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).

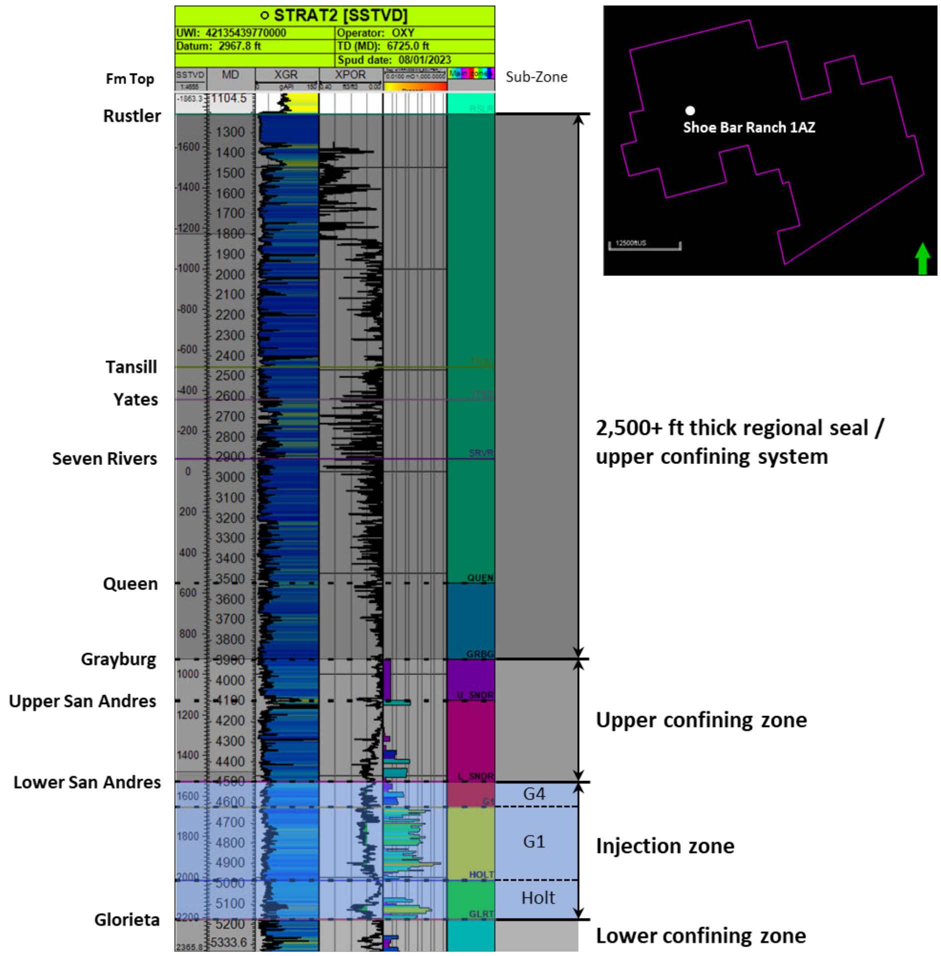

Figure 1— Stratigraphic column covering the Injection Zone, Upper Confining Zone, and Upper Confining System. UWI = Unique Well Identifier; SSTVD = True vertical depth subsea; MD = Measured depth; XGR = Gamma Ray log QCd by Oxy or OLCV petrophysicist; XPOR = porosity log QCd by Oxy or OLCV petrophysicist;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

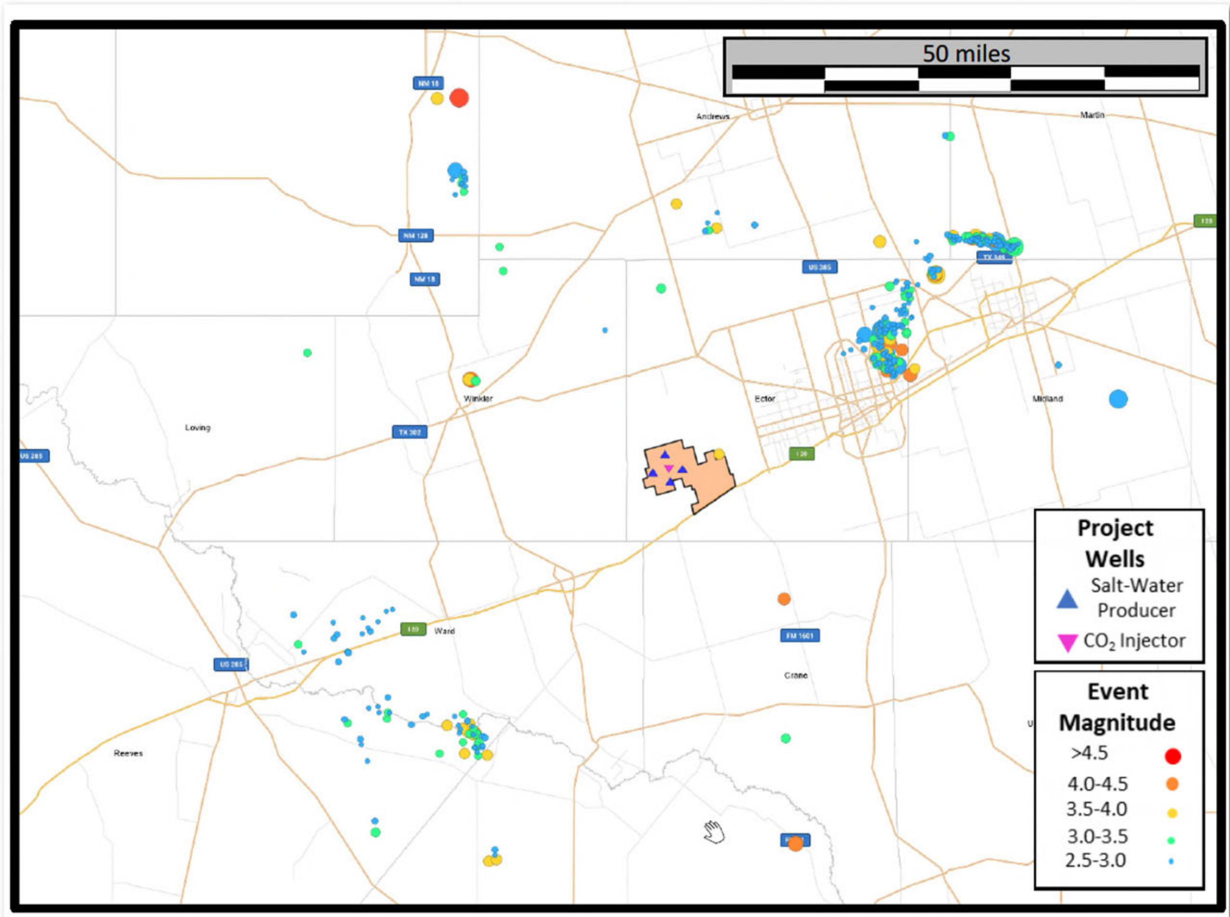

Figure 2— Seismic activity map showing a 50-mile radius around the Shoe Bar Ranch (shaded outline). The closest seismic event observed was 5 miles east of the proposed site in 2001. The seismic cluster 25 miles NE of the proposed Project site is currently attributed to SWD operations in deeper strata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

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

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.

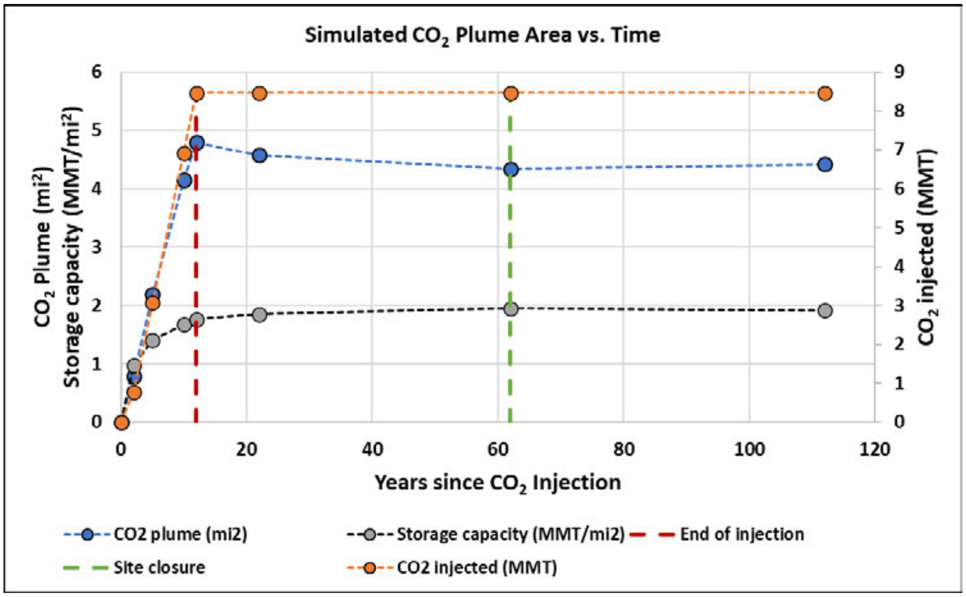

Figure 3—Dynamically simulated CO_2 plume area (blue dots), CO_2 injected mass (orange dots), and storage capacity (gray dots) from start of injection to 100 years post-injection. Plume area is based on the saturation extent of CO_2 in the reservoir.

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.

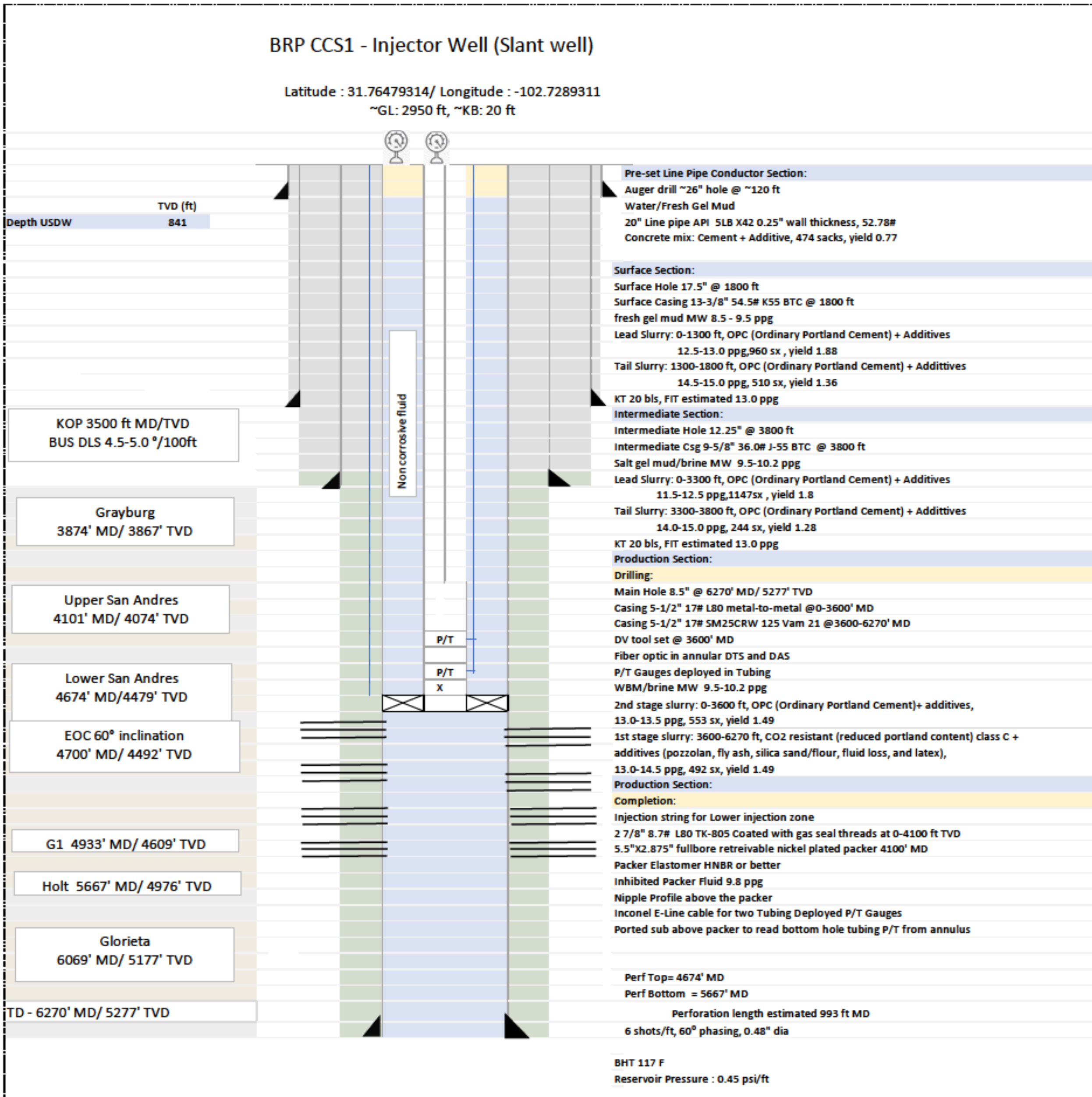

Figure 4—BRP CCS1 well proposed schematic

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.

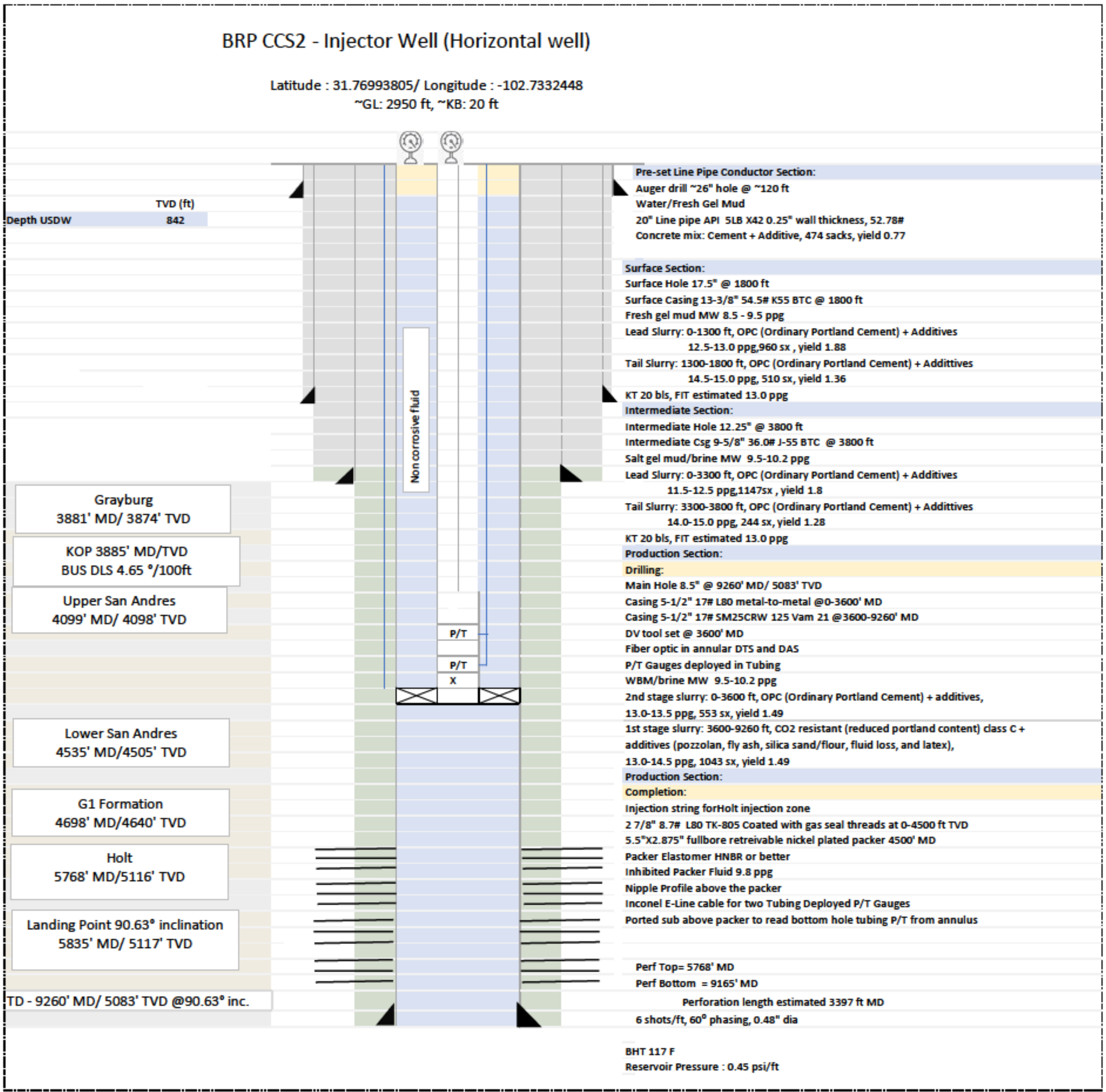

Figure 5. BRP CCS2 well proposed schematic

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 to the kickoff point (KOP) at 3,050 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 3,830 ft MD. Drill tangent section directional holding inclination to 6,842 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 3,450 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.

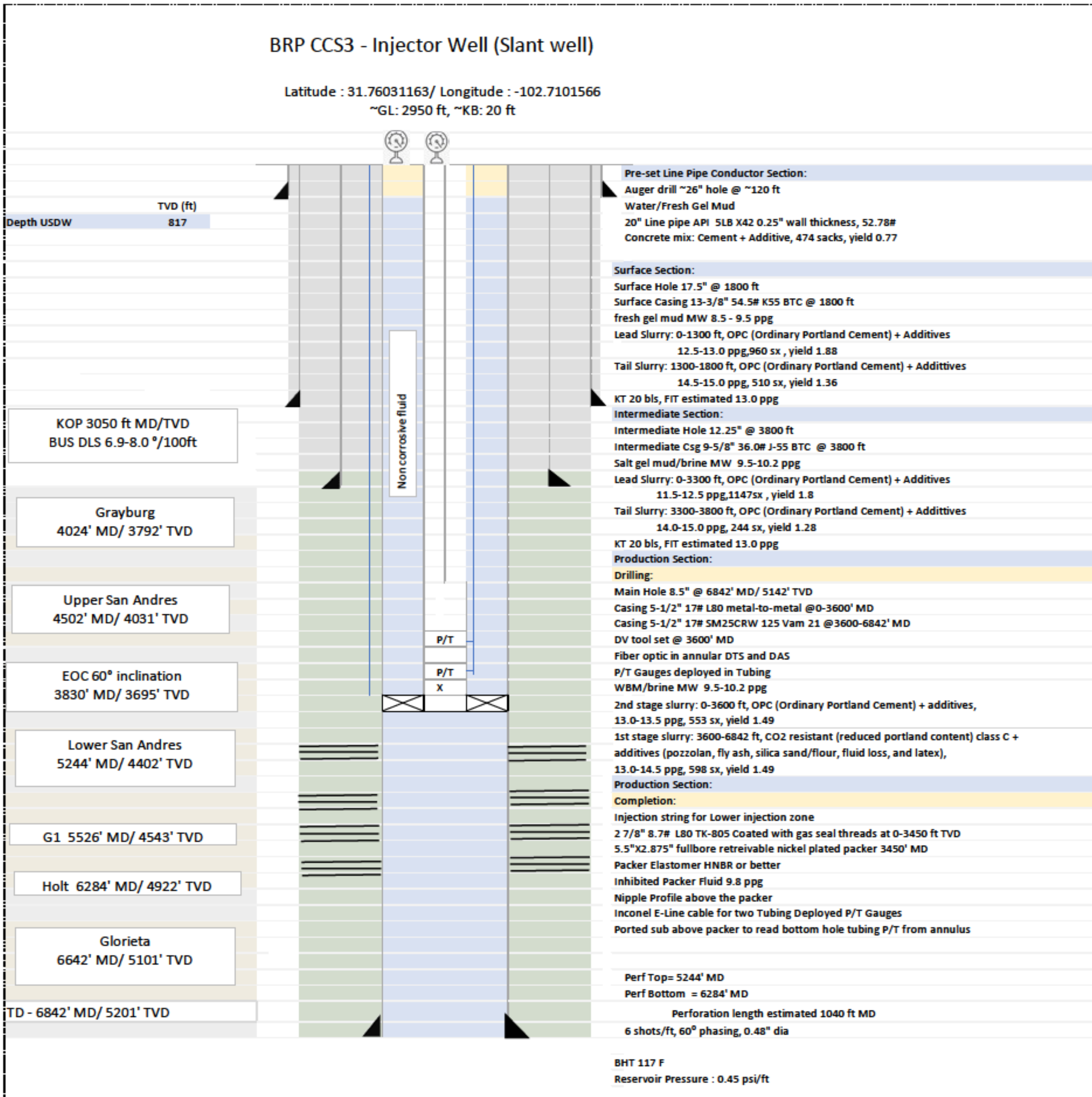

Figure 6. BRP CCS3 well proposed schematic

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

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	25.0	Million standard cubic feet per day
Daily average injection rate BRP CCS1	21.9	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	8.24	Million standard cubic feet per day
Daily average injection rate BRP CCS2	7.88	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 2. 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
Particulates ($CaCO_3$)	<1 ppm by weight

Component	Specification
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 Monitor 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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