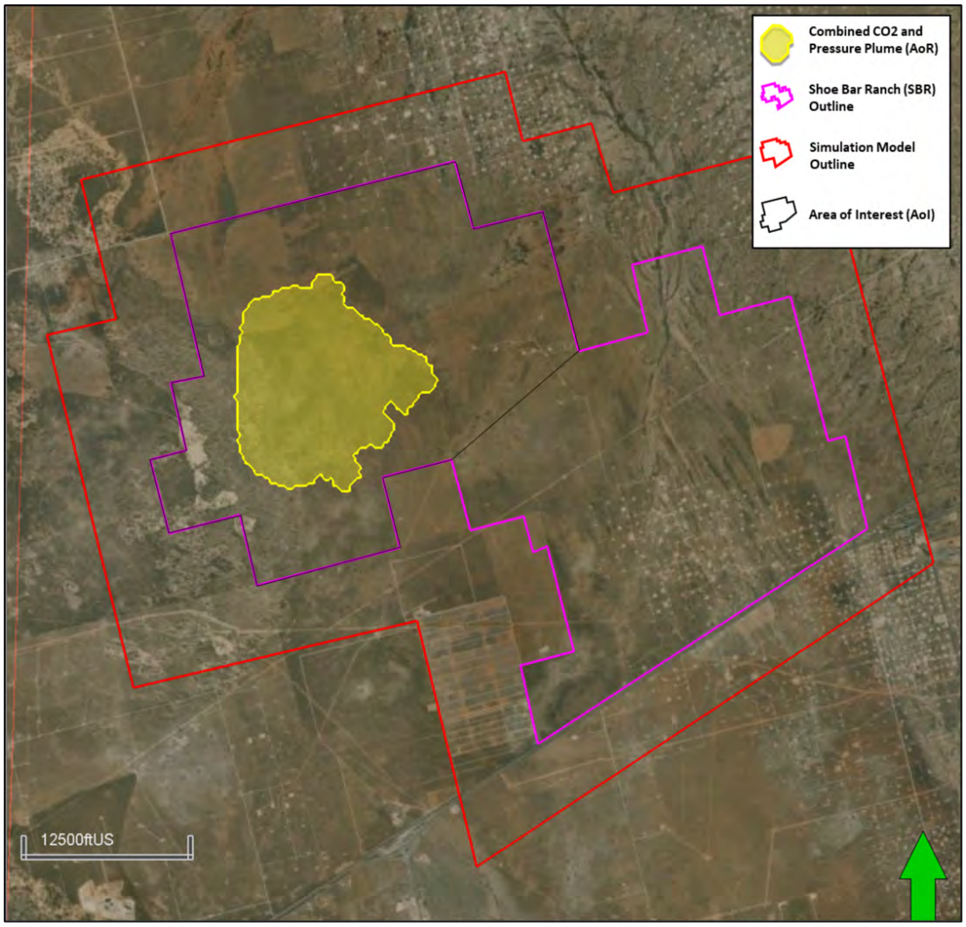

Figure 2—Definition of the outlines used in the Area of Review and Corrective Action Plan document.

2.2.2 Physical Geography

Surface geology in and around Shoe Bar Ranch (Figure 3 and Figure 4) primarily consists of Holocene sand and silt, dunes and dune ridges, caliche, associated alluvium, and other undivided Quaternary deposits (Eifler 1975). The Cretaceous Antlers Sand [Rock Unit Code: Ka] (sandstone, mudstone, and siliciclastic conglomerates) and Triassic Dockum Group [Rock Unit Code: TRd] (shale, sandstone-mudstone, some limestone, and siliciclastic conglomerates) outcrop East of Shoe Bar Ranch (Lehman 1994; Eifler 1975; mrdata.usgs.gov). Surface elevation in and around SBR is approximately 3,000 ft above sea level with a dip of 0.25° towards the southwest based on US Geological Survey (USGS) topographic maps (services.arcgisonline.com).

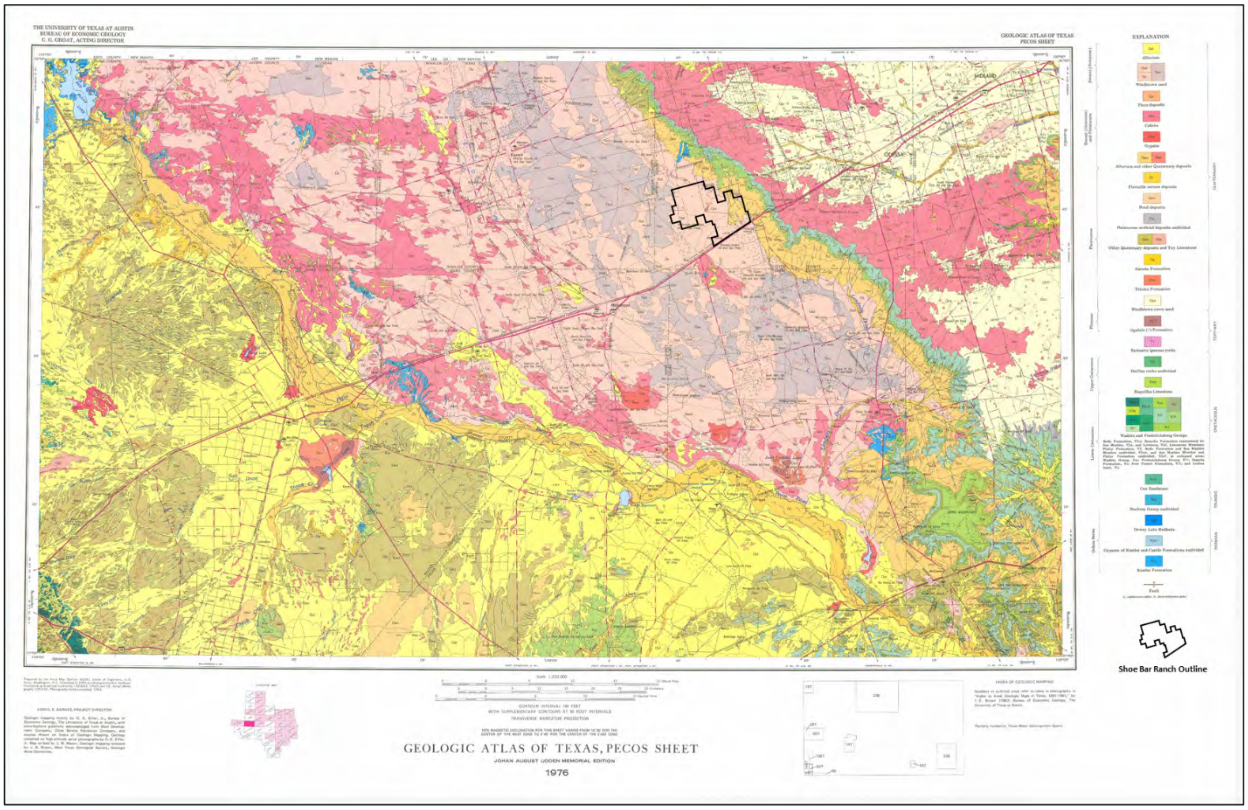

Figure 3—1:250,000 scale surface geology map, Pecos Sheet, Geological Atlas of Texas (Eifler 1975). The Shoe Bar Ranch is outlined in black.

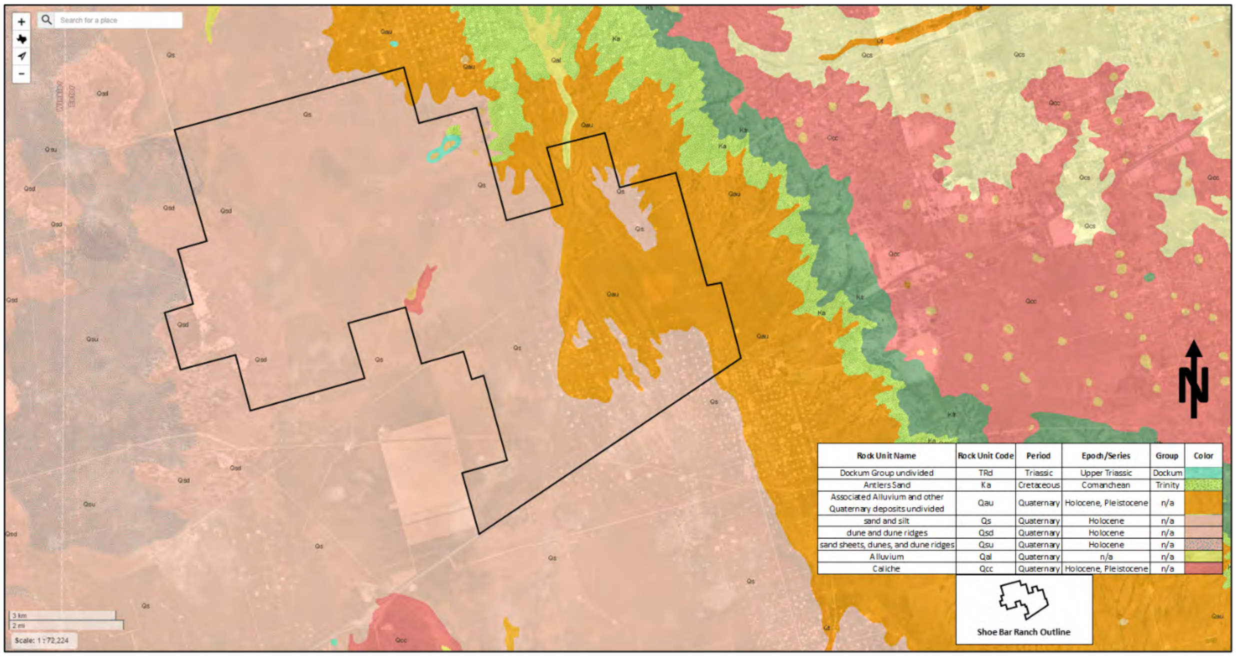

Figure 4—Detailed screenshot of surface geology in the vicinity of Shoe Bar Ranch (from https://txpub.usgs.gov).

2.2.2 Regional Geology

The Permian Basin encompasses an area of approximately 250×300 miles and extends across West Texas and southeastern New Mexico (Figure 5). Three major divergent and convergent tectonic events shaped the geometry of the Permian Basin:

1. Neoproterozoic-Cambrian age rifting of Rodinia (Mosher et al. 2004, Ewing et al. 2019);
2. Convergence during the Mississippian-Permian age Ancestral Rocky Mountains and Ouachita-Marathon orogenies (Yang and Dorobek 1995); and
3. The Eocene-Oligocene Laramide orogeny (Henry and Price 1986) (Figure 6).

The Permian Basin was initiated during the Late Mississippian to Early Pennsylvanian as a structurally segmented foreland basin resulting from north-directed convergence of the South American (Gondwanan) plate along the southern margin of the North American (Laurentian) plate (Ross 1986; McBride 1989; Reed and Strickler 1990; Yang and Dorobek 1995). Outcrop-intensive studies of the Ouachita-Marathon orogeny include King's (1937) classic study of the Marathon fold-and-thrust belt, with more recent studies focusing on syntectonic depositional processes and carbonate platform evolution and provenance of Permian Basin siliciclastic sands (Soto-Kerans et al. 2020; Janson and Hairabian 2016). Convergence and thrust-loading of the North American plate peaked in the Late Pennsylvanian to Early Permian and was followed by isostatic adjustment through fault reactivation and strain-transfer across inherited Proterozoic–Cambrian structures that produced N-S elongated, fault-bound carbonate platforms, and deep marine (1,000+ ft water depth) siliciclastic-rich basins (Yang and Dorobek 1995; Ewing et al. 2019). Major resulting paleogeographic features include the carbonate-dominated Central Basin Platform, and the siliciclastic-dominated deepwater Delaware Basin and Midland Basin (Figure 5 and 7).

Only minimal tectonic deformation occurred in the Permian Basin since the late Paleozoic, so the present structural features are essentially the same as those inherited from Proterozoic–Early Permian orogenic events (Hills 1984; Ward et al. 1986; Ewing et al. 1993; Yang and Dorobek 1995). The most recent tectonic divergence includes Cenozoic Basin and Range extension and Rio Grande rifting (Henry and Price 1986). These events have generated a complex and regional network of Miocene and younger normal faults that predominantly impact the western margin of the Delaware Basin, where Permian strata have been exhumed along escarpments and westward-dipping horst and grabens that are incised by canyons (King 1948; Boyd 1958).

Regional cross-sections from Yang and Dorobek (1995) demonstrate that Wolfcampian strata are the last interval cut by major basement-rooted faults that bound the Central Basin Platform and further illustrate that upper Pennsylvanian through Wolfcampian strata were deposited across the Permian Basin area during the most significant phase of deformation, as basement-rooted faults are largely absent in Leonardian and younger strata. This observation is consistent with seismic data in the AoI (see Section 2.2.4 Structural Setting).

The Permian Basin of West Texas and New Mexico consists of Wolfcampian to Late Ochoan cyclic and mixed carbonate-siliciclastic-evaporite strata. Platform top depositional environments include the following: salty anhydritic salinas, siliciclastic-rich eolian dunes, carbonate-rich tidal flats, oolitic shorelines and tidal bars, and open-marine shelves (Silver and Todd 1969). The Delaware and Midland basins consist of sand-filled, slope-incised channels and silt-rich slopes that pass basinward into deep-marine (500- to 1,800-ft water depths) turbiditic sandstones and pelagic mudstones (King 1948; Gardner et al. 2003). Formation-scale stratigraphic units provide a complex record of episodic deposition that was driven by the rise and fall of sea levels (100+ ft) (Meissner 1972). This record is characterized by periods of sediment starvation within the basins concurrent with development of basin-fringing carbonate platforms, followed by periods of platform erosion and sediment bypass to the basin floor. During the Late Permian, the Midland Basin became the site of a large evaporitic flat, as recorded by the shallow marine deposits of the Queen Formation. In contrast, the Delaware Basin was infilled by the Late Permian Castile and Salado evaporites that were ultimately deposited across the entire Permian Basin region, including the Northwest Shelf and Central Basin Platform (King 1948).

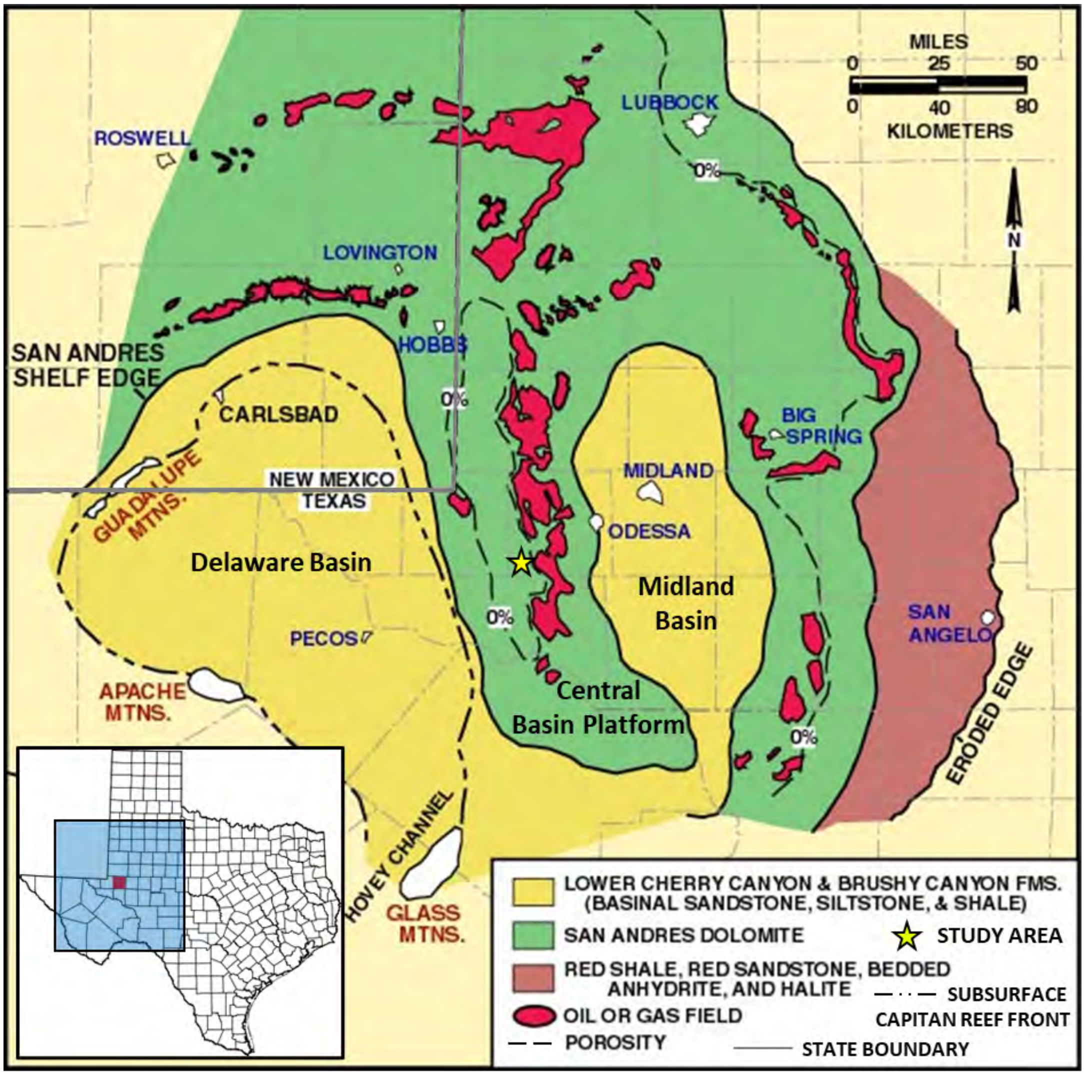

Figure 5—Map of the Permian Basin with the Delaware Basin, Midland Basin, Central Basin Platform, and productive oil and gas fields in the San Andres Formation (after Ward et al. 1986).

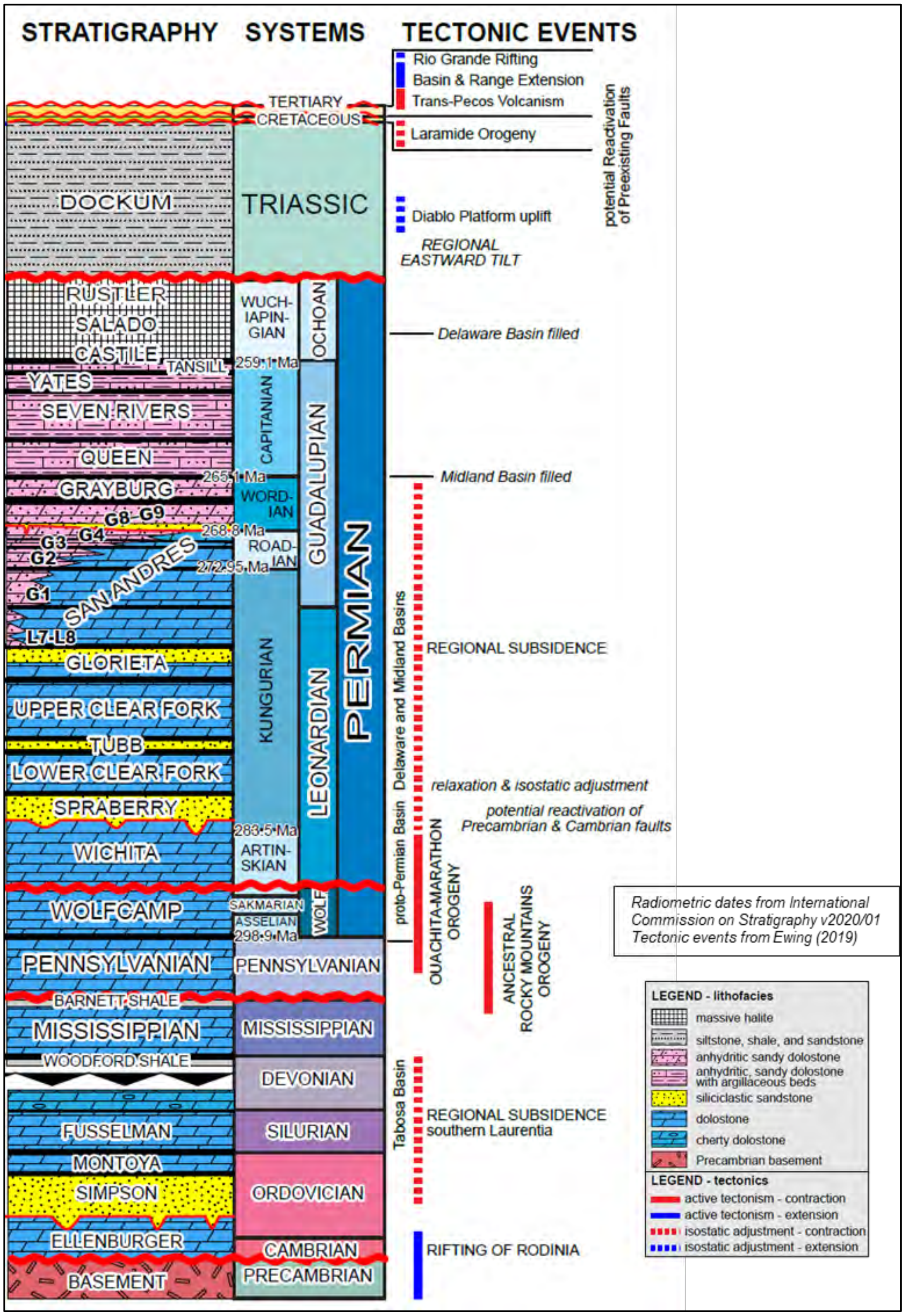

Figure 6—Stratigraphic column for the Central Basin Platform with tectonic events.

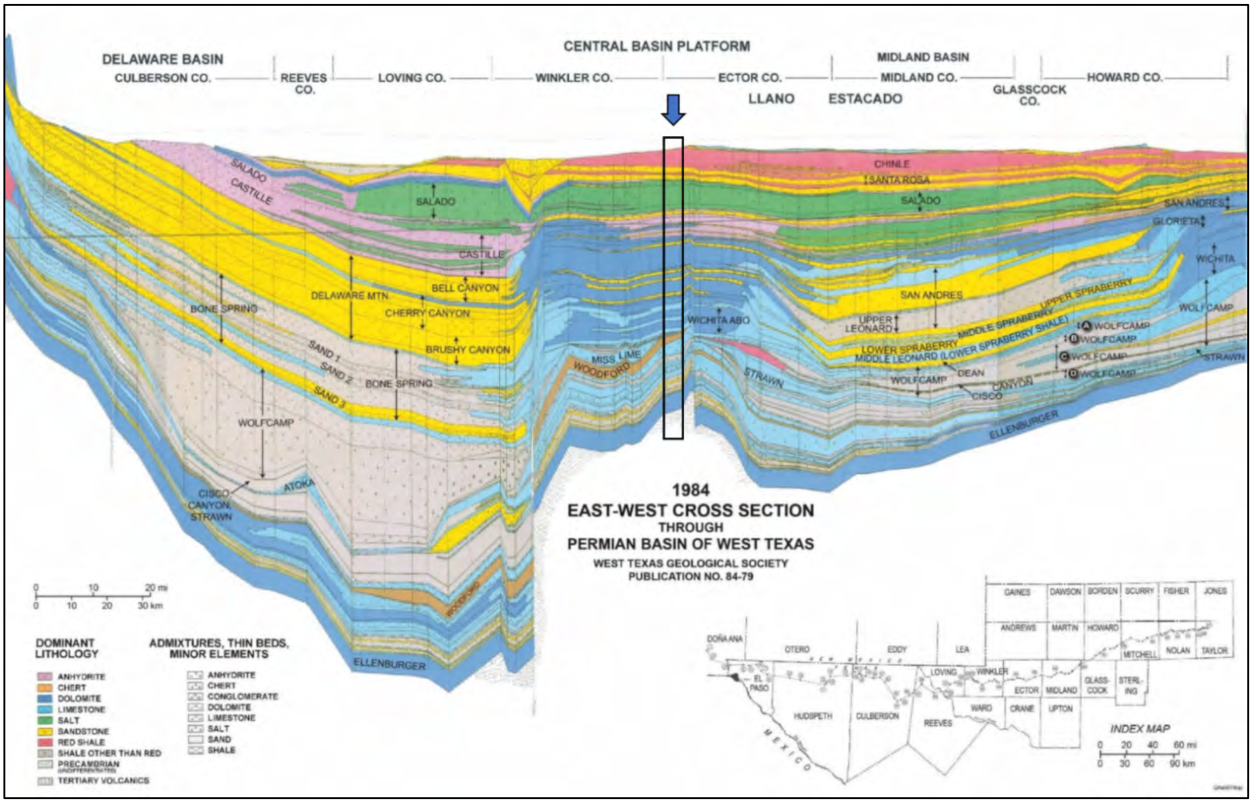

Figure 7—E-W cross section through the Permian Basin of West Texas (from Matchus and Jones 1984). Approximate AoI location on the Central Basin Platform is highlighted with blue arrow and black rectangle.

The San Andres Formation and its basinal equivalents—the Cutoff, uppermost Bone Spring, Brushy Canyon, and Cherry Canyon Formations—provide a complex record of reciprocal sedimentation characterized by periods of basin starvation and carbonate platform aggradation/progradation, followed by periods of platform subaerial exposure and siliciclastic sediment bypass to the basin floors (Figure 7). San Andres sedimentation in the Permian Basin took place in a subtropical setting. Plate reconstructions by Scotese and McKerrow (1990) place the Permian Basin just south of the paleoequator, but paleocurrent studies of approximately time-equivalent eolian strata of the Colorado Plateau (e.g., Coconino Formation) suggest a position 5° north of the paleoequator in the northern equatorial trade-wind belt (Fischer and Sarnthein 1988). This configuration agrees better with earlier work cited by Meissner (1972). Shallow-water carbonate deposits of the San Andres Formation occupied a 60-mile-wide belt separating evaporite-dominated inner-shelf sediments from the deeper-water carbonates of the upper Bone Spring Limestone and the siliciclastic-dominated deposits of the Delaware Mountain Group of the Delaware Basin and equivalent strata in the Midland Basin (Meissner 1972).

2.2.3 Stratigraphy

2.2.3.1 Overview

The CO_2 storage complex in the proposed Project consists of four main elements:

1. Injection Zone (Lower San Andres Formation) with three sub-zones (G4, G1, Holt);
2. Upper Confining Zone (Upper San Andres and Grayburg Formations);
3. Regional Seal / Upper Confining System (Queen through Rustler Formations); and
4. Lower Confining Zone (Upper Glorieta Formation) (Figure 8).

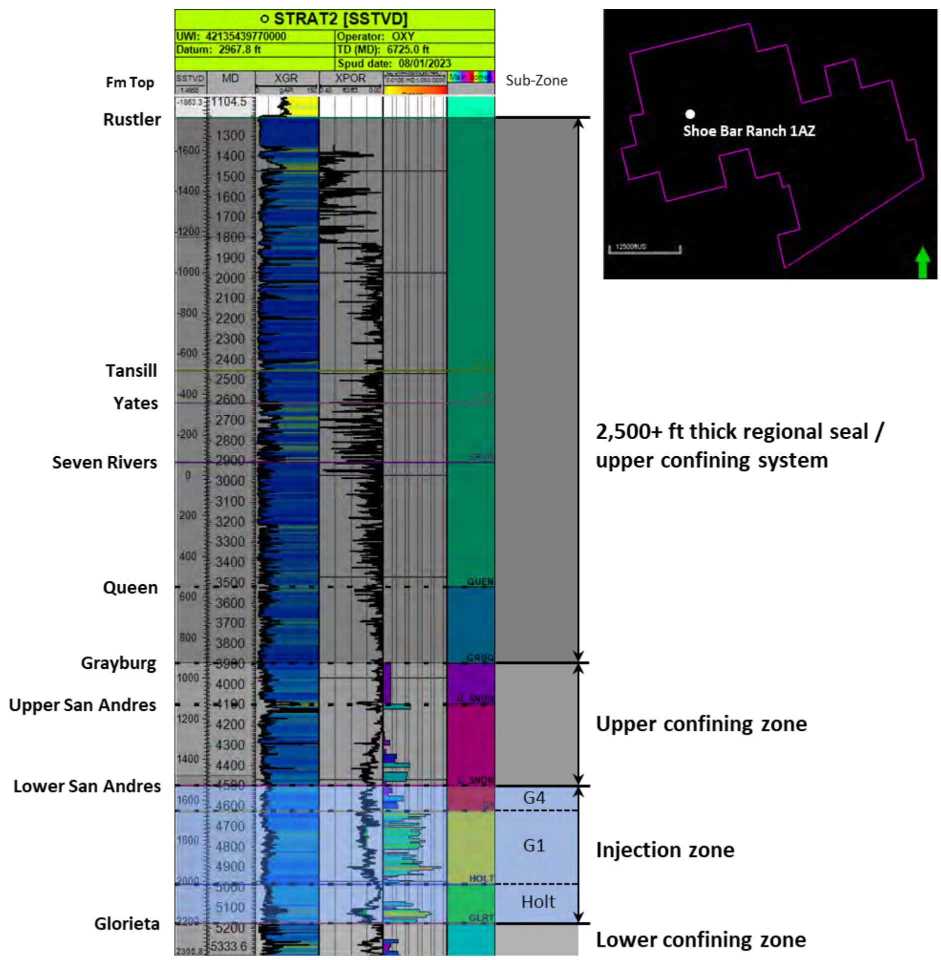

Figure 8—Stratigraphic column covering the Injection Zone, Upper Confining Zone, and Upper Confining System. UWI = Unique Well Identifier; SSTVD = True vertical depth subsea; MD = Measured depth; XGR = Gamma Ray log QCd by Oxy or OLCV petrophysicist; XPOR = porosity log QCd by Oxy or OLCV petrophysicist; K = Permeability

Well log measurements and whole core data from stratigraphic test wells Shoe Bar 1 and Shoe Bar 1AZ (Figure 8 and 9), as well as from the offset Penwell (Upper San Andres) oilfield (gft) were used for the characterization of the storage complex elements. Core analyses from the stratigraphic wells provided data on porosity, permeability, and capillary entry pressure of the Upper Confining Zone and Upper Confining System in the AoR.

2.2.3.2 Injection Zone

The Lower San Andres Formation exhibits good reservoir quality based on well log and core data in the AoI for each of the three sub-zones: G4 (average porosity = 9.7 %; average permeability = 1.2 mD), G1 (average porosity = 11.2 %; average permeability = 12 mD), Holt (average porosity = 9.4 %; average permeability = 18.8 mD). Data from the Shoe Bar 1 and Shoe Bar 1AZ wells are sufficient to adequately characterize the AoR because the rock and fluid properties from these wells were calibrated to seismic facies and extrapolated beyond the wellbores.

Seismic facies of the G4 and G1 sub-zones are characterized by medium-amplitude, medium continuity, sub-parallel, slightly inclined reflections throughout the 3D seismic coverage (Figures 9, 10A, 10B). Corresponding core facies encountered in Shoe Bar 1 and Shoe Bar 1AZ in sub-zones G4 and G1 are dominated by stacked grain-dominated and mud-dominated dolo-packstones.

Holt sub-zone seismic facies are characterized by high-amplitude, high continuity, sub-parallel, slightly inclined reflections in the western half of the 3D survey and low to medium-amplitude, low to medium-continuity, sub-parallel, slightly inclined reflections in the eastern half of the 3D survey (Figure 9, Figure 10C). Corresponding core facies encountered in the Holt sub-zone of Shoe Bar 1 are dominated by extensively leached and burrowed dolo-wackestones, which create a poor seismic impedance contrast. In contrast, core facies in the Holt sub-zone of Shoe Bar 1AZ comprise a 70’ thick tight calcite interval overlying grain-dominated dolo-packstones to dolo-wackestones, creating the strong impedance contrast seen in the seismic data.

Seismic facies observed at the Shoe Bar 1AZ are consistent with the seismic facies observed throughout the majority AoR. Based on calibration of seismic to log data, OLCV interprets that the rock and fluid properties are also anticipated to be consistent throughout the AoR. The seismic facies observed at Shoe Bar 1 are representative of seismic facies observed in the East of the AoR. More details on the seismic survey acquisition and processing are found in section 2.2.5 of this document.

[redacted]

Figure 9—Seismic cross section A-A' with key horizon interpretations and projected well trajectories. Note the change in seismic facies in the Holt sub-zone between Shoe Bar 1 and Shoe Bar 1AZ.

[redacted]

Figure 10—Amplitude extractions demonstrating similarity of seismic facies between Shoe Bar 1AZ and BRP CCS1 and BRP CCS2 in sub-zone G4 (A) and sub-zone G1 (B); amplitude extraction demonstrating change in seismic facies between Shoe Bar 1 and BRP CCS3 (C).

2.2.3.3 Upper Confining Zone

The BRP AoI is positioned in a more landward paleo-depositional environment relative to the producing Penwell oilfield (Figure 11). Therefore, the Upper San Andres Formation (main producing interval in Penwell field) exhibits tighter, more anhydritic supratidal facies and acts as the primary confining layer in the BRP Project. The Upper San Andres Formation was confirmed as a primary confining layer from well log and core data of the Shoe Bar 1 and Shoe Bar 1AZ Stratigraphic wells (average porosity = 6.1 %; average permeability = < 0.1 mD) (Figure 8). The Grayburg formation confining zone properties were also confirmed by porosity logs and MICP-derived porosity / permeability measurements in Shoe Bar 1 (average porosity = 4.1 %; average permeability = < 0.1 mD).

2.2.3.4 Regional Seal / Upper Confining System

The Queen through Rustler Formations form the regional seal / upper confining system and consist of regional, laterally continuous evaporites (anhydrite, halite), shale, and tight silt and form the 2,500-ft Permian regional seal complex for hydrocarbon accumulations in the Permian Basin. These Permian Basin deposits are one of the most extensively studied evaporite systems in the world (Beauheim and Roberts 2002; Anderson et al. 1972; Espinoza and Santamarina 2017; Kendall and Harwood 1989; Dean et al. 2000). These evaporite formations are interbedded with clay and siltstone marker beds that are traceable across much of the western Permian Basin (Anderson et al. 1972). Espinoza and Santamarina (2017) summarized the properties of common lithologies forming confining systems from carbon sequestration projects across the globe, including CO_2 breakthrough pressure for typical top seals (confining layer) such as anhydrite, which form the confining system overlying the Injection Zone. The high capillary entry pressure and low permeability make these lithologies a suitable cap rock for carbon sequestration projects (Espinoza and Santamarina, 2017), in addition to their proven track record of trapping and containing oil and gas in the Permian Basin for 200+ million years (Fairhurst et al., 2021).

2.2.3.5 Lower Confining Zone

Based on petrophysically vetted porosity log measurements in the AoI and NMR-derived permeability estimates from Shoe Bar 1 and Shoe Bar 1AZ stratigraphic wells, the Upper Glorieta Formation exhibits a porosity of <1% and <0.1 mD of permeability and will act as the lower confining layer of the CO_2 storage complex (Figure 8).

2.2.3.6 Environment of Deposition

The proposed storage complex is located approximately 5 miles NW of the Penwell (Upper San Andres) oilfield in a downdip position relative to Penwell (Figure 11). The depositional model for the San Andres Formation in the Penwell oilfield is a low-angle carbonate ramp with shoaling-upward cycles of shallow marine to tidal flat facies (Major et al. 1990; Figure 12). The primary injection and production zone at Penwell is the Upper San Andres (G8-G9).

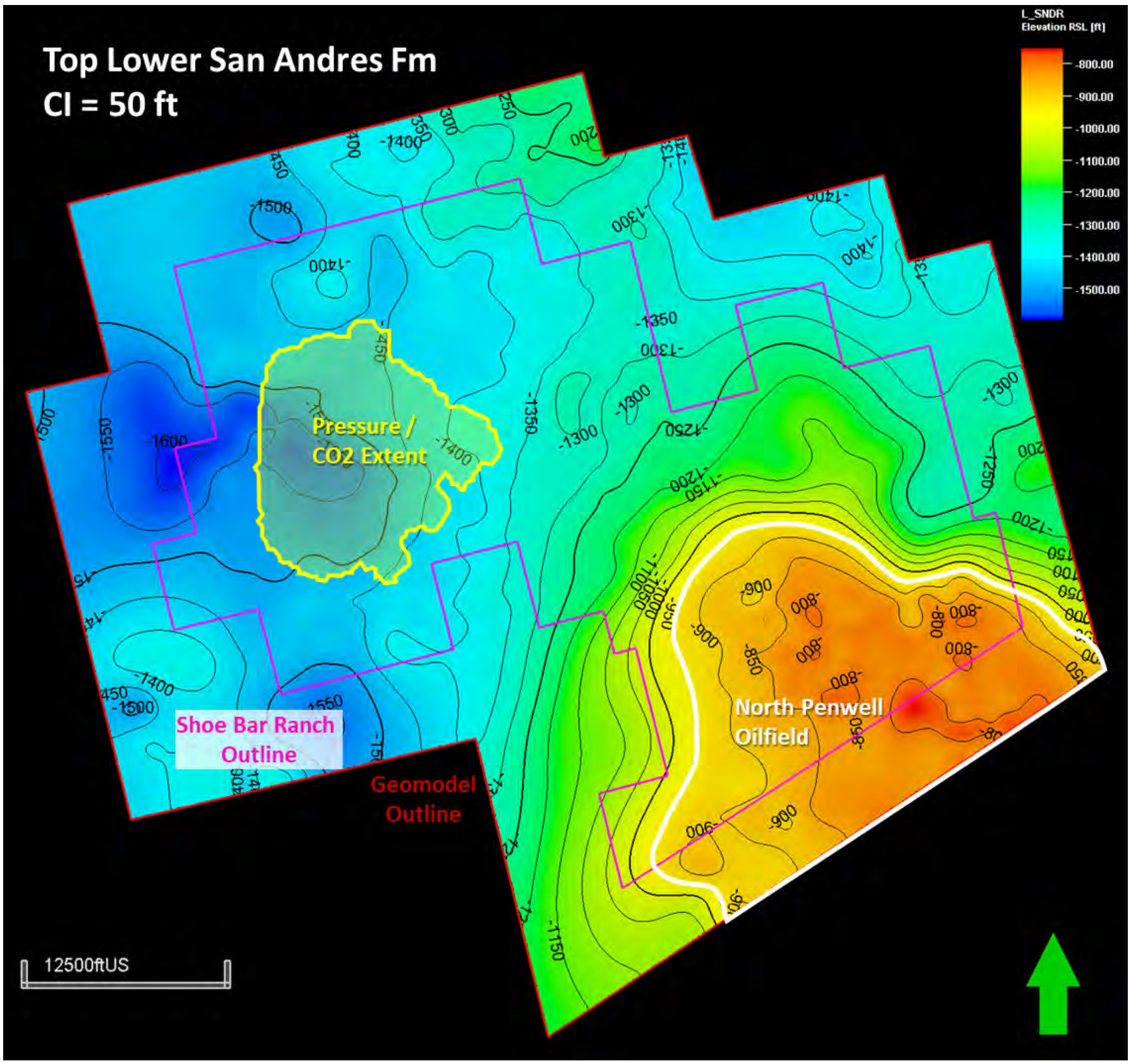

Figure 11—Structure map of the Top Lower San Andres Formation in the Project site (red polygon) with the AoR (yellow polygon) and nearby Penwell (Upper San Andres) oilfield (white polygon).

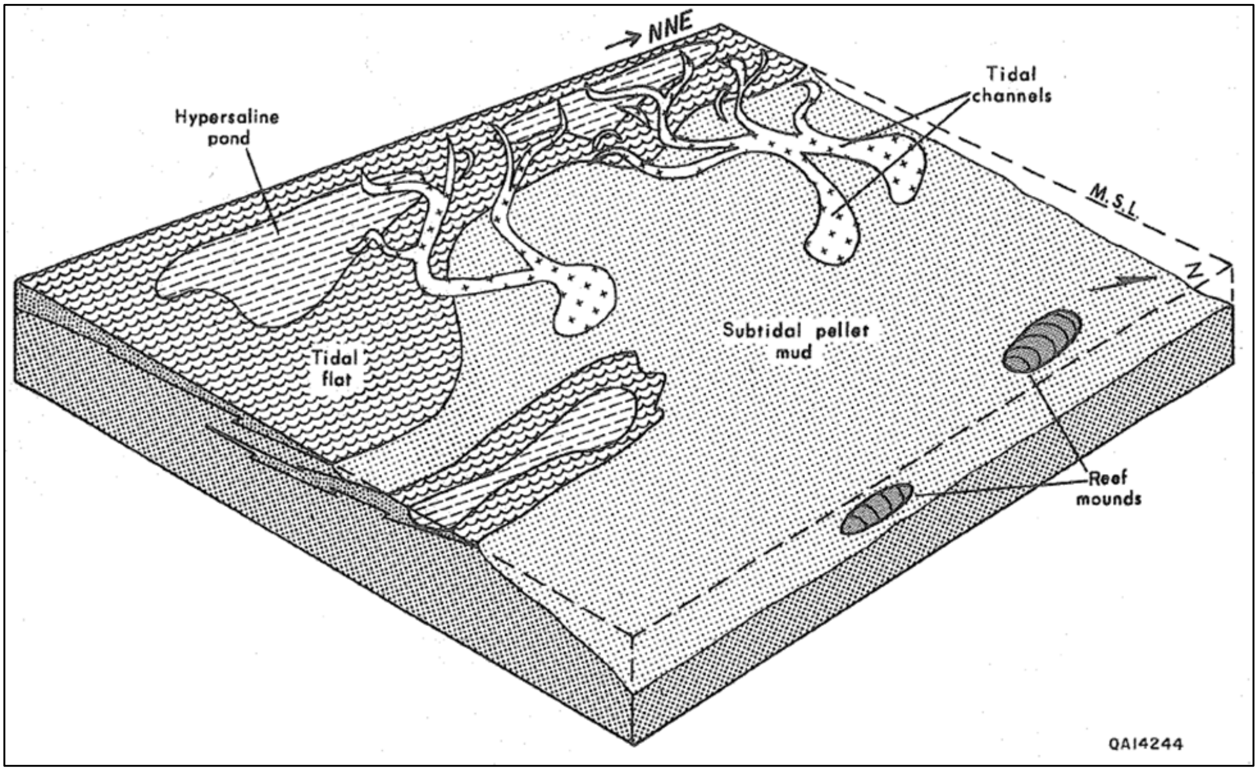

Figure 12—Depositional model of the San Andres Formation at Penwell field (Major et al. 1990).

The BRP Project Injection Zone comprises the Lower San Andres Formation High Frequency Sequences (HFSs) L7–G4. The Upper San Andres Formation (G8–G9 HFSs) (Figure 13) serves as Upper Confining Zone. The Lower San Andres (Permian composite sequence CS10) is divided into a transgressive and highstand sequence set. Key stratigraphic elements and lithofacies characteristics of these sequence sets are summarized below from Kerans and Fitchen (1995), who describe the San Andres Formation as a distally steepened mixed siliciclastic-carbonate ramp.

Key characteristics of the Permian CS10 transgressive sequence set (L7–L8 HFSs):

1. An aggradational platform margin;
2. A backstepped, very low angle (<2°) ramp, composed predominantly of skeletal wackestone and minor packstone;
3. Scattered skeletal grain-dominated mounds several hundred to thousands of acres in area that developed on antecedent platform highs within the open shelf; and
4. Grain types dominated by peloids, crinoids, fusulinids, and brachiopods, with less common bryozoans, corals, and calcareous sponges.

Key characteristics of the Permian CS10 highstand sequence set (G1– G4 HFSs):

1. Initially aggradational (G1 HFS) transitioning to progradational (G2-G3 HFSs) and finally, to strongly progradational (G4 HFS);
2. The ramp to outer ramp profile progressively increasing from 0.5° during the G1 HFS to as much as 7° to 12° during the G4 HFS;
3. Development of well-defined platform to basin facies tracts that include:
    a. Inner ramp evaporites (form the HFS-scale confining layer);
    b. Middle ramp restricted mudstones and peritidal facies (form the HFS-scale confining layer);
    c. Ramp crest ooid-peloid grain-rich facies interbedded with mud-dominated subtidal and peritidal facies (form the HFS-scale Injection Zone);
    d. Shallow outer ramp fusulinid-crinoid-peloid grain-dominated to mud-dominated facies (form the HFS-scale Injection Zone); and
    e. Distal outer ramp, deepwater, organic-rich mudstone facies (form the base of the HFS-scale Injection Zone).

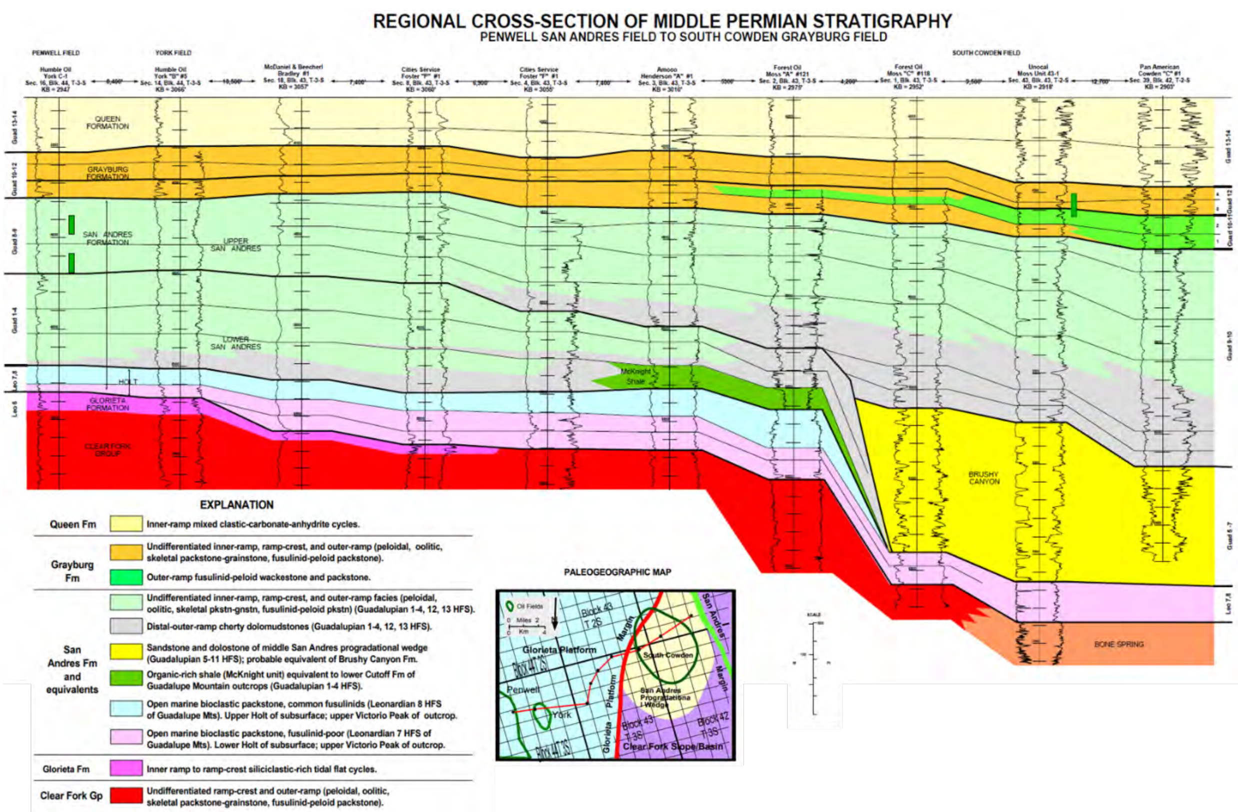

Figure 13—Stratigraphic cross section (from Ruppel and Bebout 1996).

2.2.3.7 Post-deposition Diagenesis

Key control on the lateral heterogeneity of porosity in the San Andres Formation was the early diagenetic preservation of pellets in the fusulinid and mollusk grainstone / packstone facies. Pellet preservation preserved interparticle porosity, whereas pellet compaction destroyed most porosity. The San Andres Formation has been pervasively dolomitized, but still largely retains its depositional texture. The dolomitization process converted syndepositional interparticle porosity to intercrystalline porosity during hypersaline reflux dolomitization (Lucia and Major 1994). This textural inversion process increased permeability in lower quality (i.e., mud-dominated) reservoir rocks and slightly decreased permeability in better quality (i.e., grain-dominated) reservoir rocks. These hypersaline fluids likely precipitated anhydrite and gypsum in the San Andres Formation (Major et al. 1990), resulting in porosity reduction.

2.2.4 Structural Setting

2.2.4.1 Seismic data acquired for the Project

OLCV acquired a high-density, 20.5 mi^2 3D seismic survey over the Project site in late 2022. The acquisition parameters for this 3D survey can be found in Table 1. Two orthogonal 2D lines totaling 10 line-miles were acquired in addition to the 3D survey. The 2D lines were acquired using the same source and receiver interval as was used to acquire the 3D survey.

[redacted]

OLCV designed seismic processing workflows to detect and image faults in the BRP Project AoR. Two processing flows were run in parallel for the BRP 3D survey: one flow focused on amplitude preservation for reliable quantitative interpretation, and the other focused on providing the best image for structural interpretation (the latter being used for fault interpretation). Manual fault interpretations were QCd with fault detection seismic attributes and surface seismic extractions. Fault detection attributes were extracted on full bandwidth data as well as the low, medium, and high frequencies to confirm lack of faulting at all frequency ranges.

2.2.4.2 Interpretation of regional and site-specific seismic data

The Texas Bureau of Economic Geology (BEG) has completed an investigation into faults within the Delaware Basin and Central Basin Platform, including the Shoe Bar Ranch (Figure 14). Horne et al. (2021) compiled the fault interpretations of publicly available 2D and 3D seismic data completed by BEG scientists, in addition to fault interpretations supplied to the BEG by TexNet-CISR1[9] industry participants, covering an area of approximately 23,500 mi^2 of West Texas.

[9] https://www.beg.utexas.edu/texnet-cisr

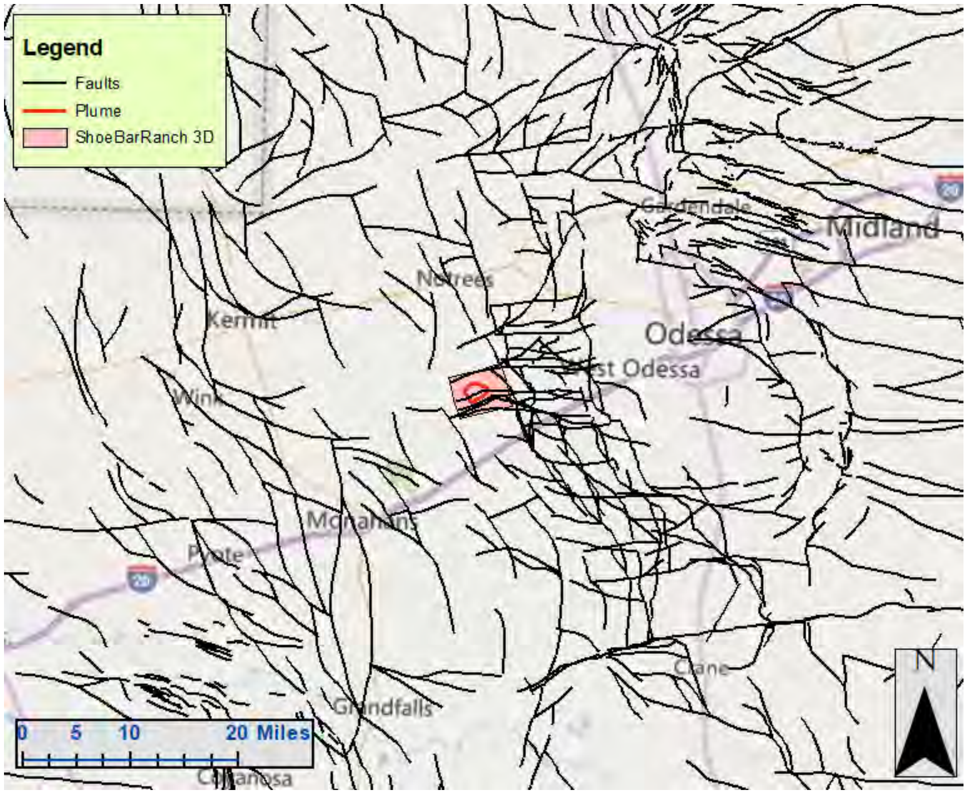

Figure 14—Regional map showing faults published by Horne et al. (2021). Note the deep basement fault interpreted at the South end of the BRP AoR.

Based on the interpretations compiled by the BEG, there is a basement fault striking approximately in an E-W direction that is present within the area of the Project site; however, the fault is interpreted to tip out in strata 1,800 feet below the Lower Confining Zone. Seismic mapping on the newly acquired 3D and 2D, and attribute analyses are consistent with the interpretation that movement on basement-related faults ceased before the time of Wolfcamp deposition. No offset is detectable above the Wolfcamp formation (1,800 feet below base of Lower Confining Zone); therefore, OLCV interprets that deeper faults do not extend to the Lower Confining Zone and Injection Zone (Figure 15 and Figure 16).

In addition to seismic data interpretation, pore pressure data from the Shoe Bar 1 shows that the Glorieta and Clearfork formations are not in pressure communication with the Lower San Andres. The Glorieta and Clearfork are separated from the Lower San Andres Injection Zone by a Lower Confining Zone. The Glorieta and Clearfork have a 0.43 psi/ft and 0.44 psi/ft gradient respectively, whereas the Lower San Andres has a 0.5 psi/ft gradient.

Because no faults are present in either the storage complex or the top or base seals, the risk of induced seismicity due to CO_2 sequestration at the BRP Project is low. There is no evidence to suggest the deep-seated faults will be reactivated due to the injection of CO_2 within the shallower injection interval by either direct pressure transfer from the reservoir to the basement or poroelastic strain transfer from the reservoir to the basement.

[redacted]

Figure 15—Map view (bottom right corner) of N-S seismic line through the Project.

Seismic cross section shows faults extend from the basement to the Devonian-age strata; however, faulting tips out in the Wolfcamp and does not extend into the Injection Zone. Oxy has licensed a number of 2D seismic lines in the area around the proposed project site. While the Devonian and older strata are faulted, as indicated by the BEG study, the sequestration zone appears to be unfaulted, including the top and upper and lower confining zones (Figure 15). Because the faulting mapped by the BEG and observed on Oxy's licensed 2D seismic data are not present in either the sequestration zone or the top or base seals, the risk of induced seismicity due to CO_2 sequestration injection into Brown Pelican San Andres reservoir is low.

[redacted]

Figure 16—Map view (bottom right corner) of seismic line location across Shoe Bar Ranch. Seismic cross section for that line shows faulting from Devonian to the basement at the site; however, the faulting is truncated at the Wolfcamp and does not extend into the injection zone or lower confining layer.

The geologic structure of the Glorieta Formation (Lower Confining Zone) through the Grayburg Formation (Upper Confining Zone) of the BRP Project (Figure 17) dips gently towards the West at 0.7° (170 ft vertically over 12,500 ft laterally). Due to the low-angle dip, there is minimal difference between true stratigraphical thickness (TST) and true vertical thickness (TVT). The thickness maps in this document are isochore maps, representing true vertical thickness.

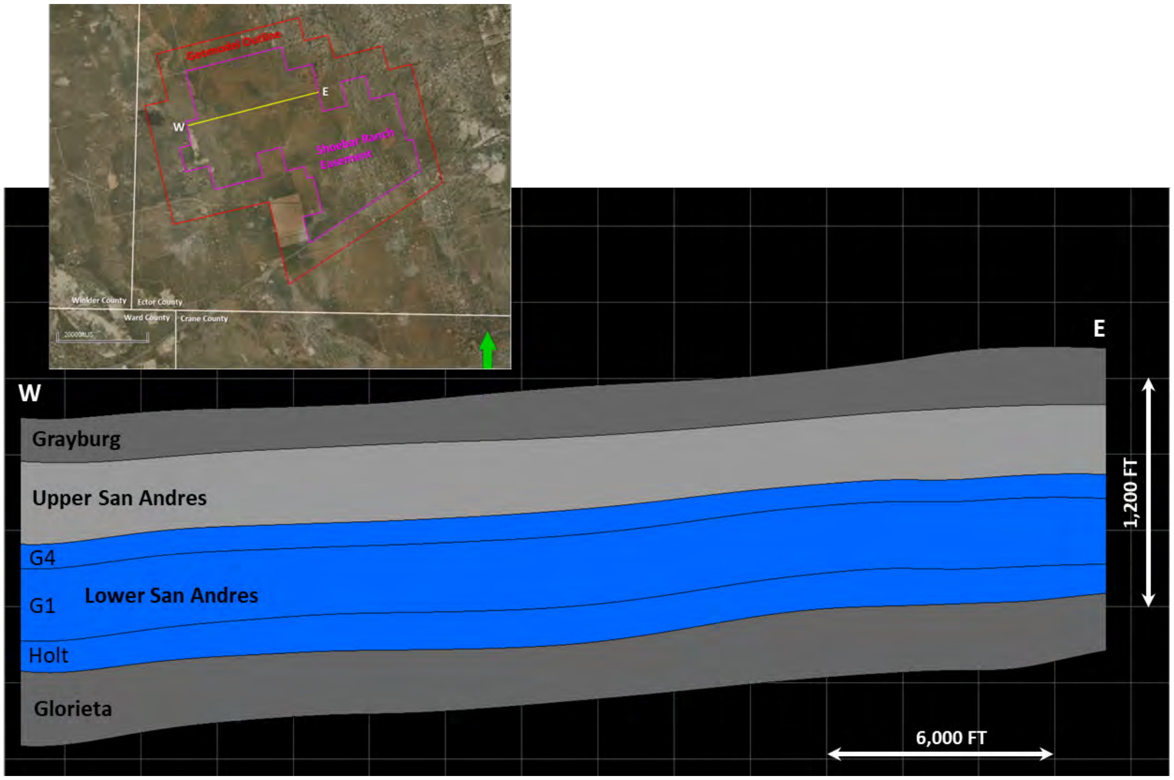

Figure 17—W-E cross section showing the zones modeled for the dynamic simulation, indicating a gentle westward dip.

2.2.5 Historical Seismic Activity

The proposed project site is situated in an area of West Texas that has historically exhibited low historical seismic activity, based on catalogs from both USGS (up to and including December 2016, Figure 18) and TexNet (January 2017 to November 2023, Figure 19). The seismic networks operated by the USGS[1], TexNet, IRIS,[10] and other researchers have varied significantly over the past 50+ years. Appendix C provides the list of the networks, station names, locations, and start and end times for the stations used by USGS and TexNet to locate seismic events.

The recorded event of local magnitude 2 (M_L 2) or greater closest to the project site occurred approximately 5 miles to the east on 22 November 2001. There have been 444 events of magnitude 2 or larger within a 50-mile radius of the Project site reported in the USGS and TexNet catalogs in the past 56 years (as listed in Appendix C: Seismic Events Near Project Site). Recent seismicity

[10] Incorporated Research Institutions for Seismology (https://www.iris.edu/)

25 miles North-Northeast of the Project site is attributed to saltwater disposal (SWD) in deeper formations near the basement rock near critically stressed basement faults according to communication on the RRC website in 2022[11]. The risk to the Project from these recent seismic events is considered minimal, because the proposed Injection Zone is vertically separated from deeper faulted strata by approximately 1,800 ft, as observed on 2D and 3D seismic images, providing sufficient vertical separation to prevent any interaction between injection pressures and the faults. Additionally, OLCV proposes to manage pressure by producing brine from the Injection Zone, further reducing the risk of seismicity from the proposed Project. The USGS predicts this site to have low future seismic hazard (Figure 20). Because of these factors, the site low risk of induced seismicity due to Project operations.

[11] https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/injection-storage-permits/oil-and-gas-waste-disposal/injection-disposal-permit-procedures/seismicity-review/seismicity-response/

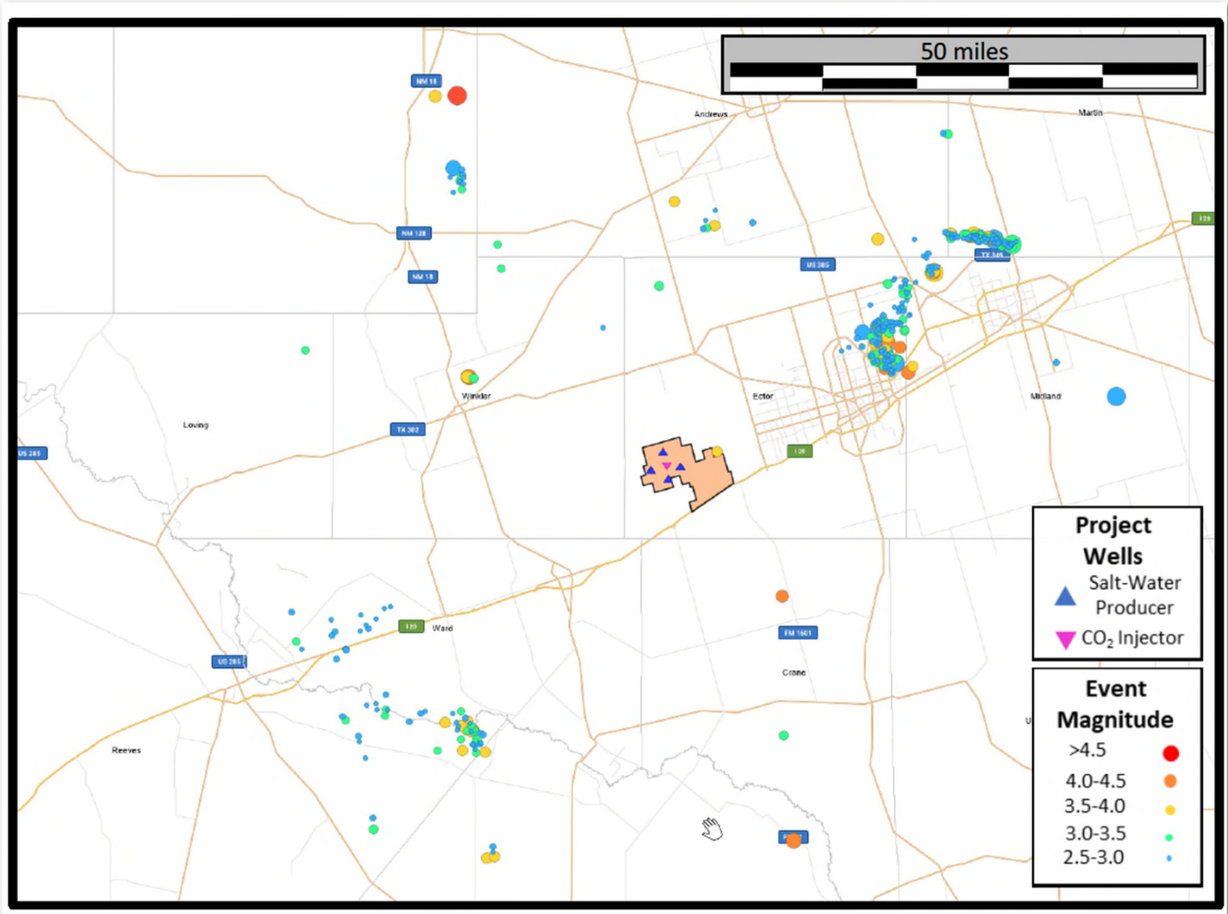

Figure 18—Seismic activity map showing a 50-mile radius around the Shoe Bar Ranch (shaded outline). The closest seismic event observed was 5 miles east of the proposed site in 2001. The seismic cluster 25 miles NE of the proposed Project site is currently attributed to SWD operations in deeper strata close to critically-stressed faults.

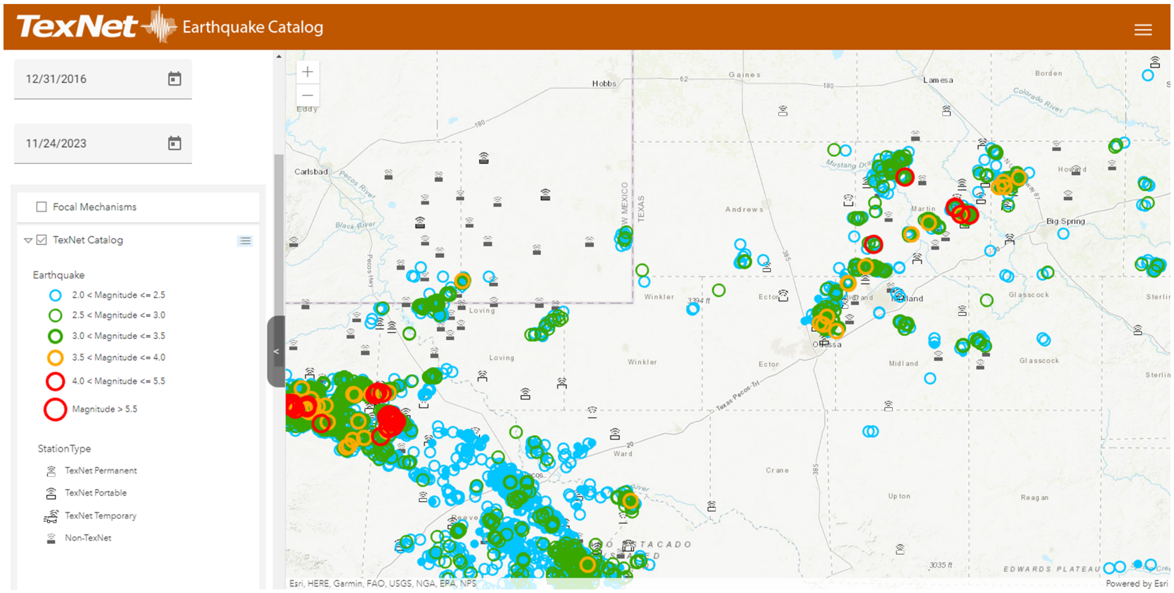

Figure 19—Seismic monitoring network and seismicity greater than 2.0 near Ector County used by TexNet as of 24 November 2023. Seismic monitoring stations are indicated by gray or black boxes (source: https://www.beg.utexas.edu/texnet-cisr/texnet/earthquake-catalog,).

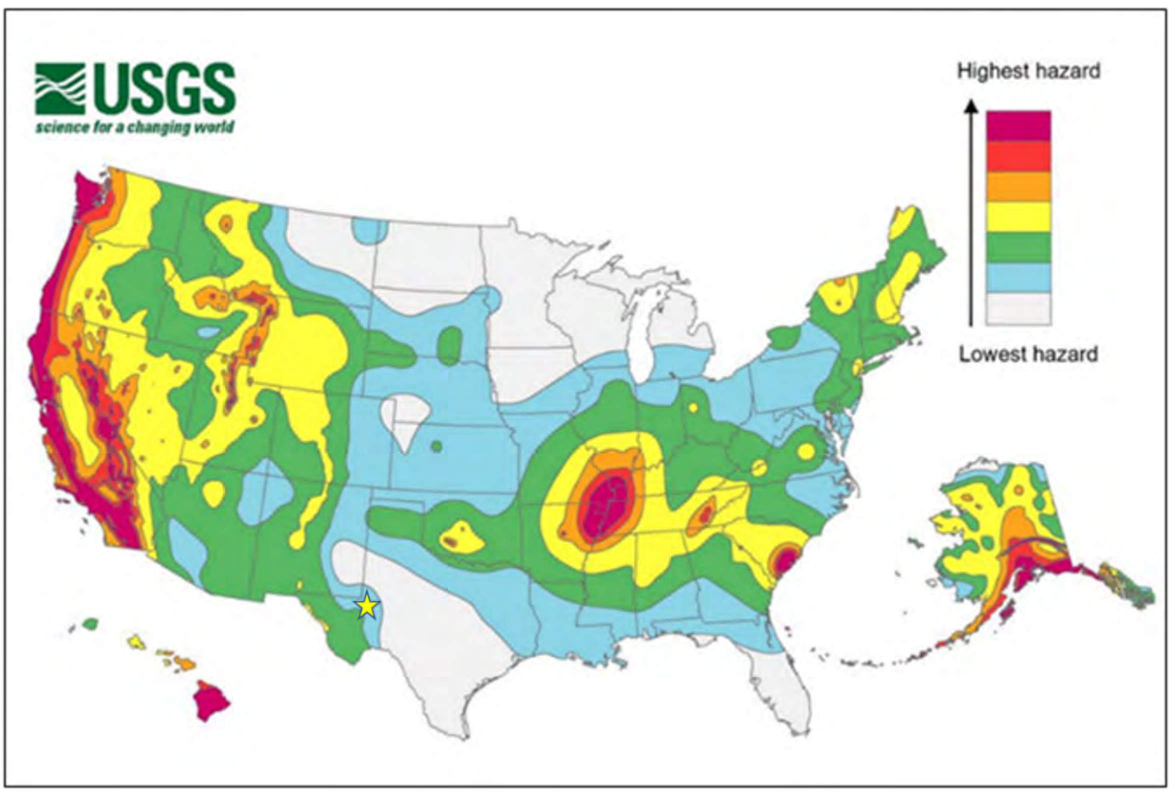

Figure 20—Seismic hazard map showing that peak ground accelerations have a 2% probability of being exceeded in 50 years from USGS 2018 Long-Term National Seismic Hazard Map (USGS 2018). Seismic hazard potential in the AoI is one of the lowest in the US.

2.2.6 Geopressure

The formation pressure information is obtained from well data acquired at Shoe Bar 1 and Shoe Bar 1AZ. The model was initialized at the first date of production using MDT pressure data versus depth. Based on the simulation model initialization, the reservoir pressure in the proposed Injection Zone is slightly overpressured relative to hydrostatic conditions.

2.2.7 Fresh Water Aquifers (Surface Geology)

The formal definition of a USDW by EPA Class VI regulation (40 CFR §144.3) is used in this study:

Underground source of drinking water (USDW) means an "aquifer" or its portion:

- *a)* *1) Which supplies any public water system; or*
  2) Which contains a sufficient quantity of ground water to supply a public water system; and:
    - *i)* *currently supplies drinking water for human consumption; or*
    - *ii)* *contains fewer than 10,000 mg/l total dissolved solids; and*
- b) *Which is not an "exempted aquifer."*

Southeast Ector County has two sources of groundwater in the extent of Shoe Bar Ranch that meet the formal definition of a USDW by EPA Class VI standard (40 CFR §144.3): the Pecos Valley major aquifer (surface; Figure 21), and the Dockum minor aquifer (base USDW; Figure 22) (Bradley and Kalaswad, 2001; Mace et al., 2006; George et al., 2011). Additional data on USDW depths specifically in and around SBR were acquired from Texas Water Development Board (TWDB) Groundwater Advisory Unit (GAU) letters[12].

[12] https://www.twdb.texas.gov/

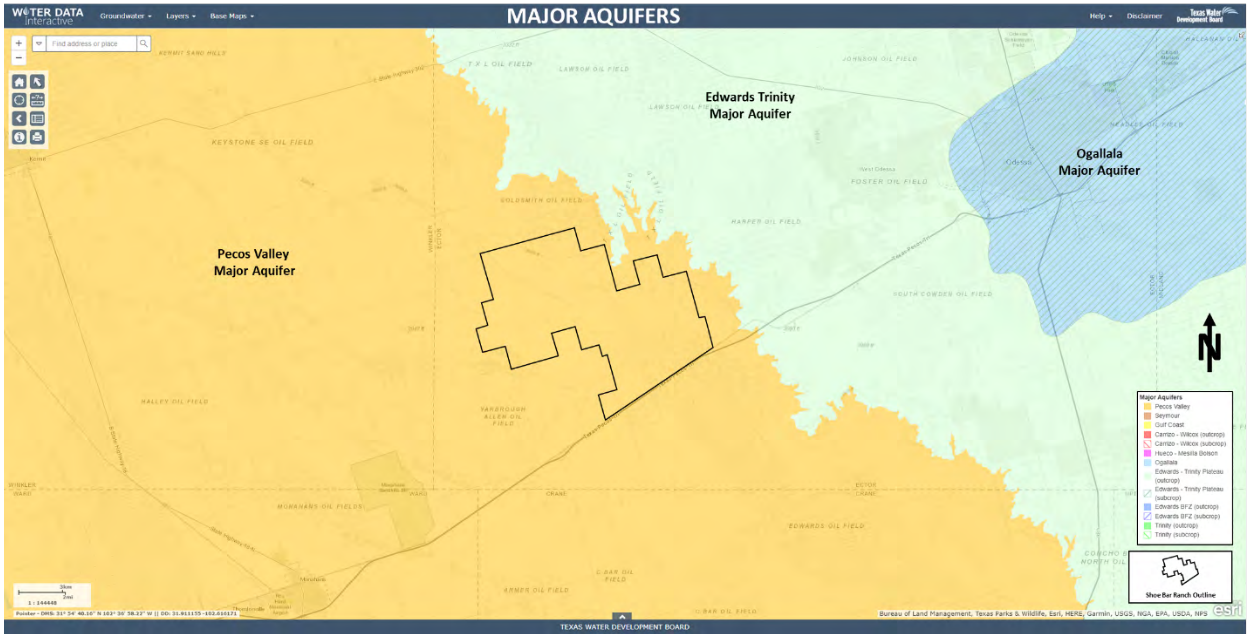

Figure 21—Major aquifers in the AoI and adjacent areas. Shoe Bar Ranch (black outline) is located in the eastern extent of the Pecos Valley aquifer (twdb.texas.gov).

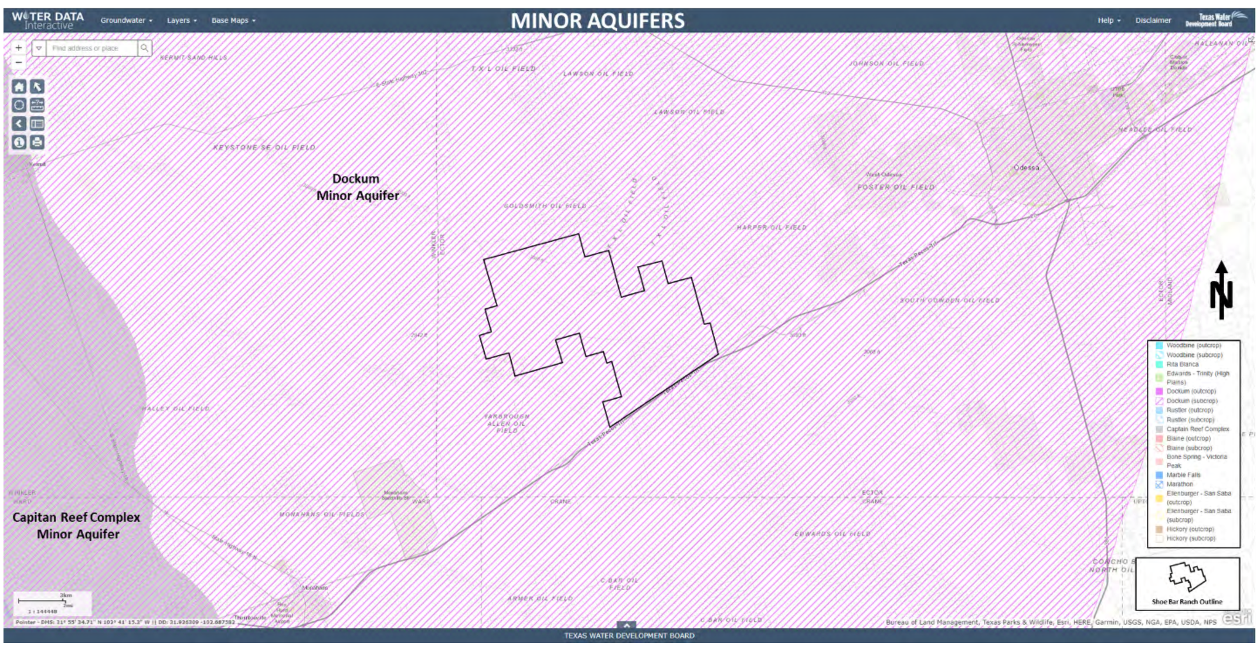

Figure 22—Minor aquifers in the AoI and adjacent areas. Shoe Bar Ranch (black outline) is located within the Dockum minor aquifer region. The closest adjacent minor aquifer is the Capitan Reef Complex aquifer, located 13 miles to the West (twdb.texas.gov).

The Cenozoic Pecos Valley Alluvium forms the Pecos Valley major aquifer and consists of unconsolidated to partially consolidated sand, silt, gravel, clay, and caliche (White 1971). Hydraulic conductivity of the Pecos Valley aquifer in southwest Ector County is ~10 ft/day (Anaya and Jones 2009). The Pecos Valley aquifer is unconfined (Meyer et al. 2012) and extends from ground level to a depth of ~250 ft in the AoI.

Based on regional water quality analyses, TDS concentrations in Ector County are <3,000 ppm in the Pecos Valley major aquifer (Meyer et al. 2012) and <5,000 ppm in the Dockum minor aquifer (Ewing et al. 2008). Therefore, both aquifers meet the definition of a USDW by EPA Class VI regulation (40 CFR §144.3). There are five water withdrawal wells (Figure 23) located within the Shoe Bar Ranch outline: 45-11-701, 45-11-902, 45-11-903, 45-19-301, and 45-19-302.[13] Only water well 45-11-701 is located in the extent of the AoR (Figure 23). The only available water quality analysis for water withdrawal well 45-11-701 is from 1948, which documents TDS concentrations of the Dockum Formation of ~7,200 ppm. Water analysis reports for wells 45-11-701, 45-11-902, 45-11-903, 45-19-301, and 45-19-302 are attached as a separate file package in the GSDT.

[13] These water analysis reports will be submitted to the EPA Geological Sequestration Data Tool (GSDT) in a separate folder.

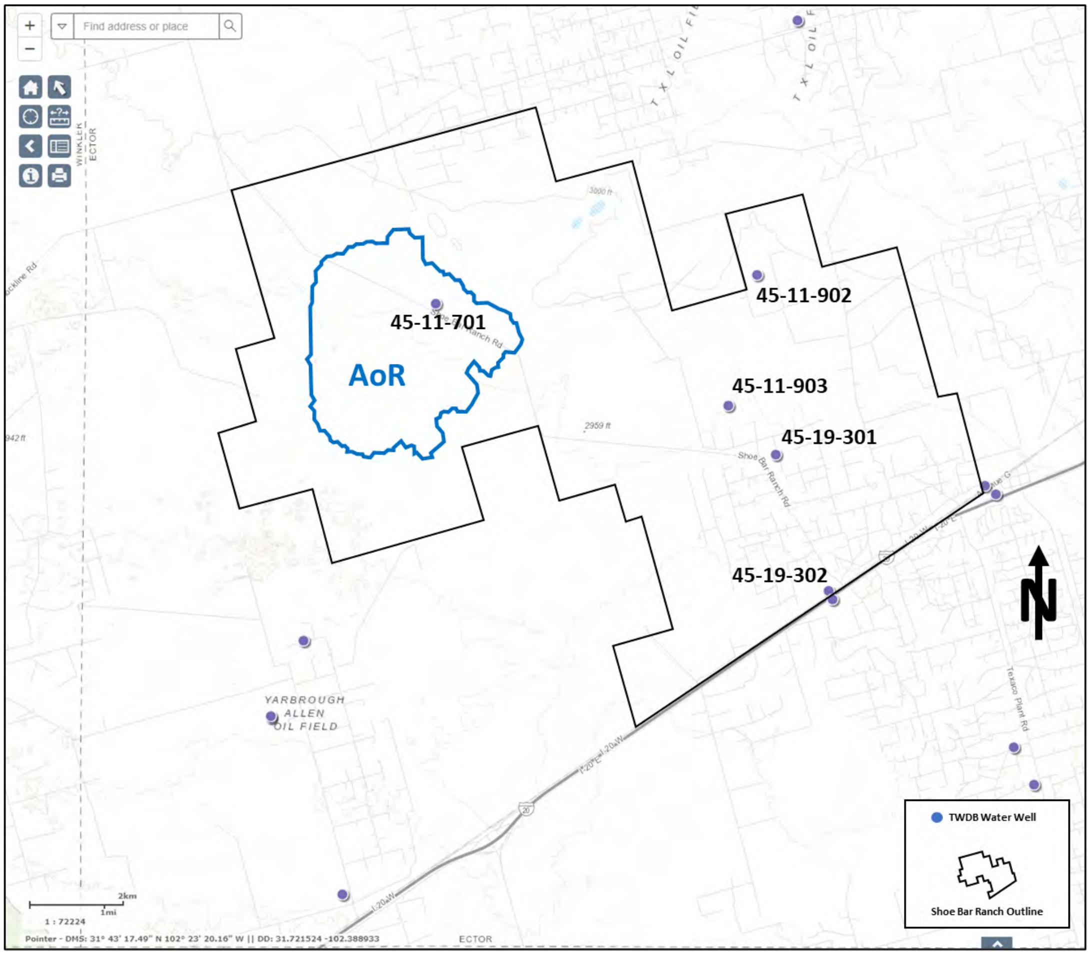

Figure 23—Texas Water Development Board (TWDB) water wells in and around the AoR and Shoe Bar Ranch (from twdb.texas.gov).

2.2.8 Base of the Underground Source of Drinking Water (USDW)

The BRP team employed two means of identifying the USDW in the Shoe Bar Ranch outline: 1) TWDB GAU letters specify the Dockum minor aquifer of the Santa Rosa Formation (depth range: 600 ft to 1,150 ft below ground level) as the base of protected aquifers in the AoI, which is consistent with EPA Class VI regulation (40 CFR §144.3) as deepest layer that has waters with a TDS concentration of less than 10,000 mg/L. 2) Additional means of aquifer identification came from interpreted gamma ray well log responses of TWDB Brackish Resources Aquifer Characterization System (BRACS) Well 1258 (API 4249532726; Figure 24) (Meyer et al. 2012). Data from both TWDB GAU letters and BRACS Well 1258 were used for well log correlation and structural mapping of the base Dockum minor aquifer in the subsurface across the AoI (Figure 24). Stratigraphic cross sections in N-S and W-E orientation with correlated Pecos Valley and Dockum Aquifers, as well as the five water withdrawal wells (45-11-701, 45-11-902, 45-11-903, 45-19-301, and 45-19-302) within the Shoe Bar Ranch outline are provided as separate attachments in the GSDT (W_E Well Log Section_cbi and N_S Well Log Section_cbi). Structural maps for the Pecos Valley and Dockum Aquifers are provided as separate attachments in the GSDT (Base Pecos Valley Aquifer_cbi; Top Dockum Aquifer_cbi; Base Dockum Aquifer_cbi).

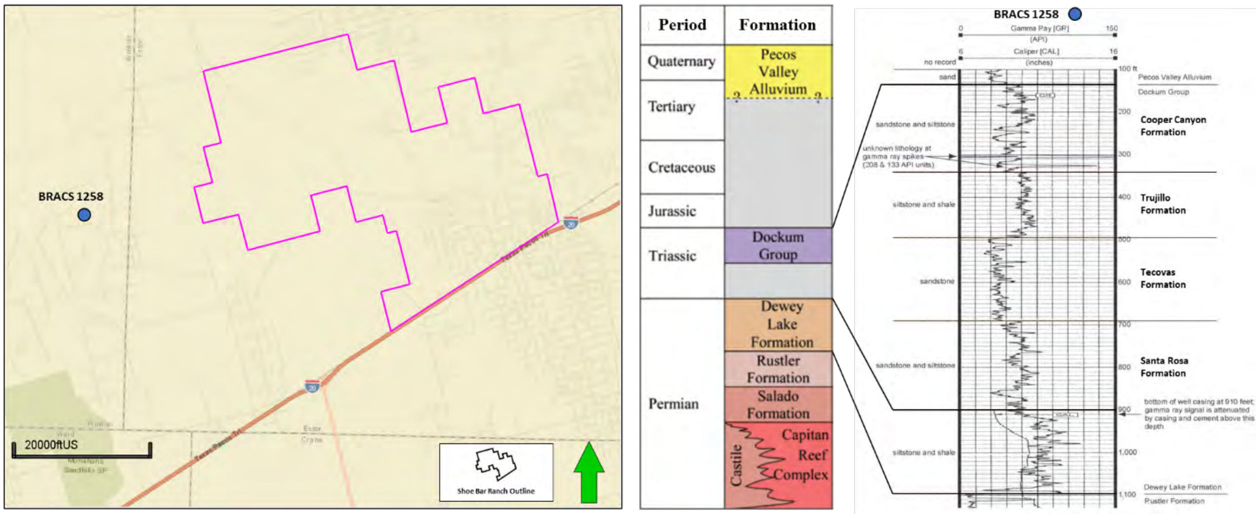

Figure 24—Left: BRACS1258 surface location in relation to Shoe Bar Ranch. Middle: Shallow geology from BRACS well 1258 ~2 miles west of the Project area (stratigraphic column from Meyer 2020). Right: BRACS 1258 well log interpretation from Meyer et al. (2012).

The Triassic Dockum group forms the Dockum minor aquifer and comprises four formations (from oldest to youngest):

1. Santa Rosa Formation consisting of red to red-brown sandstone and conglomerate, which forms the base of the USDW;
2. Tecovas Formation consisting of variegated, sometimes sandy mudstones with interbedded fine- to medium-grained sandstones;
3. Trujillo Formation consisting of gray, brown, greenish-gray, fine- to coarse-grained sandstone and sandy conglomerates with thin gray and red shale interbeds; and
4. Cooper Canyon Formation consisting of reddish-brown to orange siltstone and mudstone with lenses of sandstone and conglomerate (Bradley and Kalaswad 2001).

Hydraulic conductivity of the Dockum aquifer in southwest Ector County is in the range of 0 to 5 ft/D (Ewing et al. 2008).

Drainage of the Pecos Valley and Dockum aquifers from Shoe Bar Ranch is directed towards the Pecos River (30 miles SW), following the Monument Draw Trough (Boghici 1999). This elongated basin is oriented NW-SE with its main axis located in the vicinity of the intersection of Ector, Winkler, Ward, and Crane counties (Ashworth and Hopkins 1995).

The Dewey Lake Formation separates the base USDW from the regional seal and consists of red siltstone and shale (Meyer et al. 2012). The Dewey Lake Formation is not known to yield water to wells (Bradley and Kalaswad 2001) and is not listed as an aquifer by the TWDB. Over 2,500 ft of Rustler through Queen Formation evaporites and regional seal separate the base USDW from the Lower San Andres Injection Zone.

2.3 Geocellular Model Domain

The static geocellular framework was constructed by first modeling large-scale stratigraphic and structural features, and then modeling the petrophysical properties of these geologic features. The first step involved establishing a conceptual structural and depositional model, as well as its characteristic stratigraphic layering. The structural and stratigraphic architecture provided a first-order constraint on the spatial continuity, porosity, permeability, and other attributes within each layer. Next, petrophysical values were distributed for each zone using a cell-based methodology.

The geocellular model comprises the Grayburg and Upper San Andres formations (Upper Confining Zone), the Lower San Andres Formation (Injection Zone) with three sub-zones (G4, G1, Holt), and the Glorieta Formation (Lower Confining Zone). The areal extent of the geocellular model (12×10.8 miles) covers the Shoe Bar Ranch lease plus a 1-mile buffer zone around the lease that allowed for the evaluation of pore space under the entire acreage, while also including the northernmost extent of the nearby Penwell San Andres oilfield and the southernmost extent of the TXL oilfield (Figure 25). Well log data from Penwell Field and TXL Field served as crucial control points for the initial geomodel to inform reservoir statistics of all potential injection and confining zones, prior to the acquisition of our two stratigraphic test wells. These offset logs provided important high-density areal log coverage in the north and southeast, surrounding the sparse data coverage in the western part of the lease. In addition, historical production data from the Penwell field permitted model evaluation via simulation-based history matching.

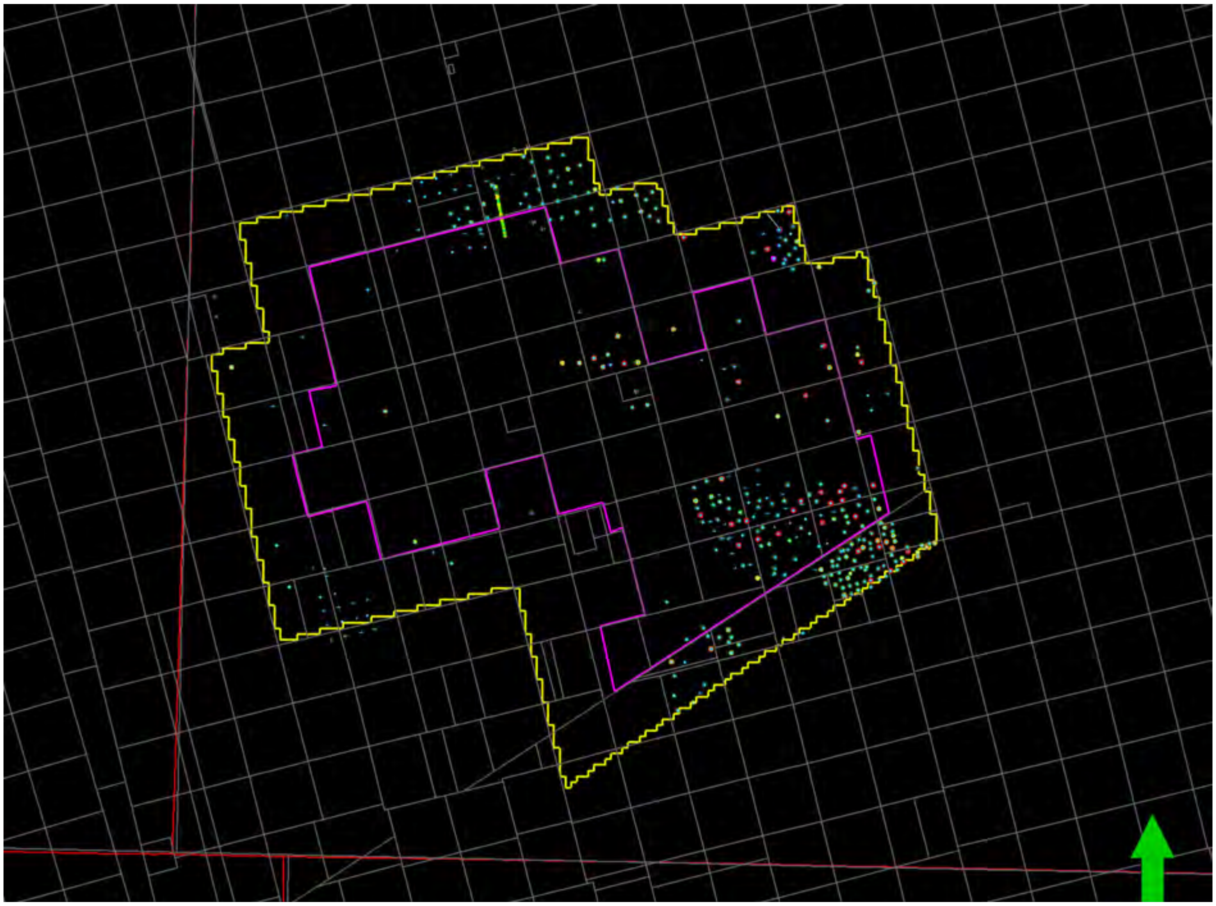

Figure 25—The Project site encompasses the areal extent of the static geocellular model (solid yellow outline).

The model consists of five horizons with four zones (Figure 26). The four zones from shallow to deep are the Grayburg, Upper San Andres, Lower San Andres (with sub-zones G4, G1, Holt), and Glorieta. The Lower San Andres, which is the proposed Injection Zone, was correlated and defined based on well log correlations from 359 well logs and 624 well tops within the geocellular model area.

The final geocellular model is represented by a 277×240×122 grid in a Cartesian system with 277 grid cells in the I-direction, 240 grid cells in the J-direction, and 122 grid cells in the K-direction, for a total of 8.1 million active grid cells. Grid cell dimensions average 200×200×13 ft.

The dynamic simulations were carried out in 3D using full physics and an equation of state. The dynamic reservoir simulation was performed using the vertically upscaled grid (200×200×26 ft cell size) from the static geocellular model (200×200×13 ft cell size). The areal extent of the geocellular and simulation model is shown in the yellow outline in Figure 25. The simulation model is large enough to capture the full extent of the critical pressure front from injection, but still retains sufficient detail to simulate the migration and extent of the CO_2 plume accurately during the injection and post-injection periods.

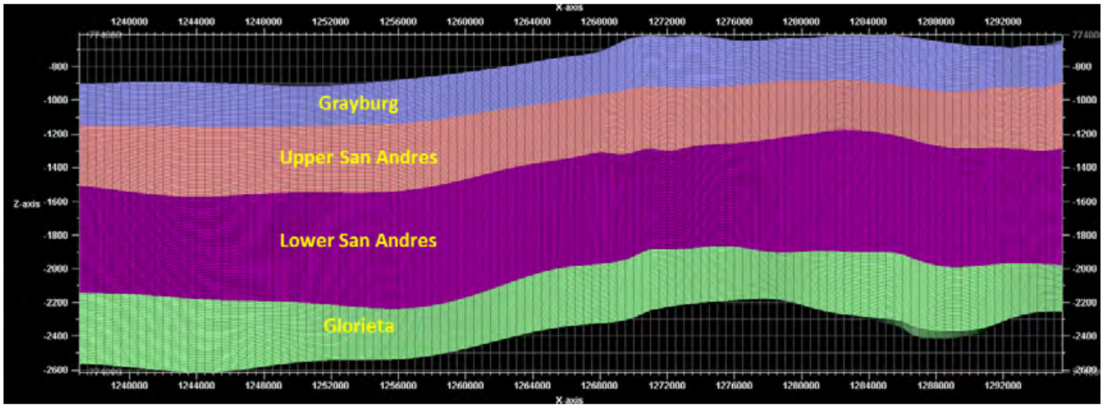

Figure 26—W-E cross section of the static geocellular model zones.

Model domain information is summarized in Table 2.

Table 2—Geocellular Model Domain Information

Coordinate system	SPCS27_4203 (ft US)		
Horizontal datum	NAD27		
Coordinate system units	ft		
Zone	State Plane of Texas Central		
Federal Information Processing Standard (FIPS) ZONE	4203		
Coordinate of X min	1235996.96	**Coordinate of X max**	1299496.96
Coordinate of Y min	735943.50	**Coordinate of Y max**	792943.5
Elevation, top of domain	--230.32	**Elevation, bottom of domain**	-3957.11

2.3.1 Model Geologic Structure

The structural framework of the geocellular model was based on well log correlation within the area, as shown in Figure 27. The structure was mapped based on seismic data and well-based formation tops in areas where seismic data were unavailable. The available 2D and 3D seismic data indicate no faults penetrating the Injection Zone at the Project site (see Section 2.2.5 for a discussion on the acquisition and interpretation of the newly acquired 2D and 3D seismic). Additionally, stratigraphic mapping shows no indications of repeat sections, missing sections, or sharp offsets, which would be characteristic of faults. As such, the geocellular model lacks a fault property model. Modeled horizons reveal a monoclinal dip to the NW, which is consistent with published data about the region (Major et al. 1990, Siemers et al. 1996).

North-south trending, basement-rooted faults were identified during regional interpretation and mapping, but they tip out 1000+ ft below the base of the geocellular model domain. These faults are deep-seated and do not cut through the CO_2 storage complex.

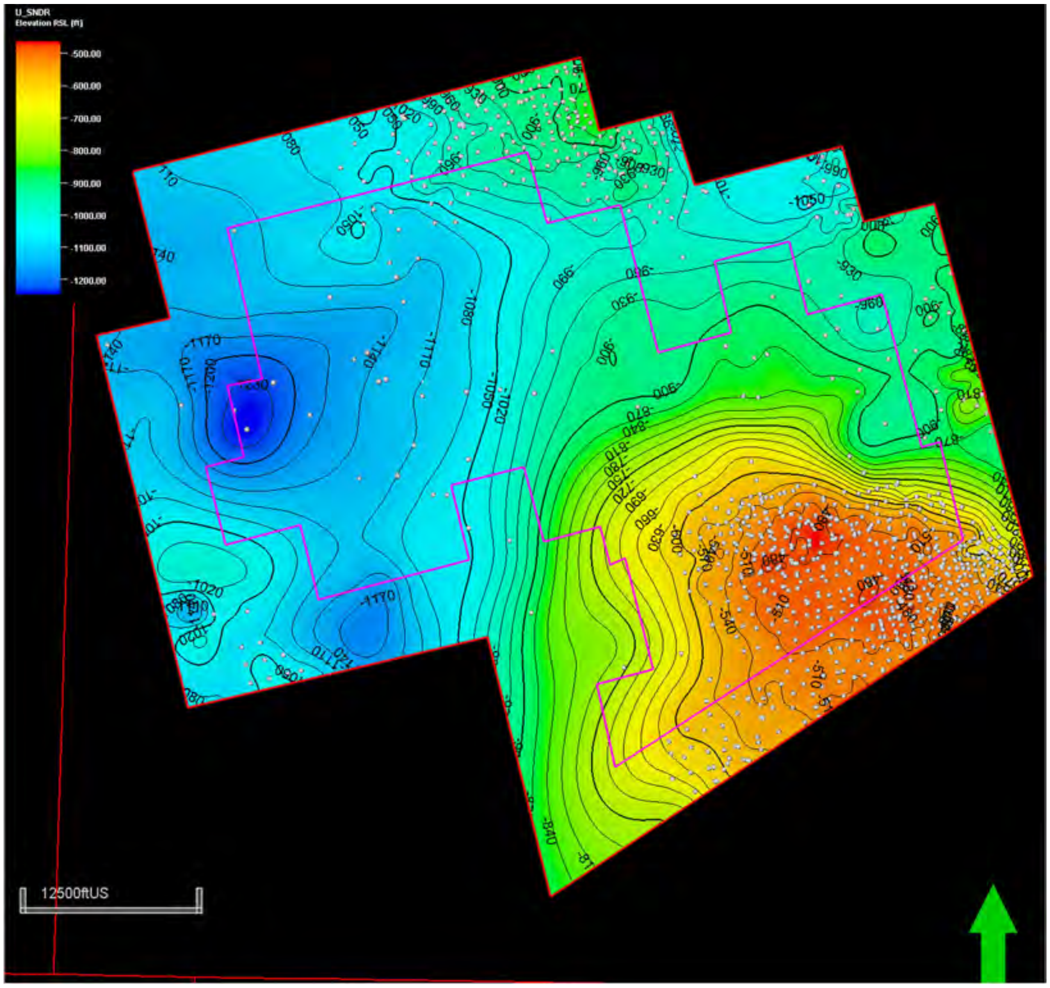

Figure 27—Well top data overlying the Upper San Andres structure at the Project site.

2.3.2 Geocellular Model Zones and Layering

Four zones in the geocellular model were created from stratigraphic surfaces based on well log correlations of formation tops: the Grayburg with mean average thickness of 23 ft, the Upper San Andres with 355 ft, the Lower San Andres with 652 ft, and the Glorieta with 341 ft. Proportional layering was applied to each model zone, and the number of layers within each model zone division was based on the upscaled thickness of each interpreted zone. An index view of the four model zones is shown in Figure 28.

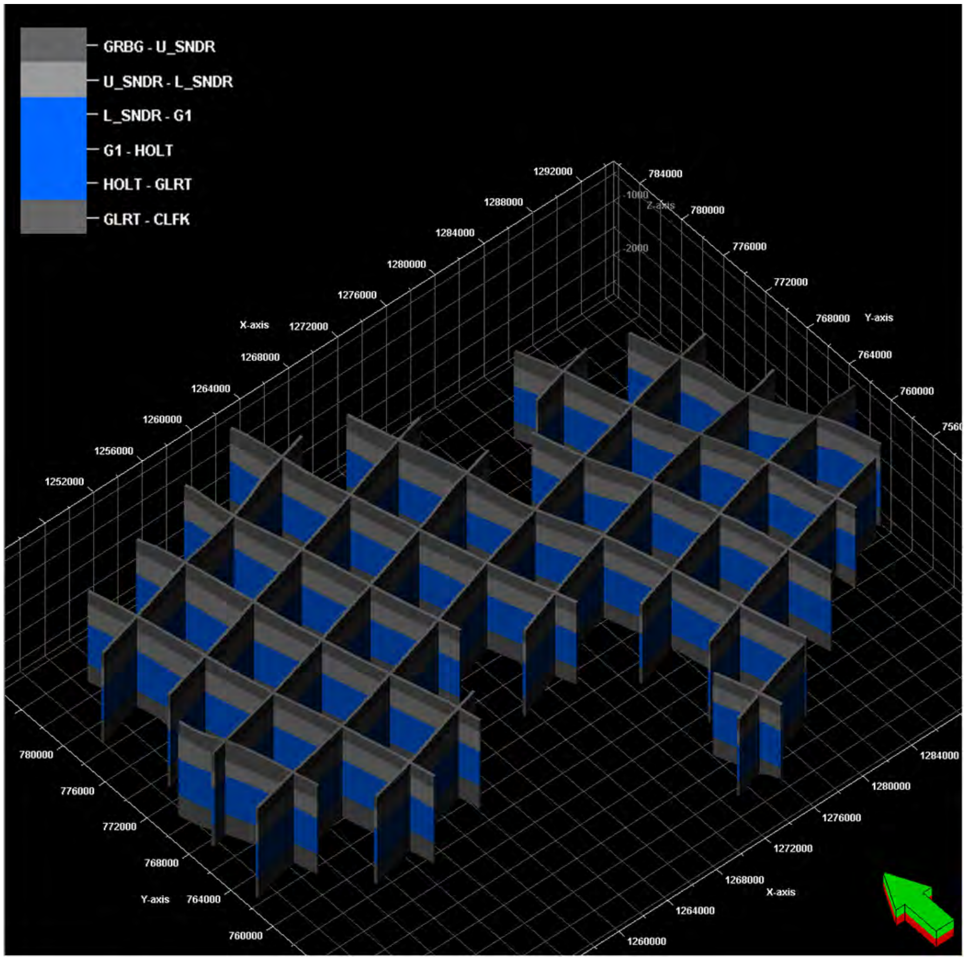

Figure 28—3D index view of geocellular model zones from the Grayburg to Glorieta.

The Lower San Andres Injection Zone is composed of high-porosity and high-permeability (average 8.2 % porosity; 3.4 mD permeability) dolomite layers. The overlying low-permeability layers (<1 mD permeability) within the Upper San Andres and Grayburg Formations correspond to the Upper Confining Zone. Underlying the Lower San Andres is the Glorieta Formation, which represents the Lower Confining Zone (Figure 29).

[redacted]

Figure 29—Composite type well log interpretation from Shoe Bar 1AZ of the Grayburg, Upper San Andres, Lower San Andres, and Glorieta from the AoI. Tracks from left to right show the following: depth, zones, spectral gamma ray and caliper logs, resistivity log, density-neutron-photoelectric factor, lithology, total porosity, and permeability. Gray shading in the Permeability track indicates tight, low-permeability packages.

2.4 Porosity and Permeability

A total of 681 horizontal plugs that are 1.5-inches in diameter were cut from ~714 feet of whole core obtained in the Shoe Bar 1 well. A total of 50 horizontal plugs were cut from ~725 feet of whole obtained in the Shoe Bar 1AZ. Routine core analysis (RCA) was performed to obtain core porosity and core permeability measurements on these 731 plugs. The Project also acquired full-diameter RCA and Mercury Injection Capillary Pressure (MICP) measurements to obtain porosity and permeability data in whole core sections that were cut to 4-inch (diameter) x 6-inch (length) sections and horizontal plug end-trims, respectively.

The resulting core-measured porosity data were used to guide and calibrate the porosity model for deriving log-based porosity estimates as an input to the static geological model. In addition, core-measured permeability data were used to construct a permeability model of Lucia Rock Fabric Number (RFN) for the Injection Zone.

Based on petrophysical analysis of wells within and surrounding the AoR, OLCV identified that the Lower San Andres was the most suitable interval for CO_2 injection based on porosity, permeability, and net thickness (Figure 30).

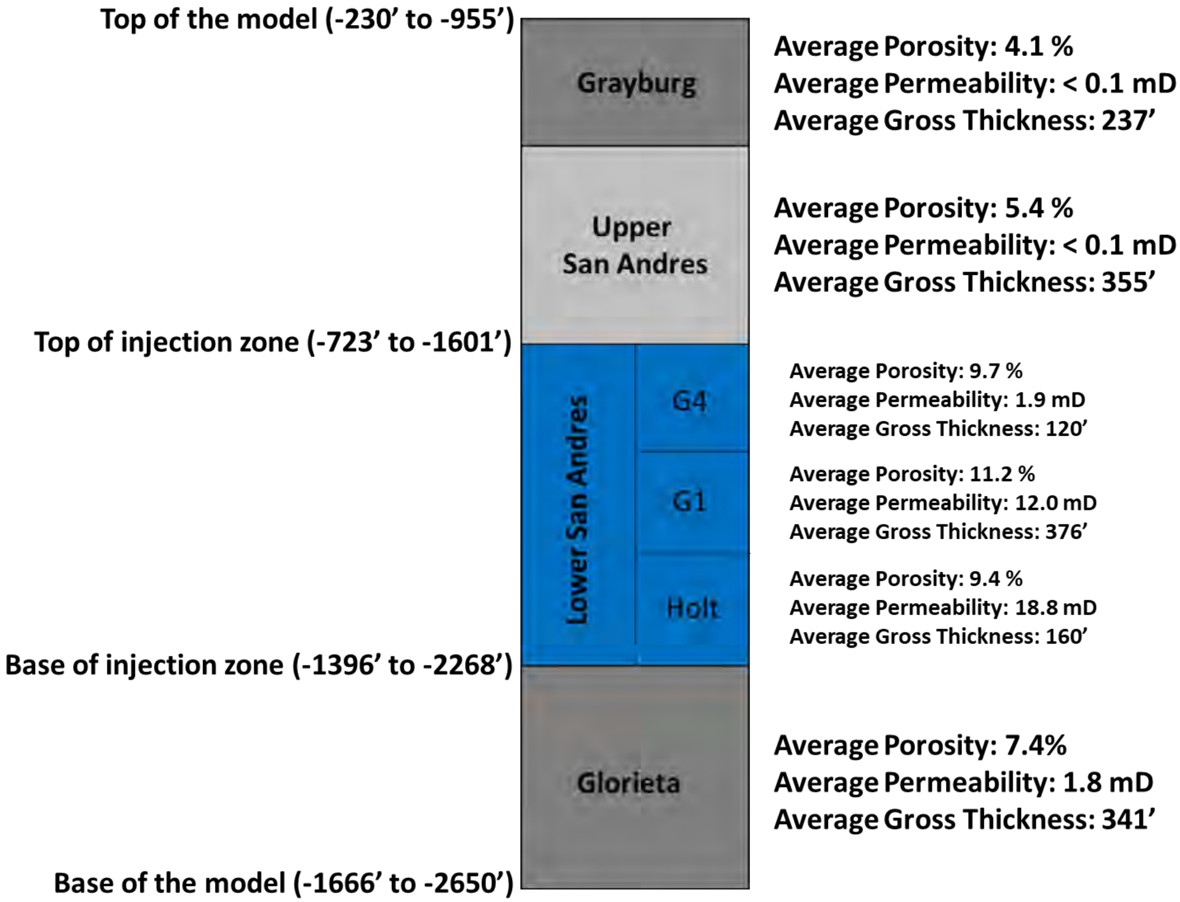

Figure 30—Depth and gross thickness of the geocellular model zones with averages of porosity and permeability based on well log and core analysis of both stratigraphic test wells.

A total of 164 neutron-density calibrated porosity curves (XPOR) that were QCd by qualified OLCV and Oxy petrophysicsts were used for the porosity property in the geocellular model (Figure 31). The Petrel 3D property grids were populated using the following procedure:

1. XPOR curves were upscaled into geocellular model grids at well locations, input parameters were set based upon data analyses, and then porosity was distributed in 3D space using Gaussian Random Function Simulation (GRFS).
2. A moving average simulation of the resulting porosity realization was then used to generate a horizontal trend model. The upscaled XPOR curves were analyzed to create a vertical porosity trend model. The final porosity property was created using GRFS co-kriged with the horizontal and vertical porosity trend models.
3. Permeabilities in the geocellular model were calculated at each cell using the model-zone-specific rock fabric number (RFN) from core-measured porosity and permeability.

Figure 31—Map view of the 164 petrophysically QCd, neutron-density calibrated porosity log curve control points for porosity modeling.

2.4.1 Porosity

The XPOR porosity logs were upscaled into the 3D grid using an arithmetic method. Data analysis was performed for normal score transform and variogram calculation and fitting. The variogram parameters of type, nugget, sill, and ranges of vertical, major, and minor directions were determined during the variogram fitting process (Table 3). The porosity property was simulated using the GRFS method with fitted variogram parameters, smoothed distribution from upscaled cells, and seed number (Figure 32).

Table 3 —Porosity property parameters

[redacted]

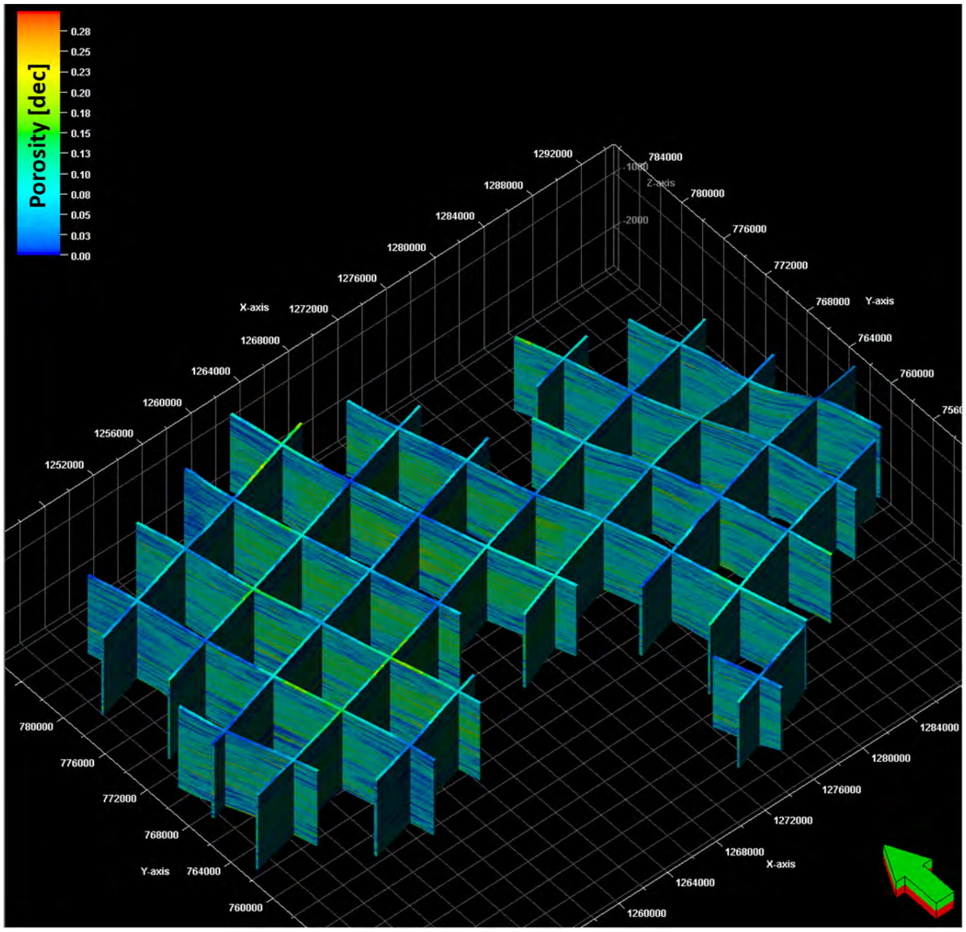

Figure 32—3D porosity distribution index view of the base case porosity.

The degree of uncertainty in the porosity property was quantified using 500 porosity modeling simulation runs. These simulation runs were performed using the same settings and varying seed numbers. The pore volumes were calculated with the 500 porosity properties and ranked from low to high using a percentile ranking (Figure 33). The results showed a tight grouping with pore volume values for P10 and P90 differing from the P50 value by 2.5%, and the P5 and P95 values differing by 4%. To further test the uncertainty ranges, a 0.005 porosity value was added to the P95 porosity property and subtracted from the P5 porosity property. The pore volumes from these two porosity properties are ~10% different from the P50 number. Figure 34 shows cross sections of the porosity property for the P5-0.005, P50, and P95+0.005 cases.

[redacted]

Figure 33—Pore volume distribution of 500 porosity simulation runs with varying seed numbers.

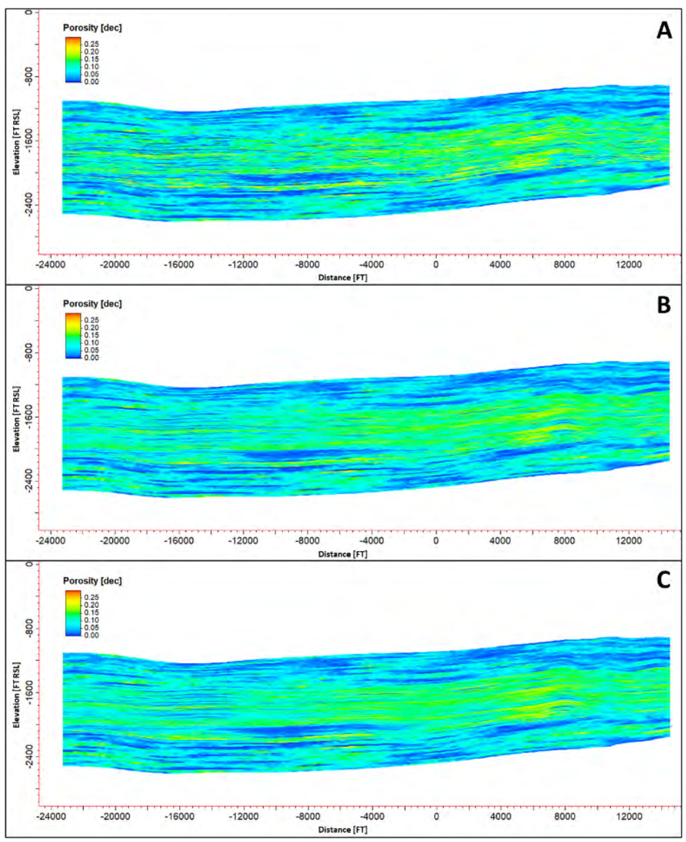

Figure 34—Cross section of the P5-0.005 (A = low), P50 (B = mid), and P95+0.005 (C = high) case porosity.

2.4.2 Permeability

To populate the permeability property in the geocellular model, OLCV:

- Determined horizontal permeability for the Injection Zone based on available core analyses from stratigraphic test wells Shoe Bar 1 and Shoe Bar 1AZ, and
- Developed a core data-based porosity-permeability transform to estimate permeability data outside core data coverage using a Lucia rock fabric number (RFN) modeling approach (Lucia, 1995).

Permeability modeling in dolomite reservoirs presents a challenge due to the varying nature and presence of vugs (connected/isolated) in the matrix. Core analysis from stratigraphic test wells Shoe Bar 1 and Shoe Bar 1AZ revealed strong heterogeneity when comparing porosity and permeability measurements at various scales, i.e., trim ends, plugs, and full-diameter core. OLCV obtained core measurements for porosity and permeability at different scales in two stratigraphic wells. OLCV observed porosity-permeability relationship trends for the G4, G1, and Holt sub-zones in the Injection Zone.

OLCV follows the Lucia rock-fabric method (Lucia, 1983; Lucia, 1995; Lucia, 2007) for carbonate reservoir characterization, which is an industry standard for distributing petrophysical properties (permeability and water saturation) within a lithofacies-constrained, flow-unit scale, reservoir model framework (Figure 35). The Lucia (1983) classification defines three major Rock Fabric Numbers (RFNs), each characterized by distinct petrophysical properties (porosity-permeability, saturation). These are: grainstones (RFN 1), grain-dominated packstones (RFN 2), and mud-dominated packstones, wackestones, and mudstones (RFN 3). Because of variance in pore throat geometry, samples cluster around discrete RFN transforms when porosity and permeability values are cross-plotted on a log-log scale (Lucia, 2007).

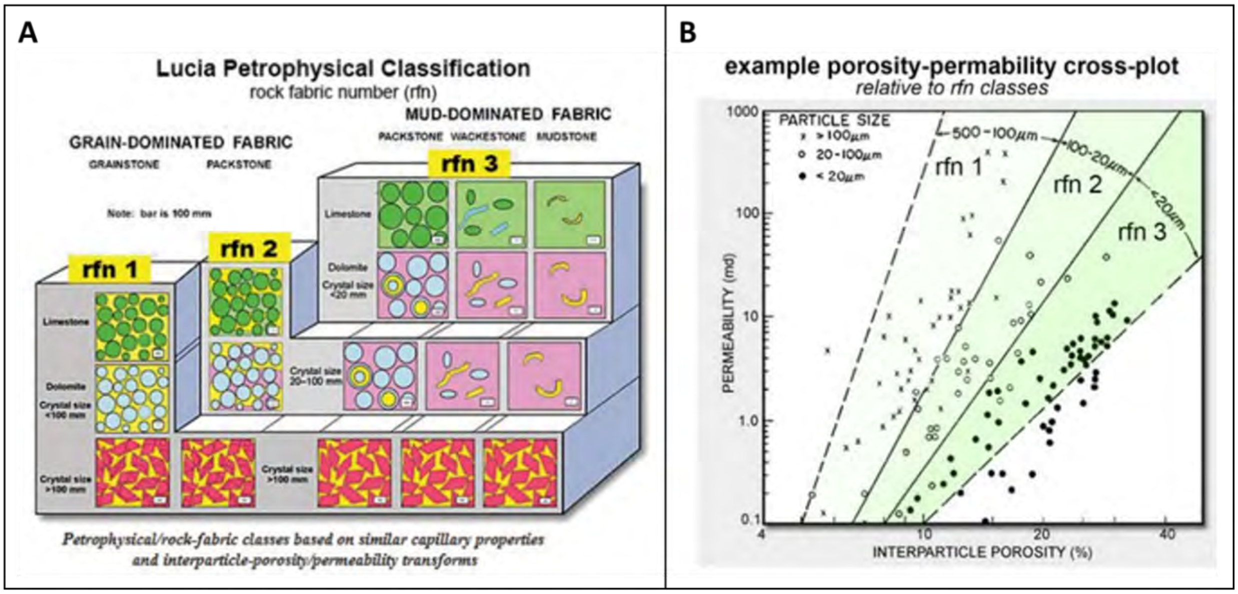

Figure 35—Lucia petrophysical classification diagram (A) and porosity-permeability relationships (B) (Lucia, 2007).

The Lucia Global Permeability Function, shown in Equation 2, is used to calculate permeability from interparticle porosity, using the RFN number.

$$Perm\ (Lucia) = 10\hat{}\left((\mathrm{A}-\mathrm{B}) + \left((\mathrm{C}-\mathrm{D}) * \mathrm{LOG10}(\mathrm{Øip})\right)\right) \qquad \textit{Equation 2}$$

where:

A = 9.7982
B = 12.0838*LOG10(RFN)
C = 8.6711
D = 8.269865*LOG10(RFN)
RFN = Lucia rock fabric number
$Ø_{ip}$ = Interparticle porosity

The permeability in the upper part of the Injection Zone between the top of the Lower San Andres and the G1 sub-zone (i.e., the G4 sub-zone) was modeled using a RFN of 2.4, shown in Figure 36 below.

[redacted]

Figure 36—A cross-plot of core porosity and core permeability at different measurement scales for the upper part of the Lower San Andres formation.

The permeability from the top of the G1 sub-zone to the top of the Holt sub-zone (i.e., G1 sub-zone) was modeled using a RFN of 1.8. Figure 37 shows the cross-plot of core porosity and core permeability at different measurement scales for this sub-zone.

[redacted]

Figure 37—Cross-plot of core porosity and core permeability at different measurement scales for the G1 sub-zone.

The permeability in the sub-zone between the top of the Holt and the base of the Lower San Andres formation (i.e., Holt sub-zone) was modeled using a RFN of 1.6. Figure 38 shows the cross-plot of core porosity and core permeability at different measurement scales for this sub-zone.

[redacted]

Figure 38—Cross-plot of core porosity and core permeability at different measurement scales for the Holt sub-zone.

The final log-derived permeability for the Injection Zone was computed using the Lucia RFN transform and delivered as in input to the static geological model. The log plot (Figure 39) from Shoe Bar 1AZ shows the match between core measured data (porosity and permeability) and log-derived porosity and log-derived Lucia RFN based permeability (Figure 39).

The correlation log plot in Figure 39 shows an example of the match between core data (porosity and permeability) and log-derived porosity and Lucia RFN permeability in stratigraphic test well Shoe Bar 1AZ (representative of the AOR).

[redacted]

Figure 39—Composite Type well-log interpretation from Shoe Bar 1AZ of the Grayburg, Upper San Andres, Lower San Andres (including the G1, G4, and Holt sub-zones), and Glorieta formations from the AoR. Tracks from left to right show Depth, Stratigraphic Zones, Spectral Gamma Ray and Caliper, Resistivity, Density-Neutron-Photoelectric Factor, Dipole Sonic, Lithology, Total Porosity, Permeability, Grain Density, NMR T2 and NMR Bins. The point data (shaded circles and squares) in tracks 8-10 represent core-measured petrophysical data. Footnote description for Track 8: 1(a)-fractured sample, 1(b)-chipped sample, 1(c)-fractured and chipped sample, 2(a)-sample permeability below measurable range, 22-laminated sample, 7-vuggy sample.

[redacted]

Figure 40—Modeled permeability-porosity cloud transform for sub-zones G4, G1, Holt, honoring their core-derived rock fabric numbers (G4 = RFN 2.4; G1 = RFN 1.8; Holt = RFN 1.6).

Average horizontal permeability in the geocellular model by sub-zone is based on the porosity-permeability transform shown in Figure 40 with the following sub-zone averages: Grayburg Formation Confining Zone: 0.19 mD; Upper San Andres Confining Zone: 0.56 mD; Lower San Andres Injection Zone: 3.4 mD with maximum up to 140 mD; Glorieta Formation Lower Confining Zone: 1.83 mD. Figure 41 shows a 3D fence diagram of horizontal permeability for all the zones.

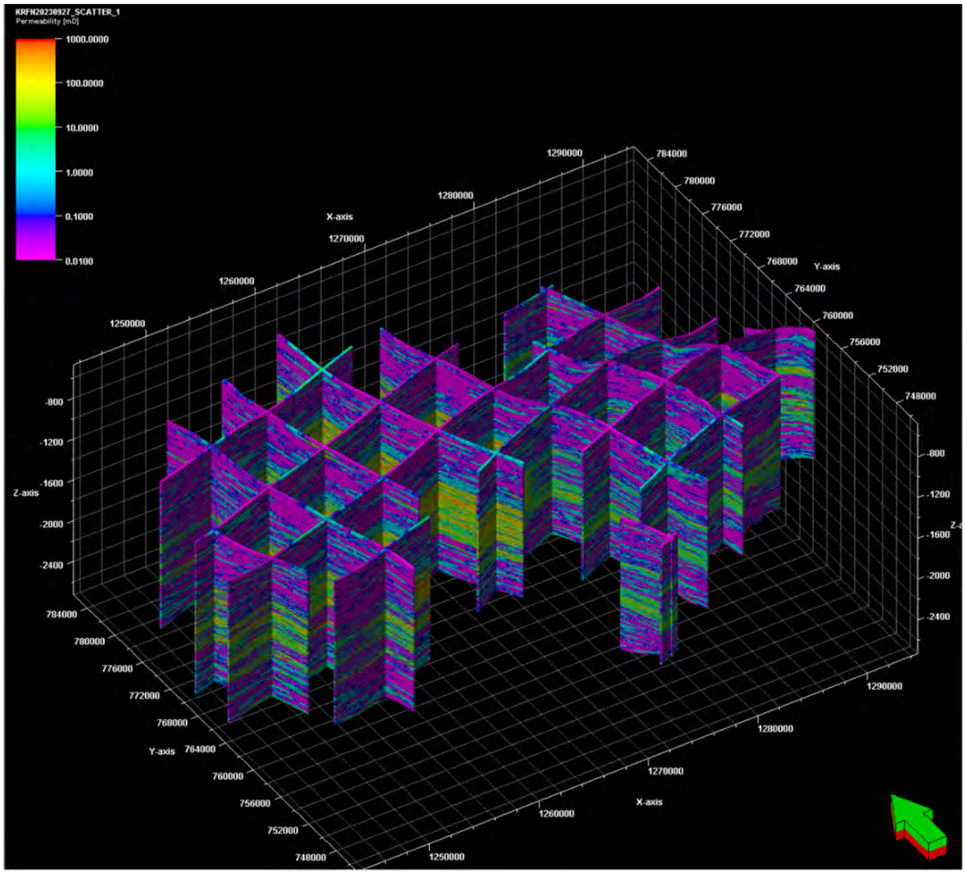

Figure 41—3D index view of the base case permeability distribution calculated using the Lucia transform.

Three permeability transforms, high (P95+0.005), mid (P50), and low (P5-0.005), were calculated from the porosity properties to represent the permeability uncertainty ranges in Figure 42.

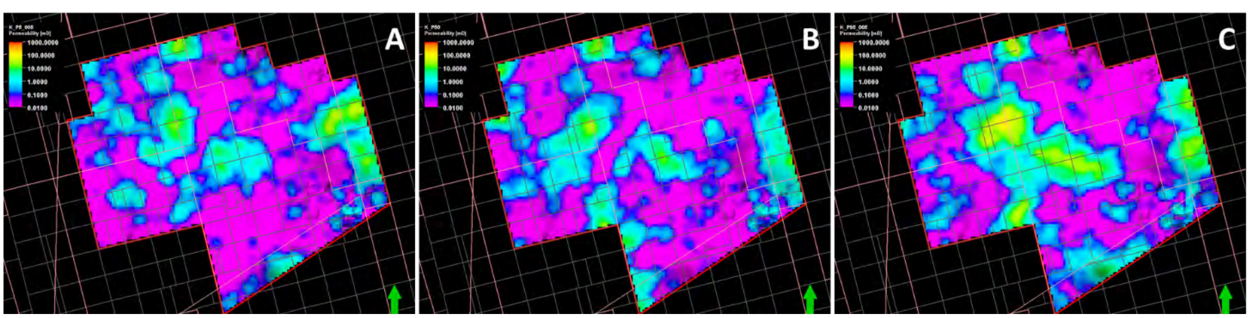

Figure 42—Plan view of the P5-0.005 (A = low), P50 (B = mid), and P95+0.005 (C = high) case permeability.

2.5 Constitutive Relationships and Other Rock Properties

The BRP Project dynamic reservoir simulation followed a method developed by Ghomian (2008), who had successfully matched the results of a 2004 Frio pilot injection test, described in detail by Sakurai et al. (2006). OLCV adopted these established processes for petrophysical evaluations, geocellular model construction, and equation-of-state (EOS) modeling for CO_2 properties and solubility. Further, all simulation runs were executed using the GEM simulator, as used by Ghomian (2008).

The grid properties of porosity and horizontal permeability (k_h) were imported directly from the static geocellular model. The base vertical permeability (k_v) for each grid cell was calculated using a multiplier of 0.1 to the horizontal permeability, based on Oxy's 30 years of experience in building simulation models for more than 20 San Andres reservoirs in the Permian Basin.

The water-gas capillary pressure curves are based on MICP laboratory data presented in Appendix A of this plan. Sample 190H is interpreted to be most representative of the Injection Zone and sample 2-60R is interpreted to be most representative of the Upper Confining Zone. The water-gas relative permeability curves for the respective samples were taken from the analytical workflow based on Greene et al. (2021) and Corey (1954) provided in Appendix A of this Plan. Based on Oxy's extensive experience in the Permian Basin, the maximum relative permeability to gas (k_{rg}) value from experimental results of Bennion (2006) and Lun et al. (2023) was slightly modified to a lower value of 0.4 that represents a conservative scenario. Ranges of relative permeability Corey parameters were tested as a sensitivity to determine the effect on the injection rate and reservoir pressure during injection. Figure 43 shows the capillary pressure and relative permeability curves for Injection and Upper Confining Zone, respectively.

[redacted]

Figure 43—Relative permeability and capillary pressure for the Injection Zone (A) and Upper Confining Zone (B). krw and krnw represent the relative permeability for the wetting (water) and non-wetting (gas) phases, respectively.

The fluid and rock properties (water density, salinity, and composition and rock compressibility) used in the simulation model are described in Section 2.3 of this document. The water density variation with depth and pressure were calculated using the linear models reported in GEM, respectively. The water viscosity was estimated using the correlation from Sharqawy et al (2010) at reservoir conditions (salinity and temperature).

2.6 Penwell Field Calibration

Because there is an active San Andres waterflood development in the Penwell field located only five miles away from the proposed BRP Project, OLCV performed a field-level calibration exercise of the Penwell wells that lie within the simulation model's boundaries (Figure 44). The motivation for this was to assess the effect of the Penwell field development on the reservoir pressure in the proposed Injection Zone and to evaluate if the Penwell and the AoI are isolated from each other. The result was a calibrated simulation model that included three leases of the Penwell field: North Penwell unit, East Penwell unit, and Penwell unit (Figure 44).

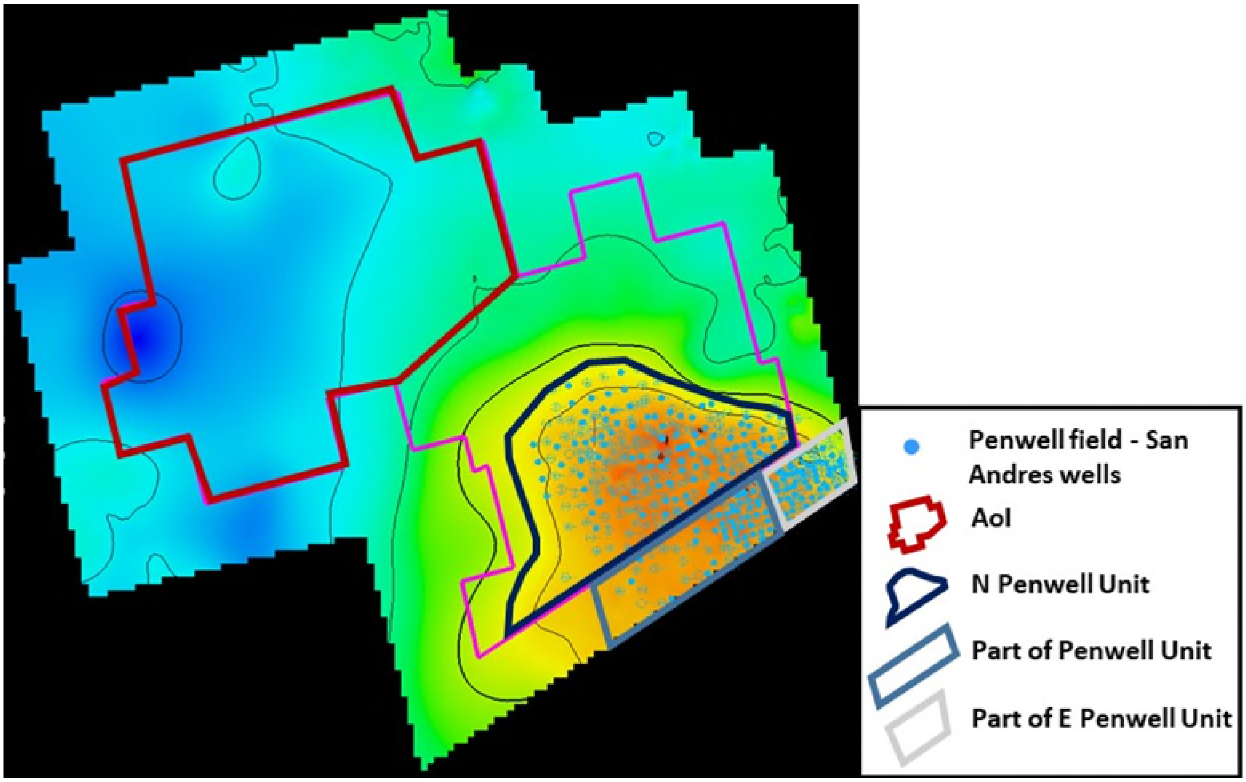

Figure 44—Areal view of the Project site showing the model, existing wells in the Penwell field, and the BRP AoI

The historical reservoir pressure information of the North Penwell field was obtained from the North Penwell unitization agreement (Figure 45). The original reservoir pressure was 1,600 psig, with the main drive mechanism being solution gas drive because there was no apparent gas cap. The saturation pressure was listed as 1,226 psig. Information obtained from Major et al. (1990) suggests that the Upper San Andres is the hydrocarbon-bearing reservoir out of which only the upper oil-producing zone was predominantly exploited (Siemers et al. 1996). The initial water saturation in the Upper San Andres or hydrocarbon-bearing zone was populated using the Lucia correlation (1995). Historical production and injection data from public databases (TRRC) indicate that the Lower San Andres is a non-oil-bearing zone. These public data were used in the field-level model calibration exercise.

1. Field Name (as per current proration schedule - including reservoir, if applicable.) Penwell	2. RRC District 8
3. Operator Phillips Petroleum Company	4. County Ector
5. Lease Name(s) and RRC Lease Number(s) North Penwell Unit	6. Reservoir Discovery Date 1927

7. Have any injection permits been granted previously to any operator in this reservoir? [X] Yes [ ] No
If answer to this question is "NO", ALL OPERATORS IN THE RESERVOIR MUST BE NOTIFIED of this application, and copies of notification attached hereto.

8. Check the Appropriate Block(s):
[X] New Project or [ ] Expansion of Previous Authority to Add Either: [ ] New Lease(s) or [ ] Additional Well(s) on Same Lease(s)
Previous Authority Dated ________ by [ ] Administrative Action or [ ] Hearing, Special Order No. ________

RESERVOIR AND FLUID DATA ON ENTIRE RESERVOIR

9. Name of Reservoir San Andres	10. Estimated Productive Area of Entire Reservoir (acres) 11,000 acres
11. Composition (sand, limestone, dolomite, etc.) Dolomite with gypsum and anhydrite	12. Type of Structure (Include cross-section and structural maps.) Anticline
13. Subsea Depth of Oil-Water Contact (ft.) -1095'	14. Subsea Depth of Gas-Oil Contact (ft.) None apparent
15. Original Bottom Hole Pressure (psig) 1600	16. Current Bottom Hole Pressure (psig) 350
17. Was a Gas Cap Present Originally? No	18. Is a Gas Cap Present Now? No
19. Ratio of Gas Cap Volume to Oil Zone Volume --	20. Saturation Pressure (psig) 1226
21. Formation Volume Factor Original: 1.22 Current: 1.16	22. Type Drive During Primary Production Solution gas

RESERVOIR AND FLUID DATA

23. Number of Productive Acres in Lease(s) within Project Area 4354	24. Average Depth to Top of Pay (ft.) 3400'	25. Average Effective Pay Thickness (ft.) 51
26. Average Horizontal Permeability (mds.) 2.5	27. Range of Horizontal Permeability (mds.) --	28. Connate Water Saturation (% of pore space) 35
29. Average Porosity (%) 9.8	30. Gravity of Oil (deg. API) 33	31. Viscosity (cps. @ ° F) 1.6

PRODUCTION HISTORY OF RESERVOIR

32. Date First Well Completed on Lease(s) 1930	33. Stage of Primary Depletion of Project Area 81%
34. Current Average Gas-Oil Ratio (SCF/bbl.) 2000	35. Current Water Production (% of total fluid production or bbls./day) 28%
36. Current Number of Producing Wells on Each Lease in Project Area 114	37. Current Average Daily Oil Production per Well (bbls./day/well) 8
38. Cumulative Oil Production to Date from Lease(s) (bbls.) 7,697,826 (1-1-70)	39. SUBMIT ATTACHED SHEET(S) GIVING THE OIL, GAS, & WATER PRODUCTION BY YEARS SINCE DISCOVERY & TOTALS. FOR THE LAST 3 YEARS, GIVE THESE FIGURES BY MONTHS.

TYPE OF INJECTION PROJECT AND RESULTS EXPECTED

40. Type of Injection Project (Check the appropriate block(s):)
[X] Waterflood, [ ] Miscible Displacement, [ ] Thermal Recovery, [ ] Pressure Maintenance, [ ] Other ________ (specify)

41. Current Estimated Oil Saturation (% of pore space) 55	42. Estimated Residual Oil Saturation at Abandonment (% of pore space) 40
43. Estimated Original Oil-In-Place (bbls.) 103,858,827	44. Estimated Ultimate Additional Oil that will be Recovered as a Direct Result of Injection (bbls.) 4,703,890

Figure 45—North Penwell Unit information obtained from the unitization agreement (Source: TRRC).

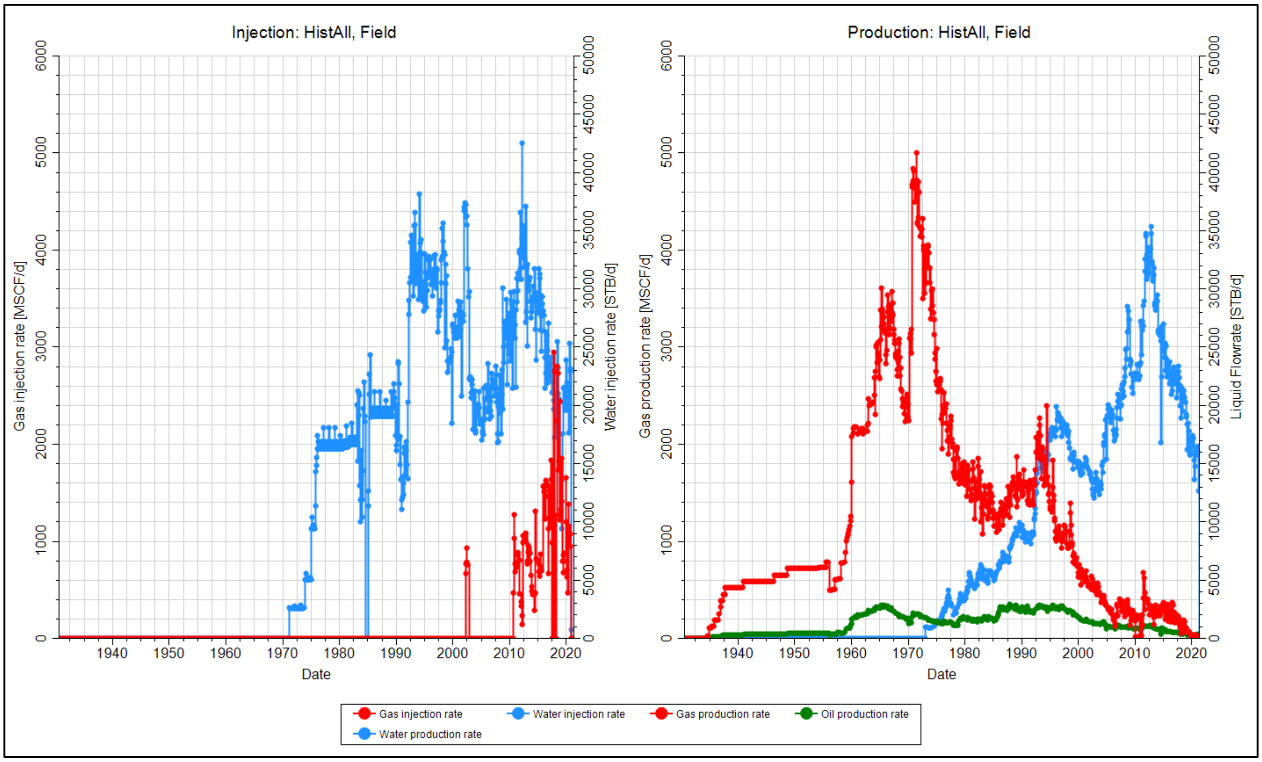

Figure 46—Historical injection and production of the Penwell field.

Figure 46 shows the historical production and injection data for the Penwell wells inside the model boundaries. For this exercise, a black-oil model was deemed suitable. Therefore, the black-oil pressure-volume-temperature (PVT) data were taken from an analog San Andres field operated by Oxy. Horizontal permeability distribution, the relative permeability endpoints, and the Corey exponents were tuned to obtain a field-level history match of the model from August 1930 to May 2021 (Figure 47).

[redacted]

Figure 47—Predictions from the history-matched Penwell model.

The tuned relative permeability exponents are listed in Table 4, and the calibrated permeability in the X- and Y-directions are shown in . The permeability distributions are shown as vertically averaged maps for the Upper San Andres Formation. It can be observed that the predominant change in permeability happened in the X-direction, consistent with the E-W direction of the maximum horizontal stress.

Table 4—Tuned Relative Permeability Data for the Penwell History-Match Model

[redacted]

[redacted]

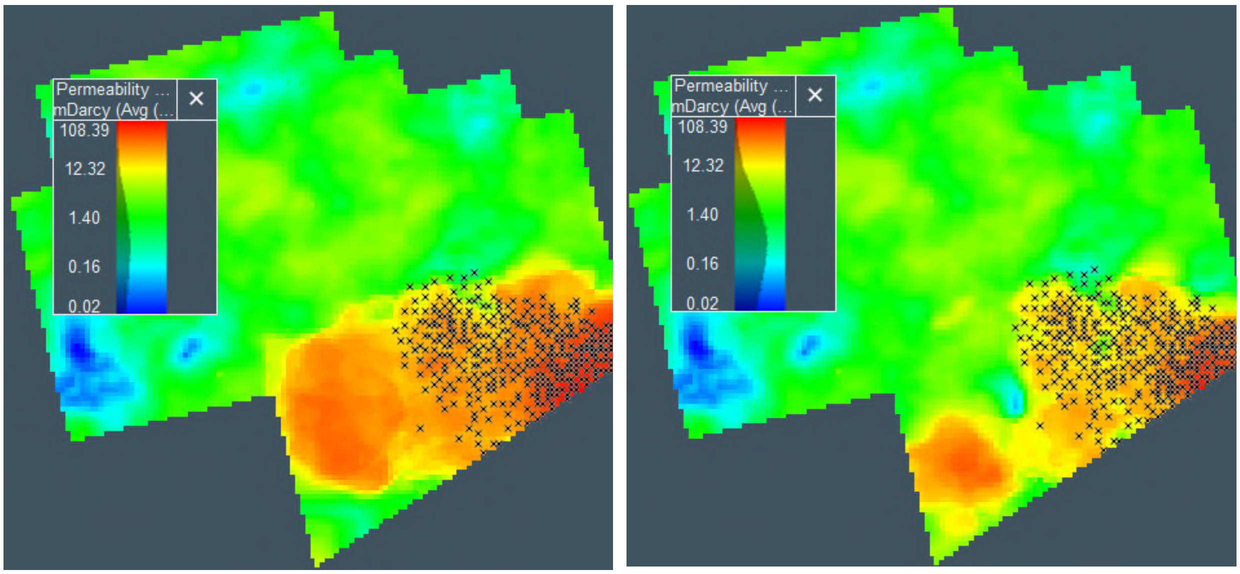

Figure 48—Left: Vertically averaged permeability in the X-direction. Right: Vertically averaged permeability in the Y-direction.

Figure 49 shows the reservoir pressure distribution at the end of the calibration period (May 2021); it shows that the pressure propagation also follows the direction of permeability modification. To assess the effect of Penwell field development on the reservoir pressure of the proposed sequestration AoI, a monitoring well was placed in the history-matched model (Figure 49). shows the well-block pressures of the monitoring well perforated in the Upper and Lower San Andres, respectively. The pressure effect on the AoI due to Penwell development is negligible—around 3 psia in Lower San Andres and 1 psia in the Upper San Andres, over the entire 91-year history of the field.

Pressure gauge measurements obtained in the Lower San Andres from the Shoe Bar 1 well support the hypothesis that Penwell field is not in communication with the BRP site. A downhole pressure gauge in the Shoe Bar 1 well between March – November 2023 has shown a consistent pressure gradient. OLCV will monitor future operation conditions in the North Penwell unit and adjust the simulation model if needed.

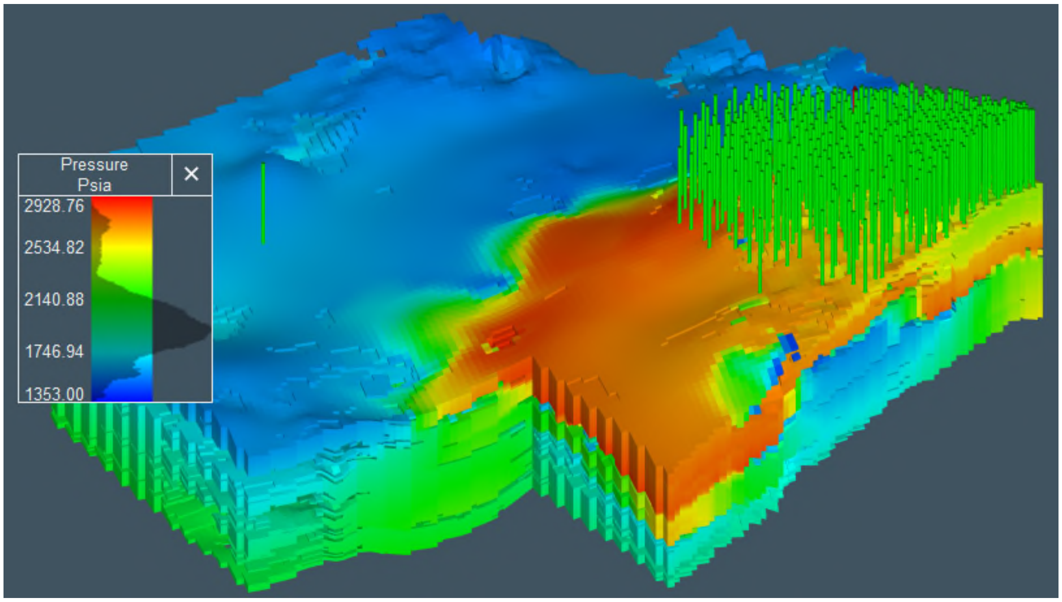

Figure 49—Reservoir pressure at the end of Penwell field calibration period.

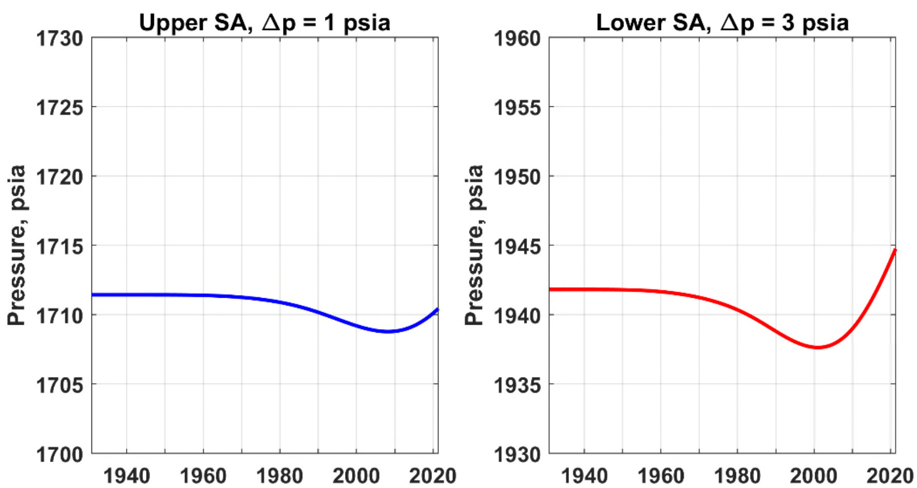

Figure 50—Well-block pressure of the monitoring well in the AoI.

2.7 Boundary Conditions

No-flow boundary conditions were applied to the upper and lower boundaries of the model, with the assumption that the Injection Zone and Confining Zones are continuous throughout the region. This hypothesis is attributed to the large entry pressure observed in the capillary pressure data (i.e., Figure 43) retrieved from MICP experiments (Section 3.4 in Appendix A, Results of Stratigraphic Test Wells). Further discussion regarding geology site specific to justify the no-flow boundary can be found in Section 2.2.3.3 (Upper Confining Zone) and Section 2.2.3.5 (Lower Confining Zone).

The side boundary conditions were also assumed to be no-flow. However, the side boundary condition was tested as a sensitivity to determine the effect on the injection rate and reservoir pressure during injection. As mentioned in Section 2.6, the hydrocarbon development in the Penwell field was not included in the CO2 injection forecast due to negligible pressure effect of the ongoing waterflood operation on the proposed Project.

2.8 Initial Conditions

OLCV used MDT data obtained in the Shoe Bar 1 to determine the pre-injection pressure vs. depth. The model was initialized with a unit water saturation ($S_w = 1$), because the Lower San Andres Injection Zone is a saline aquifer. According to pyrolysis experiments conducted for the fluid samples acquired from Shoe Bar 1 (Appendix A Section 3.2), there is no evidence of hydrocarbons in the sequestration site. Water salinity measurements were obtained from water samples collected in the Shoe Bar 1. A brine sample representing the middle of the Injection Zone was used for the salinity value in the model. Additional details on data obtained from Shoe Bar 1 are presented in Section 2.3 of this document and in Appendix A.

Table 5—Initial Model Conditions

Parameter	Value or Range	Units	Depth (ft TVD)	Data Source
Temperature	96 to 98	°F	4,393 to 6,486	Measured
Pressure	Spatially varying	psi	4,393 to 6,486	Measured
Fluid density	69.03	lb/ft^3	4,769	Measured
Salinity	130,000	ppm	4,769	Measured
Formation compressibility	4.5E-6	1/psi		Analog San Andres reservoir

2.9 Operational Information

The simulation model forecast (CO_2 injection and water production) begins by using reservoir pressure data based on data acquired in the Shoe Bar 1 and Shoe Bar 1AZ wells. To delineate the BRP AoR, the simulation model considers the influence of the CO_2 injection and water production forecast from the BRP AoI. The simulation model assumes North Penwell Unit will operate at an injection/withdrawal ratio (IWR) of 1.0, and as a result, the waterflood will not influence reservoir pressure in the AoI.

One slant and one horizontal injector (BRP CCS1 and BRP CCS2 wells) will inject at a total maximum group rate of 1,058 MTPD between January 2025 to December 2026 (0.385 MMTPA). BRP CCS1 slant injector is completed in the upper porosity packages (sub-zone G1 and G4) of the Lower San Andres Formation (approximately 360 ft gross thickness in the G1 and 125 ft gross thickness in the G4) and the BRP CCS2 horizontal well is completed at the Holt sub-zone of the Lower San Andres (approximately 170 ft gross thickness).

A third slant injector, BRP CCS3, will commence injection in January 2027. The BRP CCS3, combined with BRP CCS1 and BRP CCS2, will be injecting at a total maximum group rate of 2,116 MTPD from January 2027 to January 2037 (0.772 MMTPA). BRP CCS3 slant injector is completed in the upper porosity packages of the Lower San Andres Formation (sub-zone G1 that is approximately 390 ft thick and G4 that is approximately 130 ft thick).

The slanted injectors have a secondary bottomhole injection pressure (BHIP) constraint of 2,625.3 psig that is set at a reference depth of 4,610 ft TVD. The BHIP for the horizontal well is 3,391.8 psig, and it is set at a reference depth of 5,115 ft TVD.

All wells continue injection until January 2037 when they are shut in. The simulation continues for another 50 years post-injection to simulate CO_2 migration after post-injection site closure.

To restrict the size of the pressure plume resulting from CO_2 injection, four water (brine) withdrawal wells will be drilled and perforated in the Lower San Andres Formation. These wells are planned to commence water withdrawal in July 2024. The minimum BHP of the producers is set at 485.3 psig at a reference depth of 4,610 ft TVD. Between July 2024 to December 2026, the wells produce at a total maximum group rate of 10,000 stb/day; and from January 2027 to January 2037, the wells produce at a total maximum group rate of 15,000 stb/day. The produced brine will primarily be used for Oxy's Enhanced Oil Recovery Operations (EOR) or other makeup water needs. Some of the brine may be injected into Class I disposal wells or utilized in desalination operations. Brine produced from the Project will not be injected into Class II Saltwater Disposal Wells (SWD).

Details of the planned injection and withdrawal wells are presented in Table 6.

Table 6—Operating Details for the Planned Injection and Withdrawal Operation

Operating Information	BRP CCS1	BRP CCS2	BRP CCS3	WW1	WW2	WW3	WW4
	Location (global coordinates, NAD27)						
Latitude	31.76479	31.76994	31.76031	31.76289	31.78419	31.75008	31.76384
Longitude	-102.7289	-102.7332	-102.7102	-102.6959	-102.7276	-102.7102	-102.7540
	Model coordinates (Texas State Plane, Central Zone, USft, NAD27)						
X	1255500	1254200	1261299	1265742	1256211	1261199	1247718
Y	771100	773000	769345	770190	778193	765626	770922
Perforated Interval (ft MD) *							
MD top	4,674	5,768	5,244	4,342	4,468	4,352	4,542
MD bottom	5,667	9,165	6,284	4,982	5,139	4,993	5,201
Wellbore diameter (in) *	6	6	6	6	6	6	6
Planned injection period	1-Jan-2025 to 1-Jan-2037						
Planned water production period	1-Jul-2024 to 1-Jan-2037						
Duration (years)	12	12	10	12.5	12.5	12.5	12.5
Group injection rate (MTPD)	1058 (January 2025 to December 2026) 2116 (January 2027 to January 2037)			-			
Daily average injection mass (MT/day)	450	1,112	450	-			
Daily maximum injection mass (MT/day)	600	1,500	600	-			
Total injection volume and mass (MMT)	1.83	4.87	1.77	-			
Maximum injection BHP (psig)	2,625.3	3,391.8	2,625.3	-			
Average injection pressure (psig)	2,600.3	3,300	2,600.3	-			
Group production rate (stb/D)	-			10,000 (July 2024 to December 2026) 15,000 (January 2027 to January 2037)			
Minimum production BHP (psig)	-			485.3			

*Represents measured depth (MD) along the deviated wellbores (not SSTVD) and diameter in the model, not final wellbore design.

2.9.1 State of Stress and Critical Stress Analysis

The risk associated with fault initiation or reactivation during or after CO_2 injection can be assessed by estimating long-term pressure changes in the subsurface and the potential to induce dilation, or shear slip, on matrix rock and/or pre-existing faults and fractures (Fjaer et al. 2008). The resolved normal and shear stresses acting on an existing or potential fault surface are calculated and utilized in Mohr-Coulomb analysis (Jaeger and Cook 2007) to estimate the risk of failure during CO_2 injection. Uncertainties of inputs to the in-situ stress model increase the risk due to the decreased accuracy and precision of stress magnitudes and the injection pressures required to induce tensile or shear failure. The uncertainties in the stress analysis can be reduced with the acquisition of modern density and dipole sonic data, rock mechanical core data, and an estimate of SHmin through the interpretation of leak-off test (LOT) results to define closure pressure, parting pressure from step-rate tests, or some other means to estimate the minimum horizontal principal stress for model calibration.

The increase in fluid pressure from CO_2 injection has the potential to cause failure from the generation of fractures in the matrix of the formation, dilation or shear slip along pre-existing faults, and/or reactivation of the basement fault systems producing induced seismicity. Mohr-Coulomb failure analysis can be applied in the AoI to evaluate CO_2 injection induced seismicity, reactivation of exisiting faults, and beakdown of the formation. Mohr-Coulomb failure analysis considers the ratio of shear stress (τ) and effective normal stress (σ_n') acting on a plane in a given orientation compared to the amount of friction of that plane. The plane can be an existing fault surface or a potential failure plane in the matrix of the subsurface. The coefficient of friction (μ) is defined as the ratio of shear stress to effective normal stress:

$$\mu = \frac{\tau}{\sigma_n} \qquad \textit{Equation 3}$$

In the Mohr-Coulomb failure criterion, failure is defined as the condition in which the shear stress/effective normal stress ratio, acting on an optimally orientated plane, exceeds the failure limit defined by the relationship:

$$\tau = \mu\sigma + \mathrm{So} \qquad \textit{Equation 4}$$

where So is cohesion and is a function of friction and unconfined compressive strength (UCS):

$$UCS = 2So(\sqrt{\mu^2 + 1} + \mu) \qquad \textit{Equation 5}$$

Figure 51 shows the conceptual graphical representation of the linear Mohr-Coulomb failure criterion. The state of stress is represented by the Mohr circle defined by the maximum (σ_1) and minimum (σ_3) principal stresses. Any plane orientation is defined along the boundary of the circle by an angle of 2β from σ_1 to σ_3, where β is the angle between the σ_1 and the normal the plane. In

Figure 51, the red circle represents the original state of effective stress. In the case of CO_2 injection into the reservoir, pore pressure is estimated to increase while the magnitude of the effective principal stresses decreases, which moves the Mohr circle to the left on the X-axis. The failure limit is shown as the linear-sloped solid black line defined by Equation 4. The dashed line would represent the failure limit of a pre-existing fault with comparatively little friction. While the friction of faults is not zero, it is small compared to the friction required to intiate a fracture in the matrix.

As pore pressure increases during injection, the Mohr circle moves to the left along the X-axis and the boundary of the circle eventually intersects the failure envelope. Under those conditions, any plane orienated along the Mohr circle that crosses or intersects the failure envelope may be subject to failure risk. The linear model presented below represents a simplified version of the Mohr-Coulomb failure criterion because the failure envelope is not often linear, and as pore pressure increases, the effective stress decreases, but the horizontal principal stress magnitude increases, making the circle smaller. The result of the linear model is a conservative interpretation, which is appropriate in a scenario where large uncertainties exist in the stress model.

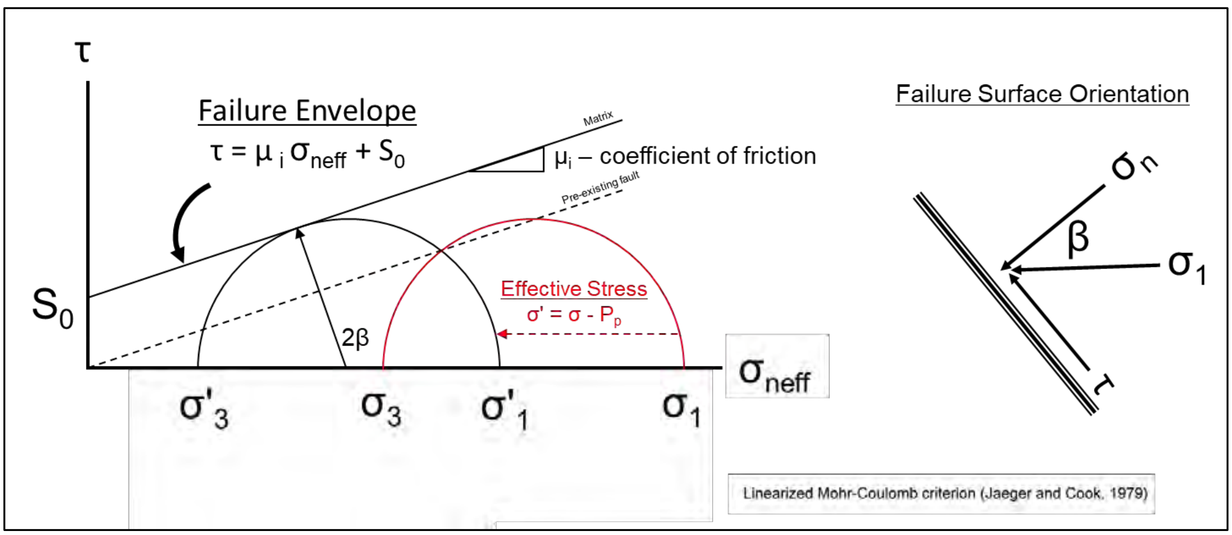

Figure 51—Graphical representation of the linear Mohr-Coulomb failure criterion.

Effective stress calculations in a Mohr-Coulomb analysis depend on an empirical stress model that includes pore pressure and three principal stress magnitudes and azimuths. OLCV calculates pore pressure and three principal stresses: vertical stress (S_V), minimum horizontal stress (S_{Hmin}), and maximum horizontal stress (S_{Hmax}). The workflow utilizes a pore pressure interpretation from SRT tests and employs a poroelastic stress model (described below) to estimate the horizontal principal stresses. Those stresses were utilized to assess the potential for shear and tensile failure in the matrix of the San Andres Formation.

Pore pressure (P_p) information was obtained from data collected in the Shoe Bar 1 and Shoe Bar 1AZ well.

The state of stress was modeled using the modified plane-strain poroelastic stress model, as shown in Equation 6.

$$\sigma_3 = \frac{\nu}{1-\nu}\left(\sigma_v - \alpha P_p\right) + \frac{\varepsilon_h E}{1-\nu^2} + \frac{\varepsilon_H \nu E}{1-\nu^2} + \alpha P_p \qquad \textit{Equation 6}$$

where:

σ_3 = least horizontal principal stress
ν = Poisson's ratio
σ_v = maximum principal stress
α = Biot's coefficient
P_p = pore pressure
ε_h = minimum tectonic strain
ε_H = maximum tectonic strain
E = Young's modulus

The geological interpretation of the failure mechanism in this area is transitional from normal faulting to strike-slip faulting (). The results of the interpretations indicate that the maximum principal horizontal stress (S_{Hmax}) is very similar in magnitude to the overburden stress (S_v). The overburden is calculated by integrating the density data over the interval from surface to the depth of interest at the bottom of the well. The overburden stress is represented by the black pressure profile in Figure 52.

[redacted]

Figure 52—Stress models used in Mohr-Coulomb analysis. Calibration used is formation pressure (blue dot), regional closure pressures (black squares), and closure pressure from mini-frac test (red square). Mohr-Coulomb analysis was conducted at 4,700 ft TVD.

The stress model was calibrated with regional fracture pressure measurements in offset wells, formation pressure interpretation from SRT, and interpreted closure pressure from a mini-frac test. A publicly available methodology for estimating the tectonic strain terms in the poroelastic stress equation (ε_h and ε_H) is used to calibrate the minimum and maximum principal horizontal stresses.

The stress model was plotted in Mohr circle space to assess the required increase in pore pressure to initiate shear or tensile failure on the rock matrix. A summary of stress magnitudes used in the Mohr circle analysis is presented in Table 7. The size of the Mohr circle is defined by the magnitudes of the minimum and maximum effective principal stresses. In this case, the minimum effective principal stress, σ_3, is 1,100 psi. The maximum effective stress (σ_1) is the overburden (2,900 psi). In this stress state, the maximum shear stress (900 psi), observed as the shear stress read from the top of the Mohr circle, is small enough that the risk of shear failure is minimal given the measured unconfined compressive strength (UCS) of 6500 psi at 4700 ft TVD. As effective stress decreases, the matrix will enter negative effective stress before reaching shear failure so tensile failure is the primary potential failure mechanism. The pore pressure required to move the effective stress state into tensile failure is near 1,100 psi. The anticipated maximum injection pressure of 750 psi is less than 90% of the 1,100-psi threshold to initiate tensile failure. Thus, CO_2 injection in the AoR is posing low risk of tensile failure in the San Andres Formation.

Table 7—Summary of stress magnitudes, injection pressures, and UCS magnitudes in Mohr-Coulomb analysis.

Depth	Injection Pressure (psi)	Over-burden (psi)	Pob Grad-ient (psi/ft)	Pore Press-ure (psi)	Pp Grad-ient (psi/ft)	Shmin (Clos-ure) (psi)	Shmin Grad-ient (psi/ft)	SHmax (psi)	SHmax Grad-ient (psi/ft)	UCS (psi)
4,700	750	5,000	1.06	2,185	0.50	3,300	0.70	4,975	1.05	6,500

The stress state of the reservoir determines the fracture initiation pressure which in turn limits the maximum operating pressure limit of the injector wells to maintain matrix flow. The fracture pressure of the target Injection Zone was estimated using Minifrac (or Diagnostic Fracture Injection Test) and Step Rate Tests performed in the Shoe Bar 1 and Shoe Bar 1AZ appraisal wells. The table below summarizes the results:

Table 8—Summary of San Andres Fracture Pressure Estimates by Mini-Frac and Step Rate Tests

Well	Sub-Zone	Tested Interval Top Perf-Bottom Perf (MD, ft)	Initial Reservoir Pressure (psi)	Type of Test	Estimated Fracture Gradient (psi-ft)
Shoe Bar 1	Lower San Andres (G1)	4827-4829	2200@4400ft	Mini-Frac	[redacted]
Shoe Bar 1	Lower San Andres (G4, G1, Holt)	4421-5024	2200@4400ft	Step Rate Test	
Shoe Bar 1AZ	Lower San Andres (Holt)	5122-5132	2522@5088ft	Step Rate Test	
Shoe Bar 1AZ	Lower San Andres (G1)	4723-4733	2307@4596ft	Step Rate Test	

2.9.2 Mohr Coulomb Failure Analysis

The maximum shear stress is less than the minimum shear stress required to initiate failure, given a measured unconfined compressive strength (UCS) of 6,500 psi (Figure 53) at the depth of investigation. The most likely mechanism for formation fracture during injection is tensile failure.

Tensile failure takes place when the minimum effective stress reaches zero or goes negative. The limit is determined by the magnitude of the tensile strength of the formation so that failure takes place when the absolute magnitude of the negative effective stress exceeds the magnitude of the tensile strength of the matrix. In this project, tensile strength is assumed to be zero as a conservative engineering safety factor. Tensile failure occurs when the minimum principal stress reaches the tensile failure limit. The magnitude of that pressure increase can be read directly off the plot. It indicates that an increase in pore pressure of around 1,100 psi would have to occur to initiate tensile failure at this depth in the San Andres.

Figure 53 is an example from 4,700 ft TVD, but the same exercise was conducted throughout the depth interval of the San Andres Formation with little change in the final interpretation. In this case, injection pressure is expected to be less than 90% of the 1,100 psi required to initiate tensile failure.

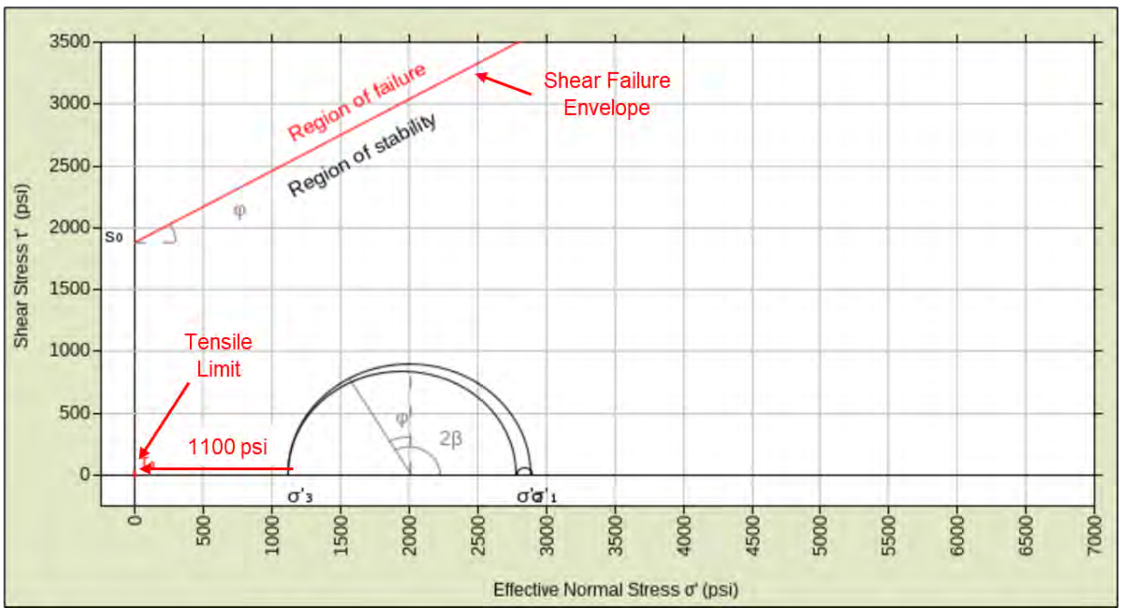

Figure 53—Mohr circle failure analysis of maximum stress state. Tensile failure risk is low given a reasonable estimate of tensile strength of the matrix.

The Mohr-Coulomb theoretical analysis was conducted using a stress model build from data acquired in the plugged heritage well, Shoe Bar Ranch 1 (API: 4213536163) using a formation pressure interpreted from SRT tests in the San Andres Formation. The well had the required density and sonic log data coverage over the interval of interest to build the geomechanical model. The geological interpretation is that the area is in a normal faulting/strike-slip transitional failure mode that is consistent with observations throughout the broader Permian Basin. The calibrated stress state indicates negligible risk of shear failure due to the generally low principal stress magnitudes and low maximum shear stress magnitude. The maximum shear stress in any orientation is less than the minimum shear stress defined by the Mohr-Coulomb failure criterion. Tensile failure is the most likely mode of failure, and it would require approximately 1,100 psi increase to initiate failure in the matrix. Estimated operating pressures during CO_2 injection are expected to be less than 90% of the 1,100 psi required to initiate tensile failure, so risk of failure during CO_2 injection operations is low.

3.0 Computational Modeling Results

3.1 Predictions of System Behavior

Figure 54 and Figure 55 show the simulated well rates and bottom-hole pressures results, respectively. The group injection constraint of 1,058 Metric Tons per Day (MTPD) (384,800 MMTPA) from January 2025 to December 2026 and 2,116 MTPD (769,600 MTPA) from January 2027 and January 2037 was honored. An injection bottomhole pressure (BHIP) for the BRP CCS1 well reported reaching a maximum of 2,640 psi. The BHIP of BRP CCS2 has variable value over the forecast period, reaching a maximum of 2,905 psi at end of December 2026 followed by increase in injection at the start 2027, reaching a maximum BHIP of 3,400 in July 2028, and decreasing to 3,150 psi at the end of the injection period. The BHIP of BRP CCS3 shows a maximum of 2,640 psi when the period starts in January 2027 until the end of injection in January 2037. The bottomhole injection pressures for all wells are below 90% fracture opening pressure (Table 9), and the brine producers help to relieve the pressure increase. Wells WW1, WW2, WW3, and WW4 produce at a group rate of 10,000 stb/d from January 2025 to December 2026 followed by a withdraw of 15,000 stb/d from January 2027 to January 2037 with a minimum flowing bottomhole pressure of 500 psi. Figure 56 describes the monthly volume and mass of CO_2 injection rate and the corresponding cumulative volumes respectively.

Figure 57 describes the CO_2 storage mass as a function of time in million metric tons (MMT). The total CO_2 stored is composed of structural and stratigraphically CO_2 (supercritical), dissolved in connate water $CO_{2,}$ and residual trapped CO_2. In Figure 57, after injection ceases in January 2037, a portion of the stratigraphical and structural supercritical CO_2 is redistributed between the residual and solubility trapped CO_2 over the next 50 years. Structural and stratigraphic CO_2 is the main storage mechanism during the injection period. However, after injection finishes, residual trapped CO_2 quickly increases being an important long-term storage mechanism, representing about 50% of total stored CO_2.This process will continue over time and increase the security of permanent storage of the injected CO_2.

A total of 8.47 MMT is estimated to be stored during the 12-year injection period. The resulting maximum extents of the CO_2 plume and the pressure front are discussed in Section 4.0 AoR Delineation. The movement of the CO_2 plume and pressure front with time are shown in Section 5.3 of the Area of Review and Corrective Action Plan and in the Post-Injection Site Care and Post-Injection Site Closure Plan of this permit application.

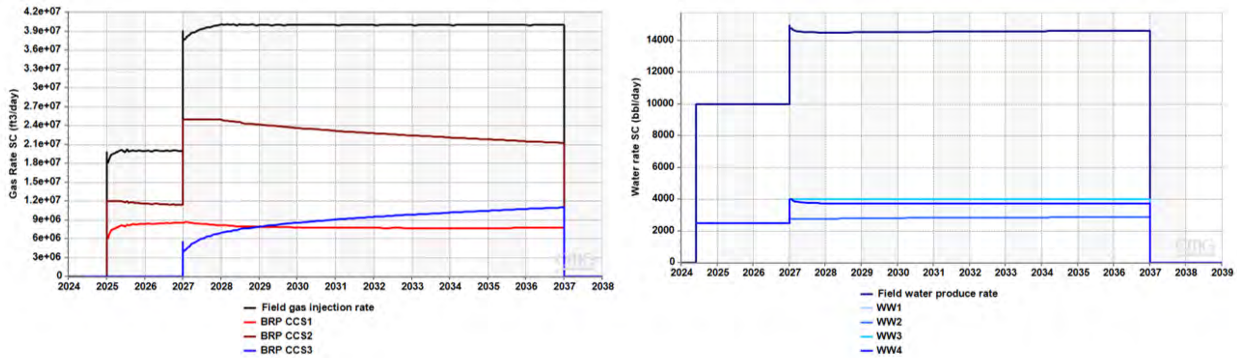

Figure 54—Left: Simulated Project and well CO_2 injection rates. Right: Project and well water production rates.

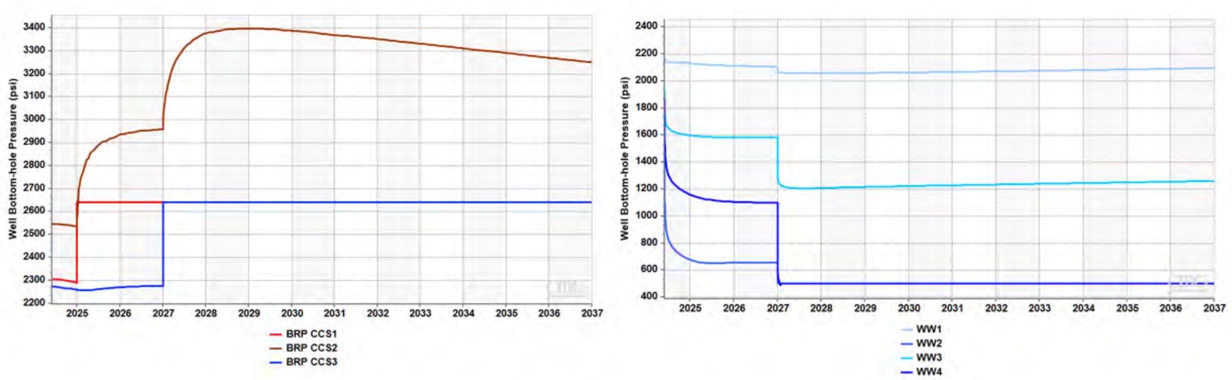

Figure 55—Simulated bottomhole pressures of CO_2 injectors and water producers.

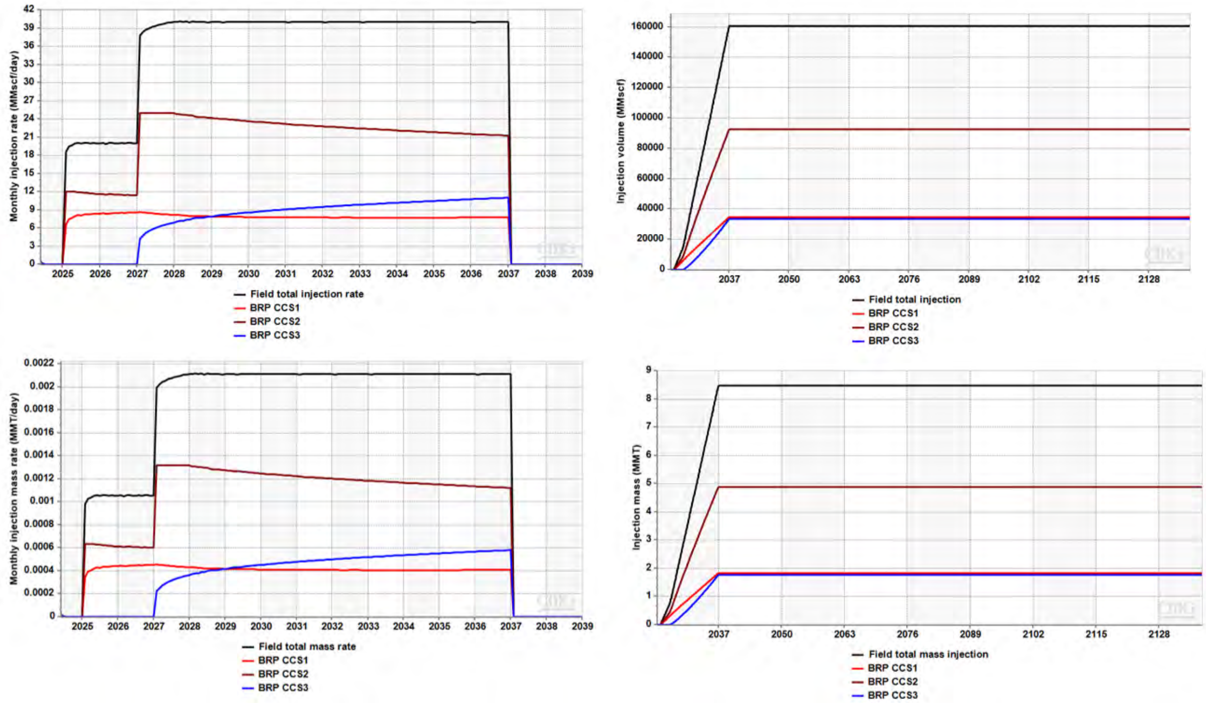

Figure 56—Monthly volume rate, mass rate, cumulative volume, and cumulative mass of CO_2 injected.

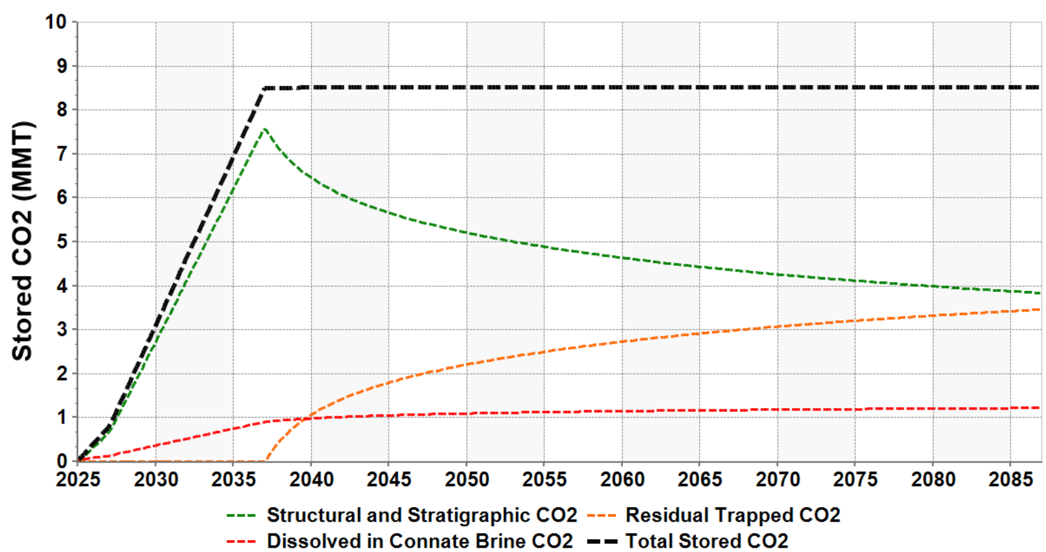

Figure 57—Forecasted CO_2 storage in mass by mechanisms (structural and stratigraphic, dissolved in connate brine, and residual) as a function of time.

3.2 Model Calibration and Validation

3.2.1 Model sensitivities

To test the field response to CO_2 injection, sensitivities of the results to subsurface uncertainties were explored. These uncertainties include horizontal permeability multiplier (Kh multi), porosity multiplier (Por multi), critical gas saturation (Sgcrit), gas endpoint relative permeability endpoint (Krg), Land trapping coefficient (Land *C*), and the aquifer boundary condition (with 0 being no flow and 1 being a leaky side boundary). Porosity and permeability multipliers are applied to the whole simulation model. The leaky side boundary was simulated by assigning an analytical Carter-Tracy aquifer with infinite extent. The relative permeability values were based on maximum and minimum values reported from laboratory experiments for the Injection Zone.

Table 9 summarizes the possible ranges of these subsurface inputs and the corresponding base case inputs. In Table 9, D indicates a discrete distribution (maximum and minimum values tested).

Table 9—Uncertainty Ranges of Reservoir Parameters

Parameter	Distribution	Base Case Input
Horizontal permeability multiplier (Kh multi)	[redacted]	
Porosity multiplier (Por multi)		
Critical gas saturation (Sgcrit)		
Gas endpoint relative permeability (Krg)		
Land coefficient (Land C)		
Aquifer boundary		

The selected response variables are summarized below:

- Field gas injected total (FGIT) in million metric tons (MMT)
- Field average reservoir pressure (FPR_AOI) in psi
- Dissolved CO_2 total in MMT
- Structural and stratigraphic (supercritical) CO_2 total in MMT
- Residual trapped CO_2 total in MMT

Figure 58 shows sensitivities of the specific simulation outputs mentioned above to the parameter ranges at the end of injection period (January 2037) and at the end of sequestration period (December 2086). The response to more favorable variable values for sequestration in the uncertainty analysis do not impact on FGIT since the field rate is limited to a group injection constraint (384,800 MMTPA, until December 2026 and 769,000 MMTPA, until January 2037). The injection is most sensitive to the lower bound horizontal permeability multiplier (KMULT = 0.8) but with only 9% reduction in total volume. The average pressure change in the AoI is slightly impacted by the aquifer boundary condition of ~10 psi because the pressure change is dominated by the well rates rather than the far-field boundary conditions. The relative permeability parameters have a minimal impact on the overall injection performance. However, critical gas saturation affects the trapped CO_2 storage mechanism, as shown in the last plot of Figure 59. A higher critical gas saturation results in a larger volume of CO_2 trapped in the pores. Both structural/stratigraphic and dissolved CO_2 volumes are sensitive to the horizontal permeability multiplier. However, it is very unlikely to have an overall reduction in the field permeability by 20% based on the data collected from Shoe Bar 1 and Shoe Bar 1AZ and the injectivity tests. In addition, permeability close to the well bore can be enhanced by stimulation to mitigate any lower permeability found in the injection wells.

[redacted]

Figure 58—Tornado charts showing the sensitivity of simulation outputs to the input parameter ranges at the end of injection and at the end of post-injection periods. Blue and orange bars represent the lower and upper bounds, respectively.

The effect of the horizontal permeability multiplier, porosity multiplier and aquifer condition in reservoir pressure over time is shown in the left subplot in Figure 59. It is important to notice that reservoir pressure stabilizes after the injection period and the effect of the flow boundary condition is negligible. Figure 59 shows in the right subplot the effect of the relative permeability parameters in the amount of trapped CO_2. The trapping mechanism continues in the post-injection period in a continued process over time and increases the security of permanent storage of the injected CO_2.

[redacted]

Figure 59—Influence of horizontal permeability multiplier, porosity multiplier and aquifer condition in reservoir pressure (left) and the relative permeability parameters (Krg, Sgcrit and Land C) in the amount of residual trapped CO_2.

3.2.2 Geochemical Modeling

3.2.2.1 Background and literature review

The main reactive transport phenomenon of interest in carbonate reservoir CO_2 storage projects is mineral dissolution by weak carbonic. The dissolution of the mineral can alter the porosity and the permeability of the reservoir rock, affecting sequestration storage capacity, well injectivity, and integrity of confining zones. For the BRP Project, dolomite is the dominant mineral in the Injection Zone and anhydrite is the dominate mineral in the Upper Confining Zones. Oxy's operational experience in San Andres reservoirs has shown that the effect of reactive transport on reservoir performance is insignificant.

- A pilot study conducted at the Denver Unit (Mathis and Sears, 1984) showed that no significant changes in porosity and pore structure were observed after more than two years of CO_2 and water injection. The study concluded that dolomite dissolution was insignificant and anhydrite loss had a minor effect on porosity.
- Mohamed et al (2011) conducted laboratory study performing CO_2 flooding on 20 Silurian dolomite cores (97.5% molar analogous to San Andres) at different conditions (temperature from 70 to 200ºF, injection rates from 2 to 10 cm^3/min and, five different flood designs of water alternating gas [WAG]). The authors concluded that CO_2 had a minor effect on core porosity and permeability. They observed slight dolomite dissolution and possible calcium carbonate precipitation.
- Hangx et al. (2009) conducted a laboratory study to evaluate the integrity of an anhydrite rock with 10 to 33 wt.% dolomite in contact with CO_2. These samples are lithologically analogous to the BRP Project Upper Confining Zone, with 0.1 - 0.3% porosity and $1x10^{-4}$

mD. Compression experiments were executed to understand rock mechanical integrity with fully CO_2-saturated pore fluid, similar to the conditions expected during injection. The authors concluded that any fractures created during injection would be healed.

[redacted]

In addition to literature and Oxy's experience in CO_2 injection at San Andres Formation, OLCV conducted geochemical equilibrium and reactive-transport simulations modeling to evaluate site specific data acquired from the Shoe Bar 1 stratigraphic test well.

3.2.2.2 Geochemical Equilibrium Simulations

Geochemical equilibrium modeling was conducted using PHREEQC Simulator Version 3 (Parkhurst and Appelo, 2013), a program developed by the USGS that includes a robust thermodynamic database for aqueous, mineral, and gaseous interactions (Krupka et al., 2010). PHREEQC includes the Peng-Robinson equation of state to improve the solubility calculation of gas at high pressures, which is important to consider when studying CO_2 sequestration in saline aquifers.

The objective of this work is to identify primary chemical reactions (solid and aqueous phase) to be included into the reactive-transport simulations and provide initial assessment of the CO_2 compatibility with rocks and fluids in the Injection and Upper Confining Zones. The modeling includes brines speciation, geochemical baseline prior injection, and CO_2 interaction with reservoir brine and minerals.

Table 10 shows the brine composition for three samples collected at 4,603, 4,770 and 5,129 ft used in geochemical simulations (See Appendix A: Stratigraphic Well Summary for full geochemical results). Other ions were not considered in modeling because their concentration is negligible or below detection limits. Trace metals (i.e., arsenic, mercury, and lead) have insignificant concentration values and were not tracked during modeling. Table 11 summarizes the rock mineralogy used during geochemical equilibrium runs for the Injection Zone. The normalized values were obtained from the average of the five closest depth samples reported in the XRD data in (See Appendix A: Stratigraphic Well Summary for XRD results). The Upper Confining Zone was modeled as 90% anhydrite and 10% dolomite weight percent, based on lithology results from log data.

Table 10—Water composition and brine properties for Samples 1, 2 and 3 from Shoe Bar 1AZ.

[redacted]

Table 11—Rock mineralogy retrieved from average XRD data for the five closest core samples.

[redacted]

Although some chemical reactions are known to be time dependent, the equilibrium assumption was selected at this stage, because it is the most conservative approach. In this method, minerals can dissolve or precipitate instantaneously and achieve final stage of interaction with other solid phase and aqueous species. Thus, this process can simulate the long-term exposure and mimic permanent CO_2 storage. For reactive-transport simulations, kinetics approach is assumed, and further details are presented in Section 3.2.2.3.

Geochemical simulations were performed to equilibrate each sample with their respective reservoir mineralogy and in-situ CO_2 concentration to simulate conditions prior to injection period and establish the baseline condition. Table 12 and 13 show the results for the Injection and Upper Confining Zones, respectively. For equilibrium simulations, a rock with porosity equal to 10% is assumed. Initial CO_2 concentration in the reservoir was retrieved using flashed gas composition and the fugacity was calculated using PHREEQC based on Peng-Robinson model at reservoir pressure and temperature. [redacted]

The PHREEQC database file was selected as the thermodynamic data and activity coefficient model for equilibrium and reactive-transport simulations. Although Pitzer virial model is known to be more suitable for brines with high ionic strength (above 1.0 M) at certain conditions, the extended Debye-Hückel equation is determined to be suitable for the brines analyzed for the BPR Project. Besides the ion-size parameters, the extended terms based on ionic strength have been fit for main ions in chloride dominated waters (Truesdell and Jones, 1974) such as calcium, magnesium, sulfate, potassium, and carbonate species. In addition, the Pitzer approach has limited parametrization for sulfate complexes (i.e., $NaSO_4^-$, $CaSO_4^0$, $MgSO_4^0$, KSO_4^-, $BaSO_4^0$), similarly observed for iron and aluminum species (Krupka et al. 2010). These aqueous complexes are very important for brines in equilibrium with sulfate-type minerals ($CaSO_{4(s)}$) because they modify the sulfate activity, having critical impact on gypsum and anhydrite solubility product (Appelo and Postma, 2005, page 129).

Several mineral phases were included in the simulation even though they are not present in measured XRD data (i.e., pyrite, hematite, chlorite, illite, kaolinite, barite, strontianite, celestite, and magnesite) to evaluate their precipitation tendency. Since the reservoir is assumed to be initially in equilibrium, saturation indexes were slightly adjusted (from database equilibrium constant value, Ksp) to avoid large mineral dissolution or precipitation and honor measured XRD data. Positive and negative saturation index numbers (ΔSI) indicate changes to more supersaturated or undersaturated condition in relation to a mineral, respectively.

Pyrite, hematite, chlorite, illite, kaolinite, barite, strontianite, celestite, and magnesite were considered stable phases without precipitation tendency. As expected, all brine samples are in very close equilibrium condition with their respective minerals and initial CO_2 in the reservoir. Sample 2 is the one that requires the largest changes in saturation index for anhydrite and gypsum. Quartz and k-mica are the most stable phases. Calculated pH from simulations is slightly smaller in comparison to laboratory measured ones. This behavior is due to the degassing effect from depressurization when the samples are open to atmospheric conditions for measurement. Even with the quickest analysis in the laboratory after chamber being open, CO_2 is quickly released to atmosphere, decreasing its amount dissolved in water, shifting the equilibria to more a basic condition (Appelo and Postma, 2005, page 14).

Table 12—Adjusted saturation indexes and pH for Sample 1, 2, and 3 at the Injection Zone prior to CO_2 injection.

[redacted]

Table 13—Adjusted saturation indexes and pH for Sample 1, 2, and 3 at the Upper Confining Zone prior to CO_2 injection.

[redacted]

The same shift in saturation index found in previous simulations were used to equilibrate the brines and minerals with fully saturated CO_2 gas to represent the injection period. [redacted] at reservoir temperature and pressure. Table 14 shows the mineral stability tendency after equilibration for each sample in the Injection and Upper Confining Zone. Delta minerals (Δ Mineral) represent the qualitative analysis of the solid to dissolve, precipitate or be stable based on the mineral mass reduction, increase or maintenance after equilibration with CO_2, respectively.

Precipitation was not observed (or negligible) for pyrite, hematite, chlorite, illite, kaolinite, barite, strontianite, celestite, and magnesite. Quartz and k-mica are the most stable phases that are originally present in the reservoir. For the Injection Zone, simulation results show dolomite and calcite dissolution as larger amount of CO_2 dissolved in water shifts the equilibria to more acidic environment. In addition, a substitution process of gypsum into anhydrite occurs for sample 1 and 2. This is because anhydrite is the most stable phase for the reservoir conditions. However, the dynamics in the reservoir during injection is more complicated as reactions are time dependent and gypsum is expected to reprecipitate much faster than anhydrite when there is an excess of calcium and sulfate. The Upper Confining Zone shows negligible reactivity as anhydrite does not dissolve. Some of the $CaSO_4$ might be transported from the Injection Zone to the interface of the Upper Confining Zone, increasing anhydrite or gypsum tendency to precipitate, and providing a healing effect to microfracture that might have been formed (i.e., mechanical deformation), as proposed by Hangx et al (2009).

Table 14—Mineral stability tendency and pH for Sample 1, 2, and 3 in equilibrium with fully saturated CO_2.

[redacted]

Thus, the most important mineral reactions with CO_2 identified for the injection are the solubility equilibria for dolomite, calcite, gypsum, and anhydrite minerals. The Upper Confining Zone is shown to be chemically compatible with CO_2 at reservoir pressure and temperature, thus its composition is not considered in the following simulations.

3.2.2.2 Reactive-Transport Simulations

The reactive-transport simulations were conducted using GEM. The objective of this section is to evaluate geochemical impact on reservoir storage capacity, possible injectivity modification, and 3mechanisms. The same activity model is used (extended Debye-Hückel equation) to be consistent with geochemical equilibrium simulations. Dolomite, calcite, gypsum, and anhydrite are the minerals considered during the dynamic simulations.

Figure 60 illustrates a cross-section for different mineralogy regions based on the Shoe Bar 1AZ lithology from well log (Figure 39). Region A represents G1 and G4 sub-zone, region B represents the limestone found at the top of the Holt sub-zone, and C represents the lower of the Holt sub-zone. Table 15 shows the mineralogy volume fraction based on the normalized average XRD data for each region. Trace mineral amount ($1x10^{-4}$ volume fraction) is given as input to make the simulation more stable. In addition, small mineral content is expected to be naturally occurring in the reservoir.

Figure 60—Cross-section schematic of the simulation model showing the different lithology regions (A, B, and C) based on lithology logs.

Table 15—Mineral volume fraction used to initialize the reactive-transport simulation model per lithology region.

[redacted]

Dolomite, calcite, and anhydrite solubility reactions were simulated using the kinetics approach based on the transition state theory (TST). Gypsum solubility reaction is simulated using the equilibrium approach because its reaction is assumed to be much faster than the fluid residence time in the reservoir and with the reaction time compared to other minerals (Appelo and Postma, 2005, page 119). Reactive surface areas, activation energies, TST reaction rate constants, and equilibrium constants are retrieved from the literature (Palandri and Kharaka, 2004, Krupka et al. 2010, Jia et al. 2021, and Zhang et al. 2019).

The effect of mineral dissolution and precipitation on porosity is also included to evaluate its impact on reservoir storage. The model is based on the simple correlation that the amount of mineral change will directly impact the solid volume using the respective mineral mass, mineral molar weight, and mineral density to calculate the new void volume (porosity) over time. In addition, the effect of porosity changes in rock permeability is included to evaluate the effect of possible changes in well injectivity. Simulations use the modified Kozeny-Carman model (Equation 7), where the porosity exponent r is assumed to be equal to 3.0.

$$\frac{k_n}{k_k} = \left(\frac{\emptyset_n}{\emptyset_k}\right)^r \left(\frac{1-\emptyset_k}{1-\emptyset_n}\right)^2 \qquad \text{Equation 7}$$

where k, Ø, and r represent permeability, porosity, and t porosity exponent, respectively. The subscripts n and k represent the properties changes in previous and current timesteps, respectively.

Region A and B were initialized using Sample 1 and Region C initialized using Sample 3 based on their depth. In total, 22 aqueous species were initialized in reservoir connate water and allowed to be transported in the reactive-transport simulations. The aqueous species modeled are H^+, Ca^{2+}, Mg^{2+}, Na^+, SO_4^{2-}, Cl^-, HCO_3^-, $CaOH^+$, $CaSO4^0$, OH^-, $MgOH^+$, $MgSO_4^0$, $NaHCO_3^0$, $NaSO_4^-$, HSO_4^-, $CaCO_3^0$, $CaHCO_3^+$, $MgCO_3^0$, $MgHCO_3^+$, $NaCO_3^-$, CO_3^{2-}, and $NaOH^0$. The selection of the aqueous complexes was based on the simulation results from geochemical equilibrium runs (PHREEQC) with minerals and CO_2. Aqueous species that were not originally in the complete water analysis were assumed to have trace concentration. The reservoir is allowed to equilibrate prior to simulation start.

Figure 61 shows map view of the layer with largest change in porosity (Holt sub-zone) and N-S cross-sections for BRP CCS1, CCS2, and CCS3 at the end of the injection period. Negative and positive values represent increase and decrease in porosity, respectively. Porosity slightly increased for regions A and C where the injectors will be perforated. Since region B has a very low permeability and small fluid mobility, no significant changes are observed. The increase in porosity is due to carbonate dissolution (dolomite and calcite) because lower pH after injection, as shown in Figure 62. Note that the pH values (initial and during injection) are in very close agreement with the values simulated using PHREEQC. For BRP CCS3, minor gypsum and anhydrite precipitation are illustrated in region B (limestone), showing the healing process as discussed before. Overall, the porosity increase is insignificant.

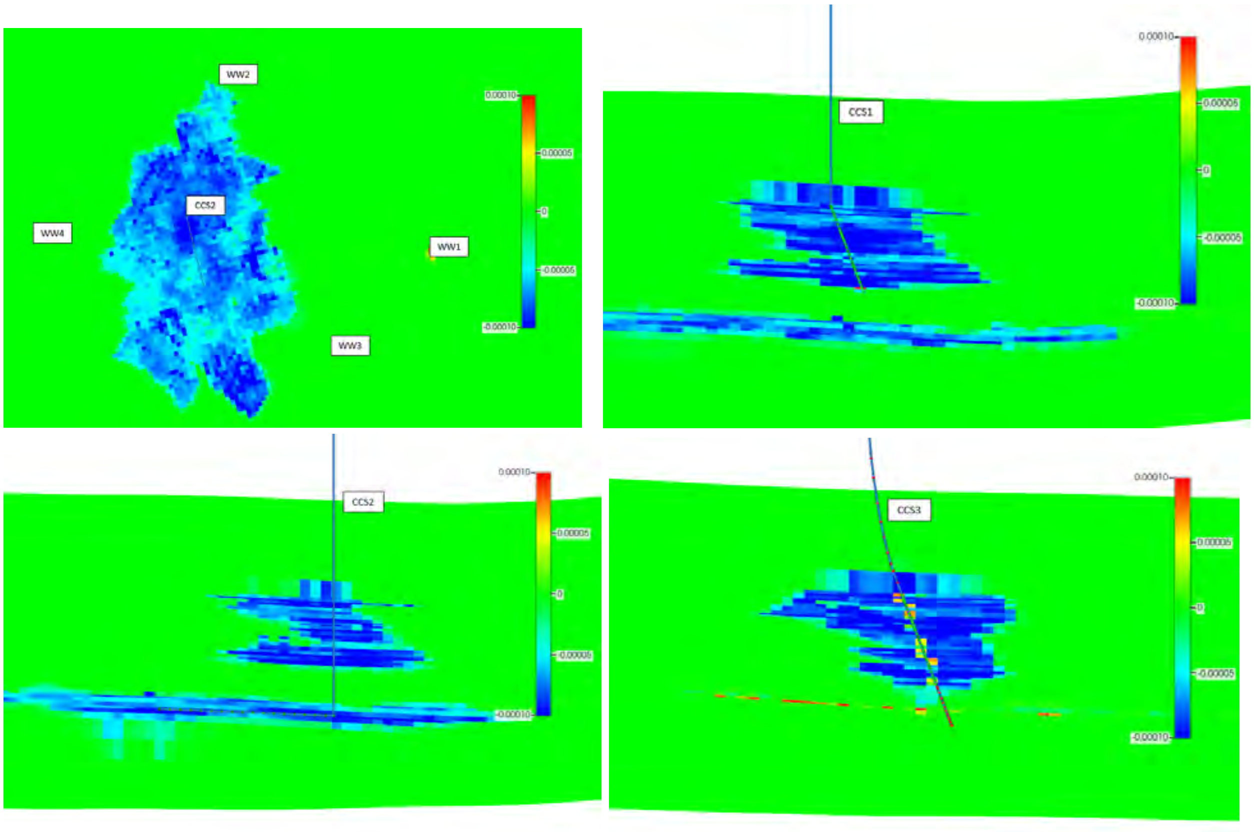

Figure 61—Porosity change map view of the layer with the largest CO_2 extension (top left subfigure) and N-S cross-section for BRP CCS1 (top right subfigure), CCS2 (bottom left subfigure), and CCS3 (bottom right subfigure) in January 2037.

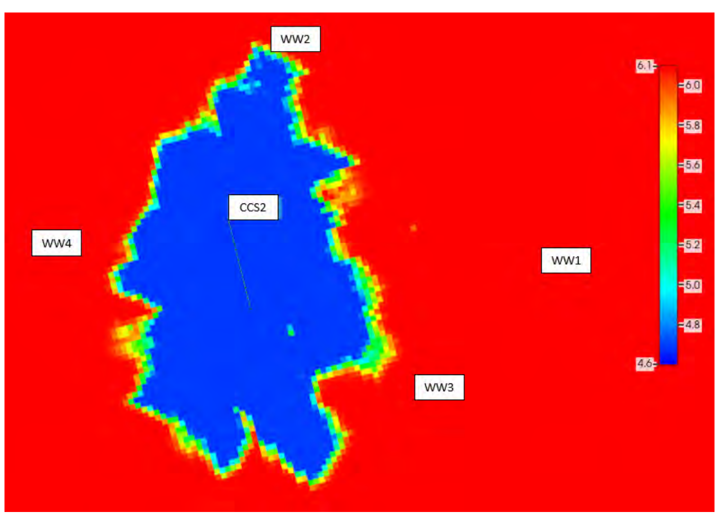

Figure 62—pH map view of the layer with the largest CO_2 extension in January 2037.

Figure 63 shows the reservoir mineral volume change for dolomite, calcite, anhydrite, gypsum, and total (Field) over time. Dolomite and calcite dissolve while anhydrite and gypsum precipitate. Most of the total increase in mineral volume because of solid change occurs during the injection period. The dissolution rate decreases in the following years. Anhydrite and gypsum precipitate due to release of calcium from the carbonate minerals and excess of sulfate originally in the reservoir. Figure 64 shows the increase of calcium ions and decrease of sulfate ions in relation to their initial value. Considering the total pore volume only where CO_2 contacted (2.98 billion ft^3) and the maximum volume change in the reservoir due to mineral dissolution/precipitation (1.36 million ft^3 in 2087), the change in pore volume is about 0.046%. Thus, the results reassure that the changes in reservoir storage volume due to injection is negligible.

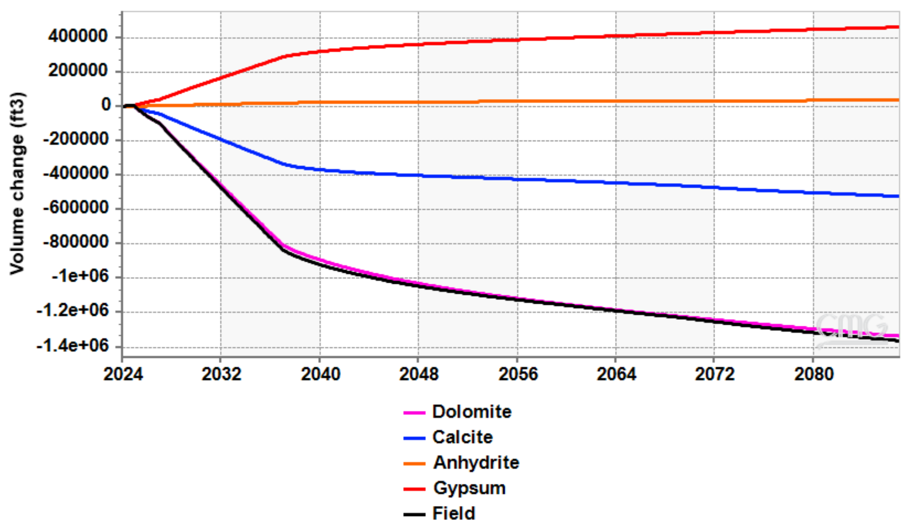

Figure 63—Volume change (ft^3) over time in the reservoir for dolomite, calcite, anhydrite, and gypsum and total (Field) due to mineral dissolution or precipitation.

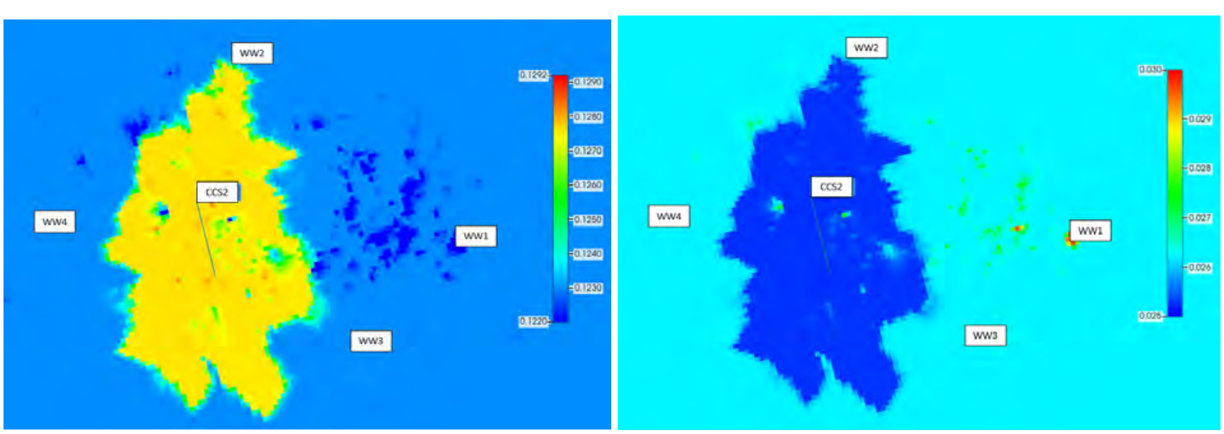

Figure 64—Map view of calcium (left) and sulfate (right) ions molality for the layer with the largest CO_2 extension in January 2037.

Figure 65 shows the injection and production comparison for the simulations with and without geochemistry capability turned one, including gas injection rate, water production rate, injectors bottom-hole pressure, and producers bottom-hole pressure over time. The differences in injection and production are negligible because the permeability is directly related to porosity modeled by the Kozeny-Carman equation (Equation 7). Thus, well injectivity is considered unchanged due mineral dissolution and precipitation.

[redacted]

Figure 65—Injection and production comparison for the simulations with and without geochemistry capability turned one, including gas injection rate, water production rate, injectors bottom-hole pressure, and producers bottom-hole pressure over time.

Figure 66 shows the CO_2 storage mechanisms (structural and stratigraphic, dissolved in connate brine, and residual) comparison over time with and without geochemistry capability turned on. Results indicate that the main stored mechanisms remain unchanged during reactive-transport simulations in comparison to conventional simulation. Figure 67 shows the mineral and aqueous ion CO_2 for the reactive-transport simulations (with geochemistry). The mineral storage is negative mainly due to dolomite dissolution that releases two mols of carbonate ion that is solubilized into aqueous ion. The aqueous Ion CO_2 stored has same values if the mineral CO_2 is multiplied by [redacted]

[redacted]

Figure 66—Structural and stratigraphic, dissolved, residual trapping, and total CO_2 storage for simulations with and without geochemistry capability turned on.

[redacted]

Figure 67—Mineral and aqueous ions CO_2 storage for simulation with geochemistry capability turned on.

4.0 AoR Delineation

4.1 Critical Pressure Calculations

To delineate the critical pressure front, one must determine the minimum pressure differential that can reverse flow direction between the lowermost USDW and the Injection Zone, thereby causing fluid flow from the Injection Zone into the USDW formation matrix in acceptable volume over the sequestration period. In other words, it is necessary to establish the critical pressure threshold at which the increase in pore pressure is high enough to overcome the hydraulic head of the fluid in a hypothetical wellbore and enter the USDW.

OLCV attempted to calculate the critical pressure front, p_c, using Method 1 provided in the EPA May 2013 Program Class VI Well Area of Review and Corrective Action Evaluation Guidance (EPA 2013). This method estimates a critical pressure threshold that would displace fluid initially present in a hypothetical borehole into the lowermost USDW and takes in consideration that the reservoir is overpressured at the start of the injection, which is the case for the proposed AoI.

As noted by Thornhill et al. (1982), the critical pressure front may be calculated using the following equation:

$$p_c = p_u + \rho_i g \cdot (z_u - z_i) \qquad \textit{Equation 8}$$

where, p_c is the critical pressure threshold, p_u is the initial fluid pressure in the USDW, ρ_i is the Injection Zone fluid density, g is the acceleration to due to gravity, z_u is the representative elevation of the lowermost 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 (Δp_{if}) can be calculated using the following equation:

$$\Delta p_{if} = p_u + \rho_i g \cdot (z_u - z_i) - p_i \qquad \textit{Equation 9}$$

where p_i is the initial pressure in the Injection Zone.

As provided by Nicot et al. (2009) and Bandilla et al. (2012), one can calculate the threshold pressure increase (Δp_c) assuming hydrostatic conditions and the uniform density approach by the equation:

$$\Delta p_c = \frac{1}{2}\rho_i \xi \cdot (z_u - z_i)^2 \qquad \textit{Equation 10}$$

and

$$\xi = \frac{(\rho_i - \rho_u)}{(z_u - z_i)} \qquad \textit{Equation 7}$$

where ρ_u is the fluid density of the USDW.

As stated for the Method 1, if the value of Δp_c given in Equation 10 is greater than absolute value of Δp_{if} given in Equation 9, then the difference in magnitude between these values can be used to estimate the allowable pressure. Assuming a freshwater of 62.4 lb/ft^3 for the USDW and applying the calculation at the top of the Lower San Andres Formation, one can observe that the criteria does not hold (Δp_c = 94.1 psi, Δp_{if} = -145.3 psi, then $\Delta p_c < |\Delta p_{if}|$). Thus, OLCV decided to define the impact of additional pressure increase from injection using combined Methods 2 (multiphase numerical model designed to model leakage through a single well bore, or multiple well bores in the formation, from UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance) and Method 3 (numerical ground water modeling conducted for the USDW to estimate how additional fluid leakage caused by the injection project is diluted within the USDW and attenuated, from UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance).

The method proposed by Birkholzer et al. (2011) and Oldenburg et al. (2014), where reservoir simulation (as multiphase numerical tool) can be used to model the leakage through single well, was selected. The method consists of providing the USDW aquifer as a separate initialization region in the simulation model. Then, a permeable conduit connects the injection and USDW regions to mimic flow in a well to the USDW (Figure 68). This simulates a well that have been cemented during abandon which is the case for the legacy wells found inside the AoI. The well is assumed to be cemented from bottom of the USDW to bottom of the Injection Zone and fluid can flow inside the well from the matrix from any direction.

The approximate distance between the USDW and the top of Lower San Andres Formation in the AoI is ~4,300 ft. The USDW is assumed to have initial average pressure of 300 psi (with average thickness of 286 ft), mean porosity of 20% (values range from a minimum of 17% to a maximum of 23%), and mean permeability of 483 mD (values range from minimum of 93 mD to a maximum of 962 mD). These permeability values are based on hydraulic conductivity reported for the Dockum aquifer (Bradley and Kalaswad, 2001; Mace et al., 2006; George et al., 2011) and in agreement with average porosity and permeability values for unconsolidated sands (Freeze and Cherry, 1979). The Injection Zone and USDW water salinity was assumed to be constant equal to 130,000 and 500 ppm, respectively. The cement permeability is assumed to have 26.3 mD in all directions as the largest value found by Kutchko et al. (2008) during laboratory experiments using Class H cement exposed to supercritical CO_2 and CO_2-saturated brine for prolonged time periods. The Upper Confining Zone surrounding the well is assumed to have permeability about $1x10^{-4}$ mD.

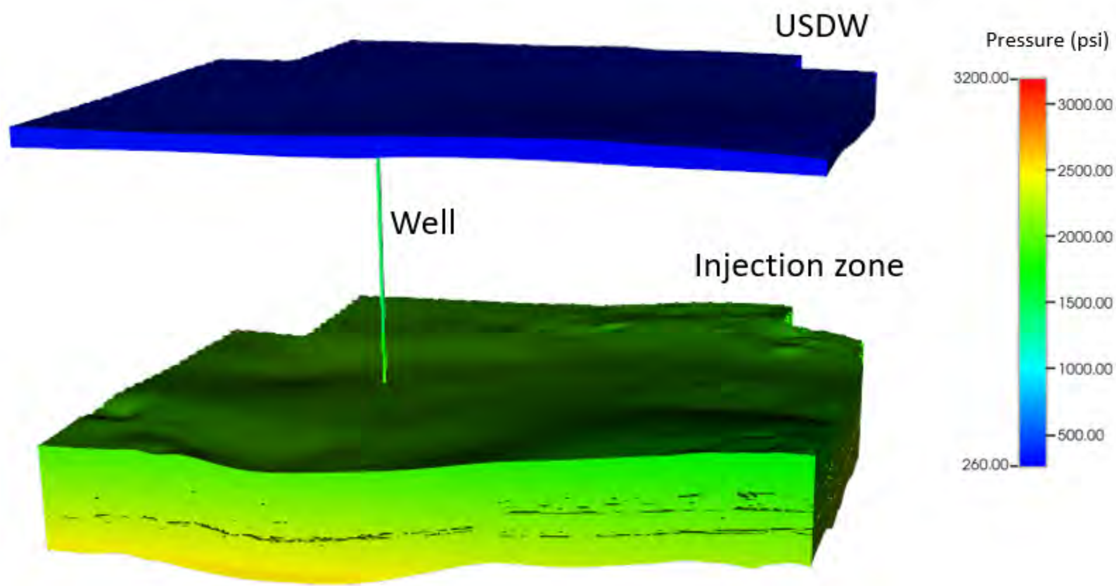

Figure 68—Schematic showing the USDW (top), Injection Zone (bottom) and the well connecting both regions. Figure with scale 5:1 in z direction. Confining Zones are not shown.

In the proposed AoI, the Santa Rosa member of the Dockum group aquifer is the lowermost USDW (Figure 68). From Equation 8, the critical pressure should be the lowest at the top of the Injection Zone, because this where the distance between the Injection Zone and the lowermost USDW will be at a minimum. However, the BRP CCS2 has the highest injection pressure and will be perforated in the Holt sub-zone. Thus, for this study, the pressure plume is evaluated for both at top of the Lower San Andres Formation (G1 sub-zone) and the top of the Holt sub-zone (Figure 69).

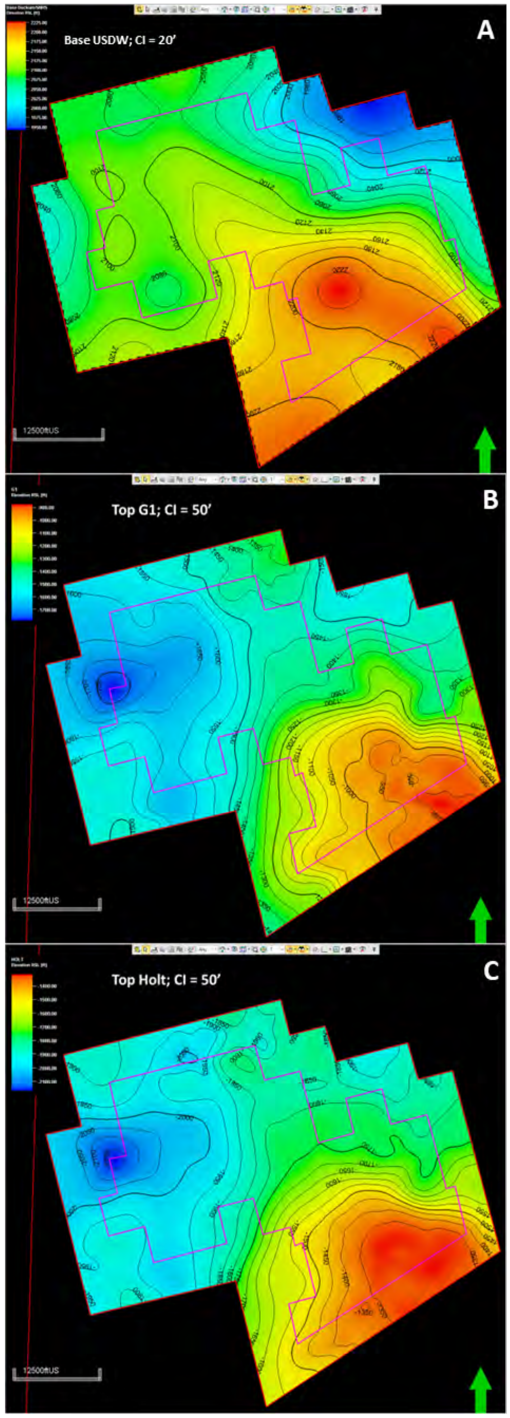

Figure 69—Structure maps for the Base USDW (A), Top G1 upper porosity interval in the Injection Zone (B), and Top Holt lower porosity interval in Injection Zone.

Hypothetical wells are placed at several locations in the simulation model to test sensitivities in the relationship between the overpressure due to injection (difference between pressure at end of injection period and initial pressure) at the top of the Lower San Andres Formation and the volume of brine that could hypothetically leak into the lowermost USDW. In total, 28 hypothetical wells were positioned at different locations (i.e., 28 simulation runs). Figure 70 shows the relationship between leak rate and the overpressure due to injection in January 2037 (i.e., time of highest pressure in reservoir). Some pressure values are negative because the brine producers lower the reservoir pressure below initial pressure in the Injection Zone. The Injection Zone pressure and the leakage rate have acceptable correlation using a cubic equation, with R^2 approximately 0.96.

[redacted]

Figure 70—Leak rate for hypothetical wells versus overpressure due to injection in the top of the Lower San Andres (G1 sub-zone) in January 2037.

Simulations were conducted to evaluate the brine leakage potential for historical Artificial Penetrations (AP) inside the AoI. In total, nine APs were simulated using the same assumptions listed above. Figure 71 shows the AP locations in the AoI. Figure 72 shows the influx (leak) rate and the cumulative influx in the USDW for each of the Aps evaluated. If left unmitigated, these APs could potentially leak to the USDW: Eidson E-1 (API 4213531130) with maximum about 0.00022 bbl/day; Eidson-Scharbauer-1 (API 4213506139) with maximum about 0.00024 bbl/day, and Scharbauer Eidson-1 (API 4213510667) with maximum about 0.00023 bbl/day. All other APs have either zero or negative leak rates (due to depletion from brine withdrawal wells).

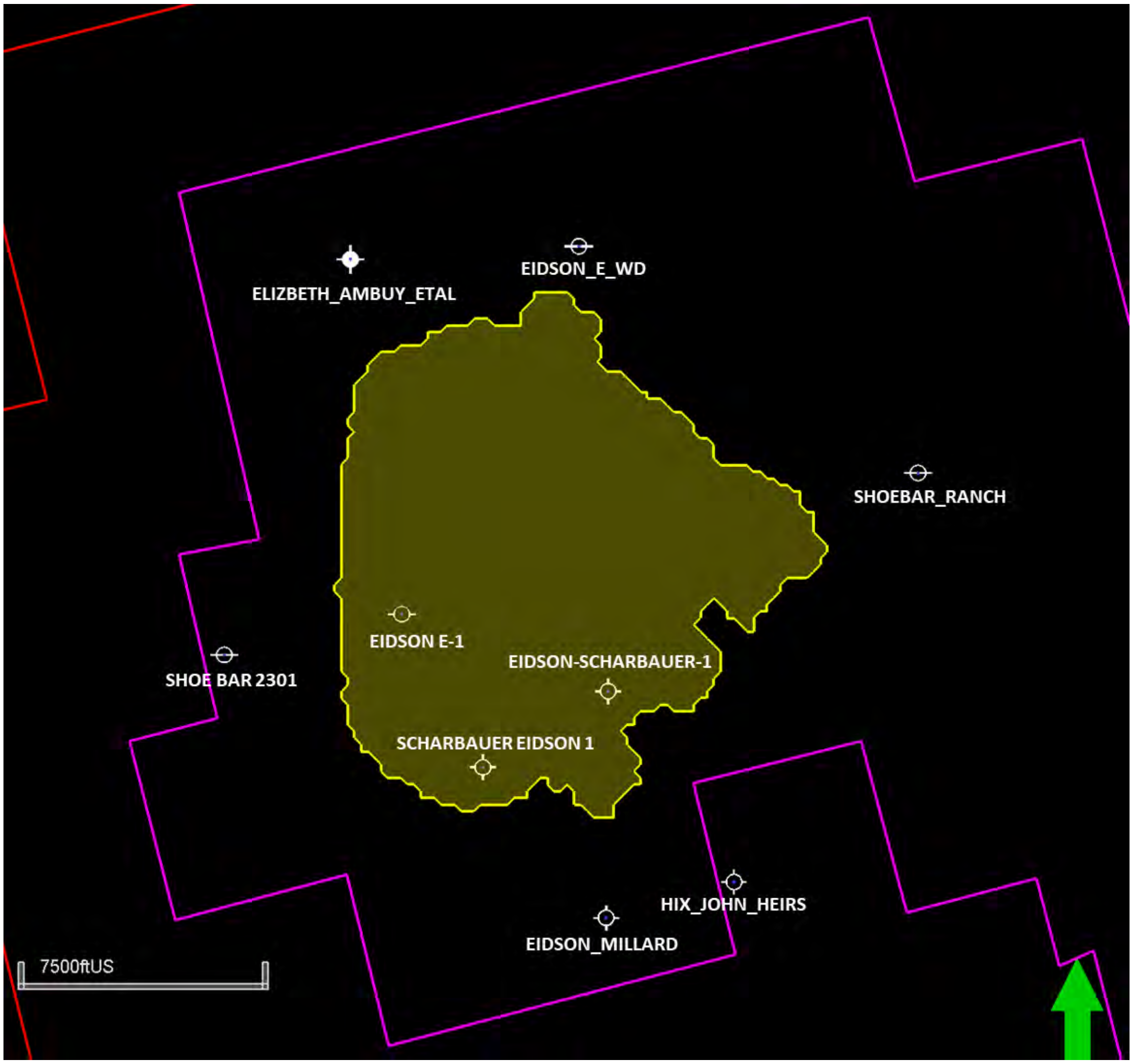

Figure 71—Map with the location of the nine legacy wells tested in the leakage modeling.

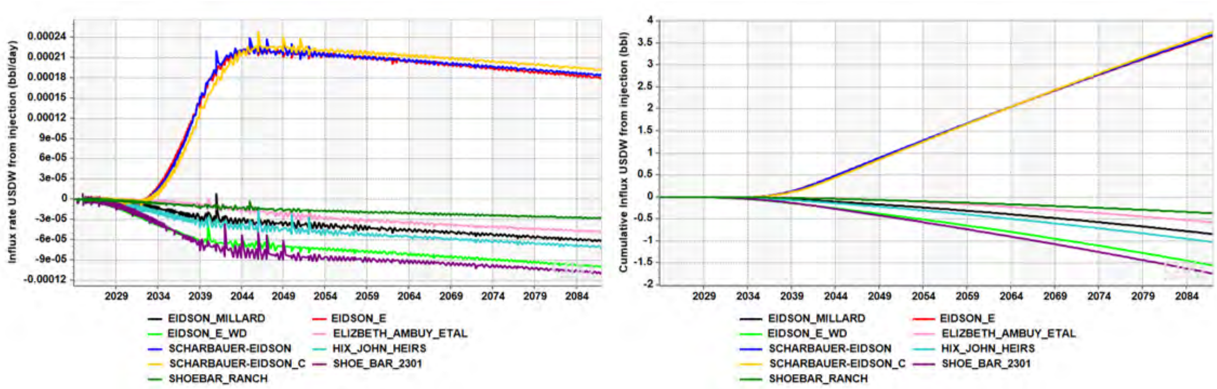

Figure 72—Leak rate and cumulative volume influx in the USDW for AP versus time. Negative values represent outflux from the USDW due depletion from initial pressure.

Thus, for the delineation of the critical pressure, a maximum leak of about 0.0005 bbl/day (double the maximum rate) is assumed, which correlates with a pressure increase in relation to initial pressure (injection overpressure) in the top of the Lower San Andres Formation of 62.2 psi (Figure 73). Applying a separation thickness between top of the Lower San Andres Formation and top of the Holt sub-zone of 450 ft and a gradient of 0.48 psi/ft, the critical pressure for the top of the Holt sub-zone is 62.2 + 450 x 0.48 = 278.2 psi.

Assuming (1) an aquifer volume of 3,928,360 acre-foot for the Dockum aquifer in Ector County (Bradley and Kalaswad, 2003); (2) a leak rate for each AP well at a constant rate of 0.0005 bbl/day; (3) continuous leak for 62 years (Injection and PISC periods); and (4) APs are unmitigated; the total leakage due to CO_2 injection is 33.9 bbl, or just 8.34×10^{-8} % of the USDW.

Figure 73 (A, B, D, and E) is the initial pressure at the start of injection and the final pressure at end of the injection at the top of Lower San Andres and at the top of the Holt sub-zone. In addition, Figure 73 (C and F) shows the buffer pressure for exceeding the critical pressure threshold at the end of the injection period which is obtained from subtracting the initial pressure at the start of injection from the critical pressure calculated previously. The end of the injection period was selected because it is the highest pressure observed during simulation.

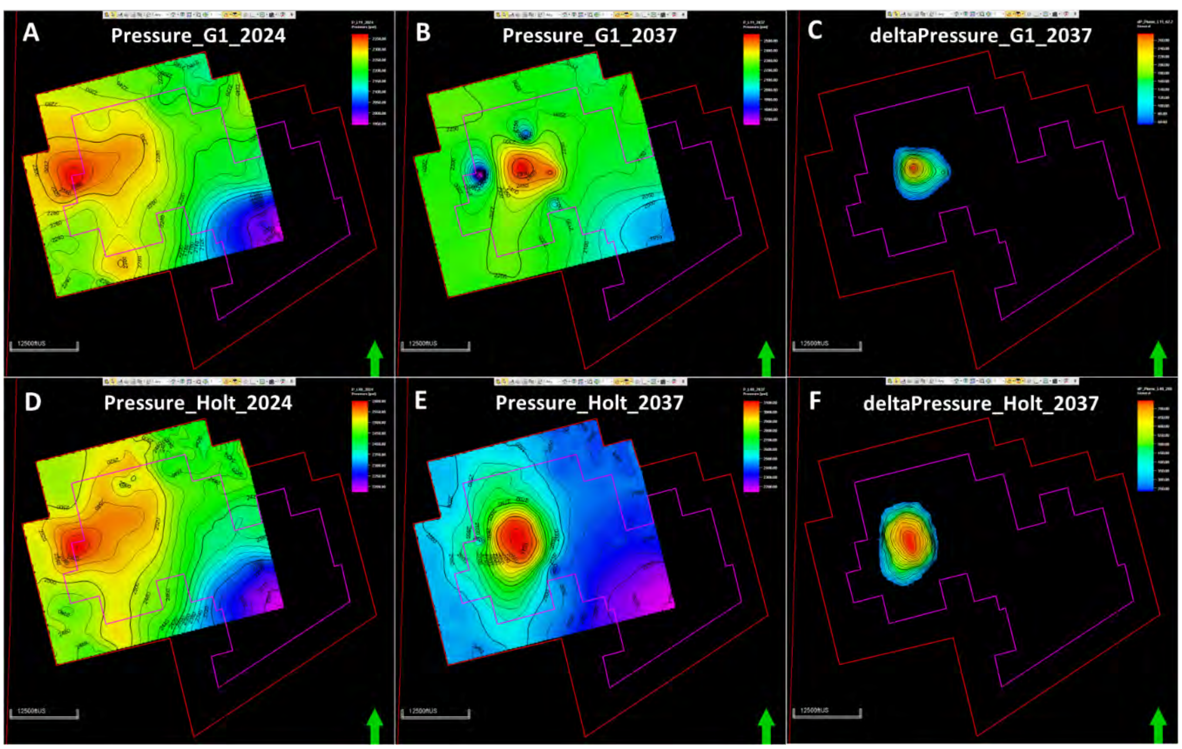

Figure 73—Pressure map for G1 sub-zone at initial time (A), at end of injection (B), and the difference map (C). Pressure map for Holt sub-zone at initial time (D), at the end of injection period (E), and the difference map (F).

4.2 AoR Delineation

4.2.1 Critical Pressure Front

The maximum differential pressure occurs at the time of maximum CO_2 cumulative injection in January 2037, because the wells are modeled to operate at a constant injection rate. Figure 74 shows the combined pressure at the time when injection ceases. Thus, the contour shown in Figure 74 represents the maximum extent of the pressure front found in the model.

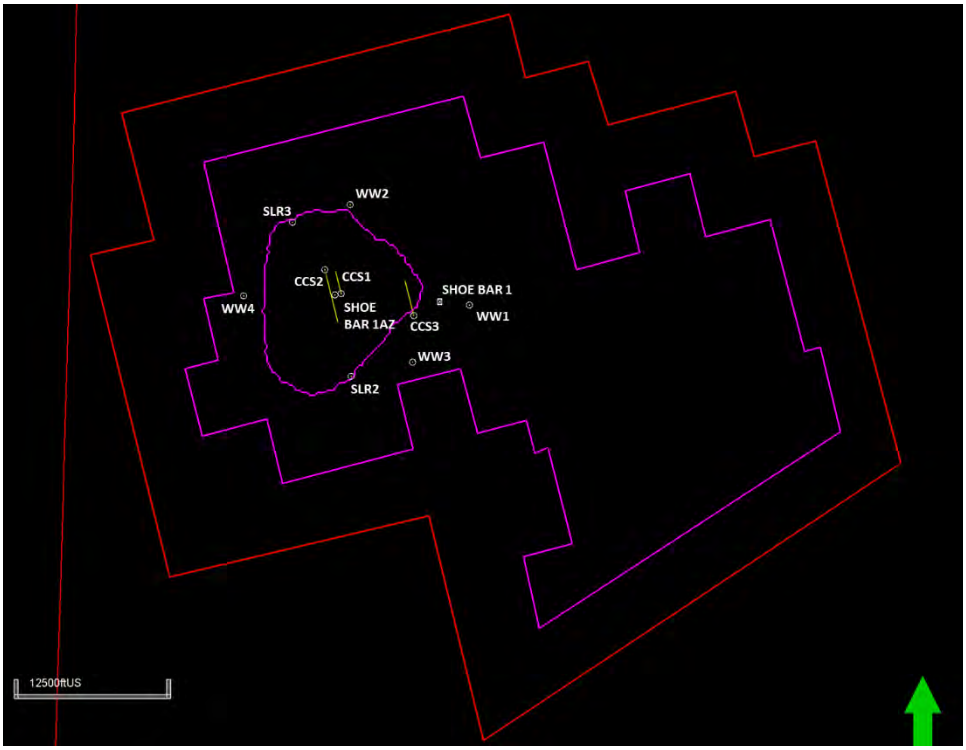

Figure 74—Maximum combined extent of pressure plumes for G4, G1, and Holt sub-zones at the end of injection in January 2037.

4.2.2 CO_2 Plume Extent

The CO_2 plume is shown as a projection of the global mole fraction of gas in the Injection Zone. The 3D property is first obtained by performing a cutoff of 0.1% to display the plume as any cells greater than the threshold value. Then the projection of all layers is performed in the map. The plume is within the boundaries of the brine producer wells. Figure 76 illustrates the CO_2 plume extent in 3D after injection ceases in January 2037, which is the maximum extent during simulation.

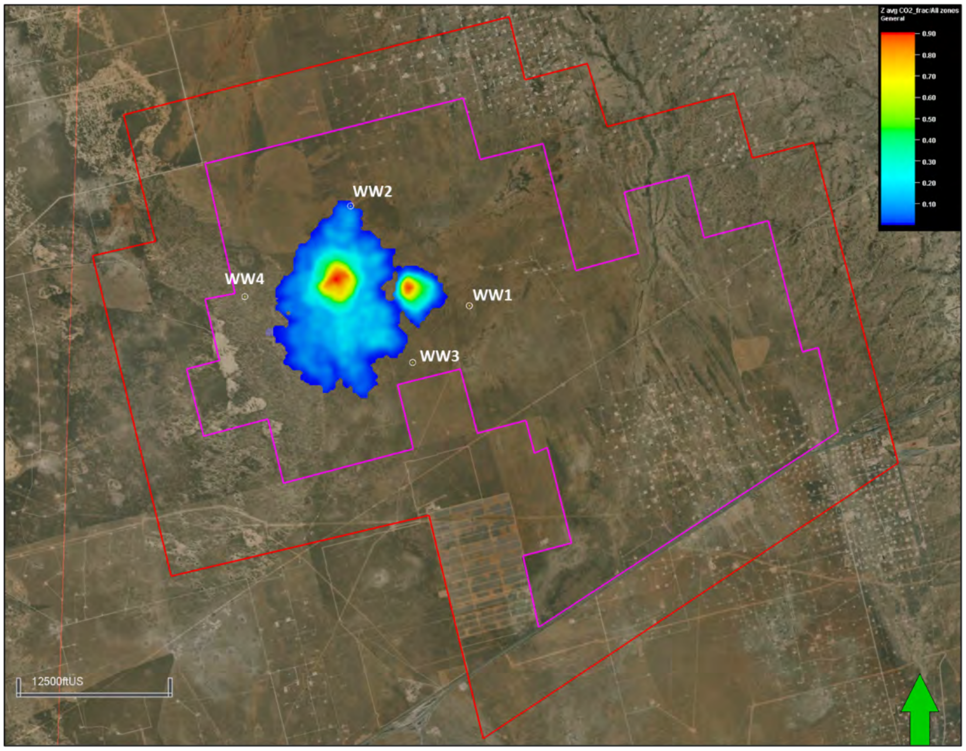

Figure 75—Areal extent of the vertically averaged maximum CO_2 plume extent at the end of injection in January 2037. Note that brine withdrawal in well WW2 occurs in the G4 and G1 sub-zones of the Lower San Andres and does not come in contact with 2D projection of the CO_2 plume extent projected from the Holt sub-zone (lower part of Lower San Andres).

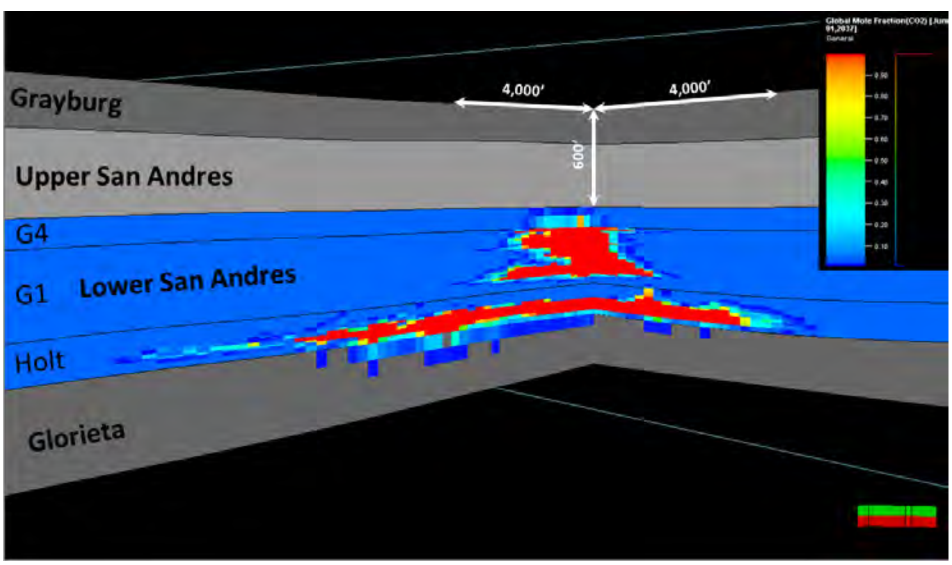

Figure 76—3D view of the maximum CO_2 plume extent, occurring at the end of injection in January 2037 (3X vertical exaggeration).

4.2.3 Final Area of Review

The final AoR (Figure 77) is the combination of the maximum pressure front (Figure 74) and the maximum CO_2 plume (Figure 75). The predicted evolution of the CO_2 plume and pressure front relative to the monitoring locations is shown in the Post-Injection Site Care (PISC) and Site Closure Plan document of this permit.

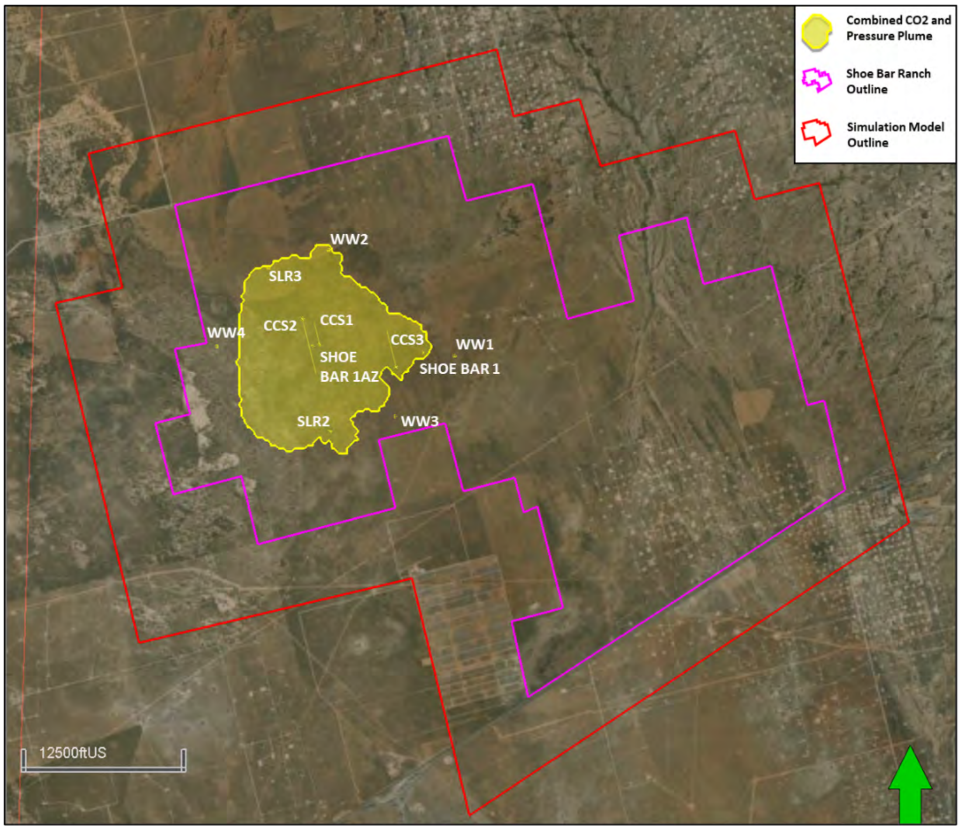

Figure 77—Combined AoR showing pressure and CO_2 plumes along with proposed injection wells (BRP CCS1-CCS3), stratigraphic wells (Shoe Bar 1 and Shoe Bar 1AZ), water withdrawal wells (WW1 - WW4), Injection Zone monitoring wells (SLR2 and SLR3), and Upper Confining Zone monitoring well (ACZ1).

5.0 Corrective Action

5.1 Tabulation of Wells Within the AoR

The BPR Project will utilize three CO_2 injection wells. The AoR represents the maximum extent of pressure from three wells at the end of 12 years of CO_2 injection and the maximum extent of the CO_2 plume 50 years after injection ceases. The AoR is modeled to be approximately 5.4 square miles.

OLCV conducted an airborne magnetic survey in May 2023 to identify and/or to confirm the location of existing artificial penetrations in the AoR. The data from this survey was analyzed and interpreted by Oxy and OLCV geophysicists. Magnetic anomalies were cross-referenced with aerial photos, drone photographic surveys, and physical site observation where necessary. See Appendix B for additional details on identifying APs.

In addition to airborne magnetic data, OLCV consulted the following databases to identify APs: TRRC, TCEQ, Texas Department of Licensing and Regulation (TDLR), Texas Water Development Board (TWDB), and the Texas Bureau of Economic Geology (BEG). Through this evaluation, OLCV identified two well locations that were incorrectly recorded in licensed databases such as IHS. OLCV cross-checked the recorded latitude and longitude with public well records, airborne magnetic survey, and drone imagery to confirm the appropriate well locations.

Excluding the wells drilled for the project: Shoe Bar 1, Shoe Bar 1AZ, Shoe Bar Ranch 1WW, Shoe Bar Ranch 2WW, Shoe Bar Ranch 3WW, Shoe Bar Ranch 4WW, and Shoe Bar USDW1; OLCV identified a total of four other APs in the AoR: three plugged wells related to oil and gas operations and one well used for USDW brine production. See Tables 16 and 17 below for tabulated well information. Additional information on all data sources consulted to identify AP is presented in Appendix B. OLCV will periodically re-evaluate the AoR and expand the tabulation of APs, as needed.

Table 16—Locations of existing wells in the AoR

					From Public and Licensed sources	
API or state well number	**Well Name**	**Recorded Status**	**Drill Date**	**Abandon Date**	**Latitude NAD27**	**Longitude NAD27**
4213543920	Shoe Bar 1	Stratigraphic test well	1/2/2023	NA	31.76343602	-102.7034981
4213543977	Shoe Bar 1AZ	Stratigraphic test well	7/29/2023	NA	31.76448869	-102.7305326
NA	Shoe Bar USDW1	Monitor	12/23/2023	NA	31.7641190	-102.7316750
4213544034	Shoe Bar Ranch 4WW	Water supply well	3/26/2024	NA	31.76384464	-102.7539505
4213544037	Shoe Bar Ranch 3WW	Water supply well	4/22/2024	NA	31.75008553	-102.7102206
4213544036	Shoe Bar Ranch 2WW	Water supply well	4/12/2024	NA	31.78419981	-102.7275869
4213544035	Shoe Bar Ranch 1WW	Water supply well	4/3/2024	NA	31.76289539	-102.6959232
4213506139	Eidson-Scharbauer-1	Dry hole, plugged	4/18/1958	9/21/1959	31.7526374	-102.7218925
4213510667	Scharbauer Eidson-1	Dry hole, plugged	12/23/1964	2/19/1965	31.7460090	-102.7343253
4213531130	Eidson E-1	Dry hole, plugged	8/1/1973	8/23/1973	31.7587481	-102.7431169
4511701	-	Brackish water producer; plugged	1940	9/20/2023	31.7719430	-102.7205540

5.1.1 Depth of the USDW in wells planned for corrective action

The Dockum is defined as the lowermost USDW in the AoR. The base of the USDW is picked on well log data from wells in the AoR with the exception of the Scharbauer Eidson-1 (API 4213510667) that does not have log data. The USDW was interpolated at this location based on well log correlation. See Appendix B for details on the depth of the USDW.

5.2 Corrective Action Plans and Schedule

5.2.1 Corrective Action Plan Overview

A detailed analysis was performed to evaluate the risk and timing of the plume and/or pressure front reaching each of the wells inside the AoR. The analysis was divided into two main categories to assess the risks and mitigations, based on the following possible mechanisms of failure:

1) **CO_2 plume corrosive effect and contamination of USDW aquifer.** The analysis focused on potential leakage paths from the Injection Zone that could endanger the USDW for those

wells that are projected to be exposed to the CO_2 plume. The lack of proper isolation, cement degradation by carbonic acid, mechanical barrier failures, and micro-annulus or casing corrosion are some of the situations that increase the risk of brine or CO_2 leaks.

2) **Pressure front effect with brine contamination from deeper saline reservoirs to USDW aquifers.** This category includes wells that were not projected to be in contact with the CO_2 plume but are inside the simulated pressure front. In this scenario, the wells were evaluated for proper hydraulic isolation between the Injection Zone and the USDW. The degradation or corrosion of cement, tubulars, and tools is not considered a high-risk scenario in this category.

5.2.2 Modeled Extent of AoR

OLCV modeled the extent of the AoR to determine which APs required corrective action and the timing of the corrective action. OLCV will conduct corrective action on three heritage APs: Eidson- E-1 (API 4213531130), Scharbauer Eidson-1 (API 4213510667) and Eidson Scharbauer-1 (API 4213506139) prior to commencement of CO_2 injection operations.

1) Simulation of three years of injection

During the first three years of injection (Figure 78), the simulated CO_2 plume does not reach any APs. However, the pressure front reaches the well **Eidson E-1 (**API 4213531130) in the Holt sub-zone of the Lower San Andres in this time period. Corrective actions are proposed and will be executed prior to the commencement of injection operations. The monitoring network (as described in the Testing and Monitoring Plan document of this permit application) will be in place. Data gathering for pressure, temperature, and CO_2 saturation in the injectors and monitoring wells will be used to track pressure and CO_2 movement, calibrate the simulation model, and validate the AoR in the initial years of injection.

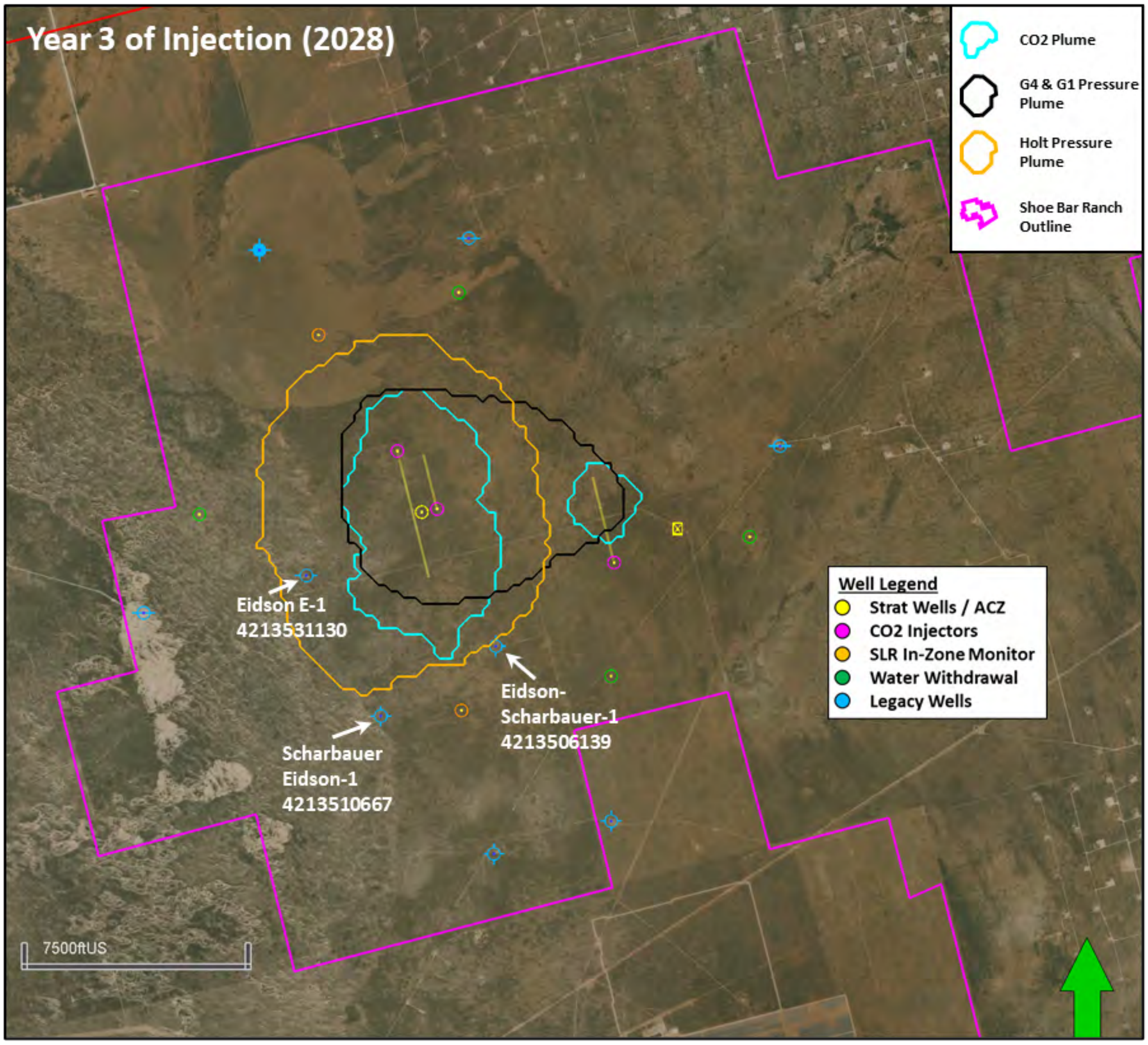

Figure 78—Three Years of injection, showing that the Holt sub-zone pressure plume reaches legacy well EIDSON E-1.

2) Simulation after five years of injection

From the second to fifth year of injection (Figure 79), the simulated CO_2 plume does not reach any APs. The pressure front reaches the **Eidson-Scharbauer-1** (API 4213506139) and **Scharbauer Eidson-1** (API 4213510667) at the Holt sub-zone of the Lower San Andres, as shown in Figure 79. Because OLCV will have already conducted corrective action on this AP, there is no expected impact to the USDW.

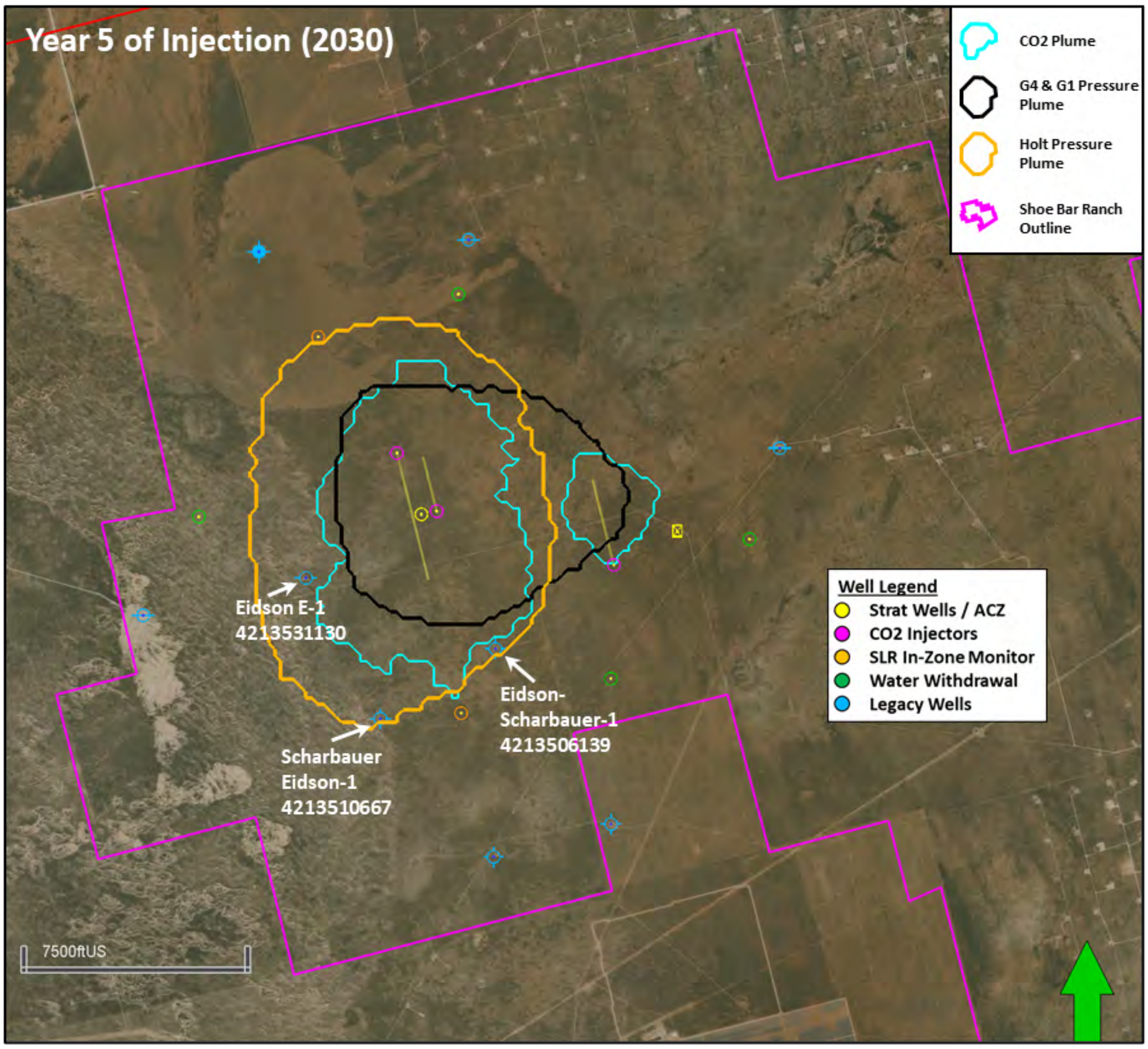

Figure 79—CO_2 plume and critical pressure front extent after 5 years of injection.

3) Simulation after seven years of injection

In the seventh year of injection, the simulated CO_2 plume reaches AP **Eidson-Scharbauer-1** (API 4213506139), as shown in Figure 80. Because OLCV will have already conducted corrective action on this AP, there is no expected impact to the USDW.

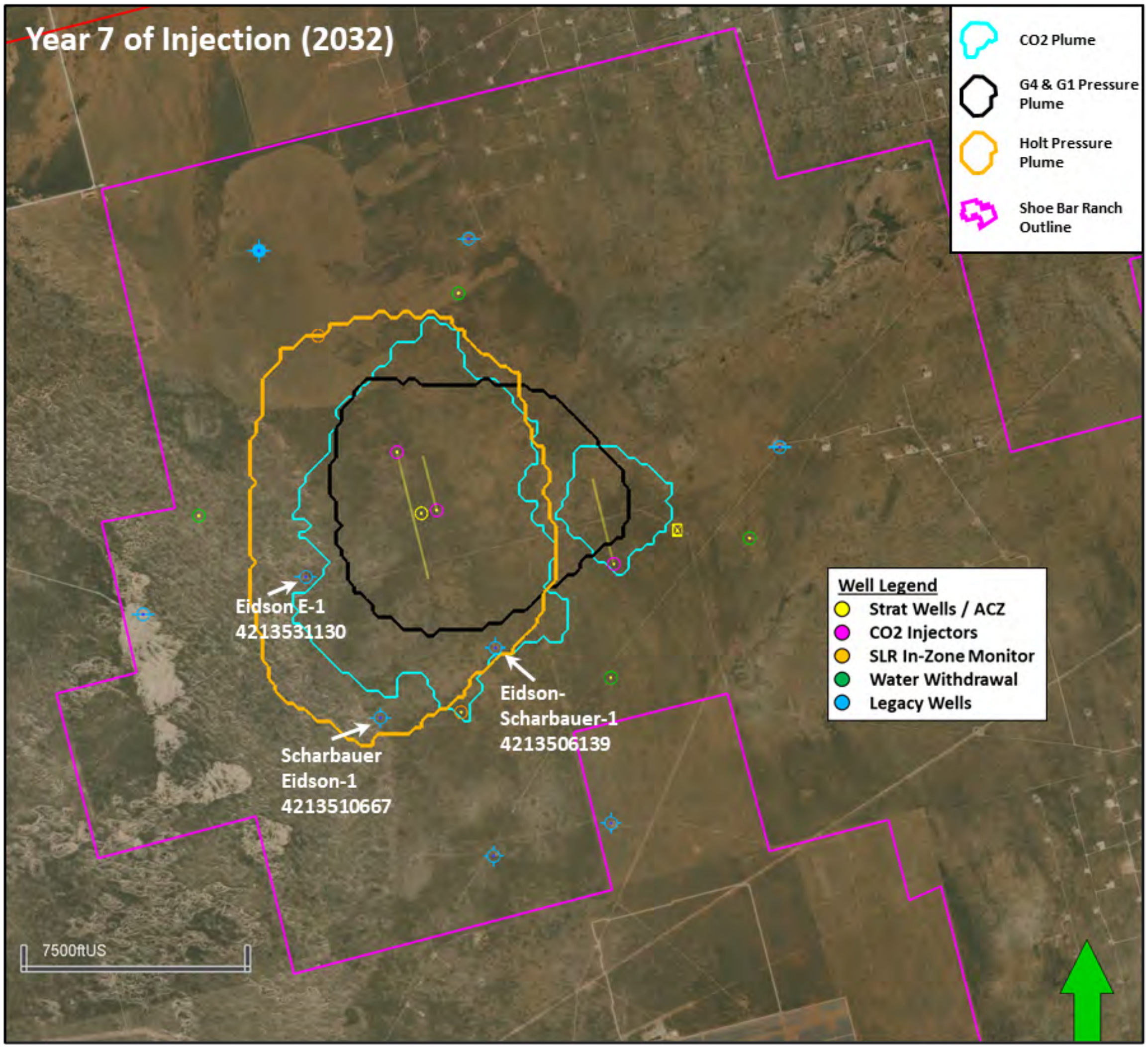

Figure 80—CO_2 plume and critical pressure front extent after 7 years of injection.

4) Simulation after 12 years of injection

By the twelfth year after the commencement of injection, the simulated CO_2 plume reaches APs **Scharbauer Eidson-1** (API 4213510667) **and Eidson E-1** (API 4213531130), as shown in Figure 81 The modeled CO_2 plume and critical pressure front reaches its maximum area and value when injection ceases. The size of the CO_2 and pressure plumes slightly shrink after the cessation of injection. Figure 82 shows the modeled CO_2 plume and critical pressure front extent 50 years after the end of injection. Because OLCV will have conducted corrective action on these APs by this time, the risk of leakage to the USDW is mitigated.

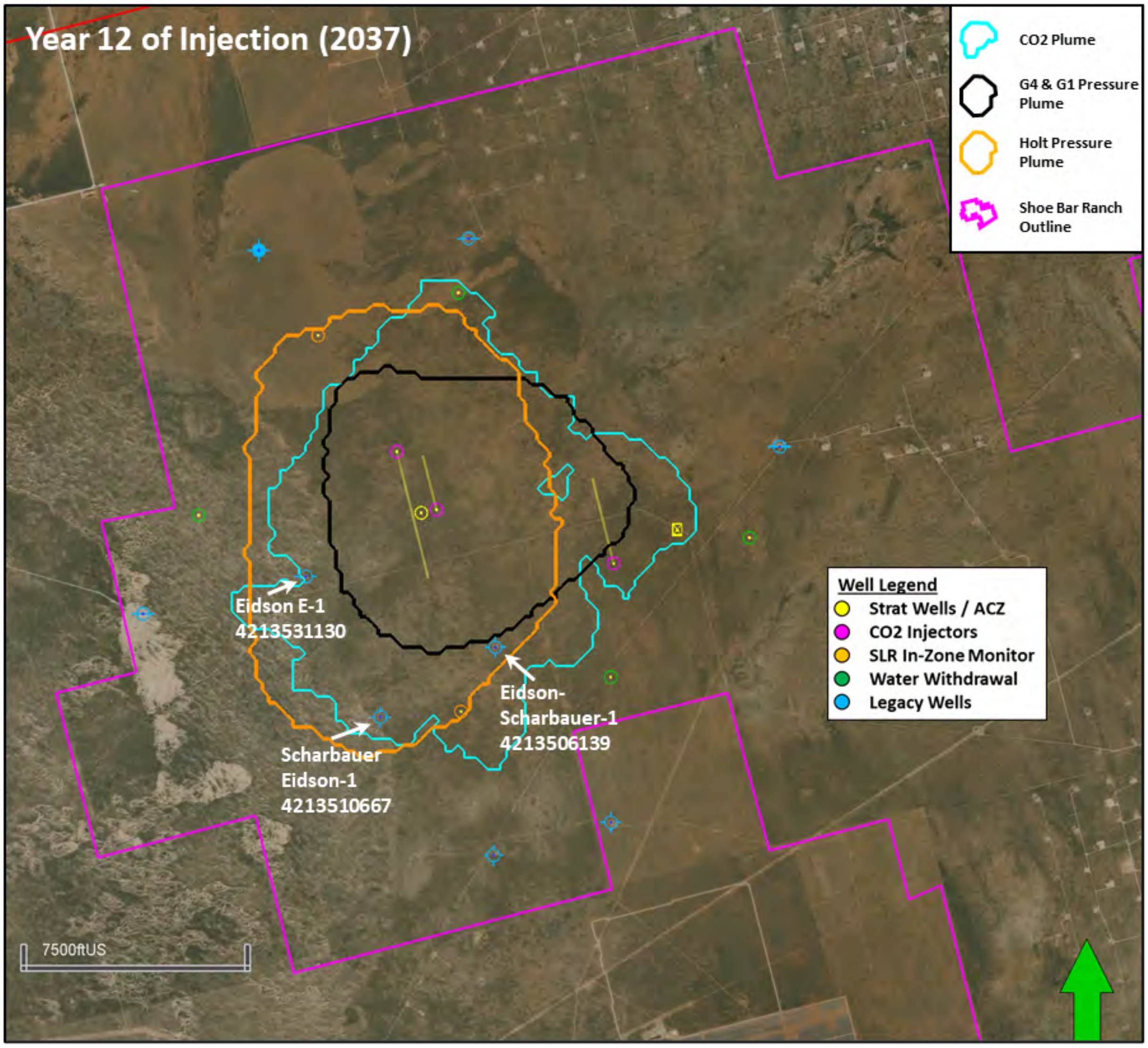

Figure 81—CO_2 plume and critical pressure front extent after 12 years of injection. Note that CO_2 plume reaches WW2 in map view but only in the Holt sub-zone and WW2 is a dedicated G4 and G1 sub-zone water withdrawal well.

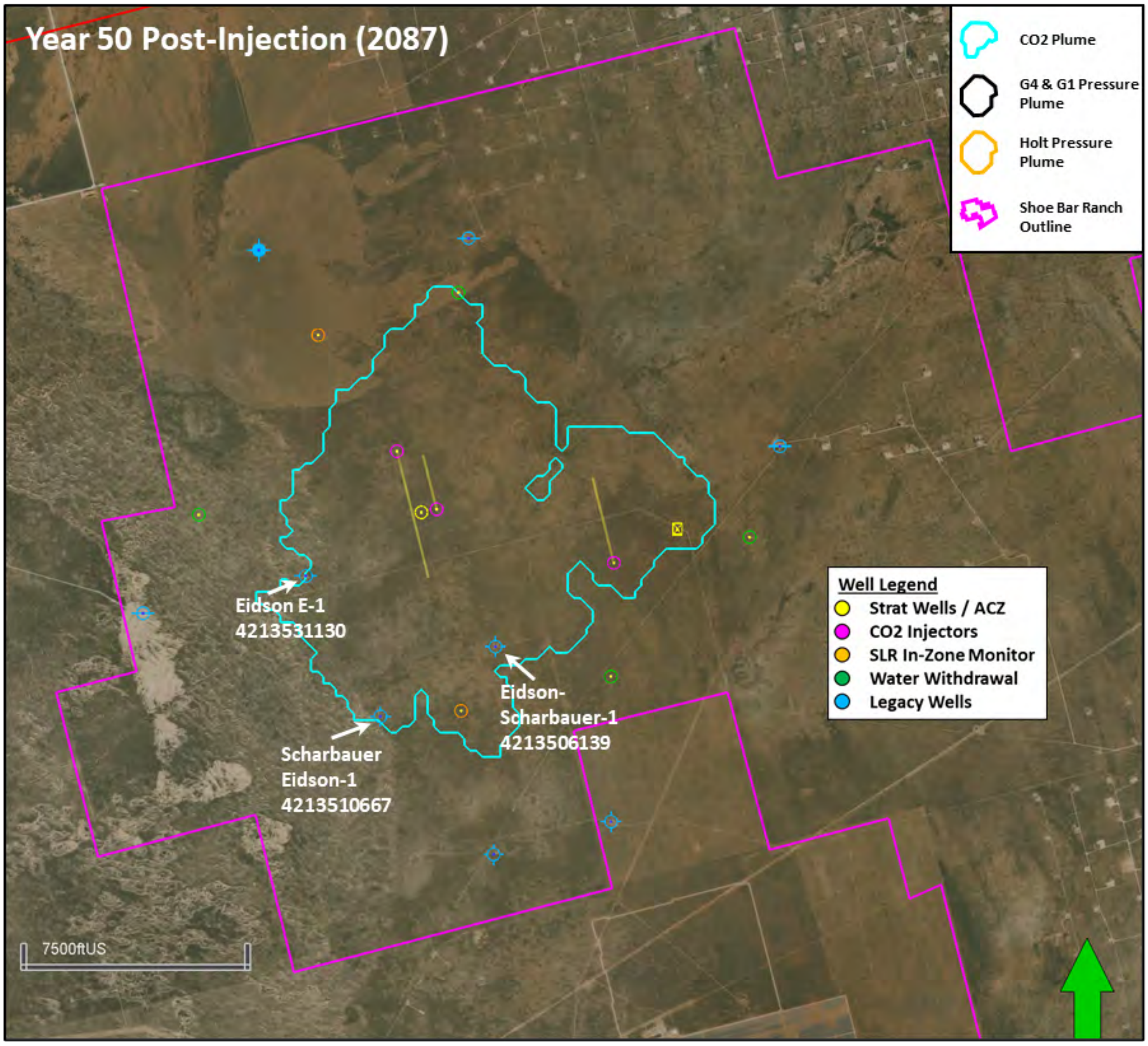

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Figure 82—CO_2 plume and critical pressure front extent 50 years after the end of injection. Note that pressure in the G1, G4 and Holt sub-zones has dissipated below the critical pressure by this point in time.

5.2.3 Timing of Corrective Action

The AoR defined by critical pressure is modeled to reach the Eidson E-1 (API 4213531130) within approximately two years following the commencement of CO_2 injection. This well will require corrective action. That action will be taken prior to the commencement of CO_2 injection operations.

The AoR defined by critical pressure is modeled to reach the Eidson-Scharbauer-1 (API 4213506139) and the Scharbauer Eidson-1 (API 4213510667) within approximately five years after the commencement of CO_2 injection. These wells will require corrective action. The corrective action will be performed prior to the commencement of CO_2 injection operations.

OLCV and a third-party water drilling contractor conducted a site investigation in July 2023 and determined that well 4511701 should be plugged and abandoned because of a shallow hole obstruction possibly due to casing corrosion or sanding event. The well was plugged and abandoned according to TCEQ standards in September 2023. No further remedial action is required on this well.

OLCV will evaluate Project data and re-evaluate the AoR on a regular basis, and a least every five years. OLCV will use data collected from injection and monitoring wells and indirect geophysical data to compare with predicted results from the dynamic simulation model. The model will be updated, if needed, to better match historical observations. If updated modeling work results in a re-delineation of the AoR, a revised corrective action plan and schedule will be completed pursuant to 40 CFR §146.84(d).

Corrective action plugging procedures for Eidson E-1 (API 4213531130), Eidson-Scharbauer-1 (API 4213506139), and the Scharbauer Eidson-1 (API 4213510667) are shown below. Please refer to Appendix A of the Plugging Plan for plugging procedures and diagrams for the other project wells currently constructed: USDW1, WW1, WW2, WW3, WW4, SLR1 and ACZ1 wells.

Table 17—Corrective action date for APs in AoR

API or state well number	Well Name	Planned actions	Date of corrective action and/or plugging
4511701	-	Remediation performed; plugged	2023
4213543920	Shoe Bar 1	Utilize as monitor during injection and post-injection periods before final plugging	2024[1] and ~10 years post Injection Period
4213543977	Shoe Bar 1AZ	Utilize as monitor during injection and post-injection periods before final plugging	2024[1], ~10 years post Injection Period
4213506139	Eidson-Scharbauer-1	Remediate	2025, prior to Injection Period
4213510667	Scharbauer Eidson-1	Remediate	2025, prior to Injection Period
4213531130	Eidson E-1	Remediate	2025, prior to Injection Period
4213544035	Shoe Bar 1WW	Brine water withdrawal	End of Injection Period
4213544036	Shoe Bar 2WW	Brine water withdrawal	After ~seven years of injection[2] End of Injection Period
4213544037	Shoe Bar 3WW	Brine water withdrawal	End of Injection Period
4213544034	Shoe Bar 4WW	Brine water withdrawal	End of Injection Period
NA	Shoe Bar 1USDW	USDW monitor	~20 years post Injection Period

[1]Plugging to convert stratigraphic test well into a monitoring well
[2]Plugging of the Holt sub-zone

5.2.4 Corrective Action Procedures

5.2.4.1 Eidson E-1 Re-entry and Plugging Procedure

[redacted]

[redacted]

The current wellbore diagram for Eidson E-1 is show in Figure 83. The proposed wellbore diagram after corrective action is shown in Figure 84.

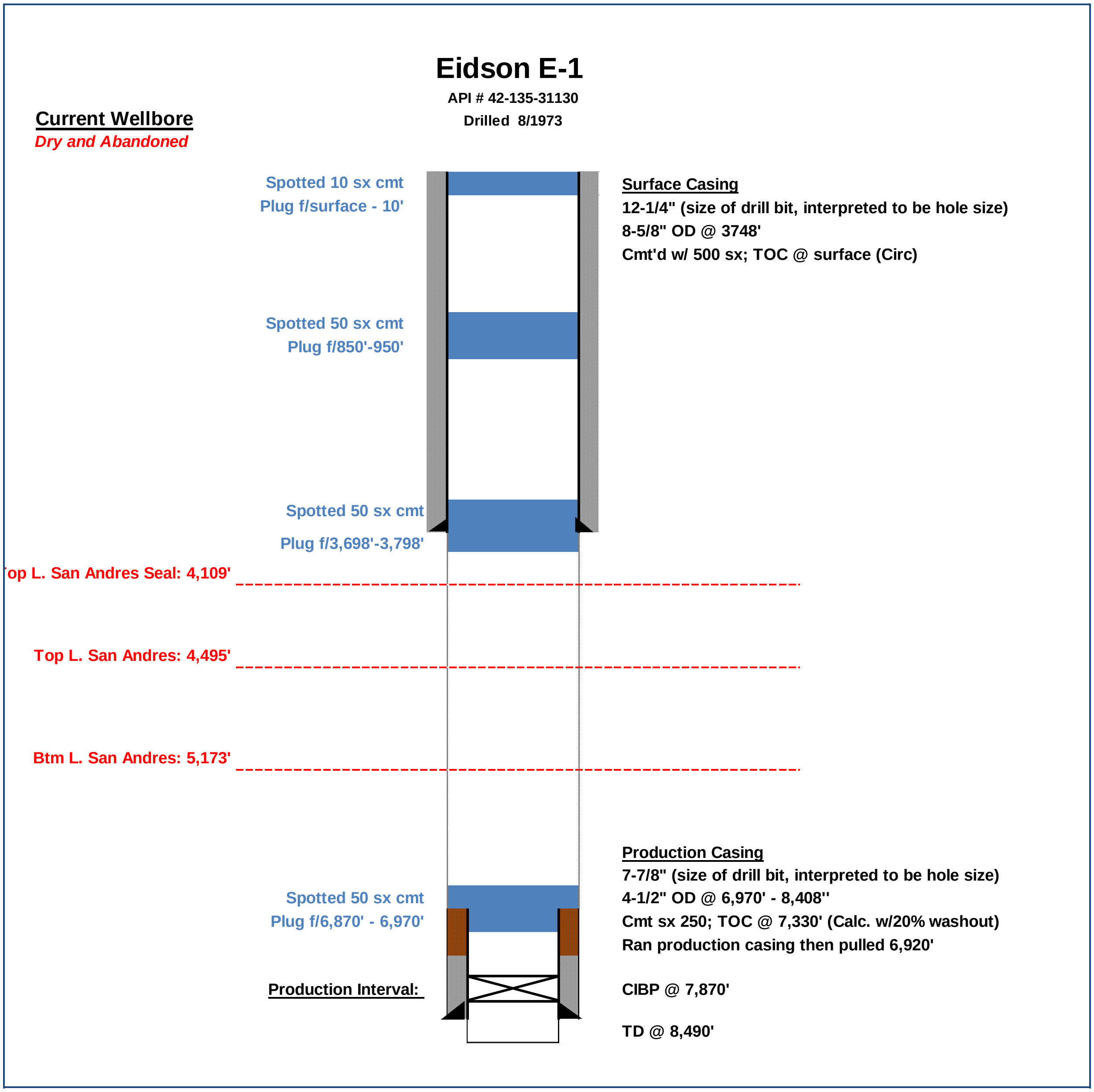

Figure 831—Eidson E-1 current wellbore diagram.

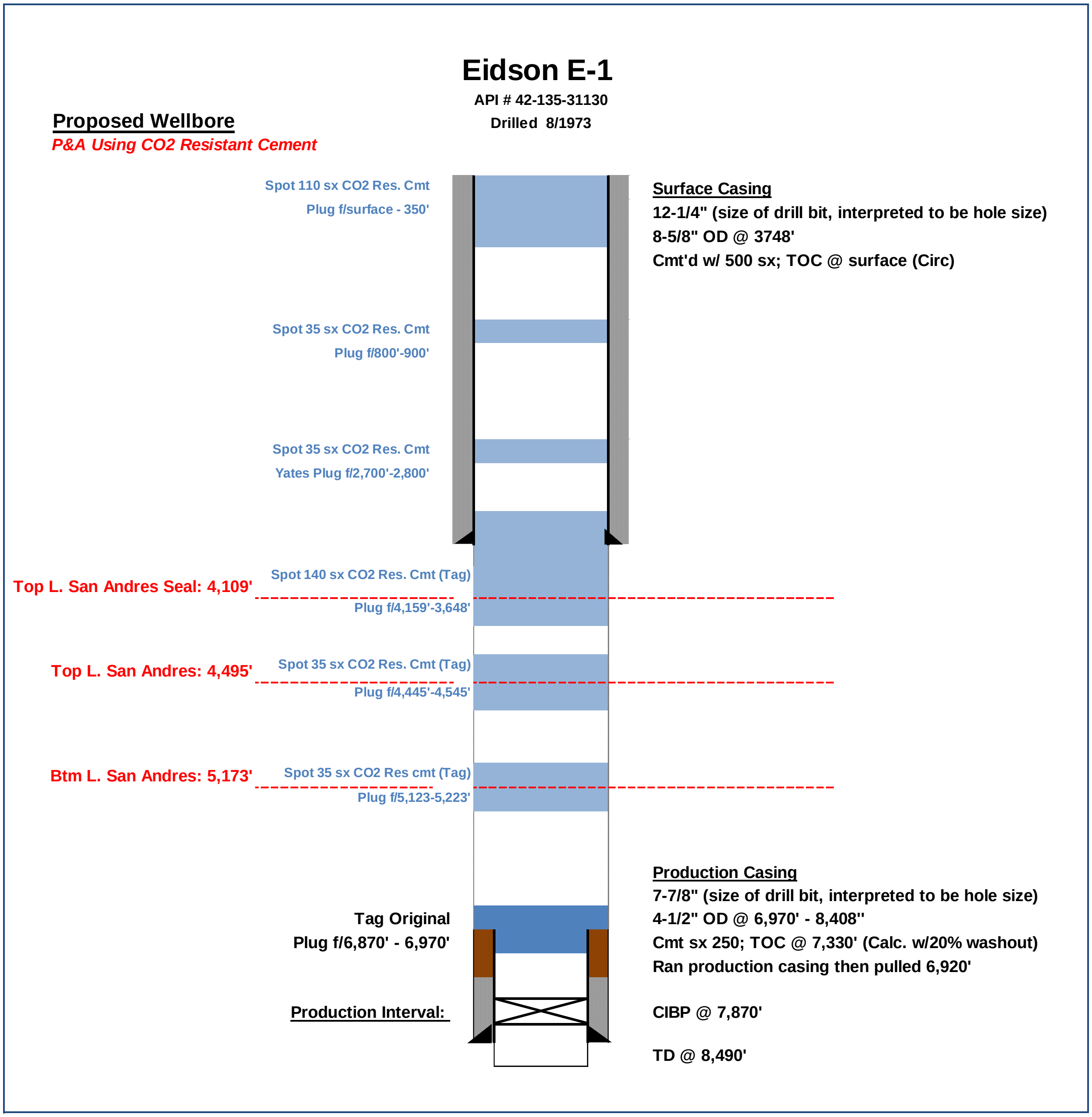

Figure 84--Proposed wellbore diagram of Eidson E-1 after corrective action.

5.2.4.2 Scharbauer Eidson-1 Re-entry and Plugging Procedure

[redacted]

[redacted]

The current wellbore diagram for Scharbauer Eidson 1 is shown in Figure 85. The proposed wellbore diagram is shown in Figure 86.

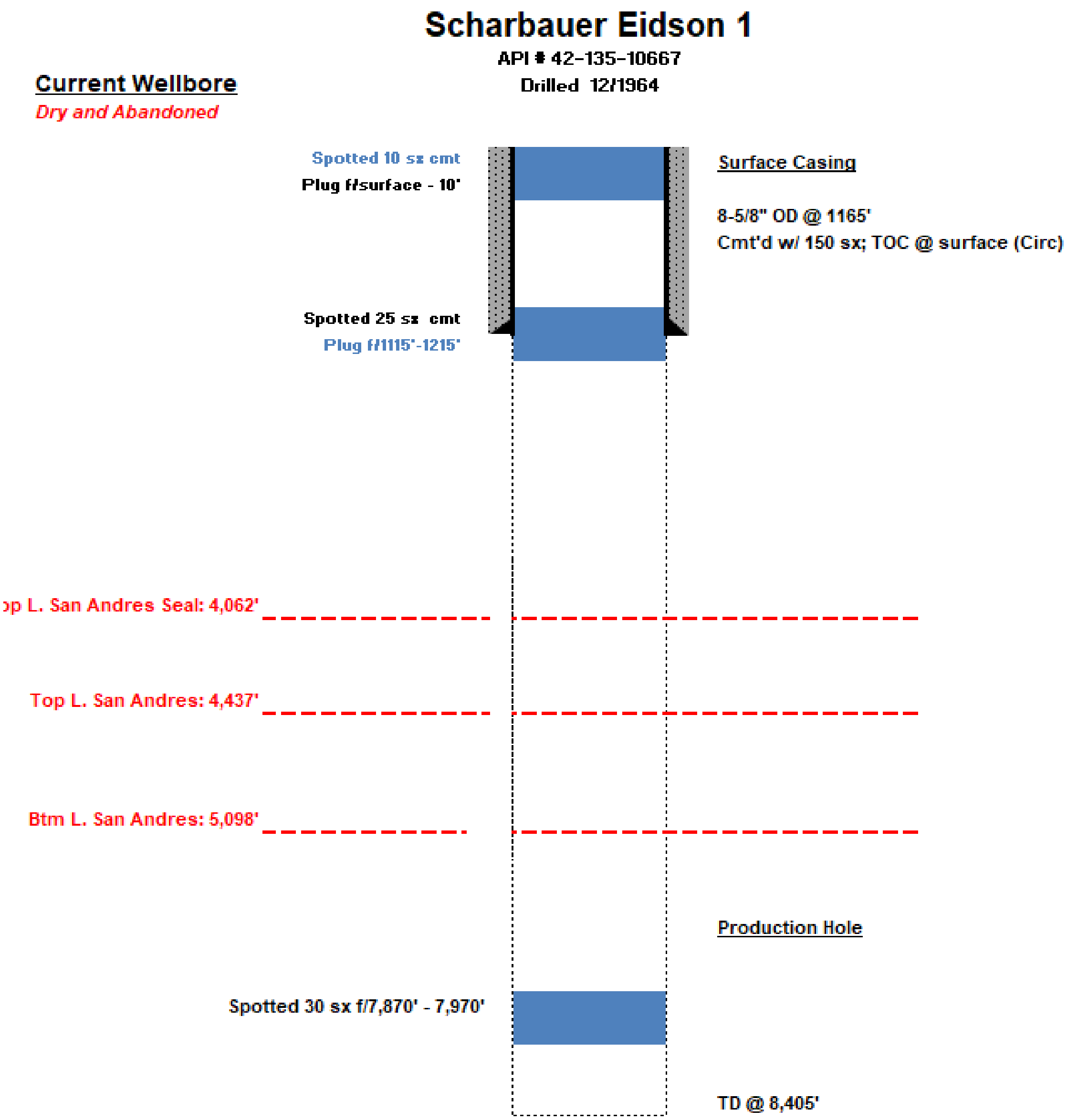

Figure 85--Current Scharbauer Eidson-1 wellbore diagram.

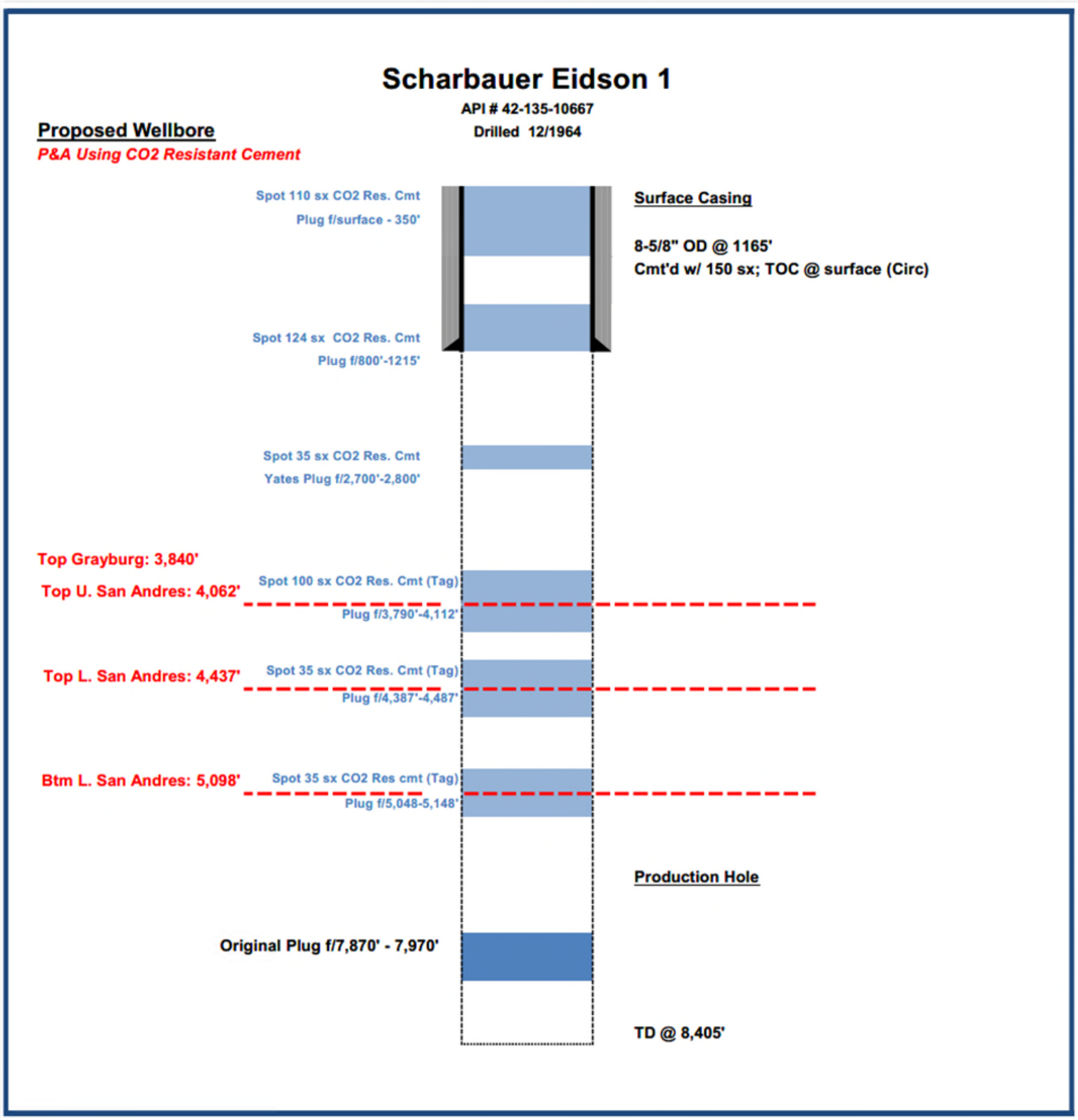

Figure 86—Proposed wellbore diagram for Scharbauer Eidson-1 after corrective action.

5.2.4.3 Eidson- Scharbauer-1 Re-entry and Plugging Procedure

[redacted]

[redacted]

The current wellbore diagram for Eidson-Scharbauer-1 is shown in Figure 87. The proposed wellbore diagram is shown in Figure 88.

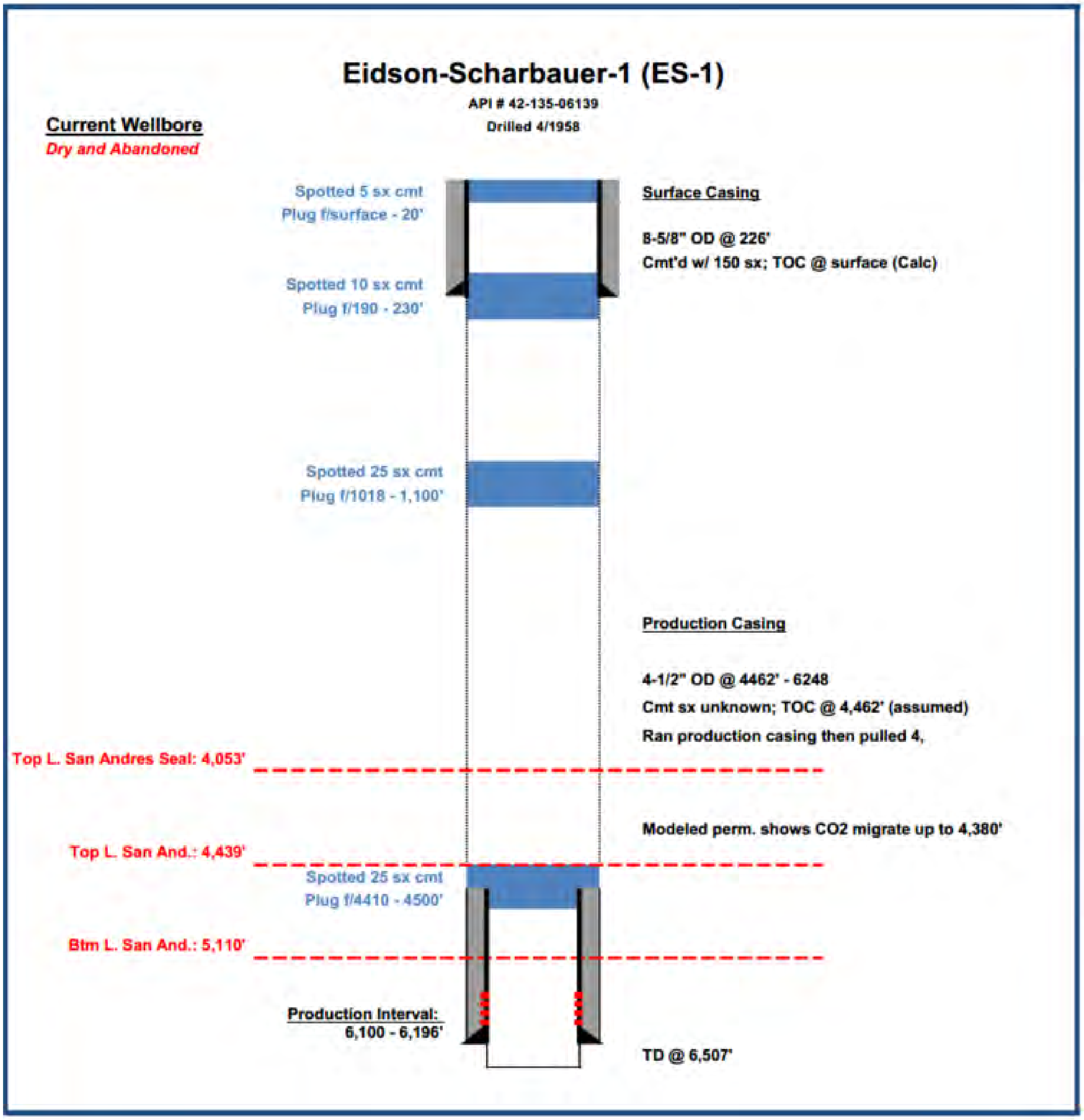

Figure 87—Current Eidson-Scharbauer-1 wellbore diagram.

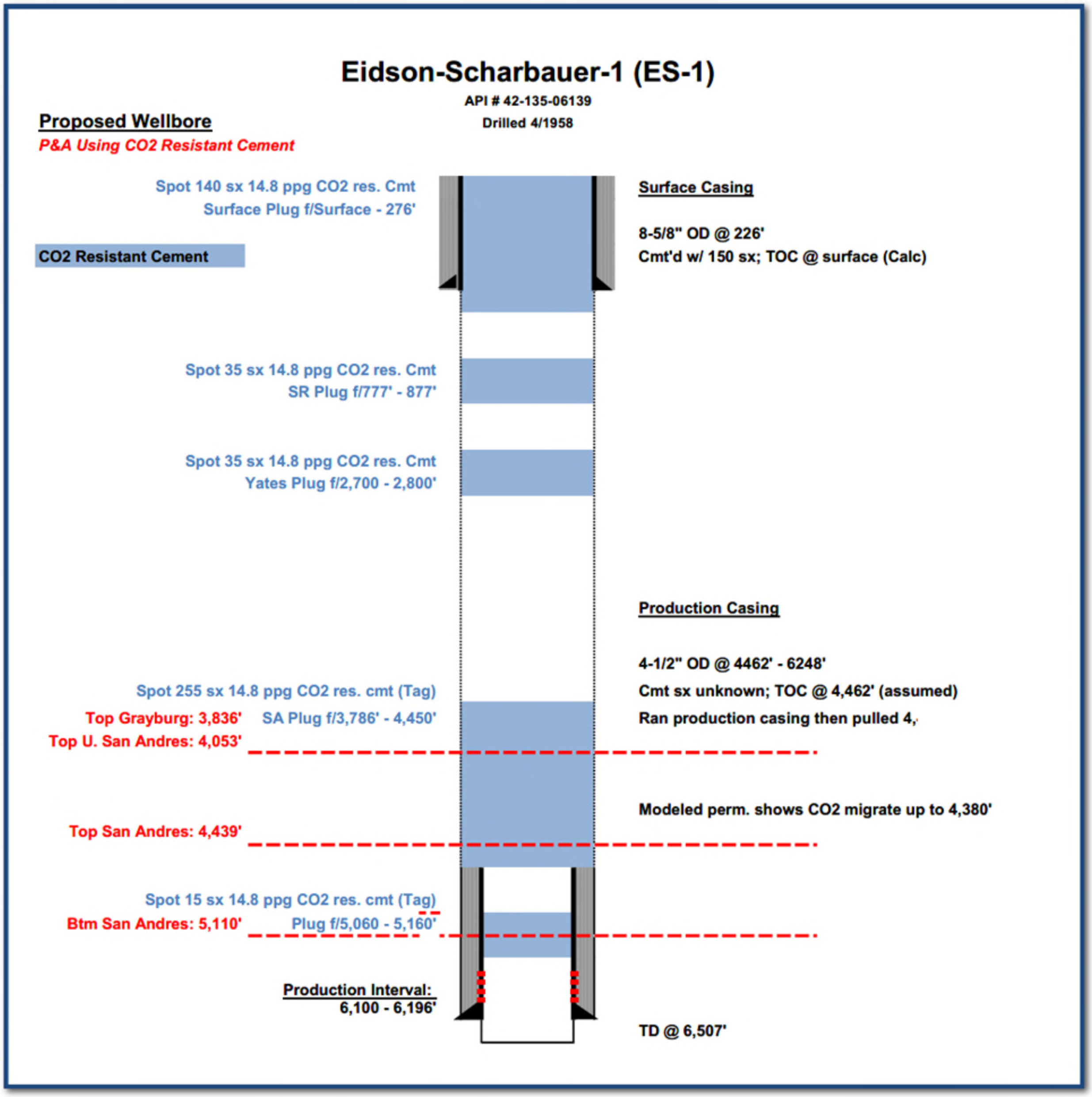

Figure 88—Proposed Eidson-Scharbauer-1 wellbore diagram following corrective action.

5.2.4.4 Plugging procedures for other Project wells

See Appendix A to the Plugging plan that is part of this document for a description of plugging plans for the Shoe Bar 1, Shoe Bar 1AZ, Shoe Bar 1WW, Shoe Bar 2WW, Shoe Bar 3WW, Shoe Bar 4WW, and the USDW1 well.

5.3 Plan for Site Access

As part of OLCV's agreement with the Shoe Bar Ranch, the operator acquired the exclusive rights to sequester and store liquids, gases, and other substances in the property. With that, OLCV has the right to maintain and operate any and all equipment necessary or useful to sequestration operations. The term of the agreement is in effect until 100 years after the cessation of sequestration operations, unless the operator elects to abandon earlier.

6.0 Re-Evaluation Schedule and Criteria

6.1 AoR Re-Evaluation Cycle

OLCV will re-evaluate the AoR every five years during the injection and post-injection phases. In addition, monitoring and operational data will be reviewed periodically by OLCV during the injection and post-injection phases.

Activities to be performed during re-evaluation include:

- Review and analyze available monitoring and operational data and compare these data to the dynamic simulation forecast to assess whether the predicted CO_2 plume migration is consistent with the observed data. OLCV will incorporate direct monitoring data from injector wells, reservoir-level monitoring well, above confining zone monitoring wells and USDW-level monitoring wells. In addition, OLCV will incorporate data from indirect geophysical monitoring. Data collection is described in the Testing and Monitoring Plan and PISC Plan that are included as part of this application. Specific steps of this review and analysis include:

  (1) Review available data on the position of the CO_2 plume and pressure front, such as pressure and temperature monitoring data, Pulsed Neutron logs (PNL), fluid samples, DInSAR, and repeat Vertical Seismic Profile and/or 2D seismic data.

    - Correlate the time-lapse PNL and time-lapse VSP/2D data to locate and track the movement of the CO_2 plume. A good correlation between the two data sets will provide confidence in the model's ability to represent the storage complex.
    - Review downhole reservoir pressure data collected from various locations and intervals using a combination of surface and downhole pressure gauges.

(2) Review water chemistry monitoring data collected in SLR wells and in the ACZ monitoring wells, verifying that there is no evidence of CO_2 or brines that represent an endangerment to any USDWs.

(3) Review operating data, e.g., injection rates and pressures, and verify they are consistent with the inputs used in the most recent modeling effort.

(4) Review geologic data acquired since the last modeling effort, e.g., additional site characterization performed or updates of petrophysical properties from core analysis. Identify whether new data are materially different from the modeling inputs and assumptions.

- Compare the results of computational modeling used for AoR delineation to the monitoring data collected. Monitoring data will be used to show that the computational model accurately represents the storage site and can be used as a proxy to determine the plume's properties and size. The degree of accuracy is demonstrated by comparing monitoring data with the model's predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model's ability to represent the storage site accurately.
- If the current data are consistent with model inputs and/or if the model forecast is unchanged after incorporation of these data, no update to the AoR will be needed. In this case, a report including data and results will be prepared to demonstrate that no re-delineation of the AoR is needed.
- If material changes in site conditions or operating parameters have occurred, or if data indicate that the actual plume or pressure front may extend beyond the modeled plume and pressure front, the AoR will be re-delineated. Steps to re-delineate the AoR include:

  (1) Revise the site conceptual model based on the new site characterization, operational, or monitoring data.

  (2) Calibrate and history-match the model to minimize the differences between monitoring data and model simulations.

- Perform the AoR delineation phased approach as described in Section 4.0 AoR Delineation of this document. Review legacy AP within the AoR and perform corrective action on wells, if needed. Specific steps include:

  (1) Identify any wells that fall within the AoR. Evaluate the status and records for wells that not previously evaluated and provide a description of each well's type, construction, date drilled, location, depth, and record of plugging and/or completion.

  (2) Determine which wells in the newly delineated AoR are plugged in a manner that prevents movement of carbon dioxide or other fluids that may endanger USDWs.

(3) Perform corrective action on all deficient wells in the AoR using methods designed to prevent the movement of fluid into or between USDWs, including the use of materials compatible with carbon dioxide.

- Prepare a report documenting the AoR re-evaluation process, data evaluated, any corrective actions determined to be necessary, and status of corrective action or a schedule for any corrective actions to be performed. The report will be submitted to EPA within 90 days of the re-evaluation and will include maps that highlight similarities and differences with previous AoR delineations.
- Update the AoR and Corrective Action Plan to reflect the revised AoR, along with other related Project plans, as needed.

6.2 Conditions Warranting an AoR Re-Evaluation Prior to Scheduled Re-Evaluation

Unscheduled re-evaluation of the AoR will be based on quantitative changes observed in monitoring wells, including unexpected changes in the following parameters: pressure, temperature, RST/PNL, or fluid chemistry changes in deep groundwater (>3,800 ft). Changes in these parameters may indicate that the actual plume or pressure front may extend beyond the modeled plume and pressure front. These changes might include:

- **Pressure:** Changes in pressure that are unexpected and outside three standard deviations from the average will trigger a new evaluation of the AoR.
- **Temperature**: Changes in temperature that are unexpected and outside three standard deviations from the average will trigger a new evaluation of the AoR.
- **RST Saturation:** Increases in CO_2 saturation that indicate the movement of CO_2 into or above the Confining Zone will trigger a new evaluation of the AoR unless the changes are found to be related to well integrity. Any identified well integrity issues will be investigated and addressed. Increases in CO_2 saturation in monitoring wells may indicate an early breakthrough of the CO_2 plume.
- **Deep Groundwater Constituent Concentrations:** Unexpected changes in fluid constituent concentrations that indicate movement of CO_2 or brine into or above the Confining Zone will trigger a new evaluation of the AoR unless the changes are found to be related to wellbore integrity. Any identified well integrity issues will be investigated and addressed.
- **Exceeding Fracture Pressure Conditions:** Pressure in any of the injection or monitoring wells exceeding 90% of the geologic formation fracture pressure at the point of measurement will trigger a new evaluation of the AoR.

- **Compromise in Injection Well Mechanical Integrity:** A significant change in annular pressure for the injection well that indicates a loss of mechanical integrity or a failed mechanical integrity test (MIT) in an injector will trigger a new evaluation of the AoR.
- **Induced Seismicity Monitoring:** Seismic monitoring data that indicate reactivation of a fault or structures due to pressurization of the reservoir as a consequence of the CO_2 injection will trigger a new evaluation of the AoR. The Project will review the monitoring data to discard naturally occurring events not related to the injection.

An unscheduled AoR re-evaluation may be needed if it is likely that the actual plume or pressure front may extend beyond what was modeled because any of the following has occurred:

- Seismic event greater than M_L 3.5 within 5.6 miles of the injection well.
- Exceedance of any Class VI operating permit condition (e.g., exceeding the permitted volumes of carbon dioxide injected); or
- New site characterization data that change the computational model to such an extent that the predicted plume or pressure front extends vertically or horizontally beyond the predicted AoR.

OLCV will discuss any such events with the UIC Program Director to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, OLCV will perform the steps described in 6.1 AoR Re-Evaluation Cycle.

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AOR Appendices

(submitted as wholly redacted)

Plan revision number: 3
Plan revision date: 07/30/2024

INJECTION WELL CONSTRUCTION PLAN
40 CFR §146.82(a)(11) and (12), §146.86, §146.87, and §146.88 (a), (b), (c), and (e)

Brown Pelican CO_2 Sequestration Project

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1.0 Facility Information

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS 1, CCS2 and CCS3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

2.0 Overview

Oxy Low Carbon Ventures, LLC (OLCV) will construct CO_2 injection wells for the Brown Pelican CO_2 Sequestration Project (BRP Project or Project) according to the procedures in this document. The matter of construction details is relevant to the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The main topics covered in this attachment are special construction requirements, open hole diameters and intervals, casing specifications, tubing specifications, data acquisition and testing plan, and demonstration of mechanical integrity.

The Brown Pelican CCS1, CCS2 and CCS3 (BRP CCS1, BRP CCS2 and BRP CCS3) injection wells are designed with the highest standards and best practices for drilling and well construction. The design parameters and material selection are aimed to ensure mechanical integrity in the system and to optimize the operation during the life of the Project.

3.0 Design Parameters and Specifications

The well was designed to maximize the rate of injection while maintaining the bottomhole pressure below 90% of the fracture gradient. The selected design provides enough clearance to deploy the pressure and temperature gauges on tubing and install a fiber optic cable on the long string casing to ensure continuous surveillance of external integrity and conformance.

Design parameters that will be employed during the life of the well are shown in Table 1, and CO_2 specifications for the Project are shown in Table 2. A nodal analysis was used to perform sensitivities on the tubing size, rate of erosion, and potential movement of the tubulars. The nodal analysis results, operating parameters, and CO_2 specifications were used in selecting materials to be used to construct the well.

Table 1—Design Parameters

Parameter	Value or Range
Injection rate (MTPD)	417-1319
Tubing pressure (psi)	1,000 to 1,800
Annular surface pressure (psi)	0 to 400
Surface temperature (°F)	60 to 90
Bottomhole temperature (°F)	120

Note:
Annular surface pressure between the tubing and long string will be kept between 0 and 400 psi to monitor changes during injection. It is not recommended to apply the maximum injection pressure to the annulus between the tubing and the long string casing to avoid unnecessary stress on the cement sheath, which could lead to a micro-annulus or microfractures.

Table 2—Specification of CO_2 Injectate

Component	Specification
CO_2 content	>95 mol%
Water	<30 lbm/MMscf
Nitrogen	<4 mol%
Sulphur	<35 ppm by weight
Oxygen	<5 mol%
Glycol	<0.3 gal/MMscf
Carbon Monoxide	<4,250 ppm by weight
NOx	<6 ppm by weight
SOx	<1 ppm by weight
Particulates ($CaCO_3$)	<1 ppm by weight
Argon	<1 mol%
Surface pressure	>1,600 psig
Surface temperature	>65°F and <120°F

4.0 Well Design

OLCV plans to construct three CO_2 injector wells: BRP CCS1, BRP CCS2, and BRP CCS3 for the Project. The locations and orientations of those wells are shown in Figure 1 below.

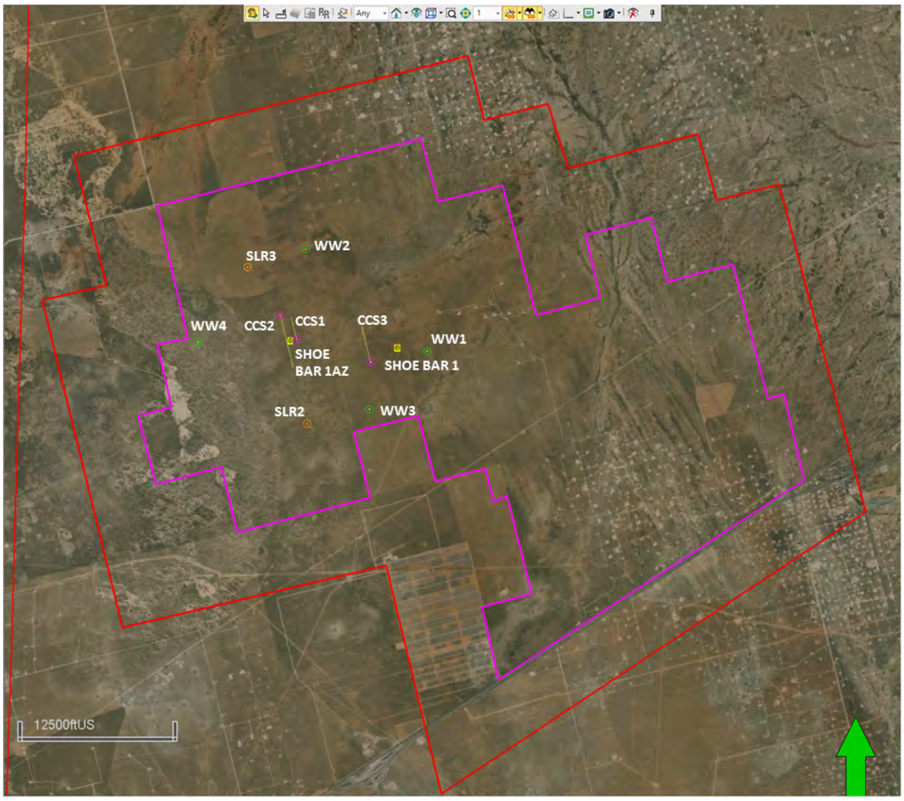

Figure 1—BRP CCS1, BRP CCS2 and BRP CCS3 Well Locations

4.1 BRP CCS1

4.1.1 Design for BRP CCS1

The BRP CCS1 well design includes three main casing sections: 1) surface casing to cover the USDW and provide integrity while drilling to the Injection Zone, 2) intermediate section, and 3) a long string section to acquire formation data and isolate the target formation while running the upper completion equipment. Figure 2 presents wellbore trajectory of BRP CCS1 and Figure 3 is BRP CCS1 well proposed schematic

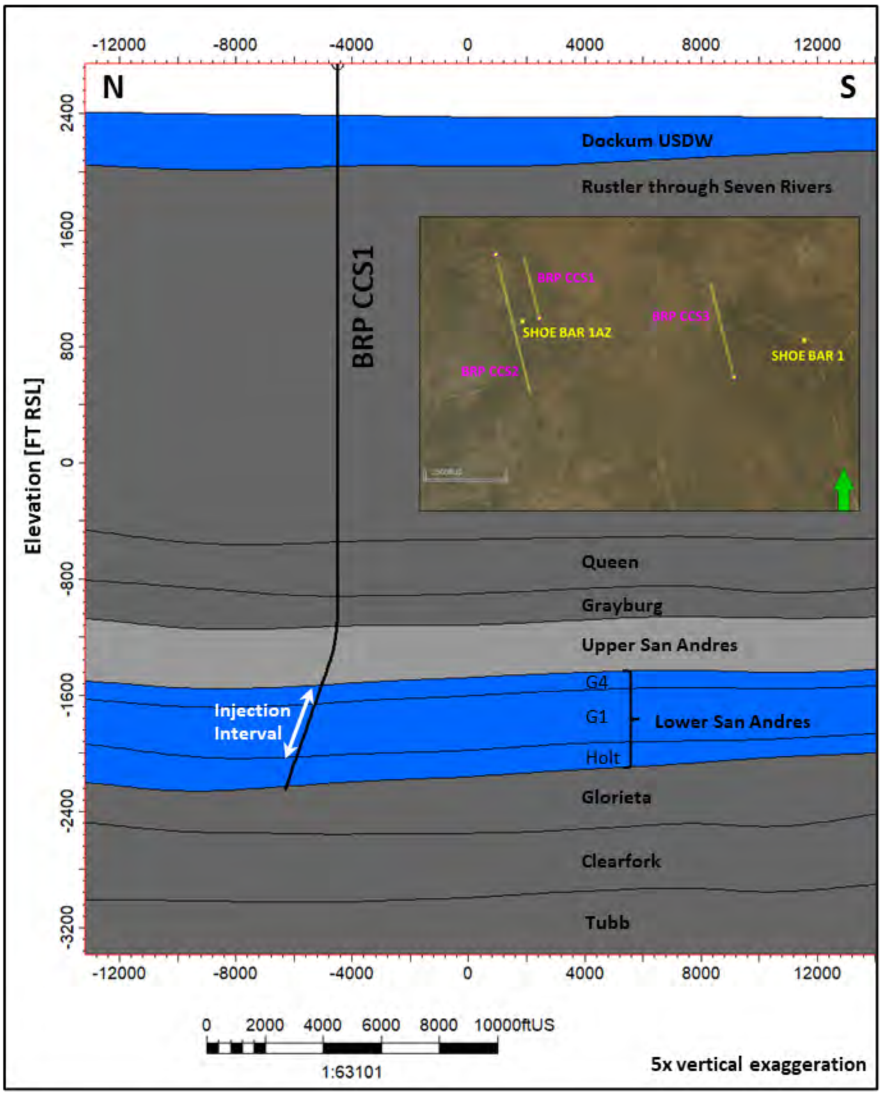

Figure 2—Wellbore trajectory of BRP CCS1 with completion interval in sub-zone G4-G1 highlighted in white.

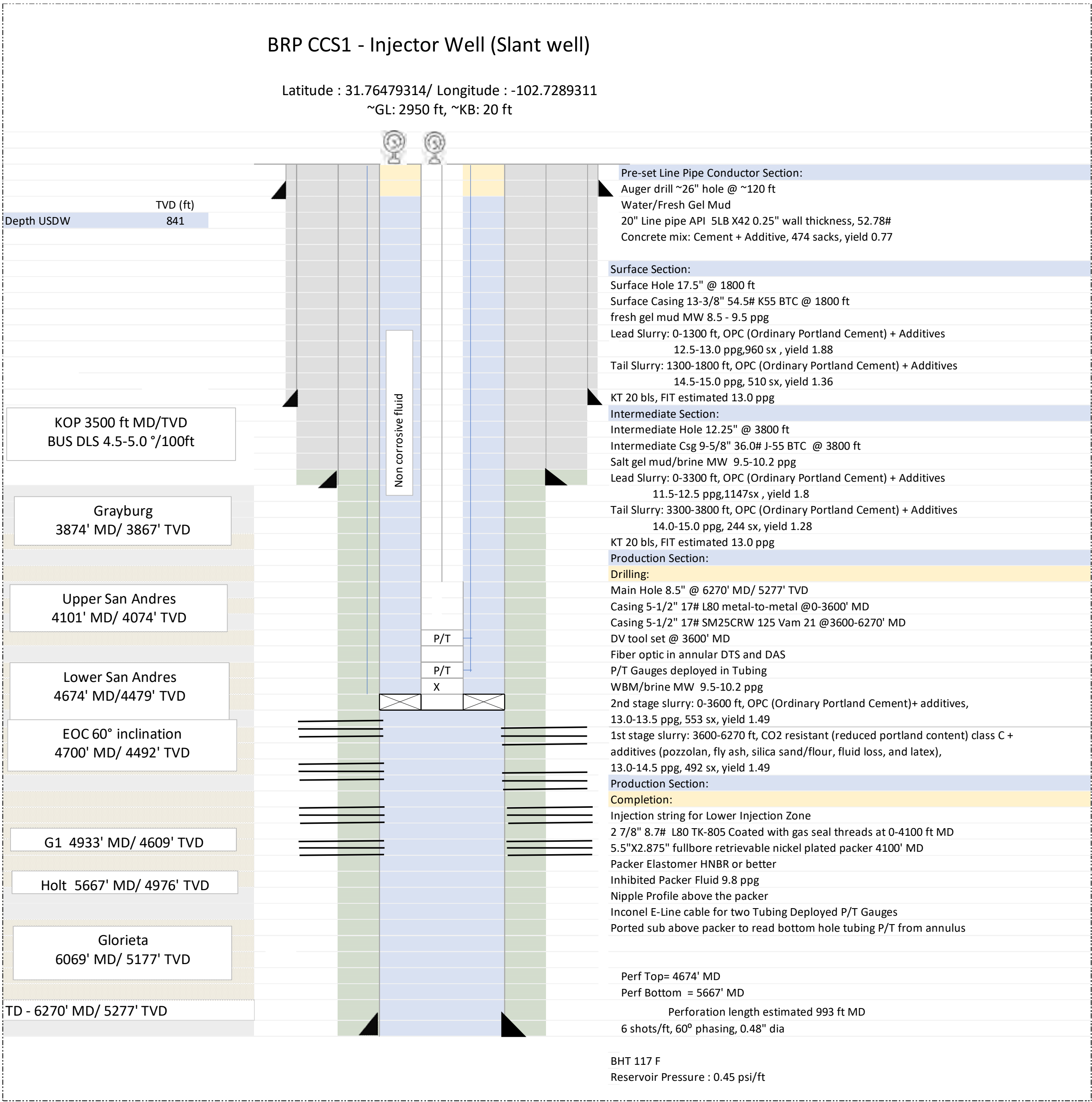

Figure 3—BRP CCS1 well proposed schematic

Details of BRP CCS1 well design are provided in the following tables. Table 3 contains the open hole diameters of each section, Table 4 lists the casing specifications, and Table 5 details the casing material properties. In addition, Table 7 contains the upper completion equipment specifications, and Table 8 shows the tubing material properties.

Table 3—Open Hole Diameters and Intervals for BRP CCS1

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor Section	0 to 120	26	Auger drill
Surface section	0 to 1,800	17 ½	Below base of USDW
Intermediate section	1,800 to 3800	12 ¼	Intermediate section
Long string section	3800 to 6270	8 ½	To total depth (TD)

Notes:

- The well TD includes a minimum 80 ft of cement shoe track, and 100 ft casing rat hole for completion operations in the Glorieta Formation.
- The USDW depth will be confirmed with open hole logs.

Table 4—Casing Specifications for BRP CCS1

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Pre-set conductor	0 to 120’	20	19.5	19.25	52.78	5LB X42	weld
Surface string	0 to 1,800	13 3/8	12.615	12.459	54.5	K-55	BTC
Intermediate string	0 to 3,800	9 5/8	8.921	8.765	36	J-55	BTC
Long string	0 to 3,600	5 1/2	4.892	4.767	17	L80	LTC or Vam 21
Long string	3,600 to 6,270	5 1/2	4.892	4.767	17	SM25CRW-125*	Vam 21

*Casing material selection

Table 5—Casing Material Properties for BRP CCS1

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)
20 in conductor	0 to 120	-	-	-
13 3/8 -in. 54.5# K-55 BTC	0 to 1,800	2,730	1,130	853
9 ⅝-in. 36# J-55 BTC	0 to 3,800	3,520	2,020	564
5 ½ -in. 17# L80	0 to 3,600	7,740	6,290	397
5 ½ -in. 17# SM25CRW-125	3,600 to 6,270	12,090	7,890	829

Notes:

- A stage tool will be located at ~3,000 to 4,000 ft in the 5-1/2-in. casing to perform the two-stage cement job.
- The centralization program will aim at 70- 90% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions.
- DTS/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

Table 6—Direction design for BRP CCS1

Name	MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	Dogleg (°/100ft)	Description
SHL	0	0	0	0	0.00	Surface hole location
KOP	3500	0	346	3500	0.00	Kick of point
EOC	4700	60	346	4492	5.00	End of curve
Well TD	6270	60	346	5277	0.00	Tangent section

Table 7—Upper Completion Equipment Specifications for BRP CCS1

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Injection (Coated TK-805) tubing	0 to 4,100	2 7/8	2.441	2.347	6.5	L80	Special
Packer	Nickel-plated / HNBR (RGD) elastomers						

Table 8—Tubing Material Properties for BRP CCS1

Tubing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Ksi)
2 7/8-in. 6.5# L80 Special – Coated TK-805	0 to 4,100	10,570	11,170	80

Notes:

- Pressure and temperature gauges will be tubing-deployed above and below casing. Cable material will be Inconel®, and gauge carriers will be CO_2-resistant material.
- The internal diameter of the tubing will be slightly reduced due to the TK-805 coating to be applied.
- The annular space between the 2 7/8-in. tubing and 5 1/2-in. casing will be filled with packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

4.1.2 Proposed Drilling Procedure for BRP CCS1

The next section is the drilling procedure for BRP CCS1.

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4.1.3 Proposed Completion Procedure for BRP CCS1

During the completion operations, the rig will test the casing to 500 psi, condition the long string casing with a bit and scraper, run a CBL-VDL-USIT-CCL[2] log to evaluate cement bonding and casing conditions, perforate the Injection Zone, and run the upper completion equipment. The 2 7/8-in. tubing and packer completion will be run to approximately 4,100 ft, in conjunction with an electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid, and the packer will be set. Once the packer is set, an annular pressure test will be performed to 500 psi to validate the mechanical seal. A leak-off test followed by a pressure fall-off test will be performed before starting injection.

A detailed proposed procedure follows:

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[2] Cement bond long (CBL), variable density log (VBL), ultrasonic imager tool (USIT), casing collar locator (CCL)

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4.2 BRP CCS2

The BRP CCS2 well design includes three main casing sections: 1) surface casing to cover the USDW and provide integrity while drilling to the Injection Zone, 2) intermediate section, and 3) a long string section to acquire formation data and isolate the target formation while running the upper completion equipment. Figure 4 presents wellbore trajectory of BRP CCS2 and Figure 5 is BRP CCS2 well proposed schematic

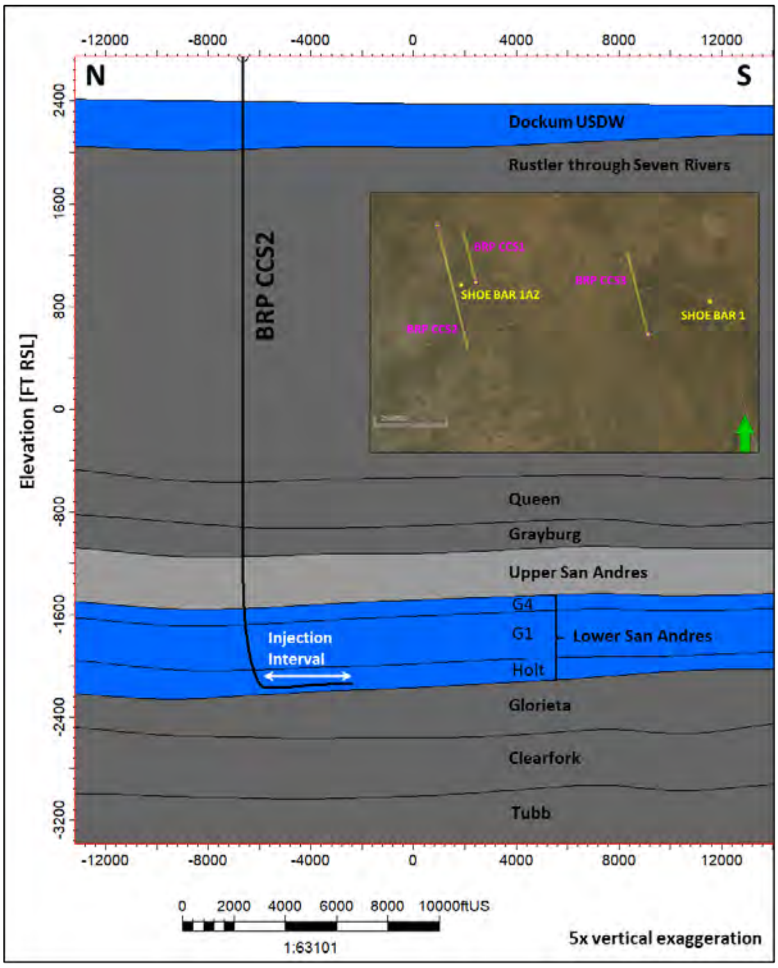
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Figure 4—Wellbore trajectory of BRP CCS2 horizontal well with completion interval in sub-zone Holt highlighted in white.

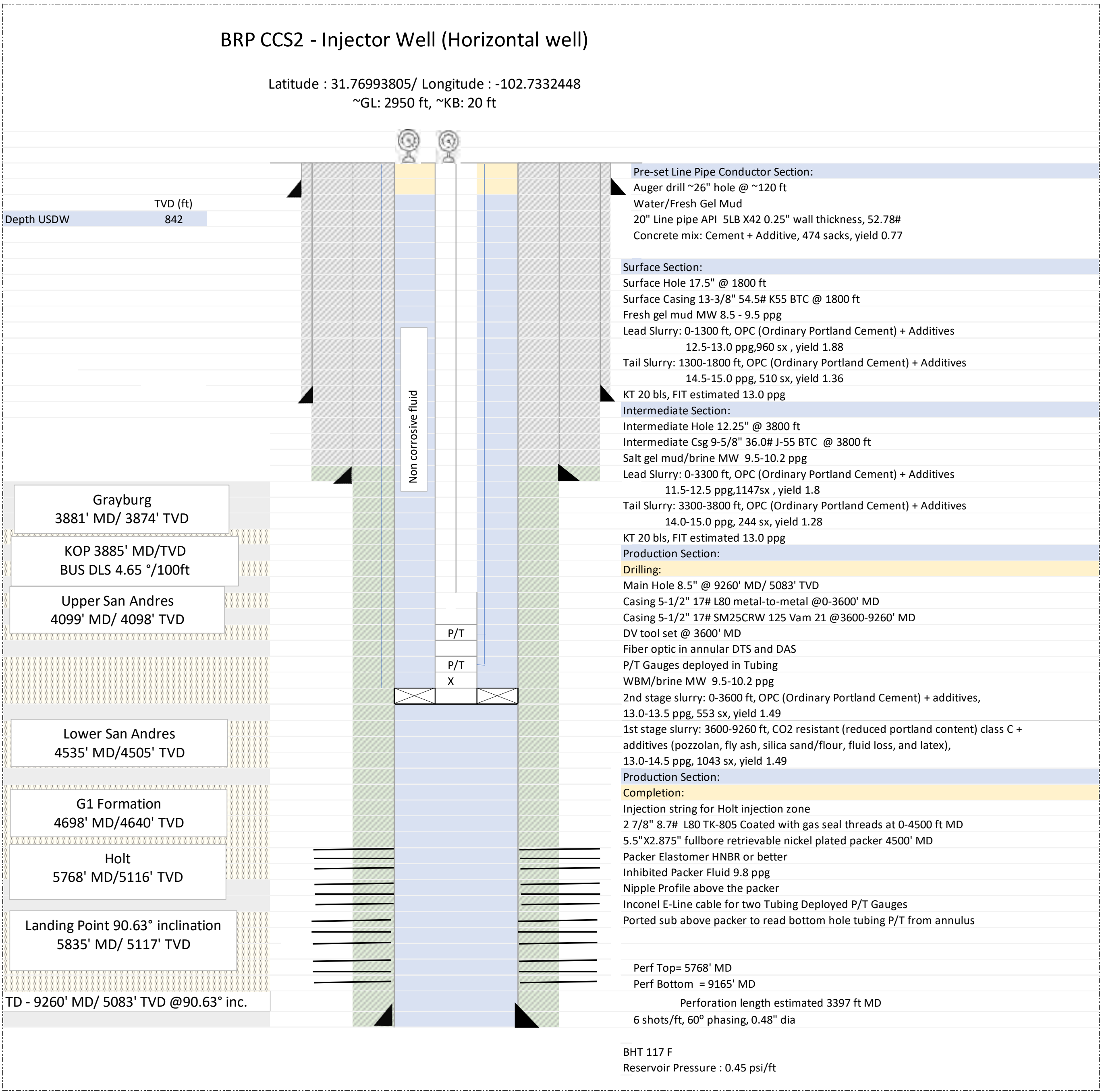

Figure 5—BRP CCS2 well proposed schematic

4.2.1 Design for BRP CCS2

Details regarding the BRP CCS2 well design are provided in the following tables. Table 9 contains the open hole diameters of each section, Table 10 lists the casing specifications, and Tables 11 details the casing material properties. In addition, Table 13 contains the upper completion equipment specifications, and Table 14 shows the tubing material properties.

Table 9—Open Hole Diameters and Intervals for BRP CCS2

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor Section	0 to 120	26	Auger drill
Surface section	0 to 1,800	17 ½	Below base of USDW
Intermediate section	1,800 to 3800	12 ¼	Intermediate section
Long string section	3800 to 9260	8 ½	To total depth (TD)

Notes:

- The well TD includes a minimum 80 ft of cement shoe track in the Holt Formation.
- The USDW depth will be confirmed with open hole logs.

Table 10—Casing Specifications for BRP CCS2

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Pre-set conductor	0 to 120’	20	19.5	19.25	52.78	5LB X42	weld
Surface string	0 to 1,800	13 3/8	12.615	12.459	54.5	K-55	BTC
Intermediate string	0 to 3,800	9 5/8	8.921	8.765	36	J-55	BTC
Long string	0 to 3,600	5 1/2	4.892	4.767	17	L80	LTC or Vam 21
Long string	3,600 to 9,260	5 1/2	4.892	4.767	17	SM25CRW-125*	Vam 21

*Casing material selection

Table 11—Casing Material Properties for BRP CCS2

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)
20 in conductor	0 to 120	-	-	-
13 3/8 -in. 54.5# K-55 BTC	0 to 1,800	2,730	1,130	853
9 ⅝-in. 36# J-55 BTC	0 to 3,800	3,520	2,020	564
5 ½ -in. 17# L80	0 to 3,600	7,740	6,290	397
5 ½ -in. 17# SM25CRW-125	3,600 to 9,260	12,090	7,890	829

Notes:

- A stage tool will be located at ~3,000 to 4,000 ft in the 5-1/2-in. casing to perform the two-stage cement job.
- The centralization program will aim at 70- 90% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions.
- DTS/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

Table 12—Direction design for BRP CCS2

Name	MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	Dogleg (°/100ft)	Description

SHL	0	0	0	0	0.00	Surface hole location
KOP	3885	0	346	3885	0.00	Kick of point
LP	5835	90.67	166	5117	4.64	Landing point
Well TD	9260	90.53	166	5083	0.00	Lateral section

Table 13—Upper Completion Equipment Specifications for BRP CCS2

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Injection (Coated TK-805) tubing	0 to 4,500	2 7/8	2.441	2.347	6.5	L80	Special
Packer	Nickel-plated / HNBR (RGD) elastomers						

Table 14—Tubing Material Properties for BRP CCS2

Tubing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Ksi)
2 7/8-in. 6.5# L80 Special – Coated TK-805	0 to 4,500	10,570	11,170	80

Notes:

- Pressure and temperature gauges will be tubing-deployed above and below casing. Cable material will be Inconel®, and gauge carriers will be CO_2-resistant material.
- The internal diameter of the tubing will be slightly reduced due to the TK-805 coating to be applied.
- The annular space between the 2 7/8-in. tubing and 5 1/2-in. casing will be filled with packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

4.2.2 Proposed Drilling Procedure for BRP CCS2

The next section is the drilling procedure for BRP CCS2.

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1 Distributed acoustic sensing (DAS) and distributed temperature sensing (DTS)

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4.2.3 Proposed Completion Procedure for BRP CCS2

During the completion operations, the rig will test the casing to 500 psi, condition the long string casing with a bit and scraper, run a CBL-VDL-USIT-CCL[4] log to evaluate cement bonding and casing conditions, perforate the Injection Zone, and run the upper completion equipment. The 2 7/8-in. tubing and packer completion will be run to approximately 4,500 ft, in conjunction with an electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid, and the packer will be set. Once the packer is set, an annular pressure test will be performed to 500 psi to validate the mechanical seal. A leak-off test followed by a pressure fall-off test will be performed before starting injection.

OPERATIONAL NOTES:

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[4] Cement bond long (CBL), variable density log (VBL), ultrasonic imager tool (USIT), casing collar locator (CCL)

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4.3 BRP CCS3

4.3.1 Design for BRP CCS3

The BRP CCS3 well design includes three main casing sections: 1) surface casing to cover the USDW and provide integrity while drilling to the Injection Zone, 2) intermediate section, and 3) a long string section to acquire formation data and isolate the target formation while running the upper completion equipment. Figure 6 presents wellbore trajectory of BRP CCS3 and Figure 7 is BRP CCS3 well proposed schematic.

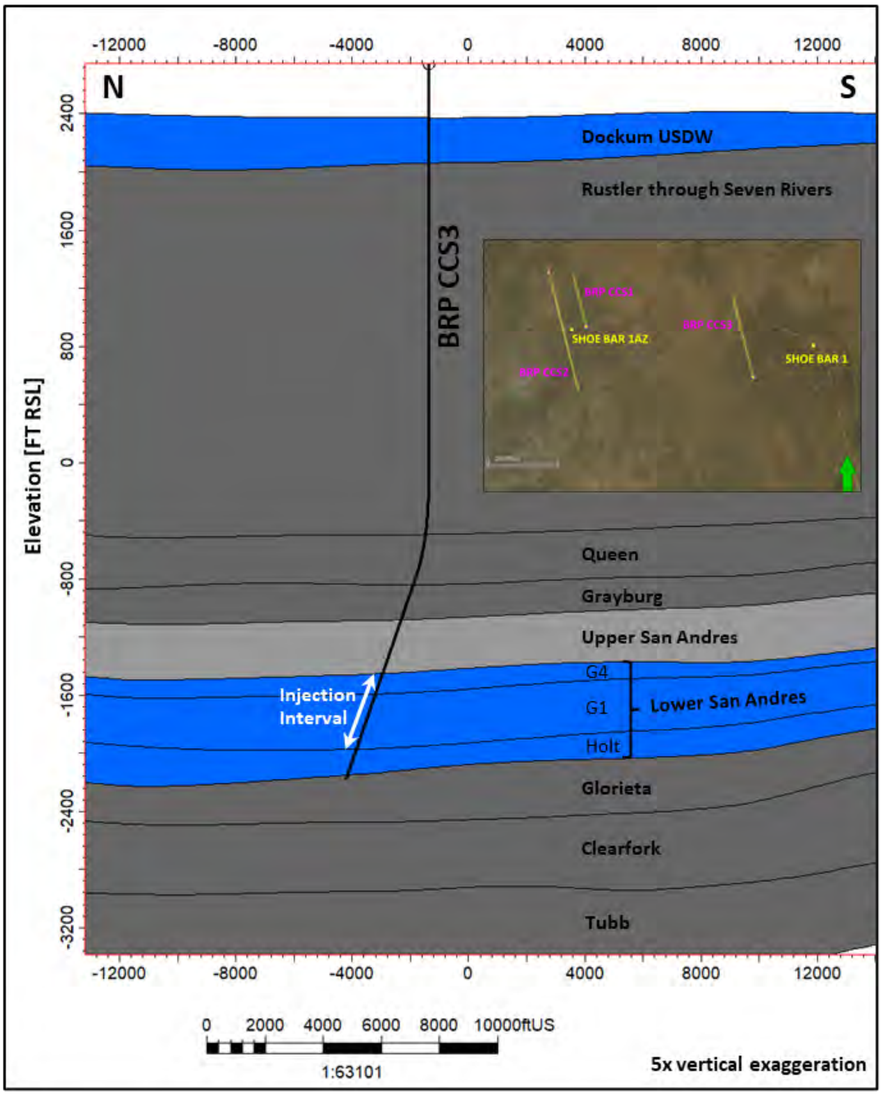

Figure 6—Wellbore trajectory of BRP CCS3 with completion interval in sub-zone G4-G1 highlighted in white

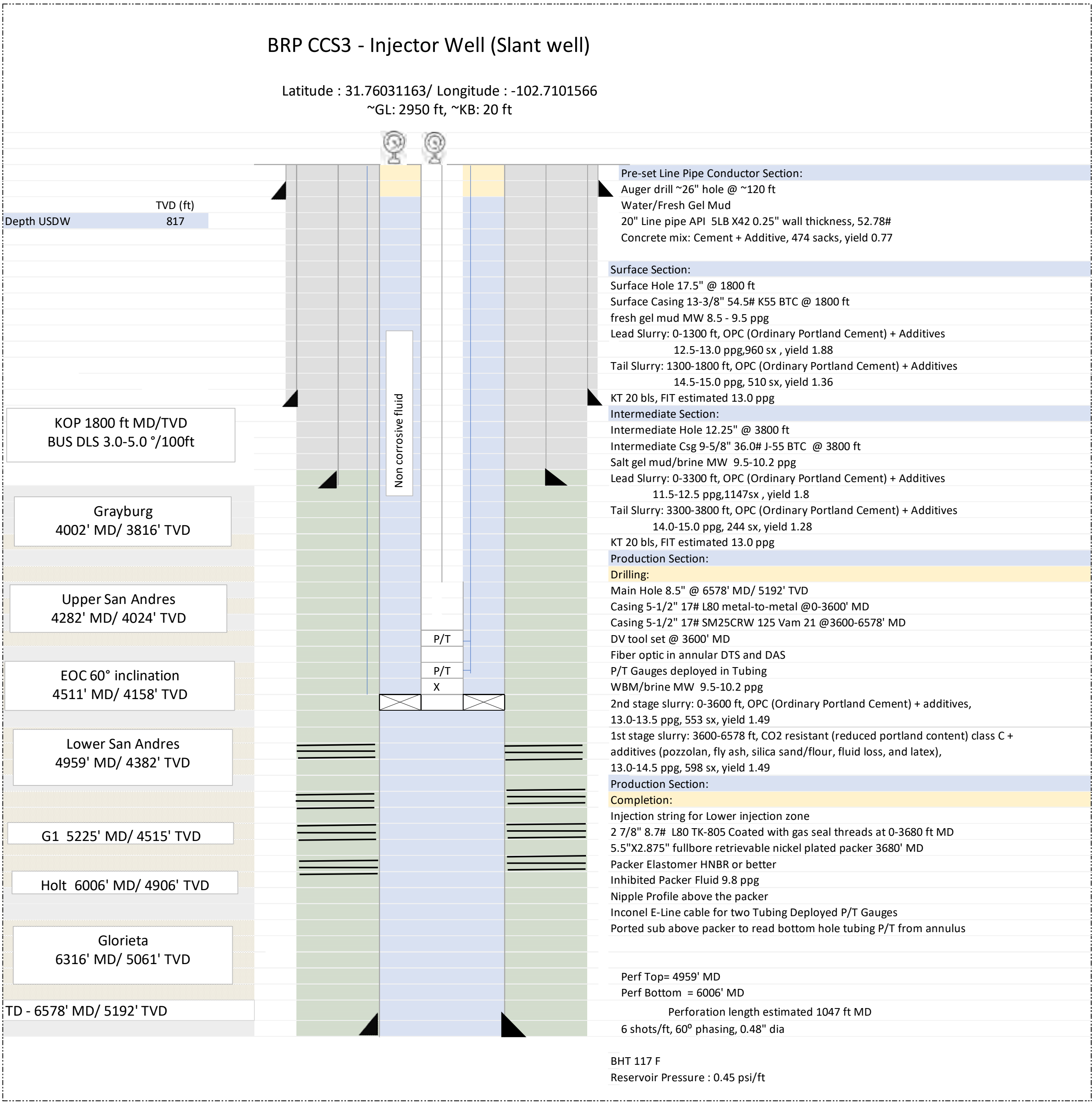

Figure 7—BRP CCS3 well proposed schematic

Details of BRP CCS3 well design are provided in the following tables. Table 15 contains the open hole diameters of each section, Table 16 lists the casing specifications, and Table 17 details the casing material properties. In addition, Table 19 contains the upper completion equipment specifications, and Table 20 shows the tubing material properties.

Table 15—Open Hole Diameters and Intervals BRP CCS3

Name	Depth Interval (ft)	Open Hole Diameter (in.)	Comment
Conductor Section	0 to 120	26	Auger drill
Surface section	0 to 1,800	17 ½	Below base of USDW
Intermediate section	1,800 to 3,800	12 ¼	Intermediate section
Long string section	3,800 to 6,578	8 ½	To total depth (TD)

Notes:

- The well TD includes a minimum 80 ft of cement shoe track, and 100 ft casing rat hole for completion operations in the Glorieta Formation.
- The USDW depth will be confirmed with open hole logs.

Table 16—Casing Specifications BRP CCS3

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Pre-set conductor	0 to 120’	20	19.5	19.25	52.78	5LB X42	weld
Surface string	0 to 1,800	13 3/8	12.615	12.459	54.5	K-55	BTC
Intermediate string	0 to 3,800	9 5/8	8.921	8.765	36	J-55	BTC
Long string	0 to 3,600	5 1/2	4.892	4.767	17	L80	LTC or Vam 21
Long string	3,600 to 6578	5 1/2	4.892	4.767	17	SM25CRW-125*	Vam 21

*Casing material selection

Table 17—Casing Material Properties for BRP CCS3

Casing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Klb)
20 in conductor	0 to 120	-	-	-
13 3/8 -in. 54.5# K-55 BTC	0 to 1,800	2,730	1,130	853
9 ⅝-in. 36# J-55 BTC	0 to 3,800	3,520	2,020	564
5 ½ -in. 17# L80	0 to 3,600	7,740	6,290	397
5 ½ -in. 17# SM25CRW-125	3,600 to 6578	12,090	7,890	829

Notes:

- A stage tool will be located at ~3,000 to 4,000 ft in the 5-1/2-in. casing to perform the two-stage cement job.
- The centralization program will aim at 70- 90% standoff and will be adjusted using the field data for deviation, caliper, and hole conditions.
- DTS/DAS fiber optic cable will be deployed alongside the casing as part of the monitoring program. Special clamps, bands, and centralizers will be installed to protect the fiber and provide a marker for wireline operations.

Table 18—Direction design for BRP CCS3

Name	MD (ft)	Inclination (°)	Azimuth (°)	TVD (ft)	Dogleg (°/100ft)	Description
SHL	0	0	0	0	0.00	Surface hole location
KOP	1800	0	346	1800	0.00	Kick of point
EOC	4511	60	346	4158	5.00	End of curve
Well TD	6578	60	346	5192	0.00	Tangent section

Table 19—Upper Completion Equipment Specifications

Name	Depth Interval (ft)	OD (in.)	ID (in.)	Drift (in.)	Weight (lbm/ft)	Grade (API)	Coupling
Injection (Coated TK-805) tubing	0 to 3680	2 7/8	2.441	2.347	6.5	L80	Special
Packer	Nickel-plated / HNBR (RGD) elastomers						

Table 20—Tubing Material Properties

Tubing	Depth Interval (ft)	Burst (psi)	Collapse (psi)	Body Yield (Ksi)
2 7/8-in. 6.5# L80 Special – Coated TK-805	0 to 3680	10,570	11,170	80

Notes:

- Pressure and temperature gauges will be tubing-deployed above and below casing. Cable material will be Inconel®, and gauge carriers will be CO_2-resistant material.
- The internal diameter of the tubing will be slightly reduced due to the TK-805 coating to be applied.
- The annular space between the 2 7/8-in. tubing and 5 1/2-in. casing will be filled with packer fluid.
- The packer depth will be adjusted once the final perforation depth interval is known.

4.3.2 Proposed Drilling Procedure for BRP CCS3

The next section is the drilling procedure for BRP CCS3.

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4.3.3 Proposed Completion Procedure for BRP CCS3

During the completion operations, the rig will test the casing to 500 psi, condition the long string casing with a bit and scraper, run a CBL-VDL-USIT-CCL[5] log to evaluate cement bonding and casing conditions, perforate the Injection Zone, and run the upper completion equipment. The 2 7/8-in. tubing and packer completion will be run to approximately 3,680 ft, in conjunction with an electric cable and pressure and temperature gauges. The fluid in the well will be displaced with packer fluid, and the packer will be set. Once the packer is set, an annular pressure test will be performed to 500 psi to validate the mechanical seal. A leak-off test followed by a pressure fall-off test will be performed before starting injection.

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4.4 Material Selection

Casing string materials for the injection wells are selected based on the risk of corrosion with the casing in the zones where no risk of CO_2 in contact with the casing is made of alloy steel as shown in the well schematics and the zone where casing will be in contact with the CO_2 and formation water will be of corrosion resistant alloy (CRA). This covers the primary casing below the packer and 3 to 5 joints above the packer being of corrosion resistant alloy and the remaining is of alloy steel.

Appendix A discusses the material selection process.

4.5 Cement Program

To ensure long term barrier integrity under anticipated CO_2 conditions at and near the Injection Zone, modifications have been made to the slurry design(s) which improve chemical and mechanical resistance to the effects of carbonic acid exposure. These are and will be referenced as '*CO_2 Resistant Slurries*.' The modifications, while may vary slightly due to well conditions, formation pressures and strengths, etc. all contain the following composition adjustments when compared to conventional and/or ordinary Portland cement (OPC).

Additional discussion about the cement selection and additives is in Appendix B

Table 21—Cementing Program for BRP CCS1

Section	Type	Depths (ft)	Density (ppg)	Sacks	Excess
20 in	concrete blend	0 to 120	-	474	100%
17 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 1,300	12.5-13.0	960	100%
	OPC (Ordinary Portland Cement) with additives	1,300 to 1,800	14.5-15.0	510	100%
12 ¼-in.	OPC (Ordinary Portland Cement) with additives	0 to 3,300	11.5-12.5	1147	100%
	OPC (Ordinary Portland Cement) with additives	3,300 to 3,800	14.0-15.0	244	100%
8 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 3,600	13.0-13.5	553	0%
	Class C reduced Portland content with additives (pozzolan, fly ash, silica sand/flour)*	3,600 to 6,270	13.0-14.5	492	20-30%

Table 22—Cementing Program for BRP CCS2

Section	Type	Depths (ft)	Density (ppg)	Sacks	Excess
20 in	concrete blend	0 to 120	-	474	100%
17 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 1,300	12.5-13.0	960	100%
	OPC (Ordinary Portland Cement) with additives	1,300 to 1,800	14.5-15.0	510	100%
12 ¼-in.	OPC (Ordinary Portland Cement) with additives	0 to 3,300	11.5-12.5	1147	100%
	OPC (Ordinary Portland Cement) with additives	3,300 to 3,800	14.0-15.0	244	100%
8 ½ -in.	OPC (Ordinary Portland Cement) with additives	0 to 3,600	13.0-13.5	553	0%
	Class C reduced Portland content with additives (pozzolan, fly ash, silica sand/flour)*	3,600 to 9,260	13.0-14.5	1043	20-30%

Table 23—Cementing Program for BRP CCS3

Section	Type	Depths (ft)	Density (ppg)	Sacks	Excess
20 in	concrete blend	0 to 120	-	474	100 %
17 ½ -in.	Class C cement with additives	0 to 1,300	12.5-13.0	960	100%
	Class C cement with additives	1,300 to 1,800	14.5-15.0	510	100%
12 ¼-in.	Class C cement with additives	0 to 3,300	11.5-12.5	1147	100%
	Class C cement with additives	3,300 to 3,800	14.0-15.0	244	100%
8 ½ -in.	Class C cement with additives	0 to 3,600	13.0-13.5	553	0%
	Class C reduced Portland content with additives (pozzolan, fly ash, silica sand/flour)*	3,600 to 6,578	13.0-14.5	598	20-30%

Notes:
- The slurry design might change in density, excess, and volumes once the conditions of the well are known after drilling.
- A staged cementing job is proposed to ensure good cement to the surface and excellent cement bonding across the Injection, Upper Confining, and USDW zones.

4.6. Mud Program

Table 24--Mud Program for BRP CCS1

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lbm/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½ -in	Fresh water gel	0 to 1,800	8.5 to 9.5	12 to 14	14 to 18	40 to 50	<20	<8
12 ¼-in	Fresh gel mud/ Brine water inhibited	0 to 3,800	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3
8 1/2-in	Brine water inhibited	3,800 to 6,270	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3

Table 25--Mud Program for BRP CCS2

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lbm/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½ -in	Fresh water gel	0 to 1,800	8.5 to 9.5	12 to 14	14 to 18	40 to 50	<20	<8
12 ¼-in	Fresh gel mud/ Brine water inhibited	0 to 3,800	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3

8 1/2-in	Brine water inhibited	3,800 to 9,260	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3

Table 26--Mud Program for BRP CCS3

Hole	Type	Depths (ft)	Density (ppg)	PV (cP)	YP (lbm/ 100 ft^2)	Funnel Viscosity (sec)	API Fluid Loss (cm^3)	LGS (%)
17 ½ -in	Fresh water gel	0 to 1,800	8.5 to 9.5	12 to 14	14 to 18	40 to 50	<20	<8
12 ¼-in	Fresh gel mud/ Brine water inhibited	0 to 3,800	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3
8 1/2-in	Brine water inhibited	3,800 to 6,578	9.5 to 10.2	14 to 18	16 to 18	40 to 50	<6	<3

5.0 Data Acquisition and Testing Plan Summary

Comprehensive details on pre-operational testing are provided in the Pre-Operational Testing Plan that is part of this application. The information below summarizes key components of the plan.

The CO_2 Injection well testing program is designed to obtain the chemical and physical characteristics of the Injection and Upper Confining zone(s). This program includes a combination of logging, sidewall coring, formation hydrogeologic testing, and other activities performed during the construction of the CO_2 injection wells.

This pre-operational testing program will determine or verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the Injection Zone, the overlying Upper Confining Zone, and other relevant geologic formations. In addition, formation fluid characteristics of the Injection Zone will be obtained to establish baseline data against which future measurements may be compared after the start of injection operations. Table 27 lists the wireline logs and tests proposed for the BRP CCS1, BRP CCS2, and BRP CCS3. Consult Table 14 of the Pre-Operations Plan or Table 6 in the QASP for details on fluid analyses.

Table 27—Wireline Logs and Tests in the CO_2 injector wells

Method	Interval Section(s)	Purpose
Open Hole Logs, Surveys and Sampling During Construction		
Deviation survey	Every 100 ft while drilling as minimum, from surface to TD	Define well trajectory, displacement, and tortuosity
Wireline- Spontaneous Potential	Surface, Intermediate, Production	Correlation log, volume of shale indicator, estimate salinity
Wireline – Resistivity	Surface, Intermediate, Production	Fluid identification, estimate salinity, correlation log
Wireline – Caliper	Surface, Intermediate, Production	Identify borehole enlargement and calculate cement volume
Wireline -Gamma ray	Intermediate, Production	Define stratigraphy, correlation log, shale indicator
Wireline -Magnetic resonance image	Production	Estimate porosity, pore size distribution, permeability index
Wireline -Sonic Scanner	Intermediate, Production	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline - Spectral gamma ray	Intermediate, Production	Define uranium rich formation, clay indicator
Wireline - Density / neutron	Intermediate, Production	Estimate porosity, mineralogical characterization
Wireline -High-definition image	Production	Identify fracture, structural information, minimum stress orientation
Wireline - Litho-scanner or an equivalent Elemental Capture Spectroscopy	Production	Identify mineralogy
Wireline - Formation Dynamics Testing	Production	Measure formation pressures, fluid sampling, mini-frac testing
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition
Cased Hole Logs and surveys Before Injection		
Wireline - CBL-VDL-USIT-CCL	Surface, Intermediate, Production	Cement bond, casing integrity. Validate external mechanical integrity
Annulus Pressure Test - Long string casing	Annular between tubing and long string	Validate internal mechanical integrity between the tubing, long-string, and packer
Wireline - Activate pulsed neutron – Long string casing	Surface, Intermediate, Production	CO_2 saturation, baseline for monitoring
Wireline - Temperature Log	Surface, Intermediate, Production	Measure baseline temperature profile on the well from surface to top of perforation
Fiber Optic - DAS, DTS survey	Surface, Intermediate, Production	Measure baseline temperature profile on the well from surface to top of perforation. Acquire baseline 3D VSP survey for monitoring plume migration over time

In addition to the logging and testing listed above, OLCV will perform mini-fracs in distinct porosity / permeability packages within the proposed Injection Zone and Upper and Lower Confining Zones. Thin intervals that are interpreted to have limited horizontal extent will not be tested. The interval for mini-frac will be selected upon review of logging data. The Fracture Extension Pressure will be interpreted by qualified OLCV reservoir and completions engineers to determine injection limits throughout the Injection Zone.

In addition to Mini-fracs, the Project will utilize the MDT tool to collect reservoir pressures and acquire fluid samples in the Injection Zone. Based on data from the Shoe Bar 1 and Shoe Bar 1AZ, OLCV anticipates encountering three distinct porosity zones. OLCV will collect fluid samples in each of these porosity zones. The final sampling depths will be selected after reviewing logs for the specific Injector well. The fluid and dissolved gas samples will be transported under pressure to a third-party lab for comprehensive analysis. See Table 14 in the Pre-Operational Testing Plan or Table 6 in the Quality Assurance and Surveillance Plan for details on the analytical program for fluids and dissolved gasses.

Fluid level testing will be conducted following well completion. The test will measure static fluid level using an echometer. See Section 3.12 of the Pre-Operations plan for details on the echometer tool.

An injection test will be performed in the Lower San Andres after the injection well is complete, including perforation of the Injection Zone and installation of the injection tubing and packer. The pre-operation injectivity testing will serve as the baseline for future pressure fall-off testing. The purpose of conducting an injectivity test is to verify or establish the injection well operating parameters and constrain the inputs used for dynamic injection simulation modeling.

The injection testing will comprise of a period (typically 12-24hrs) of injection at constant rate (typically 0.5-2bpm) subject to a maximum bottom pressure (less than the estimated fracture gradient for the perforated interval). This is followed by a shut-in/pressure fall off period (typically 24-48hrs) for monitoring. The injection period will be used to establish/monitor well injectivity performance and the fall off analysis will indicate the well/reservoir flow regime, average reservoir flow characteristics and the presence (if any) of reservoir baffles/boundaries/interwell interference. The tests will be planned to cover the entire perforated interval of the injector well. Injection profile logs will be run if needed to monitor the distribution of fluid and check of out of zone injection/non-contributing layers.

The results of the testing program will be documented in a report and submitted to the US Environmental Protection Agency (EPA) after the well construction and testing activities have been completed, but before the start of CO_2 injection operations.

The permittee shall submit to the Program Director for review all pre-injection testing procedures for logging, sampling, and testing, as required by 40 CFR §146.87. This information, along with the schedule for such testing, shall be submitted no later than 30 days before performing the first test. The permittee shall submit any changes to the schedule 30 days before the next scheduled test, and testing shall not proceed without the Program Director's approval of the schedule.

6.0 Demonstration of Mechanical Integrity and Baseline for Monitoring

Table 28 below summarizes the tests that will be conducted at the injection well before the start of injection to prove mechanical integrity.

Table 27—Summary of Pre-Injection Testing at Injection Well Site

Test	Comments
Annulus pressure test	MIT – Internal
CBL-VDL-USIT-temperature log	MIT – External
Pressure fall-off test	Formation and well testing
Leak-off test	Fracture gradient / MASP
Pulsed neutron (through tubing)	Baseline for CO_2 saturation
CIL electromagnetic (through tubing)	Baseline

Notes:
- CIL: Casing Inspection Log
- Details for the tests and procedures are described in the QASP attachment to this permit.

7.0 Blowout Preventer and Wellhead Requirements

7.1 Blowout Preventer Equipment (BOPE)

- BOPE shall be API-monogramed and adhere to API Standard 53 and Specifications 16A and 16C at a minimum and shall meet or exceed all applicable regulatory specifications.
- BOPE other than annular preventers shall have a minimum working pressure exceeding the maximum anticipated surface pressure (MASP).
- All BOPE stacks shall incorporate a set of blind rams.
- Blind rams shall be located in the lower ram cavity of a two-ram stack or the middle ram cavity of a three-ram stack.
- Choke and kill line outlets shall be located below the blind rams on either a two-ram or three-ram stack.
- All rigs shall have a calibrated trip tank. The trip tank and trip sheet are used to measure the fluid required to fill or displace fluid from the hole during all tripping operations, including when running the casing or completion string. Trip sheets shall include the number of joints or stands run into or pulled from the hole vs. the calculated and actual displacements per step and a running total as a minimum.
- A full-opening safety valve (FOSV) and an inside-BOP safety valve (IBOPSV) shall be always available on the rig floor for each drill pipe and drill collar size and connection type in use. The FOSV is used to stab into the string and shut off flow through the drill string. The IBOPSV is used above the FOSV to prevent backflow through the drill string. These valves shall remain in the fully open position until installed. **Note:** This requirement is in addition to any integral safety valve in the top drive system inclusive of casing running operations. In the event of a power failure on a

variable frequency drive (VFD) rig, it is impossible to slack off and make up the top drive to the string; therefore, there is a need for additional independent stabbing valve(s) to be available on the floor always.

- If a wireline lubricator is utilized for wireline operations, it shall not be the type that slips into and is held by the annular preventer or rams. A hydraulic cutter or other means of safely cutting the wireline shall be available if a lubricator is not in use.
- Pressure-energized metal ring gaskets shall be used on flanged well-control equipment. These gaskets shall not be reused on equipment that will be nippled-up on the wellbore.

7.2 Choke Manifolds and Kill Line

- The choke manifold shall be API-monogrammed, meet API SPEC 16C as a minimum, and meet or exceed all applicable regulatory specifications.
- All BOPE shall include a choke manifold with at least one remotely operated choke and one manual choke installed. The control panel shall contain calibrated drill pipe and casing pressure gauges that shall be both accurate and properly maintained. The choke manifold casing pressure should have the capability of being recorded on the drilling rig's recorder. If necessary, for clear dialogue, an electronic means of direct communication with the driller should be in place. This equipment shall be tested and its calibration checked at each casing shoe and at every BOPE test, and results shall be logged on every BOPE test report.
- Flare / vent lines shall be as long as practical, a minimum of 150 ft from the well center, as straight as possible, without sumps, collection areas, or uphill flow areas (to prevent fluid buildup and resulting backpressure) and shall be securely anchored.

7.3 Closing Units

- BOPE closing units shall adhere to API Spec 16D and API STD 53 as a minimum and meet or exceed all applicable regulatory specifications.
- BOPE control systems shall include full controls on the closing unit and at least one remote control station. One control station shall be located within 10 ft of the driller's console.
- BOPE closing units shall have two separate charging pumps with two independent power sources, as specified in API Spec 16D, or have nitrogen bottle backup.
- When pumps are inoperative, BOPE closing units shall have sufficient usable hydraulic fluid volume to close one annular preventer, close all ram preventers, and open one HCR valve against zero wellbore pressure with 200 psi remaining pressure above the pre-charge pressure.

7.4 Pressure Testing

- BOPE components (including the BOP stack, choke manifold, and choke lines) shall be pressure tested at the following frequency:
    - When installed. If the BOPE is stump tested, only the new connections are required to be tested at installation.
    - Before 21 days have elapsed since the last BOPE pressure test. When the 21-day test is due soon, consider testing the BOPE prior to drilling H_2S, abnormal pressure, or any lost return zones to avoid having to test while drilling these intervals.
    - Anytime a BOPE connection seal is broken, the connection shall be pressure tested after reassembly and before use.
    - When utilizing tapered strings, variable bore-type rams and annular preventers shall be pressure tested with all tubing or drill pipe sizes anticipated to be used.
- BOPE shall be tested using a test plug or other means to isolate the casing and open hole from the test pressures. The casinghead valve shall be opened and monitored to avoid exerting BOPE test pressure on the casing or open hole.
- BOPE components shall first be low-pressure tested to between 250 and 350 psi. If the pressure exceeds 350 psi during this test, the pressure shall be bled off to 0 psi and the test restarted. Pressuring up beyond 350 psi can induce a seal and give a false test result.
- BOPE components, excluding the annular preventer, shall be tested to the lesser of rated working pressure (RWP) or wellhead RWP if less than BOPE RWP. The annular preventer shall be tested to 70% of its RWP. In all cases, the test pressure shall not exceed the RWP of any of the components being tested.
- Use of a cup tester should be avoided. If a cup tester is utilized for BOP testing, consideration shall be given to casing burst pressure and possible pressure applied to the casing string or open hole below the cup tester in the event of a leaking cup tester.
- An accumulator closing test shall be performed after the initial nipple-up of the BOP, after any repairs that required isolation or partial isolation of the system, or at initial nipple-up on each well.
- During drilling, the pipe rams shall be functionally operated at least once every 24 hours. The blind rams shall be functionally operated each trip out of the wellbore.

7.5 Wellhead Schematic

Figure 8 below is a schematic diagram of the wellhead to be used for the BRP CCS1, BRP CCS2 and BRP CCS3 wells.

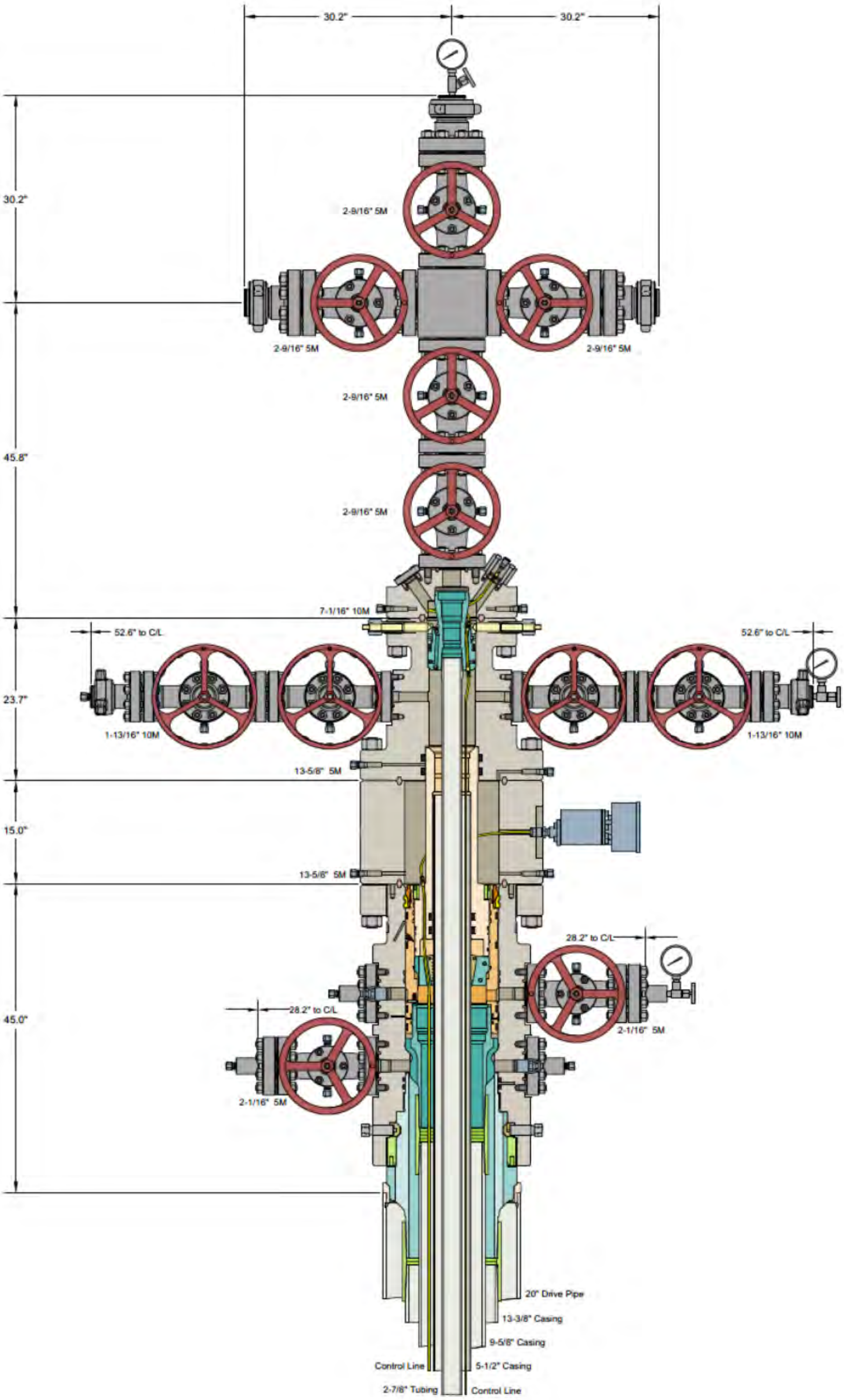

Figure 8—Schematic diagram of BRP CCS1 and BRP CCS2 wellhead

INJECTION WELL STIMULATION PLAN
40 CFR 146.82(a)(9)

BRP CO_2 Sequestration Project

INJECTION WELL STIMULATION PLAN 40 CFR 146.82(a)(9) 1
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3.2 Diverters 3
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1.0 Facility Information

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS 1, 2 and 3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

2.0 Introduction and Purpose

Oxy Low Carbon Ventures (OLCV) may stimulate the injection zone for the Brown Pelican (BRP) Project to enhance the injectivity potential of CO_2 injection wells and the productivity of water withdrawal wells. Stimulation may involve, but is not limited to, flowing fluids into or out of the well, increasing or connecting pore spaces in the injection/production formation, or other activities that are intended to allow CO_2 to move more readily into the injection zone and for the water to be more efficiently produced.

OLCV will adhere to all applicable regulatory requirements for any stimulation treatment that may be required. Specifically, and without limitation, OLCV will comply with the following:

- 40 CFR 146.82(a)(9): OLCV will submit the proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment.
- 40 CFR 146.88(a): Except during stimulation, OLCV will ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zones(s). In no case will injection pressure initiate fractures in the confining zones(s) or cause movement of injection or formation fluids that endanger a USDW.
- 40 CFR 146.91(d)(2) and (e): OLCV will notify the Director in writing 30 days in advance of any planned stimulation activities, other than stimulation for formation testing conducted under 40 CFR 146.82. Regardless of whether a state has primary enforcement responsibility, OLCV shall submit all required reports, submittals, and notifications under subpart h of this part to EPA in an electronic format approved by EPA.

The information provided in this section specifically addresses the stimulation fluids, additives, and proposed stimulation procedures OLCV may implement. This plan includes multiple stimulation methodologies that may be selected based on site-specific technical and operational conditions that may impact future well performance. The methods provided below may also be used to remediate scaling or perforation occlusion in the well.

2.1 Purpose of Stimulation

Perforated intervals in the Lower San Andres CO_2 injection / water production zone may require stimulation periodically throughout the project life to enhance performance with the aim to restore it to initial or optimum conditions. For example, stimulation may be needed to remediate injectivity loss resulting from mineral scales, clay fragments, metallic sulfide, or oxide particulates. Stimulation may also be necessary to remove any near-wellbore damage resulting from drilling and completion operations. Following well construction, remedial stimulation may be conducted before the commencement of CO_2 injection or water withdrawal.

3.0 Stimulation Fluids

At BRP, OLCV will use acid blends for matrix stimulation that are typical for the industry. These include, but are not limited to, mixtures of acetic, hydrochloric, hydrofluoric, and/or other organic acids. These blends have been historically proven to remove near-wellbore damage caused by mineral scales, drilling muds, completion fluids, and clay fines while minimizing negative impacts to permeability. There is also a potential for near-wellbore halite precipitation in the CO_2 injectors, which may require remediation by periodic flushes with less saline water.

All chemical treatments will be evaluated and selected for compatibility with the treatment method. For example, mineral acids will be treated with chemical inhibitors to prevent corrosion damage to the tubing string. In addition, chemical systems will be evaluated and selected to avoid damage to the down hole packer sealing elements, casing, and other seals within the injection system that might be exposed to the chemicals.

3.1 Additives

Additives may be utilized with the stimulation fluids to aid matrix stimulation while mitigating corrosion of tubulars and potential damage to the sequestration zone. These additives include, but are not limited to, corrosion or acid inhibitors, scale inhibitors, clay stabilizers, biocides, demulsifiers, chelating agents, mutual solvents, iron sequestrants, retarders, and/or surfactants. Compatibility of these additives with the stimulation fluids, tubulars and the reservoir will be confirmed prior to their use in any stimulation activities.

3.2 Diverters

Nitrogen or CO_2 may be added to stimulation fluids to achieve improved diversion and effective treatment for the target zone by diverting the stimulation fluids to the most impaired (*i.e.*, low injectivity/productivity) perforations. Depending on the well-specific requirements and stimulation design, organic or polymeric diverting agents may also be selected. These diverters provide temporary restrictions during stimulation operations and degrade or break-down with time due to water solubility and temperature.

The most suitable diverting agent will be selected based on one or more factors, including, anticipated pump rates, the length of the perforated interval, perforation density, and the selected technique for conveying acid to the injection zone (*e.g.*, pumping through regular tubing or pumping down coiled tubing).

4.0 Mechanical Stimulation

In addition to chemical stimulation, mechanical stimulation of the well may be required independently, or in conjunction with chemical stimulation. Mechanical stimulation may be required if there is deposition that cannot be easily remediated with chemicals, or if mechanical means may be more effective. These mechanical options include, but are not limited to, backflow, adding perforations, or re-perforating. Perforating operations may be further enhanced with the use of propellants. Propellant stimulations will be designed for nominal height growth, and to remain within the injection zone and avoid fracture growth into the confining layer (Wieland, 2006).

5.0 Ensuring Containment

Except during stimulation, injection pressure will not exceed 90% of the established fracture pressure for the injection zone. Injection pressure at the downhole tubing pressure gauge and tubing/annulus surface gauges will be continuously monitored during the stimulation operation.

Stimulation of the injection interval will be conducted to avoid affecting the confining layers. Perforations in the injection zone will be vertically separated from the base of the confining layers by a minimum of 10 feet. Chemicals injected into perforations in the injection zone will not come into contact with the confining layers.

6.0 Standard Stimulation Procedure

If injection rates decline below expected values at any time during the project life, OLCV may investigate the cause to determine whether stimulation may be required. Investigation activities may include, without limitation, the following:

- Logging operations, including but not limited to, evaluation of the injection/production profile, mechanical spinner surveys, caliper logging, downhole camera investigation, etc.
- Collecting downhole samples when necessary or feasible with wireline, slickline or coiled tubing conveyed sampling equipment, to be followed by analytical testing as appropriate to determine remediation options.

A standard stimulation procedure is outlined below. This procedure may be modified depending on site-specific operational and technical conditions and the specific treatment requirements. The conveyance methods may include coil tubing, tubing-conveyed retrievable straddle packer assembly, snubbing unit, tubing flush, or bullheading.

1. Test the potential stimulation fluids blends for compatibility with well materials, reservoir rock, and fluids.
2. Design the stimulation program.
3. Provide the recommended work procedure and stimulation program to the UIC Program Director in writing at least 30-days prior to the planned date for start of the work (40 CFR 146.91(d)(2)).
4. Perform pre-job planning.
5. Discuss job safety and monitoring assignments.
6. Prepare the location for rig up of stimulation equipment.
7. Shut-in the injection or water withdrawal well, allowing the pressures to stabilize at the well and for other wells and the facility to absorb rate and pressure changes.

8. Rig up the stimulation well intervention equipment.
9. Prepare the well for stimulation.
10. Perform the matrix stimulation as specified in this plan.
11. Flush the wellbore with treated water and prepare the well to return to normal operation.
12. Rig down and return the well back to injection or water production.

A similar procedure would be utilized for flowbacks with prior operation-specific planning for well control as well as other job-specific safety and environmental protection control practices.

7.0 References

Wieland, C. W., Miskimins, J. L., Black, A. D., and S. J. Green. "Results of a Laboratory Propellant Fracturing Test in a Colton Sandstone Block." Paper presented at the SPE Annual Technical Conference and Exhibition, San Antonio, Texas, USA, September 2006.

Well Construction Appendices

(submitted as wholly redacted)

FINANCIAL ASSURANCE DEMONSTRATION PLAN
40 CFR 146.82(a)(14) and (19), 146.85

Brown Pelican CO_2 Sequestration Project

1.0 Facility Information and Overview 1
2.0 Activities Requiring Financial Assurance 2
3.0 Instruments to Meet Financial Responsibility 2
4.0 Cost Estimate for Activities Covered by Financial Responsibility 2

1.0 Facility Information and Overview

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS 1, CCS2 and CCS 3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

The matter of financial assurance demonstration is relevant to the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H - Criteria and Standards applicable to Class VI Wells. The main topics covered in this document are activities requiring financial assurance, instruments to meet financial responsibility, and the plan to be implemented by Oxy Low Carbon Ventures, LLC ("OLCV") for the Brown Pelican CO_2 Sequestration Project ("BRP Project" or "Project").

2.0 Activities Requiring Financial Assurance

Pursuant to 40 CFR 146.85, OLCV, is required to demonstrate financial ability to successfully complete all the tasks associated with performing corrective action, plugging injection and monitoring wells, post-injection site care, site closure, and implementation of an emergency remedial response plan as specified in Table 1.

Table 1—List of Project activities that require Financial Assurance

Activity	Period of Performance
Performing corrective action	As needed
Plugging injection and monitoring wells	One time
Post-injection site care	Throughout the post-injection phase
Site closure	One time
Emergency/remedial response	As needed

3.0 Instruments to Meet Financial Responsibility

OLCV has reviewed the extensive guidance, research, and analysis documents published by the EPA and proposes to utilize a letter of credit to demonstrate financial responsibility for all activities requiring financial assurance. The letter of credit will be issued by [redacted] that has (a) assets of at least Ten Billion Dollars ($10,000,000,000) and (b) has a Long-Term Credit Rating of at least "A-" by S&P and at least "A3" by Moody's The letter of credit will require the issuing institution to provide notice if it does not plan to reissue the letter of credit and will include a provision for automatic renewal. OLCV will establish a standby trust fund in accordance with EPA's guidance to receive any funding necessary to address the cost of covered activities. OLCV may change the instrument(s) used to demonstrate financial assurance in accordance with 40 CFR 146.85.

4.0 Cost Estimate for Activities Covered by Financial Responsibility

In accordance with 40 CFR 146.85 *et seq.* and 16 TAC 5.205 (c)(2)(C)(i), the cost estimates must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities.

For future activities related to plugging injection wells, post injection site care, and site closure, OLCV applied a discounted rate of 2.341 percent to discount those future cost estimates to today's dollars. The discount rate was calculated using a 15-year historical average of the Consumer Price Index for All Urban Consumers (CPI-U).

OLCV will provide financial assurance sufficient to cover the costs identified in Table 2. Costs are in 2024 $USD. A detailed cost estimate is included as a separate document PBI_FA_BRP_COST_EST_V3_2024.pdf.

Table 2—Cost Estimate for Activities Covered by Financial Assurance

Activity	Cost (Millions of $USD); Discounted
Performing corrective action	1.57
Plugging injection wells	0.41
Post-injection site care	5.96
Site closure	2.05
Emergency/remedial response	2.06

4.1 Performing Corrective Action

Three wells within the Area of Review (AoR) were determined to require corrective action. OLCV will conduct corrective action on: Eidson-E-1 (API 4213531130), Scharbauer Eidson-1 (API 4213510667) and Eidson Scharbauer-1 (API 4213506139) prior to commencement of CO_2 injection operations. Details of the corrective action plan are found in Section 5 of the Area of Review and Corrective Action Plan documents of this permit application.

4.2 Plugging Injection Wells

Details of the well plugging plan are found in the Plugging Plan document of this permit application.

4.3 Post-Injection Site Care

Details of the post-injection site care plan are found in the Post Injection Site Care and Site Closure Plan document of this permit application. Post-injection site care costs were estimated from cessation of injection to site closure and account for seismic studies at five-year intervals, maintenance of the wells until closure, and monitoring the site to ensure protection of the USDW. Site closure costs include plugging monitoring wells, removal of surface facilities, and reclamation of the site.

4.4 Site Closure

Details of the site closure plan are found in the Post Injection Site Care and Site Closure Plan document of this permit application.

Surface infrastructure removal and restoration scope is included in the Site Closure and includes such items as:

- CO_2 pipeline abandonment and right-of-way restoration
- Water pipeline abandonment and right-of-way restoration
- Removal of pipeline valve stations
- Removal of surface facilities including pig traps, meters, monitors, etc.
- Restoration of well pads
- Removal of electrical infrastructure such as de-commissioned powerlines and communications panels

4.5 Emergency and Remedial Response

Details of the emergency and remedial response plan are found in the Emergency and Remedial Response plan document of this permit application.

Explanation of Cost Estimates

The instrument values included in this document are based upon cost estimates by the BRP Project team with input cost data from third party service providers. Cost estimates were provided during the permit application process. If the cost estimates change during the permitting process or the life of the Project, OLCV will adjust the value of the financial instruments.

The BRP Project uses a Carbon Capture and Storage stochastic Monte Carlo model that has been tailored to reflect site-specific factors for emergency and remedial response actions. This estimation approach is consistent with the U.S. EPA's Underground Injection Control (UIC) Program's Class VI regulatory requirements and is intended to inform the face value of financial assurances for the Brown Pelican site. The estimation method is based on the peer-reviewed approach developed by the BRP Project's third-party consultants and has been used to inform estimation of coverage amounts for emergency and remedial response in previously approved Class VI permits. Specifically, the model's input parameters reflect the geologic location and specific chemical composition of the Project's CO_2 injectate stream, as well as site-specific conditions that exist within the established area of review. The analysis adopts several conservative input assumptions and incorporates probabilistic calculations that allow for multiple release incidents across geologic sequestration activities – from injection through post-injection site care to site closure. The resulting coverage values are based on generally accepted response actions commonly used to respond to contamination incidents that could impair the public's ability to safely access Underground Source(s) of Drinking Water (USDWs).

A model run of 50,000 Monte Carlo trials yields an upper-bound coverage estimate to satisfy emergency and remedial response of approximately $2.06 million in current 2024 dollars.
This upper-bound estimate reflects the single Monte Carlo trial with the greatest estimate of emergency and remedial response costs out of the 50,000 trials run (comprising four separate ERR actions over the 62-year combined duration of injection and post-injection site care periods). The estimates specifically account for an array of possible risk events of potential concern at CCS sites, including undocumented deep well leaks, CO_2 injection well leaks, CO_2 monitoring well leaks, rapid leakage through the caprock, slow leakage through the caprock, releases through an existing fault, releases through an induced fault, leakage through caprock/faults then a shallow well and pipeline release events. These estimates are reasonable and appropriately conservative, in keeping with the recommendations set forth in EPA's financial assurance guidance for Class VI wells.

Financial Assurance Appendices

(submitted as wholly redacted)

Financial Assurance Cost Estimates

(submitted as wholly redacted)

Plan revision number: 3
Plan revision date: 07/30/2024

PRE-OPERATIONAL PLAN
40 CFR §146.82

Brown Pelican CO_2 Sequestration Project

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Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS1, BRP CCS2 and BRP CCS3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

1. Introduction / Purpose

The Brown Pelican CO_2 Sequestration Project (BRP Project or Project) includes participation of multidisciplinary teams from Occidental Oil & Gas Corporation (Oxy), parent company of Oxy Low Carbon Ventures (OLCV) consultants, and subcontractors. Each team will provide technical expertise and economic inputs to the Project to ensure a safe, successful, and efficient operation.

The testing activities described in this document are restricted to drilling, testing, and completing wells during the Pre-Injection phase. Testing and monitoring activities during the Injection and Post-Injection Site Care phases are described in the Testing and Monitoring Plan, along with other non-well related pre-injection baseline activities, such as geochemical monitoring.

The pre-injection operational testing plan described in this document is designed to meet the testing requirements of Title 40 of the U.S. Code of Federal Regulations Section §146.87 (40 CFR §146.87) and the well construction requirements of 40 CFR §146.86.

The pre-operational testing program will utilize a combination of open and cased hole logging, coring, fluid sampling, and formation hydrogeologic testing to determine and verify the depth, thickness, mineralogy, lithology, porosity, permeability, and geomechanical information of the Injection Zone, confining zones, and other relevant geological formations.

All pre-injection testing procedures for logging, sampling, and testing, as required by 40 CFR §146.87, will be submitted to the Underground Injection Control Director for review. The results of the testing activities will be documented in a report and submitted to the US Environmental Protection Agency (EPA) after the well drilling and testing activities have been completed, but before the start of CO_2 injection operations.

The BRP Project will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notice and the opportunity to witness these tests/logs shall be provided to the EPA at least 48 hours in advance of a given test/log.

A table of the wells described in this document is shown below (Table 1). A summary of pre-operational data collected or planned for collection is presented in Table 2.

Table 1--Summary of wells drilled/planned for the BRP Project

Regulatory Well Name	Project Well Name	Drill Date	Purpose	Latitude (NAD 27)	Longitude (NAD 27)
Shoe Bar 1	SLR1	2023	Stratigraphic test well; to be converted to SLR1	31.76343602	-102.7034981
Shoe Bar 1AZ	ACZ1	2023	Stratigraphic test well	31.76448869	-102.7305326
Shoe Bar 1USDW	USDW1	2023	Monitor lowermost USDW	31.76411900	-102.7316750
Shoe Bar 2SLR	SLR2	2025*	Monitor Injection Zone	31.74670102	-102.7259011
Shoe Bar 3SLR	SLR3	2030*	Monitor Injection Zone	31.78023685	-102.7418093
Shoe Bar 1CCS	BRP CCS1	2024*	CO_2 Injector	31.76479314	-102.7289311
Shoe Bar 2CCS	BRP CCS2	2024*	CO_2 Injector	31.76993805	-102.7332448
Shoe Bar 3CCS	BRP CCS3	2024*	CO_2 Injector	31.76031163	-102.7101566
Shoe Bar 1WW	WW1	2024	Brine water withdrawal	31.76289539	-102.6959232
Shoe Bar 2WW	WW2	2024	Brine water withdrawal	31.78419981	-102.7275869
Shoe Bar 3WW	WW3	2024	Brine water withdrawal	31.75008553	-102.7102206
Shoe Bar 4WW	WW4	2024	Brine water withdrawal	31.76384464	-102.7539505

*Anticipated drill timing

Table 2--Summary of data acquired or planned for wells in the BRP Project

	Basic Log Suite	Advanced Logging Suite				Core Acquisition		Formation Testing				Formation Fluid Sampling		Mechanical Integrity Testing	Plume Monitoring
	GR, SP, NPHI, RHOB, SGR, RES, PEF	ECS	NMR	FMI	Dipole Sonic	Whole Core	Sidewall Core	MDT - Pressure	Mini-Frac	SRT	PFOT	MDT	Downhole Fluid Sampling	Isoscanner/USIT /CBL-VDL	Pulsed Neutron Logging
Shoe Bar 1 (SLR1)	1	1	1	1	1	1	1	1	1	1	1	1	2, 3	1, 2	1, 2, 3
Shoe Bar 1AZ (ACZ1)	1	1	1	1	1	1	1	1		1	1	1	2, 3	1, 2	1, 2, 3
BRP CCS1	1	1	1	1	1			1	1		2	1		1	
BRP CCS2	1	1	1	1	1			1	1		2	1		1	
BRP CCS3	1	1	1	1	1		1	1	1		2	1		1	
USDW1	1												2, 3	1, 2	1, 2, 3
SLR2	1				1			1				1	2, 3	1, 2	1, 2, 3
SLR3	1				1			1				1	2, 3	1, 2	1, 2, 3
WW1	1				1			1				1	2, 3	1, 2	1, 2, 3
WW2	1				1			1				1	2, 3	1, 2	1, 2, 3
WW3	1				1			1				1	2, 3	1, 2	1, 2, 3
WW4	1				1			1				1	2, 3	1, 2	1, 2, 3

Notes: Summary of logging, coring, MIT, formation testing and sampling in the wells at BRP Project. The numbers indicate the phase of the Project the data will be acquired: 1 – During Construction, 2 – During Injection, 3 – During Post-Injection

1.1 Overview of Logging Suite(s)

A brief description of the logging tools that will be run during construction summarized in Table 2 is documented below.

- Basic log suite: A triple combo with spectral gamma ray will be the basic log suite that will be run in all the wells in the BRP Project. The measurements obtained include Gamma Ray (Total and Spectral), Spontaneous Potential (SP), Neutron Porosity (NPHI), Bulk Density (RHOB), Resistivity (RES), and Photoelectric Factor (PEF). The combination of these log measurements enables interpretation and quantification of key petrophysical properties such as porosity, mineralogy, fluid saturations with a high degree of resolution and accuracy.

- Advanced log suite(s)

    - Elemental Capture Spectroscopy (ECS): This tool is used to quantify elemental dry weight concentrations of key elements such as Calcium, Magnesium, Silicon, Sulfur, Iron, and others. This data can then be used to determine detailed mineralogy. The Lithoscanner tool (from Schlumberger) is an example of such a tool.

    - Nuclear Magnetic Resonance (NMR): NMR tools can quantify porosity, pore size distribution, bound and free fluid volumes and provide estimation of permeability, from which injectivity can be interpreted.

    - Formation Micro-Imager (FMI): This tool when run can generate precisely oriented false-color image of the formation at a 5mm resolution based on an array of micro-resistivity sensors. From these images geoscientists can identify bedding, sedimentary structures, diagenetic features, and tectonic features such as fractures, faults, folds, as well as mechanically induced features from drilling processes like breakouts and/or induced fractures. The orientation (e.g., dip and strike) of any feature observed in the image can also be precisely quantified.

    - Modular Formation Dynamics Tester (MDT): A mission-configurable, modular platform consisting of a series of reservoir interfaces (single-packer, dual-packer, or probe types), a downhole pump, a suite of real-time measurements to identify and quantify properties of fluid in the tool flowline, and various sizes and types of fluid sampling chambers. The principal sequestration project applications are to measure formation water mobility, to capture representative formation water samples (in both USDWs and Injection Zones), and to perform direct in-situ measurements of fracture breakdown pressure and closure pressure (in both Confining Zones and Injection Zones) by pumping fluid into a ~3ft interval isolated by inflatable dual packers.

- Dipole Sonic: These tools quantify the slowness of various acoustic wave modes in the formation, including compressional, fast, and slow shear, horizontal shear, and Stoneley. These measurements provide the starting point for a continuous 1D mechanical earth model (MEM) including interpreted formation properties such as Young's Modulus, Poisson's Ratio, Unconfined Compressive Strength (UCS), and tensile strength. The data can also be used to interpret principal stress magnitudes and orientation. The Sonic Scanner tool (from Schlumberger) is an example of such a tool.

- Sidewall Coring Tool: These tools such as XLRock (from Schlumberger) use a hydraulic-powered rotary drilling assembly that cuts and retrieves a core sample from the borehole wall measuring 1.5" in diameter and up to 3" in length. The samples are suitable for all types of routine core analysis (RCA) as well as a broad portfolio of special core analysis (SCAL) measurements appropriate for CCS projects in both Confining Zones and Injection Zones.

2. Stratigraphic Wells

2.1 Overview of Stratigraphic Wells

The Shoe Bar 1 and Shoe Bar 1AZ stratigraphic wells were drilled in 2023 to provide site-specific characterization data for the BRP site. The Shoe Bar 1AZ is located within the proposed AoR, close to the locations in proposed Injector wells. Core data collected in the Shoe Bar 1AZ is representative of the subsurface at the locations of proposed future injectors BRP CCS1 and BRP CCS2, which will be located less than 2,000 ft around Shoe Bar 1AZ (see additional details in Pre-Operational Plan Appendix A). The Shoe Bar 1 is located in the easternmost extent of the modeled AoR, approximately 1.5 miles East of Shoe Bar 1AZ.

The Project acquired a comprehensive suite of basic and advanced geophysical logs, whole core through the injection interval, sidewall cores, reservoir pressure data and fluid samples. After each well was constructed, the BRP team conducted step-rate tests in the injection and confining intervals. Shoe Bar 1 will be converted to the SLR1; it will be plugged above the Injection Zone and used for future DTS/DAS monitoring. The Shoe Bar 1AZ will be plugged above the Injection Zone prior to the commencement of injection. The portion of the well above the upper confining zone will temporarily be left unplugged and inactive pending further evaluation of utilization for this wellbore.

The following sections summarize the details of the logging and coring plans executed in the stratigraphic wells.

2.2 Logging Program in Stratigraphic Wells

The Shoe Bar 1 was drilled in January 2023. The well was planned with a 3-string casing design with the surface section (or surface string casing) at 0-1,800’ MD, intermediate section (or intermediate string casing) at 1,800-3,800' MD, and production section (or long string casing) at 3,800-6,550' MD.

Table 3 summarizes the data acquisition program conducted in the Shoe Bar 1.

Table 3--Data acquired in the Shoe Bar 1 Well

Method	Interval Section(s)	Purpose
Open Hole Logs, Surveys and Sampling During Construction		
Deviation survey [40 CFR §146.87 (a) (1)]	Every 100 ft while drilling as minimum, from surface to TD.	Define well trajectory, displacement, and tortuosity
Wireline- Spontaneous Potential – [40 CFR §146.87 (a) (2) (i)]	Intermediate, Production	Correlation log, volume of shale indicator, estimate salinity
Wireline – Caliper – [40 CFR §146.87 (a) (2) (i)]	Intermediate, Production	Identify borehole enlargement and calculate cement volume
Wireline –Resistivity – [40 CFR §146.87 (a) (3) (i)]	Intermediate, Production	Fluid identification, estimate salinity, correlation log
Wireline -Gamma ray – [40 CFR §146.87 (a) (3) (i)]	Intermediate, Production	Define stratigraphy, correlation log, shale indicator
Wireline -Magnetic resonance image – [40 CFR §146.87 (a) (3) (i)]	Production	Estimate porosity, pore size distribution, permeability index
Wireline -Sonic Scanner – [40 CFR §146.87 (a) (3) (i)]	Intermediate, Production	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline - Spectral gamma ray – [40 CFR 146.87 (a) (3) (i)]	Intermediate, Production	Define uranium rich formation, clay indicator
Wireline - Density / neutron – [40 CFR 146.87 (a) (3) (i)]	Intermediate, Production	Estimate porosity, mineralogical characterization
Wireline -High-definition image – [40 CFR §146.87 (a) (3) (i)]	Production	Identify fracture, structural information, minimum stress orientation
Wireline - Litho-scanner – [40 CFR §146.87 (a) (3) (i)]	Production	Identify mineralogy
Wireline - Formation Dynamics Testing	Production	Measure formation pressures, fluid sampling, mini-frac testing
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition

The Shoe Bar 1AZ was drilled in August 2023. This well is located in the AoR, within 2,000’ of the planned future injector locations. The well was drilled with a 3-string casing design with the surface section at 0-1,800’ MD, intermediate section at 1,800-3,910' MD, and production section at 3,910-6,725’ MD. The Shoe Bar 1AZ will be plugged above the Injection Zone prior to the commencement of injection. The portion of the well above the upper confining zone will temporarily be left unplugged and inactive pending further evaluation of utilization for this wellbore. Summarized below is the data acquisition program conducted in the Shoe Bar 1AZ.

Table 4--Data acquired in the Shoe Bar 1AZ well

Method	Interval Section(s)	Purpose
Open Hole Logs, Surveys and Sampling During Construction		
Deviation survey [40 CFR §146.87 (a) (1)]	Every 100 ft while drilling as minimum, from surface to TD	Define well trajectory, displacement, and tortuosity
Wireline- Spontaneous Potential – [40 CFR §146.87 (a) (2) (i)], [40 CFR §146.87 (a) (3) (i)]	Surface, Intermediate, Production	Correlation log, volume of shale indicator, estimate salinity
Wireline –Resistivity – [40 CFR §146.87 (a) (2) (i)], [40 CFR §146.87 (a) (3) (i)]	Surface, Intermediate, Production	Fluid identification, estimate salinity, correlation log
Wireline – Caliper – [40 CFR §146.87 (a) (2) (i)], [40 CFR §146.87 (a) (3) (i)]	Surface, Intermediate, Production	Identify borehole enlargement and calculate cement volume
Wireline -Gamma ray – [40 CFR §146.87 (a) (2) (i)], [40 CFR §146.87 (a) (3) (i)]	Surface, Intermediate, Production	Define stratigraphy, correlation log, shale indicator
Wireline -Magnetic resonance image – [40 CFR §146.87 (a) (3) (i)]	Production	Estimate porosity, pore size distribution, permeability index
Wireline -Sonic Scanner – [40 CFR §146.87 (a) (2) (i)], [40 CFR §146.87 (a) (3) (i)]	Surface, Intermediate, Production	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline - Spectral gamma ray – [40 CFR §146.87 (a) (2) (i)], [40 CFR §146.87 (a) (3) (i)]	Surface, Intermediate, Production	Define uranium rich formation, clay indicator
Wireline - Density / neutron – [40 CFR §146.87 (a) (2) (i)], [40 CFR §146.87 (a) (3) (i)]	Surface, Intermediate, Production	Estimate porosity, mineralogical characterization
Wireline -High-definition image – [40 CFR §146.87 (a) (3) (i)]	Production	Identify fracture, structural information, minimum stress orientation
Wireline - Litho-scanner – [40 CFR §146.87 (a) (3) (i)]	Production	Identify mineralogy
Wireline - Formation Dynamics Testing	Production	Measure formation pressures, fluid sampling
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition

In addition to the open-hole logs, cased-hole logs were acquired over each section post-casing in both stratigraphic wells. The table below table summarizes the cased-hole data that was acquired.

Table 5--Cased-hole logs acquired

Method	Interval Section(s)	Purpose
Cased Hole Logs and surveys Before Injection		
Wireline - CBL-VDL-USIT-CCL – [40 CFR §146.87 (a)(2) (ii)], [40 CFR §146.87 (a)(3) (ii)]	Surface, Intermediate, Production	Cement bond, casing integrity. Validate external mechanical integrity
Annulus Pressure Test - Long string casing [40 CFR §146.87 (a)(4) (i)]	Annular between tubing and long string	Validate internal mechanical integrity between the tubing, long-string, and packer
Wireline - Activate pulsed neutron – Long string casing [40 CFR §146.87 (a)(4) (ii)]	Surface, Intermediate, Production	CO_2 saturation, baseline for monitoring

2.3 Coring Program

2.3.1 Whole and Sidewall Core Acquisition

The coring program for the Shoe Bar 1 and Shoe Bar 1AZ wells was designed to obtain full 4-in whole core from the Sequestration Zone, the Lower San Andres formation. The program collected 1.5-in diameter sidewall core plugs in the Grayburg and Upper San Andres formations, which are the Upper Confining Zones, and the Glorieta and Wichita-Albany formations, which are Lower Confining Zones. In addition, sidewall cores were also obtained to evaluate a prospective secondary sequestration zone, the Clearfork formation.

In Shoe Bar 1, the Project successfully achieved 100% recovery of ~714ft of whole core through the Lower San Andres and 78 sidewall cores from Grayburg, Upper San Andres, Glorieta, Clearfork, and Wichita-Albany formations.

In Shoe Bar 1AZ, the Project successfully achieved 100% recovery of ~725ft of whole core through the Lower San Andres and 51 sidewall cores from Grayburg, Upper San Andres, Glorieta, and Clearfork formations.

2.3.2 Core Analysis Program

The laboratory analysis of core acquired in Shoe Bar 1 and Shoe Bar 1AZ involved core slabbing, routine core analysis (RCA), petrographic analysis, and special core analysis (SCAL). Table 6 summarizes the program.

Table 6--Core Analysis Performed

Core	Test	Frequency
Whole Core	Slabbing	100% of whole core
	DECT Scan	
	WL, UV Photography	
	Core description*	
Full Diameter Core	Total Porosity	12 from Shoe Bar 1; 7 from Shoe Bar 1AZ; in the Injection Zone
	Horizontal permeability	
	Vertical permeability	
	Grain density	
Whole Core, Horizontal plugs	Total Porosity	Selected samples from Upper Confining and Injection Zones
	Permeability	
	Grain density	
	XRF, XRD **	
	Thin section ***	
	SEM	
	MICP	
	Relative permeability	
Whole Core, Vertical plugs	Porosity	Selected samples from Upper Confining and Injection Zones
	Vertical permeability	
	Grain density	
	Entry pressure	
Whole Core, Geomechanical	Static/Dynamic Elastic Anisotropy	Selected samples from Upper Confining and Injection Zones
	Poro-elastic Coefficients (VTI)	
	Multistage Confined Compression	
RSWC XL	Total Porosity	Every sample from Upper Confining and Injection Zones
	Permeability	
	Grain density	

*Core description: Detailed description of the slabbed core will assign core facies based on lithology, texture, biogenic structures, fossils, grain size trends, environment of deposition, and sedimentary structures.
**XRD: This will provide bulk composition and clay typing
***Thin section: A detailed description will include grain composition, pore distribution, textural characteristics, and fabric of the rock.

2.4 Formation Fluid Characterization Program

2.4.1 Acquisition of Formation Fluid Samples

A Modular Formation Dynamics Tester (MDT) tool was utilized during the open-hole wireline logging runs to obtain representative samples of in-situ reservoir fluid. A MDT tool with pump-out module, Live Fluid Analyzer (LFA) module, and flow line resistivity measurement identifies and collects high-quality reservoir fluid samples suitable for laboratory analysis. Flowline resistivity measurements taken by the sensor on the MDT tool help discriminate between formation fluids and filtrate from muds. Equipping the MDT tool with a pump-out module makes it possible to sample fluid, while monitoring the flowline resistivity, by pumping filtrate-contaminated fluid into the mud column. Fluid removed from the formation is excluded from the sample chamber until an uncontaminated sample can be recovered.

The BRP Project utilized an MDT tool to acquire baseline reservoir fluid samples from three depths in the Lower San Andres in each of the two stratigraphic wells. These samples were transported under pressure to a third-party lab for comprehensive analysis including pH, conductivity, alkalinity, major cations, major anions, trace metals, dissolved gases, density, and TDS (Total Dissolved Solids) among others.

2.4.2 Analysis and Reporting

Table 7 indicates the analytical methods used to determine the measured parameters.

Table 7--Parameters and analytical methods for fluid analyses for Shoe Bar 1 and Shoe Bar 1AZ

Parameter	Analytical method
Lower San Andres (Injection Interval)	
Cations: Al, Ba, Cd, Ca, Cr, Co, Cu, Fe (disolved), Fe (total), Pb, Li, Mg, Mn, Mo, Ni, P, K, Si, Na, Sr, V, Zn	CL Metals by ICP – Section 1.28-2
Cations: Hg (Mercury)	SW7470A
Anions: B (as $B(OH)_4^-$)	CL Metals by ICP – Section 1.28-2
Anions: F, NO_3, NO_2, PO_4, SO_4	CL Anions by IC – Section 1.27-2
Dissolved CO_2	ASTM D 513-82
Anions: Br, Cl, I	CL Anions by IC – Section 1.27-2/ CL Chlorides Determination – Section 1.22-3
Anions: Ar (arsenic)	EPA 200.7
Anions: S (sulfide)	Standard Methods: 4500-S2-D
Total organic carbon	SM5310B
Total dissolved solids (TDS)	EPA 160.1
Total Sulfate and Sulfide	Standard Methods: 4500-S2-D
Density	ASTM D1217
Dissolved CO_2	ASTM D 513-82
Alkalinity (as HCO_3^-), Carbonate (CO_3^{2-})	Titration, ASTM D3875-97 CL Bicarbonate/Carbonate Determination Section 1.26-3
pH and Temperature	ASTM D1293 (pH Electrode)
Conductivity	ASTM D1125
Specific gravity	ASTM D1429 / ASTM D1480
$\delta^{13}C$	gas-bench IRMS
$\delta^{18}O$	gas-bench IRMS
δD	gas-bench IRMS

Dissolved Gas Abundances: CO_2, CO, N_2, Ar, He, H_2, O_2, C1-C6+	Determined by GC for full compositions
Dissolved Gas Isotopes: $\delta^{13}CO_2$, $\delta^{18}CO_2$	Conventional Offline Prep / Dual Inlet MS
$^{87}Sr/^{86}Sr$	Strontium isolation by extraction chromatography, analysis by MC-ICP-MS

2.5 Fracture Pressure

2.5.1 Confining zone

The fracture pressures of the Upper Confining Zone (Upper San Andres and Glorieta) and the Injection Zone (Lower San Andres) were estimated using mini-frac tests in the Shoe Bar 1 and Shoe Bar 1AZ wells. The fracture gradients are in the range of 1.19-1.58psi/ft. The table below shows the results.

Table 8--Summary of Confining Zone Fracture Pressure Estimates

Well	Test	Zone	Formation	Measured Depth, ft	Fracture propagation pressure, psi	Fracture gradient, psi/ft
Shoe Bar 1	Mini-frac	Upper confining zone	Upper San Andres	4042	5941	1.47
Shoe Bar 1	Mini-frac	Lower confining zone	Glorieta	5076	7044	1.39
Shoe Bar 1AZ	Mini-frac	Upper confining zone	Upper San Andres	3792	Could not initiate fracture at max. downhole pressure of 6000 psi	>1.58
Shoe Bar 1AZ	Mini-frac	Lower Confining Zone	Glorieta	5026	Could not initiate fracture at max. downhole pressure of 6000 psi	>1.19

2.5.2 Injection Zone

The fracture pressure of the Injection Zone was estimated using Mini-frac (or Diagnostic Fracture Injection Test) and Step Rate Tests (SRT) performed in the Shoe Bar 1 and Shoe Bar 1AZ wells. The table below summarizes the results:

Table 9–Summary of Injection Zone Fracture Pressure Estimates

Well	Zone	Tested Interval Top Perf-Bottom Perf (MD, ft)	Initial Reservoir Pressure (psi)	Type of Test	Estimated Fracture Gradient (psi-ft)
Shoe Bar 1	Lower San Andres	4827-4829	2200@4400ft	Mini-Frac	[redacted]
Shoe Bar 1	Lower San Andres	4421-5024	2200@4400ft	Step Rate Test	[redacted]
Shoe Bar 1AZ	Lower San Andres	5122-5132	2522@5088ft	Step Rate Test	[redacted]
Shoe Bar 1AZ	Upper San Andres	4723-4733	2307@4596ft	Step Rate Test	[redacted]

3. Injection Wells – Pre-Op Strategy

The BRP Project will construct three new wells for CO_2 injection. An extensive suite of tests and logs will be acquired during drilling, casing installation, and post-casing installation in the injector wells in accordance with the testing required under 40 CFR §146.87(a), (b), (c), and (d).

3.1 Logging Program

The Project will plan and execute an extensive data acquisition program consisting of logs, surveys, and tests consistent with the data acquired in the stratigraphic test wells, shown in Table 4.

The table below shows the proposed logging and survey planned for injector wells.

Table 10–Proposed logging program for CO_2 injectors

Method	Interval Section(s)	Purpose
Open Hole Logs, Surveys and Sampling During Construction		
Deviation survey	Every 100 ft while drilling as minimum, from surface to TD	Define well trajectory, displacement, a tortuosity
Wireline – Spontaneous Potential	Surface, Intermediate, Production	Correlation log, volume of shale indicator, estimate salinity
Wireline – Resistivity	Surface, Intermediate, Production	Fluid identification, estimate salinity, correlation log
Wireline – Caliper	Surface, Intermediate, Production	Identify borehole enlargement and calculate cement volume
Wireline – Gamma ray	Intermediate, Production	Define stratigraphy, correlation log, shale indicator

Wireline – Magnetic resonance image	Production	Estimate porosity, pore size distribution, permeability index
Wireline – Sonic Scanner	Intermediate, Production	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline – Spectral gamma ray	Intermediate, Production	Define uranium rich formation, clay indicator
Wireline – Density / neutron	Intermediate, Production	Estimate porosity, mineralogical characterization
Wireline – High-definition image	Production	Identify fracture, structural information, minimum stress orientation
Wireline – Litho-scanner or equivalent	Production	Identify mineralogy
Wireline – Formation Dynamics Testing	Production	Measure formation pressures, fluid sampling, mini-frac testing
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition
Cased Hole Logs and surveys Before Injection		
Wireline – CBL-VDL-USIT (Casing inspection log)-CCL	Surface, Intermediate, Production	Cement bond, casing inspection log (USIT); Validate external mechanical integrity
Annulus Pressure Test – Long string casing	Annular between tubing and long string	Validate internal mechanical integrity between the tubing, long-string, and packer
Wireline – Activate pulsed neutron (Oxygen Activation Log) – Long string casing	Surface, Intermediate, Production	CO_2 saturation, baseline for monitoring
Wireline – Temperature Log	Surface, Intermediate, Production	Measure baseline temperature profile on the well from surface to top of perforation
Fiber Optic – DAS, DTS survey	Surface, Intermediate, Production	Measure baseline temperature profile on the well from surface to top of perforation Acquire baseline 3D VSP survey for monitoring plume migration over time

3.2 Coring Program

The Project will not collect whole core or sidewall cores in the CO_2 injector wells BRP CCS1 and BRP CCS2 wells, because representative core data were already acquired in the Shoe Bar 1AZ, which is located less than 2,000’ away from the planned injector wells. Based on seismic interpretation of a recently acquired project-specific 3D dataset, OLCV interprets structural and stratigraphic conformance, and consistency of rock and fluid properties between the stratigraphic test well and the planned injectors. See Appendix A to the BRP Pre-Operations Testing Plan for additional justification on the similarity of geology at the stratigraphic test well location compared to the planned injectors.

The Project will collect up to 75 sidewall cores in the BRP CCS3 well, which is anticipated to have different rock properties than were encountered in the nearby Shoe Bar 1. The core depths will be finalized based on the petrophysical analysis of the triple combo logs run prior to the sidewall coring run. The Project will plan to acquire ~10 (subject to change) sidewall cores in each Confining Zone and ~50 (subject to change) sidewall cores in the Injection Zone.

Table 11–Projected depths for rotary sidewall core sampling zones in well BRP CCS3

Well Name	Formation Top	Comment	Z [FT]	MD [FT]
CCS3	Grayburg	Upper Confining Zone	-844	4002
CCS3	Upper San Andres	Upper Confining Zone	-1052	4282
CCS3	Lower San Andres (G4)	Injection Zone	-1410	4959
CCS3	Lower San Andres (G1)	Injection Zone	-1543	5225
CCS3	Lower San Andres (Holt)	Injection Zone	-1934	6006
CCS3	Glorieta	Lower Confining Zone	-2089	6316

Table 12–Core analysis plan for BRP CCS3

Core	Test	Frequency
Rotary Sidewall Cores (RSWC)	Total Porosity (Ambient and NCS) Permeability (Ambient and NCS) Grain density	Every sample
	XRD ** Thin section *** SEM MICP	Select samples from Confining Zones and Injection Zone

*XRD: This will provide bulk composition and clay typing
**Thin section: A detailed description will include grain composition, pore distribution, textural characteristics, and fabric of the rock.

Geomechanical testing of core is required to accomplish at least two primary goals. First is to calibrate the dynamic and static elastic properties that are inputs to the well-based stress model. The second objective is to build a rock mechanics database that is used to build predictive rock property models so that rock properties can be predicted in future wells with the necessary input well data. The testing results also provide the foundational data required to understand physical properties and characteristics of facies, lithotypes, textures, etc. Both dynamic and static data are required to build dynamic to static conversions. Dynamic data are calculated from velocity data and density and are equivalent to the same properties calculated from well data. Dynamic data must be converted to static data and the dynamic to static conversions based on core data are required to accomplish critical step. Table 11 summarizes the dynamic and static measurements to be completed on the core samples. Testing is accomplished using the proprietary single plug protocol from New England Research (NER). The method requires only a single horizontal plug and provide vertical and horizontal measurements required to characterize elastic anisotropy. Because it only requires a single horizontal plug, rotary sidewall cores (RSWC) plugs can be utilized to expand the scope of investigation of both seal and reservoir formations. In Shoe Bar 1, 12 samples from the suite of RSWC plugs are tested in the reservoir, upper seal, and lower seal. In Shoe Bar 1AZ, both whole core and RSWC are utilized to characterize 20 samples distributed across the upper seal, reservoir, and lower seal.

Table 13–Geomechanical Parameters from Core Testing

Property	Variable	Dynamic	Static
Density	Rhob	--	Yes
Compressional Velocity	Vp	Yes	--
Shear Velocity	Vs	Yes	--
Young’s Modulus	E	Yes	Yes
Poisson’s Ratio	v	Yes	Yes
Biot’s Coefficient	α	--	Yes
Stiffness Coefficients	Cij	Yes	Yes
Compliance Coefficients	Sij	Yes	Yes
Unconfined Compressive Strength	UCS	--	Yes

3.3 Well Mechanical Integrity Testing (MIT)

The BRP Project will conduct both internal and external mechanical integrity tests on all injection wells in the Project. Internal mechanical integrity refers to the absence of leaks in the casing by tubing annulus, the tubing, and the packer. External mechanical integrity refers to the absence of formation fluid or CO_2 movement through channels in the cement on the exterior of the casing.

Upon completion and installation of the downhole equipment in the wells, BRP will conduct an annular pressure test (APT) to verify internal mechanical integrity. The APT is a short-term pressure test (30 minutes) where the well is shut in and the fluid in the annulus is pressurized to a predetermined pressure and is monitored for leak off. BRP will use a test pressure of 500 psi for the MIT’s. BRP will use a 5% decrease in pressure (test pressure x .05) from the stabilized test pressure during the duration of the test to determine if test is successful. If the annulus pressure decreases by ≥5%, the well will have failed the APT. If a well fails an APT, the test will be repeated. If the APT is again failed, the downhole equipment will be removed from the well and the source of the failure will be investigated. In general, the test procedure will be as follows:

1. Connect a high-resolution pressure transducer to the annulus casing valve and increase the annulus pressure to 500 psi and hold this pressure for 30 minutes.
2. At the conclusion of the 30-minute test the annulus pressure will be bled off to 0 psi and the pressure recording equipment will be removed from the casing valve.

Upon well completion, BRP will run cased hole logs to demonstrate external mechanical integrity of the casing and cement sheath prior to the start-up of operations. BRP will run Casing Inspection Logs (CIL) to evaluate casing integrity. In addition, BRP will acquire baseline temperature logs to demonstrate a lack of fluid movement through channels or communication paths through the tubing or annulus. BRP will also run an ultrasonic imaging tool (USIT) to provide further confidence that there are no channels in the cement sheath for formation fluids or CO_2 to migrate upwards in the well.

3.4 Cement Logs

The BRP Project will collect noninvasive data to confirm the presence of an annular barrier and bond between casing and cement. Cement placement is a critical component of the well architecture for ensuring mechanical support of the casing, protection from fluid corrosion, and for isolation of permeable zones at different pressure regimes to prevent hydraulic communication. Tools such as Ultrasonic Imager tool (USIT) uses a single transducer mounted on an Ultrasonic Rotating Sub (USRS) on the bottom of the tool. The transmitter emits ultrasonic pulses between 200 and 700 kHz and measures the received ultrasonic waveforms reflected from the internal and external casing interfaces. The rate of decay of the waveforms received indicates the quality of the cement bond at the cement/casing interface, and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection. Because the transducer is mounted on the rotating sub, the entire circumference of the casing is scanned. This 360° data coverage enables the evaluation of the quality of the cement bond as well as the determination of the internal and external casing condition. The very high angular and vertical resolutions can detect channels as narrow as 1.2 in. [3.05 cm]. Cement bond, thickness, internal and external radii, and self-explanatory maps are generated in real time at the wellsite.

An advanced option such as Isolation Scanner can be used to provide more certainty. This tool combines a pulse-echo technique along with an ultrasonic technique to induce a flexural wave in the casing. A transmitter measures the resulting signals at two receivers, and the attenuation calculated between the two receivers is paired with the pulse-echo measurement and compared with a laboratory-measured database to produce an image of the material immediately behind the casing. By measuring radially beyond traditional cement evaluation boundaries, this service confirms zonal isolation, pinpoints any channels in the cement, and ensures confident operational decisions. The signal resulting from the interface between the annulus and the borehole or outer casing can be detected and measured. These third-interface echoes (TIEs) provide the position of the casing within the borehole, and if the borehole size is known, the velocity of the annulus material can be determined. These flexural measurements can provide useful information to image complex cement geometries and are helpful datasets if remediation is required.

3.5 Fracture Pressure

The fracture pressure of the Confining and Injection Zones is determined to understand injection pressure limit to maintain matrix flow. To determine the fracture pressure, a fracture is created and sustained for a small amount of time. The fracture pressure in the Injection Zone is determined through a mini-frac or Diagnostic Fracture Injection Test (DFIT). These tests will determine Instantaneous Shut-in Pressure (ISIP), the ISIP Gradient, and the Fracture Closure Pressure (FCP). These terms are defined as below and illustrated in Figure 1.

- Instantaneous Shut-In Pressure (ISIP) = Final Injection Pressure – friction pressure
- ISIP Gradient (or fracture gradient) = ISIP/formation depth
- Fracture Extension Pressure (FEP) = Minimum pressure need to develop and extend a fracture once it has been initiated
- Fracture Closure Pressure (FCP) = Minimum pressure needed to keep a fracture open; this is also the minimum horizontal formation stress
- Net Pressure (Δpnet) = Pressure in the fracture above fracture closure pressure

Following the drilling and logging of the injection well(s), an open hole wireline formation tester (such as MDT) mini-frac will be performed to determine the minimum horizontal stress of the formation intervals. The tester will be setup in a dual packer configuration to isolate ~3ft intervals for stress testing to determine the fracture initiation, fracture breakdown, and fracture propagation pressure. The proposed test intervals will be pre-screened to ensure no structural weaknesses (such as natural fractures) are present using a processed FMI log. The mini-frac operations will preferably occur from the deepest to shallowest depth interval following the procedure outlined below:

Step 1: Packer Inflation

- Inflate the packers until the pressure in the interval (PAQP) starts to rise. When PAQP reaches 100psi greater than hydrostatic pressure, close the inflate seal vale, stop the pump, open the interval seal valve, and exit port to relieve the pressure. This will also allow the packers to relax during the inflation process. Continue to inflate the packers to 300-400 psi inflation pressure.

Step 2: Leak Off Test

- Carry out at least one leak-off test (doing two or three is better). The purpose of the test is to check that the pressure rises roughly linearly with time during injection, which indicates that there is only a small amount of leak-off and that enough flow rate will be available to drive a hydraulic fracture into the formation. Another advantage of this test, when carried out several times, is that it minimizes the storage of the tool as the packers ease their way on the wellbore wall.

- Inject at a constant rate until pressure is approximately 1000psi below the estimated breakdown pressure.
- Stop injection and record the pressure decline. This test may take less than a minute. In low permeability formations, it is acceptable to not have to wait until pressure comes back to the initial value (it might take unreasonably long to do so).

Step 3: Hydraulic Fracturing Cycle

- To initiate a fracture, pump into the interval at a constant rate of about 1000 rpm (up to 2200 rpm). After a period of pressure build-up, a sudden decrease of injection pressure should be observed. This is the fracture initiation pressure.
- Continue pumping until a stable or gradually increasing fracture propagation trend is observed. Pump for 2-3 more minutes.
- Close the interval valve and immediately stop the pump. Monitor pressure decline until it stabilizes or reaches approximately 500 psi above hydrostatic pressure. In very low permeability intervals, the flowback sample chamber can be used to help with fracture closure.

Step 4: Re-opening Tests

- Reopen the fracture by injecting at the same rate until a fracture propagation trend is observed again. Pump for 2-3 minutes and shut in. Monitor and record the pressure decline.
- 2 or 3 more fracture reopening cycles should then be performed. These reopening tests will confirm the presence of a fracture and are critical to ensure that the minimum principal stress has indeed been measured. More cycles may be added if quality of the data, in particular the repeatability of the pressure at which the fracture propagates, is not satisfactory.

Mini-fracs will be performed in distinct porosity / permeability packages within the proposed Injection Zone and Upper and Lower Confining Zones. Thin intervals (<2ft) that are interpreted to have limited horizontal extent will not be considered. The interval for mini-frac will be selected upon review of logging data (Phi>10%, Layer thickness >5ft). The Fracture Extension Pressure will be interpreted by qualified OLCV reservoir and completions engineers to determine injection limits throughout the Injection Zone.

To perform a DFIT, the test zone will be perforated with a limited number of perforations to ensure fluid is injected over a small area. Fluid will then be injected down the tubing to apply pressure to the formation to induce a breakdown of the formation and establish a fracture. Pressure will be recorded on a surface gauge attached to the wellhead, and at a gauge at the end of the tubing. Once a fracture is created, a small volume of fluid will be pumped to extend the fracture before injection is terminated. To extend the fracture, the Δpnet needs to be above the FCP. The ISIP is the final pressure point when rate and pressure drop is zero, where net pressure is still present, and the fracture is open. At the ISIP, a fracture gradient is calculated at the depth of the fracture. Pressure decline is analyzed using G-function and root-time methods to determine fracture closure pressure.

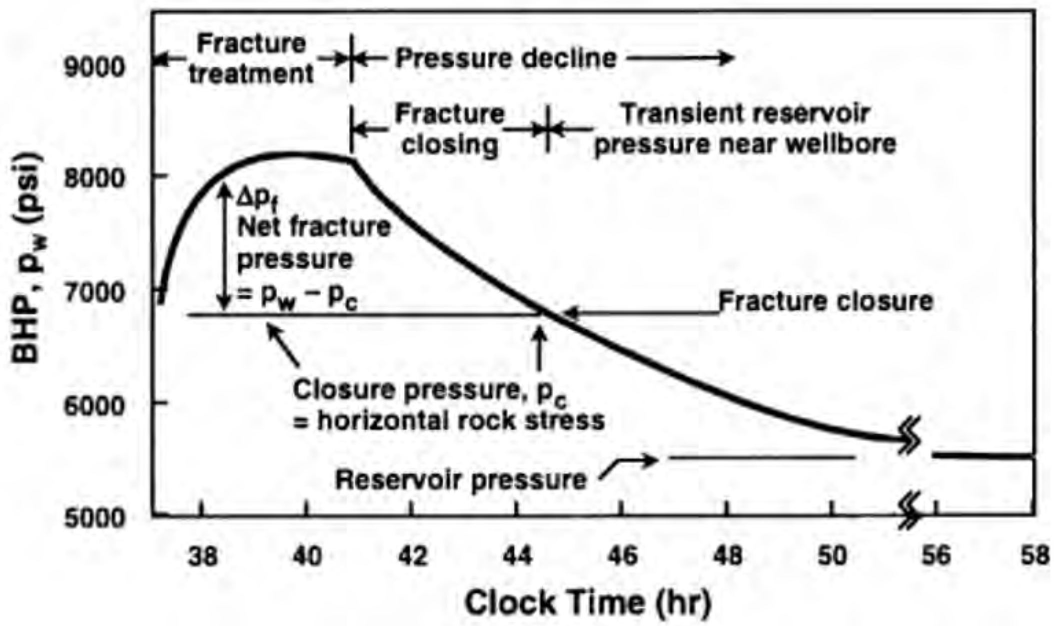

Figure 1: Well Injection Test (Talley, 1999)

3.6 Injection Well Testing

An injection test will be performed in the Lower San Andres after the injection well is complete, including perforation of the Injection Zone and installation of the injection tubing and packer. The pre-operation injectivity testing will serve as the baseline for future pressure fall-off testing. The purpose of conducting an injectivity test is to verify or establish the injection well operating parameters and constrain the inputs used for dynamic injection simulation modeling.

The injection testing will comprise of a period (typically 12-24hrs) of injection at constant rate (typically 0.5-2bpm) subject to a maximum bottom hole pressure limit (less or equal to 90% of the estimated fracture gradient for the perforated interval). This is followed by a shut-in/pressure fall off period (typically 24-48hrs) for monitoring. The injection period will be used to establish/monitor well injectivity performance and the fall off analysis will indicate the well/reservoir flow regime, average reservoir flow characteristics and the presence (if any) of reservoir baffles/boundaries/interwell interference. The tests will be planned to cover the entire perforated interval of the injector well. Injection profile logs may be run to further verify injection test results.

3.7 Pressure Fall-Off Testing

The main objectives for the pressure fall-off testing are to:

- Inform the expected rate and volume of CO_2 injectivity into the Lower San Andres formation.
- Identify potential baffles or barriers to subsurface flow.
- Verify or establish the maximum operation pressures of the well.
- Establish baseline reservoir performance for comparison with subsequent tests.

3.7.1 Test Activity Summary

The pre-injection test will be performed using brine or municipal water. There will be an injection period at constant rate followed by a zero-rate (shut-in) period for pressure monitoring (Figure 2).

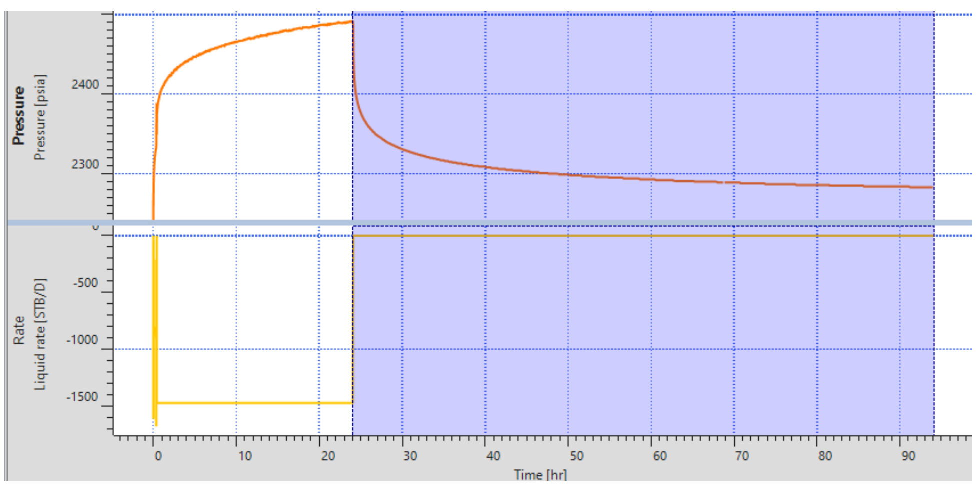

Figure 2: Schematic of Injection Fall-off testing

The test will be conducted with the following considerations:

- The maximum injection pressure will be ≤90% of the estimated fracture pressure of the interval. The shut-in period will be sufficient to observe near-wellbore reservoir and boundary effects.
- Bottomhole pressure measurements will be recorded using the downhole pressure gauge near the perforations. A surface pressure gauge may also serve as a monitoring tool for tracking the test progress.
- Injection profile logs and other complementary data may be acquired during the test.

- Testing procedures will follow the EPA recommended methodology (EPA, 2002). The recommendations provided in these guidance documents will be followed to the extent possible. If BRP proposes a significantly different approach, the proposed operational changes will be reviewed with the UIC Program Director prior to initiation.

The following general procedure will be followed for pressure fall off testing:

1. Hook-up brine or municipal water to the well to prepare for injection.
2. Record static shut-in pressure at the downhole gauge.
3. Commence injection per planned rate schedule, approximately 1bpm increase every 30mins until the planned maximum injection rate is reached.
4. Maintain the injection rate within the maximum injection pressure limit for approximately 24 hours.
5. Cease injection as rapidly as possible using a controlled shut-down, and commence pressure fall off testing.
6. Perform a preliminary analysis of the pressure fall off data after 24 hours to identify radial flow period as well as other transient reservoir features.
7. End the pressure fall off test after confirmation of sufficient data acquisition.

Note: The injection rate schedule and the duration of the injection period and the pressure fall-off testing may be modified based on dynamic reservoir response.

3.7.2 Analysis and Reporting

Fall-off testing analysis allows for calculation of the following parameters: transmissivity, storage capability, skin factor, and well flowing and static pressures. A Cartesian plot of the pressure and temperature versus real time or elapsed time will be used to confirm pressure stabilization and look for anomalous data. A log-log diagnostic of the pressure and semilog derivative analysis will be performed for well/reservoir performance characterization (Petrowiki, 2016)

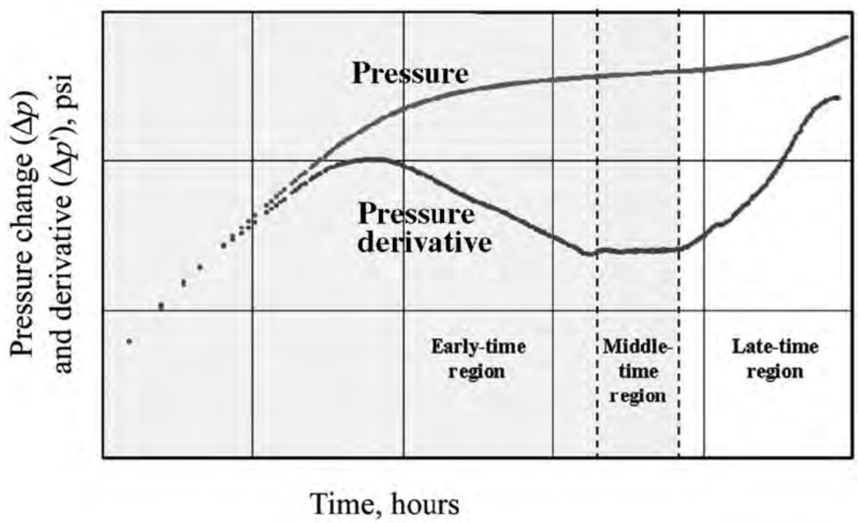

Figure 3. Pressure derivative analysis diagnostic chart (Petrowiki, 2016)

BRP will conduct the following data analysis, integration, and reporting:

- The results of the wireline logging program and the fracture pressure evaluation program will be integrated to support and corroborate the hydrogeologic properties.
- The fall-off testing report will be submitted no later than 60 days following the test and will include well schematic, gauge information, test information, rate/pressure data, reservoir parameters and summary of analysis.
- The testing will be repeated using carbon dioxide within the first 90 days following initiation of sequestration operations. This will allow for comparison to the baseline fluid-to-fluid test with the change in the injection fluid from brine water to carbon dioxide.
- The fall-off test will be performed annually at five-year intervals (within +/-3 months of the anniversary of the previous test), for the lifetime of injection operations. Periodic testing is expected to provide insight into the performance of sequestration site and potentially aid in interpreting the dimensions of the CO_2 plume, based on the expected lateral transition from supercritical CO_2 near the wellbore to native formation brine beyond the plume.
- A final pressure fall-off test will be run after the cessation of injection into the Injection Well.

3.8 Injection Wells Directional Survey

Wellbore deviation measurements will be conducted at periodic intervals while drilling the injection wells. Additionally, a final directional survey may be acquired from total depth to the surface to provide borehole inclination and azimuthal information.

3.9 Injection Wells Formation Pressure and Fluid Sampling

The BRP Project will utilize a formation testing tool (example: MDT) to quantify the reservoir pore pressure and collect fluids from selected intervals in the Injection Zone. The pore pressure testing, and fluid sampling procedure is outlined below:

1. Rig up formation testing tool.
2. Run in hole, for casing check, to above casing shoe.
3. Run in hole for depth correlation. Correlation should be recorded in the same direction as reference log (mostly log up)
4. Log depth correlation pass.
5. Perform pore pressure tests at selected depth intervals in formations of interest.
    a. Two consecutive pretests of 10cc each at every station is run using volumetric drawdown.
    b. After setting the tool and performing the first 10cc pretest, pressure should be allowed to stabilize only to a 10^{th} of a psi following which the second 10cc pretest should be carried out and pressure allowed to build up to a 100^{th} of a psi for 20 seconds.
    c. If after the first 10cc pretest the formation appears to be tight (labeled as dry test), the tool should be retracted without doing a second pretest.
6. Upon completion of pressure testing, re-log for depth correlation.
7. Pick depth intervals with good mobility (identified from pressure tests) for fluid sampling.
8. Perform fluid sampling at selected depth intervals. This involves pump out of fluid volume while monitoring the fluid properties in real time using Live Fluid Analyzer (LFA) module to capture reservoir fluid without mud or other contaminants. The sampling steps involve:
    a. Inflate the packers with 5-7 liters (between 350-400 psi). Inflation pressure may decrease during operations to as low as 20-50 psi, but no further action is required.
    b. Perform a pretest with 2-4 strokes to ensure seal. Expected pretest duration is 10-15 minutes.
    c. Pump-out starting at 300 rpm and increase the rate by 300 rpm steps to the highest rate possible without exceeding tool limitations (5000psi differential pressure on packers). Continue to pump out until formation fluid is observed on the Live Fluid Analyzer (LFA) module. Expected duration of this step is 45 minutes.
    d. Continue to pump-out at the same rate until low contamination is achieved. The expected duration is 30 minutes.
    e. Fill sampling bottle with formation fluid and seal.
    f. If more sampling volume is needed, continue to pump-out and fill additional bottles.
9. Pull out of hole to surface.

Based on data from the Shoe Bar 1 and Shoe Bar 1AZ, OLCV anticipates encountering three distinct porosity zones. OLCV will collect fluid and dissolved gas samples in each of these zones. The final sampling depths will be selected after reviewing logs for the specific Injector well. The analytes and analytical methods for fluids and dissolved gasses are shown in Table 14.

Table 14. Summary of analytical parameters for fluid and dissolved gas samples in the Injection Zone (Lower San Andres).

Laboratory Analyte	Analytical Methods[1]	Detection Limit / Range[2]	Typical Precision[2]	QC Requirements
Total and Dissolved Metals: Ag, Al, As, Ba, Cd, Co, Cr, Cu, Mn, Mo, Ni, Pb, Sb, Se, Sr, Th, Tl, U, V, and Zn	USEPA Method 200.8	0.00004 to 0.003 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof
Total and Dissolved Metals: B, Ca, Fe, K, Mg, Li, Na, Si, Sr, Ti	USEPA Method 200.7	0.003 to 0.254 mg/L	±20	Daily calibration, Initial QC checks (IPC, ICV, ICB, RL) method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Total and Dissolved Hg	USEPA Method 245.7	19.6 ng/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved Inorganic Carbon (DIC); Dissolved Organic Carbon (DOC)	Standard Method 5310C	0.198 to 0.290 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved CO_2	Standard Method 4500 CO_2 D	8 mg/L	±20	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Alkalinity: Total, Bicarbonate, Carbonate, and Hydroxide	Standard Method 2320B	8 mg/L	±20	method blank, lab control samples, matrix spikes
Major Anions: Br, Cl, F, and SO_4, NO_2 and NO_3 as N	USEPA Method 300.0	0.003 to 0.563 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof

PO_4 as P	USEPA Method 365.1	0.0215 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof
Dissolved H_2S (Sulfide)	Standard Method 4500S2-D	0.026 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup
Total Dissolved Solids (TDS)	USEPA Method 160.1	10 mg/L	±20	Method blank, lab control samples, and sample duplicate
Conductivity	Standard Method 2510B	0 to 200 mS/cm	±1%	Calibration as needed, daily QC checks (1413, 14130 and second source SRM), CCV every 10 samples or part thereof
pH and Temperature	USEPA Method 150.1	0.1 to 14 pH units	±0.1 pH units	Daily calibration, second source SRM, CCV's every 10 samples or part thereof
Specific Gravity	ASTM Method D1429-03	NA	To the nearest thousandths decimal	Duplicates
Cation Anion Balance	Calculation	NA	±10	Calculation
Dissolved Gas Abundances: CO_2, CO, N_2, Ar, He, H_2, O_2, C1-C6+	In-house Lab SOP, similar to RSK-175	1 to 100 ppm, varies by component	C1-C4: ± 5%; C5-C6+: ± 10%	20% of all analyses are check/reference standards.
Dissolved Gas Isotopes: $\delta^{13}C$ of C1-C5 and CO_2, $\delta^{2}H$ of C1	High precision (offline) analysis via Dual Inlet IRMS	Varies by component	$\delta^{13}C$: 0.1 per mil; $\delta^{2}H$: 3.5 per mil	20% of all analyses are check/reference standards.
^{14}C of C1	AMS - subcontracted to Beta Analytic	0.44 pMC	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
^{14}C of DIC	AMS - subcontracted to Beta Analytic	Depends on available sample volume	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
$\delta^{13}C$ of DIC	Gas Bench/CF-IRMS	Depends on available sample volume, minimum of	0.20 per mil	20% of all analyses are either check/reference standards or duplicate analyses.

		50mg/L required		
$\delta^{18}O$ and δ^2H of H_2O	Analyzed via CRDS	N/A	$\delta^{18}O$: 0.10 per mil; δ^2H: 2.0 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$^{87}Sr/^{86}Sr$	TIMS - subcontracted to the University of AZ	Approximately 40 ppm	± 0.00002	SRM 987 Sr standard within the long-term precision (external precision) of +/- 0.00002 accepted value of 0.71025
$^{228}Ra/^{226}Ra$	USEPA Method 901.1	50 pCi/L (RL)	± 25%	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Field Parameters				
pH (Field)	Standard Method2 4500-H+ B-2000	2 to 12 pH units	±0.2 pH units	User calibration per manufacturer recommendation
Specific conductance (Field)	EPA Method 120.1	0 to 200 mS/cm	±1%	User calibration per manufacturer recommendation
Temperature (Field)	Standard Method 2550 B-2000	-5 to 50 ºC	±0.2 ºC	Factory calibration
Oxidation-Reduction Potential (Field)	Standard Method 2580	-1999 to +1999 mV	±20 mV	User calibration per manufacturer recommendation
Dissolved Oxygen (Field)	ASTM Method D888-09 (C)	0 to 50 mg/L	0 to 20 mg/L: ±0.1 mg/L or 1% of reading, whichever is greater; 20 – 50 mg/L: ±8% of reading	User calibration per manufacturer recommendation
Turbidity (Field)	USEPA Method 180.1	0 to 1000 NTU	± 1% of reading or 0.01 NTU, whichever is greater	User calibration per manufacturer recommendation

[1]An equivalent method may be employed with the prior approval of the UIC Program Director.
[2]Detection limits and precision (laboratory control limits) are typical for these analytical methods.
* Analytical parameters to be included during the pre-injection phase, and only as needed during the injection and post-injection phases of the Project.

3.10 Temperature logging

Temperature logs are used to locate gas entries, detect casing leaks, and evaluate fluid movement behind casing. They are also used to detect lost-circulation zones and cement placement. Temperature logs are used as a basic diagnostic tool and are usually paired with other tools like acoustics or multi arms calipers if more in depth analysis is required.

Temperature instruments used today are based on elements with resistances that vary with temperature. The variable resistance element is connected with bridge circuitry or constant current circuit, so that a voltage response proportional to temperature is obtained. The voltage signal from temperature device is then usually converted to a frequency signal transmitted to the surface, where it is converted back to a voltage signal and recorded. The absolute accuracy of temperature logging instruments is not high (in the order of +- 5°F), but the resolution is good (0.05°F or better), although this accuracy can be compromised by present day digitalization of the signal on the surface. The temperature instrument usually can be included in the string with other tools, such as radioactive tracer tools or spinners flowmeters. Temperature logs are run continuously, typically at cable speeds of 20 to 30 ft/min.

Temperature logging is anticipated to be collected at the same time as oxygen activation logging. The proposed plan for logging is as follows:

1. Logging crew to arrive on location, hold safety meeting with all parties that will be present during operation prior to beginning any work.
2. Move-in and spot wireline unit and crane.
3. Perform lifting plan and validate with crew and client.
4. Verify wellhead connection and wellhead pressure to be zero before install packoff.
5. Logging crew to rig up PNX-PBMS tool string and packoff.
6. Pressure test to 3k PSI to verify the equipment integrity.
7. Surface check on tools prior to run in hole(RIH). Minitron NOT to be turned on at surface at any time.
8. RIH to 1000 ft and turn on minitron, perform a test log to verify tool is operational, once completed turn off minitron and continue RIH with tool on logging GR-CCL.
9. RIH to TD power on minitron and wait for tool stabilization.
10. Once stable, begin main pass at 900 ft/hr in GSH-Commercial mode GR-CCL-Temp-Press.
11. Log up to 500 ft “confirm logging interval with client at well-site”.
12. Once main pass completed, RIH and perform a repeat pass 200 ft.
13. Upon logging completion turn off minitron and wait below 200 ft for at least 30 minutes before pulling out of hole (POOH).
14. Upload data and confirm data integrity with Domain Champion prior to rigging down.
15. POOH and rig down tools.

3.11 Oxygen activation logging

Oxygen activation log (OAL) provides formation evaluation and reservoir monitoring in cased holes. OALis deployed as a wireline logging tool with an electronic pulsed neutron source and one or more detectors that typically measure neutrons or gamma rays. High-speed digital signal electronics process the gamma ray response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the gamma ray energy and time relationship into concentrations of elements. Each logging company has its own proprietary designs and improvements on the tool.

Schlumberger's Pulsar Multifunction Spectroscopy Service (PNX) pairs multiple detectors with a high output pulsed neutron generator in a slim tool with an outer diameter (o.d.) of 1.72 in. for through-tubing access in cased hole environments. The housing is corrosion-resistant, allowing deployment in wellbore environments such as CO2. The tool's integration of the high neutron output and fast detection of gamma rays with proprietary pulse processing electronics, allows to differentiate and quantify gas-filled porosity from liquid-filled and tight zones. The tool can accurately determine saturation in any formation water salinity across a wide range of well conditions, mineralogy, lithology, and fluid contents profile at any inclination. Detection limits for CO2 saturation for the PNX tool vary with the logging speed as well as the formation porosity. Detailed measurement and mechanical specifications for the PNX tool are provided in the QASP document. The wireline operator will provide QA/QC procedures and tool calibration for their equipment.

Haliburton's RMT-D reservoir monitor tool: The Halliburton Reservoir Monitor Tool 3-Detector™ (RMT-3D™) pulsed-neutron tool solves for water, oil, and gas saturations within reservoirs using three independent measurements (Sigma, C/O, and SATG). This provides the ability to uniquely solve simple or complex saturation profiles in reservoirs, while eliminating phase-saturation interdependency. The RMT-#D provides gas phase analysis to identify natural gases, nitrogen, CO2, steam, and air. The tool has 2.125 in diameter OD that allows it to be run through tubing.

Temperature logging is anticipated to be collected at the same time as oxygen activation logging. The proposed plan for logging is as follows:

1. Logging crew to arrive on location, hold safety meeting with all parties that will be present during operation prior to beginning any work.
2. Move-in and spot wireline unit and crane.
3. Perform lifting plan and validate with crew and client.
4. Verify wellhead connection and wellhead pressure to be zero before install packoff.
5. Logging crew to rig up PNX-PBMS tool string and packoff.
6. Pressure test to 3k PSI to verify the equipment integrity.

7. Surface check on tools prior to run in hole(RIH). Minitron NOT to be turned on at surface at any time.
8. RIH to 1000 ft and turn on minitron, perform a test log to verify tool is operational, once completed turn off minitron and continue RIH with tool on logging GR-CCL.
9. RIH to TD power on minitron and wait for tool stabilization.
10. Once stable, begin main pass at 900 ft/hr in GSH-Commercial mode GR-CCL-Temp-Press.
11. Log up to 500 ft "confirm logging interval with client at well-site".
12. Once main pass completed, RIH and perform a repeat pass 200 ft.
13. Upon logging completion turn off minitron and wait below 200 ft for at least 30 minutes before pulling out of hole (POOH).
14. Upload data and confirm data integrity with Domain Champion prior to rigging down.
15. POOH and rig down tools.

3.12 Fluid level testing

OLCV will utilize an echometer to obtain a fluid level in the injector wells. The echometer tool contains a small chamber that is loaded with compressed CO_2 or N_2. The tool is charged to a pressure greater than the well pressure and connected to the well via an appropriately rated hose. A valve is then opened allowing a pressure pulse to be expelled into the well. This acoustic pulse travels through the gas in the borehole. Some of the energy is reflected back by well construction materials: tubing collars, tubing anchors, perfs, and other downhole jewelry. The remaining pulse energy is reflected by the gas/liquid interface at the depth of the fluid level. The reflected signals are detected by microphones at the surface. A calculation is then performed to determine the depth of the fluid level based upon the speed required to travel downhole, reflect off the gas/fluid interface and return to surface.

4. <u>SLR Monitoring Wells – Pre-Op Strategy</u>

The Injection Zone for the BRP Project will be monitored by two Injection Zone Monitoring wells (SLR2 and SLR3). The SLR2 will be drilled prior to the commencement of CO_2 injection operations. The SLR3 will be drilled after operation injections commence, and its location may be refined based on updated AoR information. In addition to SLR wells, the Injection Zone will be monitored with data collected in four Water Withdrawal wells (WW).

Data collected in the water withdrawal wells (constructed and tested in Spring 2024) indicates an absence of permeable zones between the upper confining zone and the lowermost USDW. Therefore, the lowermost USDW is coincident with the first permeable zone above the confining zone. The lowermost USDW will be monitored by the USDW1 well.

The Shoe Bar 1 stratigraphic test well will be plugged above the Injection Zone prior to the commencement of CO_2 injection. The portion of the well above the Injection Zone contains

DTS/DAS fiber that may be used during VSP seismic acquisition and for monitoring pressure and temperature above the confining zone. The Shoe Bar 1 AZ will be plugged above the Injection Zone prior to the commencement of CO_2 injection. The confining zone integrity will be monitored in this well.

The need for additional monitoring wells will be considered during AoR re-evaluations, and at least every five years following commencement of injection. The locations and timing of monitor wells is discussed in the AoR and Corrective Action Plan.

4.1 Logging Program

4.1.1 Logs in SLR monitoring wells

See Section 3 of this document for a description of the data collected in the Shoe Bar 1 (SLR1) and Shoe Bar 1AZ (ACZ1) wells. The log data listed in the table below is planned for collection in the SLR2 and SLR3 wells.

Table 15–Logging program for SLR2 and SLR3 monitoring wells

Method	Interval (ft)	Purpose
Open Hole Logs, Surveys and Sampling During Construction		
Deviation survey	Every 100 ft while drilling as minimum, from surface to TD	Define well trajectory, displacement, and tortuosity
Wireline – Spontaneous Potential	Production	Correlation log, volume of shale indicator, estimate salinity
Wireline – Gamma ray	Production	Define stratigraphy, correlation log, shale indicator
Wireline – Resistivity	Production	Fluid identification, estimate salinity, correlation log
Wireline – Caliper	Production	Identify borehole enlargement and calculate cement volume
Wireline – Sonic Scanner	Production	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline – Spectral gamma ray	Production	Define uranium rich formation, clay indicator
Wireline – Density / Neutron	Production	Estimate porosity, mineralogical characterization.
Wireline – Formation dynamics testing	Production	Measure formation pressures, fluid sampling
Mud Logging	Surface to TD (every 30 ft)	Identify lithology, hydrocarbon shows, gases composition

Cased Hole Logs and surveys Before Injection		
CBL-VDL-USIT-CCL	Surface, Intermediate, Production	Cement bond, casing integrity. Validate external mechanical integrity
Annulus Pressure Test – Long string casing	Annular between tubing and long string.	Validate internal mechanical integrity between the tubing, long string, and packer
Wireline – Activate pulsed neutron, through tubing	Surface, Intermediate, Production	CO_2 saturation, baseline for monitoring
Wireline – Casing Inspection Tool	Surface, Intermediate, Production	Wall thickness, corrosion, ovality of tubulars. Validate external mechanical integrity. Baseline for monitoring
Fiber Optic – DTS survey	Surface, Intermediate, Production	Measure baseline temperature profile on the well from surface to top of perforation. Acquire baseline 3D VSP survey for monitoring plume migration over time

The logs listed in Table 15 will be conducted on the SLR2 and SLR3 wells.

4.2 Coring Program

Whole core and sidewall cores were collected in the Shoe Bar 1 and Shoe Bar 1AZ wells. The Project does not intend to acquire any additional core in future monitoring wells.

4.3 Formation Fluid Characterization Program

4.3.1 Acquisition

The BRP Project will utilize an MDT tool to acquire reservoir fluid samples from the zones being monitored in the SLR2 and SLR3 wells. The Project will obtain fluid samples from the Lower San Andres (up to six samples, subject to change). The final sample acquisition depths in these monitoring wells will be determined based on the petrophysical analysis of the open hole logs run prior to the MDT logging run.

Fluid samples were collected by an MDT tool in the water withdrawal wells, WW1, WW2, WW3 and WW4, during construction. See Section 6.3 for additional details on fluid sampling in these wells.

4.3.2 Analysis and Reporting

The fluid sample containers will be transported under pressure to a third-party lab for comprehensive analysis of fluid and dissolved. See Table 16 for the analytical methods and QC parameters for fluid and dissolved gas analyses.

Table 16–Summary of analytical parameters for fluid and dissolved gas samples in the Injection Zone (Lower San Andres).

Laboratory Analyte	Analytical Methods[1]	Detection Limit / Range[2]	Typical Precision[2]	QC Requirements
Total and Dissolved Metals: Ag, Al, As, Ba, Cd, Co, Cr, Cu, Mn, Mo, Ni, Pb, Sb, Se, Sr, Th, Tl, U, V, and Zn	USEPA Method 200.8	0.00004 to 0.003 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof
Total and Dissolved Metals: B, Ca, Fe, K, Mg, Li, Na, Si, Sr, Ti	USEPA Method 200.7	0.003 to 0.254 mg/L	±20	Daily calibration, Initial QC checks (IPC, ICV, ICB, RL) method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Total and Dissolved Hg	USEPA Method 245.7	19.6 ng/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved Inorganic Carbon (DIC); Dissolved Organic Carbon (DOC)	Standard Method 5310C	0.198 to 0.290 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved CO_2	Standard Method 4500 CO_2 D	8 mg/L	±20	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Alkalinity: Total, Bicarbonate, Carbonate, and Hydroxide	Standard Method 2320B	8 mg/L	±20	method blank, lab control samples, matrix spikes
Major Anions: Br, Cl, F, and SO_4, NO_2 and NO_3 as N	USEPA Method 300.0	0.003 to 0.563 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
PO_4 as P	USEPA Method 365.1	0.0215 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof

Dissolved H_2S (Sulfide)	Standard Method 4500S2-D	0.026 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup
Total Dissolved Solids (TDS)	USEPA Method 160.1	10 mg/L	±20	Method blank, lab control samples, and sample duplicate
Conductivity	Standard Method 2510B	0 to 200 mS/cm	±1%	Calibration as needed, daily QC checks (1413, 14130 and second source SRM), CCV every 10 samples or part thereof
pH and Temperature	USEPA Method 150.1	0.1 to 14 pH units	±0.1 pH units	Daily calibration, second source SRM, CCV's every 10 samples or part thereof
Specific Gravity	ASTM Method D1429-03	NA	To the nearest thousandths decimal	Duplicates
Cation Anion Balance	Calculation	NA	±10	Calculation
Dissolved Gas Abundances: CO_2, CO, N_2, Ar, He, H_2, O_2, C1-C6+	In-house Lab SOP, similar to RSK-175	1 to 100 ppm, varies by component	C1-C4: ± 5%; C5-C6+: ± 10%	20% of all analyses are check/reference standards.
Dissolved Gas Isotopes: $\delta^{13}C$ of C1-C5 and CO_2, $\delta^{2}H$ of C1	High precision (offline) analysis via Dual Inlet IRMS	Varies by component	$\delta^{13}C$: 0.1 per mil; $\delta^{2}H$: 3.5 per mil	20% of all analyses are check/reference standards.
^{14}C of C1	AMS - subcontracted to Beta Analytic	0.44 pMC	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
^{14}C of DIC	AMS - subcontracted to Beta Analytic	Depends on available sample volume	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
$\delta^{13}C$ of DIC	Gas Bench/CF-IRMS	Depends on available sample volume, minimum of 50mg/L required	0.20 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	Analyzed via CRDS	N/A	$\delta^{18}O$: 0.10 per mil; $\delta^{2}H$: 2.0 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$^{87}Sr/^{86}Sr$	TIMS - subcontracted	Approximately 40 ppm	± 0.00002	SRM 987 Sr standard within the long-term precision

	to the University of AZ			(external precision) of +/- 0.00002 accepted value of 0.71025
$^{228}Ra/^{226}Ra$	USEPA Method 901.1	50 pCi/L (RL)	± 25%	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Field Parameters				
pH (Field)	Standard Method2 4500-H+ B-2000	2 to 12 pH units	±0.2 pH units	User calibration per manufacturer recommendation
Specific conductance (Field)	EPA Method 120.1	0 to 200 mS/cm	±1%	User calibration per manufacturer recommendation
Temperature (Field)	Standard Method 2550 B-2000	-5 to 50 ºC	±0.2 ºC	Factory calibration
Oxidation-Reduction Potential (Field)	Standard Method 2580	-1999 to +1999 mV	±20 mV	User calibration per manufacturer recommendation
Dissolved Oxygen (Field)	ASTM Method D888-09 (C)	0 to 50 mg/L	0 to 20 mg/L: ±0.1 mg/L or 1% of reading, whichever is greater; 20 – 50 mg/L: ±8% of reading	User calibration per manufacturer recommendation
Turbidity (Field)	USEPA Method 180.1	0 to 1000 NTU	± 1% of reading or 0.01 NTU, whichever is greater	User calibration per manufacturer recommendation

[1]An equivalent method may be employed with the prior approval of the UIC Program Director.
[2]Detection limits and precision (laboratory control limits) are typical for these analytical methods.
* Analytical parameters to be included during the pre-injection phase, and only as needed during the injection and post-injection phases of the Project.

4.4 Fracture Pressure

Fracture pressure was obtained in the Shoe Bar 1 and Shoe Bar 1AZ and will be obtained in the CO_2 injection wells. No fracture pressure measurements area planned for the SLR2 or SLR3 wells.

4.5 Well Mechanical Integrity

4.5.1 Mechanical Integrity Testing (MIT)

The BRP Project will conduct both internal and external mechanical integrity tests on the SLR2 and SLR3 wells. Internal mechanical integrity refers to the absence of leaks in the casing by tubing annulus, the tubing, and the packer. External mechanical integrity refers to the absence of formation fluid or CO_2 movement through channels in the cement on the exterior of the casing.

Upon completion and installation of the downhole equipment in the wells, BRP will conduct an APT to verify internal mechanical integrity. The APT is a short-term pressure test (30 minutes) where the well is shut in and the fluid in the annulus is pressurized to a predetermined pressure and is monitored for leak off. BRP will use a test pressure of 500 psi for the MIT's. BRP will use a 5% decrease in pressure (test pressure x .05) from the stabilized test pressure during the duration of the test to determine if test is successful. If the annulus pressure decreases by ≥5%, the well will have failed the APT. If a well fails an APT, the test will be repeated. If the APT is again failed, the downhole equipment will be removed from the well and the source of the failure will be investigated. The proposed procedure will be as follows:

1. Connect a high-resolution pressure transducer to the annulus casing valve and increase the annulus pressure to 500 psi and hold this pressure for 30 minutes.
2. At the conclusion of the 30-minute test the annulus pressure will be bled off to 0 psi and the pressure recording equipment will be removed from the casing valve.

Upon well completion, BRP will run cased hole logs to demonstrate external mechanical integrity of the casing and cement sheath prior to the start-up of operations. BRP will acquire baseline temperature logs to demonstrate a lack of fluid movement through channels or communication paths through the tubing or annulus. BRP will also run an ultrasonic imaging tool (USIT) to provide further confidence that there are no channels in the cement sheath for formation fluids or CO_2 to migrate upwards in the well.

5. <u>USDW Monitoring Well</u>

The Dockum group is the lowermost Underground Source of Drinking Water. Maps and additional stratigraphic details for the USDWs are included in the "Area of Review and Corrective Action Plan" document in Section 2.2.8 and in Section 2.4 of Appendix B to the AoR document. The USDW1 well was drilled in late 2023 and completed in early 2024. The dedicated purpose of this well is to monitor the Dockum group.

Although the shallow Pecos Valley alluvium is considered a USDW, it is generally not productive of water near the BRP Project. There are no current or planned wells in the AoR or near the AoR targeting the Pecos Valley alluvium.

5.1 Logging Program

Table 17 shows the logging and surveys conducted in the USDW monitoring well.

Table 17--Logs collected in the USDW-level well

Method	Interval (ft)	Purpose
Open Hole Logs, Surveys and Sampling During Construction		
Deviation survey	Every 100 ft while drilling as minimum, from surface to TD	Define trajectory, displacement, and tortuosity
Wireline – Spectral gamma ray	Surface to TD	Define uranium rich formation, clay indicator
Wireline- Spontaneous Potential	Surface to TD	Correlation log, volume of shale indicator, estimate salinity
Wireline –Resistivity	Surface to TD	Fluid identification, estimate salinity, correlation log
Wireline – Density / Neutron	Surface to TD	Estimate porosity, mineralogical characterization
Wireline – Caliper	Surface to TD	Identify borehole enlargement and calculate cement volume

5.2 Formation Fluid Characterization Program

5.2.1 Acquisition

The Project will monitor the chemical composition of the fluids and dissolved gases in the lowermost USDW, the Dockum group. A fluid sample was collected during well construction. The results are presented in Section 5.0 of Appendix A to the AoR document. Baseline samples will be collected on a quarterly basis for approximately one year prior to the start of injection. Baseline data collection will commence in June 2024. These samples will be collected by a qualified environmental monitoring and service provider and overseen by Oxy or OLCV personnel.

5.2.2 Analysis and Reporting

Table 18 includes the analysis that will be performed by the qualified environmental service provider and verified by Oxy or OLCV personnel.

Table 18-- Summary of analytical parameters for fluid and dissolved gas samples in the USDW (Dockum group)

Laboratory Analyte	Analytical Methods[1]	Detection Limit / Range[2]	Typical Precision[2]	QC Requirements
Total and Dissolved Metals: Ag, Al, As, Ba, Cd, Co, Cr, Cu, Mn, Mo, Ni, Pb, Sb, Se, Sr, Th, Tl, U, V, and Zn	USEPA Method 200.8	0.00004 to 0.003 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof

Total and Dissolved Metals: B, Ca, Fe, K, Mg, Li, Na, Si, Sr, Ti	USEPA Method 200.7	0.003 to 0.254 mg/L	±20	Daily calibration, Initial QC checks (IPC, ICV, ICB, RL) method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Total and Dissolved Hg	USEPA Method 245.7	19.6 ng/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved Inorganic Carbon (DIC); Dissolved Organic Carbon (DOC)	Standard Method 5310C	0.198 to 0.290 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved CO_2	Standard Method 4500 CO_2 D	8 mg/L	±20	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Alkalinity: Total, Bicarbonate, Carbonate, and Hydroxide	Standard Method 2320B	8 mg/L	±20	method blank, lab control samples, matrix spikes
Major Anions: Br, Cl, F, and SO_4, NO_2 and NO_3 as N	USEPA Method 300.0	0.003 to 0.563 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
PO_4 as P	USEPA Method 365.1	0.0215 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof
Dissolved H_2S (Sulfide)	Standard Method 4500S2-D	0.026 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup
Total Dissolved Solids (TDS)	USEPA Method 160.1	10 mg/L	±20	Method blank, lab control samples, and sample duplicate
Conductivity	Standard Method 2510B	0 to 200 mS/cm	±1%	Calibration as needed, daily QC checks (1413, 14130 and second source SRM),

				CCV every 10 samples or part thereof
pH and Temperature	USEPA Method 150.1	0.1 to 14 pH units	±0.1 pH units	Daily calibration, second source SRM, CCV's every 10 samples or part thereof
Specific Gravity	ASTM Method D1429-03	NA	To the nearest thousandths decimal	Duplicates
Cation Anion Balance	Calculation	NA	±10	Calculation
Dissolved Gas Abundances: CO_2, CO, N_2, Ar, He, H_2, O_2, C1-C6+	In-house Lab SOP, similar to RSK-175	1 to 100 ppm, varies by component	C1-C4: ± 5%; C5-C6+: ± 10%	20% of all analyses are check/reference standards.
Dissolved Gas Isotopes: $\delta^{13}C$ of C1-C5 and CO_2, $\delta^{2}H$ of C1	High precision (offline) analysis via Dual Inlet IRMS	Varies by component	$\delta^{13}C$: 0.1 per mil; $\delta^{2}H$: 3.5 per mil	20% of all analyses are check/reference standards.
^{14}C of C1	AMS - subcontracted to Beta Analytic	0.44 pMC	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
^{14}C of DIC	AMS - subcontracted to Beta Analytic	Depends on available sample volume	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
$\delta^{13}C$ of DIC	Gas Bench/CF-IRMS	Depends on available sample volume, minimum of 50mg/L required	0.20 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	Analyzed via CRDS	N/A	$\delta^{18}O$: 0.10 per mil; $\delta^{2}H$: 2.0 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$^{87}Sr/^{86}Sr$	TIMS - subcontracted to the University of AZ	Approximately 40 ppm	± 0.00002	SRM 987 Sr standard within the long-term precision (external precision) of +/- 0.00002 accepted value of 0.71025
$^{228}Ra/^{226}Ra$	USEPA Method 901.1	50 pCi/L (RL)	± 25%	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Field Parameters				
pH (Field)	Standard Method2 4500-H+ B-2000	2 to 12 pH units	±0.2 pH units	User calibration per manufacturer recommendation

Specific conductance (Field)	EPA Method 120.1	0 to 200 mS/cm	±1%	User calibration per manufacturer recommendation
Temperature (Field)	Standard Method 2550 B-2000	-5 to 50 ºC	±0.2 ºC	Factory calibration
Oxidation-Reduction Potential (Field)	Standard Method 2580	-1999 to +1999 mV	±20 mV	User calibration per manufacturer recommendation
Dissolved Oxygen (Field)	ASTM Method D888-09 (C)	0 to 50 mg/L	0 to 20 mg/L: ±0.1 mg/L or 1% of reading, whichever is greater; 20 – 50 mg/L: ±8% of reading	User calibration per manufacturer recommendation
Turbidity (Field)	USEPA Method 180.1	0 to 1000 NTU	± 1% of reading or 0.01 NTU, whichever is greater	User calibration per manufacturer recommendation

[1]An equivalent method may be employed with the prior approval of the UIC Program Director.
[2]Detection limits and precision (laboratory control limits) are typical for these analytical methods.
* Analytical parameters to be included during the pre-injection phase, and only as needed during the injection and post-injection phases of the Project.

5.3 Well Mechanical Integrity

Per Texas Water Development Board, mechanical integrity testing is not required for the USDW1 monitoring well.

6. <u>Water Withdrawal Wells</u>

BRP Project has constructed four water withdrawal wells in Spring 2024. The purpose of these wells is to remove brine from the Injection Zone for pressure management. The Project collected logs and fluid samples in these wells. Preliminary results are presented in Section 5.2 of Appendix A to the AoR document.

6.1 Logging Program

The table below shows the logging and surveys for the water withdrawal wells.

Table 19--Logging, survey, and sampling program for water withdrawal wells

Method	Interval Section(s)	Purpose
Open Hole Logs, Surveys and Sampling During Construction		
Deviation survey	Every 100 ft while drilling as minimum, from surface to TD	Define well trajectory, displacement, and tortuosity
Wireline- Spontaneous Potential	Production	Correlation log, volume of shale indicator, estimate salinity
Wireline – Resistivity	Production	Fluid identification, estimate salinity, correlation log
Wireline – Caliper	Production	Identify borehole enlargement and calculate cement volume
Wireline -Gamma ray	Production	Define stratigraphy, correlation log, shale indicator
Wireline -Sonic Scanner	Production	Estimate mechanical properties, validation of velocity model, well tie to seismic
Wireline - Spectral gamma ray	Production	Define uranium rich formation, clay indicator
Wireline - Density / Neutron	Production	Estimate porosity, mineralogical characterization
Wireline - Formation Dynamics Testing	Production	Fluid sampling, estimate Kv/Kh*
Wireline – Magnetic resonance image**	Production	Estimate porosity, pore size distribution, permeability index
Cased Hole Logs		
Wireline - CBL-VDL-USIT-CCL	Surface, Intermediate, Production	Cement bond, casing integrity. Validate external mechanical integrity
Wireline – Temperature Log	Surface, Intermediate, Production	Measure baseline temperature profile on the well
Annulus Pressure Test - Long string casing	Annular between tubing and long string	Validate internal mechanical integrity between the tubing, long-string, and packer
Wireline - Activate pulsed neutron – Long string casing	Intermediate, Production	CO_2 saturation, baseline for monitoring

* - Vertical interference testing performed in SBR 1WW and SBR 2WW only, for estimation of Kv/Kh
** - Magnetic resonance log only run in SBR 2WW and SBR 3WW

The logs listed in Table 19 were conducted in the water withdrawal wells.

6.2 Coring Program

No core was collected in the water withdrawal wells.

6.3 Formation Fluid Characterization Program

The BRP Project utilized an MDT tool to acquire reservoir fluid samples in the water withdrawal wells during construction to capture baseline fluid properties and chemistry. BRP Project is awaiting the geochemical results of water samples obtained from the Injection Zone.

The BRP Project attempted to acquire reservoir fluid samples above the upper confining zone and below the lowermost USDW, however these zones were tight. See Section 5.2 of Appendix A to the AoR document for details on sampling above the confining zone.

6.4 Fracture Pressure

No fracture pressure measurements were collected in the water withdrawal wells.

6.3 Well Mechanical Integrity

The BRP Project conducted both internal and external mechanical integrity tests on four water withdrawal wells. Internal mechanical integrity refers to the absence of leaks in the casing by tubing annulus, the tubing, and the packer. External mechanical integrity refers to the absence of formation fluid or CO_2 movement through channels in the cement on the exterior of the casing.

Upon the completion of drilling of the four water withdrawal wells and prior to perforating, BRP conducted an internal mechanical integrity test (MIT) to confirm wellbore mechanical integrity. The MIT is a short-term pressure test (30 minutes) where the internal wellbore is loaded with fluid and pressured up to a predetermined pressure and is monitored for leak-off. BRP used a test pressure of 500 psi for the MITs. BRP used a 5% decrease in pressure (test pressure x .05) from the stabilized test pressure during the duration of the test to determine if test is successful. If the annulus pressure had decreased by ≥5%, the well would have failed the internal MIT. None of the four water withdrawal wells failed their MIT.

The procedure was:

1. Connect a high-resolution pressure transducer to the annulus casing valve and increase the annulus pressure to 500 psi and hold this pressure for 30 minutes.
2. At the conclusion of the 30-minute test the annulus pressure will be bled off to 0 psi and the pressure recording equipment will be removed from the casing valve.

Upon the completion of drilling, BRP conducted cased hole logs to demonstrate external mechanical integrity of the casing and cement sheath prior to the start-up of operations. BRP acquired baseline temperature logs to demonstrate a lack of fluid movement through channels or communication paths through the tubing or annulus. BRP conducted an ultrasonic imaging tool (USIT) to provide further confidence that there are no channels in the cement sheath for formation fluids or CO_2 to migrate upwards in the well.

7. References

Talley, G. R., Swindell, T. M., Waters, G. A., and K. G. Nolte. 1999. Field Application of After-Closure Analysis of Fracture Calibration Tests. Paper presented at the SPE Mid-Continent Operations Symposium, Oklahoma City, Oklahoma, March 1999. doi: https://doi.org/10.2118/52220-MS

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PRE-OPERATIONS TESTING PLAN, APPENDIX A: CORE

Brown Pelican CO_2 Sequestration Project

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2.0 Justification for Core Collection Plan 2
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1.0 Facility Information

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS1, CCS2 and CCS3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

2.0 Justification for Core Collection Plan

OLCV does not intend to acquire additional whole core data in BRP CCS1 or BRP CCS2, because the structural and stratigraphic settings, and rock properties of the Injection and Upper Confining Zones are well-constrained by the >700 feet of whole core acquired in the Shoe Bar 1AZ. The Shoe Bar 1AZ is located in close proximity, less than 2,000 ft, from the planned Injection Zone penetration points in the BRP CCS1 and BRP CCS2.

OLCV is confident that the Lower San Andres encountered at the Shoe Bar 1AZ is representative of the stratigraphy and rock properties that will be encountered in the Lower San Andres at the BRP CCS1 and BRP CCS2 for two key reasons: (1) The depositional setting of the Lower San Andres formation is interpreted to be laterally extensive for 1000s of feet, and (2) the seismic character resulting from rock and fluid properties at the Shoe Bar 1AZ is consistent with seismic character at the proposed BRP CCS1 and BRP CCS2 locations.

The paleo-structural setting encountered in the Shoe Bar 1AZ is anticipated to be consistent with the structural setting expected in the BRP CCS1 and BRP CCS2. The BRP Project area is located downdip from the Penwell structural high (present-day Penwell oil field). At the time of deposition, the Lower San Andres formation strata prograded westward at a low angle, following gentle structural dip. Outer ramp subtidal fusulinid packstone facies were stacked on top of each other by pulses of sedimentation shed from the Penwell structural high.

The stratigraphic setting encountered at Shoe Bar 1AZ is modeled to be consistent with the stratigraphic setting at BRP CCS1 and BRP CCS2. Kerans et al. (1994) and Kerans and Fitchen (1995) measured stratigraphic sections and mapped facies across a 2.5-mile outcrop window of the Lower San Andres formation centered at Lawyer Canyon along the Algerita Escarpment. Their detailed geostatistical analyses and stratigraphic framework served as a guide for geobody dimensions and geobody orientation included in the BRP Project geocellular model.

The facies encountered in the Shoe Bar 1AZ is anticipated to be consistent with the facies that will be encountered in the BRP CCS1 and BRP CCS2. The BRP Project Injection Zone is equivalent in time to the peloid-fusulinid-crinoid grain-dominated packstone facies of the Lower San Andres composite sequence described by Kerans et al. (1994). This is a subtidal facies that has a sheetlike geometry. Dip continuity ranges from approximately 7,500 ft for low-angle (0.5°) ramp margins to approximately 750 ft for high angle (5°) ramp margins. Average dip continuity for these subtidal facies in the Lower San Andres highstand sequence set is approximately 3,000 ft. Average vertical continuity is approximately 8 ft, while average strike continuity is estimated to be 3,500–4,000 ft (Kerans et al., 1994; Kerans and Fitchen 1995).

The rock properties, e.g., lithology, grain size, and porosity, encountered at the Shoe Bar 1AZ are expected to be consistent with the rock properties that will be encountered at the BRP CCS1 and BRP CCS2. The seismic character at Shoe Bar 1AZ is moderate to high seismic amplitude with high continuity of parallel, sub-horizontal seismic reflections. This seismic character is continuous and present at the BRP CCS1 and BRP CCS2 locations. Because the seismic character is calibrated to rock properties at Shoe Bar 1AZ, the rock properties at the BRP CCS1 and BRP CCS2 locations can be confidently inferred.

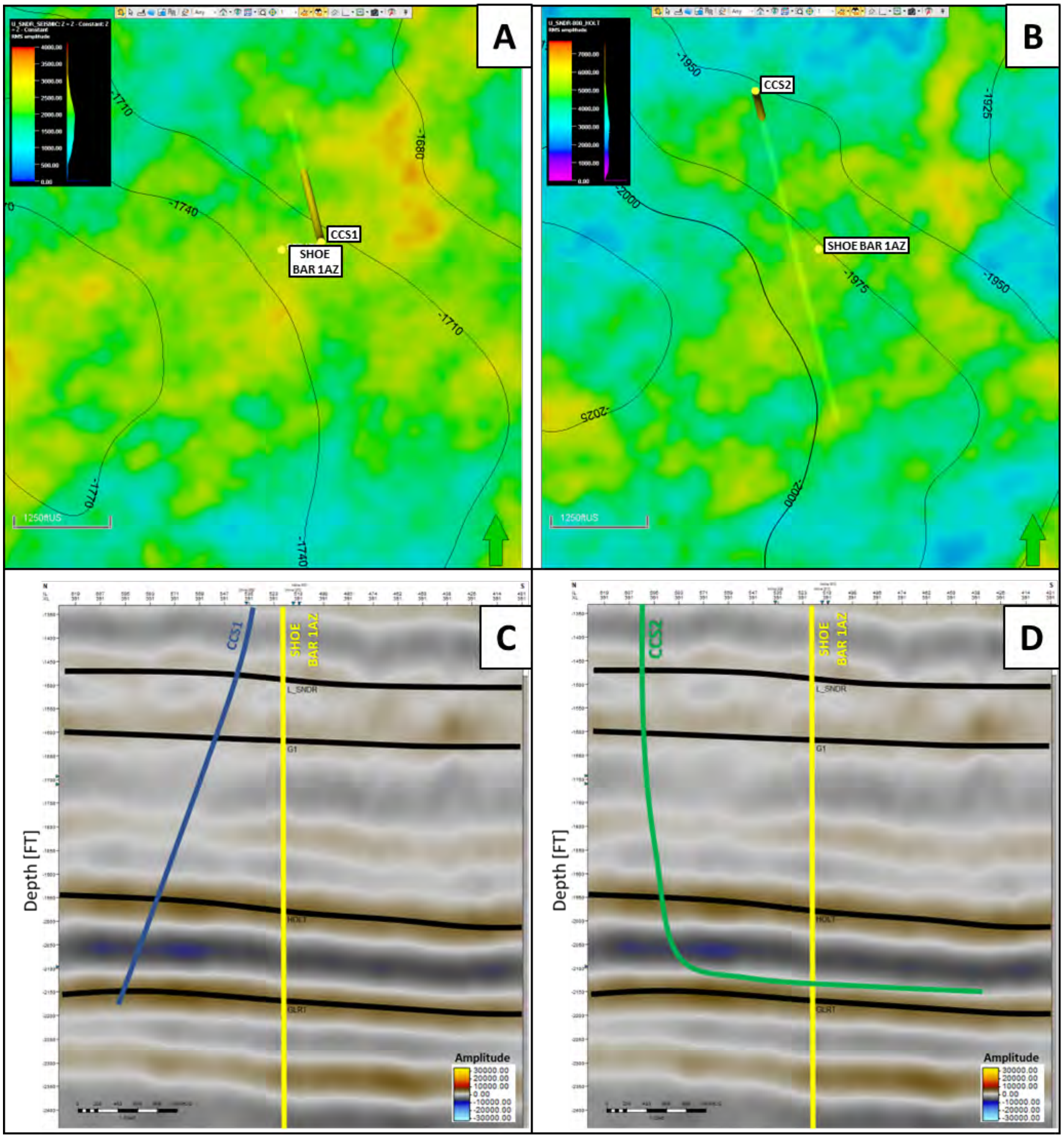

Figure 1--Wellbore trajectories for Shoe Bar 1AZ, BRP CCS2, and BRP CCS1 are located within a continuous high seismic amplitude (green to yellow color) facies, which serves as proxy for rock quality. Core and well log data acquired in well Shoe Bar 1AZ are a representative sample of porosity and permeability for the pore volume to be drilled by wells BRP CCS2 and BRP CCS1.

References:

Kerans, C., Lucia, F.J. and Senger, A.R., 1994. Integrated characterization of carbonate ramp reservoirs using Permian San Andres Formation outcrop analogs. AAPG bulletin, 78(2), pp.181-216.

Kerans, C., and Fitchen, W. M. 1995. Sequence hierarchy and facies architecture of a carbonate-ramp system: San Andres Formation of Algerita Escarpment and western Guadalupe Mountains, west Texas and New Mexico. Austin, Texas: The University of Texas Bureau of Economic Geology, *Report of Investigations 235*, 86 p.

TESTING AND MONITORING PLAN
40 CFR §146.90

Brown Pelican CO_2 Sequestration Project

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1.0 Facility Information and Plan Overview

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS1, CCS2 and CCS3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

This Testing and Monitoring Plan describes how Oxy Low Carbon Ventures, LLC (OLCV), will monitor the Brown Pelican CO_2 Sequestration Project (BRP Project or Project) site pursuant to 40 CFR §146.90. Testing and monitoring data will be used to demonstrate that the CO_2 Injection wells are operating as planned, the CO_2 plume and pressure front are behaving as predicted, and that there is no endangerment to Underground Sources of Drinking Water (USDW). In addition, the testing and monitoring data will be used to validate and adjust the geocellular and simulation models used to predict the distribution of the CO_2 within the storage zone to support Area of Review (AoR) re-evaluations and a non-endangerment demonstration at site closure.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

2.0 Overall Strategy and Approach for Testing and Monitoring

The Testing and Monitoring Plan was designed to monitor and mitigate the key risks identified for this project that are described in the Emergency and Remedial Response Plan (part of this application). During the Injection and Post-injection periods, those risks include the potential for: well integrity failure, leakage to USDW, natural disasters, induced seismicity or critical surface impacts. The testing and monitoring methods included in this document are mitigations and controls to prevent CO_2 or brine leakage out of the Injection Zone that could endanger the USDWs, migrate to a different stratum, or create a risk for people or the environment.

In addition, the testing and monitoring program is tailored to track the migration of the CO_2 plume and development of the pressure front within the Injection Zone. Data will be collected prior to injection to establish a baseline. Data collected during the injection and post-injection periods from the testing and monitoring program will help to validate the simulation models and re-evaluate the AoR.

The testing and monitoring program includes controls and mitigations in the following categories:

1. Carbon dioxide stream analysis
2. Continuous recording of operational parameters: injection rate, volume, pressure, temperature, and internal mechanical integrity
3. Corrosion monitoring and leak detection
4. Above confining zone monitoring, including the first permeable zone above the confining zone, which is coincident with the lowermost USDW, and the near-surface
5. Internal and external mechanical integrity testing
6. Pressure fall-off testing
7. Carbon dioxide plume and pressure front tracking
8. Surface Monitoring

The methodology and frequency of testing and monitoring methods is expected to change throughout the life of the project. Pre-injection monitoring and testing will focus on establishing baselines and ensuring that the site is ready to receive injected CO_2. Injection phase monitoring will be focused on collecting data that will be used to calibrate models and ensure containment of CO_2. Post-injection phase monitoring and testing is designed to demonstrate CO_2 plume stabilization and ensure containment. The testing and monitoring plan will be reviewed at least once every five years and will be amended, if necessary, to ensure monitoring and storage performance is achieved and new technologies are appropriately incorporated.

Data obtained from the testing and monitoring plan will be used to inform operational decisions on the quantity and rate of CO_2 injected and potential containment actions. Data will be used to improve computational model forecasts. Data that is interpreted to be inconsistent with model predictions will trigger additional testing, monitoring and evaluation.

A summary of the proposed testing and monitoring methods and timing of testing and monitoring is listed in Table 1.

Table 1—Summary of Testing and Monitoring Frequency

Objective	Method	Frequency Pre-Injection	Frequency During Injection	Frequency Post-Injection
CO_2 injectate stream analysis	On-line gas chromatograph and/or gas analyzers in flowline and sampling in flowline	Chemical and isotopic characterization prior to injection	Continuous monitoring using gas chromatograph and/or analyzers; quarterly or event-driven[1] sampling for composition; and isotopic analysis if capture process materially changes source stream	N/A
Continuous recording of operational parameters in injection wells: injection rate, volume, pressure, and temperature	Surface and tubing-conveyed pressure and temperature gauges, DTS fiber, and injection line flowmeter	Measurement prior to injection	Continuous measurement and recording	N/A
Corrosion Monitoring in injection wells and surface leak detection	Coupons, visual inspection at wellhead, LDAR/OGI cameras, surface sensors, and DTS	Inspection prior to injection	Quarterly coupon testing, weekly visual inspection, quarterly inspection via LDAR/OGI cameras, and continuous monitoring via surface sensors and DTS	Continuous surface monitoring and quarterly visual inspection until site closure
Internal mechanical integrity	Pressure and temperature gauges, DTS, Annulus pressure monitoring, tubing-casing monitoring	Measurement prior to injection	Continuous measurement and recording	N/A
External mechanical integrity testing	Pressure and temperature gauges, DTS, and MIT	Measurement prior to injection	Continuous measurement and recording; and routine MIT	N/A
Near well-bore formation properties testing (Pressure fall-off testing)	Pressure fall-off test	Measurement prior to injection	Once during every five-year period until plugging	N/A
In-zone pressure, temperature, CO_2 saturation and geochemistry	Pressure and temperature gauges and/or DTS; saturation logging, and fluid and dissolved gas sampling	Characterization prior to injection, including quarterly fluid and dissolved gas sampling; cased hole saturation logging; PT gauge	Continuous measurement and recording of pressure and temperature; annual saturation profile; event-driven* fluid sampling,	P/T: Continuously for the first 10 years pending an approved PISC plan, then annually until plugging; saturation profile annually; event-

Objective	Method	Frequency Pre-Injection	Frequency During Injection	Frequency Post-Injection
		and DTS measurements prior to injection	triggered by changes in P/T	driven* fluid and dissolved gas sampling, triggered by P/T data
Geochemistry of the first permeable zone above the confining zone and the lowermost USDW (Dockum Group)	Fluid and dissolved gas sampling and analysis in USDW1 well	Characterization prior to injection, including quarterly fluid and dissolved gas sampling for at least one year	Quarterly geochemical sampling in years 1-3 and annually starting in year 4; and, event-driven*, triggered by P/T data in SLR2 or SLR3 wells	Annually for first 10 years post injection pending an approved PISC plan; event-driven*, triggered by P/T data in SLR2 or SLR3 wells thereafter
Soil gas analysis (vadose zone; near surface)	Isotopic analysis and chemical evaluation at approximately 21 locations	Characterization prior to injection, including quarterly sampling for at least one year prior to commencement of injection	Quarterly gas composition sampling in years 1-3 and annually starting in year 4 for subset of stations, and event-driven*, triggered by P/T data in SLR2, SLR3 or USDW1 monitor wells and fluid sample results	Event-driven*, triggered by P/T data in SLR2, SLR3 or USDW1 monitor wells and fluids sample results
Containment of CO_2 in Injection Zone	Pressure and temperature gauges and/or DTS; saturation logging, and event-driven* fluid and dissolved gas sampling	Characterization prior to injection, including quarterly sampling for approximately one year in WW wells; saturation logging in the Upper Confining Zone in SLR1 and ACZ1	Continuous measurement and recording of pressure and temperature (SLR1 and WWs); event-triggered fluid sampling in WWs; saturation logging once every five year period in SLR1 and ACZ1 wells	P/T or DTS: continuously for the first 10 years in SLR1 well or until plugging, pending an approved PISC plan; Saturation logging: event-driven* in the SLR1 or ACZ1
Non-endangerment of shallow groundwater and soil	Geochemical and isotopic monitoring to detect deviations from expected groundwater and soil gas chemistry	Characterization prior to injection: quarterly	Groundwater and soil gas sampling: Quarterly analysis in years 1-3, then annually after that; and, event-driven*, triggered by P/T data in SLR wells	Event-driven*
CO_2 plume and pressure movement within the Injection Zone	Pressure and temperature gauges and/or DTS; and event-driven* fluid sampling	P/T measurement, fluid sampling prior to injection in the SLR2 and WW wells	Continuous P/T measurement in SLR2 and SLR3 wells; event-driven* fluid sampling in SLR or WW wells	P/T recording bimonthly for the first five years post-injection, then annually until well is plugged or plume

Objective	Method	Frequency Pre-Injection	Frequency During Injection	Frequency Post-Injection
				stabilizes in SLR2 or SLR3 wells
Indirect geophysical monitoring of plume and pressure	2D VSP utilizing in-well fiber or wireline conveyed geophones; surface 2D; saturation logging; DInSAR and GPS	Prior to injection	Annual saturation logging in SLR2 and SLR3 wells; 2D VSP after 1, 2, 5 and 10 years; 2D surface seismic at year 10 and approximately every five years thereafter; Quarterly DInSAR and GPS	Annual saturation logging in SLR2 and SLR3 wells; surface 2D VSP once every approximately five-year period until plugging; 2D surface seismic once every approximately five years until plume stabilization Annual DInSAR and GPS for first five years post-injection
Presence or absence of seismicity	Seismometers	Prior to injection	Continuous monitoring and recording	Continuous monitoring and recording until site closure

[1]Event-driven sampling of CO2 injectate stream will be triggered if there are changes in the DAC process that may arise from facility upgrades or after facility shut-in periods.

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. In addition, fluid and dissolved gas chemistry data from the lowermost USDW and soil gas chemistry from shallow soils will be monitored for trends to detect deviations from reference chemistry. If persistent and/or abrupt anomalies in chemistry are detected additional fluid or soil gas samples will be obtained to confirm the presence or absence of increased CO_2.

2.1 Well Monitoring Network Design

Multiple testing and monitoring objectives described in Table 1 will be accomplished by evaluating data from monitoring wells (Table 2). These wells will provide direct measurements to compliment indirect measurement methods for monitoring the AoR. In addition, data from monitoring wells will be used to characterize fluid chemistry and isotopic composition throughout the stratigraphic column. A summary of data by well type is shown in Table 3.

OLVC plans to install a Single Reservoir-level (SLR) well, the SLR2, in the Injection Zone prior to the commencement of CO_2 injection, and OLCV has already installed a well to monitor the Underground Source of Drinking Water Aquifer (USDW) in the lowermost USDW, the Dockum

Group. The SLR3 well is anticipated to be drilled within five years after the commencement of injection and its location will be refined after commencement of operations. The need for additional monitoring wells will be evaluated as needed, and at least annually during the injection period and until plume stabilization. OLCV describes below the locations of monitoring wells to be installed prior to first injection and the proposed locations of future monitoring wells.

In addition to SLR2 and SLR3 wells, the Injection Zone will be directly monitored with data collected in four Water Withdrawal wells (WW). The WW wells will extract brine to manage pressure in the Injection Zone. The brine will be transported via pipeline for use in Oxy or third-party operations or transported to the location of planned Class I disposal wells. The CO_2 injectate plume is not expected to reach the WW1, WW3 and WW4. If the CO_2 plume does reach these WW wells, they will be shut in. The CO_2 injectate plume is expected to reach WW2. When the plume in the Holt sub-zone reaches WW2, the well will be plugged above the Holt and continue to produce brine from the upper portion of the Lower San Andres. The CO_2 injectate plume from the upper part of the Lower San Andres (Lower San Andres sub-zone and G1 sub-zone) is not expected to reach the WW2.

Note that OLCV previously intended to utilize the Shoe Bar 1 and Shoe Bar 1 AZ to monitor the first permeable zone above the confining zone. Wireline testing in the water withdrawal wells conducted in Spring 2024 indicates the absence of permeable zones above the confining zone and below the lowermost USDW. Therefore, the Dockum group is the both the lowermost USDW and the first permeable zone above the confining zone. The Shoe Bar 1USDW well will be used to monitor geochemistry in the Dockum group to meet 40 CFR 146.90(d).

Table 2—Planned wells used for monitoring

Regulatory Well Name	Project Well Name	Drill Date	Purpose	~TD (ft)	Latitude (NAD 27)	Longitude (NAD 27)
Shoe Bar 1	SLR1	2023	Upper Confining Zone Monitor	6585, ~4200[1]	31.76343602	-102.7034981
Shoe Bar 1AZ	ACZ1	2023	Upper Confining Zone Monitor	6725, ~4300[1]	31.74670102	-102.7259011
Shoe Bar 2SLR	SLR2	2025	Injection Zone monitor	5271	31.76448869	-102.7305326
Shoe Bar 3SLR	SLR3	~2030, five years after the commencement of injection	Injection Zone monitor	5316	31.76411900	-102.7316750
Shoe Bar 1USDW	USDW1	2023	Lowermost USDW monitor	850	31.78023685	-102.7418093
Shoe Bar 1WW	WW1	2024	Water withdrawal, Injection Zone monitor	5053	31.76289539	-102.6959232
Shoe Bar 2WW	WW2	2024	Water withdrawal, Injection Zone (G1-G4) monitor	5314, 4947[2]	31.78419981	-102.7275869

Shoe Bar 3WW	WW3	2024	Water withdrawal, Injection Zone monitor	5106	31.75008553	-102.7102206
Shoe Bar 4WW	WW4	2024	Water withdrawal, Injection Zone monitor	5337	31.76384464	-102.7539505

[1]Anticipated TD following conversion to monitor well
[2]Anticipated TD following plugging above Holt zone

Table 3—Summary of monitoring by well type and project stage

Well type	Objective	Method	Monitoring Pre-Injection	Monitoring During Injection	Monitoring Post-Injection
SLR2 and SLR3; Injection Zone monitoring	Direct monitoring of CO_2 plume and pressure front	Downhole and surface pressure and temperature gauges or DTS (selected wells)	Baseline sampling in SLR2	Continuous	Continuously for the first 10 years pending an approved PISC plan, then annually until plugging
	Direct measurement of fluids to detect CO_2	Fluid and dissolved gas sampling via wireline or U-tube	Baseline sampling in SLR2	Event-driven*	Event-driven*, until plugging
	Indirect monitoring of CO_2 concentration	Pulsed Neutron Log (PNL) or Reservoir Saturation Tool (RST) log	Baseline sampling in SLR2	Annually	Annually until plugging
	Indirect geophysical monitoring of plume and pressure	2D VSP (selected wells)	Baseline survey in SLR2	At years 1, 2, 5 and 10 in SLR2	Once every approximately five-year period until plugging in SLR2
	Internal and external mechanical integrity	Pressure and temperature (P/T) gauges or DTS; and external MIT	Baseline data in SLR2	Continuous P/T MIT log once every five-year period	MIT log once every five- year period and before plugging
	Corrosion monitoring	Casing inspection logging	NA	Once every five-year period	Once every five-year period until plugging
	Surface leak detection	Visual inspection at wellhead, LDAR/OGI cameras, surface sensors	NA	Weekly to quarterly, depending on tool	Continuous surface monitoring and quarterly visual inspection until site closure
SLR1 and ACZ1; Upper Confining Zone monitoring	Direct monitoring of pressure and temperature to ensure Upper Confining Zone integrity	Downhole and surface pressure and temperature gauges and/or DTS (SLR1)	Prior to injection	Continuously	Continuously for the first 10 years pending an approved PISC plan
	Indirect monitoring of CO_2 presence above the Injection Zone	PNL or RST log	Prior to injection	Once every five year-period	Event-driven* until plugging

	Internal and external mechanical integrity	Pressure and temperature gauges; external MIT	Prior to injection	MIT log once every five-year period	MIT log once every five-year period and before plugging
	Surface leak detection	Visual inspection at wellhead, LDAR/OGI cameras, surface sensors	NA	Weekly to quarterly, depending on tool	Continuous surface monitoring and quarterly visual inspection until site closure
USDW1; Lowermost USDW monitoring	Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry	Fluid and dissolved gas sampling using a bladder pump	Baseline sampling	Quarterly sampling in years 1-3, annually starting in year 4; and event-driven*	Annually for the first 10 years post injection pending an approved PISC plan; and event-driven*, until plugging
WW1, WW2, WW3, WW4; Injection Zone monitoring	Geochemical and isotopic monitoring to detect to detect CO_2	Fluid sampling at the wellhead	Baseline sampling	Event-driven*	Event-driven*, until plugging

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. In addition, fluid and dissolved gas chemistry data from the lowermost USDW and soil gas chemistry from shallow soils will be monitored for trends to detect deviations from reference chemistry. If persistent and/or abrupt anomalies in chemistry are detected additional fluid or soil gas samples will be obtained to confirm the presence or absence of increased CO_2.

2.1.1 Injection Zone monitoring wells

The SLR2 and SLR3 well locations were selected based on potential leakage pathway scenarios, and on the computationally simulated plume and critical pressure front. The modelled CO_2 plume and pressure front extends semi-radially from the BRP CCS1, CCS2 and CCS3 wells. SLR2 and SLR3 wells were placed to detect movement of the plume and pressure front.

OLCV proposes a phased drilling approach to allow for incorporation of operational data to the monitoring plan. The data obtained during early CO_2 injection may result in adjusting the well locations or timing of drilling. The proposed location, timing and data collected in SLR wells is described below:

- The Shoe Bar 1 well is a stratigraphic test well that was completed in February 2023. This well is located near the proposed BRP CCS3 CO_2 injector well and is within the maximum extent of the modelled AoR. For monitoring purposes the well will be referred to as SLR1. The Shoe Bar 1 well was not constructed with Cr25 casing; it will be plugged above the

Injection Zone prior to the commencement of CO_2 injection. The well contains DTS/DAS fiber that may be used during VSP seismic acquisition and for monitoring pressure and temperature above the confining zone. A baseline 2D VSP will be collected in the SLR1 (or in the BRP CCS3) prior to injection and will be repeated at 1, 2, 5 and 10 years after the commencement of injection.

- The SLR2 well will be drilled prior to the commencement of CO_2 injection or shortly thereafter (dependent on availability of CO_2 compatible casing) and will be located within the extent of the CO_2 plume created after approximately seven years of injection. Pressure and temperature will be monitored using downhole gauges and DTS fiber. Fluid samples from the Injection Zone may be collected, if pressure or temperature changes indicate a change in brine composition consistent with arrival of CO_2. A baseline 2D VSP will be collected in the SLR2 prior to injection and repeated at approximately 1, 2, 5 and 10 years after the commencement of injection. No CO_2 is anticipated to reach the SLR2 before year five of injection.

- The SLR3 well will be drilled within five years after the commencement of CO_2 injection and will be located within the maximum extent of the CO_2 plume created after 12 years of injection. Pressure and temperature will be monitored using downhole gauges. Fluid samples from the Injection Zone may be collected, if pressure or temperature changes indicate a change in brine composition consistent with arrival of CO_2. No CO_2 is anticipated to reach the SLR3 before year seven of injection. This well will be plugged when CO_2 reaches it unless CO_2 compatible casing is available and utilized at the time of construction.

The SLR2 and SLR3 wells will be completed with tubing and packer, will isolate the casing and formations in the Upper San Andres and Grayburg formations (Upper Confining Zone), and will have open perforations in the Lower San Andres (Injection Zone) to allow direct measurements in the Injection Zone (Figure 1). Pressure and temperature gauges will be tubing-deployed to track changes in reservoir conditions during the injection and post-injection periods. It will be possible to obtain fluid samples from the SLR2 and SLR3 wells to conduct geochemical analyses.

The figure below illustrates the design of proposed SLR2 well. Refer to Appendix A of the Injection Well Construction Plan for a wellbore diagram of SLR2 and SLR3. Note that a U-tube system for retrieving water samples is being considered for the SLR2 and SLR3. A U-tube system may allow for cost-effective sampling of fluids and dissolved gasses from the Injection Zone. However, there are few examples of this technology deployed to active projects in the field, therefore little is known about the expected life of the equipment at field conditions. Furthermore, existing U-tube systems are not typically deployed to reservoirs where H_2S is present. OLCV is working with vendors to determine whether a U-tube is appropriate for the reservoir conditions at the BRP Project.

U-tubes are not contemplated for water withdrawal wells, because the U-tube system would interfere with operation of the electrical submersible pump (ESP) installed to produce water. U-tubes are not contemplated for wells monitoring the confining zone (SLR1 or ACZ1) because frequent monitoring of fluid chemistry and dissolve gas is not planned for these wells, as no Injection Zone fluids are expected to reach these wells. A U-tube is not planned for the USDW1 well, because the well is designed with a bladder pump to efficiently sample fluids and dissolved gasses.

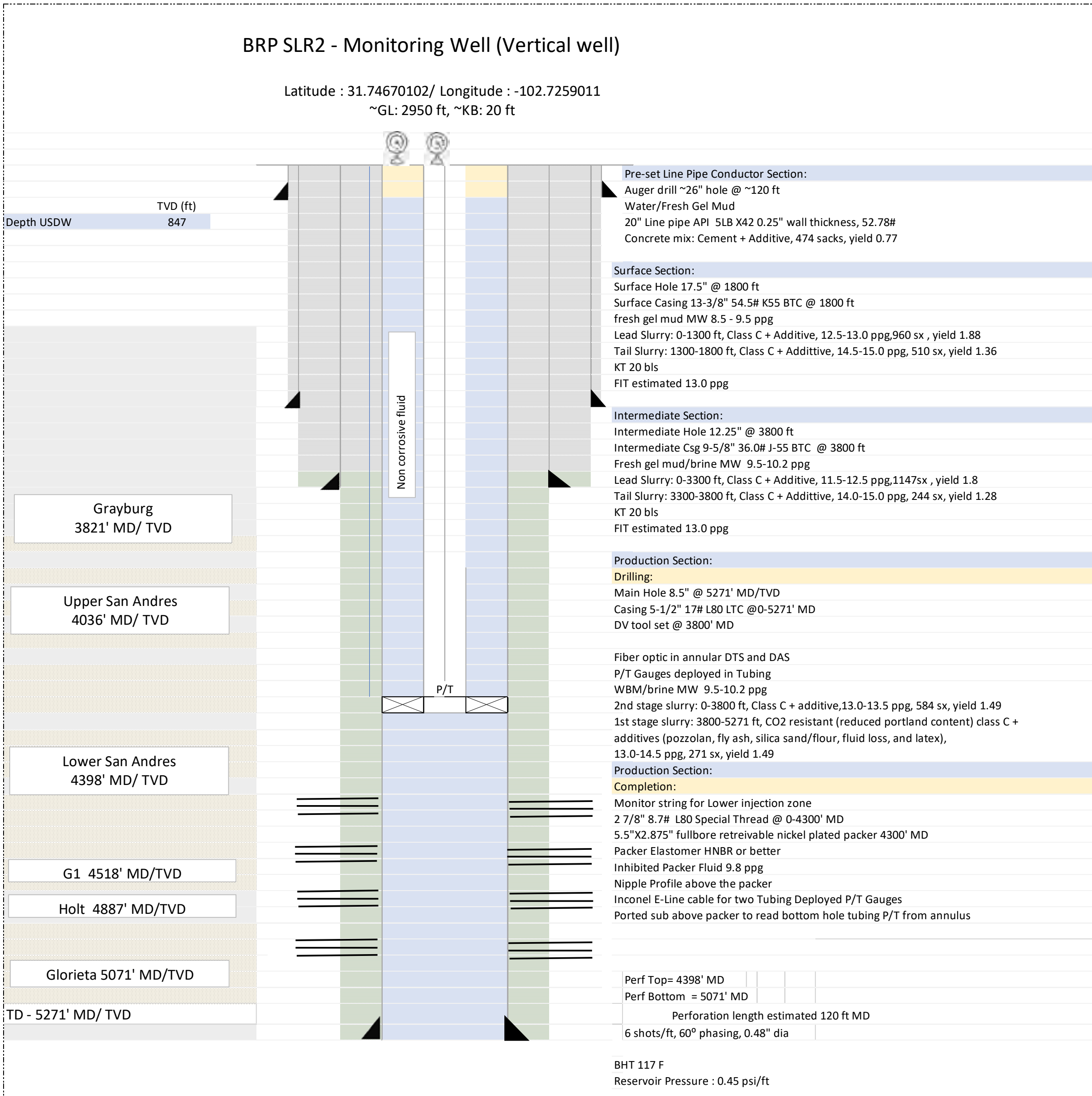

Figure 1—SLR2 schematic

2.1.2 Shoe Bar 1AZ well

The Project initially intended to convert the Shoe Bar 1AZ to be a monitoring well for the Yates formation, which was interpreted on log data from the Shoe Bar 1 and Shoe Bar 1AZ to the be first permeable zone above the Upper Confining Zone. However, wireline testing during construction of the Shoe Bar 1WW, Shoe Bar 2WW, Shoe Bar 3WW, and Shoe Bar 4WW shows the absence of permeable zones between the Upper Confining Zone and the lowermost USDW. The Dockum group is defined as the lowermost USDW. Therefore, the Dockum group is both the lowermost USDW and the first permeable zone above the confining zone. See Section 5 of Appendix A to the AoR document for a detailed description of testing and results.

The Shoe Bar 1AZ will be plugged above the Injection Zone prior to the commencement of injection. This well will be used to monitor integrity of the Upper Confining Zone through periodic saturation logging.

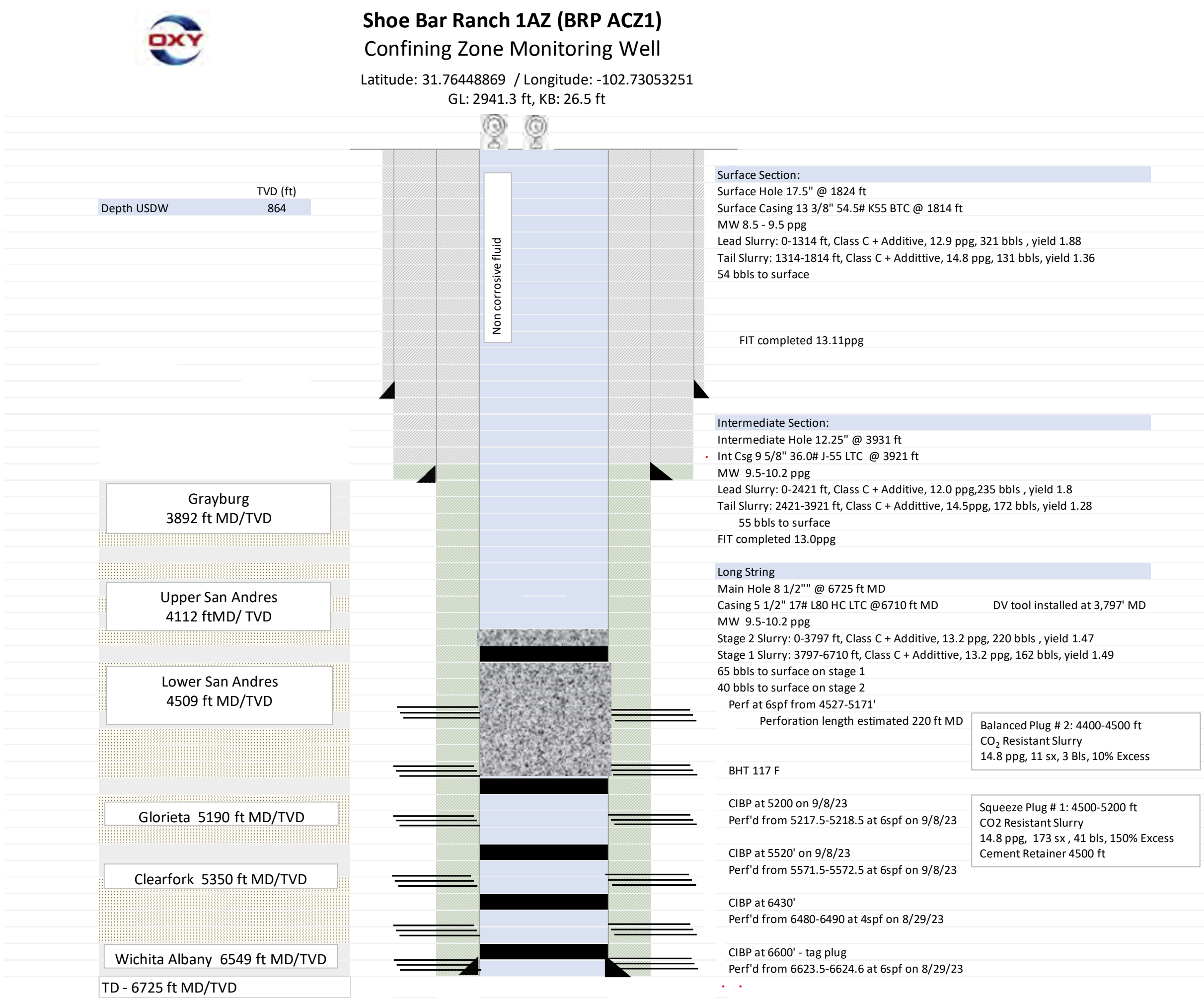

Figure 2—Shoe Bar 1AZ schematic after plugging above the Injection Zone

2.1.3 USDW Monitoring Well

A USDW-level well was drilled and completed in 2024 in the lower portion of the Dockum group, which is the lowermost USDW. This well will be used to collect baseline geochemical and isotopic information about the USDW prior to the commencement of CO_2 injection and will be used to monitor groundwater geochemistry and dissolved gas during the injection phase of the project.

The USDW monitoring well is located close to the BRP CCS1 and CCS2 wells and will be used to monitor the effects of the reservoir pressurization at the highest point of pressure and validate the sealing capacity of the Upper Confining Zone.

No other existing USDW wells are located within the expected AoR of the Project. Because the modelled AoR is small, ~2.5 miles in diameter, OLCV believes that one USDW well will provide sufficient monitoring data.

The figure below shows the wellbore diagram for the USDW1 well.

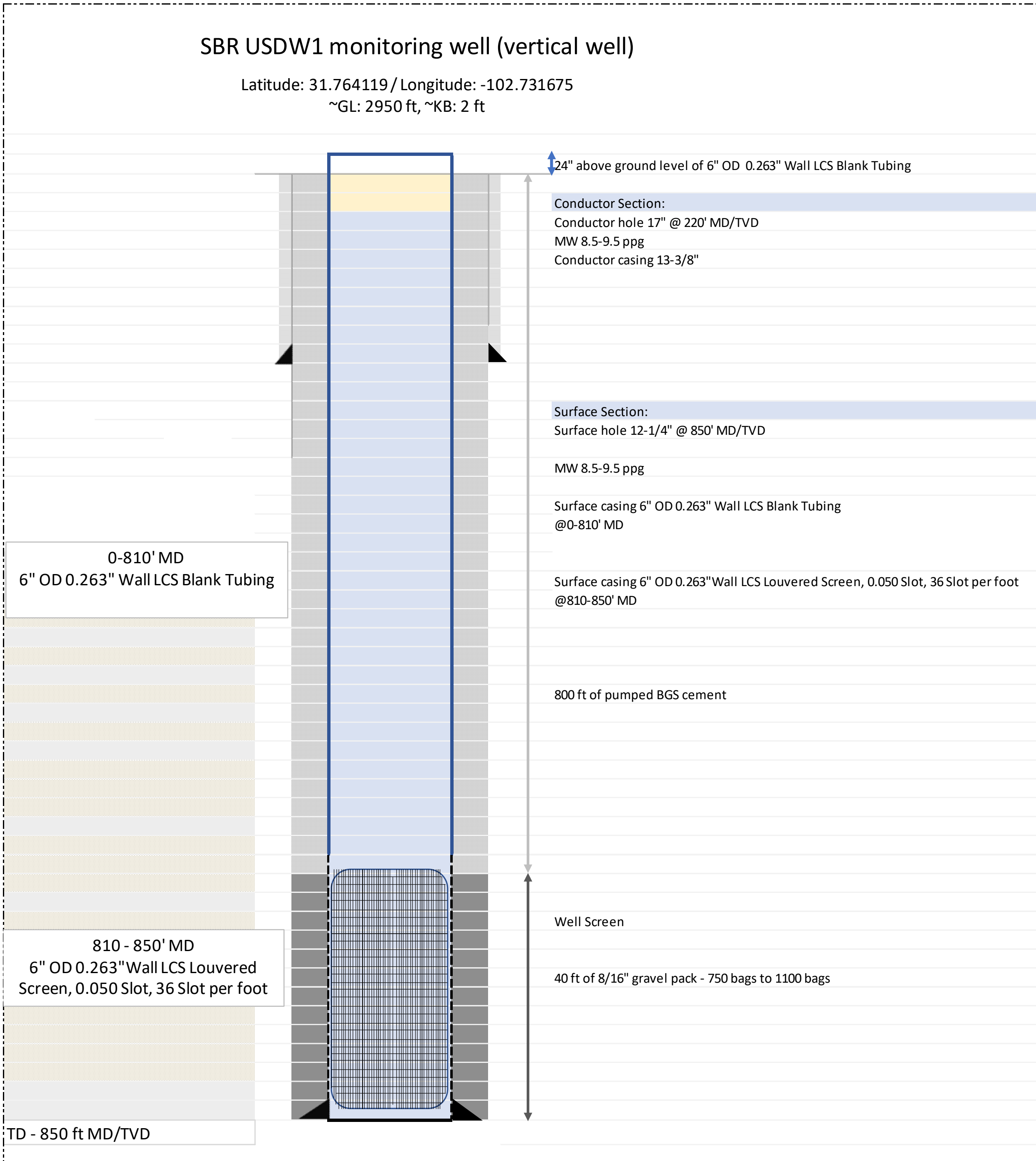

Figure 3—USDW Monitoring well

2.2 Other Monitoring Techniques

In addition to utilizing a well-based network to monitor pressure, temperature, and fluid and dissolved gas chemistry of the subsurface, OLCV will also utilize surface and near-surface methods to monitor CO_2 containment. Additional details on geophysical monitoring methods are described in Sections 11 and 12 of this document. Near-surface soil and soil gas monitoring is described in Section 8.2.

2.3 Quality Assurance Procedures Summary

A Quality Assurance and Surveillance Plan (QASP) for testing and monitoring activities, required pursuant to 40 CFR §146.90(k), is provided as a separate document.

2.4 Reporting Procedures Summary

OLCV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR §146.91.

3.0 Carbon Dioxide Stream Analysis

OLCV 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).

The source of the CO_2 for the Project is a Direct Air Capture (DAC) facility that is located near the proposed CO_2 sequestration site. The DAC facility will extract CO_2 from air, and the composition of the produced stream will be primarily composed of CO_2, O_2 and H_2O. The DAC extraction process prevents other components from being incorporated into the resulting stream.

3.1 Location and Frequency

The CO_2 injectate stream (Table 4) will be continuously monitored at the DAC facility before the injectate enters the flowline to BRP. In addition, the CO_2 injectate stream will be continuously monitored using an online gas chromatograph or gas analyzers directly upstream of the CO_2 Injector's wellheads. CO_2 stream samples will be routinely collected at a sample port in the flowline near the Injector wellheads. Continuous online monitoring of the CO_2 injectate composition, coupled with routine laboratory analysis will provide appropriate data resolution and, in the unlikely event that impurities are present, detect those impurities that might alter the corrosivity or other properties of the injectate downhole. See Table 5 for a summary of injectate monitoring plans.

The isotopic composition of the CO_2 stream will be analyzed prior to injection. This will allow for fingerprinting of the injectate stream and comparison with fluid samples obtained from SLR, WW or USDW wells during the Injection or Post-Injection periods.

If online gas chromatography / gas analyzer or laboratory analysis indicate that the CO_2 injectate stream exceeds the specifications described in Table 4, the system is alarmed to alert OLCV personnel. Based on operational experience, minor system upsets are resolved in a few minutes and the composition is restored to the specification. If the composition is not restored to the specification, or the source of the issue cannot be quickly resolved, CO_2 capturing operations at the DAC facility will be shut-in until the injectate stream meets the specification. If the DAC process is stopped, CO_2 stream will not move to the final compression system or enter the pipeline for transport to the sequestration site. This process ensures that the CO_2 stream composition entering the CO_2 Injectors is consistent with the expected composition.

Table 4—CO_2 Injectate Stream Specification

Component	Specification
CO_2 content	>95 mol% (>96.5 mass%)
Water	<30 lbm/MMscf
Nitrogen	<4 mol%
Sulphur	<35 ppm by weight
Oxygen	<5 mol%
Glycol	<0.3 gal/MMscf
Carbon Monoxide	<4,250 ppm by weight
NOx	<6 ppm by weight
SOx	<1 ppm by weight
Particulates ($CaCO_3$)	<1 ppm by weight
Argon	<1 mol%
Surface pressure	>1,600 psig
Surface temperature	>65°F and <120°F
Isotopes	$\delta^{13}C$ and ^{14}C of CO_2

Table 5—CO_2 injectate stream monitoring method and frequency

Method	Pre-Injection	Injection	Post-Injection
Online gas chromatography / gas analyzer of supercritical CO_2 in the flowline upstream of the injector wells	NA	Continuously	N/A
Laboratory gas chromatography of samples obtained from a sample port upstream of the injector wells	N/A	Quarterly; or event-driven* if the DAC process materially changes	N/A
Laboratory isotopic analysis of injectate samples	Prior to injection	Event-driven* if the DAC process materially changes	NA

*Event-driven = changes in the DAC process that may arise from facility upgrades or after facility shut-in periods.

3.1.1 Stream Monitoring at DAC facility

The DAC facility will be equipped with an online analyzer including an O_2 optical sensor and a H_2O aluminum oxide sensor to continuously monitor for O_2 and H_2O and ensure the injectate stream meets specification. In addition, gas-phase samples at known temperature and pressure will routinely be collected from the DAC facility for laboratory analysis. The DAC facility will be equipped with an on-site laboratory to measure the composition and conduct isotopic analysis of the CO_2 stream. The DAC facility is designed to prevent CO_2 injectate from entering the pipeline to sequestration if the composition does not meet the specification.

3.1.2. Stream Monitoring in the Flowline

In addition to the continuous monitoring and on-site laboratory analysis at the DAC facility, the CO_2 stream will be continuously recorded and routinely sampled directly upstream of the flowmeter near the CO_2 injector wellhead (40 CFR §98.440-98.449). A gas chromatograph and/or gas analyzers will be installed along the flowline near the flowmeter and the data will be continuously monitored at a control room staffed with personnel employed by Oxy, OLCV or its subsidiaries or third-party contractors. A sample port will be installed directly upstream of the flowmeter to allow extraction of the CO_2 stream in a supercritical phase. The samples will be collected, transported to a laboratory, and analyzed by a qualified third-party contractor experienced with analyzing gases.

3.1.3. CO_2 Isotopic Analysis

In addition to the gas composition analysis, CO_2 stream samples from the flowline port will be collected for isotopic characterization. These data will be used to determine a baseline and complement the gas, soil, and water characterization methods. Samples for isotopic compositional baseline analysis will be sent to a commercial laboratory for evaluation.

3.2 Analytical Parameters

The 1PointFive DAC facility has developed a standard CO_2 specification, as shown in Table 4. OLCV will notify the EPA before any anticipated change in CO_2 composition. In addition, any changes to the physical, chemical, and other relevant characteristics of the CO_2 stream from the established operating data specified in the permit, or a demonstration that these characteristics have not changed since the previous reporting period, shall be described in a semi-annual report, and submitted to the EPA in compliance with 40 CFR §149.91(a).

3.3 Sampling Methods

Sample collection for laboratory analysis will follow the procedure outlined in GPA-2177-20 to ensure that the sample is representative of the injected CO_2 stream. A sampling station will be installed with the ability to purge and collect samples into a container that will be sealed and sent to the third-party authorized laboratory. A third-party contractor will be responsible for collecting the samples, transporting the samples to a laboratory, and for sample analysis.

3.4 Laboratory to be Used, Chain of Custody, and Analysis Procedures

The samples will be analyzed in accordance with GPA-2177-20 by a third-party laboratory. Sampling procedures will follow contractor protocols to ensure the sample is representative of the injectant and samples will be processed, packaged, and shipped to the contracted laboratory, following standard sample handling and chain-of-custody guidance.

4.0 Continuous Recording of Operational Parameters

OLCV will install and use continuous recording devices to monitor injection pressure, rate, volume; the pressure on the annulus between the tubing and the long string casing; and the temperature of the CO_2 stream, as required by 40 CFR §146.88(e)(1), §146.89(b), and §146.90(b).

4.1 Monitoring Location and Frequency

Injection operations will be continuously monitored and controlled by the operations staff utilizing a process control system. The system will continuously monitor, control, record, and alarm for critical system parameters of pressure, temperature, and injection flow rate. The system will initiate a shutdown if specified control parameters deviate from the intended operating range and will allow for remote shutdown under emergency conditions. Trend analysis will aid in evaluating the performance (e.g., drift) of the instruments, indicating the need for maintenance or calibration.

Monitoring and metering locations and frequencies are summarized in Table 6 below.

Table 6—Continuous Monitoring Methods and Frequency

Objective	Method	Minimum sampling frequency	Minimum recording frequency
Injection pressure and temperature at surface	Surface gauges installed on injection line near wellhead	One second	30 seconds
Injection rate and volume	Mass flow meter on injection line near wellhead	One minute	One hour
Injection pressure and temperature downhole	Downhole tubing-deployed gauge above packer ported to tubing above packer	10 seconds	30 seconds
	DTS fiber	10 minutes	30 minutes
Pressure on the annulus between the tubing and long string casing	Downhole tubing-deployed gauges ported to annulus above packer	10 seconds	30 seconds
Annular pressure at surface	Pressure gauge installed in wellhead	One second	30 seconds
Annulus volume	Continuous pressure monitoring between tubing and production casing, and continuous monitoring of pressure at surface to confirm absence of leakage. Direct fluid level measurements may also be obtained, as triggered by pressure data.	10 seconds pressure gauge; fluid level as needed	30 seconds on pressure gauge, fluid level as needed

4.2 Description of Methods and Justification

4.2.1 Pressure and Temperature Monitoring

OLCV will monitor and measure injection pressure and temperature (P/T) three ways in the Injector well: downhole gauges, DTS and surface gauges. One P/T gauge will be installed downhole as part of the completion and ported into the tubing to continuously measure CO_2 injection P/T. The downhole sensor will be the point of compliance for maintaining injection pressure below 90% of formation fracture pressure.

A second P/T gauge will be installed on the outside of the tubing string above the packer to measure pressure continuously in the annular space above the packer and identify any potential loss of mechanical integrity.

At the surface, electronic pressure gauges and temperature sensors will be used to continuously monitor the pressure and temperature of the annulus between the tubing and long string casing. Gauges and sensors will be connected to the automation system to provide continuous data analysis as well as alarms for malfunctioning events when the values deviate from the intended operating range.

If the downhole gauges stop working between scheduled maintenance events, then the surface pressure limitation approved for this permit will be used as a backup until the downhole gauges are repaired or replaced. For calibration purposes, in lieu of removing the injection tubing, the accuracy of the downhole gauges will be demonstrated by using a second pressure gauge with current certified calibration lowered into the well at the same depth as the permanent downhole gauge.

In addition to gauges, fiber optic cable will be attached along the side of the casing and to a distributed temperature sensing (DTS) interrogator on the surface, which will provide a distributed temperature profile while injecting. This system will record temperature continuously to aid in monitoring the CO_2 behavior and detect any unforeseen mechanical integrity issue in the well.

4.2.2 Injection Rate and Volume Monitoring

The mass flow rate of CO_2 injected into the well will be measured using flowmeter skids with Coriolis meter in the CO_2 injection line near the interface with the wellhead, shown as FE-100 in Figure 4. Piping and valving will be configured to permit flowmeter calibration. A redundant pressure control valve will be installed to allow for continuous injection during routine maintenance of the device. The flow transmitter will be connected to a remote terminal unit (RTU) on the flowmeter skid.

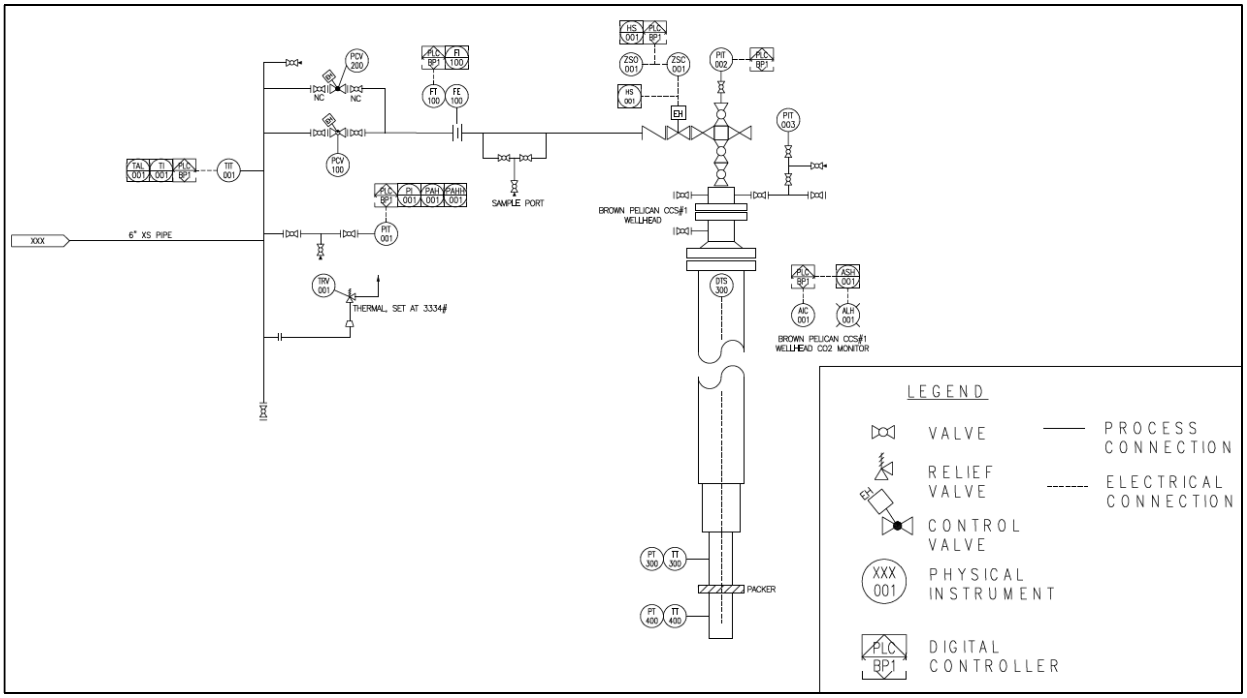

Figure 4—Representative example of wellhead process and instrumentation diagram

The process control system will limit the wellhead pressure to 1,800 psig to protect the surface equipment.

The project will follow the equations from 40 CFR Part 98-Subpart RR for CO_2 mass calculation.

4.2.3. Packer fluid / Annulus Volume Monitoring

The initial volume of packer fluid to fill the casing will be measured prior to the commencement of injection operations. Annular pressure will be kept between 100 and 400 psi on surface, and pressure data obtained from surface gauges and downhole gauges will be used to confirm the absence of unexpected changes in annulus volume. In addition, if there are changes in pressure, OLCV will conduct fluid level measurements to further confirm annulus fluid volume. This methodology will allow the operator to confirm the variation in annular fluid due to temperature changes v. potential mechanical integrity issues.

4.2.4. Justification of Continuous Monitoring Methods and Backup Options

Multiple measurements of P/T will be collected in the Injector wells to provide confidence in the data. Downhole and surface gauges are routinely used in well operations and have historically performed to expectation over the operational life of the well. DTS technology is relatively newer in operational deployment, thus its long-term performance history is less constrained. If DTS fails before the end of the monitoring period, gauges will be utilized to meet monitoring requirements.

In the event anomalous measurements are obtained from the P/T gauges or from DTS data, the gauges and wellhead will be manually inspected. Maintenance or repair operations on the instruments will commence, if required. If anomalous measurements are detected to be different between the gauges or DTS, an investigation into the cause will be conducted. OLCV will conduct appropriate repairs or adjustments and re-collect data.

The injection rate and volume metering protocols to be used at BRP follow the prevailing industry standard(s) for custody transfer as currently promulgated by the American Petroleum Institute (API), the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. This approach is consistent with EPA GHGRP's Subpart RR, section 98.444(e)(3). These meters will be maintained and calibrated routinely, operated continually, and will feed data directly to the centralized data collection systems. The meters meet the industry standard for custody transfer meter accuracy and calibration frequency.

5.0 Corrosion Monitoring and Surface Leak Detection

To meet the requirements of 40 CFR §146.90(c), OLCV 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.

Materials (Table 7) have been selected to mitigate and inhibit corrosion. The suitability of the materials has been determined with published performance data from materials suppliers. A summary of materials is listed below. These materials will be monitored via coupons that will be exposed to the CO_2 injectate stream and reservoir fluids.

Table 7—List of Equipment with Construction Materials in Pipeline, Injectors, Injection Zone monitor and water withdrawal wells

Equipment Coupon	Construction Material
Pipeline	Carbon steel
Long string casing *above Injection Zone* in injection wells and Injection Zone monitoring and water withdrawal wells	Carbon steel, L80
Long string casing *in Injection Zone* in injection wells	Carbon steel coated, Super Duplex 2507 SS, #17, 80kpsi
Long string casing *in Injection Zone* for Injection Zone monitoring and water withdrawal wells	Carbon Steel, L80
Tubing *above packer* in injection wells	Coated carbon steel, L80, Coated TK-805
Tubing for Injection Zone monitoring and water withdrawal wells	Coated carbon steel, L80, Coated TK-805
Wellhead for injection wells, Injection Zone monitoring and water withdrawal wells	Alloy Steel DD specification
Injection tree and tubing hanger for injection wells	Sour service HH specifications
Packers for injection wells and Injection Zone monitoring and water withdrawal wells	Nickel-plated / HNBR (RGD) elastomers

5.1 Monitoring Location and Frequency

Corrosion monitoring of the CO_2 injection wells and water withdrawal wells will be conducted in a surface monitoring spool located near the wellhead that contains multiple access points. To measure corrosion, coupons or probes composed of well materials will be inserted at the access points in the spool, and those coupons or probes will be exposed to fluids being injected or produced from the wellbores. For Injection Zone and Confining Zone monitoring wells, a monitoring spool will be placed at the wellhead that is open to the tubing to monitor corrosion of the fluids/gas in the tubing. Coupons/probes will be collected and sent to a third-party company for analysis in accordance with NACE Standard SP-0775-2018-SG on a quarterly basis during the Injection Period and until wells are plugged in the post-injection period. Note that CO_2 is not expected to be encountered in the water withdrawal wells or in Confining Zone monitor wells.

In addition to coupons, OLCV will conduct visual inspection of the facilities, utilize optical gas imaging cameras (OGI), and evaluate data from DTS to monitor for potential leakage that could result from corrosion.

In the event that OLCV collects data that are consistent with possible corrosion, OLCV will re-conduct a visual inspection of the facilities, physical inspection using nondestructive techniques, re-collect data from coupons or optical gas imaging. In the event that corrosion is confirmed, OLCV will assess equipment fitness for service and take appropriate remediation actions.

Casing inspection logging will be conducted during planned well maintenance operations to evaluate downhole conditions and confirm absence of corrosion.

Table 8 provides a summary of the corrosion monitoring methods.

Table 8—Corrosion Monitoring and Surface Leak Detection Summary

Objective	Method	Pre-Injection	Injection	Post-Injection
Identify material corrosion in flowline and wellbore	Corrosion coupons	N/A	Quarterly	N/A
	Casing inspection log	Caliper cased hole log prior to injection operations	During planned well maintenance	N/A
Identify loss of mechanical integrity that could lead to corrosion	DTS	Prior to injection	Continuously	N/A
Surface monitoring and leak detection	Visual inspection and portable monitors	Prior to injection	Weekly	N/A
	OGI camera	Prior to injection	Quarterly	N/A
	CO_2 surface sensors	Prior to injection	Continuously	N/A

5.2 Description of Methods and Justification

5.2.1 Corrosion Coupons

Samples of injection well materials (coupons) will be exposed to the injected CO_2 stream and monitored for signs of corrosion to verify that the well components meet the minimum standards for material strength and performance and to identify well maintenance needs. Coupons will be placed in a tray near the gas chromatograph / gas analyzer that is used to monitor the CO_2 injectate stream in the flowline. The coupon location will be safe and easily accessible for the vendor to retrieve. Coupons will be analyzed by a third party in accordance with NACE Standard SP-0775-2018-SG to determine and document corrosion wear rates based on mass loss. A summary of coupon parameters is shown in Table 9

Table 9—Summary of Analytical Parameters for Corrosion Coupons

Parameters	Analytical Method	Resolution Instruments	Precisions/Std Dev
Mass	NACE SP0775-2018-SC	0.05 mg	2%
Thickness	NACE SP0775-2018-SC	0.01 mm	± 0.05 mm

NACE SP0775-2018-SC: Preparation, Installation, Analysis, and Interpretation of Corrosion Coupons in Oilfield Operations

Coupon data will be evaluated by OLCV engineers to confirm that well components meet the standards for material strength and performance. Appropriate corrective action will be taken if needed to restore the well components to meet operational standards.

5.2.2. Casing Inspection Logs

OLCV intends to perform casing inspection logging (CIL) during planned well maintenance. Between planned maintenance events, OLCV may conduct a CIL, if corrosion coupon data indicates potential loss of material strength or performance inconsistent with operating standards.

5.2.3. Surface detection methods

Field personnel will visit the Project location on a routine, at least weekly, basis to make observations of surface equipment, identify potential leaks, and verify that equipment is operating within design limits. Field personnel will be provided with handheld equipment to identify the presence of CO_2 as part of the safety requirements for the site.

Additional, quarterly, optical analysis using OGI cameras will be performed during the injection period. OGI cameras are highly specialized cameras that provide a method to spot invisible gases as they escape. These cameras rely on infrared images to detect the leaks and they will be used during the inspection of facilities, pipelines, and well locations.

6.0 Monitoring the Injection Zone

Injection-zone monitoring of pressure and temperature, saturation, and chemistry of fluids and dissolved gasses will be conducted to directly confirm the presence or absence of CO_2 at the monitoring well locations.

6.1 Monitoring Location and Frequency

The Lower San Andres Injection Zone will be directly monitored using the SLR2 and SLR3 monitoring wells. The SLR2 will be drilled prior to the commencement of CO_2 injection and will be located within the maximum extent of the pressure front resulting from CO_2 injection. The SLR3 well will be drilled within five years after CO_2 injection commences.

The Injection Zone will be indirectly monitored by the Shoe Bar 1 stratigraphic test well that will be plugged above the Injection Zone prior to the commencement of CO_2 injection. The portion of the well above the Injection Zone contains DTS/DAS fiber that may be used during VSP seismic acquisition and for monitoring pressure and temperature above the confining zone and indirectly informing containment in the Injection Zone.

Table 10—Monitoring of the Injection Zone

Objective	Method	Frequency pre-injection	Frequency during injection	Frequency post-injection
Pressure and temperature monitoring downhole	Downhole gauge ported to tubing and ported to annulus in injection wells	Prior to injection	Continuously, 10 second sampling and 5 minute recording frequency	Continuously for the first 10 years pending an approved PISC plan then annually until plugging;10 second sampling and 5 minute recording frequency
	DTS (planned for SLR2 and possibly SLR3)	In SLR2, prior to injection	Continuously, 10 minute sampling and 30 minute recording frequency	Continuously for the first 10 years pending an approved PISC plan, then annually until plugging; 10 minute sampling and 30 minute recording frequency
Pressure and temperature monitoring at surface	Surface gauge at injection well wellhead	Prior to injection	Continuously, 1 second sampling and 30 second recording frequency	Continuously for the first 10 years pending an approved PISC plan, then annually until plugging; 1 second sampling and 30 second recording frequency
Saturation profile	PNL or RST logging in SLR2 and SLR3 and WWs	In SLR2, prior to injection	Annually in SLR2 and SLR3; event-driven* in WWs	Annually until plugging
Fluid and dissolved gas geochemistry	Fluid and dissolved gas sampling and analysis in SLR2 and SLR3	During construction of injector wells, SLR wells and WWs and prior to injection to establish characterization	In SLR2 and SLR3, or WWs; Event-driven*, triggered by P/T data	Event-driven*, triggered by P/T data

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. Saturation logging may also be conducted to further support or refute the presence of increased CO_2.

6.2. Description of Methods and Justification

Pressure and temperature downhole and surface gauges will be installed in the SLR2 and SLR3. See Section 1.4.7 in QASP for description of gauges. In addition, the SLR1 well includes DTS fiber that will be used for indirectly monitoring the Injection Zone.

A pulsed neutron log (PNL) or other saturation lot (RST) will be collected in the SLR2 and SLR3 wells annually. This log is collected in cased holes and can be used to solve for water, oil, and gas saturations. Saturation logging may also be conducted in water withdrawal wells: WW1, WW2, WW3 and WW4.

Fluid and dissolved gas samples were collected while drilling the SLR1, ACZ1, WW1, WW2, WW3, and WW4 and will be collected in the future BRP CCS1, BRP CCS2, BRP CCS3, SLR2 and SLR3 wells. Additional fluid and dissolved gas samples will be conducted to constitute a baseline. These samples will be analyzed for their geochemical composition and isotopic characterization. If anomalous pressure and temperature changes are observed in an SLR well during injection or post-injection, fluid samples and/or dissolved gas samples will be obtained for geochemical and isotopic analyses and comparison with pre-injection samples.

7.0 Monitoring the First Permeable Zone Above the Confining Zone

The first permeable zone above the confining zone is the Santa Rosa formation, which is the lowermost member of the Dockum group. It will be monitored with the USDW1 well, a dedicated well that is located close to the BRP CCS1 and BRP CCS2 injection sites. Together with shallow groundwater and near-surface monitoring (See Section 8 of this document), OLCV will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR §146.90(d). The results of ground water sampling will be compared to baseline geochemical and isotopic data collected during the site characterization baseline, consistent with 40 CFR §146.82(a)(6), to obtain evidence of potential fluid or gas movement.

7.1 Monitoring Location and Frequency

The zone of highest pressure, and thus highest potential for fluid movement, is close to the injection wells. The USDW1 well will monitor for potential loss of containment through the confining layers. Because the size of the BRP plume is expected to remain small (<6 miles^2), OLCV models that one well is sufficient to monitor above the confining zone. Additional monitoring wells for the USDW may be drilled in the future, depending on the shape and location of the CO_2/pressure plume.

The integrity of the Upper Confining Zone will also be monitored by the Shoe Bar 1 and/or Shoe Bar 1AZ stratigraphic test wells that will be plugged above the Injection Zone prior to the commencement of CO_2 injection. Saturation logging (PNL or RST) will be conducted in the wells in the intermediate hole section including the Grayburg and Upper San Andres formations. PNL and RST logs yield less reliable data through three casing strings, therefore, this method will not be appropriate for monitoring saturation in the lowermost USDW.

Monitoring above the confining zone is summarized in Table 11.

Table 11—Monitoring above the Injection Zone

Objective	Method	Frequency pre-injection	Frequency during injection	Frequency post-injection
First Permeable zone above the confining zone / lowermost USDW: Dockum				
Fluid and dissolved gas geochemistry in the first permeable zone above the confining zone	Fluid and dissolved gas sampling and analysis in USDW1	During construction and quarterly during baseline	Quarterly geochemical sampling in years 1-3 and annually starting in year 4; and event-driven*, triggered by P/T in SLR wells or soil gas chemistry	Annually for first 10 years pending an approved PISC plan; and event-driven*, triggered by P/T in SLR wells or soil gas chemistry
Upper Confining Zone integrity				
Estimate CO_2 saturation in the Upper Confining Zone	PNL or RST in SLR1 and ACZ1	Prior to injection	Every five years	Event-driven*
Pressure and temperature in the Upper Confining Zone	DTS in SLR1	Prior to injection	Continuous measurement and recording of pressure and temperature	Event-driven*

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. Saturation logging may also be conducted to further support or refute the presence of increased CO_2.

7.2 Description of Methods and Justification

See Section 8.1 for details on fluid sampling and analyses.

8.0 Monitoring the Near-Surface

The primary objectives of the near-surface monitoring program are to confirm containment of CO_2 within the Lower San Andres Injection Zone, demonstrate protection of the deepest USDW, and to provide for early detection of anomalous conditions indicative of potential leakage of CO_2 or of brine migration. Water composition in shallow wells and soil gas within the near-surface has considerable variation due to natural processes and naturally occurring events and due to anthropogenic processes unrelated to the Project. Such natural and anthropogenic variation increases the difficulty of using only composition as the baseline for CO_2 leak and brine migration monitoring purposes. Instead, characterization of the subsurface system, including near-surface conditions (i.e., soil gas, fluid and dissolved gas chemistry of the deepest USDW; Section 7.0), and target injection reservoir fluids (see discussion in Section 6.0), provides a better approach for identifying unique tracers in the system that will potentially help identify an anomalous change in condition, and if needed, the source of the changes and discard false positives associated with potential CO_2 leaking or brine migration from the storage complex.

For the BRP Project, the lowermost USDW and soil gas within the AoR will be monitored in accordance with 40 CFR §146.90(d) and 40 CFR §146.90(h), respectively, and at the frequencies specified in Table 12.

Table 12—Monitoring the Near-Surface

Objective	Method	Frequency pre-injection	Frequency during injection	Frequency post-injection
Fluid and dissolved gas geochemistry in the lowermost USDW	Fluid and dissolved gas sampling and analysis	During construction and quarterly during baseline	Quarterly geochemical sampling in years 1-3 and annually starting in year 4; and event-driven*, triggered by P/T in SLR wells or soil gas chemistry	Annually for first 10 years pending an approved PISC plan; and event-driven*, triggered by P/T or soil gas chemistry
Soil gas analysis in the near-surface vadose zone	Isotopic analysis and chemical evaluation at approximately 21 locations	Characterization prior to injection, including quarterly sampling for at least one year	Quarterly gas composition sampling in years 1-3 and annually starting in year 4 for subset of stations, and event-driven*, triggered by P/T data in SLR wells and fluid sample results	Event-driven*, triggered by P/T data in SLR wells and fluid sample results

* OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. In addition, fluid and

dissolved gas chemistry data from the lowermost USDW and soil gas chemistry from shallow soils will be monitored for trends to detect deviations from reference chemistry. If persistent and/or abrupt anomalies in chemistry are detected additional fluid or soil gas samples will be obtained to confirm the presence or absence of increased CO_2.

8.1. USDW Sampling

8.1.1 Monitoring Location and Frequency

The Project has drilled one well to monitor the Dockum group (i.e., Shoe Bar 1USDW or USDW1). The monitoring well is located close to the proposed BRP CCS1 and BRP CCS2 locations.

Note that one existing USDW-level well (Serial No. 4511701) was drilled in 1940. This well was located in the AoR during the evaluation of artificial penetrations and was determined to have low mechanical integrity. The 4511701 well was plugged and abandoned using hydrated Baroid 3/8" bentonite hole plug chips from 189 ft bgs to 5ft bgs and a cement slurry to the ground surface. There are no other existing USDW-level wells within the AoR.

Fluid and dissolved gas samples were collected after the installation and adequate development of the Shoe Bar 1USDW. Additional samples will be collected quarterly for at least one year prior to commencement of injection. Quarterly sampling commenced in June 2024. These samples will be analyzed for their geochemical and isotopic characterization shown in Table 13. After injection commences, Shoe Bar 1USDW will be sampled for geochemical analysis and a subset of the isotopic analyses at a quarterly frequency in years one to three, then annually starting in the fourth year after commencement of injection until the end of injection period. During the post-injection phase of the Project, the USDW will be monitored annually for geochemical analysis and a subset of the isotopic characterization for the first 10 years. If anomalous soil gas chemistry is observed, anomalous pressure and temperature changes are observed a SLR well, or there is any indication of leakage through the injection wells during the injection and post-injection phases of the Project, additional fluid samples may be obtained for geochemical and isotopic analysis and comparison to pre-injection sample results. If geochemistry data of fluids and dissolved gasses in the lowermost USDW are consistent with the absence of introduced Injection Zone brine or CO_2 injectate into the USDW, this monitoring method will be discontinued after 10 years post injection.

8.1.2. Description of Methods and Justification

The purpose of monitoring above the confining zone is to identify potential geochemical changes due to the introduction of CO_2 injectate stream or displaced formation fluids above the primary confining zone. Unlike some injected materials regulated by UIC, the presence of CO_2 in groundwater, surface water or soils may be the result of naturally occurring biological processes. Therefore, the presence of CO_2 in shallow or surface intervals is not necessarily diagnostic of leakage from an Injection Zone (Romanak, 2012). Furthermore, it may be impossible to establish a meaningful baseline CO_2 concentration, because the concentration of CO_2 in soils and groundwater is changing overtime due to global climatic changes (Bond-Lamberty, 2010; Macpherson, 2008; and Burger, 2020). However, the monitoring plans for the BPR project is designed to establish observable trends to characterize variabilities and changes due to natural processes and anthropogenic sources during the baseline phase of the Project.

In addition to establishing a baseline, OLCV plans to use a process-based approach along with natural tracers to characterize and attribute CO_2 measured in groundwater. The process-based approach involves characterizing groundwater prior to the commencement of injection operations. For the purpose of characterizing groundwater prior to injection while accounting for variations due to existing natural processes (and anthropogenic sources other than OLCV, if any), multiple samples will be collected during pre-injection activities. Similarly, multiple soil gas samples from across the AoR will be used to characterize the naturally-occurring variability across the site. See Section 8.2 in this document for more information on soil gas characterization.

For the process-based approach using natural tracers in groundwater, Romanak (2012) recommends characterizing $\delta^{13}C$, ^{14}C, CH_4, and δD in the fluids throughout the stratigraphic column. These isotopes can be used to trace carbon reactions. The initial characterization is intended to define components that will be diagnostic for future monitoring. In order to attribute the source of CO_2 or other relevant compounds, isotopic characterization will also be performed on the injectate fluid, fluids from the Injection Zone, fluids in first permeable layer above the Injection Zone, and fluids and dissolved gasses from the USDW.

To monitor changes, Romanak (2014) suggests using the covariation of δ13C and 14C as natural tracers. δ13C in anthropogenic sources overlaps the signature of naturally-occurring biologic sources, so the data should be considered in context with other lines of evidence. However, 14C in CO_2 is interpreted to be diagnostic between anthropogenic and naturally-occurring sources. The BRP has a unique challenge in that the source of the CO_2 injectate is captured directly from the ambient air that may contain signatures of multiple anthropogenic sources rather than from a specific industrial anthropogenic source, thus the ability to use the variation of δ13C and 14C for attribution is not well-studied.

To support the interpretation of the isotopic characterization of the natural tracers such as the variation of δ13C and 14C, geochemical properties of the lowermost USDW fluid will be characterized and a baseline will be established. Geochemical changes in the Dockum group may occur after the inadvertent introduction of foreign fluids or gases to the aquifer through a leakage pathway or conduit (i.e., CO_2 and/or brine migration from the target injection formation) during the injection phase of the Project (EPA, 2013).

At the end of the pre-injection monitoring period, OLCV will establish geochemical and isotopic trends, including seasonal variations, which characterize the natural or existing conditions in the USDW. These trends will be used to create procedures for CO_2 and brine leakage identification and characterization in the Dockum group during the injection and post-injection phases of the BRP.

The table below lists the components that will be characterized and monitored in the groundwater collected from the monitoring wells at BRP.

Table 13—Water Analysis Parameters

Laboratory Analyte	Analytical Methods[1]	Detection Limit / Range[2]	Typical Precision[2]	QC Requirements
Total and Dissolved Metals: Ag, Al, As, Ba, Cd, Co, Cr, Cu, Mn, Mo, Ni, Pb, Sb, Se, Sr, Th, Tl, U, V, and Zn	USEPA Method 200.8	0.00004 to 0.003 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof
Total and Dissolved Metals: B, Ca, Fe, K, Mg, Li, Na, Si, Sr, Ti	USEPA Method 200.7	0.003 to 0.254 mg/L	±20	Daily calibration, Initial QC checks (IPC, ICV, ICB, RL) method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Total and Dissolved Hg	USEPA Method 245.7	19.6 ng/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved Inorganic Carbon (DIC); Dissolved Organic Carbon (DOC)	Standard Method 5310C	0.198 to 0.290 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved CO_2	Standard Method 4500 CO_2 D	8 mg/L	±20	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Alkalinity: Total, Bicarbonate, Carbonate, and Hydroxide	Standard Method 2320B	8 mg/L	±20	method blank, lab control samples, matrix spikes
Major Anions: Br, Cl, F, and SO_4, NO_2 and NO_3 as N	USEPA Method 300.0	0.003 to 0.563 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
PO_4 as P	USEPA Method 365.1	0.0215 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and

				sample duplicate, CCV/CCB every 10 samples or part thereof
Dissolved H_2S (Sulfide)	Standard Method 4500S2-D	0.026 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup
Total Dissolved Solids (TDS)	USEPA Method 160.1	10 mg/L	±20	Method blank, lab control samples, and sample duplicate
Conductivity	Standard Method 2510B	0 to 200 mS/cm	±1%	Calibration as needed, daily QC checks (1413, 14130 and second source SRM), CCV every 10 samples or part thereof
pH and Temperature	USEPA Method 150.1	0.1 to 14 pH units	±0.1 pH units	Daily calibration, second source SRM, CCV's every 10 samples or part thereof
Specific Gravity	ASTM Method D1429-03	NA	To the nearest thousandths decimal	Duplicates
Cation Anion Balance	Calculation	NA	±10	Calculation
Dissolved Gas Abundances: CO_2, CO, N_2, Ar, He, H_2, O_2, C1-C6+	In-house Lab SOP, similar to RSK-175	1 to 100 ppm, varies by component	C1-C4: ± 5%; C5-C6+: ± 10%	20% of all analyses are check/reference standards.
Dissolved Gas Isotopes: $\delta^{13}C$ of C1-C5 and CO_2, $\delta^{2}H$ of C1	High precision (offline) analysis via Dual Inlet IRMS	Varies by component	$\delta^{13}C$: 0.1 per mil; $\delta^{2}H$: 3.5 per mil	20% of all analyses are check/reference standards.
^{14}C of C1	AMS - subcontracted to Beta Analytic	0.44 pMC	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
^{14}C of DIC	AMS - subcontracted to Beta Analytic	Depends on available sample volume	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
$\delta^{13}C$ of DIC	Gas Bench/CF-IRMS	Depends on available sample volume, minimum of 50mg/L required	0.20 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	Analyzed via CRDS	N/A	$\delta^{18}O$: 0.10 per mil;	20% of all analyses are either check/reference

			δ^2H: 2.0 per mil	standards or duplicate analyses.
$^{87}Sr/^{86}Sr$	TIMS - subcontracted to the University of AZ	Approximately 40 ppm	± 0.00002	SRM 987 Sr standard within the long-term precision (external precision) of +/- 0.00002 accepted value of 0.71025
$^{228}Ra/^{226}Ra$	USEPA Method 901.1	50 pCi/L (RL)	± 25%	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Field Parameters				
pH (Field)	Standard Method2 4500-H+ B-2000	2 to 12 pH units	±0.2 pH units	User calibration per manufacturer recommendation
Specific conductance (Field)	EPA Method 120.1	0 to 200 mS/cm	±1%	User calibration per manufacturer recommendation
Temperature (Field)	Standard Method 2550 B-2000	-5 to 50 ºC	±0.2 ºC	Factory calibration
Oxidation-Reduction Potential (Field)	Standard Method 2580	-1999 to +1999 mV	±20 mV	User calibration per manufacturer recommendation
Dissolved Oxygen (Field)	ASTM Method D888-09 (C)	0 to 50 mg/L	0 to 20 mg/L: ±0.1 mg/L or 1% of reading, whichever is greater; 20 – 50 mg/L: ±8% of reading	User calibration per manufacturer recommendation
Turbidity (Field)	USEPA Method 180.1	0 to 1000 NTU	± 1% of reading or 0.01 NTU, whichever is greater	User calibration per manufacturer recommendation
Laboratory Analyte	**Analytical Methods[1]**	**Detection Limit / Range[2]**	**Typical Precision[2]**	**QC Requirements**
<u>Total and Dissolved Metals:</u> Ag, Al, As, Ba, Cd, Co, Cr, Cu, Mn, Mo, Ni, Pb, Sb, Se, Sr, Th, Tl, U, V, and Zn	USEPA Method 200.8	0.00004 to 0.003 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof
Total and Dissolved Metals: B, Ca, Fe, K, Mg, Li, Na, Si, Sr, Ti	USEPA Method 200.7	0.003 to 0.254 mg/L	±20	Daily calibration, Initial QC checks (IPC, ICV, ICB, RL) method blank, lab control samples, matrix spike and matrix spike dup;

				CCV/CCB every 10 samples or part thereof
Total and Dissolved Hg	USEPA Method 245.7	19.6 ng/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved Inorganic Carbon (DIC); Dissolved Organic Carbon (DOC)	Standard Method 5310C	0.198 to 0.290 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved CO_2	Standard Method 4500 CO_2 D	8 mg/L	±20	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Alkalinity: Total, Bicarbonate, Carbonate, and Hydroxide	Standard Method 2320B	8 mg/L	±20	Method blank, lab control samples, matrix spikes
Major Anions: Br, Cl, F, and SO_4, NO_2 and NO_3 as N	USEPA Method 300.0	0.003 to 0.563 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
PO_4 as P	USEPA Method 365.1	0.0215 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof
Dissolved H_2S (Sulfide)	Standard Method 4500S2-D	0.026 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup
Total Dissolved Solids (TDS)	USEPA Method 160.1	10 mg/L	±20	Method blank, lab control samples, and sample duplicate
Conductivity	Standard Method 2510B	0 to 200 mS/cm	±1%	Calibration as needed, daily QC checks (1413, 14130

				and second source SRM), CCV every 10 samples or part thereof
pH and Temperature	USEPA Method 150.1	0.1 to 14 pH units	±0.1 pH units	Daily calibration, second source SRM, CCV's every 10 samples or part thereof
Specific Gravity	ASTM Method D1429-03	NA	To the nearest thousandths decimal	Duplicates
Cation Anion Balance	Calculation	NA	±10	Calculation
Dissolved Gas Abundances: CO_2, CO, N_2, Ar, He, H_2, O_2, C1-C6+	In-house Lab SOP, similar to RSK-175	1 to 100 ppm, varies by component	C1-C4: ± 5%; C5-C6+: ± 10%	20% of all analyses are check/reference standards.
Dissolved Gas Isotopes: $\delta^{13}C$ of C1-C5 and CO_2, $\delta^{2}H$ of C1	High precision (offline) analysis via Dual Inlet IRMS	Varies by component	$\delta^{13}C$: 0.1 per mil; $\delta^{2}H$: 3.5 per mil	20% of all analyses are check/reference standards.
^{14}C of C1	AMS - subcontracted to Beta Analytic	0.44 pMC	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
^{14}C of DIC	AMS - subcontracted to Beta Analytic	Depends on available sample volume	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
$\delta^{13}C$ of DIC	Gas Bench/CF-IRMS	Depends on available sample volume, minimum of 50mg/L required	0.20 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	Analyzed via CRDS	N/A	$\delta^{18}O$: 0.10 per mil; $\delta^{2}H$: 2.0 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$^{87}Sr/^{86}Sr$	TIMS - subcontracted to the	Approximately 40 ppm	± 0.00002	SRM 987 Sr standard within the long-term precision (external precision) of +/-

	University of AZ			0.00002 accepted value of 0.71025
$^{228}Ra/^{226}Ra$	USEPA Method 901.1	50 pCi/L (RL)	± 25%	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Field Parameters				
pH (Field)	Standard Method2 4500-H+ B-2000	2 to 12 pH units	±0.2 pH units	User calibration per manufacturer recommendation
Specific conductance (Field)	EPA Method 120.1	0 to 200 mS/cm	±1%	User calibration per manufacturer recommendation
Temperature (Field)	Standard Method 2550 B-2000	-5 to 50 ºC	±0.2 ºC	Factory calibration
Oxidation-Reduction Potential (Field)	Standard Method 2580	-1999 to +1999 mV	±20 mV	User calibration per manufacturer recommendation
Dissolved Oxygen (Field)	ASTM Method D888-09 (C)	0 to 50 mg/L	0 to 20 mg/L: ±0.1 mg/L or 1% of reading, whichever is greater; 20 – 50 mg/L: ±8% of reading	User calibration per manufacturer recommendation
Turbidity (Field)	USEPA Method 180.1	0 to 1000 NTU	± 1% of reading or 0.01 NTU, whichever is greater	User calibration per manufacturer recommendation

Notes:

[1]An equivalent method may be employed with the prior approval of the UIC Program Director.
[2]Detection limits and precision (laboratory control limits) are typical for these analytical methods.
* Analytical parameters to be included during the pre-injection phase, and only as needed during the injection and post-injection phases of the Project.

Water samples in the Shoe Bar 1USDW will be collected in appropriate containers provided by the laboratories according to EPA best practices by a qualified and experienced third-party contractor(s) as described in the QASP. All sample containers will be labeled with a unique sample identification number and sampling date, written with durable labels and indelible markings. The water samples will be preserved appropriately, as required by the specific analytical methods, and shipped within 24 hours of collection to certified laboratories, under chain-of-custody control.

Groundwater analyses from the Dockum group will be performed by third-party laboratories accredited with the EPA and/or the Texas Commission on Environmental Quality (TCEQ), following the specific methods approved by EPA or alternative methods (e.g., ASTM Methods or Standard Methods). Operators might audit the procedures and results of the selected laboratories with a third party to review laboratory internal quality control procedures. The samples will be analyzed by a third-party laboratory using standardized procedures for various instruments including for gas chromatography, mass spectrometry, detector tubes, and photo ionization. Sampling methods and chain of custody procedures are described in the QASP.

OLCV personnel experienced in fluid geochemical and isotopic analyses will evaluate the analytical reports provided by the laboratories who analyzed the fluid samples. These data will be compared with previous measurements to look for trends or changes in chemical composition. Groundwater results will be evaluated along with pressure and temperature data to determine the presence or absence of Injection Zone fluid or fluid migration above the confining zone.

An anomalous detection of CO_2 above background levels in the USDW "does not necessarily demonstrate that USDWs have been endangered, but it may indicate that a leakage pathway or conduit exists" (EPA, 2013b). Therefore, if it is determined that a departure between observed and baseline parameter patterns appears to be related to a potential CO_2 leak from the target reservoir, additional testing of the USDW may be conducted. If OLCV personnel interpret that fluids or gases from the Injection Zone may be leaking into permeable zones above the confining zone, the source of the potential leak will be investigated, and appropriate corrective actions will be taken to protect the drinking water resources within the AoR.

The elements of the USDW monitoring program may be modified throughout the baseline, injection, and post-injection operational phases of the project, as needed, and with approval of the Director, as more data and information become available for the Project.

8.2. Near-Surface Soil and Soil Gas Sampling

8.2.1 Monitoring Location and Frequency

The collection of soil gas data within the AoR will aid in the identification, characterization, and source-attribution of CO_2 encountered in the near-surface. The evaluation of near-surface data is complicated by the variations in natural processes in the vadose zone (e.g., root respiration, biologic respiration, microbial oxidation of methane), anthropogenic sources unrelated to the BRP (e.g., nearby oil and gas production), gases from deeper zones (e.g., shallow groundwater), and atmospheric exchanges driven by barometric differences, which can be seasonal (NETL, 2017). As stated by the EPA (2023b), background soil CO_2 concentrations and isotopic compositions are largely "dependent on exchange with the atmosphere, organic matter decay, uptake by plants, root respiration, deep degassing, release from groundwater due to depressurization, and microbial activities." Therefore, some component of soil gas monitoring during the baseline phase of the project is useful to i) define the baseline molecular and isotopic compositions of the shallow soil gas, and ii) characterize natural background variability, including seasonal trends. The results of the pre-injection soil gas monitoring may then be used for future reference and comparison to operational soil gas monitoring to assist in the detection, validation, and quantification of potential CO_2 leakage. To this end, a soil gas monitoring program will be conducted during pre-injection and injection utilizing permanent soil gas probes as an active, whole air, sample collection method.

Permanent subsurface soil gas probes will be installed at 21 representative locations throughout the surface projection of the AoR and adjacent DAC facility. Installation commenced in June 2024 and will extend through July 2024. The following factors were considered in siting soil gas probes: the location of artificial penetrations discussed the Area of Review and Corrective Action Plan; variable surface soil characteristics, such as caliche deposits; the potential effects of the Direct Air Capture (DAC) facility on natural processes in the near-surface; and the location of adjacent property owners. Three probe stations are located near the proposed injection wells, where highest pressures and risks of vertical migration are expected. One probe station is located near each artificial penetration within the AoR (i.e., the BRP verification/monitoring wells and heritage wells). Two probe stations are located near the DAC facility and three probe stations are located along the southern boundary of the Shoe Bar Ranch property boundary near the adjacent private property.

Soil gas samples are collected after the installation of probes. Additional soil gas samples will be collected on a quarterly basis before beginning CO_2 injection over a period of at least one year. These samples will be analyzed for geochemical and isotopic composition shown in Table 14 to evaluate and characterize the near-surface conditions prior to injection. After CO_2 injection commences, the soil gas probe stations will be sampled quarterly for gas composition analysis between year one to three, then a subset of the soil gas stations will be strategically selected based on the previous data collected and sampled annually starting in year four for gas composition analysis. In addition, during the injection and post-injection phases of the Project, if anomalous pressure and temperature changes are observed in the SLR wells, or there is any indication of CO_2 leakage through the injection well, additional soil gas samples may be collected for gas composition and/or isotopic analysis and comparison to pre-injection sample results or deeper zone fluid analysis results.

The elements of the soil gas monitoring program may be modified throughout the pre-injection and injection phases of the Project, as needed, as more data and information become available for the Site.

8.2.2 Description of Methods and Justification

Soil gas characterization and monitoring will be used in concert with fluid analyses to conduct a process-based approach according to the principles described in Romanak (2012). The process-based approach is based on the observation that for every one volume percent of O_2 that is utilized by a microbe during respiration, one volume percent of CO_2 is produced. This relationship of O_2 to CO_2 forms a respiration trend line. Samples that plot to the left of the respiration line indicate natural biological processes. Samples that plot to the right of the respiration line indicate that excess CO_2 has entered the soil (see Figure 5). The source of the excess CO_2 could potentially be attributed to leakage from an injection site, or leakage from a geologic source such as the mantle, or an anthropogenic source other than the OLCV Project.

In addition, Romanak (2012) suggests that using the ratio of N_2 to CO_2 (Figure 5) can be used to detect anomalous introductions of CO_2 into a system. An increase in CO_2 can result in relative dilution of N2 in percent gas concentration. This relative reduction in N2 may indicate a deviation from the natural signal and could be result of CO_2 leakage. In the cases of CO_2 v. O_2 and CO_2 v. N_2, the naturally-occurring ratios are consistent despite seasonal or longer-term variability (Figure 5). Variability due to short or long term naturally occurring processes fall along the same trend, but at different points on the line.

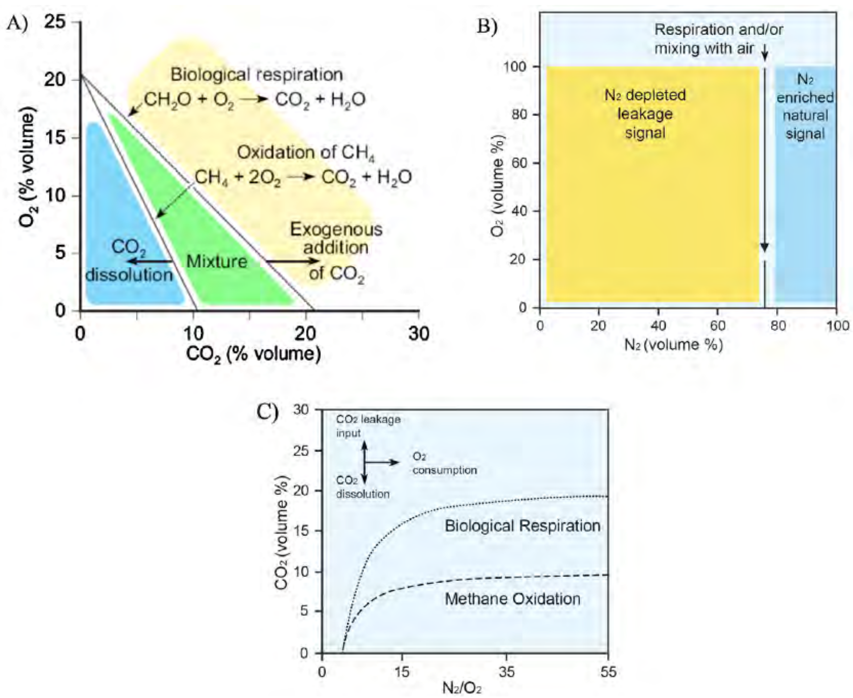

Figure 5—Process based approach for characterizing CO_2 source (modified Romanak, 2014)

As a result, the collection of soil gas samples for gas composition analysis can provide valuable information in the source attribution process for the presence of CO_2 and other gases in the vadose zone. However, the evaluation of the composition gas can be obscured in the light of the various biological processes present in the subsurface which produce or consume CO_2 (Romanak, 1997). Therefore, the collection and analysis of hydrocarbon gas as well as natural tracers (δ13C and 14C) can increase confidence in the interpretation of the data and the attribution of the CO_2 sources (i.e., natural vs. anthropogenic). Several studies have also demonstrated that analysis of soil gas for stable isotopes (δ13C and δD) and hydrocarbons (C2-C3) can help determine whether the presence of the CO_2 and methane is due to natural biological processes or from thermogenic sources (e.g., reservoir deep gas) (Romanak, 2014).

Soil gas probe sites will be installed to a depth of approximately 10 feet below ground level, dependent upon the depth to shallow groundwater and presence of low-permeability (e.g., clay) zones, utilizing either a direct-push (e.g., GeoProbe®) or hand-auger drilling equipment. During borehole advancement, a continuous soil core will be collected and logged in accordance with Unified Soil Classification System (USCS) guidelines to determine soil type. Additionally, up to three soil samples per location will be collected in general accordance with EPA Method LSASDPROC-300-R5 (EPA, 2023a) for the laboratory analysis of pH, electrical conductivity, sodium adsorption ratio, total organic carbon (TOC), and soil moisture, in accordance with the methods specified in Table 14 below.

Table 14—Soil and Soil Gas Analysis Parameters

Parameter	Analytical Method
Soil Analyses	
pH	EPA Method 9045D
Electrical Conductivity (EC)	29B_EC
Sodium Adsorption Ratio (SAR)	29B SAR
Total Organic Carbon (TOC)	Walkley Black 9060A
Moisture	SW3550
Soil Gas Analyses	
Composition gas: H_2, He, O2, N_2, CO_2, CH_4, CO, Ar, C2-C6+	In-house Lab SOP, similar to RSK-175
*$\delta^{13}C$ of CO_2 and CH_4	Gas chromatography/ combustion/ isotope ratio mass spectrometry
*C^{14} of CO_2	Accelerated mass spectrometry
*δD of CH_4	Gas chromatography/ combustion/ isotope ratio mass spectrometry

Note:
* = Analytical parameters to be included during the pre-injection phase, and only as needed during the injection and post-injection phases of the project.

The installation of the permanent soil gas probes will be conducted in accordance with EPA operating procedure LSASDPROC-307-R5 (EPA, 2023b). To construct the soil gas monitoring stations, a drilling contractor will drill 2.25-in diameter boreholes to a depth up to 10 ft, depending on the thickness of the vadose zone and soil type encountered (Figure 6). Stainless-steel vapor implant points will be attached securely to 1/8th-inch Nylaflow® tubing and lowered to the bottom of the borehole. A sand pack using U.S. mesh interval 20/40 sand will be installed to approximately

6-inches above the vapor implant point as a filter pack. The remainder of the borehole will be backfilled with granular bentonite to the ground surface and hydrated to create an annular seal. The upper 1-foot of tubing will be encased within 1-inch diameter, schedule 40 polyvinyl chloride (PVC) pipe at the surface. The tubing will be threaded through a drilled, tight-fitting PVC slip cap and sealed from atmospheric air utilizing a stainless-steal Swagelok® capping fitting. The tubing at the surface will be concealed within a 6-inch steel, flush mount manway, individually installed with a concrete pad, for protection and easy accessibility. General information for each sampling station location will be recorded, including project name, borehole designation, borehole total depth, date and time of completion, borehole GPS location information, soil gas probe construction, and field personnel information.

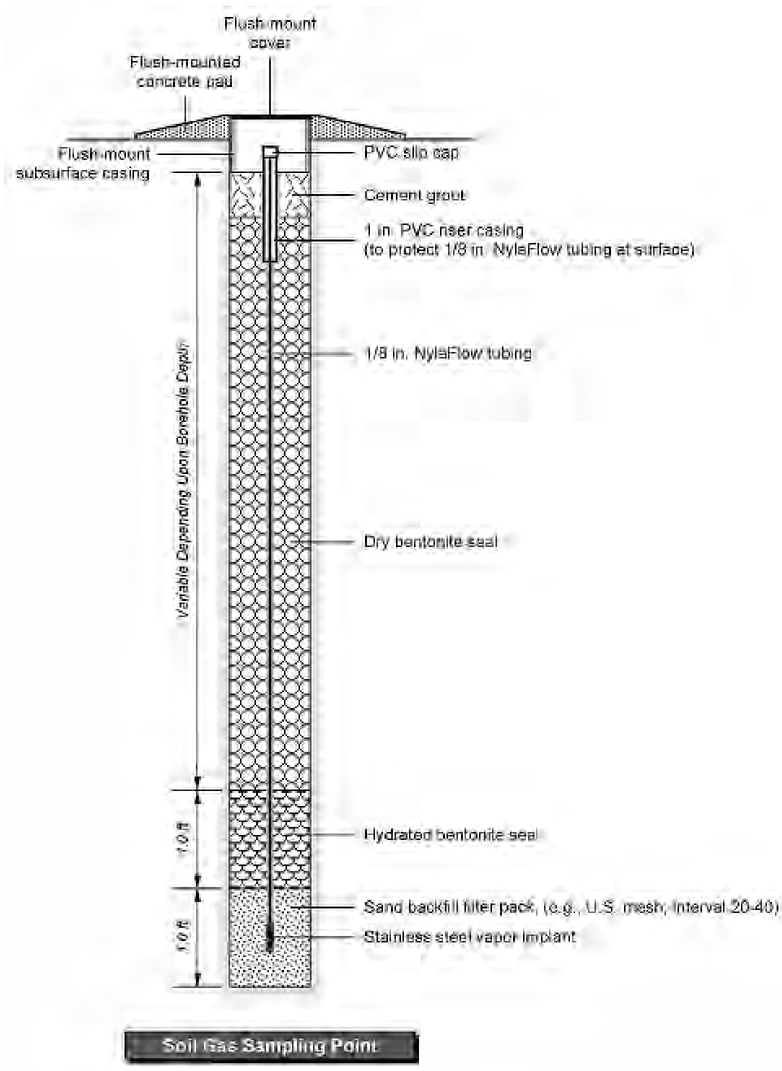

Figure 6—Soil gas probe installation diagram.

Permanent subsurface soil gas probes will be installed at approximately 21 representative locations throughout the surface projection of the AoR and adjacent DAC facility (Figure 7). The following factors will be considered in siting soil gas probes: the location of artificial penetrations discussed the Area of Review and Corrective Action Plan; variable surface soil characteristics, such as caliche deposits; the potential effects of the Direct Air Capture (DAC) facility on natural processes in the near-surface; and the location of adjacent property owners.

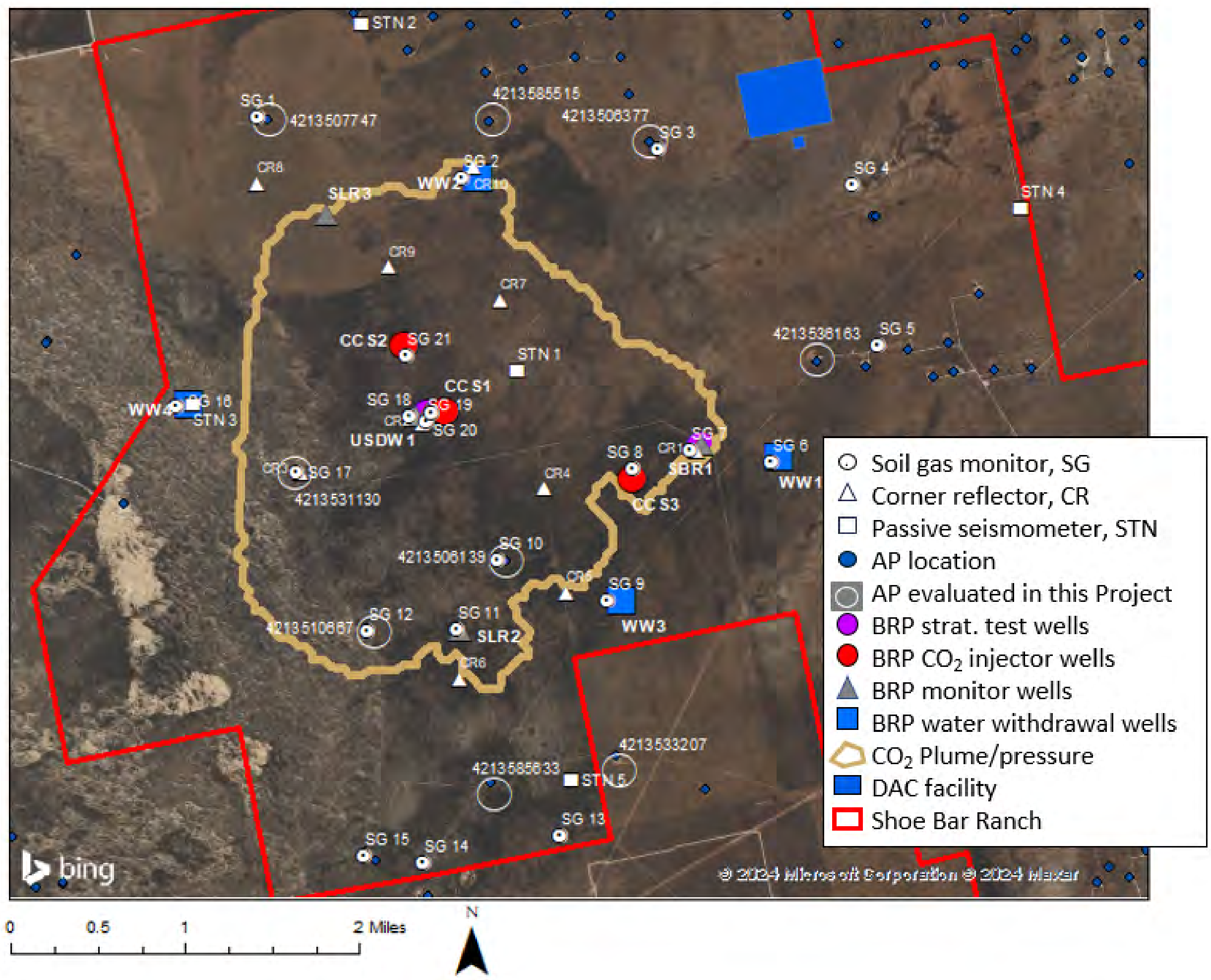

Figure 7—Approximate locations of soil gas monitoring stations and GPS station locations

Soil gas samples at the probe stations will be collected, generally following the procedures set forth in EPA Method SESDPROC-307-R5 (EPA, 2023b), by a qualified and experienced third-party contractor(s). During sample collection, a vacuum will be applied to the tubing on the surface using 60 mL gas-tight syringes, equipped with a 3-way valves, to first purge at least the full length of the tubing, then collect a soil gas sample in appropriate sample containers provided by the laboratories. During soil gas sampling, a leakage test will be conducted by releasing helium gas as a tracer gas within a shroud over each soil gas sampling site. All sample containers will be labeled with a unique sample identification number and sampling date, written with durable labels and indelible markings. The soil and soil gas samples will be preserved appropriately, as required by the specific analytical methods, and shipped within 24 hours of collection to certified laboratories, under chain-of-custody control.

Soil and soil gas sample analyses will be performed by third-party laboratories accredited with the EPA and/or the TCEQ. Operators might audit the procedures and results of the selected laboratories with a third party to review laboratory internal quality control procedures. The samples will be analyzed by a third-party laboratory using standardized procedures for various instruments including gas chromatography, as further described in the QASP.

OLCV personnel experienced in soil analysis and gas composition and isotopic analysis and/or contractors will evaluate the analysis reports provided by the laboratories who analyzed the different samples. These results will be compared with previous measurements to look for trends or changes in chemical composition and distinguish major processes involved in the subsurface which impact the gas composition. The evaluation of soil gas composition and isotopic data will also be coupled with evaluation of other fluids samples, as well as pressure and temperature data to interpret the presence or absence of CO_2 from the Injection Zone or other gases indicated of leakage pathway from the reservoir.

As mentioned in Section 8.1, an anomalous detection of CO_2 above background levels in soil gas "does not necessarily demonstrate that USDWs have been endangered, but it may indicate that a leakage pathway or conduit exists" (EPA, 2013b). Therefore, if a departure from baseline/ seasonal parameter patterns is observed, additional testing of soil gas, the atmosphere, and/or the USDW may be conducted. If OLCV personnel interpret that fluids from the Injection Zone may be leaking into permeable zones above the confining zone and migrated to the vadose zone, the source of the potential leak will be investigated, and appropriate corrective will be taken to protect the drinking water resources within the AoR.

9.0 Internal and External Mechanical Integrity Testing

OLCV will conduct tests to verify the internal and external mechanical integrity of the Injector Wells before and during the injection phase pursuant to 40 CFR §146.89(c), 40 CFR §146.90(e), 40 CFR §146.87 (a)(2)(ii), and 40 CFR §146.87 (a)(3)(ii)].

The purpose of internal mechanical integrity testing is to confirm the absence of significant leakage within the injection tubing, casing, or packers [40 CFR §146.89(a)(1)]. Continuous monitoring of injection pressure, injection rate, injected volume and annulus pressure will be used to ensure internal mechanical integrity. In addition, annulus pressure tests will be periodically conducted to confirm gauge measurements.

The purpose of external mechanical integrity testing is to confirm the absence of significant leakage outside of the casing [(40 CFR §146.89(a)(2))]. OLCV proposes to conduct temperature logging in the Injector wells on an annual basis to demonstrate external mechanical integrity. In addition, OLCV plans to collect continuous temperature profiles above the Injection Zone in Injector wells, using DTS fiber. Based on comparison of results between DTS temperature profiles and temperature logging, OLCV may recommend to the UIC Program Director to cease temperature logging and utilize DTS data only. Ultrasonic tools such as the UltraSonic Imager Tool (USIT™), or IsoScanner are industry-standard tools that provide information on wellbore integrity. One of these methods will be used to monitor integrity in SLR and WW wells.

9.1 Testing Location and Frequency

Table 15 below provides a summary of the internal and external mechanical integrity monitoring methods and mechanical integrity testing (MIT) plans in the injector and monitoring wells.

To demonstrate internal mechanical integrity of the injector wells, OLCV will perform annular pressure tests during well construction and at least once every five years thereafter, coincident with well maintenance operations in which tubing and packer are pulled. Annular monitoring tests will be performed on SLR and WW wells during construction and annually thereafter. Additional testing will be conducted if the pressure or temperature data collected from gauges or DTS indicates a potential reduction in mechanical integrity.

External mechanical integrity testing on Injector wells will be continuously conducted via DTS fiber and using temperature logging to meet and exceed the requirement of annual testing described in 40 CFR §146.89(c). In addition, at least one type of mechanical integrity log will be conducted during construction of each of the injector wells. Logging will be repeated during well maintenance events to minimize disruption to the injection schedule. If DTS data indicate potential loss of mechanical integrity, this event will trigger acquisition of a mechanical integrity log. SLR and WW wells will also have mechanical integrity testing on an annual basis and logging during construction and once at least every five years thereafter, during subsequent well maintenance. The reporting of mechanical integrity testing will comply with TAC Title 16 Chapter 5.206(e)(1): "The operator of an anthropogenic CO2 injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone."

OLCV engineers will monitor downhole P/T data to look for changes that could indicate leakage inside the annulus or outside of the casing. If anomalous measurements are recorded, OLCV personnel will immediately conduct further investigations to determine if there is evidence of surface leakage and take appropriate corrective action. If no surface leakage is detected, OLCV personnel will continue to evaluate the source of the anomalous data and may choose to conduct an annulus pressure test, wireline conveyed P/T gauge, or other logging tool to investigate the borehole integrity. If anomalous data is not found to be the result of operational changes, such as a rate change, injection operations in the affected well will be ceased until the source of the anomalous data is determined and/or corrective action it applied.

Table 15—Internal and External Mechanical Integrity Monitoring Methods and Frequency in Injector Wells

Internal Mechanical Integrity			
Method	**Pre-Injection**	**Injection**	**Post-Injection**
Annular pressure test	During construction and prior to injection	At least once every five years, during well maintenance; and before plugging	NA
DTS	Prior to injection	Continuously	NA
External Mechanical Integrity			
Method	**Pre-Injection**	**Injection**	**Post-Injection**
Temperature log	Prior to injection	Annually	NA
DTS	Prior to injection	Continuously	NA

SLR wells will also be monitored for mechanical integrity.

Table 16—Internal and External Mechanical Integrity Monitoring Methods in SLR and WW wells

Internal Mechanical Integrity			
Method	**Pre-Injection**	**Injection**	**Post-Injection**
Annular pressure test	Prior to injection	Annually and before plugging	At least once every five years, during workovers; and before plugging
Downhole P/T gauges	Prior to injection	Continuously	Continuously for the first 10 years pending an approved PISC plan, then annually until plugging
External Mechanical Integrity			
Method	**Pre-Injection**	**Injection**	**Post-Injection**
Temperature log or other methods: Cement Bond Log (CBL), Variable Density Log, UltraSonic Imager Tool (USIT™), Isolation Scanner™, Electromagnetic Pipe Examiner, Casing Inspection Log	Prior to injection	At least one method once every five years, during well maintenance and before plugging	At least one method once every five years, during workovers; and before plugging

Downhole P/T gauges	Prior to injection	Continuously	Continuously for the first 10 years pending an approved PISC plan, then annually until plugging

9.2 Description of Methods and Justification

9.2.1 Internal Mechanical Integrity Using Annular Pressure Tests

An annular pressure test is a common method to demonstrate internal mechanical integrity. The test is based on the assumption that pressure applied to fluids in the annular space should be constant unless there are significant changes in temperature or a fluid leak.

An overview of the annular pressure test procedure is as follows:

- Shut in the well to stabilize the pressures in the injectors.
- Connect the testing equipment to the annular valves and test surface lines to 1,500 psi above the testing pressure.
- Ensure there are no surface leaks from the pumping unit to the wellhead valve.
- Bleed any air in the system. If needed, fill the annular space with packer fluid and corrosion inhibitor (if so, it should require only a minimal amount).
- Record the initial tubing and casing pressure. The well will be tested to 500 psi in the annular space, and the pressure should not decrease more than 5% in 30 minutes.
- Monitor the tubing and casing pressures continuously. Record the final tubing and casing pressure, then bleed the pressure and volume. If the pressure decreases more than 5%, bleed the pressure, test the surface connection, and repeat the test. If there is an indication of mechanical failure, the operator will prepare a plan to repair the well and discuss it with the Program Director.

9.2.2 External Mechanical Integrity Using DTS

OLCV plans to install a fiber optic cable alongside the casing in the Injector wells and secure the cable with clamps. The fiber is connected at the surface to an interrogator that converts the signal to temperature values, and the data are transmitted to the monitoring platform in real time for surveillance purposes. These data can provide high-resolution temperature data that can be used to detect subtle changes in fluid movement in a wellbore. Additional information on DTS technology can be found in the Appendix A of this document.

Based on comparison of DTS data with data obtained via a conventional temperature log, OLCV may recommend to the UIC Program Director that future external mechanical integrity testing be conducted utilizing DTS in lieu of temperature logging.

9.2.3 External Mechanical Integrity Testing Using Logging Tools

OLCV proposes to use an ultrasonic tool such as the Isolation Scanner™, or UltraSonic Imager Tool (USIT™). The tools are readily available technologies on the market and are commonly used to demonstrate external mechanical integrity. These tools may be used to demonstrate mechanical integrity on SLR or WW wells. OLCV may also recommend that these tools be used to demonstrate external mechanical integrity on the Injector wells, following a comparison of results with conventional temperature logging.

In the future, new technologies or tools may be proposed for further discussion with regulators. Additional details on tools can be found in Appendix A of this document.

10.0 Pressure Fall-Off Testing

OLCV will perform a pressure fall-off test prior to injection 40 CFR §146.87(e) and during the injection phase as described below to meet the requirements of 40 CFR §146.90(f).

10.1 Testing Location and Frequency

The table below summarizes the pressure fall-off testing plan for the injector well.

Table 17—Summary of pressure fall-off testing

Method	Pre-Injection	Injection	Post-Injection
Fall-off Testing	Prior to injection	At least once every five years during workovers	N/A

Pressure fall-off testing in the form of Step Rate Test will be conducted upon completion of the injection well to characterize reservoir hydrogeologic properties, aquifer response characteristics, and changes in near-well/reservoir conditions that may affect operational CO_2 injection behavior.

Following the commencement of injection operations, pressure fall-off testing will be conducted at least once every five years during injection and before well plugging. The objective of the periodic pressure fall-off testing is to determine whether any significant changes in the near-wellbore conditions have occurred that may adversely affect the well or reservoir performance.

10.2 Description of Methods and Justification

Pressure fall-off testing is a method of monitoring changes that may impact injectivity or pressure response in the near-wellbore environment. Additionally, pressure fall-off testing can be used to monitor wellbore mechanical integrity. The fall-off test is conducted by ceasing injection for a designed time period, and continuously monitoring the pressure and temperature with downhole gauges. The duration of the test is designed to measure the pressure recovery.

Pressure fall-off testing is a proven technology that is widely used in subsurface well operations. The results of pressure fall-off tests will be interpreted by engineers and geologists who are experienced in analyzing this type of data. Experienced senior advisors will be consulted to add additional technical insight. The interpretation will be used to confirm or update operational parameters and confirm wellbore mechanical integrity.

Pressure gauges used to conduct fall-off tests will be calibrated in accordance with the manufacturers' recommendations. In lieu of removing the injection tubing to recalibrate the downhole pressure gauges, their accuracy will be demonstrated by comparison with a second pressure gauge with current certified calibration, which will be lowered into the well to the same depth as the permanent downhole gauge. Calibration curves for the downhole gauge, based on annual calibration checks using the second calibrated gauge, can be used for the fall-off test. These calibration curves (showing all historic pressure deviations) will accompany the fall-off test data.

10.3 Interpretation of fall-off test results

Quantitative analysis of the pressure fall-off test response provides the basis for assessing near-well and larger-scale reservoir behavior. Comparison of diagnostic pressure fall-off plots measured before CO_2 injection and during the operational injection phases can be used to determine whether significant changes in well or storage reservoir conditions have occurred. Diagnostic derivative plot analysis (Bourdet et al., 1989; Spane, 1993; Spane and Wurstner, 1993) of the pressure fall-off recovery response is particularly useful for assessing potential changes in well and reservoir behavior.

Plotting the downhole temperature concurrent with the observed fall-off test pressure is useful to check for anomalous pressure fall-off recovery response. Commercially available pressure gauges typically are self-compensating for environmental temperature effects within the probe sensor (i.e., within the pressure sensor housing). However, if temperature anomalies are not accounted for correctly (e.g., well/reservoir temperatures are responding differently than registered within the probe sensor), erroneous pressure fall-off response results may be derived. Thus, concurrent plotting of downhole temperature and pressure fall-off responses is useful for assessing whether temperature anomalies may be affecting pressure fall-off recovery behavior. In addition, diagnostic pressure fall-off plots should be evaluated relative to the sensitivity of the pressure gauges used to confirm adequate gauge resolution (i.e., excessive instrument noise).

Standard diagnostic log-log and semi-log plots of observed pressure change and/or pressure derivative plots vs. recovery time are commonly used as the primary means for analyzing pressure fall-off tests. In addition to determining specific well performance conditions (e.g., well skin) and aquifer hydraulic property and boundary conditions, the presence of prevailing flow regimes can be identified (e.g., wellbore storage, linear, radial, spherical, double-porosity) based on characteristic diagnostic falloff pressure derivative patterns. A more extensive list of diagnostic derivative plots for various formation and boundary conditions is presented by Horne (1990) and Renard et al. (2009).

Early pressure fall-off recovery response corresponds to flow conditions in and near the wellbore, whereas later fall-off recovery response is reflective of reservoir conditions progressively farther from the injection well location. Significant divergence in pressure fall-off response patterns from previous tests (e.g., accelerated pressure fall-off recovery rates) may be indicative of a change in well and/or reservoir conditions (e.g., reservoir leakage). A more detailed discussion of using diagnostic plot analysis of pressure falloff tests for discerning possible changes to well and reservoir conditions is presented by the EPA (2002).

11.0 Carbon Dioxide Plume and Pressure Front Tracking

OLCV will monitor the CO_2 plume and pressure front using both direct and indirect methods pursuant to 40 CFR §146.90(g)(1) and (2). A summary of the methods used for CO_2 and pressure front tracking are provided in Table 18 below.

11.1. Monitoring Location and Frequency

Direct tracking methods include:

- Geochemical monitoring of fluids in the Injection Zone and shallow fluids and gasses. Note that a detailed description of geochemical characterization and monitoring is presented in Section 6 of this document.
- Pressure and temperature measurements from the Injection Zone, and the first permeable layer above the confining zone.

Indirect tracking methods include:

- Estimation of CO_2 saturation using Reservoir Saturation Tool (RST) or Pulsed-Neutron logs (PNL) in SLR2 and SLR3 wells.
- Evaluation of the development and migration pattern of the CO_2 plume and pressure front using time-lapse 2D VSP and 2D surface seismic.
- Calibration of the dynamic simulation model for the AoR re-evaluation.

Table 18—Direct and indirect methods of tracking the CO_2 plume and pressure front

Direct Methods				
Objective	**Method**	**Pre-Injection**	**Injection**	**Post-Injection**
Measure geochemical composition of the Injection Zone	Fluid and dissolved gas sampling in SLR2 and SLR3 wells	During construction and one additional sampling in SLR2	Event-driven*	Event-driven* until plugging
	Fluid and dissolved gas sampling in USDW-level well	Quarterly for at least one year	Quarterly during years 1-3; annually starting in year 4	Annually for first 10 years pending an approved PISC plan
	Fluid sampling in WW wells	Quarterly for approximately one year	Event-driven*	NA
Measure P/T of the Injection Zone	P/T using gauges and/or DTS in SLR2 and SLR3 wells	In SLR2, prior to injection	Continuous	Continuously for the first 10 years pending an approved PISC plan
Indirect Methods				
Objective	**Method**	**Pre-Injection**	**Injection**	**Post-Injection**
Estimate CO_2 saturation in the Injection Zone	PNL or RST in INJ wells	Prior to injection	Event-driven*	NA
	PNL or RST in SLR2 and SLR3 wells	In SLR2, prior to injection	Annually	Annually until plugging
	PNL or RST in WW wells	Prior to injection	Once every five-year period	NA
Estimate CO_2 plume and pressure extent in the Injection Zone	2D VSP in INJ wells	Prior to injection	2D VSP at years 1, 2, 5 and 10	NA
	2D VSP in selected SLR wells	Prior to injection at SLR2	2D VSP in year 5 or 10	Once approximately every five-year period until plugging or plume stabilization
	2D surface seismic	Prior to injection	Year 10	Once approximately every five-year period until plume stabilization
	DInSAR with GPS	Prior to injection	Quarterly	Annually for five years or until plume stabilizes
	Computational modeling	Prior to injection	As needed, to be used for AoR re-evaluation	As needed, to be used for AoR re-evaluation

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. Saturation logging may also be conducted to further support or refute the presence of increased CO_2.

11.2 Description of Methods and Justification

The direct and indirect tracking methods described in this document meet and/or exceed the requirements of the Testing and Monitoring plan established in UIC Class VI. The proposed methods are proven technologies and have been used by the Operator to safely conduct subsurface operations for decades. Additional new technologies will be considered in a cost versus benefit analysis and added to the plan if they are deemed to be warranted.

11.2.1 Geochemical Monitoring

Geochemical monitoring will be employed in SLR2, SLR3 and USDW monitoring well. These data will be compared with the pre-injection geochemical and isotopic characterization to constrain whether changes are observed. If changes are measured, then OLCV will constrain whether the compositional changes are likely to be the result of naturally occurring biological processes or another source. Additional details on geochemical monitoring are described in Section 6 of this document.

11.2.2 Pressure and Temperature Monitoring

Pressure and temperature gauges will be deployed on the tubing above and below the injection packer to monitor bottomhole conditions in real time. In SLR2 and SLR3 wells, the gauges and cables will be selected to withstand CO_2 service conditions. These data will be integrated in the SCADA system and surveillance platform. OLCV will routinely evaluate the data and interpret the results. If a change in pressure or temperature is recorded, OLCV will evaluate and attribute the source of the change. Additional details on downhole gauge instrumentation are described in the QASP document that is part of this application.

The SLR1 well also contains DTS and DAS fiber for monitoring pressure and temperature. However, the fiber was damaged near the top of the Injection Zone. The fiber may provide pressure and temperature data on shallower zones including the Upper Confining Zone, and it may be used for collecting VSP data.

11.2.3 Saturation Detection Tool Method

Reservoir saturation tool (RST) / pulsed neutron logs (PNL) will be run through the tubing to detect changes in CO_2 saturation and identify potential breakthrough of the plume. The pulsed neutron log is considered a proven technique to detect gas saturation in reservoirs. Advances in the technology have improved the accuracy of the tool for tracking movement of CO_2 plumes in the reservoir and evaluating flow conformance. Details of the saturation log / pulsed neutron technique are described in Appendix A to the Testing and Monitoring Plan.

OLCV plans to collect saturation logs in SLR2 and SLR3 wells on a yearly basis. These measurements will provide a record to track potential changes in fluid over time in the Injection Zone. To help calibrate data from the Injection Zone, saturation logs will also be collected in the Injector wells once every five years. The first permeable zone above the confining zone is not expected to encounter any CO_2 from injection. A saturation log may be conducted in the SLR1 and ACZ1 to monitor above the confining zone approximately once every five years.

11.2.4 Repeat Seismic Methods

Baseline seismic acquisition

2D and 3D surface seismic was collected in 2022 for use in site characterization, and as pre-injection baseline of the BRP site. The 3D was acquired in an area of approximately 20 mi^2 and extends approximately one mile beyond the anticipated CO_2 and pressure plumes. Approximately 10 miles of 2D surface seismic was acquired. The survey was designed with a high density of sources and receivers to image from the near-surface down to basement. Vibroseis was used as the source for the acquisition. The processing sequence included pre-processing, pre-stack depth migration and velocity model building, followed by post-migration processing.

Justification of time-lapse seismic methods

OLCV integrated the results of the 2D and 3D seismic with rock and fluid properties measured in the Shoe Bar 1 (SLR1) and Shoe Bar 1AZ (ACZ1) to screen for detectability of a geophysical response resulting from a change in fluid or pressure in the Injection Zone. Figure 8 shows a forward model based on the Shoe Bar 1AZ that demonstrates the geophysical response resulting from a 20% CO_2 saturation in porous (>8p.u.) zones over a ~500 ft thick carbonate as described in Figure 8. This screening result demonstrates the subtlety of time-lapse changes to sonic and density logs in the Injection Zone.

The detectability of a change in fluid or pressure is improved by utilizing wellbore seismic methods, therefore OLCV proposes to acquire seismic using a Vertical Seismic Profile (VSP) in wellbores. Modeling conducted by OLCV indicates that 2D VSP is an appropriate seismic method. Because of the low dip on the Injection and Confining Zone units, 3D VSP is not modeled to yield a significant advantage over 2D VSP, and therefore 2D VSP is proposed for this study.

The imaging area of a VSP is limited to ~3500 – 3800 feet away from the wellbore, based on modeling conducted by OLCV and a third-party contractor. To image the full extent of the AoR, OLCV proposes to acquire 2D surface seismic in a radial pattern centered near the surface location of the injector wells. For surface methods, the detectability of a time-lapse response resulting from a change in fluid or pressure improves with higher concentrations of CO_2. Therefore, surface seismic will be used as a monitoring technique in the later part of the Injection Phase and in the PISC.

[redacted]

Figure 8—Example of forward modeled seismic response resulting from 20% CO_2 saturation at Shoe Bar 1AZ. Model shows a significant low impedance shift compared to the brine saturated base case.

Timing of baseline and repeat seismic acquisition

Following drilling and prior to commencement of injection, a 2D VSP baseline will be acquired in the Injector wells. The Injector wells are designed to contain DAS fiber to the top of the Injection Zone. OLCV may also collect baseline 2D VSP in the SLR1 and SLR2 monitoring wells, utilizing DAS fiber. Additional monitoring wells drilled in the future may also be equipped with DAS. In event that DAS fails, or if a VSP will be collected in a well without DAS, a borehole geophone array can be deployed for data acquisition.

Baseline surface 2D seismic will be acquired in a radial pattern around the wells, concurrent with baseline VSP survey acquisition. The acquisition will be conducted using conventional Vibroseis vehicles and/or Surface Orbital Vibroseis (SOV). The surface acquisition will be dense to improve imaging from throughout the stratigraphic column from surface to basement.

Following the commencement of injection, time-lapse 2D VSP surveys will be conducted in the Injector wells and in SLR2 at approximately 12 months and 24 months following commencement of injection. The purpose of these surveys is to provide high-resolution, early indicators of plume orientation. The timing of future VSP acquisition will be planned to provide information for AoR re-evaluation, at approximately five and 10 years after the start of injection.

Repeat surface 2D is planned to occur at approximately year 10 following the commencement of injection. Based on the detectability and resolvability observed with this survey, 2D surface acquisition may continue throughout the PISC at an interval of approximately once every five years, or until plume stabilization.

If data collected with other monitoring methods indicates a significant deviation of the plume from the modeled forecast, seismic may be acquired at a more frequent interval. Figure 9 shows the anticipated extent of VSP imaging and notional survey design.

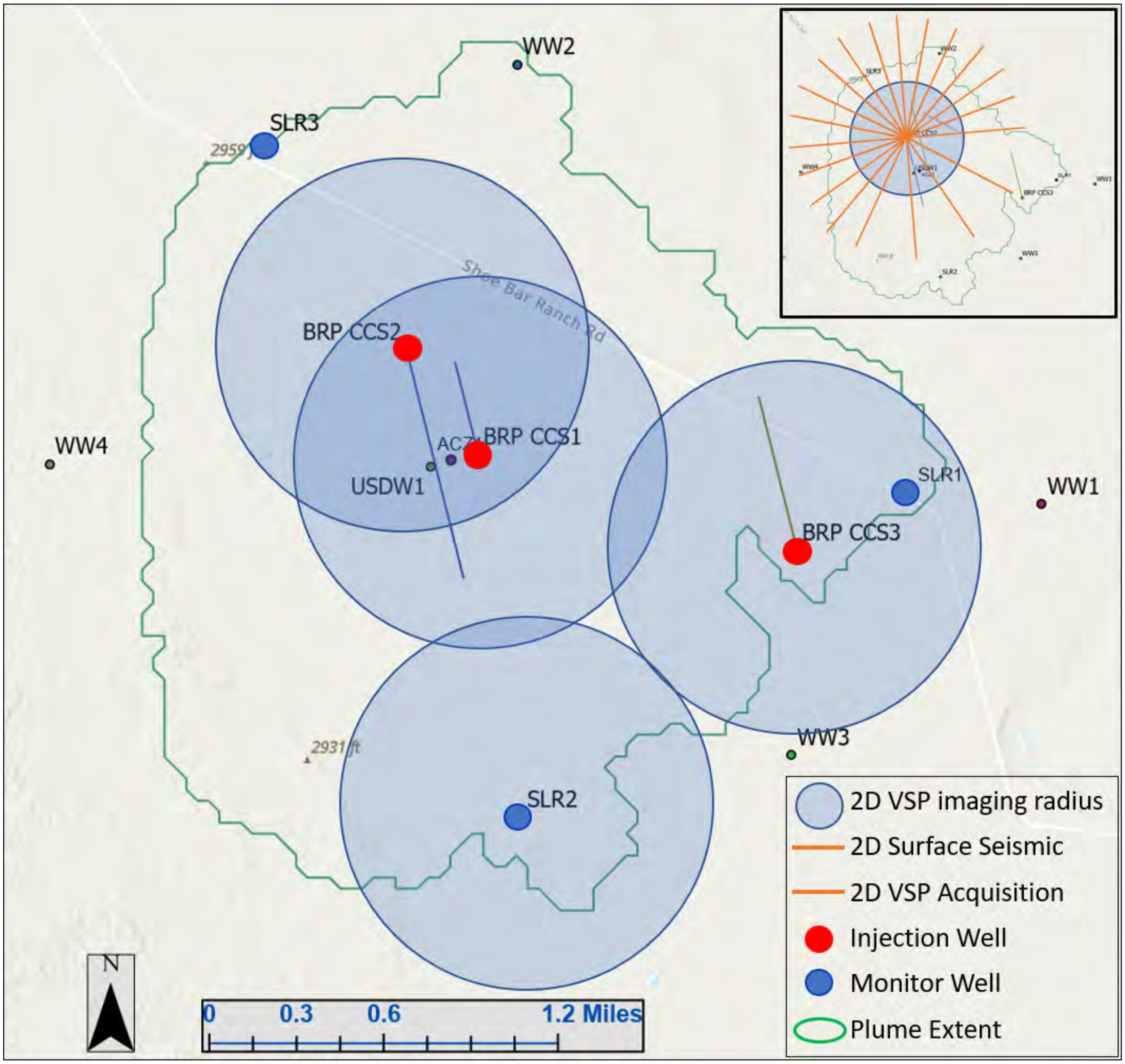

Figure 9—The extent of the 2D VSP imaging area (blue circles). The inset map shows an idealized survey design for 2D surface seismic (orange lines) with 2D VSP acquisition. The maximum distance between two open 2D lines is ~800ft for VSP and ~1,200ft for surface seismic.

New and emerging technologies

OLCV will re-evaluate new and improving time-lapse monitoring techniques, such as a Scalable, Automated, Sparse Seismic Array (SASSA), at least every five years and will recommend changes to the monitoring plan if these technologies are interpreted to provide improved monitoring results. Recommendations will be reviewed with the UIC Program Director.

11.2.5 DInSAR and GPS data acquisition

The BRP Project plans to use Differential Interferometric Synthetic-Aperture Radar (DInSAR) and Global Positioning Systems (GPS) data to indirectly monitor the position of the CO_2 pressure plume. DInSAR is a non-intrusive, non-destructive technology that measures, with high accuracy, relative displacement over time. It is highly effective for measuring ground deformation over multiple years. A network of 10 "corner reflectors" will be installed by a third-party contractor to serve as permanent monuments to aid in data processing repeatability. Prior to injection a historical evaluation of past ground movement will be conducted. These data will be licensed from a third-party DInSAR contractor and interpreted by the contractor and by qualified Oxy and OLCV personnel.

To further improve the resolution and accuracy of DInSAR, BRP plans to install a local geodetic network of GPS stations to provide a common space-temporal reference frame for all geodetic and geophysical surveys in the area. For this study area, approximately 10 stations will be placed in a regularly-spaced array. Each station typically consists of a four-inch pipe installed at a depth of 5-11 feet. Stations will be installed by a third-party contractor. Data will be processed by qualified Oxy or OLCV personnel or by third-party contractors.

DInSAR coupled with GPS technology provides sub-millimeter ground surface deformation data that informs the following interpretations:

- Surface impact caused by subsidence or uplift induced by Injection Zone operations.
- Calibration of geomechanical models by providing information on the mechanical properties of the Injection and Confining Zones.
- Monitoring of the stress field depth.
- Identification of potential leakage pathways.

Table 19 below describes the sampling and recording frequency for DInSAR and GPS data. See Figure 7 for the planned locations of corner reflectors.

Table 19—Summary of DInSAR and GPS sampling plans

Objective	Method	Minimum sampling frequency	Minimum recording frequency
Measure surface displacement	DInSAR	Quarterly	Image recording bi-weekly
	GPS	Quarterly	Quarterly

11.2.6 Dynamic simulation modeling

A dynamic simulation model has been constructed and is used to inform the interpretation of the AoR. This model will be evaluated after the commencement on injection operations and calibrated to operational data. The model will be updated, as needed, to meet the requirements of 40 CFR §146.84(e) that require AoR re-evaluation on a fixed frequency not to exceed five years. The frequency of model updates will be dependent on the amount of deviation from the predicted plume and pressure front.

Dynamic simulation modeling is used to predict changes in the Injection and Confining zones over time. OLCV first constructed a static geocellular model using log, core, and seismic data from the site. Stratigraphic tops were selected on well logs and then mapped throughout the field to form a stratigraphic framework. The framework was divided into geologic zones and assigned rock and fluid properties derived from log and core analysis. The static geomodel forms the basis for the reservoir simulation model.

OLCV constructed a dynamic simulation model that tracks the composition of brine and CO_2 through time. Following the commencement of injection operations, the predictions made on CO_2 and pressure front movement will be calibrated with direct and indirect plume and pressure tracking data. These data will be used to history match the dynamic model and then update forecasts of plume and pressure movement in the future. Significant deviation from forecasts will lead to updates to the AoR delineation. See additional information on delineation of the AoR in the AoR and Corrective Action Plan that is part of this application.

11.2.7 Interpretation and Analysis of Data Collected

The data collected with direct and indirect tracking methods will be evaluated by subsurface geologists and engineers. In addition, OLCV will utilize senior technical advisors to review work products and provide additional technical insight. Data will be routinely reviewed and integrated into and updated subsurface characterization that will be used to inform the AoR and future testing and monitoring plans.

12. Induced Seismicity Monitoring

12.1 Description of Methods and Justification

12.1.1 Traffic Light System for Monitoring Induced Seismicity

Based on information provided by the United States Geological Survey (USGS), the BRP Project area does not show high seismic activity that could endanger the containment of the CO_2 in the storage complex. Seismicity history is discussed in more detail in the Area of Review and Corrective Action Plan document of the permit.

Change of in-situ stresses on existing faults caused by human activities (e.g., mining, dam impoundment, geothermal reservoir stimulation, wastewater injection, hydraulic fracturing, and CO_2 sequestration) may induce earthquakes on critically stressed fault segments. To monitor potential induced seismicity due to the injection of CO_2 in the area, it is proposed that the project deploy surface seismometer stations.

While the historical seismicity of the project area indicates no earthquakes in the immediate vicinity, the operator intends to monitor the site with a seismic monitoring system for the duration of the project to ensure the safe operation of both the storage facility and adjacent infrastructure in the area. The seismic monitoring will be conducted with a surface array deployed to ensure detection of events above local magnitude (ML) 1.0, with epicentral locations within 10 miles of the injection well.

If an event is recorded by either the local private array or a public (national or state) array occurs within 10 miles of the injection well, OLCV will implement the response plan subject to detected earthquake magnitude limits defined below to eliminate or reduce the magnitude and/or frequency of seismic events:

- For events above ML 2.0 but below ML 3.5 within 5.6 miles of the injection wells, OLCV will closely monitor seismic activity and may implement a pause to operations or continue operations at a reduced rate, should analysis indicate a causal relationship between injection operations and detected seismicity. The 5.6 mile radius is used because this is the metric used for disposal well applications to the Railroad Commission. "Pursuant to 16 Texas Administrative Code §3.9(3)(B) and §3.46(b)(1)(C), SWD well permit applications must include a review of USGS earthquake records for a circular area of 100 square miles around the proposed SWD well location (a circular area with a radius of 9.08 kilometers, or 5.64 miles)."
- For events with ML 3.5 to ML 4.5 within 5.6 miles of the injection well, OLCV will initiate contact with relevant regulatory and/or government entities. OLCV will begin a technical review within 24 hours of the event to determine if a causal relationship exists. Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity. Such plans are dependent on the pressures and seismicity observed and may include, but not limited to:
    1. Reducing CO_2 injection pressures until reservoir pressures fall below a critical limit.
    2. Increasing water production rates until reservoir pressures fall below a critical limit
    3. Continuing operations at a reduced rate and/or below a revised maximum operation pressure.
        - OLCV will obtain approval from the relevant regulatory and/or government entities to implement revised plan.

- If the event is not related to the storage facility operation, OLCV will resume normal injection rates.

- For events above ML 4.5 within 5.6 miles of the injection well, OLCV will stop injection as soon as safely practical. OLCV will inform the regulator of seismic activity and inform them that operations have stopped pending a technical analysis. OLCV will initiate an inspection of surface infrastructure for damage from the earthquake. A detailed analysis will be conducted to determine if a causal relationship exists between injection operations and observed seismic activity. Should a causal relationship be determined, a revised injection plan would be developed to reduce or eliminate operationally related seismicity before resuming injection operations. Such plans are dependent on the pressures and seismicity observed and may include, but not be limited to:
  1. Reducing injection pressures until reservoir pressures fall below a critical limit.
  2. Increasing water production rates until reservoir pressures fall below a critical limit.
  3. Continuing operations at a reduced rate and/or below a revised maximum operation pressure.
     - OLCV will obtain approval from the relevant regulatory and/or government entities to implement a revised plan.
     - If the event is not related to the storage facility operation, and with prior approval from the regulators, OLCV will adjust injection and/or production rates to previous rates in steps, while increasing the surveillance.

12.1.2 Induced Seismicity Monitoring Network

Presently, the nearest seismometers to the AoR are part of the MTX and TexNet arrays. The USGS seismometer network in Texas is known as TexNet. The MTX array is a private subscription array. Oxy has been a subscriber to MTX since its inception in 2017. Together, the data from the TexNet and MTX arrays provide accurate seismicity information throughout the Permian Basin.

OLCV plans to install five additional seismometers delivering real-time seismicity alerts within the BRP Project area. To achieve the lowest magnitude of completeness within the AOR, modeling is ongoing to identify optimal locations to site the new seismometers. Installation is expected mid-2024. The data from seismometers installed for the purposes of the BRP Project are not intended to be publicly available.

A seismometer monitoring network will be deployed to determine the locations, magnitudes, and focal mechanisms of any injection-induced seismic events in case they occur. This information will be used to address public concerns and to monitor changes in induced seismicity risks with a goal of reacting to the perceived risk through adjustment of well operations as needed.

A map of proposed new station locations is provided in Figure 10 (and also Figure 7). Existing locations are provided as attachment in the GSDT. These station locations were used for modeling the expected sensitivity of the array at the project site. Locations are subject to change in order to optimize the station locations around surface infrastructure and access limitation and changes to the pressure plume modeled so as to provide optimum monitoring of the site.

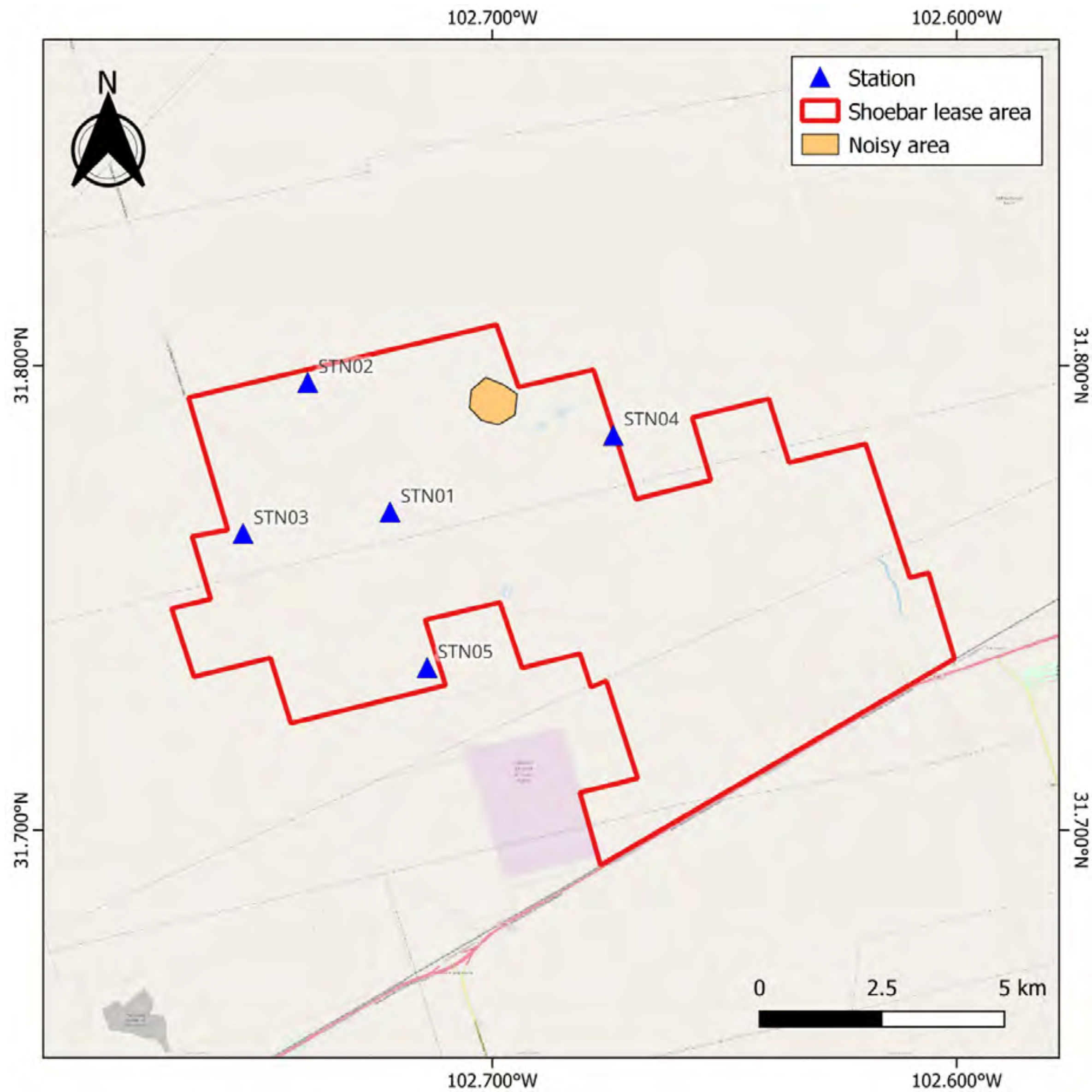

Figure 10—Locations of proposed new passive seismic monitoring stations

The design and installation of the station array is performed by specialized contractors and include the following activities:

- Project management support to design the seismometer array, model the network performance, coordinate permitting and equipment installation, conduct testing and maintenance, and ensure optimum execution of the Project.
- Field operations to deploy seismic station instrumentation, run power and communication systems, monitor data quality, and do commissioning.
- Data acquisition, system configuration, and process setup.
- Continuous support and monitoring for data verification and QA/QC.
- Continuous near-real-time reporting, including analyst reviews and alert notifications, for events at or above predetermined magnitude thresholds over the seismic area.

12.1.3 Seismicity Monitoring Equipment

The equipment proposed for seismicity monitoring includes: broadband sensors, a data logger, a solar power system and backup battery, communication system, cabling, and mounting equipment (Figure 11).

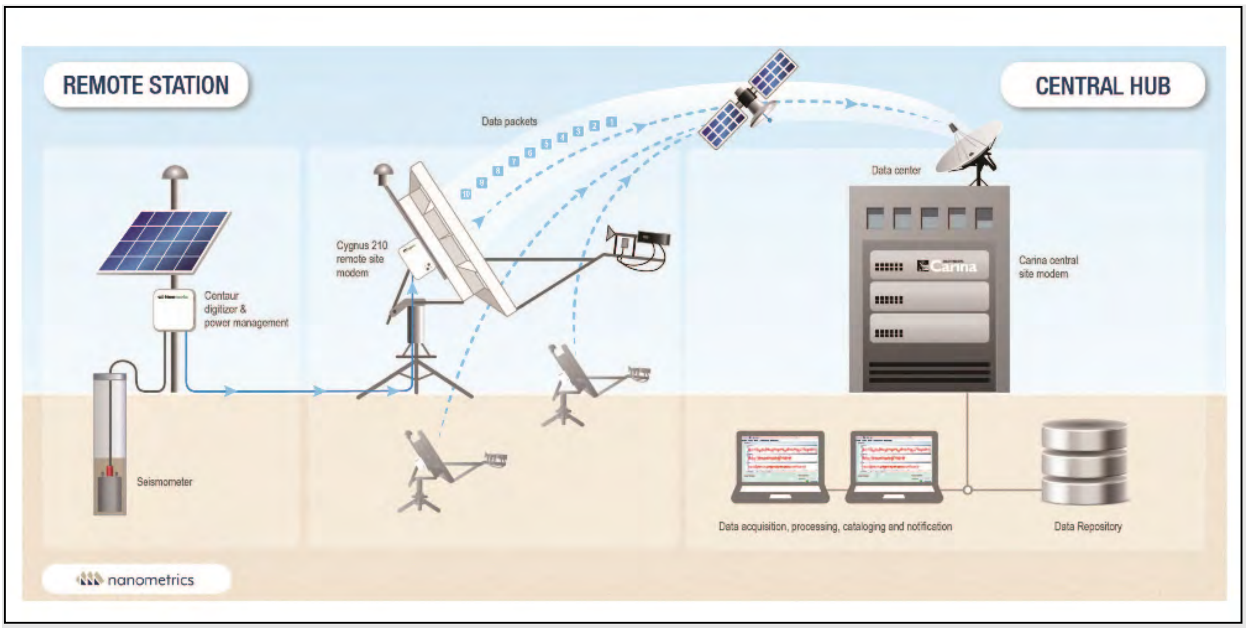

Figure 11—Example of a setup for data acquisition, transfer, storage, and analysis.

13.0 Reporting

The results of all testing and monitoring are to be described in a semi-annual report that will be submitted to the EPA.

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TESTING AND MONITORING PLAN, APPENDIX A: LOGGING TOOLS

Brown Pelican CO_2 Sequestration Project

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1.0 Facility Information

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS1, CCS2 and CCS3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

2.0 Logging Tools

2.0.1 Cement Bond Log

Cement bond log (CBL) is a basic method to evaluate cement quality in the annulus. It is an acoustic wave measurement. The tool usually includes a transmitter and receiver set 3 ft apart. The acoustic wave is emitted by the transmitter, propagated down and across the annulus, and recorded by the receiver. The attenuation of the wave is analyzed to interpret the bonding behind the pipe. A signal coming from a properly cemented casing will be more attenuated than signals coming from a poorly cemented one.

The arriving signal recorded by the receiver is a mixed signal coming from casing, cement, mud, and formations. Each signal has its own pathway because signals travel at different velocities through each medium. The signal through the casing is the fastest, as sound travels the quickest through steel. As a result, it is the first signal detected on the receiver. The second signal most likely to arrive is the signal through the formation, and the last one is the drilling fluid signal, because sound travels more slowly in a liquid.

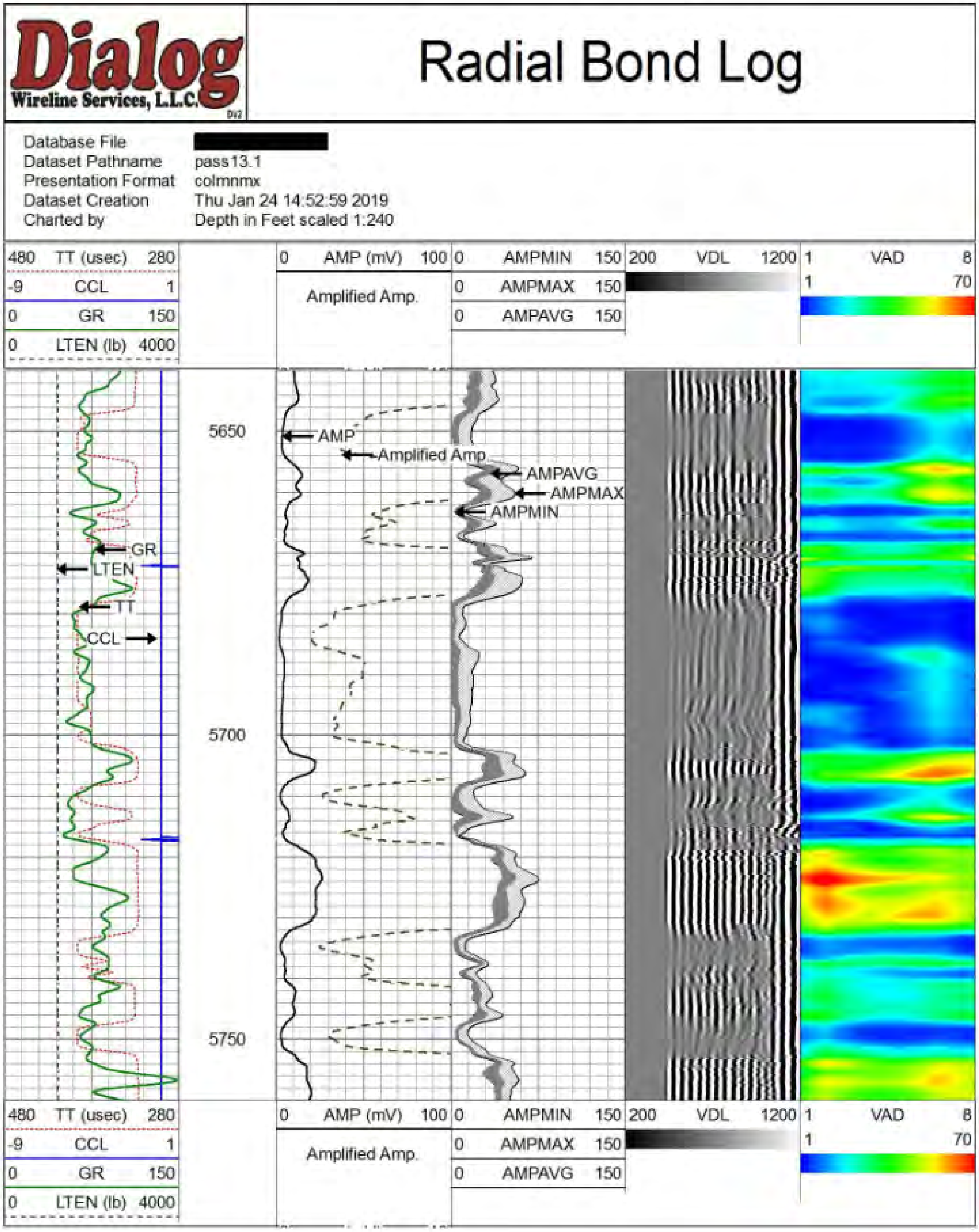

Figure 1—CBL and VDL Example from Dialog Wireline Services Web Page

Variable Density Log

A variable density log (VDL) is commonly used as an adjunct to the cement bond log and offers better insights with its interpretation. In most cases, micro-annulus and fast-formation-arrival effects can be identified using this additional display (Figure XX).

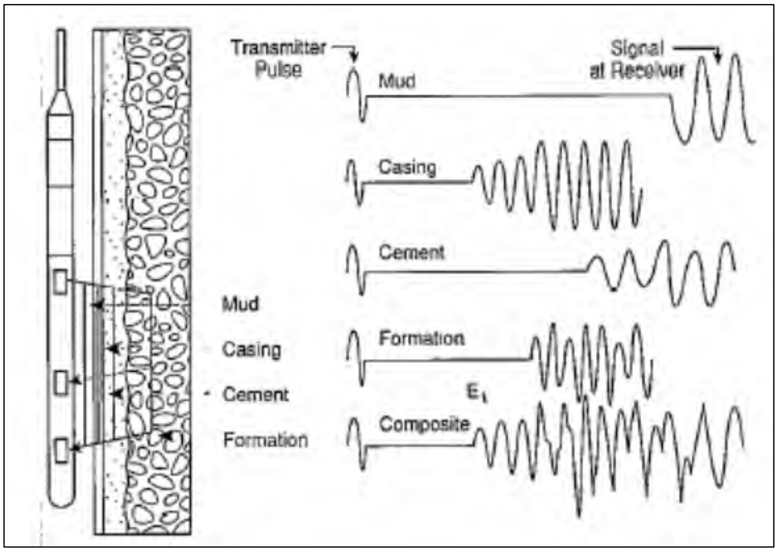

Figure 2—Signal received by CBL-VDL

The **USI[1] UltraSonic Imager Tool (USIT)** delivers an accurate, comprehensive, high-resolution confirmation of the pipe-to-cement bond quality and downhole pipe condition in real time. Casing inspection and monitoring applications include corrosion detection, identification of internal and external damage or deformation, and casing thickness analysis for collapse and burst pressure calculations.

The rate of decay of the waveforms received indicates the quality of the cement bond at the cement-casing interface. The resonant frequency of the casing provides the casing wall thickness required for pipe inspection. The resulting 360° data coverage enables evaluation of the quality of the cement bond and the determination of both the internal and external condition of the casing.

The **Isolation Scanner** (a service of Schlumberger) provides a combination of independent measurements that fully characterizes the annular environment, differentiating low-density solids from liquids to distinguish lightweight and contaminated cements from liquids. Its azimuthal coverage provides results around the entire circumference of the casing, pinpointing any channels in the cement and confirming the effectiveness of the annular barrier for zonal isolation.

[1] USI is a trademark of Schlumberger

The Isolation Scanner tool also identifies corrosion or drilling-induced wear through measurement of the inside diameter and thickness of the casing. The flexural wave measurement produces entirely new information from the third-interface echoes (TIEs) between the annulus and borehole or outer casing. The TIEs image the borehole shape, define the position of the casing within the borehole or outer casing, and image the outer string to reveal corrosion and damage.

2.0.2 Electromagnetic Log

The **Electromagnetic Pipe Xaminer®** (a Halliburton technology) induces a high-definition frequency (HDF) electromagnetic energy into the surrounding pipe, which propagates through the concentric well strings with no wellbore fluid influences. The interaction with the metal of the pipe returns a signal to the tool, yielding information about any metal loss in the tubulars. The magnitude and location of corrosion-induced defects are identified using HDF variance algorithms of the returning electromagnetic waves. This information leads to a quick total thickness calculation to determine the overall condition of the pipe structure. This technology enables users to examine the whole well with up to five concentric strings of pipe in one trip.

2.0.3 Temperature Log

Temperature logs are used to locate gas entries, detect casing leaks, and evaluate fluid movement behind casing. They are also used to detect lost-circulation zones and cement placement. Temperature logs are used as a basic diagnostic tool and are usually paired with other tools like acoustics or multi arms calipers if more in depth analysis is required.

Temperature instruments used today are based on elements with resistances that vary with temperature. The variable resistance element is connected with bridge circuitry or constant current circuit, so that a voltage response proportional to temperature is obtained. The voltage signal from temperature device is then usually converted to a frequency signal transmitted to the surface, where it is converted back to a voltage signal and recorded. The absolute accuracy of temperature logging instruments is not high (in the order of +- 5°F), but the resolution is good (0.05°F) or better, although this accuracy can be compromised by present day digitalization of the signal on the surface. The temperature instrument usually can be included in the string with other tools, such as radioactive tracer tools or spinners flowmeters. Temperature logs are run continuously, typically at cable speeds of 20 to 30 ft/min.

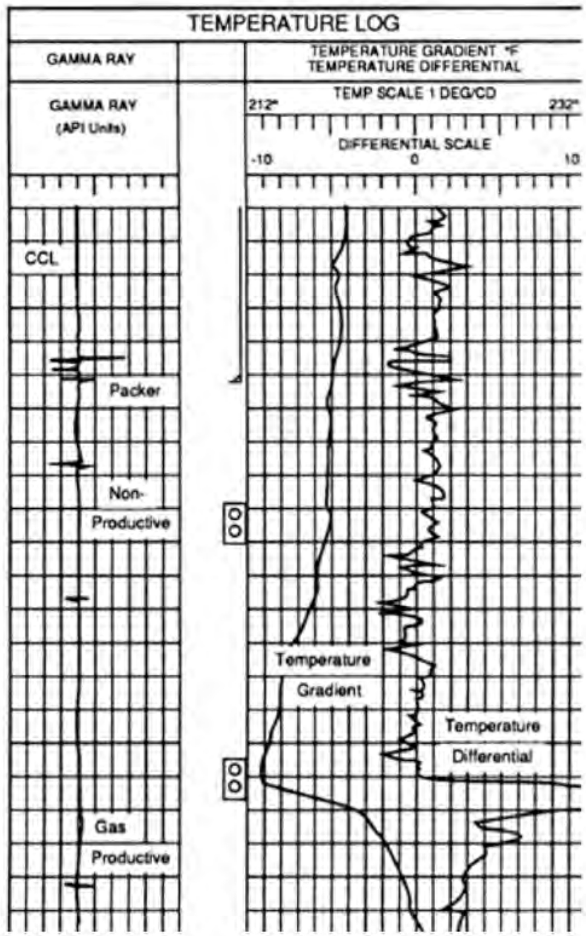

Figure 3—Example of temperature log output

2.0.4 Variable Density Log

A Variable Density Log (VDL) is a presentation of the acoustic waveform at a receiver of a sonic or ultrasonic measurement, in which the amplitude is presented in color or the shades of a gray scale. The variable-density log is commonly used as an adjunct to the cement-bond log and offers better insights into its interpretation. In most cases micro-annulus and fast-formation-arrival effects can be identified using this additional display.

2.0.5 UltraSonic Imager Log

The USI* UltraSonic Imager tool (USIT) uses a single transducer mounted on an Ultrasonic Rotating Sub (USRS) on the bottom of the tool. The transmitter emits ultrasonic pulses between 200 and 700 kHz and measures the received ultrasonic waveforms reflected from the internal and external casing interfaces. The rate of decay of the waveforms received indicates the quality of the cement bond at the cement/casing interface, and the resonant frequency of the casing provides the casing wall thickness required for pipe inspection. Because the transducer is mounted on the rotating sub, the entire circumference of the casing is scanned. This 360° data coverage enables the evaluation of the quality of the cement bond as well as the determination of the internal and external casing condition. The very high angular and vertical resolutions can detect channels as narrow as 1.2 in [3.05 cm]. Cement bond, thickness, internal and external radii, and self-explanatory maps are generated in real time at the wellsite.

2.0.6 Isolation Scanner Log

The Isolation Scanner™ cement evaluation service integrates the conventional ultrasonic pulse-echo technique with flexural wave propagation to fully characterize the cased hole annular environment while evaluating casing condition—even where the cement has a low acoustic impedance or is contaminated with mud. The Isolation Scanner service can accurately evaluate almost any type of cement— from traditional slurries and heavy cements to the latest lightweight cements. This service provides precise, real-time evaluation of the cement job and casing condition in a wider range of conditions than were previously possible with conventional technologies. Its azimuthal coverage provides a response around the entire circumference of the casing, pinpointing any channels in the cement and confirming the effectiveness of the annular barrier for zonal isolation. Processing provides a robust interpreted image of the material immediately behind the casing. The independent inputs of cement impedance and flexural wave attenuation from the Isolation Scanner service are inversely related to the properties of both the fluid inside the casing and the outside medium. This means that fluid effects are accounted for, eliminating the need for logging specific fluid-property measurements. The output is a solid-liquid-gas (SLG) map that displays the most likely material behind the casing.

2.0.7 Pulse Neutron Log (PNL)

Pulse neutron log (PNL) provides formation evaluation and reservoir monitoring in cased holes. PNL is deployed as a wireline logging tool with an electronic pulsed neutron source and one or more detectors that typically measure neutrons or gamma rays. High-speed digital signal electronics process the gamma ray response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the gamma ray energy and time relationship into concentrations of elements. Each logging company has its own proprietary designs and improvements on the tool.

Schlumberger's Pulsar Multifunction Spectroscopy Service (PNX) pairs multiple detectors with a high output pulsed neutron generator in a slim tool with an outer diameter (o.d.) of 1.72 in. for through-tubing access in cased hole environments. The housing is corrosion-resistant, allowing deployment in wellbore environments such as CO_2. The tool's integration of the high neutron output and fast detection of gamma rays with proprietary pulse processing electronics, allows to differentiate and quantify gas-filled porosity from liquid-filled and tight zones. The tool can accurately determine saturation in any formation water salinity across a wide range of well conditions, mineralogy, lithology, and fluid contents profile at any inclination. Detection limits for CO_2 saturation for the PNX tool vary with the logging speed as well as the formation porosity. Detailed measurement and mechanical specifications for the PNX tool are provided in the QASP document. The wireline operator will provide QA/QC procedures and tool calibration for their equipment.

Haliburton's RMT-D reservoir monitor tool: The Halliburton Reservoir Monitor Tool 3-Detector™ (RMT-3D™) pulsed-neutron tool solves for water, oil, and gas saturations within reservoirs using three independent measurements (Sigma, C/O, and SATG). This provides the ability to uniquely solve simple or complex saturation profiles in reservoirs, while eliminating phase-saturation interdependency. The RMT-#D provides gas phase analysis to identify natural gases, nitrogen, CO_2, steam, and air. The tool has 2.125 in diameter OD that allows it to be run through tubing.

3.0 Distributed Temperature Sensing (DTS) and Distributed Acoustic Temperature (DAS) Technology

3.0.1 DTS

DTS technology uses fiber optic sensor cables that function as linear temperature sensors. The result is a continuous temperature profile along the entire length of the sensor cable. DTS utilizes the Raman effect to measure temperature. An optical laser pulse sent through the fiber results in scattered light reflecting to the transmitting end, where the information is analyzed. The intensity of the Raman scattering is a measure of the temperature along the fiber. The Raman anti-Stokes signal changes its amplitude significantly with changing temperature, while the Raman Stokes signal is relatively stable. The position of the temperature reading is determined by measuring the time of arrival of the returning light pulse, much like a radar echo.

The fiber optic cable is run alongside the casing as an umbilical, and it is protected with clamps and centralizers to avoid any damage while deploying it into the well. The fiber is connected on the surface to an interrogator to convert the signal to temperature values, and data are transmitted to the monitoring platform in real time for surveillance purposes.

The maintenance and calibration of the equipment will be performed according to the manufacturer's manuals and will be the responsibility of the technology provider. Table 11 and Table 12 show the technical specifications for DTS systems and fiber optic cable, respectively.

3.0.2 DAS

DAS utilizes the Rayleigh backscattering to detect and locate the vibrations along the single mode optical fiber. Over long distances it can simultaneously retrieve and detect amplitude, frequency and phase of the vibrations at all positions along the optical fiber. Upon arrival at each element, backscattered light from a coherent pulse will cause interference at the receiver because the field contributions from adjacent elements within the pulse's spatial length will have similar phase relations due to the coherence of the light. This backscattering field produces a distributed coherent speckle pattern whose local phase and intensity are sensitive to local perturbations when monitored for a duration corresponding to the entire length of the fiber.

The fiber optic cable is run alongside the casing as an umbilical, and it is protected with clamps and centralizers to avoid any damage while deploying it into the well. The fiber is connected on the surface to an interrogator to convert the signal to temperature values, and data are transmitted to the monitoring platform in real time for surveillance purposes.

The maintenance and calibration of the equipment will be performed according to the manufacturer’s manuals and will be the responsibility of the technology provider. Table 11 and Table 12 in Quality Assurance and Surveillance Plan show the technical specifications for DAS systems and fiber optic cable, respectively.

QUALITY ASSURANCE AND SURVEILLANCE PLAN

Brown Pelican CO_2 Sequestration Project

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TITLE AND APPROVAL SHEET

The Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at the Brown Pelican CCS Project (BRP Project or Project) including wells BRP CCS1, BRP CCS2, BRP CCS3). The signatures below denote the approval of this document and intent to abide by the procedures outline within it.

Name

Title Date

Name

Title Date

DISTRIBUTION LIST

The following Project participants will receive the completed QASP and all future updates for the duration of the Project.

List of the names will be updated at later date.

1.0 Project Management

1.1 Project/Task Organization

Characterization of the Injection Zone, Confining Zones, and subsurface features has been done by experienced geoscience professionals using industry-recognized software and techniques. Further characterization of the features will be done by applying the industry-recognized logging and testing technologies during construction and operation of the CO_2 Injection wells.

Pipeline, surface equipment, and well designs comply with industry standards for CO_2 material selection and operating conditions to promote mechanical integrity of the system during the life of the Project.

Monitoring programs for leak detection, corrosion, and surveillance have been tailored for the site to ensure protection of Underground Sources of Drinking Water (USDWs) and the environment, maintain mechanical integrity of the installation during operations, and maximize the storage life of the asset. These plans incorporate best practices and recommendations for Carbon Capture and Storage projects worldwide as well as decades of experience by Occidental Oil & Gas Corporation (Oxy), parent company of Oxy Low Carbon Ventures (OLCV), in the development and operation of CO_2 Enhanced Oil Recovery (EOR) fields.

As part of the quality control process during testing and surveillance, most of the samples collected and the data gathered will be analyzed, processed, validated, or witnessed by third parties independent of the operations staff. For specialized data such as seismic acquisition, seismicity monitoring, and distributed temperature sensing (DTS), the Project will have additional support from the providers of the selected technologies in quality control, verification of the data, and system calibration.

Sensors, transducers, and controllers will be connected to a central platform to allow for monitoring of operating conditions, system upset alarming, and safety protocol initiation. System data interfaces will be created and integrated in a unique surveillance platform. The operating parameters, monitoring values, laboratory results, and surveillance documents for the Project will be stored in a central database to provide support for Area of Review (AoR) reviews, monitoring, quality assurance programs, and reporting.

1.1 Project/Task Organization

The Brown Pelican CO_2 Sequestration Project (BRP Project or Project) includes participation of multidisciplinary teams from Oxy, OLCV, consultants, and subcontractors. Each team will provide technical expertise and economic inputs to the Project to ensure a safe, successful, and efficient operation.

The Project will establish key staffing positions that will ensure a reliable operation with the highest standards of quality, surveillance procedures, storage evaluation, and reporting. Some of the staff will be dedicated full time to the operation, while others will be assigned as required during AoR reviews, maintenance activities, and other Project activities.

Once the Project is in operation, OLCV can provide a detailed contact list with the names of the individuals in each position.

1.1.1 Key Individuals and Responsibilities

A brief description of key management and supervision roles and responsibilities is below:

- **Project Manager:** The Project Manager is responsible for Project coordination and implementation, including obtaining required permits, ensuring compliance with reporting requirements and meeting Project technical objectives.
- **Surface Lead:** The Surface Lead is responsible for ensuring operating procedures are followed and any deviation from set parameters is corrected. For example, the Surface Lead is responsible for verifying that surveillance is being performed appropriately and results are properly communicated, ensuring personnel comply with the safety policies, and is the point of contact in the event that Emergency Response and Remedial Plan is activated.
- **Well Performance Specialist:** The Well Performance Specialist is responsible for conducting field surveillance to monitor alarms and troubleshoot any deviations from normal operation.

Additional to the key administrative positions identified in the above section, the BRP Project will be fully supported by Oxy technical staff and/or contractors. Below are examples of technical roles:

- **Geologist:** The role of the Geologist is to characterize the subsurface storage complex, to create and update the geologic model by integrating offset regional information, site-specific log and core data, and seismic and other geophysical data.
- **Petrophysicist:** The role of the Petrophysicist is to analyze the available logs and generate porosity and permeability models to be used in the geologic model of the area.
- **Geochemist:** The role of the Geochemist is to evaluate fluid and gas data obtained from wells and integrate the information with the geologic, petrophysical and reservoir engineering information to characterize fluid and gas compositional changes in the subsurface.

- **Geophysicist:** The role of the Geophysicist is to evaluate seismic and other geophysical data to help define and monitor the subsurface storage complex.
- **Drilling, Completions and Production Engineers:** The role of the Drilling Engineer is to develop cost estimates, design the wellbores and execute drilling programs. The Completions Engineer develops a cost estimate for dynamic testing, completes and tests the well. Production engineers develop monitoring plans for wellbore mechanical integrity, optimal well operation, and plugging plans.
- **Reservoir Engineer:** The role of the Reservoir Engineer is to simulate fluid flow in the Injection Zone using the geologic model, designate the AoR, and optimize well placement and number of wells.
- **Facilities Engineer:** The role of the Facilities Engineer is to ensure quality assurance and monitor compliance with Project requirements.
- **Subject Matter Experts/Task Leads:** Subject Matter Experts (SMEs) and Task Leads include both internal (Oxy) and external (subcontractors) personnel such as geologists, hydrologists, chemists, atmospheric scientists, ecologists, and others. These SMEs help develop testing and monitoring plans, collect environmental data specified in those plans using best practices, and maintain and update those plans as needed.

1.1.2 Independence from Project QA and Data Gathering

The majority of physical samples and data gathered as part of the monitoring program will be analyzed, processed, or witnessed by third parties independent and outside of the Project management structure.

1.1.3 QASP Responsibility

OLCV will be responsible for maintaining and distributing official, approved QASPs. OLCV will periodically review the QASP and consult with the UIC Program Director if changes are recommended.

1.2. Problem Definition and Background

1.2.1 Reasons for Initiating the Project

The purpose of the BRP Project is to safely and securely inject and permanently store CO_2 derived from a Direct Air Capture (DAC) facility. The purpose of this document is to support the Testing and Monitoring Plan for the BRP CCS1, BRP CCS2, and BRP CCS3 wells.

1.2.2. Background Information

OLCV will test and monitor the BRP Project site using both direct and indirect methods. The purpose of testing and monitoring is to promote safe CO_2 injection, determine the response of the Injection Zone and evaluate the movement of the pressure front and CO_2 plume with the ultimate goal of demonstrating non-endangerment of USDWs.

1.2.3. Regulatory Information

Class VI well regulations in 40 CFR §146 Subpart H require owners or operators of Class VI wells to demonstrate that injection wells maintain mechanical integrity, that fluid migration and the extent of the pressure elevation are within the limits described in the permit application, and that USDWs are not endangered. To demonstrate integrity of the wellbore, the operator will conduct continuous monitoring of pressure and temperature, and mechanical integrity tests (MITs). To demonstrate the extent of the CO_2 plume and pressure front, OLCV will obtain pressure, temperature and fluid samples in monitoring wells and geophysical data of the injection site. In addition, shallow groundwater and soil gas will also be monitored for changes that could indicate movement of CO_2 from the Injection Zone. Well data, geophysical data, and surface data, along with safe operating practices, will ensure non-endangerment of USDWs.

1.3 Project / Task Description

1.3.1. Summary of Work to be Performed

OLCV has performed a characterization of the site prior to injection operations to confirm that the site can safely accommodate the volume of anticipated CO_2 injection and ensure non-endangerment of USDWs. The site will be monitored before injection operations, to characterize natural background variability, and during and after injection to confirm operational parameters and describe CO_2 plume and pressure movement. The AoR and determination of site closure will be routinely updated based on testing and monitoring data, along with computational modelling results. Table 1 below summarizes the testing and monitoring plans. Table 2 describes the planned frequency of monitoring activities. Table 3 lists the geographic locations of wells used for monitoring.

Table 1--Summary of Monitoring and Testing Plans

Objective	Method	Location	Analytical Technique	Lab / Custody
CO_2 injectate stream analysis	On-line gas chromatograph and/or gas analyzers in flowline and sampling in flowline	Flowline upstream of injector wellheads	Chemical and isotopic analysis	Third-party contractor (e.g., Pantechs)

Objective	Method	Location	Analytical Technique	Lab / Custody
Continuous recording of operational parameters in injection wells: injection rate, volume, pressure, and temperature	Surface and tubing-conveyed pressure and temperature gauges, DTS fiber, and injection line flowmeter	Wellhead, downhole in injectors, and flowline directly upstream of injector wellhead	Direct measurement	N/A
Corrosion Monitoring in injection wells and surface leak detection	Coupons, visual inspection at wellhead, LDAR/OGI cameras, surface sensors, and DTS	Flowline and injector wellheads; downhole fiber	Physical analysis, observation, and direct measurement	Retrieval and analysis of coupons will be carried out by third-party certified lab
Internal mechanical integrity	Pressure and temperature gauges, DTS, Annulus pressure monitoring, tubing-casing monitoring	Wellhead and downhole in injectors	Direct measurement	N/A
External mechanical integrity testing	Pressure and temperature gauges, DTS, and MIT	Wellhead and downhole in injectors	Direct measurement, log analysis	N/A
Near well-bore formation properties testing (Pressure fall-off testing)	Pressure fall-off test	Injector wellbores	Direct measurement and interpretation of results	N/A
Injection Zone pressure, temperature, and geochemistry	Pressure and temperature gauges and/or DTS; saturation logging, and fluid and dissolved gas sampling	Gauges will be at the surface and downhole; DTS fiber to top Injection Zone; fluid and dissolved gas sampling	Direct measurement of pressure and temperature; saturation logging; chemical and isotopic analysis of fluids and dissolved gasses	Certified third-party lab for fluid and dissolved gas analyses
Geochemistry of lowermost USDW (Dockum group)	Fluid and dissolved gas sampling and analysis in USDW well	One USDW-level monitoring well	Chemical and isotopic analysis of groundwater and dissolved gasses	Certified third-party lab for fluid and dissolved gas analyses
Soil and soil gas analysis (vadose zone; near surface)	Isotopic analysis and chemical evaluation at a minimum of 21 locations	21 discreet soil gas monitoring stations within and adjacent to AoR	Composition gas and isotopic analyses of soil gas and soils	Certified third-party labs for soil gas and soil analyses
CO_2 plume and pressure movement within the Injection Zone	Pressure and temperature gauges and/or DTS, and event-driven* fluid sampling	Gauges at surface and downhole in Reservoir-level (SLR2 and SLR3) monitoring	Direct measurement of pressure and temperature; chemical and isotopic analysis of fluids and dissolved gasses	Certified third-party labs for fluid and dissolved gas analyses

Objective	Method	Location	Analytical Technique	Lab / Custody
		well(s); downhole fluid sampling		
Indirect geophysical monitoring of plume and pressure	2D VSP utilizing in-well fiber or wireline conveyed geophones; 2D surface seismic; saturation logging; DInSAR	Monitor and/or injection wells; satellite-acquired DInSAR	Data interpretation by qualified geophysicists and petrophysicists	Third-party acquisition and processing of seismic, DInSAR data; logging operator
Presence or absence of seismicity	Seismometers	Regional and site-specific seismometer network	Data interpretation by qualified geophysicists including consortium of industry and government professionals	Third-party acquisition and processing of data

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. In addition, fluid and dissolved gas chemistry data from the lowermost USDW and soil gas chemistry from shallow soils will be monitored for trends to detect deviations from reference chemistry. If persistent and/or abrupt anomalies in chemistry are detected additional fluid or soil gas samples will be obtained to confirm the presence or absence of increased CO_2.

Table 2—Summary of Testing and Monitoring Frequency

Objective	Method	Pre-injection	During injection	Post-injection
CO_2 injectate stream analysis	On-line gas chromatograph and/or gas analyzers in flowline and sampling in flowline	Chemical and isotopic characterization prior to injection	Continuous monitoring using gas chromatograph and/or analyzers; quarterly sampling for compositional analyses; and isotopic analysis if capture process materially changes source stream	N/A
Continuous recording of operational parameters in injection wells: injection rate, volume, pressure, and temperature	Surface and tubing-conveyed pressure and temperature gauges, DTS fiber, and injection line flowmeter	Measurement prior to injection	Continuous measurement and recording	N/A
Corrosion Monitoring in injection wells and surface leak detection	Coupons, visual inspection at wellhead, LDAR/OGI cameras, surface sensors, and DTS	Inspection prior to injection	Quarterly coupon testing, weekly visual inspection, quarterly inspection via LDAR/OGI cameras, and continuous monitoring via surface sensors and DTS	Continuous surface monitoring and quarterly visual inspection until site closure

Internal mechanical integrity	Pressure and temperature gauges, DTS, Annulus pressure monitoring, tubing-casing monitoring	Measurement prior to injection	Continuous measurement and recording	N/A
External mechanical integrity testing	Pressure and temperature gauges, DTS, and MIT	Measurement prior to injection	Continuous measurement and recording; and routine MIT	N/A
Near well-bore formation properties testing (Pressure fall-off testing)	Pressure fall-off test	Measurement prior to injection	Once during every five-year period until plugging	N/A
In-zone pressure, temperature, CO_2 saturation and geochemistry	Pressure and temperature gauges and/or DTS; saturation logging, and fluid and dissolved gas sampling	Characterization prior to injection, including quarterly fluid and dissolved gas sampling for at least one year; cased hole saturation logging; PT gauge and DTS measurements prior to injection	Continuous measurement and recording of pressure and temperature; annual saturation profile; event-driven* fluid sampling, triggered by changes in P/T	P/T: Continuously for the first 10 years pending and approved PISC plan, then annually until plugging; saturation profile annually; event-driven* fluid and dissolved gas sampling, triggered by P/T data
Geochemistry of the first permeable zone above the confining zone and the lowermost USDW (Dockum group)	Fluid and dissolved gas sampling and analysis in USDW1 well	Characterization prior to injection, including quarterly fluid and dissolved gas sampling for at least one year	Quarterly geochemical sampling in years 1-3 and annually starting in year 4; and, event-driven*, triggered by P/T data in SLR2 or SLR3 wells	Annually for first 10 years post injection pending an approved PISC plan; event-driven*, triggered by P/T data in SLR2 or SLR3 wells thereafter
Soil gas analysis (vadose zone; near surface)	Isotopic analysis and chemical evaluation at approximately 21 locations	Characterization prior to injection, including quarterly sampling for at least one year prior to commencement of injection	Quarterly gas composition sampling in years 1-3 and annually starting in year 4 for subset of stations, and event-driven*, triggered by P/T data in SLR2, SLR3 or USDW1 monitor wells and fluid sample results	Event-driven*, triggered by P/T data in SLR2, SLR3 or USDW1 monitor wells and fluids sample results
Containment of CO_2 in Injection Zone	Pressure and temperature gauges and/or DTS; saturation logging, and event-driven* fluid and dissolved gas sampling	Characterization prior to injection, including quarterly sampling for approximately one year in WW wells; saturation logging	Continuous measurement and recording of pressure and temperature (SLR1 and WWs); event-driven* fluid sampling in WWs;	P/T or DTS: continuously for the first 10 years pending an approved PISC plan, in SLR1 well or until plugging

		in the Upper Confining Zone in SLR1 and ACZ1	saturation logging once every five year period in SLR1 and ACZ1 wells	Saturation logging: event-driven* in the SLR1 or ACZ1
Non-endangerment of shallow groundwater and soil	Geochemical and isotopic monitoring to detect deviations from expected groundwater and soil gas chemistry	Characterization prior to injection: quarterly	Groundwater and soil gas sampling: Quarterly analysis in years 1-3, then annually after that; and, event-driven*, triggered by P/T data in SLR wells	Event-driven*
CO_2 plume and pressure movement within the Injection Zone	Pressure and temperature gauges and/or DTS; and event-driven* fluid sampling	P/T measurement, fluid sampling prior to injection in the SLR2 and WW wells	Continuous P/T measurement in SLR2 and SLR3 wells; event-driven* fluid sampling in SLR or WW wells	P/T recording bimonthly for the first five years post-injection, then annually until well is plugged or plume stabilizes in SLR2 or SLR3 wells
Indirect geophysical monitoring of plume and pressure	2D VSP utilizing in-well fiber or wireline conveyed geophones; surface 2D; saturation logging; DInSAR and GPS	Prior to injection	Annual saturation logging in SLR2 and SLR3 wells; 2D VSP after 1, 2, 5 and 10 years; 2D surface seismic at year 10 and approximately every five years thereafter; Quarterly DInSAR and GPS	Annual saturation logging in SLR2 and SLR3 wells; surface 2D VSP once every approximately five-year period until plugging; 2D surface seismic once every approximately five years until plume stabilization Annual DInSAR and GPS for first five years post-injection
Presence or absence of seismicity	Seismometers	Prior to injection	Continuous monitoring and recording	Continuous monitoring and recording until site closure

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. In addition, fluid and dissolved gas chemistry data from the lowermost USDW and soil gas chemistry from shallow soils will be monitored for trends to detect deviations from reference chemistry. If persistent and/or abrupt anomalies in chemistry are detected additional fluid or soil gas samples will be obtained to confirm the presence or absence of increased CO_2.

Table 3--Geographic location of injection and monitoring wells

Regulatory Well Name	Project Well Name	Drill date	API	Latitude (NAD 27)	Longitude (NAD 27)
Shoe Bar 1	SLR1	2023	4213543920	31.7634360	-102.7034981
Shoe Bar 1AZ	ACZ1	2023	4213543977	31.76448869	-102.7305326
Shoe Bar 1USDW	USDW1	2023	NA	31.76411900	-102.7316750
Shoe Bar 2SLR	SLR2	2025*	-	31.74670102	-102.7259011
Shoe Bar 3SLR	SLR3	2030*	-	31.78023685	-102.7418093
Shoe Bar 1CCS	BRP CCS1	2024*	-	31.76479314	-102.7289311
Shoe Bar 2CCS	BRP CCS2	2024*	-	31.76993805	-102.7332448
Shoe Bar 3CCS	BRP CCS3	2025*	-	31.76031163	-102.7101566
Shoe Bar 1WW	WW1	2024	4213544035	31.76289539	-102.6959232
Shoe Bar 2WW	WW2	2024	4213544036	31.78419981	-102.7275869
Shoe Bar 3WW	WW3	2024	4213544037	31.75008553	-102.7102206
Shoe Bar 4WW	WW4	2024	4213544034	31.76384464	-102.7539505

*Anticipated drill dates

1.3.2. Anticipated Evolution of Project Tasks

The methodology and frequency of testing and monitoring methods is expected to change throughout the life of the Project. Pre-injection monitoring and testing will focus on establishing baselines and ensuring that the site is ready to receive injected CO_2. Injection phase monitoring will be focused on collecting data that will be used to calibrate models and ensure containment of CO_2. Post-injection phase monitoring and testing is designed to demonstrate CO_2 plume stabilization and ensure containment. The testing and monitoring plan will be reviewed at least once every five years and will be amended, if necessary, to ensure monitoring and storage performance is achieved and new technologies are appropriately incorporated.
Data obtained from the Testing and Monitoring Plan will be used to inform operational decisions on the quantity and rate of CO_2 injected and potential containment actions. Data will be used to improve computational model forecasts. Data that is interpreted to be inconsistent with model predictions will trigger additional testing, monitoring and evaluation.

1.4 Quality Objectives and Criteria for Measurement Data

1.4.1. Measurement and Performance Criteria

The overall objective of quality assurance for monitoring is to develop and implement procedures to provide results that meet and/or exceed the requirements for the Class VI permit.

The key testing and monitoring components of the BRP Project that involve analysis of physical samples are:

- CO_2 injectate stream, Table 4
- Material corrosion, Table 5

- Fluid and dissolved gas in the Injection Zone, first permeable zone above the confining zone, and lowermost USDW; Table 6
- Fluid and dissolved gas in the Injection Zone and first permeable zone above the confining zone, alternative/future method; Table 6a
- Soil and soil gas, Table 7

Other data measurement sources listed below do not involve analysis of physical samples. The specifications of these tools are found in Section 1.4.7 of this document:

- Gauge measurements, Tables, 9a-9i
- On-line gas chromatograph, Table 10
- DTS and DAS measurements, Table 11a and 11b
- Log measurements, Tables 12a-12c
- Seismometers, Table 13
- Vertical Seismic Profiles (VSP), Table 14
- DInSAR and GPS data, Table 15
- Surface monitoring optical cameras, Table 16

The following tables provide details on analytical and field parameters and the actionable testing and monitoring outputs.

Table 4--Summary of analytical parameters for CO_2 injectate stream at surface

Parameters	Analytical Methods[1]	Detection Limit / Range[2]	Typical Precision[2]	QC Requirements
CO_2 content	GPA 2177-20[3]	>95 mol%	GPA 2177-20	GPA 2177-20
Water	GPA 2177-20	<30 lbm/MMscf	GPA 2177-20	GPA 2177-20
Nitrogen	GPA 2177-20	<4 mol%	GPA 2177-20	GPA 2177-20
Sulphur	GPA 2177-20	<35 ppm by weight	GPA 2177-20	GPA 2177-20
Oxygen	GPA 2177-20	<5 mol%	GPA 2177-20	GPA 2177-20
Glycol	GPA 2177-20	<0.3 gal/MMscf	GPA 2177-20	GPA 2177-20
Carbon Monoxide	GPA 2177-20	<4,250 ppm by weight	GPA 2177-20	GPA 2177-20
NOx	GPA 2177-20	<6 ppm by weight	GPA 2177-20	GPA 2177-20
SOx	GPA 2177-20	<1 ppm by weight	GPA 2177-20	GPA 2177-20
Particulates ($CaCO_3$)	GPA 2177-20	<1 ppm by weight	GPA 2177-20	GPA 2177-20
Argon	GPA 2177-20	<1 mol%	GPA 2177-20	GPA 2177-20
Surface pressure	GPA 2177-20	>1,600 psig	GPA 2177-20	GPA 2177-20
Surface temperature	GPA 2177-20	>65°F and <120°F	GPA 2177-20	GPA 2177-20
Isotopes	Isotope ratio mass spectrometry and accelerator mass spectrometry	$\delta^{13}C$ and ^{14}C of CO_2	±0.15 – 0.03‰	10% duplicates, 4 samples per batch

[1]An equivalent method may be employed with the prior approval of the UIC Program Director.

[2]Detection limits and precision (laboratory control limits) are typical for these analytical methods.
[3]GPA Midstream Standard licensed to OLCV

Table 5--Summary of analytical parameters for corrosion coupons

Parameters	Analytical Methods[1]	Detection Limit / Range[2]	Typical Precision[2]	QC Requirements
Mass	NACE SP0775-2018-SC	0.05 mg	2%	N/A
Thickness	NACE SP0775-2018-SC	0.01 mm	± 0.05 mm	N/A

[1]An equivalent method may be employed with the prior approval of the UIC Program Director.
[2]Detection limits and precision (laboratory control limits) are typical for these analytical methods.

Table 6--Summary of analytical parameters for fluid and dissolved gas samples in the Injection Zone (Lower San Andres) and first permeable zone above the confining zone / lowermost USDW (Dockum Group)

Laboratory Analyte	Analytical Methods[1]	Detection Limit / Range[2]	Typical Precision[2]	QC Requirements
Total and Dissolved Metals: Ag, Al, As, Ba, Cd, Co, Cr, Cu, Mn, Mo, Ni, Pb, Sb, Se, Sr, Th, Tl, U, V, and Zn	USEPA Method 200.8	0.00004 to 0.003 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof
Total and Dissolved Metals: B, Ca, Fe, K, Mg, Li, Na, Si, Sr, Ti	USEPA Method 200.7	0.003 to 0.254 mg/L	±20	Daily calibration, Initial QC checks (IPC, ICV, ICB, RL) method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Total and Dissolved Hg	USEPA Method 245.7	19.6 ng/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved Inorganic Carbon (DIC); Dissolved Organic Carbon (DOC)	Standard Method 5310C	0.198 to 0.290 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
Dissolved CO_2	Standard Method 4500 CO_2 D	8 mg/L	±20	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.

Alkalinity: Total, Bicarbonate, Carbonate, and Hydroxide	Standard Method 2320B	8 mg/L	±20	method blank, lab control samples, matrix spikes
Major Anions: Br, Cl, F, and SO_4, NO_2 and NO_3 as N	USEPA Method 300.0	0.003 to 0.563 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup; CCV/CCB every 10 samples or part thereof
PO_4 as P	USEPA Method 365.1	0.0215 mg/L	±20	Daily calibration, Initial QC checks (ICV, ICB, RL) method blank, lab control samples, matrix spikes and sample duplicate, CCV/CCB every 10 samples or part thereof
Dissolved H_2S (Sulfide)	Standard Method 4500S2-D	0.026 mg/L	±20	Calibration as needed, daily QC checks; ICV, ICB, RL, method blank, lab control samples, matrix spike and matrix spike dup
Total Dissolved Solids (TDS)	USEPA Method 160.1	10 mg/L	±20	Method blank, lab control samples, and sample duplicate
Conductivity	Standard Method 2510B	0 to 200 mS/cm	±1%	Calibration as needed, daily QC checks (1413, 14130 and second source SRM), CCV every 10 samples or part thereof
pH and Temperature	USEPA Method 150.1	0.1 to 14 pH units	±0.1 pH units	Daily calibration, second source SRM, CCV's every 10 samples or part thereof
Specific Gravity	ASTM Method D1429-03	NA	To the nearest thousandths decimal	Duplicates
Cation Anion Balance	Calculation	NA	±10	Calculation
Dissolved Gas Abundances: CO_2, CO, N_2, Ar, He, H_2, O_2, C1-C6+	In-house Lab SOP, similar to RSK-175	1 to 100 ppm, varies by component	C1-C4: ± 5%; C5-C6+: ± 10%	20% of all analyses are check/reference standards.
Dissolved Gas Isotopes: $\delta^{13}C$ of C1-C5 and CO_2, $\delta^{2}H$ of C1	High precision (offline) analysis via Dual Inlet IRMS	Varies by component	$\delta^{13}C$: 0.1 per mil; $\delta^{2}H$: 3.5 per mil	20% of all analyses are check/reference standards.
^{14}C of C1	AMS - subcontracted to Beta Analytic	0.44 pMC	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.

^{14}C of DIC	AMS - subcontracted to Beta Analytic	Depends on available sample volume	± 1 to 2 pMC	Daily monitoring of instrumentation and chemical purity in additional to extensive computer and human cross-checks.
$\delta^{13}C$ of DIC	Gas Bench/CF-IRMS	Depends on available sample volume, minimum of 50mg/L required	0.20 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	Analyzed via CRDS	N/A	$\delta^{18}O$: 0.10 per mil; $\delta^{2}H$: 2.0 per mil	20% of all analyses are either check/reference standards or duplicate analyses.
$^{87}Sr/^{86}Sr$	TIMS - subcontracted to the University of AZ	Approximately 40 ppm	± 0.00002	SRM 987 Sr standard within the long-term precision (external precision) of +/- 0.00002 accepted value of 0.71025
$^{228}Ra/^{226}Ra$	USEPA Method 901.1	50 pCi/L (RL)	± 25%	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate.
Field Parameters				
pH (Field)	Standard Method2 4500-H+ B-2000	2 to 12 pH units	±0.2 pH units	User calibration per manufacturer recommendation
Specific conductance (Field)	EPA Method 120.1	0 to 200 mS/cm	±1%	User calibration per manufacturer recommendation
Temperature (Field)	Standard Method 2550 B-2000	-5 to 50 ºC	±0.2 ºC	Factory calibration
Oxidation-Reduction Potential (Field)	Standard Method 2580	-1999 to +1999 mV	±20 mV	User calibration per manufacturer recommendation
Dissolved Oxygen (Field)	ASTM Method D888-09 (C)	0 to 50 mg/L	0 to 20 mg/L: ±0.1 mg/L or 1% of reading, whichever is greater; 20 – 50 mg/L: ±8% of reading	User calibration per manufacturer recommendation
Turbidity (Field)	USEPA Method 180.1	0 to 1000 NTU	± 1% of reading or 0.01 NTU, whichever is greater	User calibration per manufacturer recommendation

[1]An equivalent method may be employed with the prior approval of the UIC Program Director.
[2]Detection limits and precision (laboratory control limits) are typical for these analytical methods.

* Analytical parameters to be included during the pre-injection phase, and only as needed during the injection and post-injection phases of the Project.

Table 6a--Summary of analytical parameters planned as alternative/future to monitor fluid and dissolved gas in the Injection Zone and first permeable zone above the confining zone

Parameters	Analytical Methods[1]	Detection Limit / Range[2]	Typical Precision[2]	QC Requirements
Cations/metals (Al, Ba, Mn, As, CD, Cr, Cu, Pb, Sb, Se, Sr, Ti, Zn	TM-101 Note: As, Cd, Sb, Se, Tl are not included in this method and are N/A	Al: 0.1136-120 mg/L Ba: 0.7926-1,200 mg/L Mn: 0.0845-120 mg/L Cr: 0.1231-120 mg/L Cu: 0.0713-120 mg/L Pb: 0.1136-120 mg/L Sr: 2.0217-3,000 mg/L Zn: 0.063-120 mg/L	±3% ±2% ±2% ±3% ±3% ±2% ±5% ±2%	Daily calibration, method blank, lab control samples, continuous calibration verification, mass balance check
Cations: Ca, Fe, K, Mg, Na, Si	TM-101	Ca: 9.1694-12,000 mg/L Fe: 0.9183-1,200 mg/L K: 1.2941-1,200 mg/L Mg: 2.1404-3,000 mg/L Na: 63.611-120,000 mg/L Si: 0.0519-600 mg/L	±3% ±2% ±4% ±2% ±5% ±8%	Daily calibration, method blank, lab control samples, continuous calibration verification, mass balance check
Anions: Br, Cl, F, NO_3, and SO_4	Cl: SM-4500-Cl D SO4: SM-4500-SO4 E Br, F, NO3 are N/A	Cl: 0.01-150,000 mg/L SO4: 1.0-1,000 mg/L	±1.7% ±1.7%	Daily calibration, matrix spikes, SO4 values are verified using TM-101
Alkalinity (total bicarbonate)	SM-2320 B	0.01-2,000 mg/L	±1 mg/L	Matrix spikes
Total Dissolved Solids (TDS)	Calculated via French Creek	250-500,000 mg/L	±5%	Standard Calculations on software
Water density (field)	N/A			
Water density (lab)	By Weight	0.0001 g/cm3-5.9999 g/cm3	±0.0005 g/cm3	Monthly verification, annual calibration
pH (field)	SM-4500H+	0-14	±0.02 pH unit	Daily calibration
pH (lab)	SM-4500H+	0-14	±0.02 pH unit	Daily calibration
Specific conductance (field)	SM-2510	100 uS/cm-10 mS/cm	±0.5%	Daily calibration
Temperature (field)	SM-2550B	-35 - +120°F	±0.20°F	Verified against ISO Certified and Calibrated thermometer
Turbidity (field)	SM-2130 B	0-1000 NTU	±2%	Daily calibration
Oxidation-Reduction potential (field)	SM-2580	-300 - +300 mV	±10 mV	Daily calibration

Dissolved oxygen (field)	ASTM D 888-87	0.1-12ppm	±0.01 ppm	Environmental/temperature controls
Isotopes	Isotope ratio mass spectrometry and accelerator mass spectrometry	$\delta^{13}C$ and ^{14}C of CO_2	±0.15 – 0.03‰	10% duplicates, 4 samples per batch

[1]An equivalent method may be employed with the prior approval of the UIC Program Director.

[2]Detection limits and precision (laboratory control limits) are typical for these analytical methods.

* Analytical parameters to be included during the pre-injection phase, and only as needed during the injection and post-injection phases of the Project.

Table 7--Summary of analytical parameters for soil and soil gas

Parameters	Analytical Methods[1]	Detection Limit / Range[2]	Typical Precision[2]	QC Requirements
pH	EPA Method 9045D	0-14 pH Std Unit	±0.1	Lab Control/ Lab Control Duplicate, Matrix Spike/ Matrix Spike Duplicate samples, instrument calibration, field duplicates
Electrical conductivity (EC)	29B_EC	5 umhos/cm	20	Lab Control/ Lab Control Duplicate, Matrix Spike/ Matrix Spike Duplicate samples, instrument calibration, field duplicates
Sodium Adsorption Ratio (SAR)	29B SAR	0.01 meq/meq	±20%	Lab Control/ Lab Control Duplicate, Matrix Spike/ Matrix Spike Duplicate samples, instrument calibration, field duplicates
Moisture	SM 2540 B	0.1 - 100%	±20%	Lab Control/ Lab Control Duplicate, Matrix Spike/ Matrix Spike Duplicate samples, instrument calibration, field duplicates
Total Organic Carbon (TOC)	Walkley Black 9060A	0.02 wt%	±20%	Lab Control/ Lab Control Duplicate, Matrix Spike/ Matrix Spike Duplicate samples, instrument calibration, field duplicates
Soil Gas Samples				
Gas: H_2, He, O_2, N_2, CO_2, CH_4, CO, Ar, C2-C6+	Third party lab SOP, similar to RSK-175	CO_2: 50 ppm N_2 and O_2: 100 ppm CH4: 2 ppm C_2 - C_6+: 1ppm 50 ppm	for CO_2 (> 1.5%) ±0.6% (of measured value) for CO_2 (< 0.05%) ±1.7% (of measured value) for N2 and O2 (>10%) ±0.5% (of measured value) CH_4: ±0.4 to 1% (of measured value)	At a rate of 20% of the samples analyzed: A lab check standard or sample duplicate is analyzed every 5th run with a lab standard being run first every day. Method based on ASTM D1945

			C2 - C4: ±0.4 to 1% (of measured value) C5 - C6+: ±2 to 4% (of measured value) for He: ±2% (of measured value)	
*^{14}C of CO_2	AMS - subcontracted to Beta Analytic	0.44pMC	0.02 pMC - 0.5 pMC	At a rate of 20% of the samples analyzed: A lab check standard or sample duplicate is analyzed every 5th run with a lab standard being run first every day.
*$\delta^{13}C$ of CH_4 and CO_2, δ^2H of Methane	High precision (offline) analysis via Dual Inlet IRMS	Varies by component	δ13C: 0.1 per mil δ2H: 3.5 per mil	Frequent calibration, method blank, lab control samples, matrix spikes and sample duplicate. At least one secondary standard is measured with each sample batch and approx. 10% of samples submitted are prepared and measured a second time.
Soil Gas Field Analysis				
Hydrogen Sulfide (field)	EPA Method 21	0 to 100 ppm	±5% of reading or ±2 ppm	User calibration per manufacturer recommendation

[1]An equivalent method may be employed with the prior approval of the UIC Program Director.

[2]Detection limits and precision (laboratory control limits) are typical for these analytical methods.

* Analytical parameters to be included during the pre-injection phase, and only as needed during the injection and post-injection phases of the Project.

Table 8--Actionable testing and monitoring outputs

Activity or Parameter	Project Action Limit	Anticipated Reading
External mechanical integrity: DTS fiber	Action taken when there is an anomaly in the temperature profile	Continuous temperature profiles that are within expected or modeled ranges
Internal mechanical integrity: Annulus pressure test	<5% pressure loss over one hour	<5% pressure loss over one hour
Surface and downhole gauges	Action taken when pressures are substantially outside of modeled or expected range	Within the Injection Zone, pressure should be <90% of fracture opening pressure
MIT – Pulse Neutron Logging	Action taken when CO_2 is measured outside of expected range	Brine saturated ~60 CO_2 saturated ~8
Corrosion coupons	Action taken to identify source of corrosion if coupons indicate a rate of more than 4 mm per year	Corrosion measured by coupons is < 4 mm per year
Pressure fall-off Testing	Action taken to identify source if outside of expected range	Fall-off v. pressure is as expected
Surface CO_2 monitors	CO_2 injectate leak detected	No CO_2 injectate leaking
Surface CO_2 cameras	CO_2 injectate leak detected	No CO_2 injectate leaking
Surface wellhead inspection	CO_2 injectate leak detected	No CO_2 injectate leaking
CO_2 stream analysis using continuous gas chromatography	0.5% mol for High Alarm, 1% mol for HH alarm, and should trigger a shutdown	<0.05% mol

Shallow groundwater chemistry measured in the Dockum Group	A departure between observed measurements and baseline/seasonal parameter trends	Statistical methodology will be determined after collecting baseline data
Soil gas chemistry	A departure between observed measurements and baseline/seasonal parameter trends	Statistical methodology will be determined after collecting baseline data

1.4.2 Precision

Assessment of analytical precision can be made through the analysis of duplicate samples obtained in the field for testing in third-party laboratories or for testing by field instruments. Precision will be specific to each vendor or contractor selected to perform the work. Although the precision of measurement system can be affected by variations introduced in sampling and analysis, OLCV will ensure that the selected vendors and contractors follow their individual standards operating procedures (SOPs) to optimize the measurement precisions.

1.4.3. Accuracy and Bias

Laboratory accuracy is typically measured by conducting tests comparing standards of known concentrations and project samples. These tests may include the percent recovery on laboratory control samples or matrix spike analysis. These tests will be performed, as needed by the vendor or contractor, to calibrate equipment, in accordance with their individual SOPs. Field accuracy can be determined by collection of field blanks to screen for vessel contamination. Logging equipment is typically calibrated by the contractor prior to commencement of a job using known standards. Gauges and meters will be tested for accuracy prior to deployment.

1.4.4. Representativeness

Representativeness expresses the degree to which data accurately and precisely represents a characteristic subset of a given population. Representativeness was considered in designing the network of monitoring wells and the network of soil gas monitoring stations. Representativeness will be considered when evaluating chemical results of fluid and dissolved gas samples.

The network of monitoring wells was designed to provide data points inside and outside of the expected CO_2 plume and pressure front and across multiple stratigraphic levels. The data obtained from these wells will be used to calibrate and refine the dynamic simulation model. If needed to better reflect site conditions, additional wells will be added to the Project.

Soil gas sampling stations are typically selected to represent the breadth and diversity of the near-surface environments present within the AoR. Little environmental diversity is observed at the BRP site. The surface consists primarily of ranchland; no surface water or marsh lands are present. Images from airborne photos and satellite images indicate that caliche soils are likely present in some locations and there are shallow depressions that may collect ephemeral drainage. For this

Project, soil gas stations will be placed in the vicinity of existing and future artificial penetrations and the DAC facility, as well as sensitive areas, e.g., lease boundaries.

Groundwater samples will be evaluated for representativeness based on ion and mass balance. Ion balances with ±10% error are considered valid. In the case where ion balance is greater than ±10%, mass balance will be assessed to evaluate and identify the source of the error. If the relative percent difference is >10% for a sample and its duplicate, the sample may be considered non-representative.

1.4.5. Completeness

Data completeness is a measure of the amount of valid data collected compared to the amount of valid data that was expected to be collected under normal conditions. Data completeness is measured as a percentage of anticipated data obtained from the valid measurements. For this Project, 90% data completeness is acceptable to meet monitoring goals.

1.4.6. Comparability

Data comparability qualifies the level of confidence with which one data set can be compared to another. The testing and monitoring systems for this Project have been designed to allow for repeat measurements and the comparability among datasets of the same type from the same source are expected to be high due to the use of standardized methods and consistent levels of QA/QC requirements. Historical data from sources other than the BRP, if available, will be assessed for their applicability to the Project and level of quality before use.

1.4.7. Sensitivity

Sensitivity describes the minimum detection or quantification limit of a method, instrument, or laboratory. The tables below describe detection limits and operating ranges for instruments and tools used on this Project.

Table 9a--Summary of measurement parameters for field gauges

Parameters	Analytical Methods[1]	Detection Limit / Range[2]	Typical Precision[2]	QC Requirements
Surface injection line pressure gauge	Piezoresistive pressure sensor feeds data back to PLC / SCADA	2 psi / 0 – 3,000 psi	+/- 0.065% of full span	Annual or per manufacture recommendation, whichever is more frequent
Surface injection line temperature gauge	Resistance temperature detector or thermocouple	250º F	±1ºF	Annual or per manufacture recommendation, whichever is more frequent
Downhole temperature and pressure gauges	Permanent gauge	8,000 psi, 250º F	±3 psi, ± 0.27º F	Annual or per manufacture recommendation, whichever is more frequent
Wellhead tubing pressure	Piezoresistive pressure sensor feeds data back to PLC / SCADA	2 psi / 0 – 3,000 psi	+/- 0.065% of full span	Annual or per manufacture recommendation, whichever is more frequent
Wellhead annulus pressure	Piezoresistive pressure sensor feeds data back to PLC / SCADA	2 psi / 0 – 3,000 psi	+/- 0.065% of full span	Annual or per manufacture recommendation, whichever is more frequent
CO_2 injection mass flow rate	Coriolis or Orifice meter feeds data back to PLC / SCADA	1.5 metric ton/day/0-1500 metric ton/day	+/- 0.25% of full span	Quarterly or per manufacture recommendation, whichever is more frequent

[1]An equivalent method may be employed with the prior approval of the UIC Program Director.
[2]Detection limits and precision are typical for these analytical methods.

Table 9b--Downhole pressure and temperature gauge specifications

Parameter	Value
Calibrated working pressure range	Atmospheric to 10,000 psi
Initial pressure accuracy	<± 2 psi over full scale
Pressure resolution	0.005 psi at 1 sec sample rate
Pressure drift stability	<± 1 psi per year over full scale
Calibrated working temperature range	77 – 266 ºF
Initial temperature accuracy	<± 0.9 ºF at 1 sec sample rate
Temperature resolution	0.009 ºF at 1 sec sample rate
Temperature drift stability	<± 0.9 ºF at 1 sec sample rate
Max temperature	302 ºF

Table 9c--Surface pressure gauge specifications

Parameter	Value
Calibrated working pressure range	0 to 3,000 psi
Initial pressure accuracy	± 0.065%
Pressure resolution	1.95 psi
Pressure drift stability	0.05% annually

Table 9d--Multivariable pressure transmitters

Parameter	Value
Mass flow rate accuracy	±0.075%
Differential pressure	-1,000 to 1,000 in. H2O (-2.5 to 2.5 bar)
Static pressure type	Gauge
Static pressure range URL	3,626 psi
Temperature range	-328 to 1,562°F
Type of equipment orifice	Meter with multivariable transmitters and direct process variable outputs for static pressure, differential pressure, and temperature

Table 9e--Senior Orifice Meters

Parameter	Value
Sizing	8 in. meter body, orifice size by meter vendor
Temperature range	-50°F to 200°F
Tolerance	Based on manufacturer’s manual

Table 9f--Pressure gauge specifications: Injection tubing pressure

Parameter	Value
Calibrated working pressure range	0 to 3,000 psi
Initial pressure accuracy	± 0.065%
Pressure resolution	2 psi
Pressure drift stability	0.05% annually

Table 9g--Pressure gauge specifications: Annulus pressure

Parameter	Value
Calibrated working pressure range	0 to 3,000 psi
Initial pressure accuracy	± 0.065%
Pressure resolution	2 psi
Pressure drift stability	0.05% annually

Table 9h--Temperature Gauge Specifications: Injection tubing temperature

Parameter	Value
Calibrated working temperature range	0 to 250 ºF
Initial temperature accuracy	±0.12 %
Temperature resolution	0.3 ºF
Temperature drift stability	±0.54 deg. F following 1000 hours at max. specified temperature

Table 9i--CO_2 mass flow rate gauge specifications

Parameter	Value
Calibrated working flow rate range	0 – 1500 metric ton / day
Initial flow rate accuracy	± 0.1 %
Mass flow rate resolution	1.5 metric ton / day

Table 10--Summary of specifications for on-line gas chromatograph

Parameters	Analytical Methods
Analysis time	Approximately 5 minutes
Repeatability	±0.25% of heating value over temperature range
Temperature Range	-4°F to 140°F
Calibration	Besides automated calibration feature that is available to the GC, the manufacture shall recommend appropriate inspection, maintenance, and calibration frequency per the specific application.
Range	Pipeline quality gas with less than 100 ppm H_2S
Calculations	GPA 2172-96 (Z by AGA 8 or single viral summation) and 2145-03, ISO 6976-95; meets ISO 12213-2 by AGA 8 detail
Components measured	N_2 through CO, C_1, CO_2, C_2, C_3, IC_4, NC_4, $NeoC_5$, IC_5, NC5, C_6+, H_2S

Table 11a--Technical specifications for DTS fiber

Parameter	Value
Spatial resolution	1 m (3.2 ft) across entire measurement range
Sampling resolution	To 0.5 m (1.6 ft) across entire measurement range

Temperature resolution	<0.1°C (0.18°F)
Accuracy	±0.5°C (±0.9°F)
Measurement range	Up to 12 km
Measurement temperature range	-250°C to 400°C
Measurement times	10 sec to 24 hr
Dynamic range	30 dB
Operating environment	-10°C to 60°C, humidity 0% to 95% non-condensing
Tensile strength	2,372 lbf
Yield strength	2,018 lbf
Strain at yield	0.31%
Hydrostatic Pressure	23,872 psi
Burst Pressure	28,050 psi
Working Pressure	20,526 psi
Static Bend Radius	3 in.

Table 11b--Technical specifications for DAS fiber

Parameter	Value
Spatial resolution	2m - 200m
Sampling resolution,	1m
Accuracy	Typical Sensitivity −57 dB Rad/√Hz
Measurement range	100Km
Sample clock frequency	1,000 MHz
Measurement times	Interrogation Rates 0.5, 0.8, 1, 2, 2.5, 3.125, 4, 5, 8, 10 kHz
Measurement times	10 sec to 24 hr
Dynamic range	30 dB
Operating environment	-10°C to 60°C, humidity 0% to 95% non-condensing
Output channel pitch	1.027 m, 2.05m, 5.14m, 10.27m

Table 12a--Representative logging tool specifications for mechanical integrity tools

	Injectors	SLR, ACZ and WW			
Parameter	**Temperature Log**	**Isolation Scanner**	**UltraSonic Imager Tool**	**Cement Bond Log**	**Variable Density log**
Logging speed	<1800 ft/hr	< 2,700 ft/hr	<1,800 ft/ hr	<3,600 ft /hr	<3,600 ft/hr
Depth of investigation	wellbore	Casing and annulus up to 3 in	Casing to cement interface	Casing and cement interface	Depends on bonding and formation
Vertical resolution	Point measurement	0.6 - 6 in	0.6 – 6 in	3 ft	5 ft
Range of measurement	0 – 350 ºF	0.15 - 0.79 in	0 - 10 MRayl	0 – 100+mV	Waveform recording

Temperature rating	350 ºF	350 ºF	350 ºF	350 ºF	350 ºF
Pressure rating	20,000 psi	20,000 psi	20,000 psi	20,000 psi	20,000 psi

Table 12b--Representative logging tool specifications for Reservoir Saturation Tools

Parameter	**PNX Pulsar – Pulsed Neutron (Schlumberger)**	**RMT-3D Pulsed Neutron (Halliburton)**
Acquisition	Real time	Real time
Logging speed	200 to 3,600 ft/hr	180 to 900 ft/hr
Depth of investigation	3 - 10 in	6 to 12 in.
Vertical resolution	3 ft	30 in.
Range of measurement	0 to 60 pu	5 to 60 pu
Temperature rating	350°F	325°F
Pressure rating	15,000 psi	15,000 psi

Table 12c--Representative Logging Tool Specifications for Single Phase Sampling Tool

Parameter	**SRS (Schlumberger)**
Acquisition	Real time
Sample Capacity	600 cm^3
Service	Sour
Temperature rating	392°F
Pressure rating	15,000 psi

Table 13--Summary of measurement parameters for seismometers[1]

Parameters	**Value**
Nominal Sensitivity	750 V-s/m
Precision	±0.5%
Bandwidth/120s	-3 dB points at 120 s and 108 Hz
Bandwidth/20s	-3 dB points at 20 s and 108 Hz
Off-axis Sensitivity	±0.5%
Clip Level	26 mm/s up to 10 Hz and 0.17 g above 10 Hz
Operating Tilt Range/120s	±2.5°
Operating Tilt Range/20s	±10°
Parasitic Resonances	None below 200 Hz
Dynamic Range	> 152 dB @ 1 Hz

[1]Specifications for Nannometrics seismometers are shown. No vendor contract has been awarded.

Table 14--Summary of measurement parameters for Vertical Seismic Profiles

Parameter	
Horizontal Accuracy	< 6 feet
Detection limit	< 40 microseconds
DAS recording gauge length	32 feet
DAS receiver spacing	16 feet
Source spacing	82 feet

Table 15--Summary of measurement parameters for DInSAR and GPS

Parameter	Value
Sensitivity, DInSAR	±0.0001 m
Sensitivity, GPS	±0.001 m
Detection limit, DInSAR	±0.001 m/year
Detection limit, GPS	±0.01 m/year

Table 16. Summary of Measurement Parameters for Surface Optical Cameras

Parameter	Value
Sensitivity to detect CO_2	<1.1 ppm (ΔT = 10ºC, Distance = 1 m)
Thermal sensitivity	15 mK at 30ºC (86ºF)
Spectral range	4.2 µm
Operating Temperature Range	-20ºC to 50ºC (-4ºF to 122ºF)

1.5 Special Training / Certifications

1.5.1 Specialized Training and Certifications

Trained, qualified, and certified personnel will operate geophysical survey equipment and wireline logging tools. The contractor company who provides the equipment will determine the qualifications necessary to use the equipment. Data acquired from these methods will be processed according to industry standards. Fluid and dissolved gas sampling will be conducted by personnel trained to understand and follow specific sampling procedures that will be provided by the Operator. Relevant personnel will participate in a H_2S Safety Training course compliant with the scope elements defined in the ANSI Z390.1-2017 on an annual basis.

1.5.2 Providing and Assuring Training

Training for personnel will be provided by the Operator or contractor responsible for the data collection activity.

1.6 Documents and Records

1.6.1 Report Format and Package Information

OLCV will submit a semi-annual report containing the required Project data in accordance with 40 CFR §146.91, including testing and monitoring information as specified by the UIC Class VI permit. All data and Project records will be stored electronically on secure servers and will have routine backups. Data will be provided in electronic or another format, as required by the UIC Program Director.

1.6.2 Other Project Documents, Records, and Electronic Files

Other documents, records, and electronic files, such as well logs, test results, or other data will be provided, as requested by the UIC Program Director.

1.6.3 Data Storage and Duration

OLCV will maintain the required Project data in accordance with 40 CFR §146.91(f) or as specified in the UIC Class VI permit.

1.6.4 QASP Distribution Responsibility

The Project Manager will be responsible for distributing the most current copy of the approved QASP to those individuals on the distribution list.

2. Data Generation and Acquisition

2.1 Sampling Process Design

This section will focus on CO_2 stream sampling, corrosion coupons, groundwater fluid sampling and soil gas sampling, because physical samples are collected with those methods. Other monitoring methods, such as seismic, pressure, temperature, and logging do not involve physical samples and their testing methodology will not be described here.

The CO_2 injectate stream in the flowline will be continuously monitored via gas chromatography and sampled quarterly for laboratory geochemical analysis. The proposed frequency of sampling is expected to be sufficient to detect changes in composition that could potentially occur over the facility's lifetime and will serve as a backup to the gas chromatograph analyses. The CO_2 stream composition will also be analyzed in a laboratory after significant maintenance events or facilities changes to the Direct Air Capture facility.

Corrosion monitoring via coupons will be used to detect evidence of internal metal loss resulting from the CO_2 stream, which could occur if a water phase is present. Detection of corrosion past the acceptable limit of 4 mils per year (mpy) will result in review of the operating conditions to determine the source of corrosion and the required adjustment needed to control corrosion.

Sampling of fluid and dissolved gas in the Injection Zone (SLR2 and SLR3 wells) and in the first permeable zone above the confining zone, which is the lowermost USDW, will occur during construction and before injection (except for SLR3, because it is constructed after injection commences) to establish a baseline characterization. Additional monitoring of these zones will be conducted during the injection and post-injection phase of the Project at the determined schedules or as needed based on Project triggers (see Table 2 for sampling frequencies). If pressure or temperature changes in a SLR monitor well suggest that CO_2 or displaced brine has potentially reached the location during the injection or post-injection phases, the Dockum group fluid and soil gas will be sampled and analyzed to confirm the presence or absence of CO_2 or displaced brine. In the absence of a pressure or temperature trigger, no change in fluid chemistry due to injection activities is expected.

Although no CO_2 or displaced brine resulting from injection operations is expected to reach the USDW, routine fluid and dissolved gas sampling of the lowermost USDW, and routine soil gas sampling of the near-surface will be conducted to provide additional technical confidence. A comprehensive set of chemical compounds and isotopes were selected to monitor groundwater. The following considerations were evaluated: (1) constituents with primary and secondary USEPA drinking water maximum contaminant levels, (2) constituents most susceptible to react if CO_2 or brine is introduced to the system, (3) constituents necessary for controlling water quality, particularly in the injection, (4) constituents needed to discern the source of anomalous CO_2 detections or potential brine migration, and (5) constituents needed for geochemical modelling. The analytical suites for each geological layer of interest are presented in Tables 6 and 7 and include geochemical and isotopic parameters.

Soil gas will be analyzed prior to commencement of injection operations to establish a chemical and isotopic characterization that describes normal biological respiration processes and nearby anthropogenic sources, if present. During injection, sampling will be conducted at each station on a quarterly basis for the first three years and compared with the pre-injection characterization to identify deviations from the expected trend. Following the third year, sampling will be conducted at a subset of locations on an annual basis. If deviations are present, an attribution analysis will be conducted. This sampling is expected to continue during the post-injection period. Similar to the groundwater monitoring programs, the analytical parameters to characterize and monitor soil gas at the near-surface include composition gases and isotopes. The components were selected considering: (1) constituents which may suggest potential migration pathway, (2) constituents to help distinguish CO_2 produced from biological processes or anthropogenic sources, (3) constituents most susceptible to react if CO_2 is introduced to the system, and (4) constituents needed for geochemical modelling.

2.1.1 Design Strategy

2.1.1.1 Monitoring the CO_2 Stream

The purpose of monitoring the CO_2 stream is to understand potential interactions between the injectate and the fluids and solids in the Injection Zone. Another purpose of monitoring the CO_2 stream is to identify potential interactions between the injectate stream and well materials or other facilities. Additionally, it is important to monitor the chemical and isotopic composition of the CO_2 stream to potentially distinguish the injectate from native fluids in the event of leakage.

The CO_2 injectate stream for BRP will be continuously monitored using on-line analyzers at the Direct Air Capture facility and using an on-line gas chromatograph at the flowmeters directly upstream of the CO_2 Injector wellheads. Additionally, CO_2 stream samples will be routinely collected at the flowmeter directly upstream of the CO_2 Injector wellheads and analyzed by a third-party contractor.

The Class VI rule requires that monitoring frequency should be sufficient to detect changes in physical or chemical properties that may result in deviation from permitted composition. OLCV is confident that the monitoring frequency and locations selected for the BRP Project will allow prompt detection of deviation in injectate composition.

2.1.1.2 Monitoring Corrosion

The purpose of corrosion monitoring is to identify the presence or absence of loss of metal thickness, cracking, or pitting of well components that could result in loss of mechanical integrity. The Class VI rule requires that corrosion be monitored with coupons, a flow loop or alternative method approved by the Director.

Corrosion management of the injection system is based on maintaining the CO_2 stream purity specification and maintaining pressure and temperature conditions in the flowlines that prevent formation of a water phase. Because some well materials that are in contact with CO_2 may become saturated with water during shutdowns, corrosion resistant alloys are selected for these zones. Internally coated carbon steel is used for injection tubing above the packer because it will only be exposed to the CO_2 stream and not to water. During workovers, the tubing will be accessible for full inspection and could be replaced, if necessary.

The materials selected for the BRP Project will be designed to mitigate and inhibit corrosion. To further determine the presence or absence of corrosion, coupons of well materials will be collected and analyzed by a third-party company on a quarterly basis. Finally, casing inspection logs will be run during well maintenance events. OLCV is confident that these actions will prevent or detect corrosion of well materials prior to loss of mechanical integrity.

2.1.1.3 Monitoring Fluid in the Injection Zone

The purpose of monitoring the fluid in the Injection Zone is to identify the presence or absence of the CO_2 plume or pressure front away from the injection well. Direct monitoring of the pressure front is required by 40 CFR §146.90(g). Fluid sampling may be required if indirect monitoring methods are not sufficient to track the plume.

Injection-level (SLR2 and SLR3) monitoring wells and brine withdrawal (WW1, WW2, WW3, and WW4) wells at the BRP Project will be used to monitor the pressure and temperature of the Injection Zone. Changes in pressure and temperature may indicate a change in fluid or pressure in the Injection Zone. If changes in pressure and temperature are detected, fluids will be sampled to further constrain the presence or absence of the CO_2 plume. The position of WW1, WW2, WW3, WW4, SLR2 and SLR3 wells was selected to observe long-term changes in the plume and pressure front. Once CO_2 reaches the wells, they are no longer helpful for future modeling of the CO_2 plume or pressure front. OLCV is confident that this monitoring and testing strategy, along with indirect detection methods, will constrain the presence of the CO_2 plume and pressure front.

2.1.1.4 Monitoring Fluid in First Permeable Zone Above the Confining Zone, coincident with the Lowermost USDW

The purpose of monitoring fluid in the first permeable zone above the confining zone is to determine the presence or absence of injection fluids or displaced brine expelled from the Injection Zone [40 CFR §146.90(d)]. A change in pressure, temperature, or geochemical composition in the fluid above the Upper Confining Zone may indicate a breach of Upper Confining Zone integrity or mechanical integrity of a wellbore. Based on data obtained in the WW1, WW2, WW3, and WW3 there is an absence of permeable zones above the confining zone and below the lowermost USDW, which is the Dockum group. Therefore, the first permeable zone is coincident with the lowermost USDW in the Project AoR.

Due to the relatively small (<6 $miles^2$) size of the BRP Project pressure and CO_2 plume, OLCV will use one well to monitor lowermost USDW. The USDW-level well is located close to the BRP CCS1 and BRP CCS2 CO_2 injectors, because this location is likely to experience the greatest reservoir pressure resulting from injection and therefore, is the location that is most likely to experience displaced brine or injectate, in the unlikely event that leakage occurs.

The Shoe Bar 1 stratigraphic test well will be plugged above the Injection Zone and converted to a monitoring well, SLR1, before commencement of injection operations at the BRP CCS1 and BRP CCS2 wells. The Shoe Bar 1AZ well will also be plugged above the Injection Zone prior to commencement of injection operations and converted to a monitoring well, ACZ1. Both wells will be used to monitor integrity of the Upper Confining Zone by conducting saturation logging. Pressure and temperature may also be obtained in the Upper Confining Zone in the SLR1.

Prior to injection activities, temperature and pressure will be monitored, and fluid and dissolved gas samples will be collected for analysis (see Table 6 for analytical parameters) to establish baseline conditions within the first permeable zone above the Upper Confining Zone. As shown in Table 2, prior to CO_2 injection, samples from the lowermost USDW will be collected and analyzed for geochemical and isotopic parameters quarterly for at least one year to establish baseline conditions. During the injection, the USDW will be monitored for geochemical composition and a subset of isotopic analysis quarterly between year 1 and 3 and annually thereafter. During the post-injection period, the USDW will be monitored for geochemical composition and a subset of isotopic analysis annually for the first 10 years and event-driven thereafter, pending an approved PISC plan. If anomalous pressure and temperature changes are observed in the SLR2, SLR3 or ACZ1 wells, or there is any indication of leakage through the injection wells during the injection and post-injection phases of the Project, additional fluid samples may be obtained for geochemical and isotopic analysis and comparison to pre-injection sample results.

OLCV is confident that the combination of monitoring the integrity of the Upper Confining Zone, and the chemistry and isotopic composition of the lowermost USDW will confirm the presence or absence of integrity of the confining system.

2.1.1.5 Monitoring Soil and Soil Gas Composition

The objective of soil gas monitoring is to provide an additional line of evidence supporting the presence or absence of CO_2 leakage from the Injection Zone. Because soil gas in the near-surface and groundwater composition in shallow wells has considerable variation due to natural processes, monitoring both soil gas and fluid composition at multiple subsurface levels is a more reliable leak monitoring method.

Permanent subsurface soil gas probes will be installed at approximately 21 representative locations throughout the surface projection of the AoR and adjacent DAC facility. The following factors will be considered in siting soil gas probes: the location of artificial penetrations discussed in the Area of Review and Corrective Action Plan; variable surface soil characteristics, such as caliche deposits; the potential effects of the Direct Air Capture (DAC) facility on natural processes in the near-surface; and the location of adjacent property owners.

Soil gas samples will be collected and analyzed for gas and isotopic composition quarterly for at least one year prior to CO_2 injection to determine a characteristic profile for the site. During the injection phase, soil gas will be monitored for gas composition quarterly between year one and three and annually thereafter. Note that the number of sample stations may be reduced if OLCV determines that monitoring a subset of soil probe stations will provide a representative set of data to ensure that CO_2 is not migrating from the Injection Zone through preferential pathways. If anomalous pressure and temperature changes are observed in the nearby ACZ1 or SLR wells, or there is any indication of leakage through the injection wells, additional soil gas samples will be collected for gas composition and/or isotopic analysis and comparison to pre-injection sample results.

Additionally, up to three soil samples per location will be collected in general accordance with EPA Method LSASDPROC-300-R5 (EPA, 2023a) for the laboratory analysis of pH, electrical conductivity, sodium adsorption ratio, total organic carbon (TOC), and soil moisture, in accordance with the methods specified in Table 7. Soil samples will only be conducted once, during installation of soil gas probe stations.

OLCV is confident that the combination of soil gas and fluid monitoring throughout the stratigraphic column will indicate whether leakage of CO_2 injectate or displaced brine has occurred.

2.1.1.5 Monitoring the AoR with Geophysical Techniques

OLCV will directly and indirectly monitor the AoR. OLCV will directly monitor the position of the AoR through geochemical monitoring and pressure and temperature data obtained from the Injection Zone and the first permeable zone above the Upper Confining Zone. OLCV will indirectly monitor the AoR by collecting repeat saturation logs in the Injection Zone and the first permeable zone above the Upper Confining Zone. In addition, OLCV will indirectly monitor the AoR using 2D Vertical Seismic Profiles (2D VSP), 2D surface seismic, Differential Interferometric Synthetic-Aperture Radar (DInSAR), and Global Positioning Systems (GPS). More details on geophysical methods are presented in the Testing and Monitoring Plan.

2D VSP will be collected in the Injector wells and other selected wells that contain Distributed Acoustic Sensing Fiber (DTS) prior to the commencement of injection operations, and during injection operations at years one, two, five and 10. Additional VSP surveys may be conducted if temperature, pressure, or geochemical data suggest a change in the AoR that could be interpreted with geophysical data. 2D surface seismic will be conducted prior to the commencement of injection operations, during year 10 of injection, and once every five-year period during Post Injection Site Care Period.

DInSAR monuments and GPS stations will be installed prior to the commencement on injection operations. These data will be collected, processed, and interpreted on a monthly basis to detect mm-scale changes in surface deformation that may result from operational activities in the Injection Zone. These data are well-suited to provide a site-wide, frequent information on AoR movement.

2.1.2 Sample Strategy

2.1.2.1 Number of Samples and Sampling Locations

- The CO_2 injectate stream will be continuously monitored in the flowmeters directly upstream of the CO_2 Injectors. Additionally, CO_2 stream samples will be collected and analyzed quarterly at the flowline directly upstream of the CO_2 Injector wellheads.
- Corrosion coupons will be collected and analyzed on a quarterly basis. In addition to coupons, OLCV will conduct weekly visual inspection of the facilities, conduct quarterly optical gas imaging (OGI) camera evaluations, and continuously monitor pressure and temperature data for indications of potential leakage that could result from corrosion.
- Injection Zone fluid and dissolved gas sampling will be conducted in SLR monitoring wells prior to injection, and following injection, if pressure or temperature data from the Injection Zone monitoring wells indicates the potential presence of CO_2 plume front.
- Fluid and dissolved gas sampling in the lowermost USDW will be conducted in one USDW-level well on a quarterly basis for at least one-year prior injection. During the injection phase, groundwater samples will be collected quarterly starting in the first year of injection operations and continuing through the third year of injection operations. Beginning in the fourth year of operations, sampling will be conducted annually. Annual sampling will continue for the first 10 years post injection. Additional sampling will be conducted if pressure or temperature data from the SLR wells or fluid data from the USDW-level well indicates the potential presence of CO_2 injectate or displaced brine above the Upper Confining Zone.
- Soil gas sampling will be conducted at approximately 21 stations on a quarterly basis prior to injection for at least one year. During the injection phase, soil gas samples will be collected quarterly starting in the first year of injection operations and continuing through the third year of injection operations. Beginning in the fourth year of operations, sampling will be conducted annually. Annual soil gas samples will be collected post-injection until site closure. Additional samples will be collected if pressure or temperature data from the SLR wells or fluid data from the USDW-level well indicates the potential presence of CO_2 injectate or displaced brine above the Upper Confining Zone.
- GPS data will be collected from nine permanently installed stations that are evenly spaced in and around the AoR. In addition, reflective markers will be placed at GPS locations to serve as permanent monuments for calibration of DInSAR data.

2.1.2.2 Sampling Contingency

The BRP Project injection and monitoring wells and soil gas stations are located on acreage to which OLCV has surface access rights. There are no anticipated problems with access to sampling locations. Sampling schedules will be adjusted based on weather conditions or other operational activities (e.g., workovers). It is expected that adjustments to the sampling schedule would not impact the ability of OLCV to meet permit requirements.

2.1.2.3 Activity Schedule

The schedule for sampling is summarized in Table 2 of this document. In general, baseline monitoring activities will be conducted for at least one year during the pre-injection period. Testing and monitoring during the injection and post-injection phases will be conducted for 12 years and 50 years, respectively.

2.1.2.4 Critical / Secondary Data

The following information is considered critical and will be recorded during sampling: date and time of activity, persons performing activity, specific location of activity, instrument calibration data, field parameters, and other data to describe the type of activity. Secondary data may include information such as duration of sampling processes.

2.1.2.5 Sources of Variability

There are multiple sources of variability that could impact sampling and the subsequent interpretation of collected data.

Key sources of variability are:

- Variations in composition of groundwater and soil gasses are expected based on naturally occurring biologic processes, naturally occurring geologic processes and global atmospheric trends. For example, ecosystems have a naturally occurring balance of O_2 and CO_2 that varies daily, seasonally and with climate changes. In addition, naturally occurring methane may oxidize to CO_2 under certain conditions.
- Subsurface fluids in the Injection Zone and above the Injection Zone may be impacted by activities of other operators who are engaged in oil and gas production activities offset to the BRP Project site. Although these activities are >5 miles from the proposed injectors, impacts from hydrocarbon production or brine injection may result in pressure, temperature, and fluid composition changes over the life of the BRP Project injection and post-injection periods.
- Variability may result from changes in instrument calibration, changes in personnel collecting or analyzing samples, changes in environmental conditions during sample collection in the field, or data input errors.
- Variability in DInSAR data could result from atmospheric effects, such as turbulence or stratification. Variability in 2D VSP or 2D surface seismic could result from surface noise, such as from construction or industrial activities.

Activities to mitigate or reconcile variability are:

- Collecting data to establish a chemical and isotopic characterization prior to injection.

- Utilizing a process-based approach to evaluate changes in fluid chemical or isotopic composition and appropriately attribute the change.
- Evaluating data in a timely manner after collection to allow for resampling and re-analysis if anomalies are observed.
- Recording critical data in the field or laboratory that describe the conditions in which the sample was obtained, or analysis was performed.
- Checking instrument calibration according to best practices.
- Training staff and requiring training for third parties conducting sampling or analysis.
- Conducting blind checks in the laboratory.
- Utilizing qualified personnel to QC analysis and interpretations.
- Variability in DInSAR data is mitigated by processing the data in conjunction with atmospheric models.
- Noise that may impact 2D VSP or 2D surface seismic can be identified and processed out or minimized during the processing workflow.

2.2 Sampling Methods

2.2.1 Sampling Standard Operating Procedures (SOP)

2.2.1.1 SOP for Sampling CO_2 Stream

CO_2 sampling will be conducted by a third-party contractor using process GPA-2177-20.

2.2.1.2 SOP for Sampling Corrosion Coupons

The Project will use a third-party company for placement and retrieval of coupons. OLCV will ensure that the third-party has an SOP for retrieval and placement of coupons under pressure using double block and bleed retrieval tools.

2.2.1.3 SOP for Sampling Fluid in the Injection Zone

Fluid samples will be collected in Injection Zone from the SLR2 and SLR3 wells by a wireline Single Phase Sampling (SPS) tool or through a U-tube system that is under review. A SPS tool is commonly used for collecting unaltered, noncontaminated single-phase fluid samples. The samples remain in single-phase condition above reservoir pressure as the tool is retrieved from the hole. The sampler can collect up to 600 cm^3 per each of the two sample chambers, which will be sufficient to conduct the fluid and isotopic analyses planned for the Project. A U-tube sampling system is being evaluated. Further studies will be conducted before it will be considered for deployment.

Fluid samples may be obtained from the Water Withdrawal wells. These wells may be sampled at the wellhead, which is a proven, industry-accepted methodology for collecting fluid samples from producing wells. Based on a geochemical model, these fluids will be restored to downhole pressure and temperature conditions, so that they can be compared with pre-injection conditions.

2.2.1.3 SOP for Sampling Fluid in the Lowermost USDW

Fluid samples from the USDW-level well will be collected primarily using low-flow sampling techniques by qualified third-party operators who will follow procedures described in the EPA manual LSASDPROC-301-R6 (EPA, 2023a) and guidelines set by Yeskis and Zavala (2002).

- The static water level will be measured using an electronic water level indicator and the volume of water in wellbore will be calculated, if necessary for purging.
- The temperature, pH, specific conductance, dissolved oxygen, turbidity, and oxidation-reduction potential will be measured in the field using portable probes and a flow-through cell. Groundwater turbidity will be measured using a portable turbidity meter. Field chemistry probes will be calibrated at the beginning of each sampling day according to specifications set by equipment manufacturer.
- Purging will be conducted by a dedicated downhole bladder pump to mitigate cross-contamination, with the pump intake positioned in the middle of the screen interval. Groundwater will be purged until stabilization of field parameters, pH, temperature, and specific conductance, is reached to ensure samples are representative of formation water quality. Water quality parameters will be monitored in the field using portable probes and a flow-through cell consistent with standard methods given sufficient flow rates and volumes. Groundwater turbidity will be measured in the field utilizing a portable turbidity meter. Field parameters will be considered stable when three successive measurements made three minutes apart meet the criteria listed in Table 17 below.
- After field parameters have stabilized, samples will be collected from the discharge line of the pump as soon as possible after purging is complete. Sample agitation will be minimized, and the pump discharge line will not contact the sample container. Samples will be placed in labeled containers and preserved as soon as possible in an ice-filled cooler or as specified by the laboratory.
- Samples requiring filtration (e.g., dissolved metals) will be filtered through 0.45-µm flow-through filter cartridges as appropriate and consistent with ASTM D6564-00. Prior to sample collection, filters will be purged with a minimum of 100 mL of well water (or more if required by the filter manufacturer). Samples will be properly preserved per analyte requirements.
- Sample blanks will be collected if equipment is field-cleaned and re-used on site.

Table 17. Stabilization criteria of water quality parameters during USDW-Level well purging

Field Parameter	Stabilization Criteria
pH	±0.2 units
Temperature	±10% of reading
Specific conductance	±3% of reading
Oxidation-Reduction Potential (ORP)	±10 mV of reading
Dissolved oxygen	±10% of reading or 0.3 mg/L whichever is greater
Turbidity	±10% of reading or below 10 NTU

2.2.1.4 SOP for Sampling Soil and Soil Gas

Soil gas samples at the probe stations will be collected, generally following the procedures set forth in EPA Method SESDPROC-307-R5 (EPA, 2023b) and industry standards ASTM D7648/D7648M-18, by a qualified and experienced third-party contractor(s). During sample collection, a vacuum will be applied to the tubing on the surface using 60 mL gas-tight syringes, equipped with a 3-way valves, to first purge at least the full length of the tubing. A soil gas will then be collected in appropriate sample containers provided by the laboratories. During soil gas sampling, a leakage test will be conducted by releasing helium gas as a tracer gas within a shroud over each soil gas sampling site.

During the drilling activities for installation of soil gas probes, up to three soil samples per soil gas probe locations will be collected in general accordance with EPA Method LSASDPROC-300-R5 (EPA, 2023c). Sample intervals will target various depths along the length of the boring to establish site soil characteristics pre-injection. Soil samples will be collected in appropriate sample containers provided by the laboratories.

2.2.4 In-Situ and Continuous Monitoring

In-situ or continuous monitoring is not planned for the following: fluid in the Injection Zone, fluid above the Upper Confining Zone, fluid in the lowermost USDW, corrosion coupons or soil gas.

In-situ, continuous monitoring of the CO_2 injectate stream is planned. The process will be as follows:

- The CO_2 sampling line will be tapped off from the BRP CO_2 process manifold, upstream of all CCS injection wells, and immediately downstream or upstream of the CO_2 custody transfer meter.

- Pressure Control Valve(s) as part of decompressing system will be installed to reduce CO_2 sample from process pressure to an acceptable level required by sampling equipment and analyzers.
- Individual Pressure Relief Valves, Adjustable Orifice Valves, as well as Rotameters will be installed for continuous CO_2 stream chemical analysis.
- Appropriate filter / coalescer will be considered in the design.
- Appropriate heat trace circuit will be considered in the design.
- Because of the high CO_2 mol% content of the samples and diverse component sampling tasks, the sampling system will be a combination of multiple gas analysis technology that may consist of:
    - Continuous Gas Analyzers with Quantum Cascade Lasers (QCLs), Interband Cascade Lasers (ICLs) and Tunable Diode Lasers (TDLs), Non-dispersive infrared (NDIR), non-dispersive ultraviolet (NDUV), paramagnetic detector, various electrochemical cells,
    - Gas Chromatograph that meets consensus standards, with Flame Ionization Detector (FID), Flame Photometric Detector (FPD) or Thermal Conductivity Detector (TCD),
    - Other additional field proven analyzer technology as appropriate, and
    - A sample system will be bult to include above mentioned instruments / equipment, local analyzer controller, as well as any independent sensor transmitters. All analyzer signals will be communicated to nearby PLC through either analog 4 – 20mA signal or multiplex communication protocol such as Modbus.

2.2.5 Sample Homogenization, Composition, Filtration

No samples are anticipated to be homogenized.

2.2.6 Sample Equipment

2.2.6.1 Equipment for Sampling CO_2 Injectate Stream

Samples of the CO_2 injectate stream will be collected by a third-party contractor according to process GPA 2177-20.

2.2.6.1 Equipment for Sampling Coupons

Coupon retrieval equipment used to retrieve and place coupons are owned by the third-party company who provides the Project with coupon retrieval and placement services.

2.2.6.3 Equipment for Sampling Fluid from the Injection Zone

A third-party logging operator will collect fluid samples from the SLR2 and SLR3 wells. The third-party will provide the logging equipment and specified sampling containers. If a U-tube system is applicable to these wells, samples will be conducted by OLCV, Oxy personnel or a third-party operator using the U-tube system.

2.2.6.4 Equipment for Sampling the Lowermost USDW

For collecting groundwater samples from the USDW-level monitoring well, the necessary equipment will include:

- Sampling pump (i.e., bladder pump),
- Compressed gas (e.g., nitrogen) for bladder pumps,
- Water quality probes, flow-through cell, and calibration solutions,
- Water level indicator,
- Laboratory-provided containers, with appropriate preservatives (see Table 18 for details), and
- Labels, chain-of-custody forms, and coolers/shipping containers.

2.2.6.5 Equipment for Sampling Soil Gas

For collecting soil gas samples from the vadose zone, the necessary equipment will include:

- Vacuum pump (e.g., syringe),
- 60-mL syringes and 3-way valves,
- Leak detection test gas (i.e., helium),
- Helium meter,
- Laboratory-provided containers, with appropriate preservatives (see Table 18 for details), and
- Labels, chain-of-custody forms, and coolers/shipping containers.

For collecting soil samples during the installation of the soil gas probes, the necessary equipment will include:

- Sampling hand tools (e.g., spatula, trowel, core knives),
- Laboratory-provided containers, with appropriate preservatives (see Table 18 for details), and
- Labels, chain-of-custody forms, and coolers/shipping containers.

2.2.7 Sample Preservation

2.2.7.1 Preservation of CO_2 Injectate Stream Samples

Preservation, if any will be done in accordance with GPA 2177-20 by a third-party contractor.

2.2.7.1 Preservation of Coupon Samples

Coupons are collected after retrieval and stored in dry plastic bags or paper envelops.

2.2.7.3 Preservation of Fluid from the Injection Zone

Fluid samples from the Injection Zone will be preserved in accordance with SOP of the third-party contractor selected for the sampling.

2.2.7.4 Preservation of Samples from the Lowermost USDW

For groundwater and other aqueous samples for characterizing and monitoring the Dockum group, the preservation methods provided in Table 19 will be used.

2.2.7.5 Preservation of Soil and Soil Gas Samples

For soil and soil gas samples for monitoring the near-surface, the preservation methods provided in Table 20 will be used.

2.2.8 Cleaning/Decontamination of Sampling Equipment

2.2.8.1 Cleaning/Decontamination of CO_2 Injectate Stream Sampling Equipment

The cleaning and decontamination of CO_2 sampling equipment will be conducted in accordance with GPA 2177-20.

2.2.8.2 Cleaning/Decontamination of Coupon Sample Equipment

Coupons are cleaned using methanol and blasted using standard coupon cleaning procedure to remove any corrosion or scale to allow for accurate measurement of metal loss and depth of corrosion pitting.

2.2.8.3 Cleaning/Decontamination of Equipment for Sampling Fluid from the Injection Zone and First Permeable Zone Above the Confining Zone

Cleaning or decontamination will be conducted in accordance with the third-party operator's SOP.

2.2.8.4 Cleaning/Decontamination of Equipment for Sampling Fluid from the Lowermost USDW

A solution of industrial grade detergent (e.g., Liquinox® or Alkanox®) and deionized water will be used to decontaminate non-dedicated sampling equipment utilized for groundwater sampling (e.g., water level indicator).

2.2.8.5 Cleaning/Decontamination of Equipment for Sampling Soil and Soil Gas

No cleaning or decontamination will be required for soil gas samples, as a brand new 60-mL gas-tight syringe will be utilized to collect each sample, and each soil gas probe site will include dedicated sampling tubing.

A solution of industrial grade detergent (e.g., Liquinox® or Alkanox®) and deionized water will be used to decontaminate drilling rods, hand augers, hand tools, and other non-dedicated sampling equipment utilized for soil sampling.

2.2.9 Support Facilities

2.2.9.1 Support Facilities for CO_2 Injectate Stream Sampling

An onsite sampling station will be installed to sample the CO_2 injectate stream. A technician reporting to the third-party manufacture is required during initial calibration of the continuous gas analyzer, gas chromatograph and other gas analyzers that are installed at the same sampling station. The third-party technician will also assist the OLCV team in commissioning and construction to install, commission, and startup the analyzer equipment; and will provide theoretical and hands-on field training of all analyzers to the BRP Operation / Maintenance crew. Besides the automated calibration feature that is available to some of the analyzers, the third-party manufacturer will also recommend appropriate inspection, maintenance, and calibration frequency per the specific application. Finally, a full list of spare parts for equipment on the sampling skid will be provided by the third-party installer or manufacturer.

2.2.9.2 Support Facilities for Coupon Sampling

Coupon retrieval from locations above ground may require platforms to reach the coupon access fittings.

2.2.9.3 Support Facilities for Sampling Fluid from the Injection Zone and First Permeable Zone Above the Confining Zone

The third-party contractor responsible for logging will supply any support facilities that are necessary for wireline-deployed sample collection tools in the Injection Zone or the first permeable zone above the Upper Confining Zone. A U-tube sampling system is being evaluated. If selected, a third-party contractor will install the u-tube and any required support facilities.

2.2.9.4 Support Facilities for Sampling Fluid from the Lowermost USDW

Support facilities necessary for collecting and analyzing fluid and dissolved gas samples from the USDW-level monitoring well will be determined in consultation with the selected sampling contractors and laboratories, prior to each mobilization.

2.2.9.5 Support Facilities of Equipment for Sampling Soil Gas

Support facilities necessary for collecting and analyzing soil and soil gas samples from the near-surface will be determined in consultation with the selected sampling contractors and laboratories, prior to each mobilization.

2.2.10 Corrective Action, Personnel, Documentation

The party responsible for collecting samples in the field or analyzing samples in the laboratory will also be responsible for calibrating and testing equipment and performing corrective actions on broken or malfunctioning equipment. If corrective action cannot be taken, then the equipment will be returned to the manufacturer for repair or replacement. The party conducting sampling or analyses will record the actions, if corrective actions were required before or after samples were acquired or analyses were conducted.

For fluid, soil and soil gas sampling and analysis, replacements and backups for all supplies, equipment, reagents, and tools are kept on hand. If replacements are necessary, third-party field technicians will contact their managers to inform them of the replacement. Duplicates of all equipment/sample bottles are pulled to ensure backups are available.

2.3 Sample Handling and Custody

This section pertains to physical samples that will be collected in a field and analyzed in a lab. Logging, gauge measurements, fiber measurements and seismic do not have physical samples and are not discussed in this section.

2.3.1 Maximum Hold Time / Preservation

The sampling hold times described in the tables below are listed in the following tables.

Table 18--Containers, preservation techniques and holding times for samples

Sample Type	Container and volume	Preservation Technique	Max Holding Time
CO_2 Injectate Stream	In accordance with GPA 2177-20		
Coupons	Placed in sealed plastic bags or paper envelops to prevent rusting	NA	Delivered to the lab within one week
Fluid from Injection Zone	**See table below**		
Fluid from Lowermost USDW	**See table below**		
Soil Gas	See tables below		

Table 19--Containers, preservation techniques and holding times for groundwater sample parameters collected in the Injection Zone, first permeable zone above the Upper Confining Zone / the lowermost USDW

Parameters	Container and Volume	Preservation Technique	Max Holding Time
Geochemical Samples			
Total Metals/Metalloids: Al, As, Ba, B, Cd, Ca, Co, Cu, Cr, Fe, Pb, Li, Mg, Mn, Mo, Ni, P, K, Sb, Se, Si, Na, Sr, Ti, V, and Zn	250 mL/HDPE	Nitric acid, cooled to 4°C	180 days
Total Metals/Metalloids and Dissolved Metals/Metalloids: U	250 mL/HDPE	Nitric acid, cooled to 4°C	28 days
Total Metals/Metalloids and Dissolved Metals/ Metalloids: Hg	250 mL/HDPE	Nitric acid, cooled to 4°C	28 days
Dissolved Metals/Metalloids: Al, As, Ba, B, Cd, Ca, Co, Cu, Cr, Fe, Pb, Li, Mg, Mn, Mo, Ni, P, K, Sb, Se, Si, Na, Sr, Ti, V, and Zn	250 mL/HDPE	Filtered, nitric acid, cooled to 4°C	180 days
Anions: Br, Cl, F, NO2, NO3 and SO_4 Anions: PO43-	250 mL/HDPE	Cooled to 4°C, Sulfuric Acid (Phosphorus)	28 days, 48 hours for NO3 only
Total, Bicarbonate, Carbonate, & Hydroxide Alkalinity	250 mL/HDPE	Cooled to 4°C	14 days
pH (lab)	250 mL/HDPE	Cooled to 4°C	Immediately
Total dissolved solids (TDS)	500 mL/HDPE	Cooled to 4°C	7 days
Water density (lab)	500 mL/Amber Glass	Cooled to 4°C	28 days
Dissolved Inorganic Carbon (DIC)	250 mL/Amber Glass	Filtered, cooled to 4°C	28 days
Cation-Anion balance	1 L/HDPE	Cooled to 4°C	N/A
Conductivity/Specific Conductance	250 mL/HDPE	Cooled to 4°C	28 days
Water Isotopic Analyses			
$^{228}Ra/^{226}Ra$	1 L/HDPE	Nitric acid, cooled to 4°C	180 days
$^{87}Sr/^{86}Sr$	30 mL	None	> 365 days
$^{87}Sr/^{86}Sr$	30mL	None	> 365 days
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	40 mL HDPE	None	> 365 days
$\delta^{13}C$ of DIC	60 mL HDPE	Filtered, cooled to 4°C	28 days
^{14}C of DIC	250 mL HDPE	None	28 days
Dissolved Gas Samples and Isotopic Analyses			
Dissolved Gas: N_2, CO_2, CO, O_2, Ar, H_2, He, CH_4, C_2H_6, C_3H_8, i-C_4H_{10}, n-C_4H_{10}, i-C_5H_{12}, n-C_5H_{12} and C6+	0.6 L IsoFask ®	None	1 year

δ^{13}C of dissolved CO_2, C1-C5, δ^{2}H of CH_4	0.6 L IsoFask ®	None	1 year
^{14}C of CH_4	0.6 L IsoFask ®	None	1 year
Dissolved CO_2	No Container needed - Calculated from Alkalinity Analysis		
Dissolved Gas: H_2S	500 mL Plastic	Cooled to 4°C, sodium hydroxide	7 days
Composition and isotope noble gas: Ar, Kr, Xe, Ne, He, ^{3}He/^{4}He ratio, ^{20}Ne/^{22}Ne ratio, ^{36}Ar/^{40}Ar ratio	2 cm x 20 cm Copper Tube	None	> 365 days

Table 20--Containers, preservation techniques and holding times for soil gas and soil samples

Sample Type	Container and volume	Preservation Technique	Max Holding Time
Soil Samples			
pH	16 oz. clear glass jar	Cooled to 4°C	24 hours
Electrical conductivity (EC)	16 oz. clear glass jar	Cooled to 4°C	180 days
Sodium Adsorption Ratio (SAR)	16 oz. clear glass jar	Cooled to 4°C	180 days
Moisture	16 oz. clear glass jar	Cooled to 4°C	60 days
Soil Gas	See tables below		28 days
Soil Gas Samples			
Gas: H_2, He, O_2, N_2, CO_2, CH_4, CO, Ar, C2-C6+	0.3-L IsoBag Gas Bag®	None	180 days
^{14}C of CO_2	0.3-L IsoBag Gas Bag®	None	180 days
δ^{13}C of Methane and CO_2, δ^{2}H of Methane	0.3-L IsoBag Gas Bag®	None	180 days

2.3.2 Sample Transportation and Storage

It is the responsibility of the sampling contractor to ensure that all samples are delivered to the laboratories for analysis in appropriate conditions as described below.

Table 21. Containers, preservation techniques and holding times for CO_2 injectate, coupons, groundwater, soil, and soil gas samples

Sample Type	Transportation	Storage
CO_2 Injectate Stream	In accordance with GPA 2177-20	
Coupons	Placed in dry containers	Delivered to the testing lab within one week
Fluid from Injection Zone	Shipped to testing facility within 24 hours of sample collection.	Placed in appropriate containers provided by laboratories.
Fluid from Lowermost USDW	Shipped to testing facility within 24 hours of sample collection.	Placed in ice-filled coolers and maintained at 4ºC until analysis

Soil	Shipped to testing facility within 24 hours of sample collection.	Placed in appropriate containers provided by laboratories.
Soil Gas	Shipped to testing facility at the end of sampling event	Placed in ice-filled coolers and maintained at 4ºC until analysis

2.3.3 Sample Chain-of-Custody: Documentation, Identification, Tracking

All sample containers will have waterproof labels with relevant information regarding the project name, sampling date, sampling location, sample identification number, sample type, sample method, and sample preservation (if any).

2.3.3.1 Chain-of-Custody for CO_2 Injectate Samples

The third-party who collects the CO_2 injectate samples will maintain a chain-of custody procedure in accordance with GPA 2177-20.

2.3.3.2 Chain-of-Custody for Coupon Samples

Coupons are retrieved by contractor and analyzed for weight loss, pitting depth and any other damage (e.g., erosion). Results are reported to the Mechanical Integrity Engineer for action and coupons to be retained for three years.

2.3.3.3 Chain-of-Custody for Groundwater Fluid Samples

Groundwater samples will be collected in accordance with the procedures described in Section 2.2 and field logbooks or an equivalent logging method will be maintained by the sampling contractors using standardized forms (if applicable) for consistency in the information reported. The information recorded in the field logbook will include at the minimum:

- The project information (e.g., project name and location);
- Daily activity entries (e.g., date, sampling start and end, weather conditions, name of sampling personnel);
- Field instrumentation used and calibration results; and
- Sample records, which should document the sample collection and field measurements (e.g., water quality parameters and water level). Sample records should also document sample locations and identification, consistent with the sample container labels for internal tracking.

When transferring the possession of samples, the personnel relinquishing and receiving the samples will sign, date, and note the time on the record. If a signature cannot be obtained, a note will be made in the "Received By" space of the chain-of-custody form. Copies of the form will be provided to the person/lab receiving the samples as well as the person/lab transferring the samples. The field logbooks and chain-of-custody forms will be retained and archived to allow simplified tracking of sample status. The chain-of-custody forms and the record-keeping task are both the responsibilities of the groundwater sampling team personnel and selected laboratories.

2.3.3.4 Chain-of-Custody for Soil and Soil Gas Samples

The chain-of-custody and field logbook requirements for soil and soil gas sampling are the same as the chain-of-custody requirements for groundwater described above.

2.4 Analytical Methods

This section pertains to physical samples that will be collected in a field and analyzed in a lab. Logging, gauge measurements, fiber measurements and seismic do not have physical samples and are not discussed in this section.

2.4.1 Description of Analytical Methods

2.4.1.1 Analytical Methods for CO_2 Injectate

CO_2 injectate will be analyzed by third-party lab in accordance with GPA 2177-20.

2.4.1.1 Analytical Methods for Coupons

Weight loss and pitting depth are measured to calculate the general corrosion and pitting corrosion rates and reported to an OLCV Mechanical Integrity Engineer. Data is trended to determine if corrosion is present and changing over time.

2.4.1.3 Analytical Methods for Groundwater

All laboratory analyses of groundwater samples collected for monitoring the lowermost USDW, the first permeable zone above the Upper Confining Zone, and the Injection Zone will be conducted in accordance with USEPA-approved methodologies or standardized methods (see Tables 6). Laboratory analyses of groundwater samples will be completed in accordance with SOPs developed by the respective laboratories to be consistent with referenced methods. Upon request, OLCV can provide all SOPs implemented for specific parameters using appropriate standard methods after a contract with the selected laboratories are established. The laboratories will summarize the analytical results, associated QA/QC results, and the laboratory certifications in a laboratory report.

2.4.1.4 Analytical Methods for Soil and Soil Gas

All laboratory analyses of soil and soil gas samples collected for characterizing and monitoring near-surface conditions will be conducted in accordance with USEPA-approved methodology or standardized methods (see Table 7). Laboratory analyses of soil and soil gas samples will be completed in accordance with SOPs developed by the respective laboratories to be consistent with referenced methods. Upon request, OLCV can provide all SOPs implemented for specific parameters using appropriate standard methods after a contract with the selected laboratories are established. The laboratories will summarize the analytical results, associated QA/QC results, and the laboratory certifications in a laboratory report.

2.4.2 Performance Criteria

2.4.2.1 Performance Criteria for CO_2 Injectate Measurements

CO_2 injectate is considered acceptable if it meets the specifications established in the Testing and Monitoring Plan. Those specifications are also listed below in Table 22.

Table 22—CO_2 injectate specifications

Component	Specification
CO_2 content	>95 mol% (>96.5 mass%)
Water	<30 lbm/MMscf
Nitrogen	<4 mol%
Sulphur	<35 ppm by weight
Oxygen	<5 mol%
Glycol	<0.3 gal/MMscf
Carbon Monoxide	<4,250 ppm by weight
NOx	<6 ppm by weight
SOx	<1 ppm by weight
Particulates ($CaCO_3$)	<1 ppm by weight
Argon	<1 mol%
Surface pressure	>1,600 psig
Surface temperature	>65°F and <120°F
Isotopes	δ13C and 14C of CO_2

2.4.2.1 Performance Criteria for Coupon Measurements

Corrosion monitoring by coupons are considered acceptable if corrosion rates are:

- General corrosion rate < 0.1 mm/yr (4 mpy)
- Pitting corrosion rate < 0.2 mm/yr (8 mpy)

2.4.2.2 Performance Criteria for Groundwater Measurements

Internal audits of field activities for collection of physical groundwater samples will be conducted by OLCV or contractor, as necessary, to verify that the protocols specified in this document are being followed and correct any deficiencies in the execution of the field procedures. These internal audits may include an evaluation of the field sampling records, instrument operation records and groundwater sample collection and handling.

Laboratory performance criteria will be designated once the third-party analytical laboratory is selected and contracted, based on their quality assurance and quality control specifications. The selected laboratory will be responsible for implementing their internal laboratory assessments and correct any deficiencies to ensure their compliance with the analytical method SOPs. Any performance criteria failure will be reported to OLCV as pertinent to the testing and monitoring program for the BRP Project.

2.4.2.3 Performance Criteria for Soil and Soil Gas Measurements

Meeting the performance criteria for field and laboratory activities for soil and soil gas samples will follow the same procedures described in Section 2.4.2.2.

2.4.3 Corrective Action Plans

2.4.3.1 Corrective Action Plans for CO_2 Injectate

Short term anomalous variations recorded by the on-line gas chromatographs related to temporary system upsets may occur. If the composition is not restored to the specification within a few minutes, the operations control room engineers will evaluate the data and may recommend that operations are shut in until the further laboratory testing can be conducted. If laboratory data is confirmed to be outside of the specified range, CO_2 injection will be stopped until the CO_2 injectate stream is restored to the specified composition.

2.4.3.1 Corrective Action Plans for Coupons

If corrosion rates exceed the target, process conditions must be reviewed to determine if operating conditions contributed to corrosion or erosion and if these changes remain or are corrected. The determination of whether corrosion continues will be confirmed with the next retrieval cycle, or OLCV may reduce the retrieval frequency until corrosion is under control. High corrosion rates may trigger further inspection for verification of the condition of the equipment.

2.4.3.3 Corrective Action Plans for Groundwater

Corrective actions during groundwater sample collections will be triggered during the preparation for and performance of the field activities if any of the following conditions are encountered:

- Insufficient equipment or materials available for collection of groundwater samples in accordance with the procedures specified in this document;
- The sampling program must be modified due to unexpected field conditions (i.e., extreme weather conditions);
- Field and/or laboratory specifications must be altered or are not achieved; and/or
- Field and/or laboratory procedures are not properly implemented as confirmed during audits.

Minor adjustments in field and laboratory procedures (e.g., change in sampling order, change in location of equipment blank, change in sample on which matrix spike and matrix spike duplicate analysis is performed) will be made at the discretion of the sampling contractors and laboratory personnel without prior approval from OLCV, and the modifications will be recorded in the field logbooks and laboratory reports. EPA will be notified of the modifications made in the submittal of regular project reports.

If major modifications which could affect the Project objectives are necessary, as determined by OLVC and/or contractors (e.g., change in sampling method for deep zone), OLVC immediately will notify the EPA UIC Director for approval before implementation.

The sampling contractors and selected laboratories will be responsible for implementing the corrective actions necessary to address the change in field and laboratory conditions while ensuring adherence to the Project protocols. Potential types of corrective action may include re-sampling by sampling technicians or re-injection/re-analysis of samples by the laboratory personnel. The corrective actions conducted will be recorded in the field logbook and laboratory reports.

2.4.3.4 Corrective Action Plans for Soil and Soil Gas

The corrective action plan for soil and soil gas sampling will follow the same procedures described for groundwater.

2.5 Quality Control (QC)

2.5.1 Field Quality Control Activities and Frequency

2.5.1.1 Field QC of Groundwater

In addition to the samples collected at the Project monitoring wells, QC samples will be collected. General practices regarding the QC protocol for groundwater sampling are summarized in the table below for each sampling zone (i.e., lowermost USDW, first permeable zone above the Upper Confining Zone, and Injection Zone). All QC samples will be placed on ice after collection and shipped to respective third-party laboratories under chain-of-custody control.

Table 23--Field QC of groundwater

QC Sample Type	Frequency
Field Duplicate	10% of the Primary Samples (minimum of 1 sample per field mobilization and sample zone)
Field Blank [1]	1 per sampling field mobilization
Equipment Blank [1]	1 per equipment or type of supplies, if non-dedicated equipment is used

[1]QC sample collected for the lowermost USDW monitoring program only.

<u>Field Duplicate</u>

A field duplicate sample will be collected at a frequency of one duplicate sample for every 10 samples, or, 10% of the primary samples. OLCV anticipates collecting one field duplicate sample for each sampling event and sampling zone. General precautions for collecting duplicate samples will be followed while sampling, including but not limited to alternating sample containers between the primary and duplicate samples if multiple containers are used. The duplicate samples will be analyzed for the same analytical parameters as the primary samples.

Field Blank

A field blank will be collected at a frequency of at least one field blank per field mobilization for sampling the USDW-level well. To collect the field blank sample, an open container of deionized water supplied by the laboratory will be placed near the monitoring well on the day of the field mobilization. At the end of the field mobilization, the water in the open container will be poured into a set of laboratory-supplied containers and immediately placed on ice for shipment to the laboratory under chain-of-custody control. OLCV anticipates collecting one field blank sample for each sampling event and the field blank sample will be analyzed for geochemical parameters only.

Equipment Blank

If additional USDW-level wells are constructed and non-dedicated equipment is used to collect groundwater samples, one equipment blank sample will be collected from at least one equipment type (sample pump) or type of supply (tubing). To prepare an equipment blank, the same decontamination procedures employed between sampling locations will be followed and a sample of deionized water provided by the laboratory will be run through the sample pump or tubing and collected in an appropriate sample container. OLCV anticipates collecting one equipment blank sample for each sampling event, if applicable, and the equipment blank sample will be analyzed for geochemical parameters only.

2.5.1.2 Field QC of Soil and Soil Gas

Field duplicate samples of soil and soil gas will be collected at a frequency of one duplicate sample for every 10 samples, or, 10% of the primary samples. General precautions for collecting duplicate samples will be followed while sampling, including but not limited to alternating sample containers between the primary and duplicate samples if multiple containers are used. The duplicate samples will be analyzed for the same analytical parameters as the primary samples for each sample medium.

2.5.1.3 Field QC of other samples collected

- Injectate sampling will be conducted by a third-party contractor in accordance with GPA 2177-20.
- Coupon testing will be performed by a third-party. OLCV will require an annual audit of the third-party contractor's retrieval procedures, coupon handling and transfer.
- Logging will be performed by a third-party contractor according to their SOP. The contractor will record information including: operating company; log type; well name; location and elevation; collection date; number of logging runs conducted; log depths; any environmental corrections that were performed; and, the name of the person who recorded

the log and a witness. Following data collection, log data are QCd in the office by the contractor.

- Gauges, on-line chromatographs, and geophysical data are collected in the field by a third-party contractor. Instrument QC and calibration is discussed in Section 2.7 of this document.

2.5.2 Laboratory or Office Quality Control Activities

- CO_2 injectate samples will be QCd in the laboratory by a third-party contractor according to that lab's procedures and in accordance with GPA 2177-20.
- For coupons, OLCV will require an annual audit of the third-party contractor's sample handling, sample analysis procedures, reporting, data management and reporting.
- Groundwater samples will be analyzed in the laboratory by a third-party contractor. The contractor will QC samples in the laboratory according to industry standard processes. Duplicates and blanks will be analyzed, in accordance with the contractors SOP. QC requirements are presented in Table 6.
- Soil and soil gas analysis will be conducted by a third-party contractor according to their SOP. QC requirements are presented in Table 6.
- Logging data will be QC'd in the office by the third-party contractor before being reviewed by the BRP team.
- Gas chromatograph data, gauge measurements, and optical cameras will be QC'd in the office by the BRP team.
- DInSAR, GPS, 2D VSP, 2D Surface seismic, and Seismicity data will be QC'd by third-party contractors in conjunction with qualified Oxy or OLCV personnel prior to being used for interpretations by the BRP Project team.

2.5.3 Control Limits and Corrective Action

- The specified composition is the control limit for the CO_2 injectate. Deviations in excess of the specified limit will result in repeat sampling. If the composition is confirmed to be out of specification, injection will be shut in until the injectate stream is restored to meet the specification.
- If corrosion rates of 0.1 mm/yr (4 mpy) and 0.2 mm/yr (8 mpy) pitting rate are exceeded, review of operating conditions for the past three months will be conducted to determine possible events that may have contributed to the increase in corrosion rates. This may result in increase in frequency of coupon retrieval to monthly. At 2 mm/yr corrosion rate (i.e., 0.5 mm in three months) in addition to increase in coupon retrieval frequency, inspection of equipment will be conducted.
- If the analytical results for groundwater samples collected from the BRP monitoring zones exceed the ion balances by ±10%, further examination of the analytical results will be conducted. This evaluation will include the ratio of the measured total dissolved solids (TDS) to the calculated TDS (i.e., mass balance) per APHA method (APHA, 1999). The

identification and evaluation of the suspected ion will be conducted in accordance with the APHA method. The results from the calculations will be compared to typical acceptance criteria, as well as historical data, if available. Potential corrective actions to address exceedance of control limits may include reanalyzing the suspected sample or suspected ion analytes, and potentially given less importance in data interpretations.

- For soil and soil gas, if sample analytical results do not fall within control limits set by the third-party laboratory, further examination of the results will be conducted and additional or repeat analyses may be conducted. The source of the deviation from control parameters will be determined before action is taken.
- Pressure Transmitters / Switch data inputs will be programmed within facility PLC to trigger an alarm if injection pressure is approaching Operation limits; and will trigger an automatic injection well shut in (through closing the actuated shutdown valve at the well head) if the injection pressure is approaching: 90% of fracture pressure, pipeline operating limits, or casing pressure limits.
- Gas chromatographs will be programmed to trigger an alarm if the composition exceeds the specification. If an alarm is triggered, OLCV Engineers will be alerted and the source of the problem will be investigated. In the case of minor system upsets, the composition is typically restored to specification within a few minutes. In cases where the source of the problem cannot be quickly determined and/or is not quickly restored to normal operating conditions, the injection well will be shut in until the injectate composition is restored to the specification.
- DAS/DAT, seismic, seismicity, DInSAR, GPS and surface monitoring cameras do not have control limits. The data obtained by these sources will be evaluated by the third-party contractor who collects the data.

2.5.4 Applicable QC Statistics

2.5.4.1 Applicable QC Statistics CO_2 Injectate Samples

CO_2 injectate sample composition analyzed by a third-party contractor will be evaluated for trends and compared with data from on-line gas chromatographs.

2.5.4.2 Applicable QC Statistics Coupons

Corrosion rate data to be trended and correlated to operating parameters to identify events that have contributed to change in corrosion rates.

2.5.4.3 Applicable QC Statistics Groundwater

Groundwater data quality validation will include a review of the concentration units, sample holding times, a review of the duplicates, blanks, and other results. Data will be entered into a database that will be periodically reviewed for trends.

The following statistical analyses will be used to evaluate the accuracy of the groundwater sample results. If any of these tests are not met, additional investigation will be conducted and corrective action will be taken, including re-analysis of questionable parameters.

Field Precision

Field precision objectives for target parameters are ±30% relative percent difference (RPD) between field duplicates and expressed by the following equation:

$$\mathrm{RPD}\ (\%) = \frac{|\mathrm{X}_1 - \mathrm{X}_2|}{(\mathrm{X}_1 + \mathrm{X}_2)/2} \times 100$$

Where: RPD (%) = relative percent difference
X_1 = Original sample concentration
X_2 = Duplicate sample concentration

Charge Balance

The analytical results for the lowermost USDW will be evaluated to determine the accuracy of the analyses based on anion-cation charge balance calculations (APHA, 1999). All potable waters are expected to be electrically neutral, so the anion-cation charge balance calculated using the following formula below should yield zero percent, as the ion sums are calculated in milliequivalents per liter (meq/L):

$$\%\ difference = 100 \times \frac{\sum cations - \sum anions}{\sum cations + \sum anions}$$

The criterion for acceptable charge balance is ±10% for the BRP.

Mass Balance

The ratio of the measured TDS to the calculated TDS will be calculated in instances where the charge balance acceptance criteria are exceeded using the following formula:

$$1.0 < \frac{Measured\ TDS}{Calculated\ TDS} < 1.2$$

Outliers

Outliers will be evaluated using EPA approved statistical tools before conducting additional statistical evaluation of the groundwater analytical results (EPA, 2009). These tools may include Probability Plots, Box Plots, and Dixon’s test.

2.5.4.4 Applicable QC Statistics Soil and Soil Gas

<u>Field Precision</u>

Field precision objectives for target parameters are ±30% RPD between field duplicates and expressed by the following equation:

$$\text{RPD (\%)} = \frac{|X_1 - X_2|}{(X_1 + X_2)/2} \times 100$$

Where: RPD (%) = relative percent difference
X_1 = Original sample concentration
X_2 = Duplicate sample concentration

If RPD objectives are not met for the soil and soil gas analytical parameters, additional investigation will be conducted and corrective action will be taken, including re-analysis of questionable parameters.

<u>Outliers</u>

Outliers will also be evaluated using USEPA approved statistical tools before conducting additional statistical evaluation of the groundwater analytical results (EPA, 2009). These tools may include Probability Plots, Box Plots, and Dixon's test.

2.5.4.5 Applicable QC Statistics for Other Data Types

- Log data, seismic data, seismicity data and InSAR will be QCd by the third-party vendor collecting the logs.
- Gauge, fiber and GPS measurements will QCd based on their measurement resolution.

2.6 Instrument/Equipment Testing, Inspection, and Maintenance

2.6.1 Instrument/Equipment Maintenance and Testing Plan and Schedule

2.6.1.1 Maintenance and Testing for CO_2 Injectate On-line Chromatographs

Maintenance and calibration of on-line gas chromatographs is conducted by a third-party contractor or the equipment vendor. These units are designed to require minimal routine maintenance and extend for months between calibration events.

2.6.1.2 Maintenance and Testing for Coupons

Access fittings maintenance are conducted during retrieval and replacement of coupons along with the retrieval tools are the responsibility of the third-party contractor.

2.6.1.3 Maintenance and Testing for Groundwater

Water quality sensors used to measure field parameters during groundwater sampling (i.e., pH, temperature, specific conductance, oxidation-reduction potential, turbidity, and dissolved oxygen) will be calibrated according to manufacturer recommendations and equipment manuals each day before sample collection begins. Recalibration is performed if any components yield atypical values or fail to stabilize during sampling. All calibrations will be documented in the field logbook and will include:

- Date/time of calibration,
- Name of person performing the calibration,
- Reference standard used,
- Temperature at which readings were taken, and
- Calibration readings, as appropriate.

The typical calibrations standards for water quality sensors are described in the table below. However, the water quality sensor vendor may require different calibration standards.

Table 24—Calibration standards for groundwater samples

Field Parameter	Typical Calibration Standard
pH	2-Point calibration: 4, 7, or 10 pH standard unit solutions
Specific conductance	1-Point calibration: 1,413 microsiemens per centimeter (µS/cm) at 25°C
Dissolved oxygen	1-Point calibration: 100% saturation
Oxidation-Reduction Potential	1-Point calibration: 223 mV Zobell solution at 25°C
Turbidity	1-Point calibration: 10 NTU

Sensor maintenance may also include factory-service, and factory-calibration per manufacturer's recommendations. If equipment is outside the calibration interval, the equipment will be placed out of service and replaced with similar equipment in proper working conditions.

For all laboratory equipment testing and maintenance will be the responsibility of the analytical laboratory per standard practices, method-specific protocols (i.e., SOPs), or accreditation agency (e.g., NELAP) requirements.

2.6.1.4 Maintenance and Testing for Soil and Soil Gas

For soil gas sampling, the portable field H_2S meter will be maintained, factory-serviced, and factory-calibrated per manufacturer's recommendations.

For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory per standard practices, SOPs, or accreditation agency requirements.

2.6.1.5 Maintenance and Testing for Logging

Logging equipment is maintained by the third-party contractor selected to conduct logging operations.

2.6.1.6 Maintenance and Testing for Gauges and Instruments

- Gauges are designed to require no routine maintenance. If anomalous downhole gauge results are recorded, the BRP team will determine the source of the anomaly. Downhole gauge measurements can be corroborated with gauges deployed via wireline. If a surface gauge is suspected to require maintenance, the BRP team will investigate the source of the potential error and contact the vendor for replacement parts, as needed. Based on operational experience, OLCV recognizes that the gauges may fail during normal use and may need to be replaced at some point during the injection period.
- Fiber does not require routine maintenance. If the fiber yields anomalous measurements or fails, the OLCV team will investigate the source of the apparent issue. If the fiber is damaged near the wellhead, it may be repairable. Downhole issues are generally not repairable. In the case of downhole fiber failure, OLCV will rely on installed gauge measurements for the remainder of the injection or monitoring period.
- GPS and DInSAR monuments will be maintained by the third-party vendor responsible for their installation. These instruments are designed to be deployed for decades with no/minimal maintenance.
- Seismometers that are part of the network for measuring passive seismicity do not require routine maintenance. In the event that a seismometer fails, a third-party operator will be contracted to replace or repair the device as needed. Because the BRP Project will have a network of passive seismic monitors, the temporary absence of one station will not impede the ability to monitor seismicity in the area.
- Surface optical cameras and CO_2 sensors are designed to require minimal maintenance. In the event that a sensor or camera fails, the vendor will be contacted to provide maintenance or replacements.

2.6.2 Description of Preventive Maintenance

- Maintenance of on-line gas chromatographs is conducted by a third-party contractor or the equipment vendor. These units are designed to require minimal routine maintenance.
- Access fittings and retrieval equipment for corrosion coupons must be kept clean, covered, and protected from dirt and the external environment by maintaining covers.
- The sampling contractor will be responsible for ensuring the water quality probes are stored in appropriate conditions and the sensors are maintained or replaced at regular intervals according to the manufacturer(s) recommendations, to make sure that the equipment remains in proper conditions (e.g., replace potassium chloride (KCl) solution and

membrane cap every 30 days for dissolved oxygen sensors). Laboratory personnel will be responsible for conducting the necessary preventative maintenance on their equipment in accordance with the analytical laboratory per standard practices, SOPs, or accreditation agency requirements.

- Soil gas stations are not anticipated to require routine maintenance. Stations will be inspected upon each sampling event. If a station requires maintenance or replacement, it will be conducted by a third-party contractor. The sampling contractor will be responsible for ensuring the H_2S meter is stored in appropriate conditions and the sensors are maintained or replaced at regular intervals according to the manufacturer(s) recommendations, to make sure that the equipment remains in proper conditions. Laboratory personnel will be responsible for conducting the necessary preventative maintenance on their equipment in accordance with the analytical laboratory per standard practices, SOPs, or accreditation agency requirements.
- Logging equipment will be maintained by the third-party contractor responsible for logging.
- Downhole and surface gauges are designed to require minimal maintenance. If maintenance is required on surface gauges, OLCV field personnel will inspect the equipment to determine whether it can be fixed in the field. If the equipment cannot be fixed in the field, the equipment vendor will be contacted to provide a repair or replacement. Downhole gauges will be repaired or replaced by a third-party contractor.
- Fiber does not require routine maintenance. If fiber data is anomalous, the OLCV team will visually inspect the fiber connections at the wellhead. If maintenance at the wellhead is required, a fiber vendor or third-party contractor will be contacted to provide the service.
- Passive seismic monitoring stations do not require routine maintenance. If a station fails or yields anomalous data a third-party contractor will be contacted to make an inspection of the station and perform a repair or replacement, if necessary.
- GPS stations do not require routine maintenance. If a station fails or yields anomalous data a third-party contractor will be contacted to make an inspection of the station and perform a repair or replacement, if necessary.
- Seismic and DInSAR equipment will be maintained by the third-party contractor responsible for acquiring those data.
- Surface monitoring optical cameras and surface sensors require minimal routine maintenance. This equipment will be inspected on a weekly basis by OLCV staff or contractors. If maintenance is needed, the field team will conduct the maintenance or contact a third-party contractor.

2.6.3 Critical Spares

2.6.3.1 Critical Spares for CO_2 Injectate On-line Gas Chromatographs

- If the on-line gas chromatograph fails, a portable chromatograph can be deployed, or a will be replaced as soon as is feasible. Increased frequency of sampling for laboratory analysis will be conducted if the on-line gas chromatograph is unavailable.
- Critical spares are not applicable to coupons. Coupons will be provided by the third-party contractor as part of their retrieval contract.
- Spare equipment for groundwater sampling and monitoring will be provided by the third-party laboratory responsible for conducing the sampling and analyses. Those key equipment include but are not limited to sample containers in proper condition, calibration solutions for water quality sensors, sampling pump parts that require regular replacement (e.g., O-rings), compressed gas (e.g., nitrogen) for bladder pumps and decontamination solutions. The laboratory will be responsible for ensuring that the critical spares are available to conduct necessary maintenance in order to avoid erroneous results or project delays.
- Spare equipment for soil and soil gas sampling and monitoring will be provided by the third-party laboratory responsible for conducing the sampling and analyses. Those key equipments include, but are not limited to sample containers in proper condition, sampling equipment (e.g., 60 mL gas-tight syringes and 3-way valves), helium gas as a tracer. The laboratory will be responsible for ensuring that the critical spares are available to conduct necessary maintenance in order to avoid erroneous results or project delays.
- In the event that a downhole gauge fails, surface gauges or fiber measurements will be used to collect continuous monitoring data until a replacement gauge can be installed. In the event that a surface gauge fails, a gauge can be sourced and replaced in a few days. During this time, the injection well will be shut in.
- It is not possible to have spare fiber. If fiber fails near the wellhead, it may be possible to conduct a repair. Fiber that fails downhole is not possible to repair. In the event that downhole fiber fails, gauge measurements will be used to provide continuous reporting of operational parameters.
- The logging operator is responsible for spare logging tools.
- Passive GPS and seismometer stations are expected to operate for years without maintenance or failure. If one station does fail, the seismicity will continue to be monitored by the remaining seismometer network until the station can be repaired for replaced.
- The third-party companies responsible for acquiring seismic and DInSAR data are responsible for spare equipment.
- Surface monitoring CO_2 detectors and optical cameras provide complimentary information to downhole gauge and fiber measurements. In the event that a CO_2 detector or camera fails, the downhole gauge and fiber will continue to provide information on mechanical integrity, until the surface equipment can be repaired or replaced.

2.6.4 Re-inspection and Effectiveness of Corrective Actions

- CO_2 injectate samples may be re-collected for duplicate analyses. If the injectate stream is found to be off-specification, injection wells will be shut in until samples meet the specification. Re-inspection is not applicable to on-line gas chromatographs.
- Re-inspection is not applicable to coupons.
- Equipment and materials used for collecting groundwater samples will be inspected at the beginning of each sampling day to ensure their adequate working conditions. Equipment or materials found to be defective will be removed from service and replaced with brand-new items of similar effectiveness. If equipment or materials are suspected of becoming compromised during sampling activities, the sampling contractors will re-inspect the equipment or materials in question. After inspection, corrective actions may be necessary to address the defective items, including re-calibration or replacement. The sampling technicians will continue to monitor the conditions of the recalibrated or replacement item to ensure that the implemented corrective actions were successful in addressing the issues.
    - Laboratory personnel will be responsible for re-inspecting their instruments and evaluating the effectiveness of any corrective actions taken to amend or replace defective parts. If instrument deficiencies are suspected to affect the quality of the data, the laboratory personnel will reanalyze the affected samples.
    - Re-inspection on groundwater samples may be conducted if data is anomalous. If re-sampling is determined to be appropriate, it will be conducted as quickly as is feasible. Other monitoring methods, including gauges, fiber and surface CO_2 monitors and cameras will be utilized to provide plume monitoring in the interim.
- Soil gas sampling equipment and materials (e.g., 60 mL gas-tight syringes, 3-way valves, laboratory provided sample containers) will be inspected at the beginning of each sampling day to ensure their adequate working conditions. If equipment or materials are suspected of becoming compromised during sampling activities, the sampling contractors will replace them with a similar item in proper working conditions.
    - Laboratory personnel will be responsible for re-inspecting their instruments and evaluating the effectiveness of any corrective actions taken to amend or replace defective parts. If instrument deficiencies are suspected to affect the quality of the data, the laboratory personnel will reanalyze the affected samples.
    - Soil gas may be re-sampled if data is anomalous. If re-sampling is determined to be appropriate, it will be conducted as quickly as is feasible. Other monitoring methods, including gauges, fiber and surface CO_2 monitors and cameras will be utilized to provide plume monitoring in the interim.
- Re-inspection is not applicable to gauges. If gauge data is determined to be anomalous, wireline deployed gauges may be used to provide a comparison, or the results will be compared to fiber data.

- If log data is determined to be anomalous, alternative logging tools may be run and/or another vendor may be used so that results could be compared.
- Re-inspection is not applicable to seismic data, seismicity data, DInSAR, surface monitors or surface cameras.

2.7 Instrument Calibration, Frequency and Methodology

2.7.1 Instruments to be Calibrated

- On-line gas chromatographs will be calibrated at by the equipment vendor at the frequency specified by the manufacturer. Laboratory sampling equipment will be calibrated by the third-party laboratory.
- Instrument calibration is not applicable to coupons.
- Water quality sensors used to measure field parameters during groundwater sampling (i.e., pH, temperature, specific conductance, oxidation-reduction potential, turbidity, and dissolved oxygen) will be calibrated according to manufacturer recommended schedules by sampling personnel each day before sample collection begins or factory-calibrated as needed.
- Laboratory equipment for analyzing water and dissolved gas will be tested inspected, and maintained by the analytical laboratory responsible for the work. Calibration will be conducted at schedules determined by equipment manufacturer, standard practices, SOPs, or accreditation agency requirements.
- Soil gas samples will be analyzed by a third-party laboratory. For all laboratory equipment, testing, inspection, and maintenance will be the responsibility of the analytical laboratory and will be conducted at schedules determined by equipment manufacturer, standard practices, SOPs, or accreditation agency requirements.
- Logging equipment is calibrated by the logging vendor.
- Gauges are calibrated by the vendor on a frequency specified by the manufacturer.
- Fiber does not require routine calibration
- Seismometers, VSP and DInSAR instrumentation will be collected by a third-party vendor and instrumentation used to collect these data will be performed by the vendor.
- Surface CO_2 monitors and optical cameras will be calibrated by the vendor according to the frequency and methodology specified by the manufacturer.

2.7.2 Maintaining and Tracking Calibration Records

Records will be archived for the life of the Project and maintained in an accessible database.

- Calibration records for equipment used during groundwater sampling, as well as any deviation, will be kept in field logbooks by sampling contractor. Corrective actions implemented to resolve any discrepancies will also be recorded.

- The laboratory will be responsible for maintaining records of their calibration records in compliance with standard practices, SOPs, or accreditation agency requirements. The laboratory may provide applicable certifications of instrument calibration to OLCV upon request.
- Field calibration records are not anticipated for soil and soil gas sampling. However, should any field instrument be used for collecting measurements, the sampling contractors will record the calibration results in the field logbooks, as well as any deviations.
- The laboratory will be responsible for maintaining records of their calibration records in compliance with standard practices, SOPs, or accreditation agency requirements. The laboratory may provide applicable certifications of instrument calibration to OLCV upon request.

2.8 Inspection/Acceptance of Supplies and Consumables

2.8.1 List of Supplies and Consumables, Acceptance Criteria, Responsibility

- The vendor for the on-line gas chromatograph or the laboratory conducting the analyses will maintain spare parts, supplies and consumables.
- The third-party contractor conducting coupons must maintain spare parts for the retrieval tools and coupons to allow for immediate coupon retrieval upon call.
- The third-party contractor for groundwater sampling and analysis must maintain spare sampling equipment and analysis instrumentation. Samples will be collected in method-specified containers, with appropriate preservatives, supplied and certified contaminant-free by the laboratory. Sample containers with appropriate preservatives will be inspected by field crew for breakage and proper sealing of caps. Other sampling equipment/supplies (e.g., sample coolers, tubing etc.) and field measurement supplies (e.g., calibration solutions) will also be inspected before use by field personnel for damage and proper seals. Defective supplies and equipment will be discarded and replaced.
- The third-party contractor responsible for installing and maintaining soil gas sampling equipment, logging equipment, gauges, seismometers, VSP, DInSAR, surface monitors and surface cameras will be responsible for inspecting and accepting consumables.
- There are no supplies and consumables for fiber following the installation.

2.9 Non-direct Measurements

2.9.1 Sources and Description of Non-direct Data

Indirect geophysical monitoring techniques including DInSAR, 2D VSP and 2D surface seismic will be used to monitor the CO_2 plume and pressure front. In addition, saturation logging data, temperature gauge data, and DTS data from selected monitoring wells will be used to constrain movement of the plume.

The interpretation of indirect monitoring methods requires a pre-injection baseline. OLCV plans to collect baseline data on DInSAR, VSP and saturation logging prior to injection. Gauges and DTS will also be installed, and data will be collected prior to commencement of injection.

2.9.2 Acceptance Criteria of Non-direct Data

Geophysical and logging data will be collected by third-party vendors using practices that are accepted by the industry. The third-party operator will perform QA checks before, during, and after data acquisition. Data will also be checked by the geophysical processing vendor and further checked by qualified OLCV geophysicists.

2.10 Data Management

2.10.1 Data Management Scheme

OLCV will maintain required Project data using a custom-designed data management system involving state-of-the art cloud storage solutions. Data will be maintained for the required duration of the project.

2.10.2 Recordkeeping and Tracking Practices

BRP Project data will be categorized with appropriate metadata for future tracking and retrieval. The data will be securely stored using cloud-based services that were specifically designed to meet the needs of the BRP Project.

2.10.3 Data Handling Equipment and Procedures

Gauge, fiber, on-line gas chromatograph and other instrument-derived field data collected at the BRP site will be transmitted to a control room staffed by Oxy and OLCV personnel. A fiberoptic network will be installed to transmit high-density data from CO_2 Injector wells and some monitoring wells. Other monitoring wells that are expected to have a lower density of data will utilize wireless transmission. OLCV will implement a Supervisory Control and Data Acquisition (SCADA) system to collect data and support monitoring. For events that require maintenance or remediation, tickets will be created to track the progress of action to completion.

Data that is collected and processed or analyzed by third-party vendors, such as fluid and soil gas analyses, VSP, and DInSAR will be delivered to OLVC's office location for interpretation by integration by OLCV or Oxy geologists and engineers.

2.10.4 Responsibility

The BRP Project Manager will be responsible for ensuring that proper data management is maintained. The Project Manager will utilize third-party contractors, OLCV and Oxy Information Technology support staff, as needed.

2.10.5 Data Archival and Retrieval

Data will be securely stored and archived on cloud-based systems. Metadata will be used to categorize the data for future retrieval. These data will be retrievable from the digital repositories.

2.10.6 Hardware and Software Configurations

BRP will ensure that hardware and software are compatible between office and field locations.

2.10.7 Checklists and Forms

Checklists or forms will be generated, if needed, to audit data storage and retrievability.

3. Assessment and Oversight

3.1 Assessment and Response Actions

3.1.1 Activities to be Conducted

The testing and monitoring activities will be conducted at a frequency outlined in Table 2 of this document. The data resulting from these activities will be evaluated by OLCV or Oxy geologists and engineers. Data will be integrated, as appropriate, into updates of the AoR and shared with the EPA Class VI Administrator, as needed.

3.1.2 Responsibility for Conducting Assessments

Internal assessments of data will be conducted by the department responsible for evaluating and interpreted those data. For example, petrophysicists and geologists will evaluate log data, geophysicists will evaluate VSP and passive seismic data. Field instrumentation analysists will evaluate gauge and on-line chromatography data.

3.1.3 Assessment Reporting

Assessment data will be reported, as required.

3.1.4 Data Corrections

Corrections that may impact multiple teams or functions will be communicated to those functions. Corrective actions impacting multiple teams or functions will be shared with appropriate personnel. The BRP Project Manager is responsible for ensuring that information on data corrections is distributed to those who need the information.

3.2 Reports to Management

3.2.1 Status Reports

QA status reports are not required unless there are significant adjustments to the methods and procedures described in this document. If the QA process is substantially changed, the revisions will be discussed with the UIC Program Director and distributed to relevant parties.

4. Data Validity and Useability

4.1 Data Review, Verification and Validation

4.1.1 Criteria for Accepting, Rejecting, or Qualifying Data

Validations of data will include a review of concentration units, sample holding times, and a review of duplicate, blank and other QA/QC results. Laboratory results will be retained for the life of the Project and reported according to the requirements for the Permit. Reports will present data in a graphical or tabular format, as appropriate to characterize the specific component being analyzed. After sufficient data have been collected, additional methods, such as those described in the US EPA 2009 Unified Guidance (EPA 2009), will be used to examine intrawell variations for groundwater constituents to assess whether significant changes have occurred that could be the result of CO_2 or brine seepage into the storage reservoir.

4.2 Verification and Validation Methods

4.2.1 Data Verification and Validation Process

Verification will include a review of documentation to confirm the location, date, data type and other identifying information. Oxy and OLCV geologists and engineers will utilize decades of industry experience to interpret the data and integrate the data into updated subsurface characterization and simulation modelling.

4.2.2 Data Verification and Validation Responsibility

Third-party contractors who are responsible for collecting and analyzing data are responsible for verification and validation. Data collected in the field from gauges, DTS and on-line gas chromatography will be verified and validated by Field Leads.

4.2.3 Checklist, Forms, and Calculations

If needed to meet permit requirements, checklists and forms will be designed to collect and report the required data.

4.3 Reconciliation with User Requirements

4.3.1 Evaluation of Data Uncertainty

OLVC or designated contractors will use statistical tools consistent with EPA guidelines (EPA, 2009) to provide data uncertainty, if applicable. The evaluation and reporting of the generated data to EPA will describe and quantify those uncertainties

4.3.2 Data Limitations Reporting

Each function will be responsible for ensuring that the data presented in their interpretation or analyses are appropriately used. OLCV will comply with Class VI Permit guidance on use, sharing, and presentation of data. OLCV will use the operating procedures described in this document for utilizing, sharing, and presenting results and/or data for the BRP Project. The procedures have been developed to ensure quality and internal consistency and facilitate tracking and record keeping of data end users and associated publications and reporting, as well as compliance with 40 CFR §146.90(h).

5.0 References

APHA, 1999, Standard Methods for the Examination of Water and Wastewater, American Public Health Association, Washington, DC.

EPA, 2009. Statistical Analysis of Groundwater Monitoring Data at RCRA Facilities, Unified Guidance. EPA Office of Resource Conservation and Recovery – Program Implementation and Information Division. EPA 530/R-09-007. March 2009.

EPA, 2023a. Groundwater Sampling: LSASDPROC-301-R6. Region 4 U.S. Environmental Protection Agency Laboratory Services and Applied Science Division, Athens, Georgia, 22 April 2023.

EPA, 2023b. Soil Gas Sampling: LSASDPROC-307-R5. Region 4 U.S. Environmental Protection Agency Laboratory Services and Applied Science Division, Athens, Georgia, 22 April 2023.

EPA, 2023c. Soil Sampling: LSASDPROC-300-R5. Region 4 U.S. Environmental Protection Agency Laboratory Services and Applied Science Division, Athens, Georgia, 22 April 2023.

Yeskis, D., and Zavala, B, 2002. Ground-Water Sampling Guidelines for Superfund and RCRA Project Managers: Groundwater Forum Issue Paper, Technology Innovative Office of Solid Waste and Emergency Response, US EPA, Washington, DC

INJECTION WELL PLUGGING PLAN
40 CFR §146.92(b)

Brown Pelican CO_2 Sequestration Project

INJECTION WELL PLUGGING PLAN 40 CFR §146.92(b) 1
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1.0 Facility Information and Overview

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS1, CCS2 and CCS3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

Oxy Low Carbon Ventures, LLC (OLCV) will conduct injection well plugging and abandonment (P&A) according to the procedures contained in this document.

The injection wells will be plugged and abandoned in accordance with the requirements of Environmental Protection Agency (EPA) document 40 CFR Subpart H – Criteria and Standards Applicable to Class VI Wells. The plugging procedure and materials will be designed to prevent any unwanted fluid movement, resist the corrosive aspects of carbon dioxide (CO_2) with water mixtures, and protect any underground sources of drinking water (USDWs).

Plugging procedures for CO_2 Injection wells are presented in this document. Plugging plans for monitoring and water withdrawal wells are presented in Appendix A of this document.

2.0 CO_2 Injection Wells

2.1 Planned Tests or Measures to Determine Bottomhole Reservoir Pressure

1. After injection has ceased, the well will be flushed with a kill fluid. A minimum of three tubing volumes will be injected without exceeding the fracture pressure. All kill fluids that will be pumped will be 10 ppg NaCl brine.
2. Bottomhole pressure measurements will be taken using the installed downhole gauges. In case the gauges are not functioning properly, the operator will run a pressure gauge during the P&A process of the well.
3. A Temperature log will be run, and the well will be pressure tested to ensure integrity both inside and outside the casing before plugging. Production Logging Tool (PLT), tracers, and noise or active pulsed neutron logs could be run in substitution.
4. If a loss of mechanical integrity is discovered, the well will be repaired before proceeding further with the plugging operations.
5. All casing in this well will have been cemented to the surface at the time of construction and will not be retrievable at abandonment.
6. After injection is terminated permanently, the injection tubing and packer will be removed.
7. The balanced-plug placement method will be used to plug the well. A cement retainer will be used to isolate the perforated section and prevent flowback of formation fluids that could contaminate the plug.
8. All of the casing strings will be cut off at least 5 ft below the surface and plow line.
9. A blanking plate with the required permit information will be welded on top of the cutoff casing.

Any necessary revisions to the well plugging plan to address any new information collected during logging, testing, and completion of the well will be made after these activities have been completed. The final plugging plan will be submitted to the Underground Injection Control (UIC) Program Director.

2.2 Planned Mechanical Integrity Test(s)

OLCV will conduct a temperature log and potentially additional logs listed in Table 1 and a pressure test to verify mechanical integrity before plugging the injection well, as required by 40 CFR §146.92(a).

Table 1—Planned and Possible Mechanical Integrity Tests

Test Description	Location
Temperature log (External MIT)	Injection wells and monitoring wells
Pulsed neutron log (External MIT)	Injection wells and monitoring wells
Noise log (External MIT)	Injection wells and monitoring wells
Annular Pressure Test (Internal)	Injection wells and monitoring wells

The following tools are able to detect fluid movements behind the long string casing. Tools will be run on wireline. Quality assurance for the logs will be provided by the vendor at time of selection.

Temperature logs are used to locate gas entries, detect casing leaks, and evaluate fluid movement behind casing. They are also used to detect lost-circulation zones and cement placement. Temperature logs are used as a basic diagnostic tool and are usually paired with other tools like acoustics or multi arms calipers if more in depth analysis is required.

Temperature instruments used today are based on elements with resistances that vary with temperature. The variable resistance element is connected with bridge circuitry or constant current circuit, so that a voltage response proportional to temperature is obtained. The voltage signal from temperature device is then usually converted to a frequency signal transmitted to the surface, where it is converted back to a voltage signal and recorded. The absolute accuracy of temperature logging instruments is not high (in the order of +- 5°F), but the resolution is good (0.05°F) or better, although this accuracy can be compromised by present day digitalization of the signal on the surface. The temperature instrument usually can be included in the string with other tools, such as radioactive tracer tools or spinners flowmeters. Temperature logs are run continuously, typically at cable speeds of 20 to 30 ft/min.

The following tools could be run in substitution of temperature log. They follow the same principle of detection of anomalies outside the injection zone.

Pulse neutron log (PNL) provides formation evaluation and reservoir monitoring in cased holes. PNL is deployed as a wireline logging tool with an electronic pulsed neutron source and one or more detectors that typically measure neutrons or gamma rays. High-speed digital signal electronics process the gamma ray response and its time of arrival relative to the start of the neutron pulse. Spectral analysis algorithms translate the gamma ray energy and time relationship into concentrations of elements. Each logging company has its own proprietary designs and improvements on the tool.

Schlumberger's Pulsar Multifunction Spectroscopy Service (PNX) pairs multiple detectors with a high output pulsed neutron generator in a slim tool with an outer diameter (o.d.) of 1.72 in. for through-tubing access in cased hole environments. The housing is corrosion-resistant, allowing deployment in wellbore environments such as CO_2. The tool's integration of the high neutron output and fast detection of gamma rays with proprietary pulse processing electronics, allows to differentiate and quantify gas-filled porosity from liquid-filled and tight zones. The tool can accurately determine saturation in any formation water salinity across a wide range of well conditions, mineralogy, lithology, and fluid contents profile at any inclination. Detection limits for CO_2 saturation for the PNX tool vary with the logging speed as well as the formation porosity. Detailed measurement and mechanical specifications for the PNX tool are provided in the QASP document. The wireline operator will provide QA/QC procedures and tool calibration for their equipment.

Haliburton's RMT-D reservoir monitor tool: The Halliburton Reservoir Monitor Tool 3-Detector™ (RMT-3D™) pulsed-neutron tool solves for water, oil, and gas saturations within reservoirs using three independent measurements (Sigma, C/O, and SATG). This provides the ability to uniquely solve simple or complex saturation profiles in reservoirs, while eliminating phase-saturation interdependency. The RMT-#D provides gas phase analysis to identify natural gases, nitrogen, CO_2, steam, and air. The tool has 2.125 in diameter OD that allows it to be run through tubing.

Pass/Fail Criteria

Well Plugging is considered pass when it meets the objective of minimizing the chance of leak of fluid to USDW.

Temperature Survey

The temperature log is one of the approved logs for detecting fluid movement outside pipe. A final differential temperature survey will be run during plugging operations and will provide a final temperature curve.

The temperature will be logged down from the surface to total depth in the well. Recommended line speed for the logging operations is 20 to 30 ft/min. In general, the procedure for wireline operations will be as follows:

1. Attach a temperature probe and casing collar locator (CCL) to the wireline.
2. Begin the temperature survey. The tools will be lowered into well at 20 to 30 feet/minute, recording temperature in wellbore. The temperature survey will be run to the deepest attainable depth in the wellbore.
3. Following completion of the survey, the wireline tools will be retrieved from the wellbore.
4. A successful temperature log will “PASS” if there are no observed, unexplained anomalies outside of the permitted injection zone.
5. If temperature anomalies are observed outside of the permitted zone, additional logging may be conducted to determine whether a loss of mechanical integrity or containment has occurred. Depending on the nature of the suspected movement, radioactive tracer, noise, oxygen activation, or other logs approved by the UIC Program Director may be required to further define the nature of the fluid movement or to diagnose a potential leak.

Pressure Test

After setting the initial plug across the well completion interval / perforation, an annular pressure test (APT) will be conducted to verify internal mechanical integrity. The APT is a short-term pressure test (30 minutes) where the well is shut in and the fluid in the annulus is pressurized to a predetermined pressure and is monitored for leak off. BRP will use a test pressure of 500 psi for the Mechanical Integrity Test. BRP will use a 5% decrease in pressure (test pressure x .05) from the stabilized test pressure during the duration of the test to determine if test is successful. If the annulus pressure decreases by ≥5%, the well will have failed the APT. If a well fails an APT, the test will be repeated. If the APT is again failed, the downhole equipment will be removed from the well and the source of the failure will be investigated. In general, the test procedure will be as follows:

1. Connect a high-resolution pressure transducer to the annulus casing valve and increase the annulus pressure to 500 psi and hold this pressure for 30 minutes.
2. At the conclusion of the 30-minute test the annulus pressure will be bled off to 0 psi and the pressure recording equipment will be removed from the casing valve.

Note: If a failure in the long string casing is identified, the operator will prepare a plan to repair the well before plugging and abandonment

2.3 Information on Plugs

OLCV will use the materials and methods noted in Table 2, Table 3, and Table 4 to plug the Injection wells. The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction.

The cement(s) formulated for plugging will be compatible with CO_2. Discussion about CO_2 resistant cement selection and additive is located in the Construction Plan – Appendix B. The cement formulation and required certification documents will be submitted to the agency along with the well plugging plan. OLCV will report the wet density and will retain duplicate samples of the cement used for each plug. In plugging procedures in Section 3.0, curing time for CO_2 resistant cement is assumed to be 4 hours. The curing time for the CO_2 resistant plugs will be determined at time of operation via laboratory testing in compliance with API 10B2 (Testing of Oilwell Cements). OLCV utilizes industry recognized thresholds of 50 psi compressive strength to pressure test and 500 psi compressive strength for physically tagging. 500 psi (or greater) compressive strength will be achieved for abandonment slurries and will be reached in < 48 hours after placement. All plug mud will be 9.5-10 ppg NaCl brine with lime added at 1.0 ppb (pound per barrel) to raise the PH to >10.5 to combat corrosion, H_2S and CO_2 contamination. Xanthan gel will be added to the mud so that the viscosity is > 50 sec/qt.

Table 2—Information on Cement Plugs for BRP CCS1

Plug No.	Placement Method	Type Slurry	ID (in.)	MD Depths (ft)	Density (ppg)	Sacks	bbl
1	Squeeze plug	CO_2-resistant cement	4.892	4,624 to 5,667	14.8	246	58
2	Balance plug	CO_2-resistant cement	4.892	4,524 to 4,624	14.8	12	3
3	Balance plug	CO_2-resistant cement	4.892	4,000 to 4,200	14.8	24	6
4	Balance plug	CO_2-resistant cement	4.892	3,750 to 3,950	14.8	24	6
5	Balance plug	CO_2-resistant cement	4.892	2,700 to 2,800	14.8	12	3
6	Balance plug	CO_2-resistant cement	4.892	1,750 to 1,850	14.8	12	3
7	Balance plug	CO_2-resistant cement	4.892	791 to 891	14.8	12	3
8	Balance plug	CO_2-resistant cement	4.892	0 to 475	14.8	56	13

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by EPA and Texas regulators.
- Formation tops will be adjusted after running openhole electric logs.

Table 3—Information on Cement Plugs for BRP CCS2

Plug No.	Placement Method	Type Slurry	ID (in.)	MD Depths (ft)	Density (ppg)	Sacks	bbl
1	Squeeze plug	CO_2-resistant cement	4.892	4,450 to 5,768	14.8	326	77
2	Balance plug	CO_2-resistant cement	4.892	4,350 to 4,450	14.8	12	3
3	Balance plug	CO_2-resistant cement	4.892	4,000 to 4,200	14.8	24	6
4	Balance plug	CO_2-resistant cement	4.892	3,750 to 3,950	14.8	24	6
5	Balance plug	CO_2-resistant cement	4.892	2,700 to 2,800	14.8	12	3
6	Balance plug	CO_2-resistant cement	4.892	1,750 to 1,850	14.8	12	3
7	Balance plug	CO_2-resistant cement	4.892	792 to 892	14.8	12	3
8	Balance plug	CO_2-resistant cement	4.892	0 to 475	14.8	56	13

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by EPA and Texas regulators.
- Formation tops will be adjusted after running open hole electric logs.

Table 4—Information on Cement Plugs for BRP CCS3

Plug No.	Placement Method	Type Slurry	ID (in.)	MD Depths (ft)	Density (ppg)	Sacks	bbl
1	Squeeze plug	CO_2-resistant cement	4.892	4,900 to 6,006	14.8	268	63
2	Balance plug	CO_2-resistant cement	4.892	4,800 to 4,900	14.8	12	3
3	Balance plug	CO_2-resistant cement	4.892	4,182 to 4,382	14.8	24	6
4	Balance plug	CO_2-resistant cement	4.892	3,700 to 3,900	14.8	24	6
5	Balance plug	CO_2-resistant cement	4.892	2,737 to 2,837	14.8	12	3
6	Balance plug	CO_2-resistant cement	4.892	1,750 to 1,850	14.8	12	3
7	Balance plug	CO_2-resistant cement	4.892	767 to 867	14.8	12	3
8	Balance plug	CO_2-resistant cement	4.892	0 to 475	14.8	56	13

Notes:

- All plug depths will be adjusted after the well is drilled and completed.
- The plugging procedure will be updated as required by EPA and Texas regulators.
- Formation tops will be adjusted after running open hole electric logs.

2.4 Plugging Schematics

The proposed plugging schematic for BRP CCS1 is shown in Figure 1, the proposed plugging schematic for BRP CCS2 is shown in Figure 2 and the plugging schematic for BRP CCS3 is shown in Figure 3. A sample EPA Plugging and Abandonment Plan form is found in Figure 4.

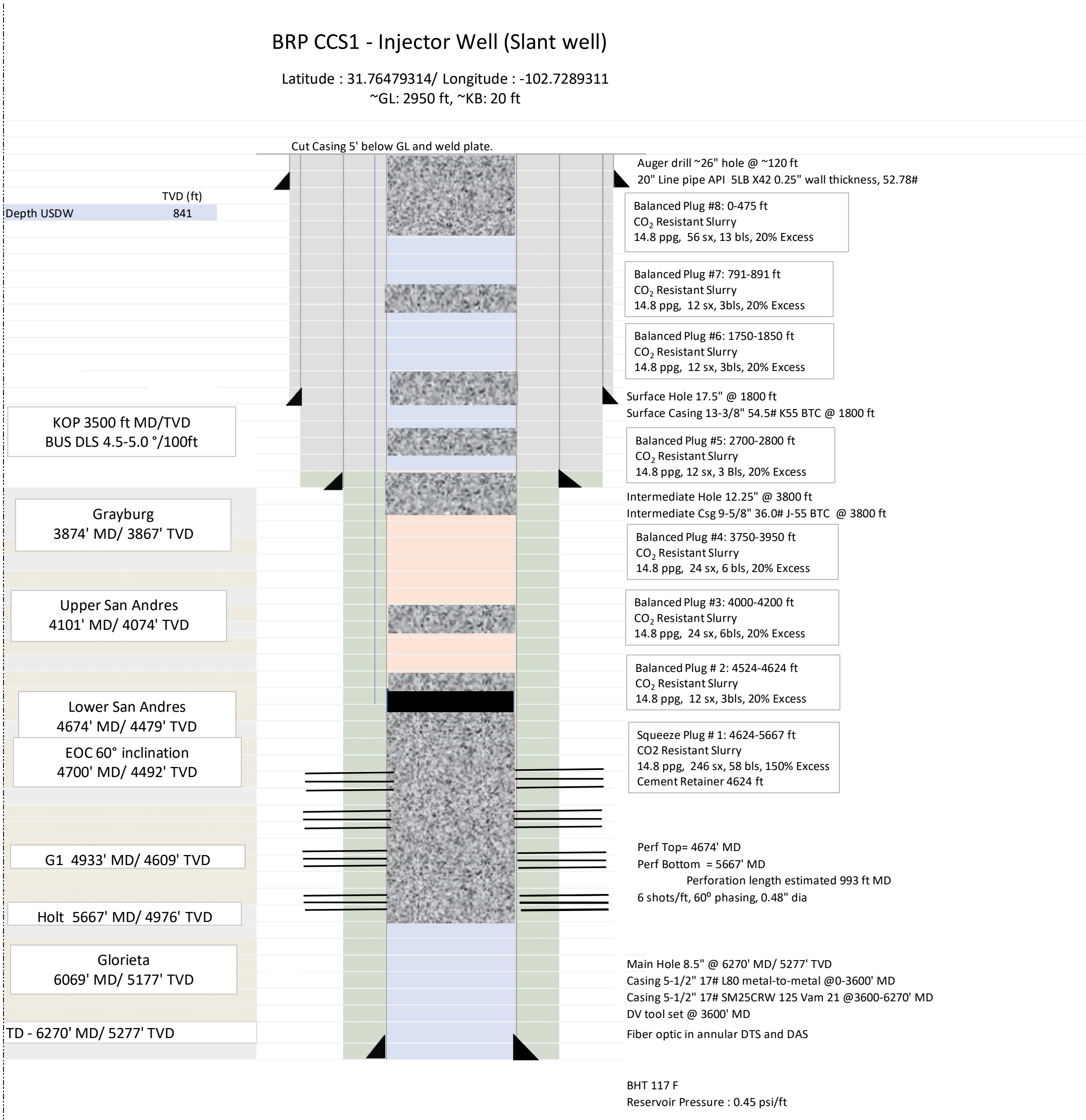

Figure 1—BRP CCS1 injection well plugging schematic

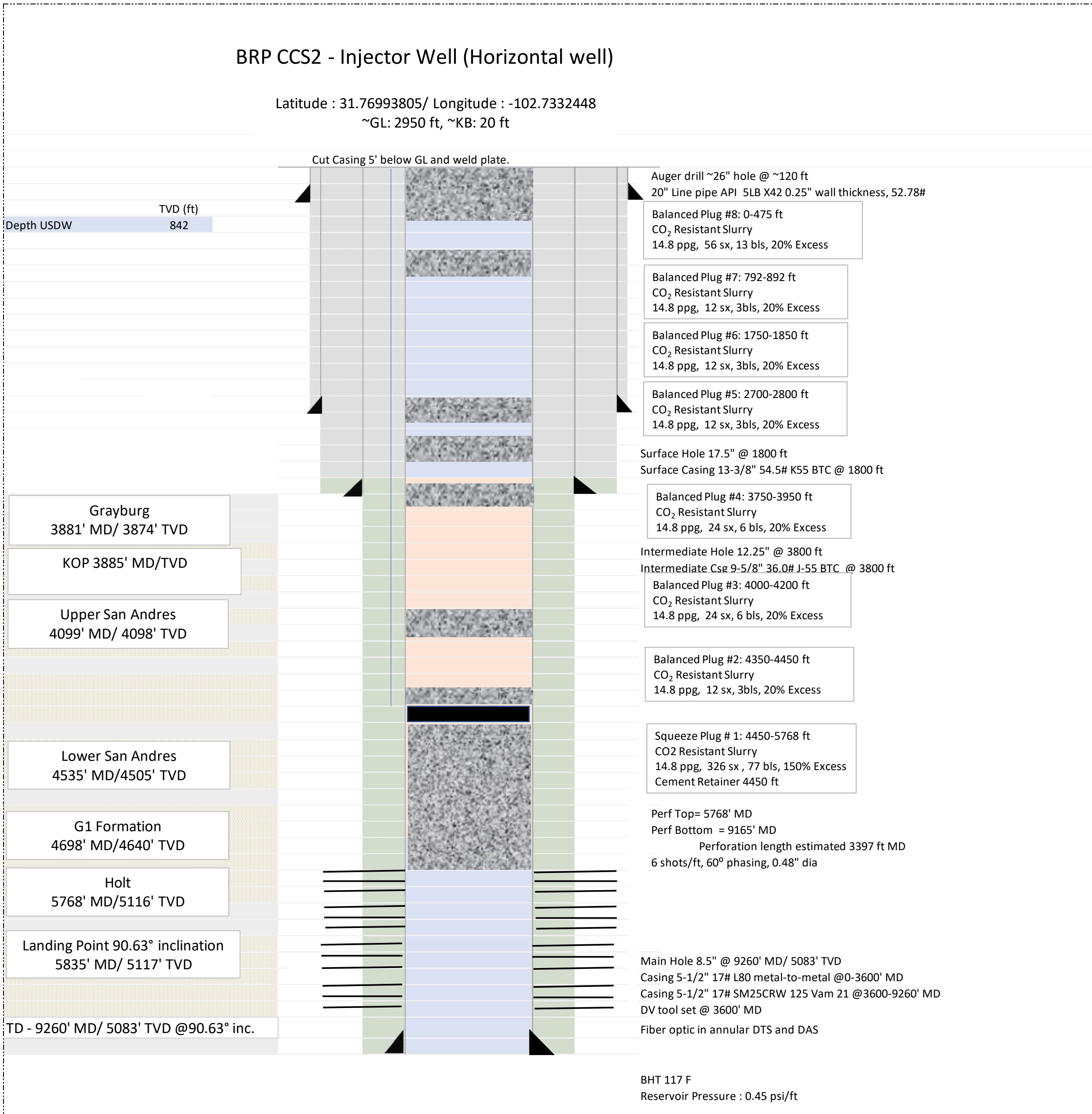

Figure 2—BRP CCS2 injection well plugging schematic

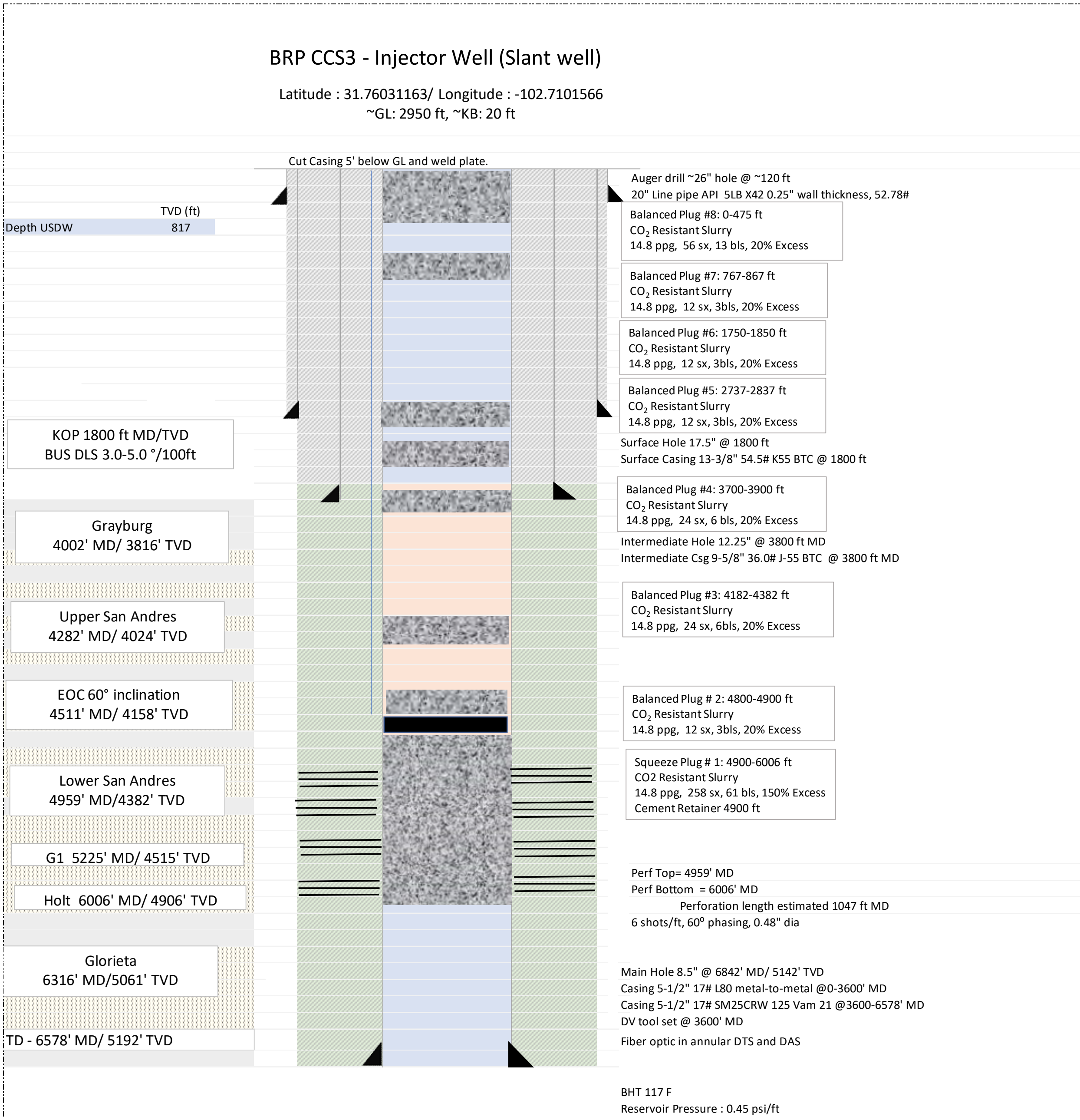

Figure 3—BRP CCS3 injection well plugging schematic

OMB No. 2040-0042 Approval Expires 11/30/2014

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility
Morgan County Class VI UIC Well #1
(cased well completion, 1,500 ft lateral) [address not yet available]

Name and Address of Owner/Operator
FutureGen Alliance, Inc.
73 Central Park Plaza East, Jacksonville, IL 62650

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W E

X

S

State	County	Permit Number
Illinois	Morgan	not yet issued

Surface Location Description
SE 1/4 of SE 1/4 of SW 1/4 of SE 1/4 of Section 26 Township 16N Range 9W

Locate well in two directions from nearest lines of quarter section and drilling unit
Surface Location ___ ft. frm (N/S) ___ Line of quarter section
and ___ ft. from (E/W) ___ Line of quarter section.

TYPE OF AUTHORIZATION
- [x] Individual Permit
- [ ] Area Permit
- [ ] Rule

Number of Wells 1

WELL ACTIVITY
- [ ] CLASS I
- [ ] CLASS II
  - [ ] Brine Disposal
  - [ ] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Lease Name

Well Number

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
24"	140.0	140'	140'	30"
16"	84.0	570'	570'	20"
10 3/4"	51.0	3,150'	3150'	14 3/4"
7"	29.0	6,004'	6,004'	9 1/2"

METHOD OF EMPLACEMENT OF CEMENT PLUGS
- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	7"	7"	7"	7'	7"	7'	
Depth to Bottom of Tubing or Drill Pipe (ft	6,004	3,900	3,100	1,800	1,500	700	
Sacks of Cement To Be Used (each plug)	451	149	0	53	0	124	
Slurry Volume To Be Pumped (cu. ft.)	505	167	271	63	167	146	
Calculated Top of Plug (ft.)	3,900	3,100	1,800	1,500	700	0 (GL)	
Measured Top of Plug (if tagged ft.)	3,900	3,100	1,800	1,500	700	0 (GL)	
Slurry Wt. (Lb./Gal.)	15.82	15.82	8.6	15.6	8.6	15.6	
Type Cement or Other Material (Class III)	EverCrete	EverCrete	6% Gel	Class A	6% Gel	Class A	

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
(7" perforated casing) 3,950 ft MD	6,004 ft MD		

Estimated Cost to Plug Wells
Plug #1 Set through a cement retainer set at 3,900 ft MD
$600,000.00

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Name and Official Title *(Please type or print)*	Signature	Date Signed
Kenneth K. Humphreys, Chief Executive Officer	Kenneth K. Humphreys	03/03/2014

EPA Form 7520-14 (Rev. 12-11)

Figure 4—Sample EPA Plugging and Abandonment Plan form

3.0 Narrative Description of Plugging Procedures

3.1 Notifications, Permits, and Inspections

In compliance with 40 CFR §146.92(c), OLCV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

3.2 Plugging Procedures for BRP CCS1

[redacted]

[redacted]

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

3.3 Plugging Procedures for BRP CCS2

[redacted]

[redacted]

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

3.4 Plugging Procedures for BRP CCS3

[redacted]

[redacted]

[redacted]

[redacted]

The procedures described above are subject to modification during execution as necessary to ensure a successful plugging operation. Any significant modifications due to unforeseen circumstances will be described in the plugging report.

Plugging Appendix
Monitoring Wells

(submitted as wholly redacted)

EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR §146.94(a)

Brown Pelican CO_2 Sequestration Project

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1.0 Facility Information

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS1, CCS2 and CCS3 Wells

Facility contact: [redacted]

Well location: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

2.0 Plan Overview

This Emergency and Remedial Response Plan (ERRP) describes actions Oxy Low Carbon Ventures, LLC (OLCV) shall take to address movement of the injection fluid or formation fluid to prevent endangerment of an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

If OLCV obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a USDW, OLCV will perform the following actions:

1. Initiate the shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency Underground Injection Control (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: OLCV will immediately cease injection. However, in some circumstances, OLCV in consultation with the UIC Program Director, will determine whether gradual cessation of injection is appropriate (using the parameters set forth in the Summary of Operating Conditions document of the Class VI permit).

3.0 Local Resources and Infrastructure

The USDWs in the vicinity of the Brown Pelican CO_2 Sequestration Project (BRP CCS or Project) that may be affected as a result of an emergency event at the project site include the Pecos Valley major aquifer and the Dockum minor aquifer. The base of the USDW in the Project area of review (AoR) is in the Dockum minor aquifer in the Santa Rosa Formation (depth range: 600 to 1,150 ft below ground level). Drainage of the Pecos Valley and Dockum aquifers from the study area is directed towards the Pecos River (30 miles SW). Figure 1 shows the surface features within the project AoR, which mainly consist of Holocene sand and silt, dunes and dune ridges, caliche, associated alluvium, and other undivided Quaternary deposits.

The Area of Review and Corrective Action Plan document provides further details on the USDWs within the project area.

Infrastructure in the vicinity of the BRP Project that may be affected as a result of an emergency at the project site includes local solar power generation operations on the surface projection of the AoR and the direct air capture (DAC) facility adjacent to the AoR.

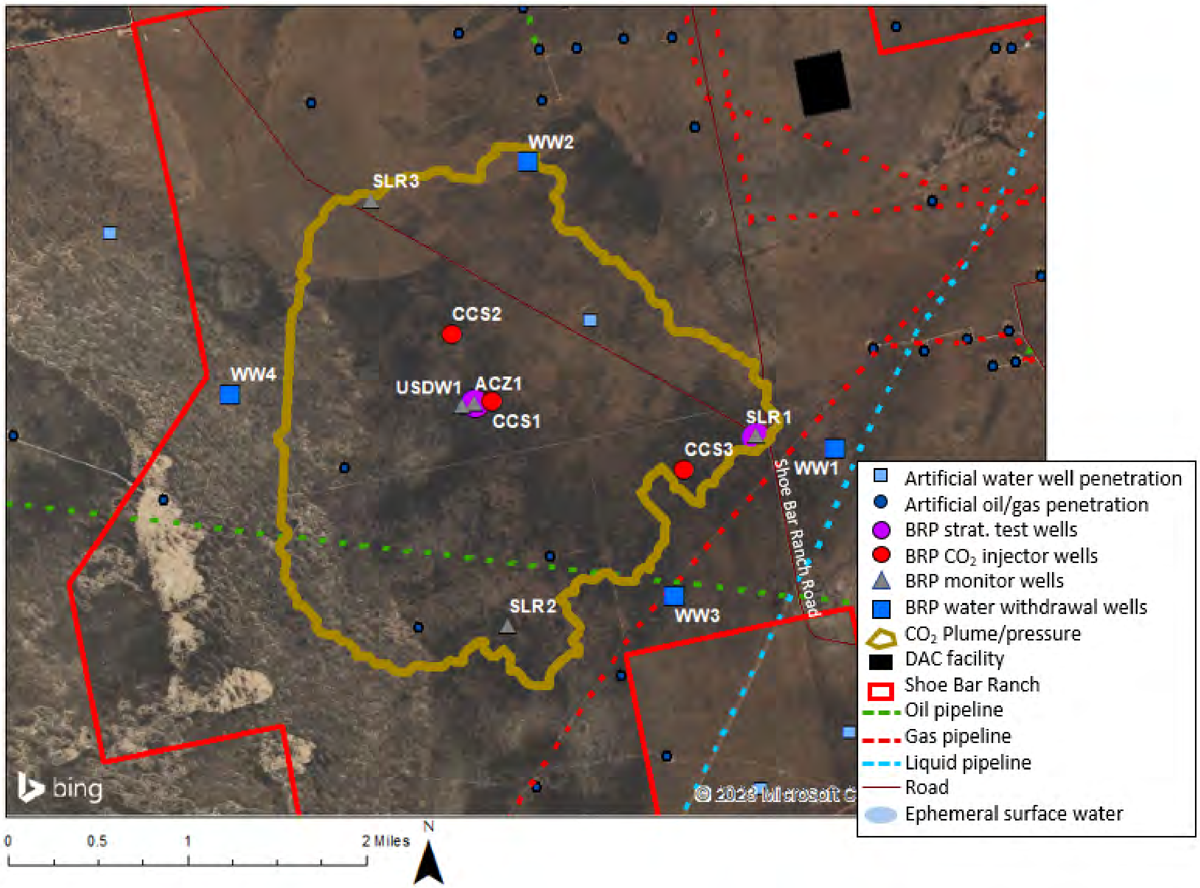

Figure 1—Map of surface features within the area of review.

4.0 Potential Risk Scenarios

The events related to the BRP Project that could potentially result in an emergency response are included in Table 1. This table lists the types of potential adverse incidents that will trigger response actions to protect USDWs if the incidents occur during the construction, injection, or post-injection site care periods. OLCV will undertake emergency or remedial actions in response to these incidents. The worst-case consequences of various scenarios have been developed to ensure that response plans are in place for all eventualities.

Table 1—Potential Emergency Events

Construction / Pre-Injection Period
• Well control event during drilling or completions with loss of containment
Injection Period
• Well integrity failure o Loss of mechanical well integrity due to tubing or packer leak in injection or monitoring well o Loss of mechanical well integrity due to casing leak in injection, monitoring, or water withdrawal well • Potential leakage to USDW o Vertical migration of CO_2, brines, or applicable production fluid in injection, monitoring, or water withdrawal well o Vertical migration of CO_2 from the Injection Zone through plugged and abandoned (P&A'd) wells in the storage complex or undocumented wells o Vertical migration of CO_2 from the Injection Zone through failure of the confining zone, faults, and fractures (loss of containment) o Lateral migration of CO_2 outside the defined AoR • Well monitoring equipment failure or malfunction (e.g., shutoff valve or pressure gauge) • A natural disaster (e.g., earthquake, tornado, hurricane, lightning strike) • Induced seismic event • Surface impacts o External impact to injection, monitoring, or water withdrawal wellhead o External impact to surface piping or buried pipelines o Loss of mechanical integrity pipeline on the surface piping or buried pipelines (e.g., internal or external corrosion) o Incorrect valve position leading to pipeline overpressure o CO_2 thermal expansion in injection pipeline
Post-Injection Site Care Period
• Well integrity failure o Loss of mechanical well integrity due to tubing or packer leak in monitoring well o Loss of mechanical well integrity due to casing leak in monitoring well • Potential leakage to USDW o Vertical migration of CO_2, brines, or applicable production fluid in monitoring well o Vertical migration of CO_2 from the Injection Zone through P&A'd wells in the storage complex or undocumented wells o Vertical migration of CO_2 from the Injection Zone through failure of the confining zone, faults, and fractures (loss of containment) o Lateral migration of CO_2 outside the defined AoR • Natural disaster (e.g., earthquake, tornado, lightning strike, freezing) • Induced seismic event • Surface impacts o External impact to monitoring wellhead

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 2.

Table 2—Risk Severity for Emergency Events

Risk Severity	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 are taken.
Minor	Emergency event poses no immediate risk to human health, resources, or infrastructure, no response action required.

5.0 Emergency Identification and Response Actions

Steps to identify and characterize the event will depend on the specific issue identified and the severity of the event. The potential risk scenarios listed in Table 1 are detailed below. OLCV will also submit a report to the Director where applicable under 40 CFR §146.91(c).

5.1 Well Control Event

Loss of containment could occur during drilling and completions operations if the hydrostatic column controlling the well decreases below the formation pressure, allowing fluids to enter the well.

Severity (residual)[1]: Serious

Timing of event: Construction / Pre-Injection

Avoidance measures: Blowout prevention (BOP) equipment, kill fluid, well control training, BOP testing protocol, kick drill, lubricators for wireline operations.

Detection methods: Flow sensor, pressure sensor, tank-level indicator, tripping displacement practices, mud weight control.

Potential response actions:

- Drilling
  - Stop operation.
  - Close BOP.

[1] Residual severity accounts for consequences after implementation of avoidance measures and detection methods.

  - Clear floor and secure area.
  - Execute well control procedure.
  - Evaluate drilling parameters and identify root cause.
  - Resume operations.
- Completion
  - Stop operation.
  - Close BOP.
  - Clear floor and secure area.
  - Execute well control procedure.
  - Resume operations.

Response personnel: Rig crew and downhole (DH) contractors, rig manager, field superintendent, project manager.

5.2 Well Integrity Failure

Integrity loss of the injection well, monitoring well, and/or water withdrawal well may endanger USDWs. Integrity loss may occur during the following scenarios:

- Loss of mechanical integrity due to a tubing or packer leak in the injection well or monitoring well.
- Loss of mechanical integrity due to a casing leak in the injection well, monitoring well or water withdrawal well.

5.2.1 Loss of Mechanical Integrity: Tubing or Packer Leak in Injection Well

Loss of mechanical integrity due to a tubing or packer leak in the injection well could occur due to corrosion, damage in the tubulars during installation, packer leak (undetected), fatigue, or higher load profiles. This loss could cause a communication of the formation fluids within the annulus between the casing and tubing and sustained casing pressure. There is no loss of containment in this scenario and no movement of injection or formation fluids anticipated to endanger USDW.

Severity (residual): Minor

Timing of event: Injection

Avoidance measures: Coated tubing, inhibited packer fluid in the annulus, corrosion monitoring plan, dry CO_2 injected, trim on tubing hanger and tree, corrosion-resistant (CR) tubing tailpipes below packers, CR or Inconel® carrier for the sensors, new casing and tubing installed.

Detection methods: Real-time pressure and temperature gauges at the surface and downhole, electromagnetic casing inspection log, annulus pressure test, CO_2 sensor on the wellhead, distributed temperature sensing (DTS) fiber alongside production casing with real-time monitoring.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Follow protocol to stop operation, vent, or deviate CO_2.
- Troubleshoot the well.
- If tubing leak is detected, discuss action plan with regulating authority.
- Schedule well service to repair tubing.

Response personnel: Operations engineer, field superintendent, project manager, rig crew and DH contractors.

5.2.2 Loss of Mechanical Integrity: Tubing or Packer Leak in Monitoring Well

Loss of mechanical integrity due to a tubing or packer leak in the monitoring well could occur due to corrosion, damage in the tubulars during installation, packer leak (undetected), fatigue, or higher load profiles. This loss could cause a communication of the formation fluids within the annulus between the casing and tubing and sustained casing pressure. There is no loss of containment in this scenario and no movement of injection or formation fluids anticipated to endanger USDW.

Severity (residual): Minor

Timing of event: Injection and Post-Injection

Avoidance measures: Coated tubing, inhibited packer fluid in the annulus, corrosion monitoring plan, CR tubing tailpipes below the packer, CR or Inconel carrier for the sensors, new casing and tubing installed.

Monitoring wells are designed to be outside the projected plume for the majority of the project operation, reducing the risk of contact with CO_2.

Detection methods: Real-time pressure and temperature gauges at the surface, downhole pressure monitoring, annulus pressure test.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Troubleshoot the well.
- If tubing leak is detected, discuss action plan with regulating authority.

- Schedule well service to repair tubing.

Response personnel: Operations engineer, field superintendent, project manager, rig crew and DH contractors.

5.2.3 Loss of Mechanical Integrity: Casing Leak in Injection Well

Loss of mechanical integrity due to a casing leak in the injection well could occur due to corrosion, damage to the tubulars during installation, packer leak (undetected), fatigue, or higher load profiles. This loss could cause a migration of CO_2 and brines through the casing, the cement sheath, and into different formations than the injection target or into a USDW.

Severity (residual): Minor

Timing of event: Injection

Avoidance measures: CO_2-resistant cement and metallurgy (casing) across the Injection Zone, injection through tubing and packer, CR or Inconel carrier sensors, inhibited packer fluid in the annulus, cement to surface, corrosion monitoring plan, cement bond log (CBL) after installation, new casing installed.

Detection methods: Real-time pressure and temperature gauges at the surface and downhole, electromagnetic casing inspection log, CO_2 sensor on the wellhead, DTS fiber alongside production casing with real-time monitoring, flow rate monitoring, soil gas probes, neutron-activated logs, USDW water monitoring.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Follow protocol to stop operation, vent, or deviate CO_2.
- Troubleshoot the well.
- Evaluate if there is movement of CO_2 or brines to USDW.
- If USDW is affected, discuss remediation with regulating authority.
- If casing leak is detected, discuss action plan with regulating authority.
- Schedule well service to repair casing or plug and abandon (P&A) well based on findings of assessment.

Response personnel: Operations engineer, field superintendent, project manager, rig crew and DH contractors, remediation contractors.

5.2.4 Loss of Mechanical Integrity: Casing Leak in Monitoring Well

Loss of mechanical integrity due to a casing leak in the monitoring well could occur due to corrosion, damage in the tubulars during installation, packer leak (undetected), fatigue, or higher load profiles. This loss could cause a migration of CO_2 and brines through the casing, the cement sheath, and into different formations in the injection target or USDW.

Severity (residual): Minor

Timing of event: Injection and Post-Injection

Avoidance measures: CO_2-resistant cement, inhibited packer fluid in the annulus, CR or Inconel carrier sensors, cement to surface, corrosion monitoring plan, CBL after installation, new casing and tubing installed.

Monitoring wells are designed to be outside the projected plume for the majority of the project operation, reducing the risk of contact with CO_2.

Detection methods: Real-time pressure gauges at surface, downhole pressure monitoring, pulsed neutron logs, annulus pressure test.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Troubleshoot the well.
- Evaluate if there is movement of CO_2 or brines to USDW.
- If USDW is affected, discuss remediation with regulating authority.
- If casing leak is detected, discuss action plan with regulating authority.
- Schedule well service to repair casing or P&A the well based on findings of assessment.

Response personnel: Operations engineer, field superintendent, project manager, rig crew and DH contractors, remediation contractors.

5.2.5 Loss of Mechanical Integrity: Casing Leak in Water Withdrawal Well

Loss of mechanical integrity due to a casing leak in the water withdrawal well could occur due to corrosion, damage in the tubulars during installation, fatigue, or higher load profiles. This loss could cause a migration of brines through the casing, the cement sheath, and into different formations than the injection target or into a USDW.

While a water withdrawal well is down for repairs, it is unable to pull water from the reservoir to decrease pressure across the formation to allow for CO_2 injection. It is possible this would increase pressure in the formation from excess water and increase the area of review. However, multiple water withdrawal wells are included in the design of the Brown Pelican CO_2 Sequestration Project, so the loss of one water withdrawal well would not cause significant project concerns. Multiple water wells would need to be down for pressure to increase in the formation.

Severity (residual): Minor

Timing of event: Injection

Avoidance measures: CO_2-resistant cement and metallurgy (casing) across producing zones, CO_2-resistant electrical submersible pump (ESP) equipment, cement to surface, corrosion monitoring plan, CBL after installation, new casing and tubing installed.

Detection methods: Real-time pressure and temperature gauges at the surface and downhole, electromagnetic casing inspection log, flow rate monitoring.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Follow protocol to stop water production.
- Troubleshoot the well.
- Evaluate if there is movement of CO_2 or brines to USDW.
- If USDW is affected, discuss remediation with regulating authority.
- If casing leak is detected, discuss action plan with regulating authority.
- Schedule well service to repair casing or P&A the well based on findings of assessment.

Response personnel: Operations engineer, field superintendent, project manager, rig crew and DH contractors, remediation contractors.

5.3 Potential Brine or CO_2 Leakage to USDW

Potential brine or CO_2 leakage to the USDW from the injection well, monitoring well, or water withdrawal well may endanger USDWs. Integrity loss may occur during the following scenarios:

- Vertical migration of CO_2 or brine between formations through the injection well, a monitoring well, or a water withdrawal well.
- Vertical migration of CO_2 or brine between formations through legacy or P&A'd wells.
- Vertical migration of CO_2 or brine between formations due to failure of the confining rock, faults, or fractures.
- Lateral migration or CO_2 outside the defined AoR.

5.3.1 Vertical Migration of Brine or CO_2 to USDW: Injection Well

Vertical migration of brine or CO_2 during injection could occur if there are induced stresses or a chemical reaction on the tubulars or cement of the injection well exposed to the CO_2 pressure or plume.

Severity (residual): Minor

Timing of event: Injection

Avoidance measures: CO_2-resistent cement and metallurgy (casing) across the Injection Zone, injection through tubing and packer, cement to surface, CBL after installation, USDW covered as section barrier with surface casing and surface cement sheath, new casing installed, corrosion monitoring plan.

Detection methods: CO_2 sensors on the wellhead, DTS fiber alongside production casing with real-time monitoring, soil gas probes, USDW water monitoring, pulsed neutron logs to be run to determine external mechanical integrity (MI), pressure gauges at the surface, flow rate monitoring, downhole pressure monitoring.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Follow protocol to stop operation, vent, or deviate CO_2.
- Troubleshoot the well.
- Evaluate if there is movement of CO_2 or brines to USDW.
- Discuss remediation options, action plan, and monitoring plan with regulating authority, if necessary.
- Discuss plan to repair the well with the regulating authority or P&A the well based on findings of assessment.

Response personnel: Operations engineer, field superintendent, project manager, rig crew and DH contractors, remediation contractors.

5.3.2 Vertical Migration of Brine or CO_2 to USDW: Monitoring Well

Vertical migration of brine or CO_2 during or after injection could occur if there are induced stresses or a chemical reaction on the tubulars or cement of the monitoring well exposed to the CO_2 pressure or plume.

Severity (residual): Minor

Timing of event: Injection and Post-Injection

Avoidance measures: CO_2-resistent cement across Injection Zone, CO_2-resistent metallurgy (casing) in select monitoring wells, cement to surface, CBL after installation, USDW covered as section barrier with surface casing and surface cement sheath, new casing installed, corrosion monitoring plan.

Detection methods: USDW water monitoring, pulsed neutron logs to be run for external MI, pressure gauges at surface, downhole pressure monitoring.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Troubleshoot the well.
- Evaluate if there is movement of CO_2 or brines to USDW.
- Discuss remediation options, action plan, and monitoring plan with regulating authority, if necessary.
- Discuss plan to repair or P&A the well with the regulating authority.

Response personnel: Operations engineer, field superintendent, project manager, rig crew and DH contractors, remediation contractors.

5.3.3 Vertical Migration of Brine or CO_2 to USDW: Water Withdrawal Well

Vertical migration of brine or CO_2 during injection could occur if there are induced stresses or a chemical reaction on the tubulars or the cement of the water withdrawal well exposed to the CO_2 pressure or plume.

Severity (residual): Minor

Timing of event: Injection

Avoidance measures: CO_2-resistent cement and metallurgy (casing) across producing zone, CO_2-resistent ESP equipment, cement to surface, CBL after installation, USDW covered as section barrier with surface casing and surface cement sheath, new casing installed, corrosion monitoring plan.

Detection methods: Real-time pressure and temperature gauges on surface and downhole, USDW water monitoring, electromagnetic casing inspection log, flowrate monitoring.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Follow protocol to stop water production.
- Troubleshoot the well.
- Evaluate if there is movement of CO_2 or brines to USDW.

- Discuss remediation options, action plan, and monitoring plan with regulating authority, if necessary.
- Discuss plan to repair or P&A the well with the regulating authority.

Response personnel: Operations engineer, field superintendent, project manager, rig crew and DH contractors, remediation contractors.

5.3.4 Vertical Migration of Brine or CO_2 to USDW: Legacy and P&A'd Wells

Vertical migration of brine or CO_2 during injection or post-injection could occur if there is poor cement bonding, cement degradation, or cracking in the legacy or P&A'd wells exposed to the CO_2 pressure or plume.

Severity (residual): Minor

Timing of event: Injection and Post-Injection

Avoidance measures: Legacy wells to be properly plugged and abandoned for brine movement and CO_2 plume according to the corrective action plan, injectors will be abandoned as soon as CO_2 injection in the project ends, unless they are left as monitoring wells.

Detection methods: Soil gas probes, monitoring of USDW, monitoring of injector wells that could indicate a broken seal and be causing CO_2 migration.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Evaluate if there is movement of CO_2 or brines to USDW due to a leak in a legacy or P&A'd well.
- Discuss remediation options, action plan, and monitoring plan with regulating authority, if necessary.
- Discuss plan to repair the well and specific remediation actions with the regulating authority.

Response personnel: Operations engineer, field superintendent, project manager, rig crew and DH contractors, remediation contractors.

5.3.5 Vertical Migration of Brine or CO_2 to USDW: Failure of Confining Rock, Faults, or Fractures

Vertical migration of brine or CO_2 during injection could occur if the pressure of the Injection Zone exceeds the sealing capacity of the caprock or seal above or if fault or fracture features are reactivated. Brine or CO_2 could leak to a shallower formation, including a USDW.

Severity (residual): Minor

Timing of event: Injection and Post-Injection

Avoidance measures: Seismic survey in the area shows no faults in the sequestration zone, injection is limited to 90% of the fracture gradient, characterization of the rocks show good sealing capacity.

Detection methods: USDW water sampling, time-lapse seismic survey, pulsed neutron logs in injection and monitoring wells, soil gas monitoring, surface pressure monitoring.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Follow protocol to stop CO_2 injection and/or water production.
- Assess root cause by reviewing monitoring data.
- If required, conduct geophysical survey to delineate potential leak path.
- Evaluate if there is movement of CO_2 or brines to USDW due to a failure of confining rock, faults, or fractures.
- Discuss remediation options, action plan, and monitoring plan with regulating authority, if necessary.
- Take actions to restore injection depending on nature of the leak path and the extent.

Response personnel: Monitoring staff, geologist, reservoir engineer, project manager, remediation contractors.

5.3.6 Lateral Migration of CO_2 to Outside the Defined AoR

Lateral migration of CO_2 outside the defined AoR could occur during or after injection if the plume moves faster or in an unexpected pattern and expands beyond the secure pore space and AoR for the project.

Severity (residual): Minor

Timing of event: Injection and Post-Injection

Avoidance measures: Detailed geologic model with nearby well logging as a calibration, seismic survey integrated in the model, characterization of the rocks and formation, AoR review and calibration at least every five years, monitoring of the plume until stabilization.

Detection methods: Time-lapse seismic survey, pulsed neutron logs in monitoring wells, real-time pressure and temperature gauges in monitoring wells.

Potential response actions:

- During Injection:

  - Trigger alarm by the monitoring system or monitoring personnel.
  - Review monitoring data and trends compared with simulation.
  - Discuss findings with regulating authority; request to maintain injection during AoR evaluation if data show that CO_2 will stay in secured pore space.
  - Perform logging in monitoring wells.
  - Conduct geophysical survey as required to evaluate AoR.
  - Recalibrate model and simulate new AoR.
  - Assess if additional corrective actions are needed and if additional pore space is needed.
  - Assess if remediation is needed; prepare action plan and review with regulating authority.
  - Present AoR review to regulating authority for approval; adjust monitoring plan.
- Post-Injection:
  - Trigger alarm by the monitoring system, or monitoring personnel.
  - Review monitoring data and trends compared with simulation.
  - Discuss findings with regulating authority.
  - Conduct geophysical survey as required to evaluate AoR.
  - Recalibrate model and simulate new AoR.
  - Assess if additional corrective actions are needed and if additional pore space is needed.
  - Assess if remediation is needed; prepare action plan and review with regulating authority.
  - Present AoR review to regulating authority for approval; adjust monitoring plan.

Response personnel: Monitoring staff, geologist, reservoir engineer, project manager.

5.4 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 (residual): Minor

Timing of event: Injection

Avoidance measures: Preventative maintenance program, periodic inspections.

Detection methods: Real-time monitoring systems redundancy, field inspections.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Follow protocol to stop operation, vent, or deviate CO_2, if needed.
- If there is an injury or property damage, contact field superintendent and activate emergency evacuation to secure the location.
- 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.
- Assess mechanical integrity of the system and propose repair actions, if necessary.
- Assess potential environmental impact and discuss remedial action with regulating authority.
- If assessment allows, discuss plan with the regulating authority to safely resume injection.
- Repair or replace instrumentation; calibrate equipment.
- Review monitoring records and, if needed, perform a falloff test to evaluate the reservoir.

Response personnel: Operations engineer, field superintendent, project manager, remediation contractors, emergency teams, geologist, reservoir engineer, monitoring staff, rig crew and DH contractors.

5.5 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. A major seismic event may disturb surface and/or subsurface facilities; weather-related disasters (e.g., tornado, lightning strike, or freezing) may affect surface facilities.

Severity (residual): Depending on severity of event, potentially serious

Timing of event: Injection and Post-Injection

Avoidance measures: Seismic survey of the storage complex shows no faults that could be activated in the Injection Zone, shutdown devices present on wellhead and piping to shutoff CO_2 and water production.

Detection methods: Seismometers on the surface to monitor induced seismicity will detect naturally occurring major seismic event.

Potential response actions:

- Major Seismic Event
    - For event with local magnitude level (ML) from 2.0 but below 3.5 within 5.6 miles of injection well:
        - Monitor seismic activity.
        - If needed, pause operations or make adjustments to operations at a reduced rate.
    - For event with ML from 3.5 to 4.5 within 5.6 miles of injection well:
        - Initiate contact with regulating authority regarding seismic event.
        - If needed, pause operations or make adjustments to operations at a reduced rate.
        - Review regional information and monitoring records to determine origin of the event.
        - If event is induced, re-evaluate model, define new injection parameters, and discuss with regulating authority.
        - If assessment allows for resuming injection safely, increase surveillance to validate effectiveness of actions.
    - For event above ML 4.5 within 5.6 miles of injection well:
        - Trigger alarm by the monitoring system or monitoring personnel.
        - If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure the location.
        - Follow protocol to stop injection.
        - Assess mechanical integrity of the system; propose repair actions based on findings.
        - Assess environmental impact; discuss remedial action with regulating authority, if necessary.
        - Review regional information and monitoring records to determine origin of the event.
        - If event is induced, re-evaluate model, define new injection parameters, and discuss with regulating authority.
        - If assessment allows for resuming injection safely, increase surveillance to validate effectiveness of actions.

- Weather Disaster
    - Trigger alarm by the monitoring system or monitoring personnel.
    - If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure the location.
    - Follow protocol to stop CO_2 injection and/or water production.
    - Assess mechanical integrity of the system; propose repair actions based on findings.
    - Assess potential environmental impact and discuss remedial action with regulating authority.
    - If assessment allows for resuming injection and/or production safely, increase surveillance to validate effectiveness of actions.

Response personnel: Operations engineer, field superintendent, project manager, geologist, reservoir engineer, monitoring staff, remediation contractors, emergency teams.

5.6 Induced Seismic Event

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside a 5.6-mile radius from the wellhead. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a 5.6-mile radius of the injection well. A geophone array on surface will be used to monitor the area for seismicity.

Severity (residual): Depending on severity of event; potentially serious

Timing of event: Injection and Post-Injection

Avoidance measures: Seismic survey of the storage complex shows no faults that could be reactivated, detailed geomechanical model created to evaluate whether the storage complex and region is seismically stable.

Detection methods: Geophone array on surface.

Potential response actions:

- For event with ML from 2.0 to 3.5 within 5.6 miles of injection well:
    - Monitor seismic activity.
    - If needed, pause operations or make adjustments to operations at a reduced rate.
- For event with ML from 3.5 to 4.5 within 5.6 miles of injection well:
    - Initiate contact with regulating authority regarding seismic event.
    - If needed, pause operations or make adjustments to operations at a reduced rate.

  - Review regional information and monitoring records to determine origin of the event.
  - If event is induced, re-evaluate model, define new injection parameters, and discuss with regulating authority.
  - If assessment allows for resuming injection safely, increase surveillance to validate effectiveness of actions.
- For event above ML 4.5 within 5.6 miles of injection well:
  - Trigger alarm by the monitoring system or monitoring personnel.
  - If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure the location.
  - Follow protocol to stop injection.
  - Assess mechanical integrity of the system; propose repair actions based on findings.
  - Assess environmental impact; discuss remedial action with regulating authority, if necessary.
  - Review regional information and monitoring records to determine origin of the event.
  - If event is induced, re-evaluate the model, define new injection parameters, and discuss with regulating authority.
  - If assessment allows for resuming injection safely, increase surveillance to validate effectiveness of actions.

Response personnel: Operations engineer, field superintendent, project manager, geologist, reservoir engineer, monitoring staff, remediation contractors, emergency teams.

5.7 Surface Impacts

Surface impact may cause loss of containment during the follow scenarios:

- External impact to the injection wellhead.
- External impact to the monitoring wellhead.
- External impact to the water withdrawal wellhead.
- External impact to the surface piping or buried pipelines.
- Loss of mechanical integrity due to internal or external corrosion on the surface piping or buried pipelines.
- Incorrect valve position leading to pipeline overpressure.

- CO_2 thermal expansion in the injection surface piping or buried pipelines.

5.7.1 Loss of Containment: External Impact to Injection Wellhead

External impact to the injection wellhead due to heavy trucks or equipment could cause loss of containment of brine or CO_2 if the wellhead is disconnected from the well pipe or the surface pipeline. No movement of injection or formation fluids is anticipated to endanger USDW.

Severity (residual): Serious

Timing of event: Injection

Avoidance measures: Fenced location and bollards installed, signage.

Detection methods: Real-time pressure and temperature at the wellhead and surface facilities, field inspections, optical gas imaging (OGI) cameras.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Automated shutdown will initiate; follow protocol to shut down CO_2 delivery if the automated shutdown devices are not functional.
- If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure the location.
- Contact the field superintendent or asset manager to activate emergency plan and uncontrolled release protocol.
- Clear the location and secure the perimeter.
- Contact well control special team to execute uncontrolled release protocol that may include capping the well, drilling a relief well to kill the injector, repairing the well, or abandoning the well; discuss plan with regulating authority.
- Evaluate environmental impact to soil, water, vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system as needed.

Response personnel: Operations engineer, field superintendent, project manager, rig crew and DH contractors, remediation contractors, well control specialist.

5.7.2 Loss of Containment: External Impact to Monitoring Wellhead

External impact to the monitoring wellhead due to heavy trucks or equipment could cause loss of containment of brine if the wellhead is disconnected from the well pipe. No movement of injection or formation fluids is anticipated to endanger USDW.

Severity (residual): Minor

Timing of event: Injection and Post-Injection

Avoidance measures: Fenced location and bollards installed, signage, reduced pressure in the monitoring well compared with the injection well.

Detection methods: Real-time pressure at the wellhead, field inspections.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure the location.
- Contact the field superintendent or asset manager to activate emergency plan and uncontrolled release protocol.
- Clear the location and secure the perimeter. If possible, install containment devices or equipment to direct fluid away from possible sensitive areas around the location.
- Contact well control special team to execute uncontrolled release protocol that may include capping the well, drilling a relief well, repairing the well, or abandoning the well; discuss plan with regulating authority.
- Evaluate environmental impact to soil, water, and vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system as needed.

Response personnel: Operations engineer, field superintendent, project manager, rig crew and DH contractors, remediation contractors, well control specialist.

5.7.3 Loss of Containment: External Impact to Water Withdrawal Wellhead

External impact to the water withdrawal wellhead due to heavy trucks or equipment could cause loss of containment of brine if the wellhead is disconnected from the well pipe or the surface pipeline. No movement of injection or formation fluids is anticipated to endanger USDW.

Severity (residual): Minor

Timing of event: Injection

Avoidance measures: Fenced location and bollards installed, signage.

Detection methods: Real-time pressure and temperature monitoring at surface and downhole, field inspections.

Potential response actions:

- Trigger alarm by the monitoring system or monitoring personnel.
- Automated shutdown will initiate; follow protocol to shut down water withdrawal if the automated shutdown devices are not functional.
- If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure the location.
- Contact the field superintendent or asset manager to activate the emergency plan and uncontrolled release protocol.
- Clear the location and secure the perimeter. If possible, install containment devices or equipment to direct fluid away from possible sensitive areas around the location.
- Contact well control special team to execute uncontrolled release protocol that may include capping the well, drilling a relief well, repairing the well, or abandoning the well; discuss plan with regulating authority.
- Evaluate environmental impact to soil, water, and vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system as needed.

Response personnel: Operations engineer, field superintendent, project manager, rig crew and DH contractors, remediation contractors, well control specialist.

5.7.4 Loss of Containment: External Impact to Surface Piping or Buried Pipeline

External impact to the surface piping or buried pipeline due to heavy trucks or equipment could cause loss of containment of brine or CO_2 if the pipe ruptures. No movement of injection or formation fluids is anticipated to endanger USDW.

Severity (residual): Serious

Timing of event: Injection

Avoidance measures: Fenced location and bollards installed to protect surface piping, field pipeline is buried, pipeline right-of-way is identified with signage, One Call 811 program.

Detection methods: Real-time pressure, temperature, and flow measurement; field inspections.

Potential response actions:

- Trigger alarm by the system or operations staff.
- Automated shutdown will initiate; follow protocol to shut down CO_2 delivery or water withdrawal if the automated shutdown devices are not functional.
- If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure the location.

- Clear the location and secure the perimeter. If possible, for water withdrawal pipelines, install containment devices or equipment to direct fluid away from possible sensitive areas around the location.
- Assess mechanical integrity of the system and propose repair actions based on the findings.
- Evaluate environmental impact to soil, water, vegetation; present remediation plan to the regulating authority.
- Execute remediation and install monitoring system as needed.

Response personnel: Operations engineer, field superintendent, project manager, remediation contractors, plant manager, HSE representatives.

5.7.5 Loss of Mechanical Integrity: Internal or External Corrosion on the Surface Piping or Buried Pipeline

Loss of mechanical integrity due to internal or external corrosion in the injection pipeline or water withdrawal pipeline could cause loss of containment of brine or CO_2 if a leak develops. No movement of injection or formation fluids anticipated to endanger USDW.

Severity (residual): Serious

Timing of event: Injection

Avoidance measures: Application of asset integrity / mechanical integrity (AI/MI) program, use of lined pipe, as appropriate.

Detection methods: Real-time pressure, temperature, and flow measurement, field inspections.

Potential response actions:

- Trigger alarm by the system or operations staff.
- Automated shutdown will initiate; follow protocol to shut down CO_2 delivery or water withdrawal if the automated shutdown devices are not functional.
- If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure the location.
- Clear the location and secure the perimeter. If possible, for water withdrawal pipelines, install containment devices or equipment to direct fluid away from possible sensitive areas around the location.
- Assess mechanical integrity of the system and propose repair actions based on the findings.
- Evaluate environmental impact to soil, water, vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system as needed.

Response personnel: Operations engineer, field superintendent, project manager, remediation contractors, plant manager, HSE representatives.

5.7.6 Loss of Containment: Incorrect Valve Position on the Surface Piping or Buried Pipeline

An incorrect valve position within the injection or production piping network could lead to high pressure within the piping and possible loss of containment of brine or CO_2 if the pipe ruptures. No movement of injection or formation fluids anticipated to endanger USDW.

Severity (residual): Serious

Timing of event: Injection

Avoidance measures: Relief valve located on pipeline at CO_2 injection wellhead, pipeline pressure rating exceeds max compressor or pump discharge pressure.

Detection methods: Real-time pressure monitoring with automatic shutdown, pressure monitoring in control room with operator response.

Potential response actions:

- Trigger alarm by the system or operations staff.
- Automated shutdown will initiate; follow protocol to shut down CO_2 delivery or water withdrawal if the automated shutdown devices are not functional.
- If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure the location.
- Clear the location and secure the perimeter. If possible, for water withdrawal pipelines, install containment devices or equipment to direct fluid away from possible sensitive areas around the location.
- Assess the mechanical integrity of the system and propose repair actions based on the findings.
- Evaluate environmental impact to soil, water, and vegetation; present remediation plan to regulating authority.
- Execute remediation and install monitoring system as needed.

Response personnel: Operations engineer, field superintendent, project manager, remediation contractors, plant manager, HSE representatives

5.7.7 Loss of Containment: CO_2 Thermal Expansion in the Injection Surface Piping or Buried Pipeline

High-pressure CO_2 has the potential for thermal expansion when exposed to high temperatures and could lead to loss of containment of CO_2 if the pipe ruptures. No movement of injection or formation fluids anticipated to endanger USDW.

Severity (residual): Serious

Timing of event: Injection

Avoidance measures: Relief valve located on the pipeline at the CO_2 injection wellhead, thermal relief valve, pipeline pressure rating exceeds maximum compressor discharge pressure.

Detection methods: Real-time pressure monitoring with automatic shutdown, pressure monitoring in control room with operator response.

Potential response actions:

- Trigger alarm by the system or operations staff.
- Automated shutdown will initiate; follow protocol to shut down CO_2 delivery if the automated shutdown devices are not functional.
- If there are injured personnel or property damage, contact the field superintendent to activate emergency evacuation and secure the location.
- Clear the location and secure the perimeter.
- Assess mechanical integrity of the system and propose repair actions based on the findings.
- Evaluate environmental impact to soil, water, and vegetation; present remediation plan to the regulating authority.
- Execute remediation and install monitoring system as needed.

Response personnel: Operations engineer, field superintendent, project manager, remediation contractors, plant manager, HSE representatives.

6.0 Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement the ERRP.

Monitoring, control, and routine maintenance of the injection operations will be the responsibility of the Injection Operations Staff. Site personnel are expected to include, at a minimum, the positions listed below in Table 3.

If an adverse event is discovered, the Operations Manager and Emergency Coordinator on duty will be notified immediately. The Emergency Coordinator will be responsible for notifying offsite emergency agencies and resources. The Operations Manager will contact outside emergency response organizations if the Emergency Coordinator is not available. The EPA Region 6 UIC Program Director will also be notified within 24 hours.

Table 3–Operations Staff Descriptions

Position	Function	Qualifications
Emergency Coordinator	Responsible for notification of offsite support agencies in accordance with written procedures. Responsible for coordination and overseeing contact with the media.	Trained in the Communications Plan and Emergency Notification Procedures requirements as contained in the ERRP.
Operations Manager	Serves as the Emergency Response Manager responsible for the overall management of the Incident Response Team. Manages facility operations and personnel during an emergency and is responsible for implementation of appropriate emergency procedures and their follow-up activities.	Trained in the requirements of the ERRP and facility operations.
Project Manager	Serves as the Emergency Response Coordinator responsible for the overall communication between Incident Response Team members. Directs facility operations during an emergency and is responsible for communication between on-site personnel and professional services. Implements emergency procedures and ensures documentation of follow-up activities.	Trained in the requirements of the ERRP and facility operations.
Reservoir Engineer	Responsible for injection operation and monitoring. Lead incident response manager regarding injection and storage zone operation at the facility.	Undergraduate degree in engineering, related to chemical or reservoir engineering.
Geologist/ Geophysicist	Professional serving to assist in operation, maintenance, and monitoring of the injection process. Conducts routine data management and interpretation. Assists in implementing response actions regarding Injection Zone integrity.	Undergraduate degree in geophysics or geology with specialization in hydrology/fluid mechanics.
Operations Engineer	Oversees mechanical and fluid management operation of the injection wells, annulus pressure control system, and wellhead piping systems. Maintains and repairs injection-related equipment, including valves, instruments, and piping. Assists in mechanical and electronic control of the injection process.	Undergraduate degree in engineering related to mechanical, chemical, or process control.

A site-specific emergency contact list will be developed and maintained during the life of the project. OLCV will provide the current site-specific emergency contact list to the UIC Program Director.

A list of contacts for state agencies having jurisdiction within the AoR and key local emergency agencies is presented below in Table 4.

There are no federally recognized Native American Tribes located within the AoR. If a federally recognized Native American Tribe were to exist in the AoR at the time of a site emergency, then that tribe(s) will be notified of the site emergency at that time.

Table 4–Contact Information for Key Local, State, and Other Authorities

Agency	Location	Phone
West Odessa Fire Department	West Odessa, TX	911 or 432-381-3033
Odessa Fire Rescue	Odessa, TX	911 or 432-257-0502
Odessa Police Department	Odessa, TX	911 or 432-333-3641
Odessa Regional Hospital	Odessa, TX	432-334-8000
Odessa Medical Center	Odessa, TX	432-640-4000
Highway Police	Odessa, TX	432-332-6100
Ector County Sheriff	Odessa, TX	432-335-3050
Texas Division of Emergency Management	Austin, TX	512-424-2208
Ector County Office of Emergency Management	Odessa, TX	432-257-0502
US EPA Region 6	Dallas, TX	214-665-2294

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, OLCV shall be responsible for its procurement.

7.0 Emergency Communications Plan

OLCV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether 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.

OLCV will describe what happened, impacts to the environment or other local resources, how the event was investigated, what response actions were taken, and the status of the response. For responses that occur over the long term (e.g., ongoing cleanups), OLCV will provide periodic updates on the progress of the response action(s).

OLCV will communicate with entities who need to be informed about or take action in response to the event, including local water systems, CO_2 source(s), pipeline operators, landowners, and regional response teams (as part of the National Response Team).

If a seismic event occurs, OLCV will provide information about whether the event was naturally occurring or induced by the injection, whether any damage to the well or other structures in the area occurred, the investigative process, and what responses, if any, were taken by OLCV or others.

8.0 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 a prescribed period (to be determined by the permitting agency) 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, OLCV 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 six months following an event that initiates the ERRP review procedure.

9.0 Staff Training and Exercise Procedures

All operations employees will receive training related to health and safety, operational procedures, and emergency response according to the roles and responsibilities of their work assignments. Initial training will be conducted by, or under the supervision of, the operations manager or a designated representative. Trainers will be thoroughly familiar with the Operations Plan and ERRP.

Facility personnel will participate in annual training that teaches them to perform their duties in ways that prevent CO_2 discharge. The training will include familiarization with operating procedures and equipment configurations appropriate to the job assignment as well as emergency response procedures, equipment, and instrumentation. New personnel will be instructed before beginning their work.

Refresher training will be conducted at least annually for all operations personnel. Monthly briefings will be provided to operations personnel according to their respective responsibilities and will highlight recent operating incidents, actual experience in operating equipment, and recent storage reservoir monitoring information.

Only personnel who have been properly trained will participate in drilling, construction, operations, and equipment repair at the storage site. A record including the person's name, date of training, and instructor's signature will be maintained.

Plan Revision number: 3
Plan revision date: 07/30/2024

POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR §146.93(a)

Brown Pelican CO_2 Sequestration Project

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1.0 Facility Information

Facility name: Brown Pelican CO_2 Sequestration Project
BRP CCS1, BRP CCS2 and BRP CCS3 Wells

Facility contact: [redacted]

Well locations: Penwell, Texas

BRP CCS1	31.76479314	-102.7289311
BRP CCS2	31.76993805	-102.7332448
BRP CCS3	31.76031163	-102.7101566

2.0 Plan Overview

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Oxy Low Carbon Ventures, LLC (OLCV) will perform on the Brown Pelican CO_2 Sequestration Project (BRP Project or Project) to meet the requirements of 40 CFR §146.93. OLCV will monitor groundwater quality and track the position of the CO_2 plume and pressure front for 50 years or for the duration of an alternative timeframe approved by the UIC Program Director pursuant to the requirements of 40 CFR §146.93(c) unless OLCV makes a demonstration under 40 CFR §146.93(b)(2) that OLCV has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to Underground Sources of Drinking Water (USDWs). Pursuant to 40 CFR §146.93(b)(3), OLCV will continue post-injection site care until the UIC Program Director approves a demonstration that no additional monitoring is needed to ensure non-endangerment of USDWs. Following approval for site closure, OLCV will plug all remaining monitoring wells and submit a site closure report and associated documentation.

3.0 Pre- and Post-Injection Pressure Differential [40 CFR §146.93(a)(2)(i)]

Based on modeling the pressure front as part of the Area of Review (AoR) delineation, the maximum predicted pressure differential for the top of the G1 sub-zone and Holt sub-zone is 246 psi in January 2037 and 849 psi in January 2029, respectively. The values are located at the top of injectors BRP CCS1 (G1 sub-zone) and CCS2 (Holt sub-zone). The magnitude and area of elevated pressure gradually decreases until the end of the injection period for the top of the Holt-sub-zone, and there is a sharp decrease in pressure when injection cease for both G4 and G1 injection sub-zones.

Table 1 and Table 2 shows the predicted pressure differential (pressure at Year – initial pressure) vs. time at the top of the G1 sub-zone and Holt sub-zone for the monitoring well locations in the AoR (Figure 9). The G1 sub-zone is reported because it is the top of the Injection Zone including the G1, G4 and Holt sub-zones. The top of the Holt sub-zone is reported because it is the region with the highest pressure differential in the simulation model. Note that the negative values at time zero result from a decrease in pressure due to brine production that starts six months prior to the commencement of CO_2 injection. The purpose of brine withdrawal is to manage reservoir pressure within the AoR.

The highest pressures are expected in the immediate vicinity of each injection well. The pressure is anticipated to quickly decrease below the estimated critical pressure in all areas of the site within a few years after the conclusion of injection operations (i.e., below the pressure levels at which fluids could be forced from the Injection Zone through a conduit into an overlying USDW). The pressure then stabilizes through the end of the post-injection site care period (PISC) and reaches similar values as those observed during pre-injection conditions.

Additional information on the projected post-injection pressure declines and differentials is presented in the Area of Review and Corrective Action Plan document.

Table 1—Pressure Differential to Pre-Injection Conditions at the top of the G1 sub-zone at monitoring well locations.

Well Name	**SLR 1**	**SLR 2**	**SLR 3**	**WW1**	**WW2**	**WW3**	**WW4**
Well distance from BRP CCS1 (ft)	8494	8093	5565	10,837	5772	9174	7598
Top of G1 sub-zone (ft MD)	4521	4538	4622	4470	4598	4463	4561
Year / Pressure Differential	**psi**	**psi**	**psi**	**psi**	**psi**	**psi**	**psi**
Start water production	0	0	0	0	0	0	0
0 (start injection)	-18	-15	-9	-42	-826	-314	-574
1	-34	-21	-26	-62	-856	-327	-646
2	-42	-14	-23	-91	-924	-483	-888
3	-36	-14	-22	-95	-924	-505	-965
4	-29	-7	-20	-92	-916	-497	-976
5	-23	0	-17	-89	-910	-490	-979
10	9	26	0	-67	-895	-463	-979
12 (end of injection)	23	34	6	-56	-892	-454	-978
15	24	39	24	19	47	32	-7
20	22	26	19	21	26	25	13
25	20	21	16	20	19	21	15
35	19	18	14	18	16	18	15
45	18	17	14	18	15	17	14
55	17	16	14	17	15	17	14
62 (site closure)	17	16	14	17	15	16	14

Table 2—Pressure Differential to Pre-Injection Conditions at the top of the Holt sub-zone at monitoring well locations.

Well Name	SLR 1	SLR 2	SLR 3	WW1	WW2	WW3	WW4
Well distance from BRP CCS2 (ft)	8,312	4,510	8,720	10,594	9,378	6,788	7,789
Top of Holt sub-zone (ft MD)	4883	4904	4972	4824	4968	4813	5021
Year / Pressure Differential	**psi**	**psi**	**psi**	**psi**	**psi**	**psi**	**psi**
Start water production	0	0	0	0	0	0	0
0 (start injection)	-18	-11	-4	-48	-41	-273	-201
1	-30	47	51	-68	-11	-282	-171
2	-36	74	86	-100	6	-419	-241
3	-24	157	177	-104	82	-430	-193
4	-16	200	236	-101	121	-421	-168
5	-9	225	268	-98	142	-413	-154
10	18	294	308	-76	193	-383	-137
12 (end of injection)	28	302	304	-65	201	-372	-139
15	23	94	120	19	81	42	76
20	21	38	43	21	32	28	32
25	19	24	23	20	21	22	20
35	17	18	15	18	15	18	15
45	17	17	13	17	14	17	14
55	16	16	13	17	14	17	13
62 (site closure)	16	16	13	17	14	16	13

Figure 1 and 2 show the simulated pressure vs. time for the BRP CCS1, CCS2 and CCS3 and monitoring well locations at the top of the commingled G4/G1 sub-zones and the top of the Holt sub-zone, respectively.

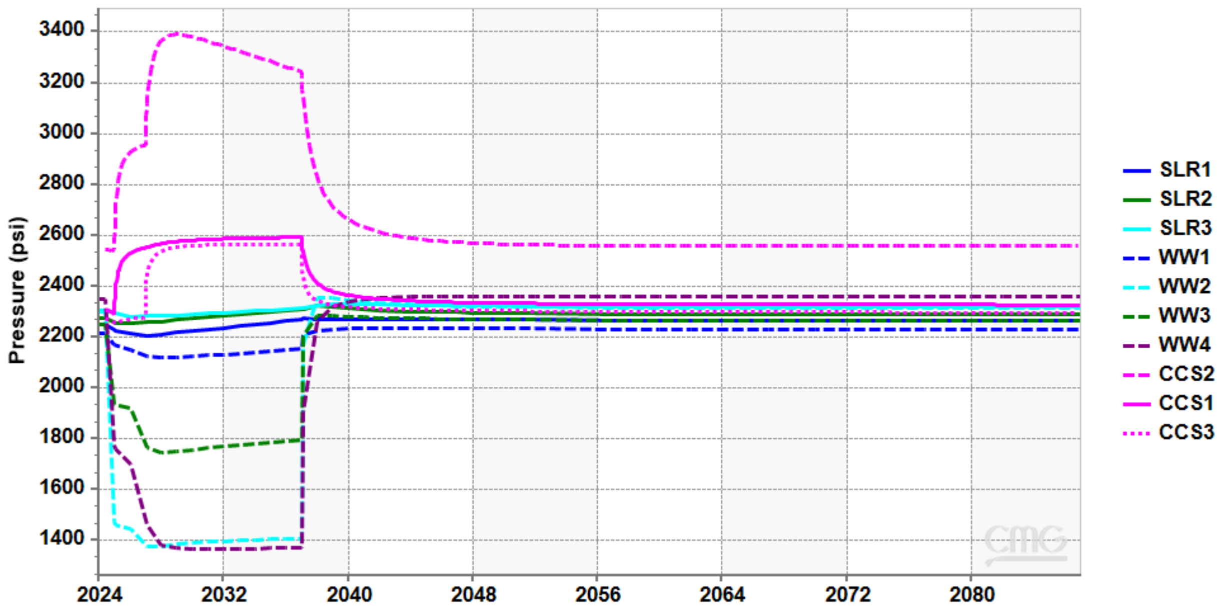

Figure 1--Simulated pressure vs. time at the top perforation in the BRP CCS1, CCS2 and CCS3 injection wells and at the top of the commingled G4/G1 sub-zones at monitoring well locations.

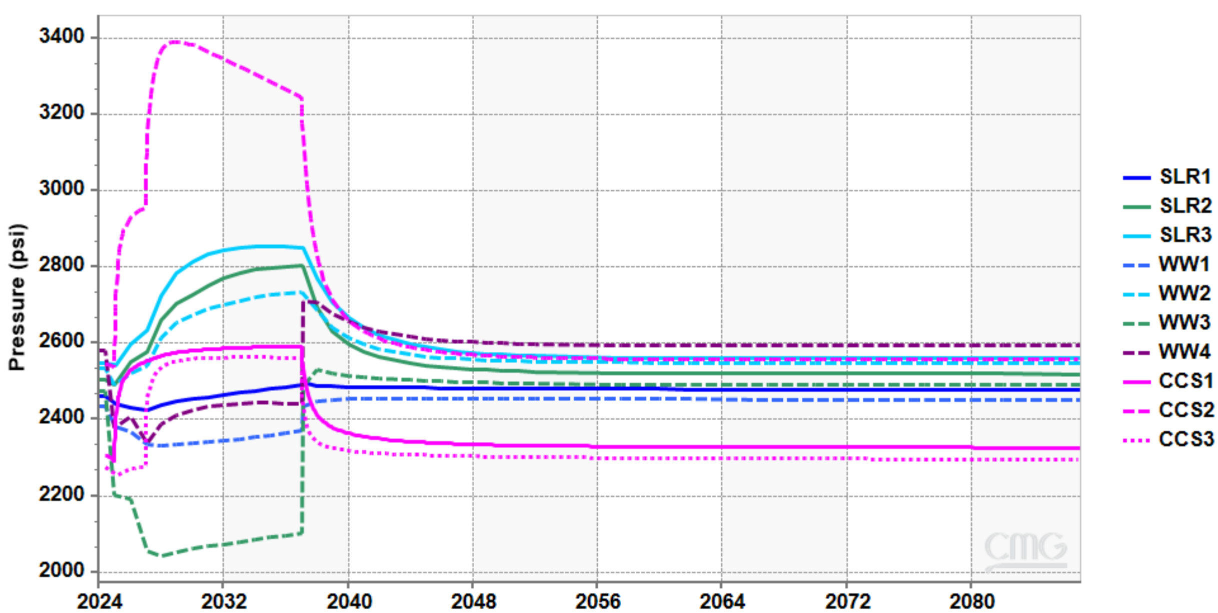

Figure 2--Simulated pressure vs. time at the top perforation in the BRP CCS1, CCS2 and CCS3 injection wells and at the top of the Holt sub-zone at monitoring well locations.

Figure 3 and Figure 4 show the simulated pressure differentials from the critical pressure values at the top of the Holt sub-zone at the end of injection and 50 years after the end of injection, respectively. In Figure 2, only the values that exceed the critical pressure threshold are shown, indicating that any area outside the shown values is below the critical pressure. In Figure 3, the pressure differential shows a negative pressure differential for most of the area, indicating that the pressure has dissipated below the critical pressure in all areas of the site at Year 62, which is anticipated to be the year of site closure.

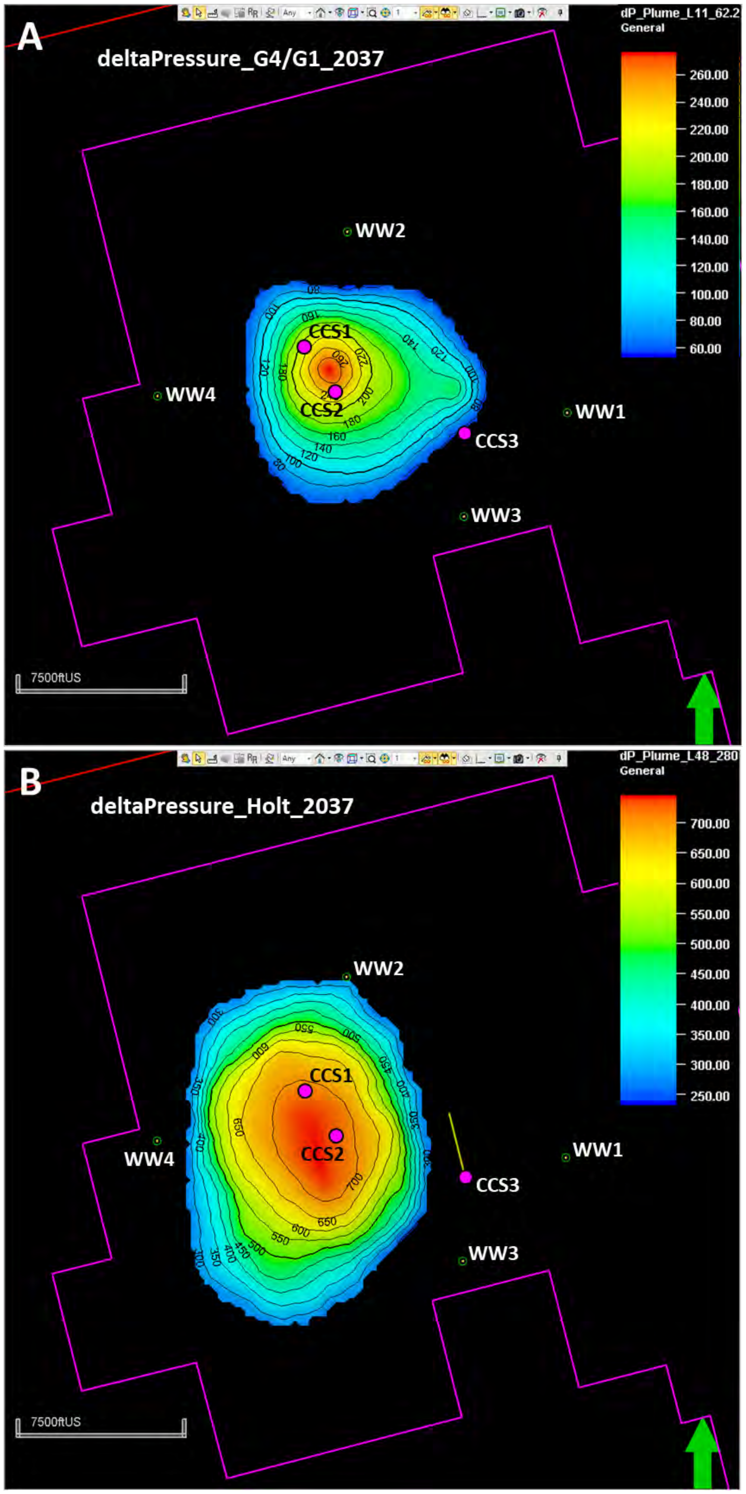

Figure 3--Aqueous pressure differential from the initial condition for commingled sub-zones G4 and G1 (upper Injection Zone – subplot A) and for sub-zone Holt (lower Injection Zone – subplot B) at end of injection in January 2037.

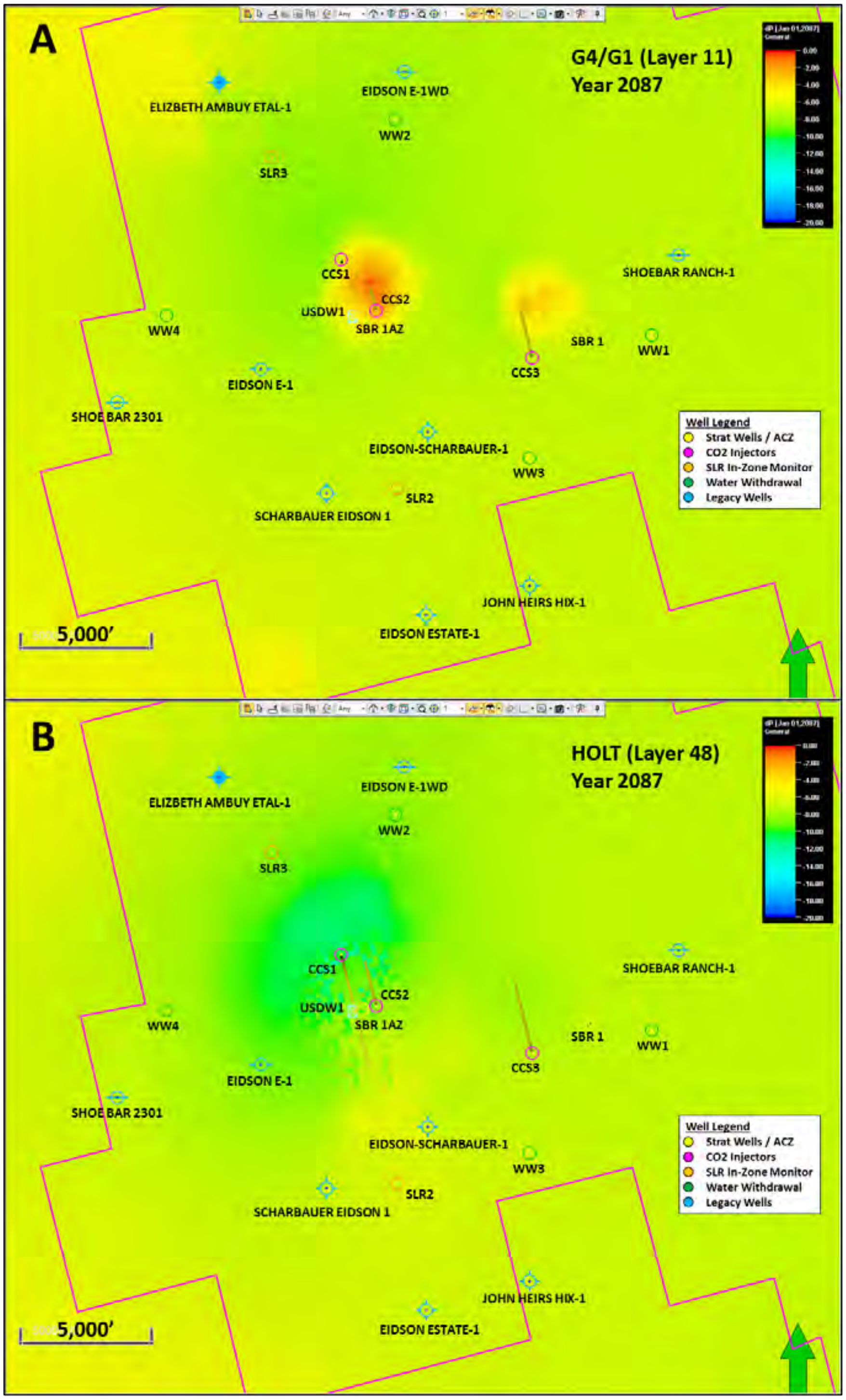

Figure 4--Aqueous pressure differentials from the initial condition at the top of the commingled G4 and G1 sub-zones (subplot A) and the top of the Holt sub-zone (subplot B) in January 2087 (50 years post-injection).

4.0 Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR §146.93(a)(2)(ii)]

The reservoir simulation indicates that after injection ceases, the predicted CO_2 plume remains within the Lower San Andres Formation and the area does not expand over time. The colored area in Figure 5 shows the CO_2 plume extent in Year 62, as defined by the global mole fraction of CO_2. Figure 6 to 8 show a N-S cross section with the CO_2 global mole fraction at the end of the injection period at Year 12 and the Year 62 for wells BRP CCS1, CCS2, and CCS3, respectively. There is some minor vertical migration of CO_2 to upper portions of the Injection Zone due to buoyancy forces. The AoR is defined by the plume shape and size in Year 12 (end of injection period) because this is the time with the largest differential pressure and CO_2 plume. Also, as previously shown in Figure 3, all pressures are predicted to have been reduced to levels below the level of endangerment to USDWs by Year 62. Therefore, Year 62 (50 years post-injection) is predicted to be the site closure date.

The map in Figure 5 is based on the final AoR delineation modeling results submitted pursuant to 40 CFR §146.84.

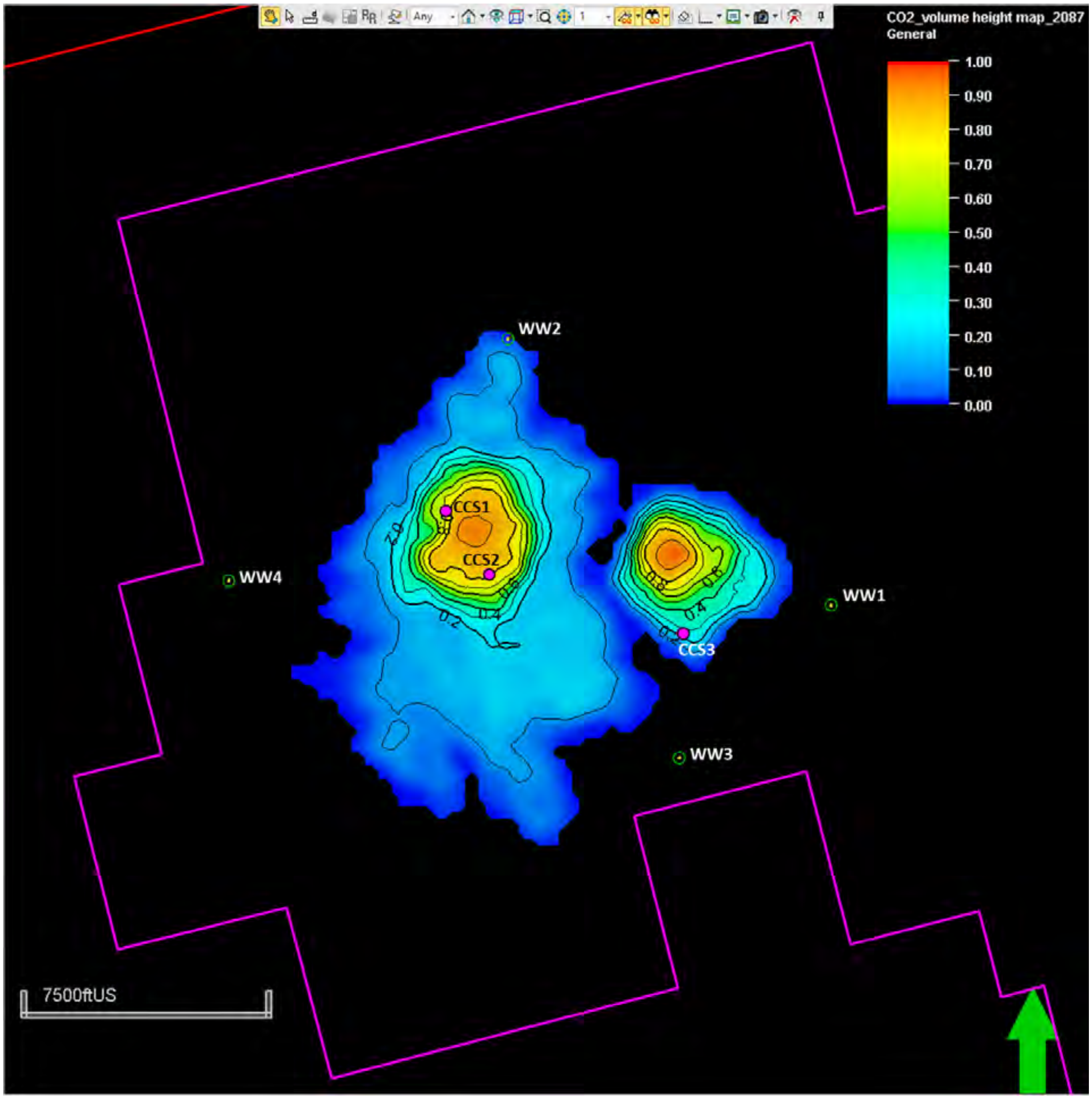

Figure 5--Areal extent of the CO_2 plume at site closure in Year 62 since start of CO_2 injection (2087), defined by the vertical integration of saturation of CO_2 injected.

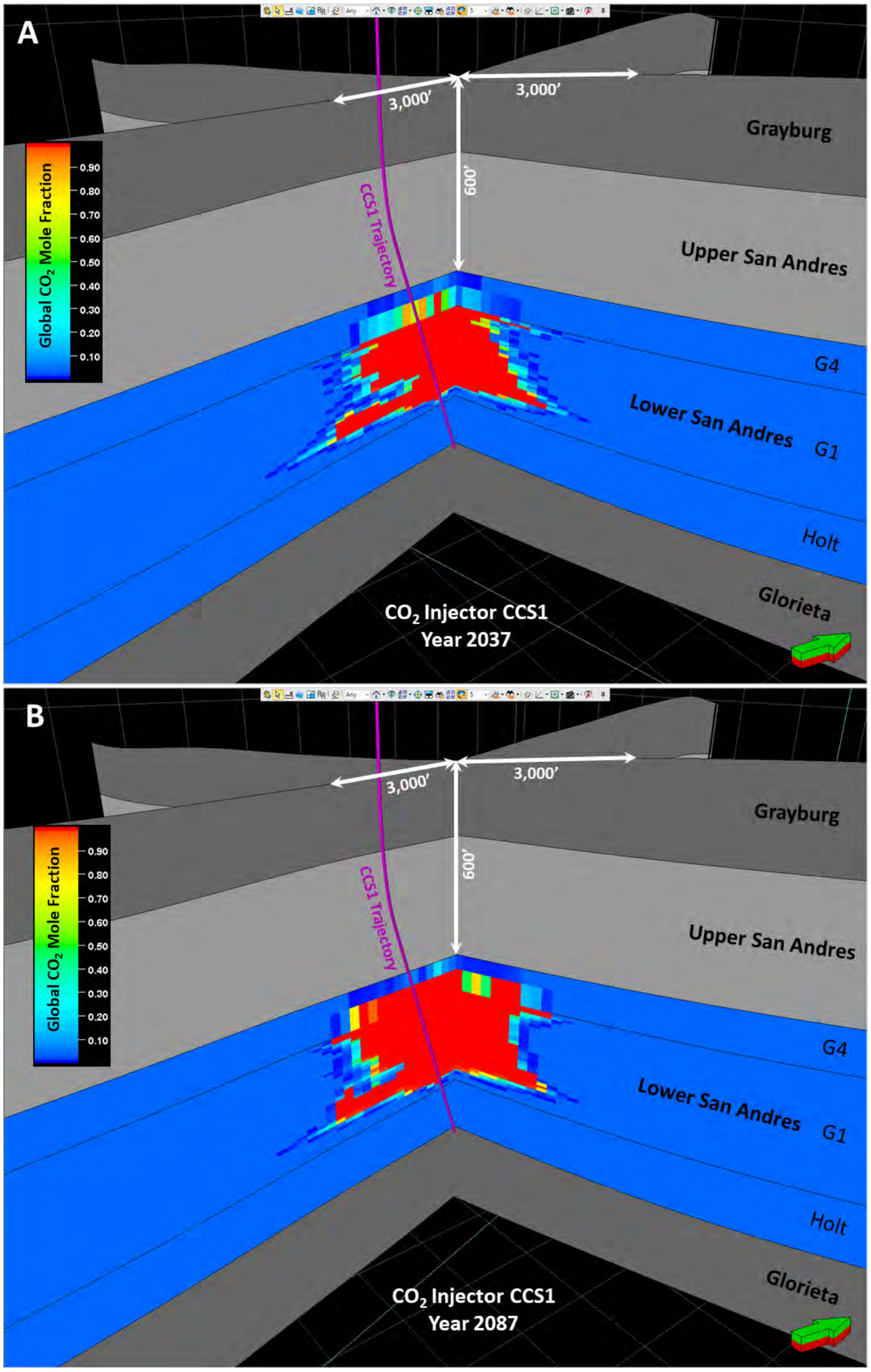

Figure 6--Cross section through the geomodel with simulated CO_2 plume for injector CCS1 at the end of injection period in 2037 (subplot A) and at time of site closure in 2087 (subplot B).

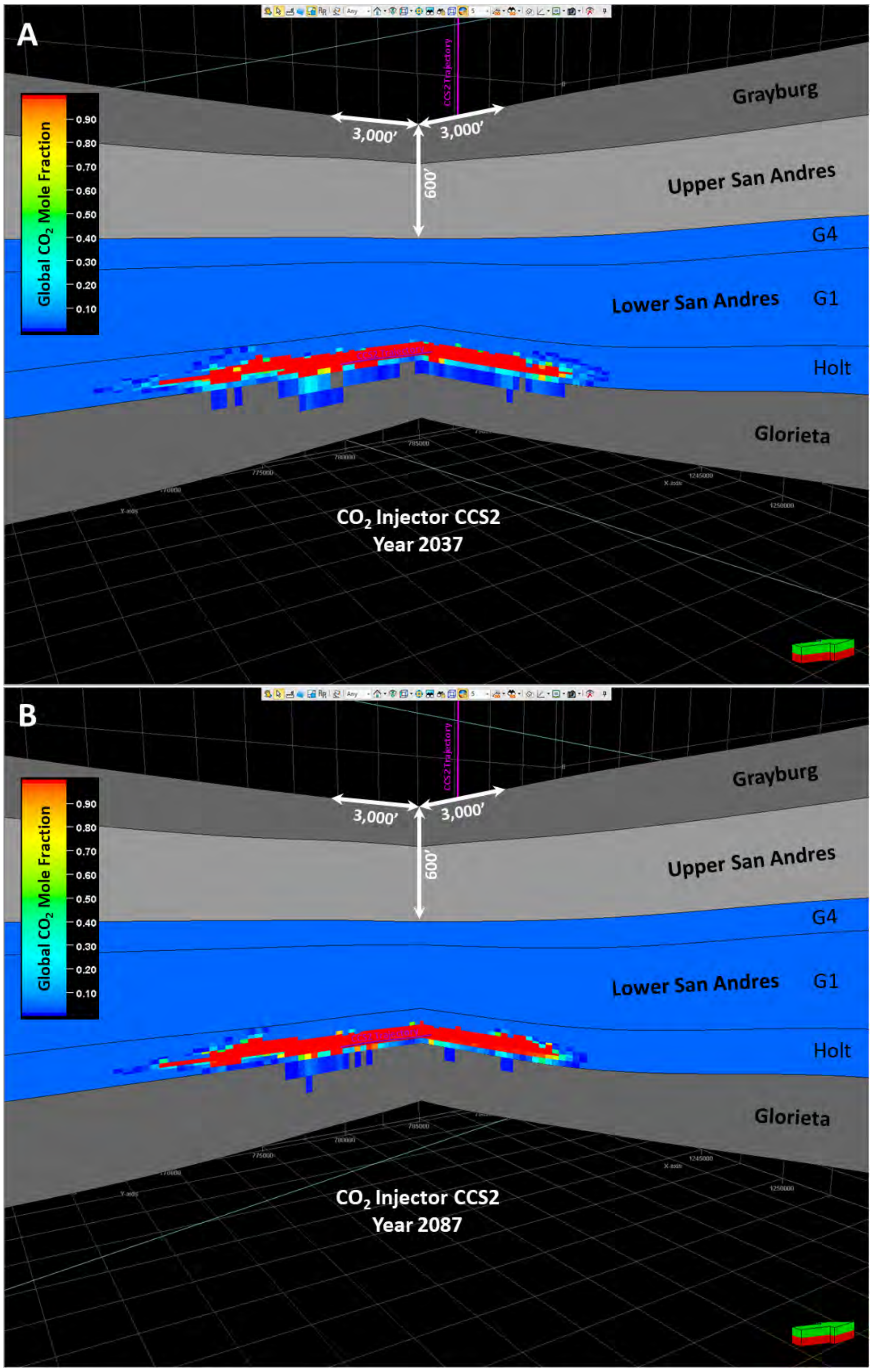

Figure 7--Cross section through the geomodel with simulated CO_2 plume for injector CCS2 at the end of injection period in 2037 (subplot A) and at time of site closure in 2087 (subplot B). Note that the large grid blocks in the Glorieta formation are an upscaling artifact. CO_2 is only pushed into the uppermost part of the Glorieta formation and moves upward over time due to buoyancy.

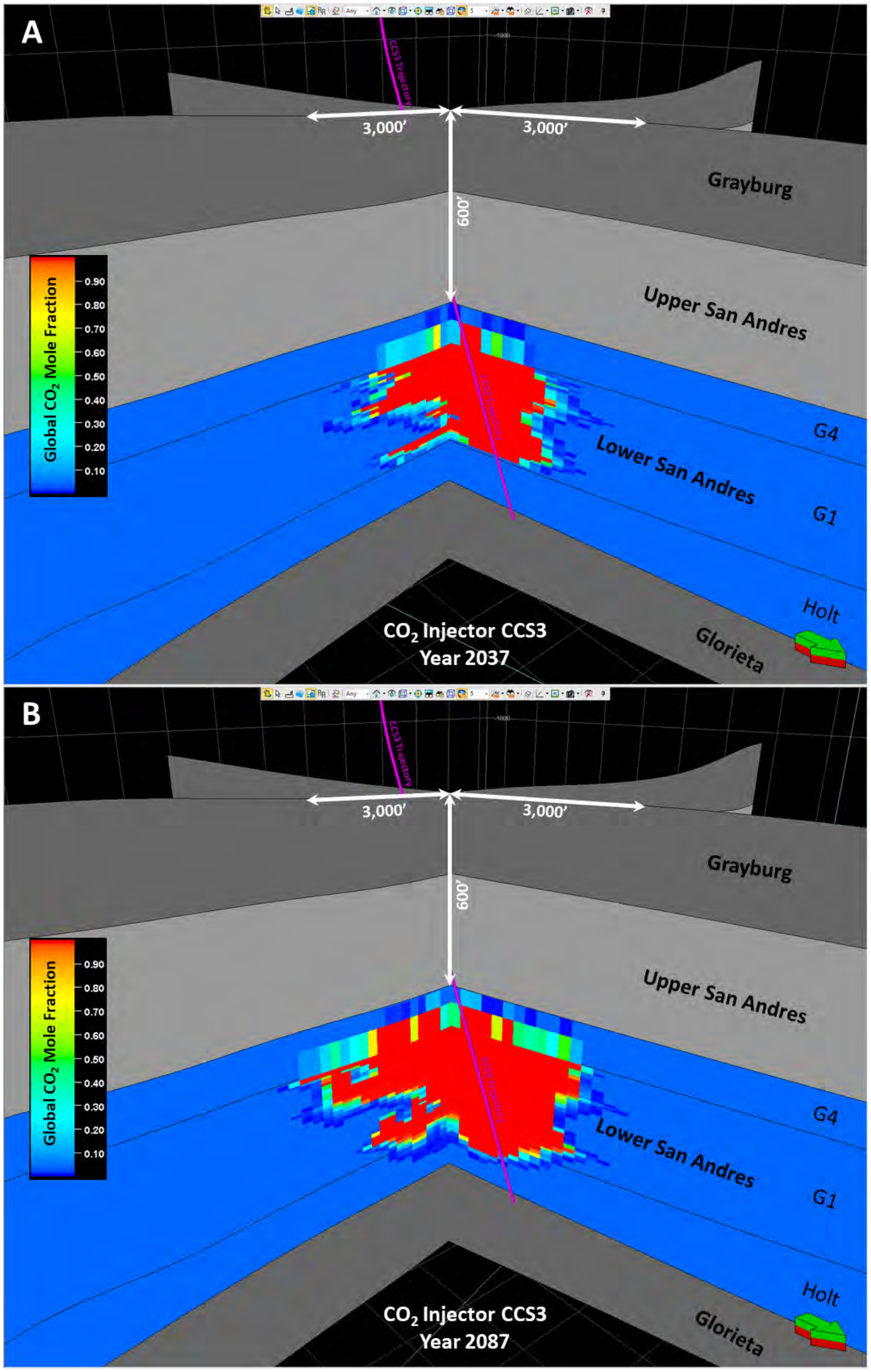

Figure 8--Cross section through the geomodel with simulated CO_2 plume for injector CCS3 at the end of injection period in 2037 (subplot A) and at time of site closure in 2087 (subplot B).

Figure 9 shows the CO_2 plume size, injected mass, and storage capacity as a function of time, with Year 0 being the initiation of injection. The simulation model predicts that the CO_2 plume (defined as the area containing 99% of the total volume of injected CO_2) increases rapidly during injection. The maximum CO_2 plume area is 4.8 mi^2 at the end of the injection period with a storage capacity of 1.77 MMT/mi^2. The plume shrinks after the injection stops from Year 12 to Year 50 and stabilizes in the following years. The shrink behavior of the plume after is due to the buoyancy of the mobile supercritical CO_2 phase which moves in upward direction, and continued dissolution in aqueous phase, decreasing its concentration in the plume edges. Thus, the storage capacity increase until a maximum of 1.95 MMT/mi^2. Figure 10 depicts areal plume movement based on CO_2 global mole fraction with a 0.1% cutoff. The plume slightly moves from west to east direction, close to Shoe Bar 1 well, due to the model geological features combined with compressibility effect (lower pressure in that region from WW1 water withdraw) allowing small plume migration in the strata. The change in plume size is negligible 50 years after injection, which is the proposed site closure time.

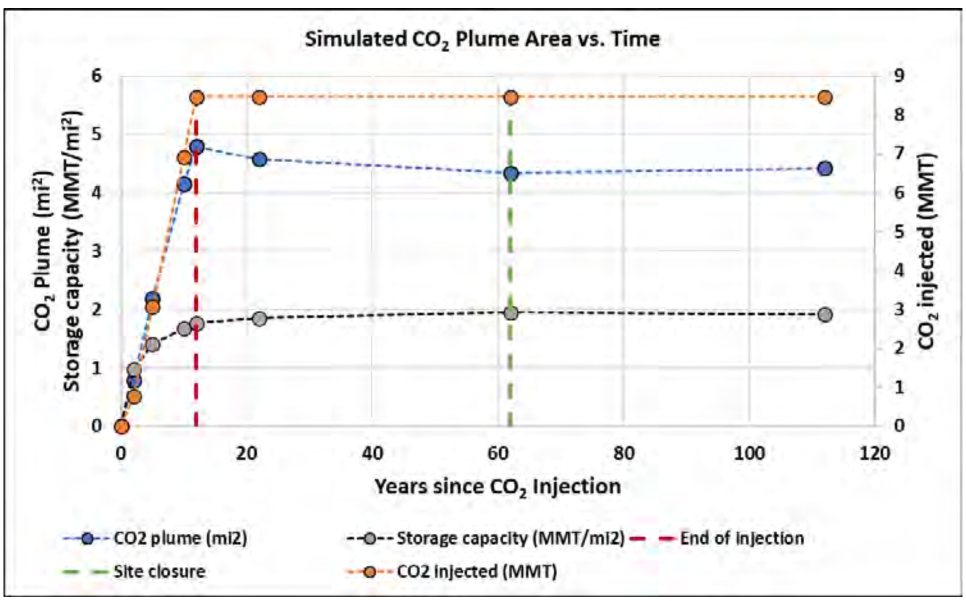

Figure 9--Simulated CO_2 plume area, injected mass, and storage capacity over time. The red and green dashed line denotes the time of end of injection and site closure, respectively.

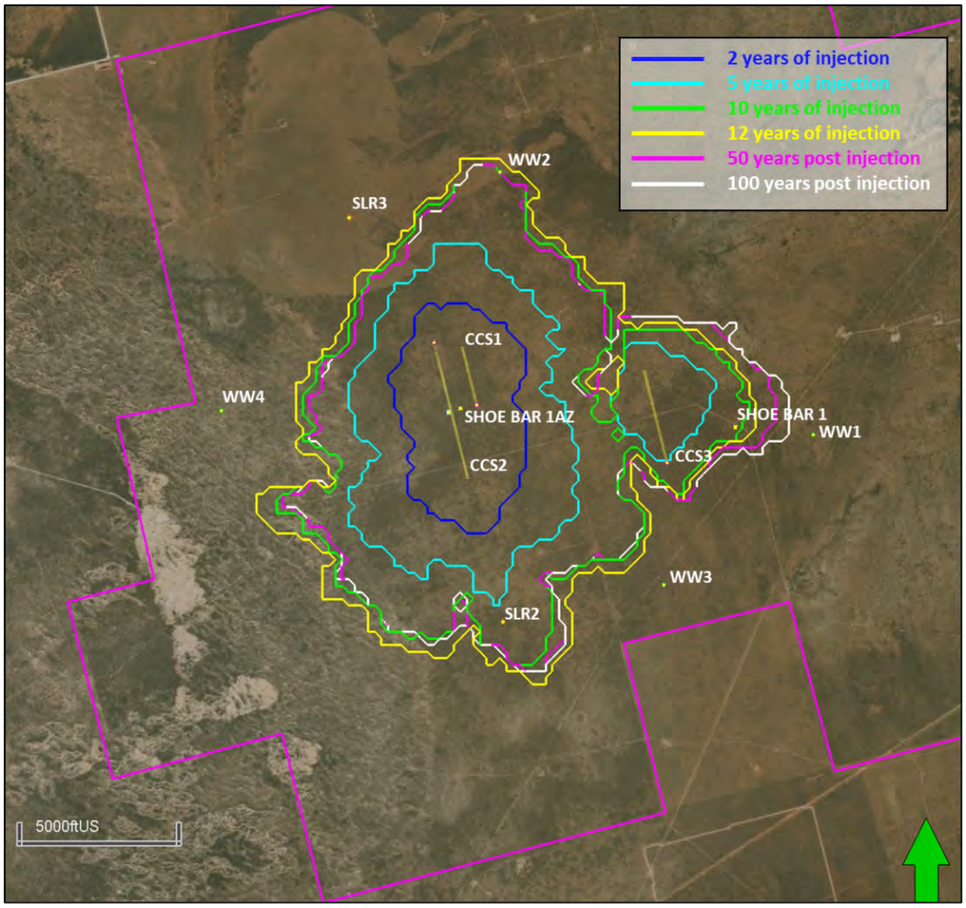

Figure 10--Simulated areal extent of the CO_2 plume from injection start-up to shut-in, then to 100 years after shut-in. Colored outlines represent the migration of the 1% CO_2 saturation front through time.

5.0 Post-Injection Monitoring Plan [40 CFR §146.93(b)(1)]

As described in the following sections, groundwater quality monitoring and plume and pressure-front tracking during the post-injection phase 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 60 days of the anniversary of the date that injection ceases, as described below under Section 5.3 Schedule for Submitting Post-Injection Monitoring Results [40 CFR §146.93(a)(2)(iv)]. Please refer to the Testing and Monitor Plan and Quality Assurance and Surveillance Plan (QASP) document included as part of this application for additional details on testing and monitoring activities during the Post-Injection phase.

A summary of key components of the PISC plan is as follows:

- After the injection ceases, the Injector wells will be plugged and abandoned according to the procedure proposed in the Plugging Plan document of this permit application.
- Pending an approved PISC Plan, for the first 10 years after the cessation of injection, direct measurements of pressure and temperature in the Injection Zone will be obtained in Single Layer Reservoir (SLR) monitoring wells that have not yet been plugged. Fluid samples will be collected if pressure or temperature indicate a change in fluid encountered by the wellbore. If pressure and temperature data are consistent with lack of continued CO_2 migration, pressure and temperature monitoring in the Injection Zone will be continued annually after 10 years until plugging.
- Pending an approved PISC Plan, for the first 10 years following the cessation of injection operations, OLCV will annually collect and analyze the geochemistry of fluids and dissolved gasses from the lowermost USDW in the USDW1 well. These data will confirm the integrity of the Upper Confining Zone. Measurements will be event-driven thereafter. If geochemistry data of fluids and dissolved gasses in the lowermost USDW are consistent with the absence of introduced Injection Zone brine or CO_2 injectate into the USDW, this monitoring method will be discontinued after 10 years.
- If pressure or temperature data in the SLR wells indicates a change in the Injection Zone that could indicate migration of CO_2 plume out of the storage complex, soil gas analysis will be conducted. If changes in soil gas are detected, an attribution study will be performed.
- Annual saturation logging will be conducted in SLR2 and SLR3 wells until plugging and saturation logging will be conducted once every five-year period in ACZ1 and SLR1 if triggered by other data.
- Time-lapse VSP data will be collected in selected SLR wells that have DAS fiber once every five-year period until plugging.
- 2D time-lapse surface seismic will be collected once every five-year period until plume stabilization.
- DInSar and GPS data will be analyzed annually for the first five years post injection.

5.1 Monitoring Above the Upper Confining Zone

Table 3 presents the monitoring methods, locations, and frequencies for monitoring above the Upper Confining Zone.

Table 3—Post-Injection Monitoring Techniques in/above the Confining Zone

Location	Objective	Method	Monitoring Post-Injection
Lowermost USDW / first permeable zone above the confining zone monitoring	Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry	Fluid and dissolved gas sampling	Event-driven*, until plugging
Vadose Zone, Near surface	Isotopic analysis and chemical evaluation to detect changes from expected vadose zone chemistry	Isotopic analysis and chemical evaluation at a minimum of 15 locations	Event-driven*, triggered by P/T data in SLR or ACZ1 wells and fluids sample results
ACZ1 and/or SLR1	Confirming integrity of the Upper Confining Zone	Saturation logging (RST/PNL)	Event-driven*, until plugging
		DTS (SLR1 only)	Continuously for the first 10 years, pending an approved PISC plan

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. In addition, fluid and dissolved gas chemistry data from the lowermost USDW and soil gas chemistry from shallow soils will be monitored for trends to detect deviations from reference chemistry. If persistent and/or abrupt anomalies in chemistry are detected additional fluid or soil gas samples will be obtained to confirm the presence or absence of increased CO_2. Saturation logging may also be conducted to further support or refute the presence of increased CO_2.

5.2 Carbon Dioxide Plume and Pressure Front Tracking [40 CFR §146.93(a)(2)(iii)]

OLCV will employ direct and indirect methods to track the extent of the CO_2 plume and the presence or absence of elevated pressure. Table 4 presents the direct and indirect methods that OLCV will use to monitor the CO_2 plume, including the activities, locations, and frequencies. Fluid sampling, sampling handling and custody, quality control, and quality assurance will be performed as described in the QASP.

Table 4—Post-Injection Monitoring Techniques Plume and Pressure Front Tracking

Location	Objective	Method	Monitoring Post-Injection
SLR2 and SLR3, Injection Zone monitor wells	Fluid and dissolved gas chemistry	Fluid and dissolved gas sampling via wireline	Event-driven* until plugging
	Direct monitoring of pressure and temperature to ensure seal integrity	P/T gauges or DTS	Continuously for the first 10 years pending an approved PISC plan, then annually until plugging

	Indirect monitoring of CO_2 concentration	PNL or RST	Annually until plugging
	Plume and pressure extent over time	2D VSP	Once every five-year period until plugging or plume stabilization
	Internal and external mechanical integrity	Pressure and temperature gauges; external MIT	MIT log once every five-year period and before plugging
	Surface leak detection	Visual inspection at wellhead, LDAR/OGI cameras, surface sensors	Continuous surface monitoring and quarterly visual inspection until site closure
ACZ1 and SLR1, Confining Zone monitoring wells	Direct monitoring of pressure and temperature to ensure Upper Confining Zone integrity	DTS (SLR1 only)	Continuously for the first 10 years or until plugging, pending an approved PISC Plan
	Internal and external mechanical integrity	Pressure and temperature gauges; external MIT	MIT log once every five-year period and before plugging
	Indirect monitoring of CO_2 presence above the Injection Zone	PNL or RST	Event-driven* until plugging
	Surface leak detection	Visual inspection at wellhead, LDAR/OGI cameras, surface sensors	Continuous surface monitoring and quarterly visual inspection until site closure
Lowermost USDW monitor well	Geochemical and isotopic monitoring to detect deviations from expected fluid chemistry	Fluid and dissolved gas sampling	Annually for first 10 years post injection pending an approved PISC plan; event-driven*, triggered by P/T data in SLR wells or soil gas chemistry
Vadose Zone, Near surface	Isotopic analysis and chemical evaluation to detect changes from expected vadose zone chemistry	Isotopic analysis and chemical evaluation at a minimum of 15 locations	Event-driven*, triggered by P/T data in SLR wells or fluid sample results
2D VSP in selected SLR wells and 2D surface seismic	Estimate CO_2 plume and pressure extent	2D VSP and 2D surface seismic	Once approximately every five-year period until plugging or plume stabilization
DInSAR with GPS	Estimate CO_2 plume and pressure extent	DInSAR with GPS	Annually for five years or until plume stabilizes
Surface seismicity	Presence or absence of seismicity	Seismometers	Continuous monitoring and recording until site closure

*OLCV will monitor pressure and temperature data obtained from downhole gauges and/or DTS fiber daily, and also routinely evaluate long-term data trends to detect deviations from the reference temperature or pressure gradient. If persistent deviations in temperature or pressure are detected, OLCV will obtain reservoir fluid samples and analyze fluid and dissolved gas chemistry to determine the presence or absence of increased CO_2. In addition, fluid and dissolved gas chemistry data from the lowermost USDW and soil gas chemistry from shallow soils will be monitored for trends to detect deviations from reference chemistry. If persistent and/or abrupt anomalies in chemistry are detected additional fluid or soil gas samples will be obtained to confirm the presence or absence of increased CO_2. Saturation logging may also be conducted to further support or refute the presence of increased CO_2.

5.3 Schedule for Submitting Post-Injection Monitoring Results [40 CFR §146.93(a)(2)(iv)]

OLCV will re-evaluate the AoR every five years during the post-injection phases. In addition, monitoring and operational data will be reviewed periodically by OLCV during the injection and post-injection phases. Monitoring reports will be prepared and submitted to the EPA Region 6 UIC Branch office twice per year. These reports will summarize methods and results of groundwater quality monitoring, CO_2 Injection Zone pressure tracking, and indirect geophysical monitoring for CO_2 plume tracking.

The PISC and Site Closure Plan will be reviewed every five years during the PISC period. Results of the plan review will be included in the PISC monitoring reports. The operational and monitoring results will be reviewed for adequacy in relation to the objectives of the PISC. The monitoring locations, methods, and schedule will be analyzed in relation to the size of the CO_2 Injection Zone, pressure front, and protection of USDWs. In case of changes to the PISC plan, a modified plan will be submitted to the EPA Region 6 UIC Branch Office within 30 days of such changes.

6.0 Non-Endangerment Demonstration Criteria

Prior to approval of the end of the post-injection phase, OLCV will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR §146.93(b)(2) and (3). This demonstration of USDW non-endangerment will be based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The demonstration will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Program Director to review the analysis. The demonstration will include the following sections:

6.1 Introduction and Overview

A summary of relevant background information will be provided, including the operational history of the injection project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

6.2 Summary of Existing Monitoring Data

A summary of all previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan document and this PISC and Site Closure Plan, including data collected during the injection and post-injection phases of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the UIC Program Director, and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization.

6.3 Summary of Computational Modeling History

The computational modeling results used for the AoR delineation will be compared to monitoring data collected during the operational and PISC periods. Monitoring data will also be compared with baseline data collected during the site characterization required under 40 CFR §146.82(a)(6) and §146.87(d)(3). The data will be used to update the computational model and monitor the site and will include both direct and indirect geophysical methods. Direct methods include measurements of pressure, temperature, fluid and dissolved gas chemistry. Indirect methods include Vertical Seismic Profile (VSP) and 2D seismic, Differential Interferometric Synthetic-Aperture Radar (DInSAR), and saturation logging using Pulsed Neutron (PNL).

Data generated during the PISC period will be used to show that the computational model accurately represents the storage site and can be used as a proxy to determine the plume’s properties and size. OLCV will demonstrate this degree of accuracy by comparing the monitoring data obtained during the PISC period with the model’s predicted properties (i.e., plume location, rate of movement, and pressure decay). Statistical methods will be employed to correlate the data and confirm the model’s ability to represent the storage site accurately. The validation of the computational model with the large quantity of measured data will be a significant element to support the non-endangerment demonstration. Further, the validation of the complete model over the entire area, and at the points where direct data collection has taken place, will ensure confidence in the model for those areas with no direct observation wells where the surface infrastructure precludes geophysical data collection.

6.4 Evaluation of Reservoir Pressure

OLCV will demonstrate non-endangerment to USDWs by showing that the pressure within the Injection Zone will rapidly decrease to levels near its pre-injection static reservoir pressure during the PISC period. Because increased pressure is the primary driving force for fluid movement that could endanger a USDW, the decay in the pressure differential provides strong justification that the injectate will no longer pose a risk to any USDWs.

OLCV will monitor the downhole reservoir pressure at various locations and intervals using a combination of surface and downhole pressure gauges. The measured pressure at a specific depth interval will be compared with the pressure predicted by the computational model, which was previously shown in Figure 1, Figure 2, and Figure 3. Agreement between the actual and predicted values will validate the accuracy of the model and further demonstrate non-endangerment.

6.5 Evaluation of Carbon Dioxide Plume

OLCV will use a combination of monitoring data, logs, geophysical surveys, and seismic methods to locate and track the movement of the CO_2 plume. The data produced by these activities will be compared with the modeled predictions (previously shown in Figure 7) using statistical methods to validate the model's ability to represent the storage site accurately. PISC monitoring data will be used to show the stabilization of the CO_2 plume as the reservoir pressure returns to its near-pre-injection state. The risk to USDWs will decrease when the extent of pure-phase CO_2 ceases to grow either laterally or vertically. The stabilization of the CO_2 plume combined with the lack of unmitigated Artificial Penetrations in the confining formation will be significant factors in the Project's demonstration of non-endangerment.

Fluids and dissolved gasses collected from USDW1 or soil or soil gas samples may be used to determine aqueous-phase CO_2 concentrations and mobilized constituents to assess USDW endangerment. If a demonstration can be made that the majority of the CO_2 has been immobilized via trapping mechanisms, then there is strong evidence that the risk to USDWs posed by the CO_2 plume has decreased. Modeling results, including sensitivity analyses, may also be used to demonstrate that plume migration rates are negligible based on available site characterization, monitoring, and operational data.

6.6 Evaluation of Emergencies or Other Events

In addition to the CO_2 plume, mobilized fluids may also pose a risk to USDWs, as the reservoir fluids include brines that are high in total dissolved solids (TDS) and contain hydrogen sulfide. The geochemical data collected from monitoring wells will be used to demonstrate that no mobilized fluids have moved above the Upper Confining Zone and therefore would not pose a risk to USDWs after the PISC period. Monitoring data indicating steady or decreasing trends of potential drinking water contaminants below actionable levels (e.g., secondary, and maximum contaminant levels) will be used for this demonstration.

To demonstrate non-endangerment, OLCV will compare the operational and PISC period fluid and dissolved gas samples from the lowermost USDW with the pre-injection baseline samples. This comparison is expected to show chemical similarity to baseline samples. Changes in chemistry will be evaluated to demonstrate attribution. This work will demonstrate the absence of CO_2 injectate or brine forced from the Injection Zone into the lowermost USDW.

Corrective action will be performed on Artificial Penetrations identified to be potential leak pathways. Based on this information, the potential for fluid movement through artificial penetrations of the confining formation does not present a risk of endangerment to any USDWs.

7.0 Site Closure Plan

OLCV will conduct site closure activities to meet the requirements of 40 CFR §146.93(e) as described below. OLCV will submit a final Site Closure Plan and notify the permitting agency at least 120 days in advance of its intent to close the site. Once the permitting agency has approved closure of the site, OLCV will plug the monitoring wells and submit a site closure report to EPA within 90 days of site closure. The activities described below represent the planned activities based on information provided to EPA. The actual site closure plan may employ different methods and procedures. A final Site Closure Plan will be submitted to the UIC Program Director for approval with the notification of the intent to close the site.

7.1 Plugging Monitoring Wells

Upon receiving authorization for site closure from the Director, all monitoring wells will be plugged within 90 days of site closure. All Injection Zone monitoring wells at the site will be plugged and abandoned using best practices to prevent any upward migration of the CO_2 or communication of fluids between the Injection Zone and USDWs. The deep monitoring wells in the Injection Zone have a direct connection between the injection formation and the ground surface; therefore, the well plugging program is specifically designed to prevent communication between the Injection Zone and USDWs. Details of the Plugging Program are located in the Plugging Plan document.

Before the wells are plugged, the internal and external integrity of the wells will be confirmed by conducting a pressure test and a cement and casing inspection log. The results of this logging and testing will be reviewed and approved by the appropriate regulatory agencies before plugging the wells.

Infrastructure removal and site restoration efforts will comply with applicable state and local requirements

7.2 Site Closure Report

A Site Closure Report (SCR) will be prepared and submitted to the Director within 90 days after site closure. The SCR will document the following aspects of the site closure process:

- Plugging of all injection, water withdraw and monitoring wells;
- Details of site restoration activities;
- Location of the sealed injection well on a survey plat submitted to the local zoning authority, a copy of which will be sent to the Regional Administrator for EPA Region 6;
- Notifications sent to state and local authorities;
- Records regarding the nature, composition, and volume of CO_2 injected;
- Records of pre-injection, injection, and post-injection monitoring; and
- Certifications that all injection and storage activities have been completed.

OLCV will record a notation on the deed of the property on which the injection well was located, which will include the following:

- An indication that the property was used for carbon dioxide sequestration,
- The name of the local agency to which the survey plat with injection well location was submitted,
- The volume of fluid injected,
- The Injection Zone or zones into which the fluid was injected, and
- The period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by the owner or operator for a period of 10 years following site closure. Additionally, the owner or operator will maintain the records collected during the post-injection site care period for a period of 10 years after which these records will be delivered to the UIC Program Director.