Technical Review of Subpart RR MRV Plan for Rose Carbon Capture and Sequestration Facility

April 2026

Contents

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted by ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) for Rose Carbon Capture and Sequestration Facility (Rose) located in Beaumont, Texas. Note that this evaluation pertains only to the subpart RR MRV plan for Rose, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

1 Overview of Project

Section 3 of the MRV plan states that Rose is in Jefferson County, Texas, within the Gulf Coast Basin, an area known for its favorable geologic formations for CO_2 injection and containment. The project is designed to collect, transport, and sequester a maximum of 5 million metric tons (MMT) of CO_2 per annum. Rose plans to utilize three injection wells to sequester approximately 53 MMT of CO_2 over a 13-year period. CO_2 will be injected into the Fleming and Upper Frio formations in multiple intervals as part of a staged approach. The project includes a comprehensive monitoring network (Figure 3-1) consisting of an above-zone monitoring well, an in-zone monitoring well, and three shallow monitoring wells installed in the underground sources of drinking water (USDW) (i.e., the upper Chicot Aquifer) to support in-zone plume tracking, detection of potential above-zone CO_2 migration, and protection of drinking water resources.

Figure 3-2 in the MRV plan shows a simplified diagram of the injection process, following the flow of CO_2 from its source to each of the three injection wells. The injected CO_2 will come from multiple high concentration industrial sources, including clean hydrogen and ammonia production facilities, direct reduced iron plants, natural gas treatment facilities, and other industrial sources that feed directly into ExxonMobil's Gulf Coast CO_2 pipeline network. The pipeline network maintains a CO_2 composition of >97 percent (%) CO_2, <1% hydrogen, and <3% methane.

The MRV plan states that the3 project area is suitable for CO_2 injection into the proposed injection intervals of the Fleming and Upper Frio formations. The sands within these formations exhibit high porosity and permeability that are ideal for CO_2 storage and are of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO_2 stream. The MRV plan also states that both the upper composite confining zone (UCCZ) and Anahuac Shale are thick, extensive, continuous sealing intervals extending across the AOR, MMA, and miles beyond in every direction. Their lateral extent has been confirmed both in the literature and through seismic and stratigraphic analysis of regional as well as local well data. An extensive data collection campaign on the project confirms the seals and their efficacy. They are sufficient to contain the injected CO_2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).

The description of the project provides the necessary information for 40 CFR 98.448(a)(6).

2 Evaluation of the Delineation of the Maximum Monitoring Area (MMA) and Active Monitoring Area (AMA)

As part of the MRV plan, the reporter must identify and delineate both the maximum monitoring area (MMA) and active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines the MMA as "the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." Subpart RR defines the AMA as "the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) the area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; (2) the area projected to contain the free phase CO_2 plume at the end of year t + 5." See 40 CFR 98.449.

Section 3.4 of the MRV plan states that the Fleming and Upper Frio formations were assessed to characterize the sealing effects of the confining zone and reservoir heterogeneity within the injection zone. Based on the analysis and understanding of the project area, a three-dimensional geologic model was developed to estimate the storage potential for the CO_2 and evaluate its confinement, both laterally and vertically.

Rose states that Schlumberger's Petrel™ software was chosen to create the detailed geologic model for the project. This software is used worldwide and combines information from logs and seismic data to build a sophisticated representation of underground reservoirs. The geologic model incorporates the available data for all relevant subsurface layers of the project site.

The MRV plan states that the geologic model was used as an input into the Schlumberger Eclipse-300™ numerical reservoir simulator. Eclipse-300™ is a widely recognized tool used for modeling both compositional and unconventional reservoirs. The simulator uses advanced computational methods and equation-of-state algorithms to produce a reliable prediction for CO_2 sequestration projects. The software has modules and options specifically intended to allow the study of CO_2 injection activities, can handle large data sets and multiple grids, and offers various tools for data management, visualization, and uncertainty analysis.

According to the MRV plan, the areal extent of the aggregated CO_2 plume is expected to grow rapidly during injection and slow after injection ceases. The areal growth rate is expected to reach a stability threshold, which is defined conservatively at less than 0.25% per year, 39 years after the start of injection, demonstrating plume stability. The stabilized CO_2 plume is shown on Figure 4-1 in the MRV plan.

Section 4.1 of the MRV plan states that subpart RR defines the MMA as the area that must be monitored and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized, plus an all-around buffer zone of at least one-half mile. Rose has simulated the maximum plume extent to occur 26 years post-injection (39 years after the start of injection). Figure 4-1 in the MRV plan shows the extent of the stabilized CO_2 plume with a one-half mile buffer area.

Section 4.2 of the MRV plan states that Rose has established one AMA boundary for 39 years and does not anticipate expansion of the monitoring area under 40 CFR 98.448 based on the currently planned operating conditions. Given the definitions used to delineate the MMA and the AMA, the AMA is functionally equivalent to the MMA. The AMA is composed of two combined areas:

- The area projected to contain the free phase CO_2 plume at the end of year "t," plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.
- The area projected to contain the free phase CO_2 plume at the end of year t+5.

Rose assumed an active monitoring timeframe of t = 39 years post start-up, aligning with the expected stabilization of the CO_2 plume. This AMA is controlled by the 39-year plume plus the one-half mile buffer.

The delineations of the MMA and AMA are acceptable per the requirements in 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV plan are clearly delineated in the plan and are consistent with the definitions in 40 CFR 98.449.

3 Identification of Potential Surface Leakage Pathways

As part of the MRV plan, the reporter must identify potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and duration of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). Rose identified the following as potential leakage pathways in Section 5 of the MRV plan that required consideration:

- Injection or monitoring well casing or cement seal
- Legacy well casing or cement seal
- Injection well monitoring equipment failure
- UCCZ
- Induced or natural seismic event
- Surface equipment

3.1 Leakage through Injection or Monitoring Well Casing or Cement Seal

Section 5.1 of the MRV plan states that corrosion of the mechanical components or casing cement are two hypothetical release mechanisms identified for the injection and monitoring wells that have the potential to release CO_2. For example, Rose explains that CO_2 detected at an injection or monitoring well potentially implies that internal or external mechanical integrity of a well may have been compromised, causing release of CO_2. Potentially, CO_2 or brine could be released at an injection or monitoring well due to subsurface cement degradation or annular space defects in cement completion. In the case of either of these hypothetical examples, the likelihood of surface leakage due to a breakdown of materials in injection or monitoring wells is very low because of the CO_2 compatible materials used and the continuous monitoring techniques deployed. Furthermore, the plan states that the timing of such an event would occur during the injection and/or post-injection phase, and that the magnitude would be quantified based on operating conditions at the time of release.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through injection or monitoring well casing or cement seal.

3.2 Leakage through Legacy Well Casing or Cement Seal

Existing Wells Within the MMA

Section 5.2 of the MRV plan states that legacy wells that penetrate the UCCZ were identified within the predicted stabilized CO_2 plume boundary and MMA. Within the stabilized CO_2 plume, one legacy well was plugged as a corrective action prior to operation; the other legacy well was recompleted as an above-zone monitoring well for the project. Rose asserts that all other legacy wells within the MMA that penetrate the UCCZ are located outside of the stabilized CO_2 plume boundary. Current reservoir models predict no migration of CO_2 plume nor brine to reach the legacy wells in the MMA; therefore, the likelihood of leakage is low. Furthermore, the plan states that the timing of such an event would occur during the injection and/or post-injection phase, and that the magnitude would be quantified based on operating conditions at the time of release.

Future Wells within the MMA

Section 5.2 also states that future wells drilled through the UCCZ will be completed with the appropriate materials and integrated into the testing and monitoring plan. Drilling activity within the MMA and above the UCCZ do not pose a risk as a leakage pathway. Any drilling permits issued by the Railroad Commission of Texas (RRC) within the MMA must comply with 16 Texas Administrative Code 3.13, which requires operators drilling within a quarter-mile radius of an injection well to set steel casing and cement above and across the identified injection zone and all flow zones or zones that contain corrosive formation fluids. Potential leakage pathways caused by future drilling activity within the MMA and penetrating the UCCZ are not expected to occur. Furthermore, the plan states that the timing of such an event would occur during the injection and/or post-injection phase, and that the magnitude would be quantified based on operating conditions at the time of release.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through legacy well casing or cement seal.

3.3 Leakage from Well Monitoring Equipment Failure

Section 5.3 of the MRV plan states that loss of mechanical integrity of well pressure equipment may occur during operation of the injection wells. A pressure gauge (or other similar equipment) malfunction could create a shut-off valve malfunction and result in an uncontrolled pressure situation and CO_2/brine crossflow to USDW by fault or fracture activation or well casing and/or cement failure in the vicinity of the production casing perforations. Furthermore, the plan states that the timing of such an event would occur during the injection and/or post-injection phase, and that the magnitude would be negligible.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected from well monitoring equipment failure.

3.4 Leakage through the UCCZ

Section 5.4 of the MRV plan states that several potential risk scenarios were considered that involve a hypothetical release through naturally occurring faults and fractures or other penetrations of the UCCZ, creating a migration pathway for CO_2. Based on Rose's assessment of the subsurface, one visible fault was identified that extends through the UCCZ within the MMA. The maximum displacement, which occurs outside the MMA, is much less than the thickness of the UCCZ (13% of total thickness). Seal analysis indicates high sealing properties such that the integrity of the UCCZ should not be compromised, indicating that this is not a likely leakage pathway for CO_2. Furthermore, the plan states that the timing of such an event would occur during the injection and/or post-injection phase, and that the magnitude would be negligible.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through the UCCZ.

3.5 Leakage from an Induced or Natural Seismic Event

Section 5.5 of the MRV plan states that based on the projected operating conditions in addition to the regional and local geologic conditions, injection operations are not expected to result in an induced seismic event mandating a response action. Rose states that induced or natural seismic events would be monitored at a minimum during the injection phase, and the anticipated magnitude is negligible.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected from an induced or natural seismic event.

3.6 Leakage from Surface Equipment

Section 5.6 of the MRV plan states that the surface components of the injection system include the CO_2 injection wellheads and the associated surface piping that transports CO_2 from the mass flow meters located on the central pad to the wellheads.

To mitigate the potential for surface leakage of CO_2 from equipment, Rose will implement the following measures:

- Adherence to Class VI regulatory requirements for well construction (40 CFR 146.86), well operation (40 CFR 146.88), and testing and monitoring of surface facilities (40 CFR 146.90).
- Continuous monitoring via a Supervisory Control and Data Acquisition (SCADA) system monitored remotely by ExxonMobil's Operations Control Center. Surface equipment pressure and flow rates are included in the SCADA system.
- Routine visual inspections and preventative maintenance of all surface components.
- Surface equipment will be inspected, tested, and calibrated in accordance with manufacturer specifications prior to commissioning.

The MRV plan concludes that the likelihood of CO_2 leakage from surface equipment during injection operations is very low. Rose states that in the unlikely event of a release, the volume would be limited to the amount of CO_2 contained within the surface piping and equipment due to automatic shut-off devices. The plan also states that the quantification approach will be adaptable to the specific characteristics of each leakage scenario, with methods selected based on site conditions and the nature of the release.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected from surface equipment. In summary, the MRV plan provides an acceptable characterization of potential CO_2 leakage pathways as required by 40 CFR 98.448(a)(2).

4 Strategy for Detecting and Quantifying Surface Leakage of CO_2 and for Establishing Expected Baselines for Monitoring

40 CFR 98.448(a)(3) requires that an MRV plan contains a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan includes a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Sections 5, 6, and 8 of the MRV plan discuss the strategies that Rose will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in the previous section to meet the requirements of 40 CFR §98.448(a)(3).

Section 6.0 of the MRV plan states that Rose installed and will use continuous measurement devices to monitor injection pressure, temperature, rate, and mass; the pressure on the annulus between the tubing and the long-string casing; and the temperature of the CO_2 stream, as required under [40 CFR 146.88(e)(1), 146.89(b), and 146.90(b)]. Rose states that data will also be collected to document the addition or removal of any fluid from the annulus system. Data interfaces will be created for equipment that is not linked directly to a data management system or suitable equivalent and will be integrated into a unique surveillance platform. In the monitoring program, the sensors, transducers, and controllers will be connected in a central platform to monitor operating conditions, set alarms for alerting operations of malfunction, and maintain safety protocols in case of abnormal conditions. Rose explains that alarms will be set for pressures outside described tolerances (generally 90% of fracture gradient and prescribed wellhead pressures) and changes in annular pressure and fluid).

Instrument calibration standards, precision, and tolerances will be maintained based on manufacturer recommendations. The automated control system data will be monitored for anomalies on a regular basis. Average values will be compared to baseline and predicted values to assess if there are any significant deviations relevant to integrity or containment.

The operating parameters, monitoring values, laboratory results, reports, and surveillance documents for the project will be stored in a database to support MMA reviews, quality assurance/quality control review programs, and routine reporting. Table 6-1 in the MRV plan (copied below) provides a summary of the typical sampling devices, locations, and data storage frequencies for the continuous monitoring program.

Continuous Sampling Parameter	Device(s)	Location	Estimated Min. Sampling Frequency	Estimated Min. Recording Frequency
Surface Injection Pressure	Wellhead Pressure Logger	Surface, injection well piping	5 seconds	5 minutes
Downhole pressure gauge	Pressure Gauges	Injection Unit	5 seconds	5 minutes
Injection rate	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Injectate density	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Total mass injected	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Annular pressure	Pressure Gauge	Well Head	5 seconds	5 minutes
Annulus fluid volume	Level Transmitter	Annulus System Tank	5 seconds	5 minutes
Carbon dioxide stream temperature	Coriolis Meter/Wellhead Pressure Logger	Well Head, injection well flowing	5 seconds	5 minutes
Note: The word “continuous” is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument’s normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application. Measurements that are collected “continuously” will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.				

Additionally, as part of its Class VI well permit application, Rose developed a comprehensive testing and monitoring strategy for the project using a risk-based approach. The monitoring frequency is outlined in Table 6-2 in the MRV plan (copied below), and the monitoring strategy is outlined in Table 6-3 (see MRV plan). The monitoring program aligns with the three operational phases of the project: (1) the pre-operational baseline data collection phase; (2) the operational phase for the three injectors; and (3) the PISC phase. During the pre- and early operational phases, a selection of technologies will be used to develop baseline seismic response, pressure, temperature, and certain geochemical parameters needed to monitor the CO_2 plume and pressure front.

Rose states that this testing and monitoring information will also be used to assess the predictive modeling results and refine the model as necessary. During the operational phase, the frequency of direct monitoring data collection activities will be aligned with the initiation of injection into each new stage of the injection intervals. The accuracy of the model at predicting the CO_2 plume and pressure front migration will inform the frequency of indirect monitoring data collection. Upon assessment of the predictive capabilities of the model, the frequency of indirect monitoring activities listed in Table 6-2 may be reduced as justified by the rates of change and variations observed by the monitoring results. The data generated from the implementation of this plan provides the basis to assess the confinement of the CO_2 in the permitted injection formations during the active injection phase.

Section 5 of the MRV plan details the detection methods in place for each leakage pathway. Rose will continue to assess the feasibility of emerging technologies and conduct performance evaluations to continue to improve the performance of the testing and monitoring program.

Equipment / Measurement	Regulation (40 CFR)	Objective	Frequency
Coriolis flow meter	146.90b	Measure mass flow rate	Continuously
Corrosion coupon	146.90c	Measure corrosion levels on the types of metal used in the Project	Quarterly
Injection stream sampling	146.90a	Provide more detailed analysis via periodic lab analysis of injection stream	Quarterly
Central pad temperature gauge	146.90a	Measure temperature of the total injection stream at the pad before partitioning to injections	Continuously
Injection wellhead tubing Pressure gauge	146.90a	Measure downstream of choke	Continuously
Injection wellhead annulus Pressure gauge	146.90b	Verify annulus pressure maintained	Continuously

Equipment / Measurement	Regulation (40 CFR)	Objective	Frequency
Injection annulus pressure test	146.89b	Verify absence of leak in annulus	Annually
Injection Well downhole pressure and temperature gauge for active/open injection interval	146.90b	Measure downhole pressure and temperature (injection mass to volume conversion, verifying that it is not exceeding maximum pressure)	Continuously
	146.90f	Measure falloff of pressure after abandoning injection stage and before initiating injection in next stage above	At the end of every injection stage
	146.90g(1)	Direct measurement of pressure, sensitive to pressure from other injections, especially when injection intervals are staggered between wells	Continuously
Time-lapse surface seismic survey	146.90g(2)	Indirect method to monitor CO_2 plume growth in the subsurface over time	Frequency from start of operations: Survey Event #1: completed; Survey Event #2: one to 3 years; Survey Event #3: 6 to 8 years; Survey Event #4: 13 years. Contingent additional survey events as needed and approved by UIC Program Director.
	146.87a(3)(ii)	DTS for cement long portion of long-string casing where fiber is cemented in place	One-time event
	146.90e	DTS to assess potential flow through channels through or along cement	Annually
Injection well casing inspection log	146.90e	Through-tubing log to detect loss of metal mass in casing due to corrosion	Baseline only; repeat survey is triggered if risk of leakage is apparent or upon request by UIC Program Director
In-zone monitoring well downhole pressure and temperature gauges	Not required 146.90g(1)	Collect pressure and temperature measurements for evaluating the rate of CO_2 plume and pressure front movement	Continuously
Above-zone monitoring well fluid sampling from above UCCZ	146.90d	Above UCCZ fluid collection is recommended by guidelines	Quarterly

Equipment / Measurement	Regulation (40 CFR)	Objective	Frequency
USDW fluid sampling	146.90d	Sample fluids from the Chicot Aquifer which is the most prolific USDW aquifer within the MMA, as recommended by guidelines, and analyze composition	Quarterly
DTS = Distributed Temperature Sensing; UCCZ = upper composite confining zone; UIC = Underground Injection Control; USDW = underground source of drinking water Note: The word “continuous” is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument’s normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application. Measurements that are collected “continuously” will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.			

4.1 Detection of Leakage through Injection or Monitoring Well Casing or Cement Seal

Section 5.1 of the MRV plan states that leakage through injection or monitoring well casing or cement seal will be detected via well casing and cement bond logs conducted on injection wells during shut-ins to assess loss decay or corrosion more than acceptable limits via distributed temperature sensing (DTS) as described in Table 6-2. Additional detection methods include deficiency identified during pressure falloff tests and annulus pressure tests, wellhead pressure exceeds the maximum pressure specified in the permit, annulus pressure indicates a loss of external or internal integrity/containment, CO_2 plume and pressure front tracking above UCCZ indicates a change in conditions, fluid samples from above the UCCZ and/or USDW indicate a statistically significant change in conditions, and mechanical integrity testing identifies a potential issue in the integrity of the well.

Table 6-2 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through injection or monitoring well casing or cement seal. Thus, the MRV plan provides adequate characterization of Rose’s approach to detect potential leakage through injection or monitoring well casing or cement seal as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through Legacy Well Casing or Cement Seal

Section 5.2 of the MRV plan states that leakage through legacy well casing or cement seal will be detected using CO_2 plume and pressure front tracking, fluid sampling from above the UCCZ and/or USDW, and legacy well re-entry to collect casing and cement bond logs to assess well integrity and well completion materials.

Table 6-2 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through legacy well casing or cement seal. Thus, the MRV plan provides adequate characterization of Rose’s approach to detect potential leakage through legacy well casing or cement seal as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage from Well Monitoring Equipment Failure

Section 5.3 of the MRV plan states that leakage from well monitoring equipment failure will be detected via anomalies in pressure and rate monitoring, pressure falloff tests, and annulus pressure tests.

Table 6-2 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected from well monitoring equipment failure. Thus, the MRV plan provides adequate characterization of Rose's approach to detect potential leakage from well monitoring equipment failure as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage through the UCCZ

Section 5.4 of the MRV plan states that leakage through the UCCZ will be detected using CO_2 plume and pressure front tracking, fluid sampling from above the UCCZ and/or USDW, and third party direct or indirect data identification.

Table 6-2 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through the UCCZ. Thus, the MRV plan provides adequate characterization of Rose's approach to detect potential leakage through the UCCZ as required by 40 CFR 98.448(a)(3).

4.5 Detection of Leakage from an Induced or Natural Seismic Event

Section 5.5 of the MRV plan states that Rose has installed a permanent seismicity monitoring system on-site, which is being monitored by a third party to detect seismic activity prior to and during injection operations. This array has been recording baseline data since July 1, 2024. The design of the array consists of a near-surface network of seismometers with continuous data sampling, incorporation of publicly available data, and telemetry to cloud-based storage. Near-real-time, high-resolution signal processing and quality assurance will be implemented for event detection, magnitude, and location accuracy. The MRV plan also states that if a review of the data indicates that a seismic event of magnitude 2 or larger occurred within a 5.6-mile radius of an injector, Rose will notify the UIC Program Director to jointly assess if the events are likely to be associated with the operations, and, if so, implement response actions for seismic events.

Table 6-2 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected from an induced or natural seismic event. Thus, the MRV plan provides adequate characterization of Rose's approach to detect potential leakage from an induced or natural seismic event as required by 40 CFR 98.448(a)(3).

4.6 Detection of Leakage from Surface Equipment

Section 5.6 of the MRV plan states that a data management system, or a suitable equivalent, will be used to facilitate the continuous collection of key operational parameters, including:

- Intake pressure at the central pad transfer point.
- Pressure within the distribution system to each injection well.
- Pressure at each injection wellhead.

The MRV plan also states that two Coriolis flow meters installed at the central pad will be used to directly measure the mass flow rate of the injected fluid. Rose states that the Coriolis meters will be calibrated in accordance with the manufacturer's specifications.

During injection, Rose will review and interpret continuously monitored parameters against permitted limits. This review will also include trend analyses to assess maintenance, recalibration, or system optimization opportunities.

Table 6-2 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected from surface equipment. Thus, the MRV plan provides adequate characterization of Rose's approach to detect potential leakage from surface equipment as required by 40 CFR 98.448(a)(3).

4.7 Quantifying CO_2 Leakage

Section 8.2 of the MRV plan states that in addition to monitoring the mass of CO_2 received, injected into the subsurface, emitted from equipment leaks, and sequestered in subsurface geologic formations, Rose will monitor and report the total estimated CO_2 emitted in the event of surface leakage. The quantification approach will be adaptable to the specific characteristics of each leakage scenario, with methods selected based on site conditions and the nature of the release. These methods may include direct monitoring data, engineering-based calculations, or the application of established emission factors.

Although the specific types of leaks cannot be anticipated ahead of time, Rose states that quantification methods will adhere to accepted engineering standards and best practices, with example approaches for different leak types. If anomalies of the monitored parameters (i.e., injection zone pressure, etc.) are detected, field personnel will investigate to identify the issue. For minor problems, repairs will be completed promptly and any resulting CO_2 emissions will be documented in the annual subpart RR report. In cases requiring more extensive repairs, Rose will evaluate the best method for estimating the leaked CO_2 based on relevant factors such as leakage rate, concentration, and duration.

The MRV plan also states that issues such as anomalies in annular pressure or other concerns identified during maintenance activities will be addressed using the same protocol. Field personnel will examine the affected equipment to assess the problem. If the issue is minor, repairs will be completed promptly during the inspection and any associated CO_2 emissions will be recorded in the annual subpart RR report. For more significant repairs, the well will be shut-in until the necessary work can be completed. In such cases, Rose will evaluate the best method for estimating the leaked CO_2 based on relevant factors such as leakage rate, concentration, and duration.

4.8 Determination of Baselines

Section 7 of the MRV plan identifies the strategies that Rose will use to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR 98.448(a)(4). The MRV plan states that Rose has developed a comprehensive pre-injection (baseline) testing and monitoring plan to develop reference conditions against which future data will be compared throughout the operational phase of the project. Rose states that baseline data collection has been completed or is underway, and comparisons to these baseline conditions will be used to evaluate any deviations that may occur during injection activities.

Groundwater Sampling

Rose has collected baseline groundwater quality and geochemical samples from the Above-Zone Monitoring Well No. 1 (Bead Farm Co. #1) installed in the formation directly above the UCCZ and from the three USDW monitoring wells at the project site.

Continuous Pressure/Temperature Monitoring

Rose states that reservoir temperature and pressure will be monitored using a downhole gauge installed in the tubing above the production packer. At In-Zone Monitoring Well No. 1, a tubing encapsulated conductor cable with in-line pressure/temperature gauges will be installed. Baseline measurements will be collected prior to the start of injection to establish reference operating conditions.

Seismic Survey

Rose states that a seismic survey to monitor the CO_2 plume extent is planned to take place four times throughout the life of the project. The baseline survey was conducted using the data purchased and reprocessed in 2024/2025 for site characterization.

Visual Inspection

Rose states that prior to operations, surface equipment will be inspected and tested to confirm proper function and integrity.

Soil Gas and Air Monitoring

Rose states that soil gas and air monitoring are proposed only as responses to triggering events. However, baseline samples of each have been collected.

Thus, Rose provides an acceptable approach for detecting and quantifying surface leakage and for establishing the expected baselines for monitoring CO_2 surface leakage in accordance with 40 CFR 98.448(a)(3) and 40 CFR 98.448(a)(4).

5 Considerations Used to Calculate Site-Specific Variables for the Mass Balance Equation

Section 8.0 of the MRV plan summarizes the considerations that Rose intends to use to calculate site-specific variables for the mass balance equation. Rose states that CO_2 will be injected into saline aquifers via three injection wells at the facility. To accommodate the anticipated injection volume, two separate flowlines will be utilized at the central pad. Each flowline will be equipped with a mass flow meter to continuously measure and record the quantity of CO_2 injected. Rose will utilize the two flow meters to estimate CO_2 injected for the Project. All CO_2 injected will be sourced from a single pipeline that enters the central pad.

5.1 Calculation of Mass of CO_2 Received

Section 8.1 of the MRV plan states that the CO_2 stream received will be wholly injected into the storage complex. Therefore, pursuant to 40 CFR 98.444(a)(4) and 98.444(b), the annual CO_2 received will be equivalent to the annual CO_2 injected.

Rose provides an acceptable approach for calculating the mass of CO_2 received under subpart RR.

5.2 Calculation of Mass of CO_2 Injected

Section 8.1 of the MRV plan also states that the point of measurement for CO_2 injected is the mass flow meters located at the central pad. CO_2 will be measured through two-meter runs, each equipped with a mass flow meter. These meter runs will merge at a single point, from which the CO_2 is distributed to the three injection wells via flowlines. The annual CO_2 injected at each well will be calculated using Equation RR-4.

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_2,p,u}$$

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

Additionally, the sum of the mass of CO_2 injected through the two mass flow meters will be calculated using Equation RR-6.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) through all injection wells.

$CO_{2,u}$ = Annual CO2 mass injected (metric tons) as measured by flow meter u.

u = Flow meter.

Rose provides an acceptable approach for calculating the mass of CO_2 injected under subpart RR.

5.3 Calculation of Mass of CO_2 Lost through Surface Leakage

Section 8.2 of the MRV plan states that should surface leakage occur, Rose will document and report the estimated mass of CO_2 released in the annual subpart RR submission, along with a summary of the measurement or estimation techniques employed. Data and supporting documentation will be retained to ensure regulatory compliance and transparency. The total annual mass of CO_2 emitted from all leakage pathways will be calculated using Equation RR-10.

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

Rose provides an acceptable approach for calculating the mass of CO_2 lost by surface leakage under subpart RR,

5.4 Calculation of Mass of CO_2 Emitted from Equipment Leaks and Vented Emissions (CO_{2FI})

Section 8.3 of the MRV plan also states that the annual mass of CO_2 emitted from equipment leaks and vented emissions between the injection flow meter and wellhead will be measured and reported in accordance with the requirements of 40 CFR 98.444(d).

Rose provides an acceptable approach for calculating the mass of CO_2 emitted from equipment leaks and vented emissions under subpart RR.

5.5 Calculation of Mass of CO_2 Sequestered in Subsurface Geologic Formations

Section 8.4 of the MRV plan states that the total annual mass of CO_2 sequestered in geologic formations for the reporting year will be calculated and reported using Equation RR-12.

$$CO_2 = CO_{2I} – CO_{2E} – CO_{2FI}$$

where:

> CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.
>
> CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.
>
> CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.
>
> CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98.

Rose provides an acceptable approach for calculating the mass of CO_2 sequestered in subsurface geologic formations under subpart RR.

6 Summary of Findings

The subpart RR MRV plan for Rose Carbon Capture and Sequestration Facility meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specify the requirements for MRV plans, are summarized below along with a summary of relevant provisions in Rose's MRV plan.

Subpart RR MRV Plan Requirement	Rose Carbon Capture and Sequestration Facility MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 4 of the MRV plan delineates the MMA and AMA. The MRV plan states that Rose has simulated the maximum plume extent to occur 26 years post-injection (39 years after the start of injection). Figure 4-1 shows the extent of the stabilized CO_2 plume with a half-mile buffer area. Rose also states that the AMA is functionally equivalent to the MMA.

40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 5 of the MRV plan identifies the following potential surface leakage pathways and evaluates the likelihood, magnitude, and timing of surface leakage through each: integrity of injection or monitoring well casing or cement seal, integrity of legacy well casing or cement seal, injection well monitoring equipment failure, integrity of the UCCZ, induced or natural seismic event, and integrity of surface equipment.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Sections 6 and 8 of the MRV plan discuss the strategy that Rose will use to detect and quantify any surface leakage of CO_2. The MRV plan states that the quantification method will be adaptable to the specific characteristics of each leakage scenario, with methods selected based on site conditions and the nature of the release. These methods may include direct monitoring data, engineering-based calculations, or the application of established emission factors.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 7 of the MRV plan describes the strategy that Rose will use for establishing the expected baselines for monitoring CO_2 surface leakage. Rose will use groundwater sampling, continuous pressure/temperature monitoring, seismic surveys, visual inspections, and soil gas and air monitoring.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 8 of the MRV plan summarizes the considerations that Rose intends to use to calculate site-specific variables for the mass balance equation. Rose uses Equation RR-12 to calculate the annual mass of CO_2 sequestered in subsurface geologic formations.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 1 of the MRV plan identifies the well identification numbers used for the UIC permit application as well as the UIC permit class. Rose submitted UIC Class VI permits for the three injection wells.

40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 9 of the MRV plan states that implementation of the MRV Plan will commence immediately following the effectiveness of the permit. The MRV plan also states data collection activities will be initiated prior to the start of injection to develop baseline conditions and will continue throughout the operational phase of the project and into the post-injection site care (PISC) period, until the EPA approves the cessation of subpart RR reporting.

Appendix A: Submissions and Responses to Requests for Additional Information

Rose Carbon Capture and Sequestration Facility

Facility (GHGRP) ID: 590420

MONITORING, REPORTING, AND VERIFICATION PLAN

Rose Carbon Capture and Storage Facility

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

November 2025

TABLE OF CONTENTS

List of Tables

List of Figures

List of Acronyms and Abbreviations

Name	Definition
%	percent
AMA	active monitoring area
AoR	Area of Review
API	American Petroleum Institute
CCS	carbon capture and sequestration or carbon capture and storage
CFR	Code of Federal Regulations
CO_2	carbon dioxide
CO_{2I}	carbon dioxide injected
CO_{2E}	carbon dioxide emitted via surface leakage
CO_{2FI}	mass of CO_2 emitted from equipment leaks and vented emissions
COC	Chain-of-Custody
DTS	Distributed Temperature Sensing
EPA	U.S. Environmental Protection Agency
ExxonMobil	ExxonMobil Low Carbon Solutions Onshore Storage LLC
GHG	greenhouse gas

Name	Definition
KB	Kelly bushing
LCZ	Lower Confining Zone
mD	millidarcy
MMA	maximum monitoring area
MRV	Monitoring, Reporting, and Verification
PISC	post-injection site care
Project	Rose Carbon Capture and Sequestration Project or Rose Carbon Capture and Storage Project
RRC	Railroad Commission of Texas
Storage	Sequestration
TVD	true vertical depth
UCCZ	upper composite confining zone
UIC	Underground Injection Control
USDW	underground sources of drinking water

Distribution Sheet

This Monitoring, Reporting, and Verification Plan was prepared and approved by ExxonMobil for use in collecting information for the reporting of greenhouse gases received and injected by the Rose Carbon Capture and Sequestration Project. ExxonMobil will incorporate the monitoring and reporting actions described in this document into the standard ExxonMobil operating program, as appropriate, for the control of work associated with the scope of data quality and detection monitoring for the Project.

Revision History for MRV Plan.

Version	**Date**	**Description of Change**
Version 1.0	November, 2025	Submission of MRV Plan for EPA Review.

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1.0 Introduction

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is submitting a Monitoring, Reporting, and Verification (MRV) Plan in accordance with Title 40 of the Code of Federal Regulations, Part 98, Sections 440–449 (40 CFR 98.440–449 [Subpart RR]). This Plan details the MRV activities for ExxonMobil's Rose Carbon Capture and Sequestration Facility (Project or Rose Carbon Capture and Storage Project) in Jefferson County, Texas. The proposed Project site consists of three injection wells injecting carbon dioxide (CO_2) sources received by a single pipeline from multiple industrial emitters.

The Project is designed to collect, transport, and sequester a maximum of 5 million metric tons per annum of CO_2. ExxonMobil plans to sequester a total of approximately 53 million metric tons of CO_2 over a 13-year injection period into the Fleming and Upper Frio Formations.

An application has been submitted in accordance with the requirements of the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Sequestration Wells promulgated in 40 CFR 146.81–146.95. Until Texas receives primacy, U.S. Environmental Protection Agency (EPA) Region 6 is responsible for processing the federal Class VI permit application.

The objective of this MRV Plan is to satisfy the requirements of Subpart RR as applicable to MRV plans.

Pursuant to 40 CFR 98.448, this MRV Plan meets the content requirements and otherwise satisfies the key data collection and monitoring activities, including the following seven major components:

- Delineation of the maximum monitoring area (MMA) and active monitoring areas (AMAs) (40 CFR 98.448(a)(1));
- Identification of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways (40 CFR 98.448(a)(2));
- Strategy for detection and quantification of surface leakage of CO_2 (40 CFR 98.448(a)(3));
- Approach for establishing the expected baselines for monitoring CO_2 surface leakage (40 CFR 98.448(a)(4));
- Considerations made to calculate site-specific variables for the mass balance equation (40 CFR 98.448(a)(5));
- Identification numbers for wells (see Section 2 below) (40 CFR 98.448(a)(6)); and
- Timing of data collection (see Section 9 below) (40 CFR 98.448(a)(7)).

2.0 Facility Information [40 CFR 98.448(a)(6)]

The following are registration numbers associated with the Project:

- Project Site Name—ExxonMobil's Rose Carbon Capture and Sequestration Facility
- Greenhouse Gas Reporting Program ID number—590420
- EPA UIC Class VI Permits for Rose Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03—Under Review

Table 2-1 provides the location of the three injection wells. A map showing the injection wells, monitoring wells, artificial penetrations, and the Area of Review (AoR) is provided on Figure 3-1. The AoR represents the furthest extent of the modeled free phase CO_2 plume and critical pressure front as described in Section 3.4.2.

Table 2-1: Injection Well Locations

Well Name and Number	API	Location	Latitude (NAD83)	Longitude (NAD83)
LaBelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)	4224532913	RRC District 3, Section 42, Abstract 874	29° 59' 58.84" 29.999678	-94° 17' 6.39" -94.285108
Bead Farm Co. #2 (Rose CCS Project Injection Well No. 02)	4224532911	RRC District 3, Section 41, Abstract 266	29° 59' 27.66" 29.991017	-94° 17' 52.93" -94.298036
Bead Farm #3 (Rose CCS Project Injection Well No. 03)	4224532912	RRC District 3, Section 8, Abstract 658	30° 00' 42.40" 30.011778	-94° 17' 52.29" -94.297858
API = American Petroleum Institute; CCS = carbon capture and sequestration; RRC = Railroad Commission of Texas				

3.0 Project Description

The Project is located in Jefferson County, Texas, within the Gulf Coast Basin, an area known for its favorable geologic formations for CO_2 injection and containment. The Project site is ideally suited for the sequestration of CO_2 within the proposed injection zone in the Fleming and Upper Frio Formations. The selected injection intervals within these formations exhibit high porosity and permeability that are ideal for CO_2 storage and are of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of CO_2 stream. The CO_2 is derived from multiple industrial sources, where industrial, atmospheric emission points under long-term contract will be captured and compressed for transportation to the Project area.

As part of the Project, ExxonMobil drilled a stratigraphic well in October and November 2023 (Bead Farm Co. #1; American Petroleum Institute 4224532908) and implemented a data acquisition program. The data acquisition program for the stratigraphic well produced a significant amount of site-specific information. Field observations were made of the core samples, geological logging data were collected through the injection and confining zones, injectivity testing yielded measurements of injection zone permeability, and numerous laboratory tests were performed on core and fluid samples for refining the site characterization and geochemical model. As a result, an AoR model and injection strategy were developed and well designs made to align with the site characterization data. Sufficient geologic characterization data are available to model the AoR, optimize the operating parameters, and identify the risks and uncertainties of the Project. The potential for uncertainty that could result in the leakage of CO_2 was addressed on a risk-by-risk basis in the operating strategy, injection well design, and the testing and monitoring program. The stratigraphic well (Bead Farm Co. #1) has since been converted to an above-zone monitoring well to conduct monitoring above the confining zone.

Another in-zone monitoring well has been placed for direct monitoring, subsurface model calibration, and CO_2 plume and pressure front verification.

ExxonMobil plans to utilize three injection wells to sequester approximately 53 million metric tons of CO_2 over a 13-year period. Each well will inject into the Fleming and Upper Frio Formations in multiple intervals as part of a staged approach. The Project includes a comprehensive monitoring network (Figure 3-1) consisting of an above-zone monitoring well, an in-zone monitoring well, and three shallow monitoring wells installed in the underground sources of drinking water (USDW) (i.e., the upper Chicot Aquifer) to support in-zone plume tracking, detection of potential above-zone CO_2 migration, and protection of drinking water resources.

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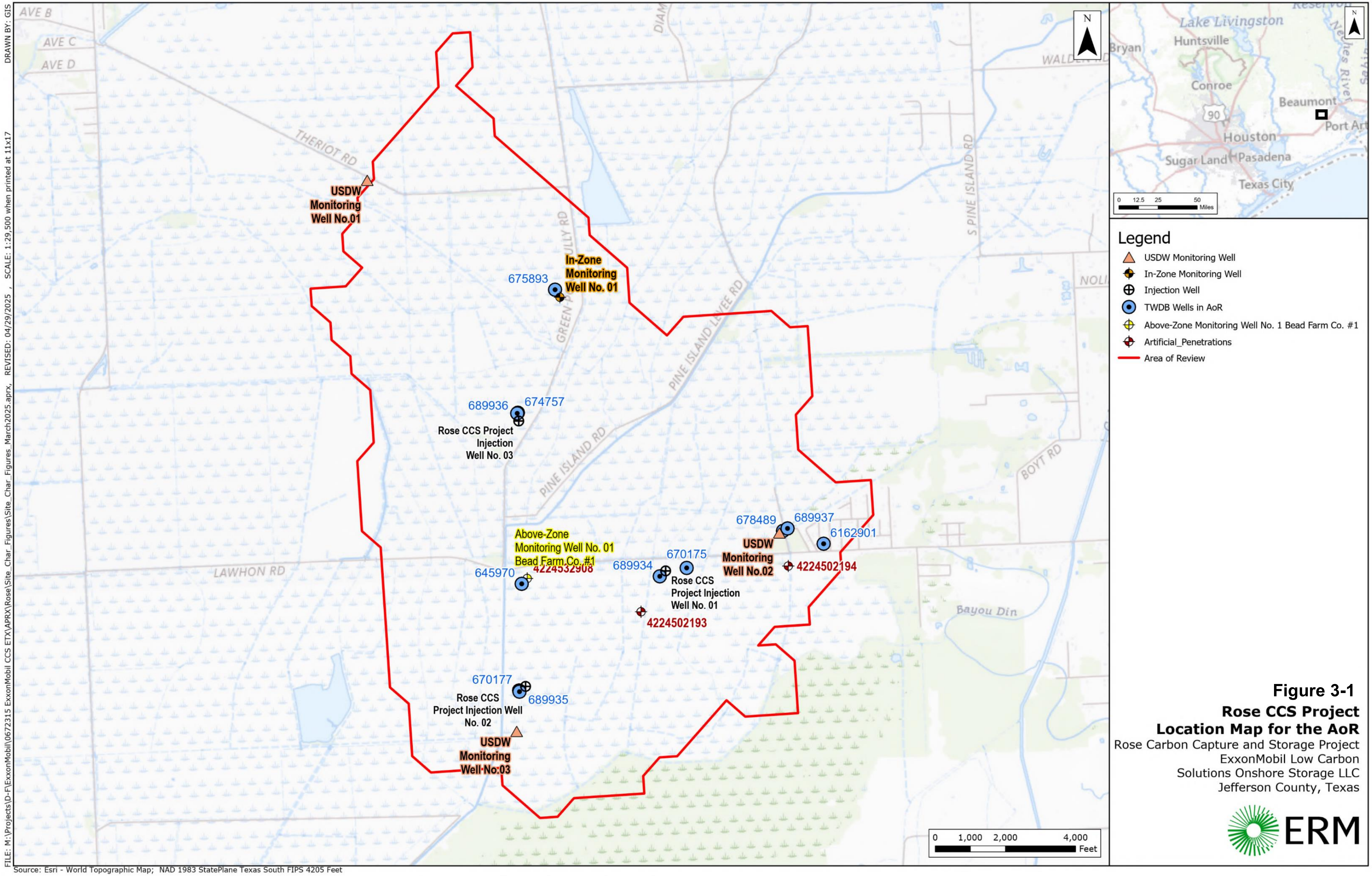

Legend
USDW Monitoring Well
In-Zone Monitoring Well
Injection Well
TWDB Wells in AoR
Above-Zone Monitoring Well No. 1 Bead Farm Co. #1
Artificial_Penetrations
Area of Review
USDW Monitoring Well No.01
In-Zone Monitoring Well No. 01
675893
689936
674757
Rose CCS Project Injection Well No. 03
Above-Zone Monitoring Well No. 01 Bead Farm Co. #1
4224532908
645970
689934
670175
Rose CCS Project Injection Well No. 01
4224502193
678489
689937
6162901
USDW Monitoring Well No.02
4224502194
670177
689935
Rose CCS Project Injection Well No. 02
USDW Monitoring Well No.03
THERIOT RD
LAWHON RD
PINE ISLAND RD
PINE ISLAND LEVEE RD
S PINE ISLAND RD
BOYT RD
Bayou Din
AVE B
AVE C
AVE D
Lake Livingston
Huntsville
Bryan
Conroe
Beaumont
Port Art
Houston
Sugar Land
Pasadena
Texas City
0 12.5 25 50 Miles
0 1,000 2,000 4,000 Feet
Figure 3-1
Rose CCS Project
Location Map for the AoR
Rose Carbon Capture and Storage Project
ExxonMobil Low Carbon
Solutions Onshore Storage LLC
Jefferson County, Texas
ERM
DRAWN BY: GIS
SCALE: 1:29,500 when printed at 11x17
REVISED: 04/29/2025
Source: Esri - World Topographic Map; NAD 1983 StatePlane Texas South FIPS 4205 Feet

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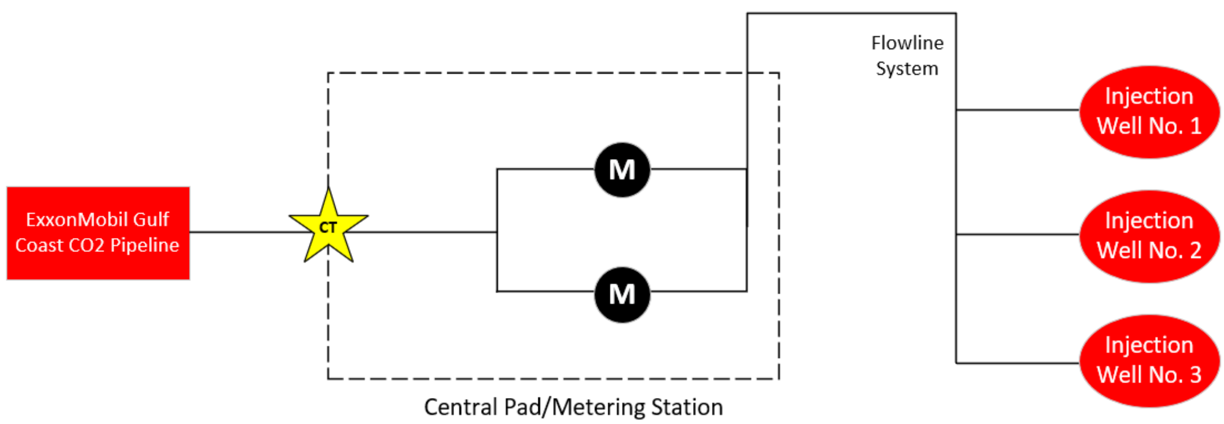
3.1 Injection Process

Figure 3-2 shows a simplified diagram of the injection process, following the flow of CO_2 from its source to each of the three injection wells. The black "M" points represent flow meters that will be utilized to measure the amount of CO_2 being injected. The yellow star represents the point of custody transfer from the single CO_2 pipeline. The dotted line represents the central pad where metering will be conducted prior to injection; the central pad is co-located with the Above-Zone Monitoring Well No. 01/Bead Farm Co. #1 pad. All CO_2 sequestered will be metered at the central pad.

Figure 3-2: Simplified Facilities Flow Diagram for Rose Project.



The injected CO_2 will come from multiple high concentration industrial sources, including clean hydrogen and ammonia production facilities, direct reduced iron plants, natural gas treatment facilities, and other industrial sources that feed directly into ExxonMobil's Gulf Coast CO_2 pipeline network. The pipeline network maintains a CO_2 composition of >97 percent (%) CO_2, <1% hydrogen, and <3% methane.

CO_2 will arrive at the central pad via pipeline in a supercritical state. At the central pad, CO_2 will pass through a gas chromatograph before a flowline system transports the CO_2 to each of the three injection wells. Three injection wells will be used to sequester the CO_2 at the Project site. The name and location of each well are provided in Table 2-1.

Each injection well was completed with a single completion string and assembly consisting of injection packer, nipple profile, safety injection valve, pressure/temperature gauges, and tubing. Upon permit approval, injection will start based on a staged bottoms-up injection approach. A total of seven injection stages within the four formation intervals are planned for each well. Once the target injection volume of CO_2 is attained, that injection stage will be plugged back to isolate that interval from subsequent injection intervals. The next injection interval will then be completed and accessed through additional perforations to establish communication with the reservoir. CO_2 will continue into that new injection interval until the target CO_2 storage amount has been achieved for that interval.

3.2 Geologic Setting

The Project is located within the Houston Embayment of the Gulf Basin. On shore and near-shore, the Gulf Basin is referred to as the Gulf Coast region. The stratigraphic column of the Houston Embayment is presented on Figure 3-3 (Treviño and Rhatigan, 1995). The Gulf Basin was formed by crustal extension and seafloor spreading during the breakup of Pangea that took place in the Mesozoic Era. A regional unconformity at the base of the sedimentary section is marked by the base of an evaporite layer (Galloway, 2008). These substantial evaporitic deposits (up to 4 kilometers thick) became a defining characteristic for later structural evolution of the Basin. Salt deposition ceased at the end of the Late Jurassic Era, as continued rifting produced oceanic crust.

The outline and morphology of the present-day Gulf Basin was sculpted by subsidence and rimming carbonate platform formation by the Early Cretaceous Era (Galloway, 2008). The Cenozoic Era depositional episodes along the northwestern Gulf Basin are fluvial-deltaic and shore-zone dominated, which reflect major phases of adjacent North American structural events (Galloway, 2008).

The Project area is suitable for CO_2 injection into the proposed injection intervals of the Fleming and Upper Frio Formations. The sands within these formations exhibit high porosity and permeability that are ideal for CO_2 storage and are "of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the [CO_2] stream" (40 CFR 146.83(a)(1)). Both the upper composite confining zone (UCCZ) and Anahuac Shale are thick, extensive, continuous sealing intervals extending across the AoR, MMA, and miles beyond in every direction. Their lateral extent has been confirmed both in the literature (e.g., Galloway, 2008) and through seismic and stratigraphic analysis of regional and local well data. An extensive data collection campaign at the Project confirms the seals and their efficacy. They are sufficient to "contain the injected [CO_2] stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s)" (40 CFR 146.83(a)(2)).

As detailed in the section below, the Project includes a Miocene-age upper composite confining zone (UCCZ) belonging to the Fleming Formation and includes the Amphistegina 'B' (Amph 'B') Shale marker. The UCCZ is a fine-grained, muddy sequence and the Amph 'B' is a regionally extensive shale (Galloway, 2008). The Anahuac Formation is located within the injection zone, overlying the Frio Formation, and underlying the Fleming Formation. The Anahuac Formation (Anahuac Shale) is a thick, continuous shale interval that was deposited during a transgressive event following Frio deposition (Galloway, 2008).

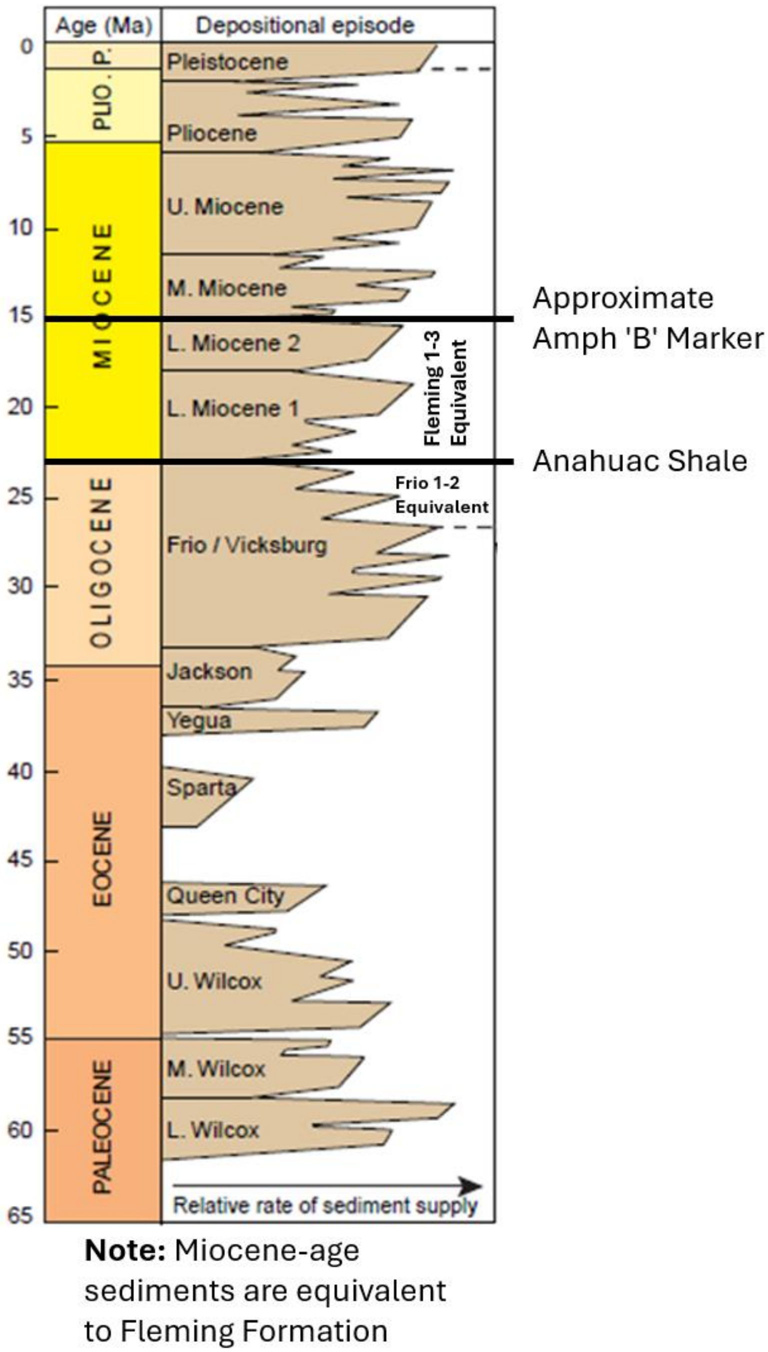
The major stratigraphic units, from deepest to shallower, are detailed below:

- Lower Confining Zone (LCZ): The LCZ comprises over 3,000 feet of thick Frio sediments, dominated by fine-grained lithologies (shales), which underlie the Upper Frio injection interval. A limited number of wells have log data to verify the gross thickness of this interval near the site. ExxonMobil relied on seismic data to assess the occurrence and lateral continuity of the LCZ.
- Upper Frio: The Upper Frio Formation consists of alternating shales and sands, stemming from progradational shore-zone systems of the Gulf coastal plain. Specifically, in the

Houston area and during the Early Oligocene, deposition of large volumes of sand from the fluvially dominated Houston and Central Mississippi deltas occurred, with subsequent waves reworking resulting in thick, sand-rich prograding shore-zone systems fronted by muddy shelf sequences. Regionally, the reservoir quality of the Frio in the Houston Embayment area exhibits porosities ranging from 16 to 36% and permeabilities of approximately 50 to 3,000 millidarcies (mD) (Swanson et al., 2013). The analysis of core data from the stratigraphic well showed porosity values to be generally consistent with regional data.

- Anahuac Formation: The Anahuac Formation is located within the injection zone, overlying the Frio Formation and underlying the Fleming Formation. It is a thick, continuous shale interval. The Anahuac Formation (Anahuac Shale) was deposited during a transgressive event following Frio deposition (Galloway, 2008). Prograding Miocene intervals, including the Fleming Formation, cap the Anahuac transgression (Swanson et al., 2013).
- Fleming Formation: The Lower Miocene was characterized by high sediment supply rates and general deltaic progradation in the Project area. Some transgressive sequences interrupted the Lower Miocene deposition, but the Lower Miocene is mainly bracketed by the underlying Anahuac Shale and overlying UCCZ that include the Amph 'B' Shale as the major transgressive sequence. South of the Project site, the estimated porosities of the Miocene reservoirs range from 5 to 38%, with an average of 28% (Carr et al., 2017). A review of available literature also indicated that permeabilities range from 16 to 1,600 mD with an average of 338 mD (Carr et al., 2017). Analysis of the Lower Miocene core samples from the stratigraphic well demonstrate consistent reservoir characteristics.
- UCCZ: The UCCZ is a thick, muddy sequence that includes the Middle Miocene Amph 'B' Shale, a regionally continuous, transgressive marine unit (Galloway, 2008) that is recognized by the U.S. Geological Survey National Assessment of Carbon Dioxide Storage Resources to be a good sealing unit and, therefore, a competent confining zone as required for CO_2 sequestration project sites (Roberts-Ashby et al., 2014).

Figure 3-3: Gulf Basin Stratigraphic Column.



Modified from: Treviño and Rhatigan, 2017

3.3 Artificial Penetrations in the MMA

As outlined in the Rose Project Class VI Application and in accordance with 40 CFR 146.82(a)(4) and 40 CFR 146.84(c)(2), a search was conducted to identify and assess the occurrence of artificial penetrations within the AoR. A summary of the identified artificial penetrations is provided in Table 3-1. Based on available data, other than the Project injection and monitoring wells drilled in 2024, two artificial penetrations were identified to intersect the UCCZ: one legacy well (Broussard JE Jr-1) and the Project's stratigraphic test well (Bead Farm Co. #1). Details for each well are provided in Table 3-1.

Pursuant to 40 CFR 146.84(c)(3), corrective actions were undertaken for both penetrations to prevent fluid movement that could endanger USDWs. Each well was re-entered and appropriate barriers were installed at critical intervals. Barriers were installed at the UCCZ, surface casing shoe, base of the lowermost USDW, and the wellhead for the legacy well. A barrier at the UCCZ was installed in Bead Farm Co. #1 in order to remain open for above-zone monitoring. For each well, the barrier at the UCCZ was constructed using CO_2-compatible material, as required by 40 CFR 146.84(d).

The Broussard JE Jr-1 legacy well was re-entered and plugged and abandoned on 14 March 2025. The Bead Farm Co. #1 stratigraphic test well was converted into the above-zone monitoring well on 7 February 2025 to support the Project's testing and monitoring program.

Within the MMA, artificial penetrations were evaluated to identify legacy wells intersecting the UCCZ. Fifteen (15) legacy wells were identified within the MMA that penetrate the UCCZ and four (4) wells were identified that terminate above the UCCZ (Table 3-2). The modeling results indicate that these wells are not anticipated to come in contact with the CO_2 plume or the critical pressure front. As discussed in Section 5.2, time-lapse seismic surveys will be conducted at the intervals specified in Tables 6-2 and 6-3 to monitor unexpected lateral or vertical CO_2 plume migration above the UCCZ and the corrective action plan will be updated accordingly. Table 3-2 summarizes the additional wells identified within the MMA.

Table 3-1: Summary of Artificial Penetrations within AoR

Well Name	State/ Federal Well ID (API Number)	Well Type	Well Status	Date Drilled	Depth (ft KB)	Latitude, Longitude (NAD83)	Penetrates UCCZ?
Above-Zone Monitoring Well No. 01 Bead Farm Co. #1	4224532908	Project Monitoring Well	Active	10/15/2023 Recompleted 02/07/2025	8,664	29.999222, -94.297364	Yes
Broussard JE Jr-1	4224502193	Dry Hole	P&A	2/10/1958	9,050	29.996539, -94.287435	Yes
Broussard J. E. Etal-1	4224502194	Dry Hole	P&A	Unknown	2,518**	29.999730, -94.274070	No
BFC-1 Rig Supply Water Well #1	645970	Water Rig Supply	In Use	8/11/2023	290*	29.999028, -94.298056	No
D. S. Wier	Not Available	Water Supply	P&A	1941	7*	30.001389, -94.270833	No
Labelle Properties Ltd #1	4224532913	Project Injection Well No. 01	Active	06/23/204	8,672	29.999678, -94.285108	Yes
Bead Farm Co. #2	4224532911	Project Injection Well No. 2	Active	07/15/2024	8,752	29.991017, -94.298036	Yes
Bead Farm #3	4224532912	Project Injection Well No. 3	Active	08/05/2024	8,565	30.011778, -94.297858	Yes
Bead Farm Company #4	4224532914	Project Monitoring Well	Active	08/31/2024	8,383	30.021558, -94.293978	Yes
Rose Rig Supply Water Well #1	670175	Water Rig Supply	Active	6/14/2024	300*	29.999857, -94.28321	No
Rose Rig Supply Water Well #2	670177	Water Rig Supply	Active	7/2/2024	300*	29.990716, -94.298632	No
Rose Rig Supply Water Well #3	674757	Water Rig Supply	Active	7/19/2024	300*	30.012428, -94.297908	No
Rose Rig Supply Water Well #4	675893	Water Rig Supply	Active	8/15/2024	300*	30.021947, -94.294199	No
USDW Monitoring Well No. 1	678487	USDW Monitoring Well	Active	8/20/2024	330*	30.030833, -94.310556	No

Well Name	State/ Federal Well ID (API Number)	Well Type	Well Status	Date Drilled	Depth (ft KB)	Latitude, Longitude (NAD83)	Penetrates UCCZ?
USDW Monitoring Well No. 2	678489	USDW Monitoring Well	P&A***	8/20/2024	440*	30.0025, -94.274444	No
USDW Monitoring Well No. 3	678491	USDW Monitoring Well	Active	8/20/2024	330*	29.9875, -94.298889	No
USDW Monitoring Well No. 2R	683826	USDW Monitoring Well	Active	11/9/2024	320*	30.0025, -94.274444	No
Shallow Groundwater Well #1	689934	Monitoring Well	Active	9/19/2024	25*	29.99927, -9428565	No
Shallow Groundwater Well #2	689935	Monitoring Well	Active	9/17/2024	25*	29.99062, -94.2986	No
Shallow Groundwater Well #3	689936	Monitoring Well	Active	9/17/2024	25*	30.01238, -94.29797	No
Shallow Groundwater Well #4	689937	Monitoring Well	Active	9/18/2024	20*	30.00268, -94.27403	No

Notes:
API = American Petroleum Institute; ID = identification; KB = Kelly bushing; UCCZ = upper composite confining zone; USDW = underground sources of drinking water
*Water well datum is below ground level
**KB not available in historical records
***Casing collapsed above water table, couldn't collect sample, redrilled as 2R in same location

Table 3-2: Summary of Wells Evaluated Within the MMA and Outside of the Predicted Stabilized CO_2 Plume

Well Name	API Number or State Well ID	Surface Location Latitude, Longitude (NAD83)	Status	Date Drilling or Recompletion Complete	Well Depth (ft TVD)	Penetrates the UCCZ?
Walter Co. 1	24532667	30.0479207, -94.2960335	Gas Well	1/6/2011	15,577	Yes
Walter Co. 2	24532736	30.0450865, -94.2979686	Gas Well	1/1/2019	15,248	Yes
Sunset Unit 1H	24532729	30.01374, -94.25681	Oil Well	4/27/2018	8,231	Yes
Broussard Unit 1	24532862	29.99733669, -94.26210890	Dry Hole	3/7/2018	8,300	Yes
Vaughan 1	24532799	29.99424, -94.26941	Plugged Gas Well	3/18/2014	14,500	Yes
Burrell Estate 1	24532125	29.98283161, -94.28273884	Dry Hole	4/15/1996	9,100	Yes
Broussard, Et Al 1	24531254	29.97798666, -94.29521881	Dry Hole	2/5/1979	8,366	Yes
Walter Co. 'C' 1	24531720	29.977486, -94.3012888	Plugged Oil Well	12/3/1983	9,000	Yes
Walter Co. 2	24531452	29.97873115, -94.30382344	Plugged	3/27/1981	8,702	Yes
Walter Company 1	24531387	29.98137196, -94.30693397	Plugged Oil Well	7/7/1980	9,000	Yes
Walter Co. 'B' 1	24531488	29.98006035, -94.31094003	Dry Hole	5/11/1981	8,815	Yes
Walter Company 1WD	24531848	29.98183461, -94.3075098	Dry Hole	7/3/1985	2,800	No
Walter Co. 1	24531725	30.02038438, -94.32145035	Plugged Gas Well	12/8/1983	16,000	Yes
Beaumont Farms 1	24500109	30.03063294, -94.29401318	Dry Hole	1/31/1956	8,517	Yes
Broussard Tr 1	24500111	30.01214737, -94.26244721	Dry Hole	6/13/1937	7,360	Yes
Broussard Trust Co. 1	24502191	29.99958128, -94.31390135	Dry Hole	12/23/1949	9,010	Yes
Broussard Unit #1	469176	29.993983, -94.26965	Plugged Rig Supply Well	12/28/2017	330	No
Vaughan #1	355705	29.994167, -94.269444	Plugged Rig Supply Well	1/4/2014	332	No
Bright Edge #1	165222	29.978889, -94.306667	Rig Supply Well	2/28/2005	325	No
API = American Petroleum Institute; TVD = true vertical depth; UCCZ= upper composite confining zone						

3.4 Reservoir Characterization and Modeling

The Fleming and Upper Frio Formations were assessed to characterize the sealing effects of the confining zone and reservoir heterogeneity within the injection zone. Based on the analysis and understanding of the Project area, a three-dimensional geologic model was developed to estimate the storage potential for the CO_2 and evaluate its confinement, both laterally and vertically.

3.4.1 Modeling Background

Schlumberger's Petrel™ Software was chosen to create the detailed geologic model for the Project. This software is used worldwide and combines information from logs and seismic data to build a sophisticated representation of underground reservoirs. The Petrel™ developed geologic model for the Project incorporates the available data for all relevant subsurface layers of the site.

The geologic model developed in Petrel™ was used as an input into the Schlumberger Eclipse-300™ numerical reservoir simulator. Eclipse-300™ is a widely recognized tool used for modeling both compositional and unconventional reservoirs. The simulator uses advanced computational methods and equation-of-state algorithms to produce a reliable prediction for CO_2 sequestration projects. The software has modules and options specifically intended to allow the study of CO_2 injection activities, can handle large data sets and multiple grids, and offers various tools for data management, visualization, and uncertainty analysis.

3.4.2 AoR Delineation Based on Model Results

The Eclipse-300™ model was used to generate projections of CO_2 plume and pressure front migration versus time over the anticipated life of the Project. Each well's operational plan was incorporated into the modeling and followed the staged approach outlined in Section 3.1, beginning with initial completion and progressing through successive recompletions in incrementally shallower sections of the injection intervals. For each injection interval, as the volume of CO_2 injected increases the areal extent of CO_2 within that zone expands. Eventually, the CO_2 plumes from each injection well commingle within the layers of each distinct injection interval. The combined effects of relative permeability, capillary pressure, and limited structural dip ultimately arrest the extent of migration of the CO_2 plume within each injection interval up-dip to the northwest.

The areal extent of the aggregate CO_2 plume is expected to grow rapidly during injection and slow after injection ceases. The areal growth rate is expected to reach a stability threshold, which is defined conservatively at less than 0.25% per year, 39 years after the start of injection, demonstrating plume stability. The stabilized CO_2 plume is shown on Figure 4-1.

In accordance with 40 CFR 146.84, the AoR is delineated via the maximum areal extents within the injection interval of both the CO_2 plume and critical pressure front at any time interval or depth. Critical pressure is the increase in reservoir pressure that has a potential to create crossflow of brine from the injection zone into the lowermost USDW, assuming the presence of a hypothetical bridging conduit such as an unplugged borehole. The first step to predict the pressure front of interest is to calculate the critical pressure for each completion stage. Once critical pressure is estimated, a numerical simulation is used to predict the size and shape of the critical pressure front defined by this pressure contour. The critical pressure front represents the

maximum areal cone of influence and combines results from the seven completion intervals for each of the three injection wells.

Superimposing the stabilized CO_2 plume and critical pressure boundaries, Figure 4-1 shows the AoR boundary for the Project.

4.0 Delineation of Monitoring Areas [40 CFR 98.448(a)(1)]

Reservoir simulator modeling (Section 3.4), informed by site characterization data, was conducted to delineate the maximum areal extent of the plume area for the life of the Project and to identify the MMA and AMA. ExxonMobil will reevaluate the AoR (including free phase CO_2 plume), MMA, and AMA based on site-specific monitoring data at the minimum frequency of 5 years in accordance with 40 CFR 146.84. Information gathered from testing and monitoring activities will be used to evaluate whether a more frequent review period is warranted based on the observed conditions of CO_2 plume and pressure front migration.

ExxonMobil will not cease post-injection monitoring until the non-endangerment demonstration pursuant to 40 CFR 146.93(b)(3) has been approved by the UIC Program Director. Pursuant to 40 CFR 146.93(b)(1), the default post-injection site care (PISC) monitoring timeframe is 50 years after cessation of injection. ExxonMobil will monitor groundwater quality and track the position of the CO_2 plume and pressure front for 50 years after cessation of injection unless a lesser period of time is approved by the UIC Program Director. At the conclusion of the PISC period, a request for discontinuation of Subpart RR reporting will be submitted including a demonstration that current monitoring and modeling show that the cumulative mass of CO_2 reported as sequestered is not expected to migrate in the future or encounter leakage pathways.

4.1 Maximum Monitoring Area [40 CFR 98.449]

Subpart RR defines the MMA as the area that must be monitored and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized, plus an all-around buffer zone of at least one half-mile. ExxonMobil has simulated the maximum plume extent to occur 26 years post-injection (39 years after the start of injection). Figure 4-1 shows the extent of the stabilized CO_2 plume with a half-mile buffer area.

4.2 Active Monitoring Area [40 CFR 98.449]

ExxonMobil has established one AMA boundary for 39 years and does not anticipate expansion of the monitoring area under 40 CFR 98.448 based on the currently planned operating conditions. Given the definitions used to delineate the MMA and the AMA, the AMA is functionally equivalent to the MMA. Monitoring the entire MMA boundary provides maximum operational flexibility.

The AMA is the portion of the MMA where monitoring is actively conducted at any given time during the injection and post-injection phases (orange dash line on Figure 4-1). The AMA is composed of two combined areas:

- The area projected to contain the free phase CO_2 plume at the end of year “t,” plus an all-around buffer zone of one half-mile or greater if known leakage pathways extend laterally more than one half-mile; and
- The area projected to contain the free phase CO_2 plume at the end of year t+5.

Based on the definition above, ExxonMobil has assumed an active monitoring timeframe of t = 39 years post start-up, aligning with the expected stabilization of the CO_2 plume. For the Rose Project, this AMA is controlled by the 39-year plume plus the one half-mile buffer.

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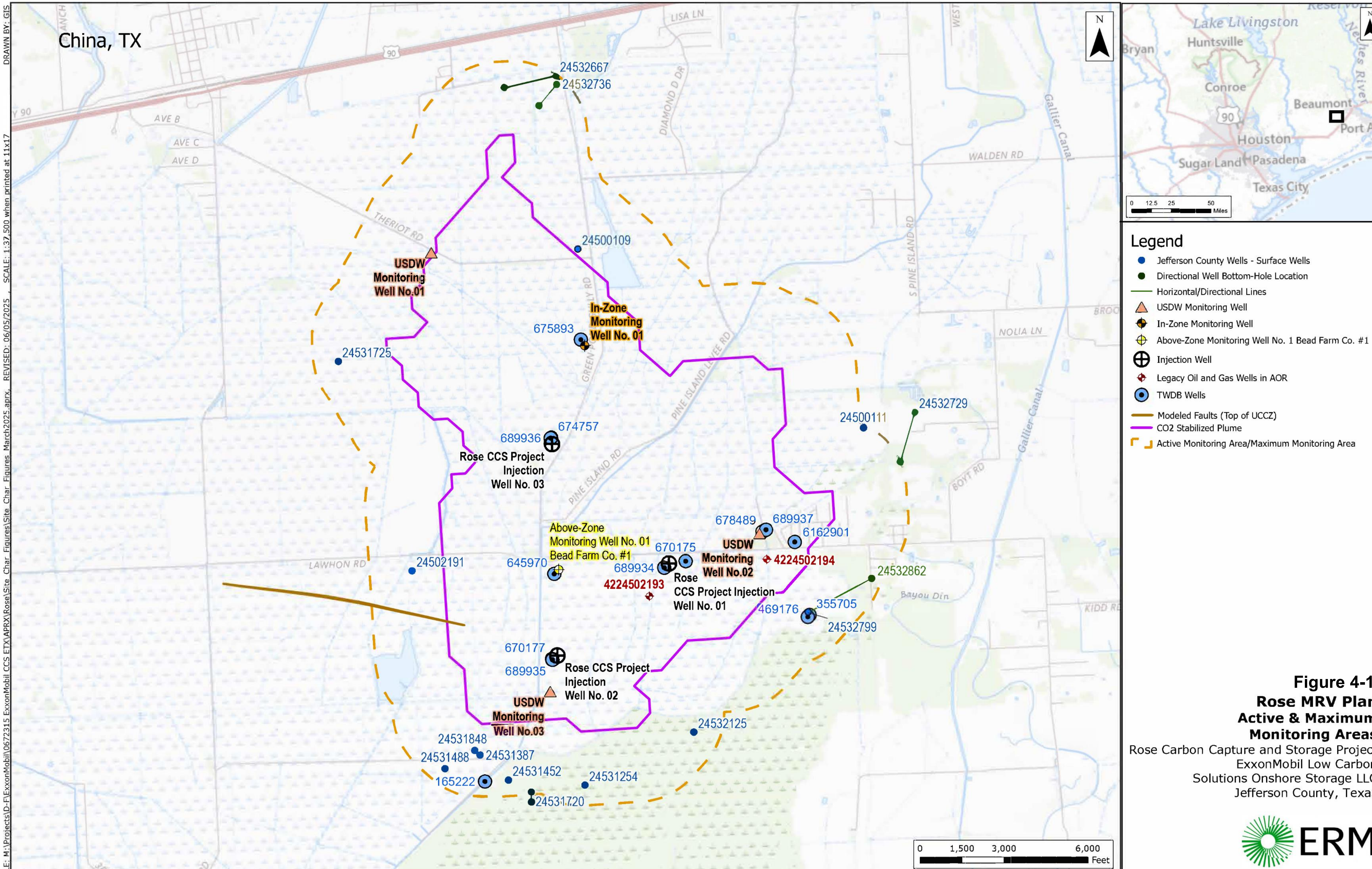

Figure 4-1
Rose MRV Plan
Active & Maximum Monitoring Areas
Rose Carbon Capture and Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson County, Texas

Source: Esri - World Topographic Map; NAD 1983 StatePlane Texas South FIPS 4205 Feet

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5.0 Identification of Potential Leakage Pathways [40 CFR 98.448(a)(2)]

ExxonMobil identified the following scenarios as potential leakage pathways for the Project through a risk assessment process. Each of the identified leakage pathways carries a low likelihood of occurrence due to the engineering design of the Project, mitigating measures taken, and implementation of the Testing and Monitoring Plan developed as part of the Class VI application process.

The potential leakage pathways described in Sections 5.1 through 5.6 are summarized below:

- Integrity of Injection or Monitoring Well Casing or Cement Seal;
- Integrity of Legacy Well Casing or Cement Seal;
- Injection Well Monitoring Equipment Failure;
- Integrity of the UCCZ;
- Induced or Natural Seismic Event; and
- Integrity of Surface Equipment.

5.1 Integrity of Injection or Monitor Well Casing or Cement Seal

Corrosion of the mechanical components or casing cement are two hypothetical release mechanisms identified for the injection and monitoring wells that have the potential to release CO_2. For example, CO_2 detected at an injection or monitoring well potentially implies that internal or external mechanical integrity of a well may have been compromised, causing release of CO_2. Potentially, CO_2 or brine could be released at an injection or monitoring well due to subsurface cement degradation or annular space defects in cement completion. In the case of either of these hypothetical examples, the likelihood of surface leakage due to a breakdown of materials in injection or monitoring wells is very low because of the CO_2 compatible materials used and the continuous monitoring techniques deployed.

Hypothetical Release Mechanism: mechanical integrity failure at an injection or monitoring well resulting in release of CO_2.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Proper wellbore design and construction of the project wells, which will utilize CO_2 compatible materials for cement, casing, and tubing.
• Routine inspection of the well casing and cement integrity to identify potential corrosion or deficiencies.
Detection methods:
• Well casing and cement bond logs conducted on injection wells during shut-ins to assess loss decay or corrosion more than acceptable limits via distributed temperature sensing (DTS) as described in Table 6-2.
• Deficiency identified during pressure falloff tests and annulus pressure tests.
• Wellhead pressure exceeds the maximum pressure specified in the permit.
• Annulus pressure indicates a loss of external or internal integrity/containment.
• CO_2 plume and pressure front tracking above UCCZ indicates a change in conditions.

• Fluid samples from above the UCCZ and/or USDW indicate a statistically significant change in conditions.
• Mechanical integrity testing identifies a potential issue in the integrity of the well.
Magnitude: Should a leakage result from the injection or monitoring wellbores and into the atmosphere, the volume of CO_2 released will be quantified based on operating conditions at the time of release.

5.2 Integrity of Legacy Well Casing or Cement Seal

Consistent with the potential for CO_2 to leak at an injection well, artificial penetrations of the UCCZ from legacy oil and gas activities may represent a similar risk scenario. Legacy wells that penetrate the UCCZ were identified within the predicted stabilized CO_2 plume boundary and MMA. Within the stabilized CO_2 plume, one legacy well was plugged as a corrective action prior to operation; the other legacy well was recompleted as an above-zone monitoring well for the Project. All other legacy wells within the MMA that penetrate the UCCZ are located outside of the stabilized CO_2 plume boundary, as detailed in Table 3-2. Current reservoir models predict no migration of CO_2 plume nor brine to reach the legacy wells in the MMA; therefore, the likelihood of leakage is low.

The objective of this risk scenario is to provide the response actions in the event that unknown legacy wells are identified and suspected of being within the pathway of the CO_2 plume or brine due to unexpected lateral migration, causing CO_2 leakage due to potential casing or cement integrity issues. To further reduce this unlikely risk, an aeromagnetic survey was conducted on September 2023 to assess the predicted CO_2 plume boundary for undocumented artificial penetrations. No additional artificial penetrations were identified.

Additionally, Tables 3-1 and 3-2 detail the artificial penetrations located within the predicted CO_2 plume and MMA that do not penetrate the UCCZ. Because these wells do not penetrate the UCCZ, the likelihood of them serving as leakage pathways is low. To monitor above the UCCZ, ExxonMobil will implement a monitoring program that includes fluid sampling from the first laterally continuous zone above the UCCZ, supplemented by time-lapse seismic surveys. Details of the above-zone monitoring program are provided in Table 6-3.

Future wells drilled through the UCCZ by ExxonMobil will be completed with the appropriate materials and integrated into the testing and monitoring plan. Drilling activity within the MMA and above the UCCZ do not pose a risk as a leakage pathway. Any drilling permits issued by the Railroad Commission of Texas (RRC) within the MMA must comply with 16 Texas Administrative Code 3.13, which requires operators drilling within a quarter-mile radius of an injection well to set steel casing and cement above and across the identified injection zone and above and across all flow zones or zones that contain corrosive formation fluids. Potential leakage pathways caused by future drilling activity within the MMA and penetrating the UCCZ are not expected to occur.

Hypothetical Release Mechanism: CO_2 leaks at an artificial penetration as detected within the MMA.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Compliance with CO_2 plume and brine tracking systems.
• Time-lapse seismic surveys will be conducted at the intervals specified in Tables 6-2 and 6-3 to monitor for any indication of unexpected lateral or vertical CO_2 plume migration above the UCCZ.

• CO_2 Plume reservoir model forecast updates to predict pressure front changes that may impact legacy wells outside of the boundary of the predicted stabilized CO_2 plume, but within the MMA, and adjust timing of monitoring and phased-corrective action.
Detection methods:
• CO_2 plume and pressure front tracking indicates potential impact.
• Fluid samples from above the UCCZ and/or USDW indicate a statistically significant change in conditions.
• Legacy well re-entry to collect casing and cement bond logs to assess integrity and well completion materials.
Magnitude: Should a leakage result from a legacy well and into the atmosphere, the volume of CO_2 released will be quantified based on operating conditions at the time of release.

5.3 Injection Well Monitoring Equipment Failure

Loss of mechanical integrity of well pressure equipment may occur during operation of the injection wells. A pressure gauge (or other similar equipment) malfunction could create a shut-off valve malfunction and result in an uncontrolled pressure situation and CO_2/brine crossflow to USDW by fault or fracture activation or well casing and/or cement failure in the vicinity of the production casing perforations.

Hypothetical Release Mechanism: Loss of mechanical integrity of well pressure equipment could trigger a shut-off valve malfunction and result in an uncontrolled pressure situation and CO_2 release by near wellbore fault or fracture activation or by well casing and/or cement failure in the vicinity of the production casing perforations.
Timing of event: Injection phase and/or post-injection phase.
Avoidance measures:
• Routine equipment inspection and maintenance to identify potential integrity issues that may be a result of equipment failure.
• Routine inspections and calibration of monitoring equipment in accordance with manufacturer's recommended procedures.
• Consistent fluid sampling throughout the detection monitoring well network to detect a release above the UCCZ.
• Redundant pressure and temperature measurements in the injection zones to maintain compliance with permitted operating conditions.
Detection methods:
• Anomalies in pressure and rate monitoring, pressure falloff tests, and annulus pressure tests.
Magnitude: Anticipated CO_2 leakage is negligible.

5.4 Integrity of the UCCZ

Several potential risk scenarios were considered that involve a hypothetical release through naturally occurring faults and fractures or other penetrations of the UCCZ, creating a migration pathway for CO_2. For example, CO_2 could hypothetically leak through seismically visible faults or fractures in the UCCZ within the MMA, or CO_2 or brine could hypothetically migrate horizontally to artificial penetrations within the MMA that are not sealed at the UCCZ and result in a release of CO_2. Based on ExxonMobil's assessment of the subsurface, one visible fault was identified that extends through the UCCZ within the MMA. The maximum displacement, which occurs outside the MMA, is much less than the thickness of the UCCZ (13% of total thickness).

Seal analysis indicates high sealing properties such that the integrity of the UCCZ should not be compromised, indicating that this is not a likely leakage pathway for CO_2. The Shale Gouge Ratio was calculated to be greater than 0.75 (i.e., greater than 75% clay content) for hundreds of feet of the fault occurrence within the UCCZ, which is indicative of effective fault sealing within the confining zone. Appraisal well data demonstrated pressure offset above and below the UCCZ, further supporting an effective seal.

CO_2 and brine leaks through shales due to mechanical fracturing were not considered a potential concern for the Project because of the physical nature of the confining shale materials. Above the UCCZ is approximately 3,000 feet of saturated shale, mudstone, and sand. A release through the UCCZ would likely be detected by the groundwater monitoring program prior to release to the surface.

Evidence of fracture development was assessed by examining eight slabbed cores, core computed tomography, borehole imagery logs, and core data from the stratigraphic well. The natural structural features observed in the stratigraphic well core are predominantly non-tectonic pedogenic slickensides that form due to soil processes and sediment compaction, an expected feature of paleo-vertisols. No natural fractures, stylolites, deformation bands, or significant faults were observed in the core samples and no significant risk of high permeability pathways along natural faults and fractures is predicted. The finding of no significant permeability is consistent with the occurrence of trapped hydrocarbons in these structural features documented across the Gulf Coast and no evidence of any formation fluid transmission was observed in the cores.

The following actions were developed to mitigate the potential for releases through the UCCZ:

Hypothetical Release Mechanism: release through naturally occurring faults and fractures or penetration of the UCCZ, creating an unexpected migration pathway for CO_2.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Time-lapse seismic surveys will be conducted at the intervals specified in Tables 6-2 and 6-3 to monitor for any indication of CO_2 plume migration above the UCCZ.
• Compliance with CO_2 plume and brine tracking systems.
Detection methods:
• CO_2 plume and pressure front tracking indicates a potential impact.
• Fluid samples from above the UCCZ and/or USDW indicate a statistically significant change in conditions.
• Third-party direct or indirect data identify a potential impact to subsurface outside of MMA.
Magnitude: As described above, anticipated leakage magnitude is negligible.

5.5 Induced or Natural Seismic Event

Based on the projected operating conditions and regional and local geologic conditions, injection operations are not expected to result in an induced seismic event mandating a response action. Induced or natural seismic events would be monitored at a minimum during the injection phase. ExxonMobil has installed a permanent seismicity monitoring system on-site, which is being monitored by a third party to detect seismic activity prior to and during injection operations. This array has been recording baseline data since 1 July 2024. The design of the array consists of a near-surface network of seismometers with continuous data sampling, incorporation of publicly available data, and telemetry to cloud-based storage. Near-real-time, high-resolution signal processing and quality assurance will be implemented for event detection, magnitude, and location accuracy. ExxonMobil will additionally receive notifications from the United States Geological Survey of recorded seismicity events for the site and surrounding area, should an event occur. If a review of the data indicates that a seismic event of magnitude 2 or larger was within a 5.6-mile radius of an injector, ExxonMobil will notify the UIC Program Director to jointly assess if the events are likely to be associated with the operations, and, if so, implement response actions for seismic events. As described in this section, anticipated leakage magnitude is negligible.

5.6 Integrity of Surface Equipment

The surface components of the injection system include the CO_2 injection wellheads and the associated surface piping that transports CO_2 from the mass flow meters located on the central pad to the wellheads. A data management system, or a suitable equivalent, will be used to facilitate the continuous collection of key operational parameters, including:

- Intake pressure at the central pad transfer point;
- Pressure within the distribution system to each injection well; and
- Pressure at each injection wellhead.

Two Coriolis flow meters, installed at the central pad, will be used to directly measure the mass flow rate of the injected fluid. The Coriolis meters will be calibrated in accordance with the manufacturer's specifications.

During injection, ExxonMobil will review and interpret continuously monitored parameters against permitted limits. This review will also include trend analyses to assess maintenance, recalibration, or system optimization opportunities.

To mitigate the potential for surface leakage of CO_2 from equipment, ExxonMobil will implement the following measures:

- Adherence to Class VI regulatory requirements for well construction (40 CFR 146.86), well operation (40 CFR 146.88), and testing and monitoring of surface facilities (40 CFR 146.90).
- Continuous monitoring via a Supervisory Control and Data Acquisition system monitored remotely by ExxonMobil's Operations Control Center. Surface equipment pressure and flow rates (as noted above and in Section 3.1) are included in the Supervisory Control and Data Acquisition system.
- Routine visual inspections and preventative maintenance of all surface components.
- Surface equipment will be inspected, tested, and calibrated in accordance with manufacturer specifications prior to commissioning.

The likelihood of CO_2 leakage from surface equipment during injection operations is considered to be very low. In the unlikely event of a release, the volume would be limited to the amount of CO_2 contained within the surface piping and equipment due to automatic shut-off devices. The quantification approach will be adaptable to the specific characteristics of each leakage scenario, with methods selected based on site conditions and the nature of the release.

6.0 Detection and Verification [40 CFR 98.448(a)(3)]

ExxonMobil installed and will use continuous measurement devices to monitor injection pressure, temperature, rate, and mass; the pressure on the annulus between the tubing and the long-string casing; and the temperature of the CO_2 stream, as required under [40 CFR 146.88(e)(1), 146.89(b), and 146.90(b)]. Data will also be collected to document the addition or removal of any fluid from the annulus system. Data interfaces will be created for equipment that is not linked directly to a data management system or suitable equivalent and will be integrated into a unique surveillance platform. In the monitoring program, the sensors, transducers, and controllers will be connected in a central platform to monitor the operating conditions, set alarms for alerting operations of malfunction, and maintain safety protocols in case of abnormal conditions. Alarms will be set for pressures outside described tolerances (generally 90% of fracture gradient and prescribed wellhead pressures) and changes in annular pressure and fluid.

Instrument calibration standards, precision, and tolerances will be maintained based on manufacturer recommendations. The automated control system data will be monitored for anomalies on a regular basis. Average values will be compared to baseline and predicted values to assess if there are any significant deviations relevant to integrity or containment.

The operating parameters, monitoring values, laboratory results, reports, and surveillance documents for the Project will be stored in a database to support MMA reviews, quality assurance / quality control review programs, and routine reporting. Table 6-1 provides a summary of the typical sampling devices, locations, and data storage frequencies for the continuous monitoring program.

Table 6-1: Sampling Devices, Locations, and Data Frequencies for Continuous Monitoring

Continuous Sampling Parameter	Device(s)	Location	Estimated Min. Sampling Frequency	Estimated Min. Recording Frequency
Surface Injection Pressure	Wellhead Pressure Logger	Surface, injection well piping	5 seconds	5 minutes
Downhole pressure gauge	Pressure Gauges	Injection Unit	5 seconds	5 minutes
Injection rate	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Injectate density	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Total mass injected	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Annular pressure	Pressure Gauge	Well Head	5 seconds	5 minutes
Annulus fluid volume	Level Transmitter	Annulus System Tank	5 seconds	5 minutes
Carbon dioxide stream temperature	Coriolis Meter/Wellhead Pressure Logger	Well Head, injection well flowing	5 seconds	5 minutes
Note: The word “continuous” is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument’s normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application. Measurements that are collected “continuously” will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.				

Additionally, as part of its Class VI well permit application, ExxonMobil developed a comprehensive testing and monitoring strategy for the Project using a risk-based approach. The monitoring frequency is outlined in Table 6-2 and the monitoring strategy is outlined in Table 6-3. The monitoring program aligns with the three operational phases of the Project: (1) the pre-operational baseline data collection phase; (2) the operational phase for the three injectors; and (3) the PISC phase. During the pre- and early-operational phases, a selection of technologies will be used to develop baseline seismic response, pressure, temperature, and certain geochemical parameters needed to monitor the CO_2 plume and pressure front.

This testing and monitoring information will also be used to assess the predictive modeling results and refine the model as necessary. During the operational phase, the frequency of direct monitoring data collection activities will be aligned with the initiation of injection into each new stage of the injection intervals as described in Section 3.1. The accuracy of the model at predicting the CO_2 plume and pressure front migration will inform the frequency of indirect monitoring data collection. Upon assessment of the predictive capabilities of the model, the frequency of indirect monitoring activities listed in Table 6-2 may be reduced as justified by the rates of change and variations observed by the monitoring results, which are subject to approval by the UIC Program Director and incorporation into the Class VI permit. The data generated from the implementation of this Plan provides the basis to assess the confinement of the CO_2 in the permitted injection formations during the active injection phase of the Project.

Section 5 of this Plan details the detection methods in place for each leakage pathway. Consistent with EPA guidance, the monitoring program is intended to be a flexible approach using appropriate technologies and techniques that are refined and adapted based on site-specific information over time. ExxonMobil will continue to assess the feasibility of emerging technologies and conduct performance evaluations to continue to improve the performance of the testing and monitoring program.

Table 6-2: Testing and Monitoring Plan Measurements and Frequency

Equipment / Measurement	Regulation (40 CFR)	Objective	Frequency
Coriolis flow meter	146.90b	Measure mass flow rate	Continuously
Corrosion coupon	146.90c	Measure corrosion levels on the types of metal used in the Project	Quarterly
Injection stream sampling	146.90a	Provide more detailed analysis via periodic lab analysis of injection stream	Quarterly
Central pad temperature gauge	146.90a	Measure temperature of the total injection stream at the pad before partitioning to injections	Continuously
Injection wellhead tubing Pressure gauge	146.90a	Measure downstream of choke	Continuously
Injection wellhead annulus Pressure gauge	146.90b	Verify annulus pressure maintained	Continuously

Equipment / Measurement	Regulation (40 CFR)	Objective	Frequency
Injection annulus pressure test	146.89b	Verify absence of leak in annulus	Annually
Injection Well downhole pressure and temperature gauge for active/open injection interval	146.90b	Measure downhole pressure and temperature (injection mass to volume conversion, verifying that it is not exceeding maximum pressure)	Continuously
	146.90f	Measure falloff of pressure after abandoning injection stage and before initiating injection in next stage above	At the end of every injection stage
	146.90g(1)	Direct measurement of pressure, sensitive to pressure from other injections, especially when injection intervals are staggered between wells	Continuously
Time-lapse surface seismic survey	146.90g(2)	Indirect method to monitor CO_2 plume growth in the subsurface over time	Frequency from start of operations: Survey Event #1: completed; Survey Event #2: one to 3 years; Survey Event #3: 6 to 8 years; Survey Event #4: 13 years. Contingent additional survey events as needed and approved by UIC Program Director.
	146.87a(3)(ii)	DTS for cement long portion of long-string casing where fiber is cemented in place	One-time event
	146.90e	DTS to assess potential flow through channels through or along cement	Annually
Injection well casing inspection log	146.90e	Through-tubing log to detect loss of metal mass in casing due to corrosion	Baseline only; repeat survey is triggered if risk of leakage is apparent or upon request by UIC Program Director
In-zone monitoring well downhole pressure and temperature gauges	Not required 146.90g(1)	Collect pressure and temperature measurements for evaluating the rate of CO_2 plume and pressure front movement	Continuously
Above-zone monitoring well fluid sampling from above UCCZ	146.90d	Above UCCZ fluid collection is recommended by guidelines	Quarterly

Equipment / Measurement	Regulation (40 CFR)	Objective	Frequency
USDW fluid sampling	146.90d	Sample fluids from the Chicot Aquifer which is the most prolific USDW aquifer within the MMA, as recommended by guidelines, and analyze composition	Quarterly
DTS = Distributed Temperature Sensing; UCCZ = upper composite confining zone; UIC = Underground Injection Control; USDW = underground source of drinking water Note: The word "continuous" is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument's normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application. Measurements that are collected "continuously" will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.			

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Table 6-3: Summary of Monitoring Technologies for Direct and Indirect CO_2 Plume and Pressure Front Tracking

Target Zone	Requirement	Technology	Placement Location	Target Depths	Phased/Triggered Approach	Monitoring Frequency	Data Evaluation Objectives
Injection Zone	Direct per 40 CFR 146.90(g)(1)	Downhole tubing mounted pressure and temperature gauge	Injection Wells No. 01, No. 02, and No. 03	Four injection intervals in Fleming and Upper Frio Formations	No	Continuous monitoring during injection operations for each injection interval Annual pressure falloff test during well shut-ins	Identify pressure differential and location of pressure front for the four injection intervals
		Tubing encapsulated conductor cable with in-line pressure/ temperature gauges	In-Zone Monitoring Well No. 01	Four injection intervals in Fleming and Upper Frio Formations	No	Continuous monitoring	CO_2 plume and pressure front tracking
	Indirect, geophysical techniques per 40 CFR 146.90(g)(2)	Time-lapse seismic surveys, or equivalent technologies	CO_2 Plume Area	Four injection intervals in the Upper Frio and Fleming Formations	No	Surface Seismic Survey Event #1 (Survey Event #1) is the baseline event conducted prior to injection. Survey Event #2 will be performed within the first 3 years after injection, Survey Event #3 within 6 to 8 years after injection, Survey Event #4 in year 13 at cessation of injection. Additional survey events if necessary, during PISC, as approved by UIC Program Director.	Monitor CO_2 plume growth in the subsurface over time
		Passive Seismicity Monitor Station Array	Selected locations within AoR	Surface	Yes, contingent on triggering seismic events	Continuous monitoring	AoR-specific seismicity data collection and event analyses
Above UCCZ	Direct per 40 CFR 146.90(g)(1)	Fluid sampling protocol using converted Bead Farm Co. #1 collected through tubing	Above-Zone Monitoring Well - Bead Farm Co. #1	First laterally continuous water-bearing zone above UCCZ	No	Quarterly samples	Detection monitoring for CO_2 plume and/or brine crossflow from injection zones to top of UCCZ
	Indirect, geophysical techniques per 40 CFR 146.90(g)(2)	Time-lapse seismic surveys, or equivalent technologies	CO_2 Plume Area	From surface to base of Frio Sand 2	No.	Surface Seismic Survey Event #1 (Survey Event #1) is the baseline event conducted prior to injection. Survey Event #2 will be performed within the first 3 years after injection, Survey Event #3 within 6 to 8 years of injection, Survey Event #4 in year 13 at	Detection monitoring for presence of CO_2 plume above UCCZ Detection monitoring and evaluation of trends in water quality and geotechnical parameters

Target Zone	Requirement	Technology	Placement Location	Target Depths	Phased/Triggered Approach	Monitoring Frequency	Data Evaluation Objectives
						cessation of injection. Additional survey events if necessary, during PISC, as approved by UIC Program Director.	
USDW	Direct per 40 CFR 146.90(d)	Fluid Sampling	USDW Monitoring Wells No. 01, No. 02, No. 03	Groundwater samples collected just below the typical total depth of water wells completed in the area (e.g., 300 to 350 feet below ground level).	Yes, three USDW monitoring wells prior to start of injection and additional USDW monitoring wells depending on the results of CO_2 plume and pressure front tracking as discussed in AoR reevaluations	Pre-Operational Phase – Quarterly Operational Phase – Quarterly	Detection monitoring and evaluation of trends in water quality and geotechnical parameters
Soil Gas Monitoring	Direct per 40 CFR 146.90(h)	Soil gas samples collected from the unsaturated zone	Contingent on confirmed release to USDW				
Air Monitoring	Direct per 40 CFR 146.90(h)	Portable and/or stationary CO_2 detectors monitor record ambient CO_2 concentrations	Contingent on confirmed release to USDW				
AoR = Area of Review; CFR = Code of Federal Regulations; CO_2 = carbon dioxide; PISC = post-injection site care; UCCZ = upper composite confining zone; UIC = Underground Injection Control; USDW = underground source of drinking water							

7.0 Assessment of Expected Baselines [40 CFR 98.448(a)(4)]

ExxonMobil has developed a comprehensive pre-injection (baseline) Testing and Monitoring Plan to develop reference conditions against which future data will be compared throughout the operational phase of the Project. Baseline data collection has been completed or is underway, and comparisons to these baseline conditions will be used to evaluate any deviations that may occur during injection activities. The following summarizes the key elements of baseline data collection:

- Groundwater Sampling—ExxonMobil has collected baseline groundwater quality and geochemical samples from the Above-Zone Monitoring Well No. 1 (Bead Farm Co. #1) installed in the formation directly above the UCCZ and from the three USDW monitoring wells at the Project site.
- Continuous Pressure/Temperature Monitoring—Reservoir temperatures and pressures will be monitored using a downhole gauge installed in the tubing above the production packer. At In-Zone Monitoring Well No. 01, a tubing encapsulated conductor cable with in-line pressure/temperature gauges will be installed. Baseline measurements will be collected prior to the start of injection to establish reference operating conditions.
- Seismic Survey—A seismic survey to monitor the CO_2 plume extent is planned to take place four times throughout the life of the Project. The baseline survey was conducted using the data purchased and reprocessed in 2024/2025 for site characterization.
- Visual Inspection—Prior to operations, surface equipment will be inspected and tested to confirm proper function and integrity.
- Soil Gas and Air Monitoring—Soil gas and air monitoring are proposed only as responses to triggering events. However, baseline samples of each have been collected.

8.0 Mass Balance Equations [40 CFR 98.448(a)(5)]

CO_2 will be injected into saline aquifers via three injection wells at the Project site. To accommodate the anticipated injection volume, two separate flowlines will be utilized at the central pad (Figure 3-2). Each flowline will be equipped with a mass flow meter to continuously measure and record the quantity of CO_2 injected. ExxonMobil will utilize the two flow meters to estimate CO_2 injected for the Project. All CO_2 injected will be sourced from a single pipeline that enters the central pad.

8.1 CO_2 Injected (CO_{2I})

The CO_2 stream received will be wholly injected into the storage complex. Therefore, pursuant to 40 CFR 98.444(a)(4) and 98.444(b), the annual CO_2 received will be equivalent to the annual CO_2 injected. The point of measurement for CO_2 injected is the mass flow meters located at the central pad. CO_2 will be measured through two-meter runs, each equipped with a mass flow meter. These meter runs will merge at a single point, from which the CO_2 is distributed to the three injection wells via flowlines.

The annual CO_2 injected at each well will be calculated using Equation RR-4 from 40 CFR 98, Subpart RR:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_2,p,u}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.
$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).
$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flow meter.

The sum of the mass of CO_2 injected through the two mass flow meters will be calculated using Equation RR-6:

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

Where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) through all injection wells.
$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.
u = Flow meter.

8.2 Mass of CO_2 Emitted by Surface Leakage (CO_{2E})

In addition to monitoring the mass of CO_2 received, injected into the subsurface, emitted from equipment leaks, and sequestered in subsurface geologic formations, ExxonMobil will monitor and report the total estimated CO_2 emitted in the event of surface leakage. The quantification approach will be adaptable to the specific characteristics of each leakage scenario, with methods selected based on site conditions and the nature of the release. These methods may include direct monitoring data, engineering-based calculations, or the application of established emission factors.

Although the specific types of leaks cannot be anticipated ahead of time, quantification methods will adhere to accepted engineering standards and best practices, with example approaches for different leak types. If anomalies of the monitored parameters (i.e., injection zone pressure, etc.) are detected, field personnel will investigate to identify the issue. For minor problems, repairs will be completed promptly and any resulting CO_2 emissions will be documented in the Subpart RR report. In cases requiring more extensive repairs, ExxonMobil will evaluate the best method for estimating the leaked CO_2 based on relevant factors such as leakage rate, concentration, and duration.

Issues such as anomalies in annular pressure or other concerns identified during maintenance activities will be addressed using the same protocol. Field personnel will examine the affected equipment to assess the problem. If the issue is minor, repairs will be completed promptly during the inspection and any associated CO_2 emissions will be recorded in the Subpart RR report. For more significant repairs, the well will be shut-in until the necessary work can be completed. In such cases, ExxonMobil will evaluate the best method for estimating the leaked CO_2 based on relevant factors such as leakage rate, concentration, and duration.

Should a surface leakage event occur, ExxonMobil will document and report the estimated mass of CO_2 released in the annual Subpart RR submission, along with a summary of the measurement or estimation techniques employed. Data and supporting documentation will be retained to ensure regulatory compliance and transparency.

The total annual mass of CO_2 emitted from all leakage pathways will be calculated using Equation RR-10:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.
$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.
x = Leakage pathway.

8.3 Mass of CO2 Emitted from Equipment Leaks and Vented Emissions (CO2FI)

The annual mass of CO_2 emitted from equipment leakage and vented emissions between the injection flow meter and wellhead will be measured and reported in accordance with the requirements of 40 CFR 98.444(d)/Subpart W.

8.4 Mass of CO2 Sequestered in Geologic Formations (CO2)

The total annual mass of CO_2 sequestered in geologic formations for the reporting year will be calculated and reported using Equation RR-12:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.
CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.
CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.
CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98.

9.0 Estimated Schedule for Implementation of MRV Plan [40 CFR 98.448(a)(7)]

Implementation of the MRV Plan will commence immediately following the effectiveness of the permit. The MRV data collection activities will be initiated prior to the start of injection to develop baseline conditions and will continue throughout the operational phase of the Project and into the PISC period, until the EPA approves the cessation of Subpart RR reporting. Key milestones include completion of baseline monitoring, commissioning of monitoring equipment, and initiation of data collection and reporting systems. In the event of material changes to the Project, the Plan will be resubmitted to and approved by the EPA prior to injection, in accordance with 40 CFR 98.448(d).

Data collection and implementation of this MRV Plan is proposed on October 1, 2025 and upon the EPA's approval of this MRV Plan.

10.0 Quality Assurance Program [40 CFR 98.444]

ExxonMobil has designed its monitoring plan and network to meet the quality assurance and quality control requirements of 40 CFR 98.444 of Subpart RR.

10.1 Measurement of CO2 Concentration

The CO_2 injection stream will be measured with a gas chromatograph and will be sampled quarterly at the central pad. Sufficient mixing and residence time in the system will have occurred at this sampling point for the sample to be representative of the injected CO_2 stream to meet the requirements of 40 CFR 146.91(a). The sampling station will be equipped with the ability to purge and collect a gas sample into a sealed container. The central pad is the connection point between the CO_2 pipeline and the sequestration field's distribution system.

The sample will be collected by site representatives following established company sampling procedures. It will then be transferred to a certified or accredited laboratory, where analysis will be performed using industry standard methods for CO2 based on the minimum regulations at the time the analysis is completed.

Each sample will be accompanied by a facility or contract laboratory Chain-of-Custody (COC) form that provides a record of sample handling, starting with sample acquisition, documenting the sample transfer process up to laboratory analysis. Samples taken are to be logged in the field using the COC form. Sample transfer containers (e.g., coolers) will be sealed and delivered to the laboratory with a COC form. The COC form shall provide the following items recorded by the sampler:

1. Sample ID including code or name, in addition to date and time;
2. Name of sample collector (including sampling company name if not site personnel);
3. Sample collection method;
4. Sample collection date;
5. Sample collection point; and
6. Sample presentation technique, as applicable.

Standard laboratory COC forms that document the times and dates of all personnel handling the sample, along with standard labels and container seals sufficient to distinguish between samples and prevent tampering, will be acceptable. Sample COC will be followed at all times during the sampling and subsequent analysis. COC will be used to document the handling and control necessary to identify and trace a sample from collection to final analytical results.

10.2 Measurement of CO_2 Mass

To meet the requirements of 40 CFR 98.444(e), ExxonMobil will conduct the following activities for operation and maintenance of meters associated with the Project:

- Flow meters will be operated continuously except as necessary for maintenance and calibration.
- Flow meters will be calibrated to measure quantities reported in 40 CFR 98.446 according to the calibration and accuracy requirements in 40 CFR 98.3(i).
- Measurement devices will be operated according to an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute, the American Gas Association, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.
- Assess flow meter calibrations performed are traceable by the National Institute of Standards and Technology.

10.3 Estimating Missing Data

ExxonMobil will follow all quality assurance and quality control procedures to record the mass of CO_2 injected. In the event ExxonMobil is unable to collect the necessary data for greenhouse gas (GHG) reporting, the following procedures will be followed to estimate missing injection data as required by 40 CFR 98.445. Generally, the methods include:

- A quarterly quantity of CO_2 flow rate that is missing will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures will follow those specified in subpart W of this part.
- A quarterly concentration value that is missing will be estimated using a representative concentration value from the nearest previous time period. If the CO_2 stream was sampled by the capture facility in the same time period, sales contract data may be used.
- A quarterly quantity of CO_2 injected that is missing will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

11.0 Reporting [40 CFR 98.442]

ExxonMobil will submit reports consistent with 40 CFR 98.442.

12.0 Records Retention [40 CFR 98.447]

ExxonMobil will retain the following documents and records to remain in compliance with 40 CFR 98.447(a) and 98.3(g), including but not limited to:

- A list of all units, operations, processes, and activities for which GHG emission were calculated. The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):

  - The GHG emissions calculations and methods used. For data required by § 98.5(b) to be entered into verification software specified in § 98.5(b), maintain the entered data in the format generated by the verification software according to § 98.5(b).
  - Analytical results for the development of site-specific emissions factors.
  - Any facility operating data or process information used for the GHG emission calculations.
- The annual GHG reports.
- Missing data computations. For each missing data event, also retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
- A written GHG Monitoring Plan.
- The results of required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
- Maintenance records for continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
- Quarterly records of CO_2 received, including mass flow rate of contents of containers (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams. No CO_2 received is anticipated for the facility as all CO_2 received is wholly injected and not mixed with any other supply of CO_2.
- Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams. No produced CO_2 is anticipated for the facility.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.
- Other records as specified for retention in the EPA-approved MRV Plan.

12.1 Revisions to the MRV Plan

In accordance with 40 CFR 98.448(d), ExxonMobil will revise and submit the MRV Plan within 180 days to the Administrator for approval if any of the following applies:

- A material change was made to monitoring and/or operational parameters that was not anticipated in the original MRV Plan. Examples of material changes include but are not limited to:
  - Significant changes in the volume of CO_2 injected;
  - The construction of new injection wells not identified in the MRV Plan;
  - Failures of the monitoring system including monitoring system sensitivity, performance, location, or baseline;
  - Changes to surface land use that affects baseline or operational conditions;
  - Observed CO_2 plume location that differs significantly from the predicted CO_2 plume area used for developing the MRV Plan;
  - A change in the MMA or AMA;
  - Or a change in monitoring technology that would result in coverage or detection capability different from the MRV Plan.
- A change in the permit class of the Underground Injection Control Permit.
- If ExxonMobil is notified by EPA of substantive errors in the MRV Plan or monitoring report.
- If the MRV Plan must be changed for any other reason in any reporting year.

ExxonMobil will include the reason(s) for the revisions in the MRV Plan submittal.

Appendices

Appendix A: References

Carr, D.L., K.J. Wallace, A.J. Nicholson, and C. Yang, 2017, Regional CO_2 Static Capacity Estimate Offshore Saline Aquifers, Texas State Waters, Geological CO_2 Sequestration Atlas of Miocene Strata, Offshore Texas State Waters, Report of Investigations No. 283, Bureau of Economic Geology, University of Texas at Austin, Austin

Galloway, W.E., 2008, Depositional Evolution of the Gulf of Mexico Sedimentary Basin, Chapter 15, The Sedimentary Basins of the United States and Canada, Elsevier, The Netherlands, pp. 505-549.

Roberts-Ashby, T.L., S.T. Brennan, M.L. Buursink, J.A. Covault, W.H. Craddock, R.M. Drake II, M.D. Merrill, E.R. Slucher, P.D. Warwick, M.S. Blondes, M.A. Gosai, P.A. Freeman, S.M. Cahan, C.A. DeVera, and C.D. Lohr, 2014, Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources - U.S. Gulf Coast, Chapter H, U. S. Geological Survey, Open-File Report 2012-1024-H, Reston, VA.

Gosai, P.A. Freeman, S.M. Cahan, C.A. DeVera, and C.D. Lohr, 2014, Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources - U.S. Gulf Coast, Chapter H, U. S. Geological Survey, Open-File Report 2012-1024-H, Reston, VA.

Swanson, S.M., A.W. Karlsen, and B.J. Valentine, 2013, Geologic Assessment of Undiscovered Oil and Gas Resources-Oligocene Frio and Anahuac Formations, United States Gulf of Mexico Coastal Plain and State Waters, Open-File Report 2013-1257, U.S. Geological Survey, Reston.

Treviño, R.H., and J.-L.T. Rhatigan, 2017, Regional Geology of the Gulf of Mexico and the Miocene Section of the Texas Near-Offshore Waters, Geological CO_2 Sequestration Atlas of Miocene Strata, Offshore Texas State Waters, Report of Investigations No. 283, Chapter 1, Bureau of Economic Geology, University of Texas at Austin, Austin, TX.

Request for Additional Information: Rose Carbon Capture and Sequestration Facility
November 19, 2025

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	8.1	40	"$CO_{2,u}$ = Annual CO_2 mass injected (metric tonnes) as measured by flow meter u." Per 40 CFR 98.443(c)(1), this variable should be, "$CO_{2,u}$ = Annual CO_2 mass injected (metric **tons**) as measured by flow meter u." Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443. Additionally, this issue appears in multiple other equations included in this section.	Section 8 of the MRV plan has been updated to be consistent with the text in 40 CFR 98.443. Additionally the document has been QA/QC to be consistent.
2.	8.2	40	The mass of CO2 emitted by surface leakage (CO_{2E}) is determined via Eq. RR-10. Section 40 CFR 98.444(d) is only applicable to " equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead or between the flow meter used to measure production quantity and the production wellhead," which is covered by the term CO_{2FL} (separately from equation RR-10). We recommend removing the reference to 98.444(d) in section 8.2.	Removed the reference to 40 CFR 98.444(d) in section 8.2

Rose Carbon Capture and Sequestration Facility

Facility (GHGRP) ID: 590420

MONITORING, REPORTING, AND VERIFICATION PLAN

Rose Carbon Capture and Storage Facility

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

September 2025

TABLE OF CONTENTS

List of Tables

List of Figures

List of Acronyms and Abbreviations

Name	Definition
%	percent
AMA	active monitoring area
AoR	Area of Review
API	American Petroleum Institute
CCS	carbon capture and sequestration or carbon capture and storage
CFR	Code of Federal Regulations
CO_2	carbon dioxide
CO_{2I}	carbon dioxide injected
CO_{2E}	carbon dioxide emitted via surface leakage
CO_{2FI}	mass of CO_2 emitted from equipment leaks and vented emissions
COC	Chain-of-Custody
DTS	Distributed Temperature Sensing
EPA	U.S. Environmental Protection Agency
ExxonMobil	ExxonMobil Low Carbon Solutions Onshore Storage LLC
GHG	greenhouse gas

Name	Definition
KB	Kelly bushing
LCZ	Lower Confining Zone
mD	millidarcy
MMA	maximum monitoring area
MRV	Monitoring, Reporting, and Verification
PISC	post-injection site care
Project	Rose Carbon Capture and Sequestration Project or Rose Carbon Capture and Storage Project
RRC	Railroad Commission of Texas
Storage	Sequestration
TVD	true vertical depth
UCCZ	upper composite confining zone
UIC	Underground Injection Control
USDW	underground sources of drinking water

Distribution Sheet

This Monitoring, Reporting, and Verification Plan was prepared and approved by ExxonMobil for use in collecting information for the reporting of greenhouse gases received and injected by the Rose Carbon Capture and Sequestration Project. ExxonMobil will incorporate the monitoring and reporting actions described in this document into the standard ExxonMobil operating program, as appropriate, for the control of work associated with the scope of data quality and detection monitoring for the Project.

Revision History for MRV Plan.

Version	Date	Description of Change
Version 1.0	September, 2025	Submission of MRV Plan for EPA Review.

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1.0 Introduction

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is submitting a Monitoring, Reporting, and Verification (MRV) Plan in accordance with Title 40 of the Code of Federal Regulations, Part 98, Sections 440–449 (40 CFR 98.440–449 [Subpart RR]). This Plan details the MRV activities for ExxonMobil's Rose Carbon Capture and Sequestration Facility (Project or Rose Carbon Capture and Storage Project) in Jefferson County, Texas. The proposed Project site consists of three injection wells injecting carbon dioxide (CO_2) sources received by a single pipeline from multiple industrial emitters.

The Project is designed to collect, transport, and sequester a maximum of 5 million metric tonnes per annum of CO_2. ExxonMobil plans to sequester a total of approximately 53 million metric tonnes of CO_2 over a 13-year injection period into the Fleming and Upper Frio Formations.

An application has been submitted in accordance with the requirements of the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Sequestration Wells promulgated in 40 CFR 146.81–146.95. Until Texas receives primacy, U.S. Environmental Protection Agency (EPA) Region 6 is responsible for processing the federal Class VI permit application.

The objective of this MRV Plan is to satisfy the requirements of Subpart RR as applicable to MRV plans.

Pursuant to 40 CFR 98.448, this MRV Plan meets the content requirements and otherwise satisfies the key data collection and monitoring activities, including the following seven major components:

- Delineation of the maximum monitoring area (MMA) and active monitoring areas (AMAs) (40 CFR 98.448(a)(1));
- Identification of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways (40 CFR 98.448(a)(2));
- Strategy for detection and quantification of surface leakage of CO_2 (40 CFR 98.448(a)(3));
- Approach for establishing the expected baselines for monitoring CO_2 surface leakage (40 CFR 98.448(a)(4));
- Considerations made to calculate site-specific variables for the mass balance equation (40 CFR 98.448(a)(5));
- Identification numbers for wells (see Section 2 below) (40 CFR 98.448(a)(6)); and
- Timing of data collection (see Section 9 below) (40 CFR 98.448(a)(7)).

2.0 Facility Information [40 CFR 98.448(a)(6)]

The following are registration numbers associated with the Project:

- Project Site Name—ExxonMobil's Rose Carbon Capture and Sequestration Facility
- Greenhouse Gas Reporting Program ID number—590420
- EPA UIC Class VI Permits for Rose Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03—Under Review

Table 2-1 provides the location of the three injection wells. A map showing the injection wells, monitoring wells, artificial penetrations, and the Area of Review (AoR) is provided on Figure 3-1. The AoR represents the furthest extent of the modeled free phase CO_2 plume and critical pressure front as described in Section 3.4.2.

Table 2-1: Injection Well Locations

Well Name and Number	API	Location	Latitude (NAD83)	Longitude (NAD83)
LaBelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)	4224532913	RRC District 3, Section 42, Abstract 874	29° 59' 58.84" 29.999678	-94° 17' 6.39" -94.285108
Bead Farm Co. #2 (Rose CCS Project Injection Well No. 02)	4224532911	RRC District 3, Section 41, Abstract 266	29° 59' 27.66" 29.991017	-94° 17' 52.93" -94.298036
Bead Farm #3 (Rose CCS Project Injection Well No. 03)	4224532912	RRC District 3, Section 8, Abstract 658	30° 00' 42.40" 30.011778	-94° 17' 52.29" -94.297858
API = American Petroleum Institute; CCS = carbon capture and sequestration; RRC = Railroad Commission of Texas				

3.0 Project Description

The Project is located in Jefferson County, Texas, within the Gulf Coast Basin, an area known for its favorable geologic formations for CO_2 injection and containment. The Project site is ideally suited for the sequestration of CO_2 within the proposed injection zone in the Fleming and Upper Frio Formations. The selected injection intervals within these formations exhibit high porosity and permeability that are ideal for CO_2 storage and are of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of CO_2 stream. The CO_2 is derived from multiple industrial sources, where industrial, atmospheric emission points under long-term contract will be captured and compressed for transportation to the Project area.

As part of the Project, ExxonMobil drilled a stratigraphic well in October and November 2023 (Bead Farm Co. #1; American Petroleum Institute 4224532908) and implemented a data acquisition program. The data acquisition program for the stratigraphic well produced a significant amount of site-specific information. Field observations were made of the core samples, geological logging data were collected through the injection and confining zones, injectivity testing yielded measurements of injection zone permeability, and numerous laboratory tests were performed on core and fluid samples for refining the site characterization and geochemical model. As a result, an AoR model and injection strategy were developed and well designs made to align with the site characterization data. Sufficient geologic characterization data are available to model the AoR, optimize the operating parameters, and identify the risks and uncertainties of the Project. The potential for uncertainty that could result in the leakage of CO_2 was addressed on a risk-by-risk basis in the operating strategy, injection well design, and the testing and monitoring program. The stratigraphic well (Bead Farm Co. #1) has since been converted to an above-zone monitoring well to conduct monitoring above the confining zone.

Another in-zone monitoring well has been placed for direct monitoring, subsurface model calibration, and CO_2 plume and pressure front verification.

ExxonMobil plans to utilize three injection wells to sequester approximately 53 million metric tonnes of CO_2 over a 13-year period. Each well will inject into the Fleming and Upper Frio Formations in multiple intervals as part of a staged approach. The Project includes a comprehensive monitoring network (Figure 3-1) consisting of an above-zone monitoring well, an in-zone monitoring well, and three shallow monitoring wells installed in the underground sources of drinking water (USDW) (i.e., the upper Chicot Aquifer) to support in-zone plume tracking, detection of potential above-zone CO_2 migration, and protection of drinking water resources.

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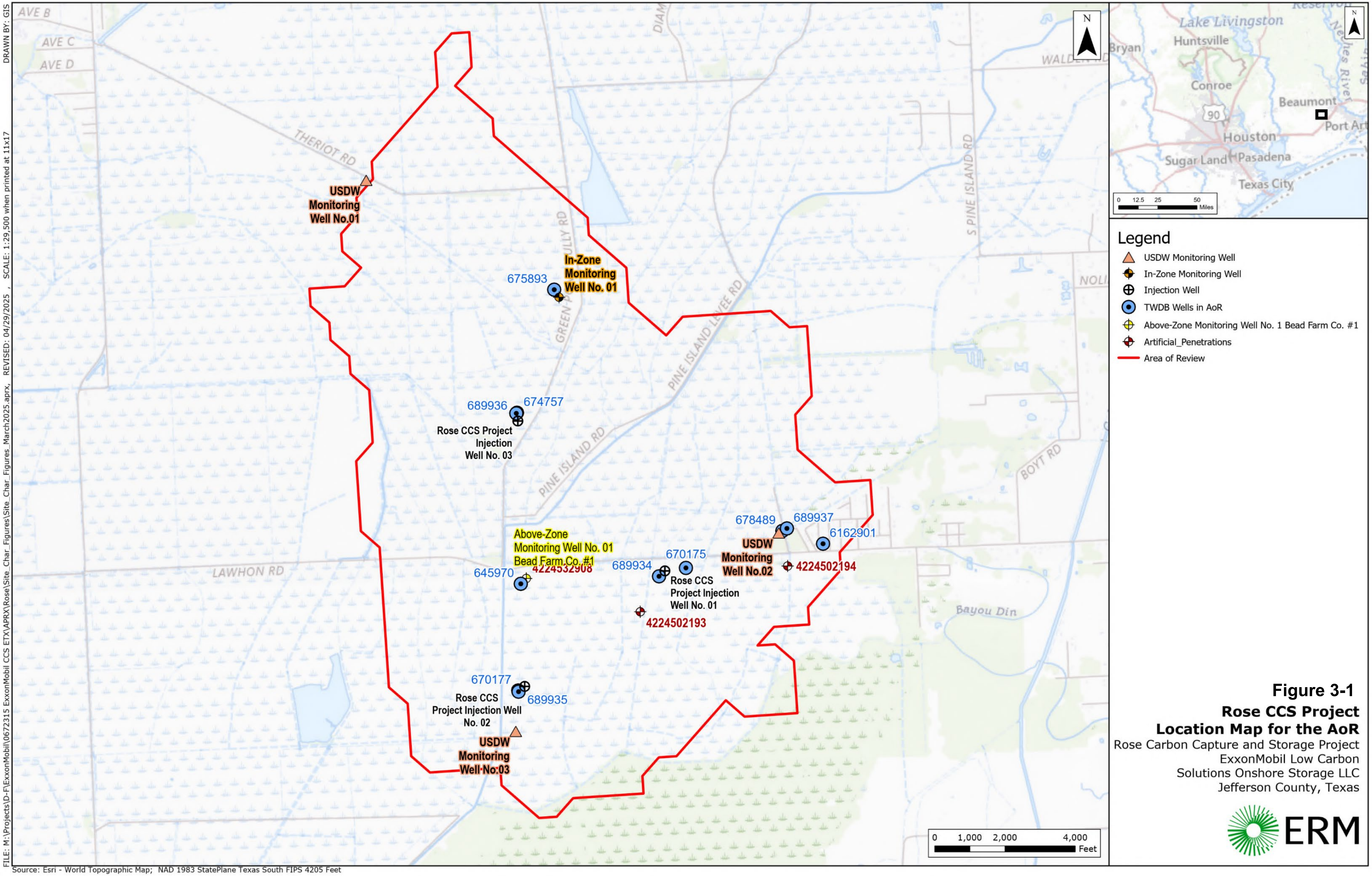

USDW Monitoring Well No.01
In-Zone Monitoring Well No. 01
675893
689936
674757
Rose CCS Project Injection Well No. 03
Above-Zone Monitoring Well No. 01 Bead Farm Co. #1
4224532908
645970
689934
670175
Rose CCS Project Injection Well No. 01
678489
689937
6162901
USDW Monitoring Well No.02
4224502194
4224502193
670177
689935
Rose CCS Project Injection Well No. 02
USDW Monitoring Well No.03
Legend
USDW Monitoring Well
In-Zone Monitoring Well
Injection Well
TWDB Wells in AoR
Above-Zone Monitoring Well No. 1 Bead Farm Co. #1
Artificial_Penetrations
Area of Review
Figure 3-1
Rose CCS Project
Location Map for the AoR
Rose Carbon Capture and Storage Project
ExxonMobil Low Carbon
Solutions Onshore Storage LLC
Jefferson County, Texas
ERM
0 1,000 2,000 4,000 Feet
Source: Esri - World Topographic Map; NAD 1983 StatePlane Texas South FIPS 4205 Feet
FILE: M:\Projects\D-F\ExxonMobil\0672315 ExxonMobil CCS ETX\APRX\Rose\Site_Char_Figures\Site_Char_Figures_March2025.aprx, REVISED: 04/29/2025 , SCALE: 1:29,500 when printed at 11x17 DRAWN BY: GIS

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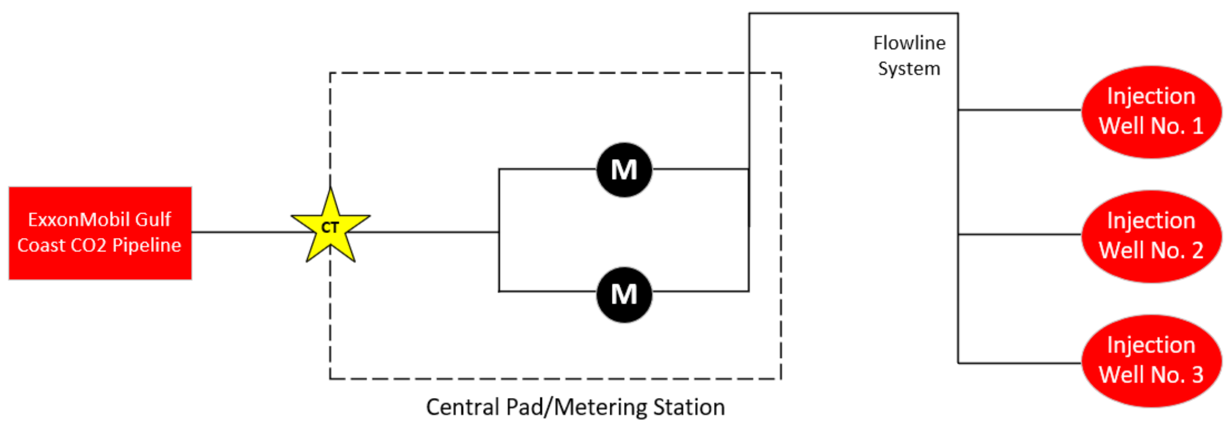
3.1 Injection Process

Figure 3-2 shows a simplified diagram of the injection process, following the flow of CO_2 from its source to each of the three injection wells. The black "M" points represent flow meters that will be utilized to measure the amount of CO_2 being injected. The yellow star represents the point of custody transfer from the single CO_2 pipeline. The dotted line represents the central pad where metering will be conducted prior to injection; the central pad is co-located with the Above-Zone Monitoring Well No. 01/Bead Farm Co. #1 pad. All CO_2 sequestered will be metered at the central pad.

Figure 3-2: Simplified Facilities Flow Diagram for Rose Project.



The injected CO_2 will come from multiple high concentration industrial sources, including clean hydrogen and ammonia production facilities, direct reduced iron plants, natural gas treatment facilities, and other industrial sources that feed directly into ExxonMobil's Gulf Coast CO_2 pipeline network. The pipeline network maintains a CO_2 composition of >97 percent (%) CO_2, <1% hydrogen, and <3% methane.

CO_2 will arrive at the central pad via pipeline in a supercritical state. At the central pad, CO_2 will pass through a gas chromatograph before a flowline system transports the CO_2 to each of the three injection wells. Three injection wells will be used to sequester the CO_2 at the Project site. The name and location of each well are provided in Table 2-1.

Each injection well was completed with a single completion string and assembly consisting of injection packer, nipple profile, safety injection valve, pressure/temperature gauges, and tubing. Upon permit approval, injection will start based on a staged bottoms-up injection approach. A total of seven injection stages within the four formation intervals are planned for each well. Once the target injection volume of CO_2 is attained, that injection stage will be plugged back to isolate that interval from subsequent injection intervals. The next injection interval will then be completed and accessed through additional perforations to establish communication with the reservoir. CO_2 will continue into that new injection interval until the target CO_2 storage amount has been achieved for that interval.

3.2 Geologic Setting

The Project is located within the Houston Embayment of the Gulf Basin. On shore and near-shore, the Gulf Basin is referred to as the Gulf Coast region. The stratigraphic column of the Houston Embayment is presented on Figure 3-3 (Treviño and Rhatigan, 1995). The Gulf Basin was formed by crustal extension and seafloor spreading during the breakup of Pangea that took place in the Mesozoic Era. A regional unconformity at the base of the sedimentary section is marked by the base of an evaporite layer (Galloway, 2008). These substantial evaporitic deposits (up to 4 kilometers thick) became a defining characteristic for later structural evolution of the Basin. Salt deposition ceased at the end of the Late Jurassic Era, as continued rifting produced oceanic crust.

The outline and morphology of the present-day Gulf Basin was sculpted by subsidence and rimming carbonate platform formation by the Early Cretaceous Era (Galloway, 2008). The Cenozoic Era depositional episodes along the northwestern Gulf Basin are fluvial-deltaic and shore-zone dominated, which reflect major phases of adjacent North American structural events (Galloway, 2008).

The Project area is suitable for CO_2 injection into the proposed injection intervals of the Fleming and Upper Frio Formations. The sands within these formations exhibit high porosity and permeability that are ideal for CO_2 storage and are "of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the [CO_2] stream" (40 CFR 146.83(a)(1)). Both the upper composite confining zone (UCCZ) and Anahuac Shale are thick, extensive, continuous sealing intervals extending across the AoR, MMA, and miles beyond in every direction. Their lateral extent has been confirmed both in the literature (e.g., Galloway, 2008) and through seismic and stratigraphic analysis of regional and local well data. An extensive data collection campaign at the Project confirms the seals and their efficacy. They are sufficient to "contain the injected [CO_2] stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s)" (40 CFR 146.83(a)(2)).

As detailed in the section below, the Project includes a Miocene-age upper composite confining zone (UCCZ) belonging to the Fleming Formation and includes the Amphistegina 'B' (Amph 'B') Shale marker. The UCCZ is a fine-grained, muddy sequence and the Amph 'B' is a regionally extensive shale (Galloway, 2008). The Anahuac Formation is located within the injection zone, overlying the Frio Formation, and underlying the Fleming Formation. The Anahuac Formation (Anahuac Shale) is a thick, continuous shale interval that was deposited during a transgressive event following Frio deposition (Galloway, 2008).

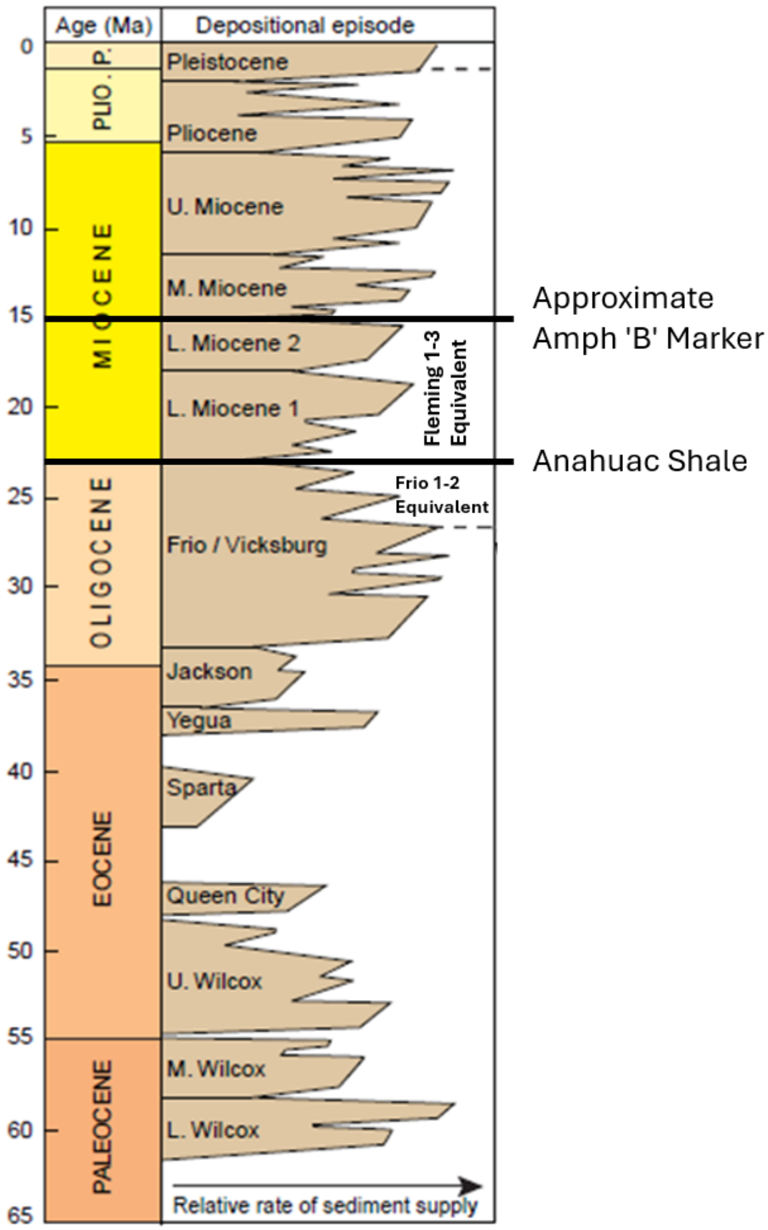
The major stratigraphic units, from deepest to shallower, are detailed below:

- Lower Confining Zone (LCZ): The LCZ comprises over 3,000 feet of thick Frio sediments, dominated by fine-grained lithologies (shales), which underlie the Upper Frio injection interval. A limited number of wells have log data to verify the gross thickness of this interval near the site. ExxonMobil relied on seismic data to assess the occurrence and lateral continuity of the LCZ.
- Upper Frio: The Upper Frio Formation consists of alternating shales and sands, stemming from progradational shore-zone systems of the Gulf coastal plain. Specifically, in the

Houston area and during the Early Oligocene, deposition of large volumes of sand from the fluvially dominated Houston and Central Mississippi deltas occurred, with subsequent waves reworking resulting in thick, sand-rich prograding shore-zone systems fronted by muddy shelf sequences. Regionally, the reservoir quality of the Frio in the Houston Embayment area exhibits porosities ranging from 16 to 36% and permeabilities of approximately 50 to 3,000 millidarcies (mD) (Swanson et al., 2013). The analysis of core data from the stratigraphic well showed porosity values to be generally consistent with regional data.

- Anahuac Formation: The Anahuac Formation is located within the injection zone, overlying the Frio Formation and underlying the Fleming Formation. It is a thick, continuous shale interval. The Anahuac Formation (Anahuac Shale) was deposited during a transgressive event following Frio deposition (Galloway, 2008). Prograding Miocene intervals, including the Fleming Formation, cap the Anahuac transgression (Swanson et al., 2013).
- Fleming Formation: The Lower Miocene was characterized by high sediment supply rates and general deltaic progradation in the Project area. Some transgressive sequences interrupted the Lower Miocene deposition, but the Lower Miocene is mainly bracketed by the underlying Anahuac Shale and overlying UCCZ that include the Amph 'B' Shale as the major transgressive sequence. South of the Project site, the estimated porosities of the Miocene reservoirs range from 5 to 38%, with an average of 28% (Carr et al., 2017). A review of available literature also indicated that permeabilities range from 16 to 1,600 mD with an average of 338 mD (Carr et al., 2017). Analysis of the Lower Miocene core samples from the stratigraphic well demonstrate consistent reservoir characteristics.
- UCCZ: The UCCZ is a thick, muddy sequence that includes the Middle Miocene Amph 'B' Shale, a regionally continuous, transgressive marine unit (Galloway, 2008) that is recognized by the U.S. Geological Survey National Assessment of Carbon Dioxide Storage Resources to be a good sealing unit and, therefore, a competent confining zone as required for CO_2 sequestration project sites (Roberts-Ashby et al., 2014).

Figure 3-3: Gulf Basin Stratigraphic Column.



Note: Miocene-age sediments are equivalent to Fleming Formation

Modified from: Treviño and Rhatigan, 2017

3.3 Artificial Penetrations in the MMA

As outlined in the Rose Project Class VI Application and in accordance with 40 CFR 146.82(a)(4) and 40 CFR 146.84(c)(2), a search was conducted to identify and assess the occurrence of artificial penetrations within the AoR. A summary of the identified artificial penetrations is provided in Table 3-1. Based on available data, other than the Project injection and monitoring wells drilled in 2024, two artificial penetrations were identified to intersect the UCCZ: one legacy well (Broussard JE Jr-1) and the Project's stratigraphic test well (Bead Farm Co. #1). Details for each well are provided in Table 3-1.

Pursuant to 40 CFR 146.84(c)(3), corrective actions were undertaken for both penetrations to prevent fluid movement that could endanger USDWs. Each well was re-entered and appropriate barriers were installed at critical intervals. Barriers were installed at the UCCZ, surface casing shoe, base of the lowermost USDW, and the wellhead for the legacy well. A barrier at the UCCZ was installed in Bead Farm Co. #1 in order to remain open for above-zone monitoring. For each well, the barrier at the UCCZ was constructed using CO_2-compatible material, as required by 40 CFR 146.84(d).

The Broussard JE Jr-1 legacy well was re-entered and plugged and abandoned on 14 March 2025. The Bead Farm Co. #1 stratigraphic test well was converted into the above-zone monitoring well on 7 February 2025 to support the Project's testing and monitoring program.

Within the MMA, artificial penetrations were evaluated to identify legacy wells intersecting the UCCZ. Fifteen (15) legacy wells were identified within the MMA that penetrate the UCCZ and four (4) wells were identified that terminate above the UCCZ (Table 3-2). The modeling results indicate that these wells are not anticipated to come in contact with the CO_2 plume or the critical pressure front. As discussed in Section 5.2, time-lapse seismic surveys will be conducted at the intervals specified in Tables 6-2 and 6-3 to monitor unexpected lateral or vertical CO_2 plume migration above the UCCZ and the corrective action plan will be updated accordingly. Table 3-2 summarizes the additional wells identified within the MMA.

Table 3-1: Summary of Artificial Penetrations within AoR

Well Name	State/ Federal Well ID (API Number)	Well Type	Well Status	Date Drilled	Depth (ft KB)	Latitude, Longitude (NAD83)	Penetrates UCCZ?
Above-Zone Monitoring Well No. 01 Bead Farm Co. #1	4224532908	Project Monitoring Well	Active	10/15/2023 Recompleted 02/07/2025	8,664	29.999222, -94.297364	Yes
Broussard JE Jr-1	4224502193	Dry Hole	P&A	2/10/1958	9,050	29.996539, -94.287435	Yes
Broussard J. E. Etal-1	4224502194	Dry Hole	P&A	Unknown	2,518**	29.999730, -94.274070	No
BFC-1 Rig Supply Water Well #1	645970	Water Rig Supply	In Use	8/11/2023	290*	29.999028, -94.298056	No
D. S. Wier	Not Available	Water Supply	P&A	1941	7*	30.001389, -94.270833	No
Labelle Properties Ltd #1	4224532913	Project Injection Well No. 01	Active	06/23/204	8,672	29.999678, -94.285108	Yes
Bead Farm Co. #2	4224532911	Project Injection Well No. 2	Active	07/15/2024	8,752	29.991017, -94.298036	Yes
Bead Farm #3	4224532912	Project Injection Well No. 3	Active	08/05/2024	8,565	30.011778, -94.297858	Yes
Bead Farm Company #4	4224532914	Project Monitoring Well	Active	08/31/2024	8,383	30.021558, -94.293978	Yes
Rose Rig Supply Water Well #1	670175	Water Rig Supply	Active	6/14/2024	300*	29.999857, -94.28321	No
Rose Rig Supply Water Well #2	670177	Water Rig Supply	Active	7/2/2024	300*	29.990716, -94.298632	No
Rose Rig Supply Water Well #3	674757	Water Rig Supply	Active	7/19/2024	300*	30.012428, -94.297908	No
Rose Rig Supply Water Well #4	675893	Water Rig Supply	Active	8/15/2024	300*	30.021947, -94.294199	No
USDW Monitoring Well No. 1	678487	USDW Monitoring Well	Active	8/20/2024	330*	30.030833, -94.310556	No

Well Name	State/ Federal Well ID (API Number)	Well Type	Well Status	Date Drilled	Depth (ft KB)	Latitude, Longitude (NAD83)	Penetrates UCCZ?
USDW Monitoring Well No. 2	678489	USDW Monitoring Well	P&A***	8/20/2024	440*	30.0025, -94.274444	No
USDW Monitoring Well No. 3	678491	USDW Monitoring Well	Active	8/20/2024	330*	29.9875, -94.298889	No
USDW Monitoring Well No. 2R	683826	USDW Monitoring Well	Active	11/9/2024	320*	30.0025, -94.274444	No
Shallow Groundwater Well #1	689934	Monitoring Well	Active	9/19/2024	25*	29.99927, -9428565	No
Shallow Groundwater Well #2	689935	Monitoring Well	Active	9/17/2024	25*	29.99062, -94.2986	No
Shallow Groundwater Well #3	689936	Monitoring Well	Active	9/17/2024	25*	30.01238, -94.29797	No
Shallow Groundwater Well #4	689937	Monitoring Well	Active	9/18/2024	20*	30.00268, -94.27403	No
Notes: API = American Petroleum Institute; ID = identification; KB = Kelly bushing; UCCZ = upper composite confining zone; USDW = underground sources of drinking water *Water well datum is below ground level **KB not available in historical records ***Casing collapsed above water table, couldn't collect sample, redrilled as 2R in same location							

Table 3-2: Summary of Wells Evaluated Within the MMA and Outside of the Predicted Stabilized CO_2 Plume

Well Name	API Number or State Well ID	Surface Location Latitude, Longitude (NAD83)	Status	Date Drilling or Recompletion Complete	Well Depth (ft TVD)	Penetrates the UCCZ?
Walter Co. 1	24532667	30.0479207, -94.2960335	Gas Well	1/6/2011	15,577	Yes
Walter Co. 2	24532736	30.0450865, -94.2979686	Gas Well	1/1/2019	15,248	Yes
Sunset Unit 1H	24532729	30.01374, -94.25681	Oil Well	4/27/2018	8,231	Yes
Broussard Unit 1	24532862	29.99733669, -94.26210890	Dry Hole	3/7/2018	8,300	Yes
Vaughan 1	24532799	29.99424, -94.26941	Plugged Gas Well	3/18/2014	14,500	Yes
Burrell Estate 1	24532125	29.98283161, -94.28273884	Dry Hole	4/15/1996	9,100	Yes
Broussard, Et Al 1	24531254	29.97798666, -94.29521881	Dry Hole	2/5/1979	8,366	Yes
Walter Co. 'C' 1	24531720	29.977486, -94.3012888	Plugged Oil Well	12/3/1983	9,000	Yes
Walter Co. 2	24531452	29.97873115, -94.30382344	Plugged	3/27/1981	8,702	Yes
Walter Company 1	24531387	29.98137196, -94.30693397	Plugged Oil Well	7/7/1980	9,000	Yes
Walter Co. 'B' 1	24531488	29.98006035, -94.31094003	Dry Hole	5/11/1981	8,815	Yes
Walter Company 1WD	24531848	29.98183461, -94.3075098	Dry Hole	7/3/1985	2,800	No
Walter Co. 1	24531725	30.02038438, -94.32145035	Plugged Gas Well	12/8/1983	16,000	Yes
Beaumont Farms 1	24500109	30.03063294, -94.29401318	Dry Hole	1/31/1956	8,517	Yes
Broussard Tr 1	24500111	30.01214737, -94.26244721	Dry Hole	6/13/1937	7,360	Yes
Broussard Trust Co. 1	24502191	29.99958128, -94.31390135	Dry Hole	12/23/1949	9,010	Yes
Broussard Unit #1	469176	29.993983, -94.26965	Plugged Rig Supply Well	12/28/2017	330	No
Vaughan #1	355705	29.994167, -94.269444	Plugged Rig Supply Well	1/4/2014	332	No
Bright Edge #1	165222	29.978889, -94.306667	Rig Supply Well	2/28/2005	325	No
API = American Petroleum Institute; TVD = true vertical depth; UCCZ= upper composite confining zone						

3.4 Reservoir Characterization and Modeling

The Fleming and Upper Frio Formations were assessed to characterize the sealing effects of the confining zone and reservoir heterogeneity within the injection zone. Based on the analysis and understanding of the Project area, a three-dimensional geologic model was developed to estimate the storage potential for the CO_2 and evaluate its confinement, both laterally and vertically.

3.4.1 Modeling Background

Schlumberger's Petrel™ Software was chosen to create the detailed geologic model for the Project. This software is used worldwide and combines information from logs and seismic data to build a sophisticated representation of underground reservoirs. The Petrel™ developed geologic model for the Project incorporates the available data for all relevant subsurface layers of the site.

The geologic model developed in Petrel™ was used as an input into the Schlumberger Eclipse-300™ numerical reservoir simulator. Eclipse-300™ is a widely recognized tool used for modeling both compositional and unconventional reservoirs. The simulator uses advanced computational methods and equation-of-state algorithms to produce a reliable prediction for CO_2 sequestration projects. The software has modules and options specifically intended to allow the study of CO_2 injection activities, can handle large data sets and multiple grids, and offers various tools for data management, visualization, and uncertainty analysis.

3.4.2 AoR Delineation Based on Model Results

The Eclipse-300™ model was used to generate projections of CO_2 plume and pressure front migration versus time over the anticipated life of the Project. Each well's operational plan was incorporated into the modeling and followed the staged approach outlined in Section 3.1, beginning with initial completion and progressing through successive recompletions in incrementally shallower sections of the injection intervals. For each injection interval, as the volume of CO_2 injected increases the areal extent of CO_2 within that zone expands. Eventually, the CO_2 plumes from each injection well commingle within the layers of each distinct injection interval. The combined effects of relative permeability, capillary pressure, and limited structural dip ultimately arrest the extent of migration of the CO_2 plume within each injection interval up-dip to the northwest.

The areal extent of the aggregate CO_2 plume is expected to grow rapidly during injection and slow after injection ceases. The areal growth rate is expected to reach a stability threshold, which is defined conservatively at less than 0.25% per year, 39 years after the start of injection, demonstrating plume stability. The stabilized CO_2 plume is shown on Figure 4-1.

In accordance with 40 CFR 146.84, the AoR is delineated via the maximum areal extents within the injection interval of both the CO_2 plume and critical pressure front at any time interval or depth. Critical pressure is the increase in reservoir pressure that has a potential to create crossflow of brine from the injection zone into the lowermost USDW, assuming the presence of a hypothetical bridging conduit such as an unplugged borehole. The first step to predict the pressure front of interest is to calculate the critical pressure for each completion stage. Once critical pressure is estimated, a numerical simulation is used to predict the size and shape of the critical pressure front defined by this pressure contour. The critical pressure front represents the

maximum areal cone of influence and combines results from the seven completion intervals for each of the three injection wells.

Superimposing the stabilized CO_2 plume and critical pressure boundaries, Figure 4-1 shows the AoR boundary for the Project.

4.0 Delineation of Monitoring Areas [40 CFR 98.448(a)(1)]

Reservoir simulator modeling (Section 3.4), informed by site characterization data, was conducted to delineate the maximum areal extent of the plume area for the life of the Project and to identify the MMA and AMA. ExxonMobil will reevaluate the AoR (including free phase CO_2 plume), MMA, and AMA based on site-specific monitoring data at the minimum frequency of 5 years in accordance with 40 CFR 146.84. Information gathered from testing and monitoring activities will be used to evaluate whether a more frequent review period is warranted based on the observed conditions of CO_2 plume and pressure front migration.

ExxonMobil will not cease post-injection monitoring until the non-endangerment demonstration pursuant to 40 CFR 146.93(b)(3) has been approved by the UIC Program Director. Pursuant to 40 CFR 146.93(b)(1), the default post-injection site care (PISC) monitoring timeframe is 50 years after cessation of injection. ExxonMobil will monitor groundwater quality and track the position of the CO_2 plume and pressure front for 50 years after cessation of injection unless a lesser period of time is approved by the UIC Program Director. At the conclusion of the PISC period, a request for discontinuation of Subpart RR reporting will be submitted including a demonstration that current monitoring and modeling show that the cumulative mass of CO_2 reported as sequestered is not expected to migrate in the future or encounter leakage pathways.

4.1 Maximum Monitoring Area [40 CFR 98.449]

Subpart RR defines the MMA as the area that must be monitored and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized, plus an all-around buffer zone of at least one half-mile. ExxonMobil has simulated the maximum plume extent to occur 26 years post-injection (39 years after the start of injection). Figure 4-1 shows the extent of the stabilized CO_2 plume with a half-mile buffer area.

4.2 Active Monitoring Area [40 CFR 98.449]

ExxonMobil has established one AMA boundary for 39 years and does not anticipate expansion of the monitoring area under 40 CFR 98.448 based on the currently planned operating conditions. Given the definitions used to delineate the MMA and the AMA, the AMA is functionally equivalent to the MMA. Monitoring the entire MMA boundary provides maximum operational flexibility.

The AMA is the portion of the MMA where monitoring is actively conducted at any given time during the injection and post-injection phases (orange dash line on Figure 4-1). The AMA is composed of two combined areas:

- The area projected to contain the free phase CO_2 plume at the end of year "t," plus an all-around buffer zone of one half-mile or greater if known leakage pathways extend laterally more than one half-mile; and
- The area projected to contain the free phase CO_2 plume at the end of year t+5.

Based on the definition above, ExxonMobil has assumed an active monitoring timeframe of t = 39 years post start-up, aligning with the expected stabilization of the CO_2 plume. For the Rose Project, this AMA is controlled by the 39-year plume plus the one half-mile buffer.

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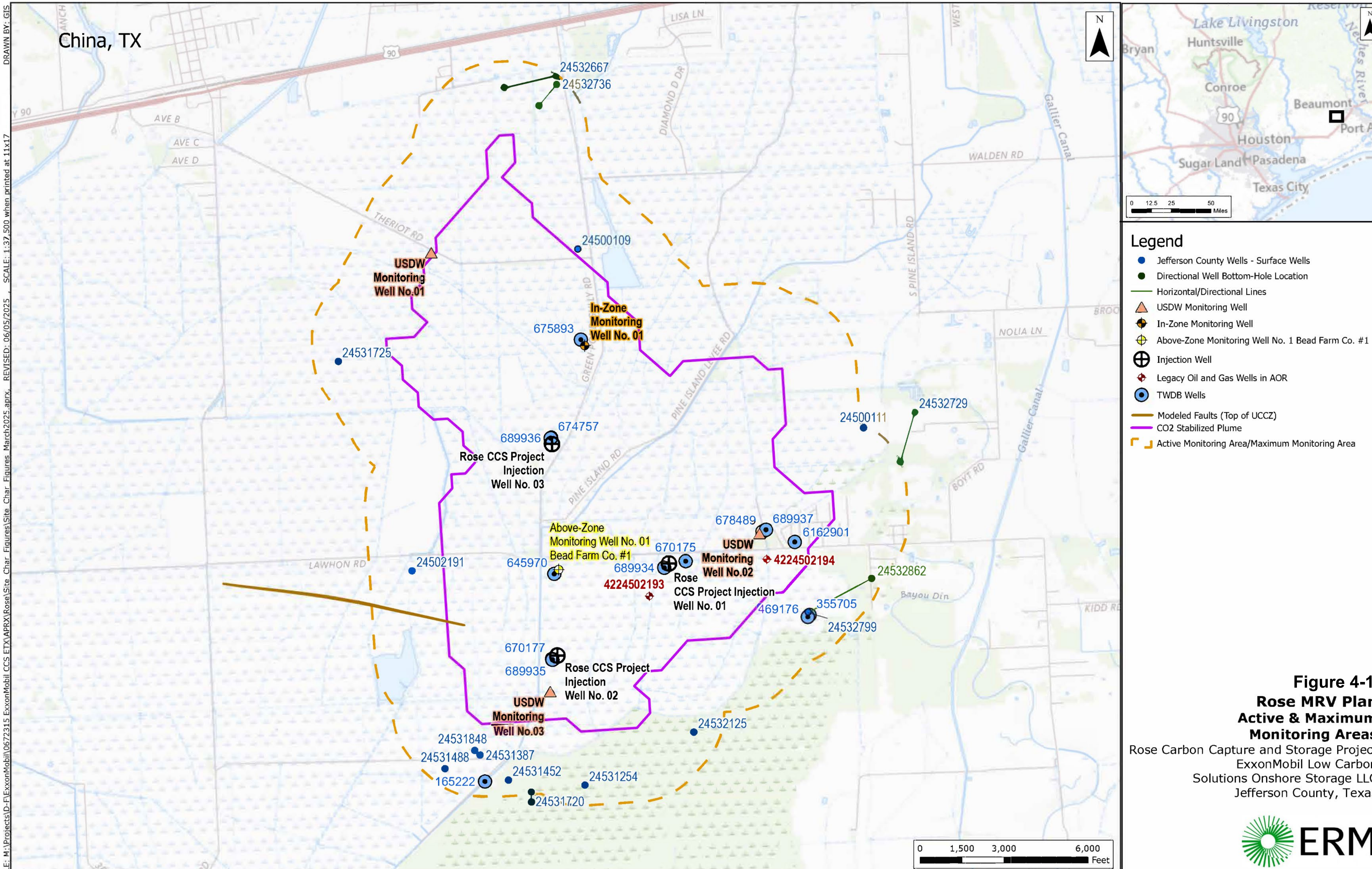

Figure 4-1
Rose MRV Plan
Active & Maximum Monitoring Areas
Rose Carbon Capture and Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson County, Texas

Source: Esri - World Topographic Map; NAD 1983 StatePlane Texas South FIPS 4205 Feet

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5.0 Identification of Potential Leakage Pathways [40 CFR 98.448(a)(2)]

ExxonMobil identified the following scenarios as potential leakage pathways for the Project through a risk assessment process. Each of the identified leakage pathways carries a low likelihood of occurrence due to the engineering design of the Project, mitigating measures taken, and implementation of the Testing and Monitoring Plan developed as part of the Class VI application process.

The potential leakage pathways described in Sections 5.1 through 5.6 are summarized below:

- Integrity of Injection or Monitoring Well Casing or Cement Seal;
- Integrity of Legacy Well Casing or Cement Seal;
- Injection Well Monitoring Equipment Failure;
- Integrity of the UCCZ;
- Induced or Natural Seismic Event; and
- Integrity of Surface Equipment.

5.1 Integrity of Injection or Monitor Well Casing or Cement Seal

Corrosion of the mechanical components or casing cement are two hypothetical release mechanisms identified for the injection and monitoring wells that have the potential to release CO_2. For example, CO_2 detected at an injection or monitoring well potentially implies that internal or external mechanical integrity of a well may have been compromised, causing release of CO_2. Potentially, CO_2 or brine could be released at an injection or monitoring well due to subsurface cement degradation or annular space defects in cement completion. In the case of either of these hypothetical examples, the likelihood of surface leakage due to a breakdown of materials in injection or monitoring wells is very low because of the CO_2 compatible materials used and the continuous monitoring techniques deployed.

Hypothetical Release Mechanism: mechanical integrity failure at an injection or monitoring well resulting in release of CO_2.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Proper wellbore design and construction of the project wells, which will utilize CO_2 compatible materials for cement, casing, and tubing.
• Routine inspection of the well casing and cement integrity to identify potential corrosion or deficiencies.
Detection methods:
• Well casing and cement bond logs conducted on injection wells during shut-ins to assess loss decay or corrosion more than acceptable limits via distributed temperature sensing (DTS) as described in Table 6-2.
• Deficiency identified during pressure falloff tests and annulus pressure tests.
• Wellhead pressure exceeds the maximum pressure specified in the permit.
• Annulus pressure indicates a loss of external or internal integrity/containment.
• CO_2 plume and pressure front tracking above UCCZ indicates a change in conditions.

• Fluid samples from above the UCCZ and/or USDW indicate a statistically significant change in conditions.
• Mechanical integrity testing identifies a potential issue in the integrity of the well.
Magnitude: Should a leakage result from the injection or monitoring wellbores and into the atmosphere, the volume of CO_2 released will be quantified based on operating conditions at the time of release.

5.2 Integrity of Legacy Well Casing or Cement Seal

Consistent with the potential for CO_2 to leak at an injection well, artificial penetrations of the UCCZ from legacy oil and gas activities may represent a similar risk scenario. Legacy wells that penetrate the UCCZ were identified within the predicted stabilized CO_2 plume boundary and MMA. Within the stabilized CO_2 plume, one legacy well was plugged as a corrective action prior to operation; the other legacy well was recompleted as an above-zone monitoring well for the Project. All other legacy wells within the MMA that penetrate the UCCZ are located outside of the stabilized CO_2 plume boundary, as detailed in Table 3-2. Current reservoir models predict no migration of CO_2 plume nor brine to reach the legacy wells in the MMA; therefore, the likelihood of leakage is low.

The objective of this risk scenario is to provide the response actions in the event that unknown legacy wells are identified and suspected of being within the pathway of the CO_2 plume or brine due to unexpected lateral migration, causing CO_2 leakage due to potential casing or cement integrity issues. To further reduce this unlikely risk, an aeromagnetic survey was conducted on September 2023 to assess the predicted CO_2 plume boundary for undocumented artificial penetrations. No additional artificial penetrations were identified.

Additionally, Tables 3-1 and 3-2 detail the artificial penetrations located within the predicted CO_2 plume and MMA that do not penetrate the UCCZ. Because these wells do not penetrate the UCCZ, the likelihood of them serving as leakage pathways is low. To monitor above the UCCZ, ExxonMobil will implement a monitoring program that includes fluid sampling from the first laterally continuous zone above the UCCZ, supplemented by time-lapse seismic surveys. Details of the above-zone monitoring program are provided in Table 6-3.

Future wells drilled through the UCCZ by ExxonMobil will be completed with the appropriate materials and integrated into the testing and monitoring plan. Drilling activity within the MMA and above the UCCZ do not pose a risk as a leakage pathway. Any drilling permits issued by the Railroad Commission of Texas (RRC) within the MMA must comply with 16 Texas Administrative Code 3.13, which requires operators drilling within a quarter-mile radius of an injection well to set steel casing and cement above and across the identified injection zone and above and across all flow zones or zones that contain corrosive formation fluids. Potential leakage pathways caused by future drilling activity within the MMA and penetrating the UCCZ are not expected to occur.

Hypothetical Release Mechanism: CO_2 leaks at an artificial penetration as detected within the MMA.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Compliance with CO_2 plume and brine tracking systems.
• Time-lapse seismic surveys will be conducted at the intervals specified in Tables 6-2 and 6-3 to monitor for any indication of unexpected lateral or vertical CO_2 plume migration above the UCCZ.

• CO_2 Plume reservoir model forecast updates to predict pressure front changes that may impact legacy wells outside of the boundary of the predicted stabilized CO_2 plume, but within the MMA, and adjust timing of monitoring and phased-corrective action.
Detection methods:
• CO_2 plume and pressure front tracking indicates potential impact.
• Fluid samples from above the UCCZ and/or USDW indicate a statistically significant change in conditions.
• Legacy well re-entry to collect casing and cement bond logs to assess integrity and well completion materials.
Magnitude: Should a leakage result from a legacy well and into the atmosphere, the volume of CO_2 released will be quantified based on operating conditions at the time of release.

5.3 Injection Well Monitoring Equipment Failure

Loss of mechanical integrity of well pressure equipment may occur during operation of the injection wells. A pressure gauge (or other similar equipment) malfunction could create a shut-off valve malfunction and result in an uncontrolled pressure situation and CO_2/brine crossflow to USDW by fault or fracture activation or well casing and/or cement failure in the vicinity of the production casing perforations.

Hypothetical Release Mechanism: Loss of mechanical integrity of well pressure equipment could trigger a shut-off valve malfunction and result in an uncontrolled pressure situation and CO_2 release by near wellbore fault or fracture activation or by well casing and/or cement failure in the vicinity of the production casing perforations.
Timing of event: Injection phase and/or post-injection phase.
Avoidance measures:
• Routine equipment inspection and maintenance to identify potential integrity issues that may be a result of equipment failure.
• Routine inspections and calibration of monitoring equipment in accordance with manufacturer's recommended procedures.
• Consistent fluid sampling throughout the detection monitoring well network to detect a release above the UCCZ.
• Redundant pressure and temperature measurements in the injection zones to maintain compliance with permitted operating conditions.
Detection methods:
• Anomalies in pressure and rate monitoring, pressure falloff tests, and annulus pressure tests.
Magnitude: Anticipated CO_2 leakage is negligible.

5.4 Integrity of the UCCZ

Several potential risk scenarios were considered that involve a hypothetical release through naturally occurring faults and fractures or other penetrations of the UCCZ, creating a migration pathway for CO_2. For example, CO_2 could hypothetically leak through seismically visible faults or fractures in the UCCZ within the MMA, or CO_2 or brine could hypothetically migrate horizontally to artificial penetrations within the MMA that are not sealed at the UCCZ and result in a release of CO_2. Based on ExxonMobil's assessment of the subsurface, one visible fault was identified that extends through the UCCZ within the MMA. The maximum displacement, which occurs outside the MMA, is much less than the thickness of the UCCZ (13% of total thickness).

Seal analysis indicates high sealing properties such that the integrity of the UCCZ should not be compromised, indicating that this is not a likely leakage pathway for CO_2. The Shale Gouge Ratio was calculated to be greater than 0.75 (i.e., greater than 75% clay content) for hundreds of feet of the fault occurrence within the UCCZ, which is indicative of effective fault sealing within the confining zone. Appraisal well data demonstrated pressure offset above and below the UCCZ, further supporting an effective seal.

CO_2 and brine leaks through shales due to mechanical fracturing were not considered a potential concern for the Project because of the physical nature of the confining shale materials. Above the UCCZ is approximately 3,000 feet of saturated shale, mudstone, and sand. A release through the UCCZ would likely be detected by the groundwater monitoring program prior to release to the surface.

Evidence of fracture development was assessed by examining eight slabbed cores, core computed tomography, borehole imagery logs, and core data from the stratigraphic well. The natural structural features observed in the stratigraphic well core are predominantly non-tectonic pedogenic slickensides that form due to soil processes and sediment compaction, an expected feature of paleo-vertisols. No natural fractures, stylolites, deformation bands, or significant faults were observed in the core samples and no significant risk of high permeability pathways along natural faults and fractures is predicted. The finding of no significant permeability is consistent with the occurrence of trapped hydrocarbons in these structural features documented across the Gulf Coast and no evidence of any formation fluid transmission was observed in the cores.

The following actions were developed to mitigate the potential for releases through the UCCZ:

Hypothetical Release Mechanism: release through naturally occurring faults and fractures or penetration of the UCCZ, creating an unexpected migration pathway for CO_2.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Time-lapse seismic surveys will be conducted at the intervals specified in Tables 6-2 and 6-3 to monitor for any indication of CO_2 plume migration above the UCCZ.
• Compliance with CO_2 plume and brine tracking systems.
Detection methods:
• CO_2 plume and pressure front tracking indicates a potential impact.
• Fluid samples from above the UCCZ and/or USDW indicate a statistically significant change in conditions.
• Third-party direct or indirect data identify a potential impact to subsurface outside of MMA.
Magnitude: As described above, anticipated leakage magnitude is negligible.

5.5 Induced or Natural Seismic Event

Based on the projected operating conditions and regional and local geologic conditions, injection operations are not expected to result in an induced seismic event mandating a response action. Induced or natural seismic events would be monitored at a minimum during the injection phase. ExxonMobil has installed a permanent seismicity monitoring system on-site, which is being monitored by a third party to detect seismic activity prior to and during injection operations. This array has been recording baseline data since 1 July 2024. The design of the array consists of a near-surface network of seismometers with continuous data sampling, incorporation of publicly available data, and telemetry to cloud-based storage. Near-real-time, high-resolution signal processing and quality assurance will be implemented for event detection, magnitude, and location accuracy. ExxonMobil will additionally receive notifications from the United States Geological Survey of recorded seismicity events for the site and surrounding area, should an event occur. If a review of the data indicates that a seismic event of magnitude 2 or larger was within a 5.6-mile radius of an injector, ExxonMobil will notify the UIC Program Director to jointly assess if the events are likely to be associated with the operations, and, if so, implement response actions for seismic events. As described in this section, anticipated leakage magnitude is negligible.

5.6 Integrity of Surface Equipment

The surface components of the injection system include the CO_2 injection wellheads and the associated surface piping that transports CO_2 from the mass flow meters located on the central pad to the wellheads. A data management system, or a suitable equivalent, will be used to facilitate the continuous collection of key operational parameters, including:

- Intake pressure at the central pad transfer point;
- Pressure within the distribution system to each injection well; and
- Pressure at each injection wellhead.

Two Coriolis flow meters, installed at the central pad, will be used to directly measure the mass flow rate of the injected fluid. The Coriolis meters will be calibrated in accordance with the manufacturer's specifications.

During injection, ExxonMobil will review and interpret continuously monitored parameters against permitted limits. This review will also include trend analyses to assess maintenance, recalibration, or system optimization opportunities.

To mitigate the potential for surface leakage of CO_2 from equipment, ExxonMobil will implement the following measures:

- Adherence to Class VI regulatory requirements for well construction (40 CFR 146.86), well operation (40 CFR 146.88), and testing and monitoring of surface facilities (40 CFR 146.90).
- Continuous monitoring via a Supervisory Control and Data Acquisition system monitored remotely by ExxonMobil's Operations Control Center. Surface equipment pressure and flow rates (as noted above and in Section 3.1) are included in the Supervisory Control and Data Acquisition system.
- Routine visual inspections and preventative maintenance of all surface components.
- Surface equipment will be inspected, tested, and calibrated in accordance with manufacturer specifications prior to commissioning.

The likelihood of CO_2 leakage from surface equipment during injection operations is considered to be very low. In the unlikely event of a release, the volume would be limited to the amount of CO_2 contained within the surface piping and equipment due to automatic shut-off devices. The quantification approach will be adaptable to the specific characteristics of each leakage scenario, with methods selected based on site conditions and the nature of the release.

6.0 Detection and Verification [40 CFR 98.448(a)(3)]

ExxonMobil installed and will use continuous measurement devices to monitor injection pressure, temperature, rate, and mass; the pressure on the annulus between the tubing and the long-string casing; and the temperature of the CO_2 stream, as required under [40 CFR 146.88(e)(1), 146.89(b), and 146.90(b)]. Data will also be collected to document the addition or removal of any fluid from the annulus system. Data interfaces will be created for equipment that is not linked directly to a data management system or suitable equivalent and will be integrated into a unique surveillance platform. In the monitoring program, the sensors, transducers, and controllers will be connected in a central platform to monitor the operating conditions, set alarms for alerting operations of malfunction, and maintain safety protocols in case of abnormal conditions. Alarms will be set for pressures outside described tolerances (generally 90% of fracture gradient and prescribed wellhead pressures) and changes in annular pressure and fluid.

Instrument calibration standards, precision, and tolerances will be maintained based on manufacturer recommendations. The automated control system data will be monitored for anomalies on a regular basis. Average values will be compared to baseline and predicted values to assess if there are any significant deviations relevant to integrity or containment.

The operating parameters, monitoring values, laboratory results, reports, and surveillance documents for the Project will be stored in a database to support MMA reviews, quality assurance / quality control review programs, and routine reporting. Table 6-1 provides a summary of the typical sampling devices, locations, and data storage frequencies for the continuous monitoring program.

Table 6-1: Sampling Devices, Locations, and Data Frequencies for Continuous Monitoring

Continuous Sampling Parameter	Device(s)	Location	Estimated Min. Sampling Frequency	Estimated Min. Recording Frequency
Surface Injection Pressure	Wellhead Pressure Logger	Surface, injection well piping	5 seconds	5 minutes
Downhole pressure gauge	Pressure Gauges	Injection Unit	5 seconds	5 minutes
Injection rate	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Injectate density	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Total mass injected	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Annular pressure	Pressure Gauge	Well Head	5 seconds	5 minutes
Annulus fluid volume	Level Transmitter	Annulus System Tank	5 seconds	5 minutes
Carbon dioxide stream temperature	Coriolis Meter/Wellhead Pressure Logger	Well Head, injection well flowing	5 seconds	5 minutes
Note: The word “continuous” is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument’s normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application. Measurements that are collected “continuously” will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.				

Additionally, as part of its Class VI well permit application, ExxonMobil developed a comprehensive testing and monitoring strategy for the Project using a risk-based approach. The monitoring frequency is outlined in Table 6-2 and the monitoring strategy is outlined in Table 6-3. The monitoring program aligns with the three operational phases of the Project: (1) the pre-operational baseline data collection phase; (2) the operational phase for the three injectors; and (3) the PISC phase. During the pre- and early-operational phases, a selection of technologies will be used to develop baseline seismic response, pressure, temperature, and certain geochemical parameters needed to monitor the CO_2 plume and pressure front.

This testing and monitoring information will also be used to assess the predictive modeling results and refine the model as necessary. During the operational phase, the frequency of direct monitoring data collection activities will be aligned with the initiation of injection into each new stage of the injection intervals as described in Section 3.1. The accuracy of the model at predicting the CO_2 plume and pressure front migration will inform the frequency of indirect monitoring data collection. Upon assessment of the predictive capabilities of the model, the frequency of indirect monitoring activities listed in Table 6-2 may be reduced as justified by the rates of change and variations observed by the monitoring results, which are subject to approval by the UIC Program Director and incorporation into the Class VI permit. The data generated from the implementation of this Plan provides the basis to assess the confinement of the CO_2 in the permitted injection formations during the active injection phase of the Project.

Section 5 of this Plan details the detection methods in place for each leakage pathway. Consistent with EPA guidance, the monitoring program is intended to be a flexible approach using appropriate technologies and techniques that are refined and adapted based on site-specific information over time. ExxonMobil will continue to assess the feasibility of emerging technologies and conduct performance evaluations to continue to improve the performance of the testing and monitoring program.

Table 6-2: Testing and Monitoring Plan Measurements and Frequency

Equipment / Measurement	Regulation (40 CFR)	Objective	Frequency
Coriolis flow meter	146.90b	Measure mass flow rate	Continuously
Corrosion coupon	146.90c	Measure corrosion levels on the types of metal used in the Project	Quarterly
Injection stream sampling	146.90a	Provide more detailed analysis via periodic lab analysis of injection stream	Quarterly
Central pad temperature gauge	146.90a	Measure temperature of the total injection stream at the pad before partitioning to injections	Continuously
Injection wellhead tubing Pressure gauge	146.90a	Measure downstream of choke	Continuously
Injection wellhead annulus Pressure gauge	146.90b	Verify annulus pressure maintained	Continuously

Equipment / Measurement	Regulation (40 CFR)	Objective	Frequency
Injection annulus pressure test	146.89b	Verify absence of leak in annulus	Annually
Injection Well downhole pressure and temperature gauge for active/open injection interval	146.90b	Measure downhole pressure and temperature (injection mass to volume conversion, verifying that it is not exceeding maximum pressure)	Continuously
	146.90f	Measure falloff of pressure after abandoning injection stage and before initiating injection in next stage above	At the end of every injection stage
	146.90g(1)	Direct measurement of pressure, sensitive to pressure from other injections, especially when injection intervals are staggered between wells	Continuously
Time-lapse surface seismic survey	146.90g(2)	Indirect method to monitor CO_2 plume growth in the subsurface over time	Frequency from start of operations: Survey Event #1: completed; Survey Event #2: one to 3 years; Survey Event #3: 6 to 8 years; Survey Event #4: 13 years. Contingent additional survey events as needed and approved by UIC Program Director.
	146.87a(3)(ii)	DTS for cement long portion of long-string casing where fiber is cemented in place	One-time event
	146.90e	DTS to assess potential flow through channels through or along cement	Annually
Injection well casing inspection log	146.90e	Through-tubing log to detect loss of metal mass in casing due to corrosion	Baseline only; repeat survey is triggered if risk of leakage is apparent or upon request by UIC Program Director
In-zone monitoring well downhole pressure and temperature gauges	Not required 146.90g(1)	Collect pressure and temperature measurements for evaluating the rate of CO_2 plume and pressure front movement	Continuously
Above-zone monitoring well fluid sampling from above UCCZ	146.90d	Above UCCZ fluid collection is recommended by guidelines	Quarterly

Equipment / Measurement	Regulation (40 CFR)	Objective	Frequency
USDW fluid sampling	146.90d	Sample fluids from the Chicot Aquifer which is the most prolific USDW aquifer within the MMA, as recommended by guidelines, and analyze composition	Quarterly
DTS = Distributed Temperature Sensing; UCCZ = upper composite confining zone; UIC = Underground Injection Control; USDW = underground source of drinking water Note: The word “continuous” is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument’s normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application. Measurements that are collected “continuously” will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.			

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Table 6-3: Summary of Monitoring Technologies for Direct and Indirect CO_2 Plume and Pressure Front Tracking

Target Zone	Requirement	Technology	Placement Location	Target Depths	Phased/Triggered Approach	Monitoring Frequency	Data Evaluation Objectives
Injection Zone	Direct per 40 CFR 146.90(g)(1)	Downhole tubing mounted pressure and temperature gauge	Injection Wells No. 01, No. 02, and No. 03	Four injection intervals in Fleming and Upper Frio Formations	No	Continuous monitoring during injection operations for each injection interval Annual pressure falloff test during well shut-ins	Identify pressure differential and location of pressure front for the four injection intervals
		Tubing encapsulated conductor cable with in-line pressure/ temperature gauges	In-Zone Monitoring Well No. 01	Four injection intervals in Fleming and Upper Frio Formations	No	Continuous monitoring	CO_2 plume and pressure front tracking
	Indirect, geophysical techniques per 40 CFR 146.90(g)(2)	Time-lapse seismic surveys, or equivalent technologies	CO_2 Plume Area	Four injection intervals in the Upper Frio and Fleming Formations	No	Surface Seismic Survey Event #1 (Survey Event #1) is the baseline event conducted prior to injection. Survey Event #2 will be performed within the first 3 years after injection, Survey Event #3 within 6 to 8 years after injection, Survey Event #4 in year 13 at cessation of injection. Additional survey events if necessary, during PISC, as approved by UIC Program Director.	Monitor CO_2 plume growth in the subsurface over time
		Passive Seismicity Monitor Station Array	Selected locations within AoR	Surface	Yes, contingent on triggering seismic events	Continuous monitoring	AoR-specific seismicity data collection and event analyses
Above UCCZ	Direct per 40 CFR 146.90(g)(1)	Fluid sampling protocol using converted Bead Farm Co. #1 collected through tubing	Above-Zone Monitoring Well - Bead Farm Co. #1	First laterally continuous water-bearing zone above UCCZ	No	Quarterly samples	Detection monitoring for CO_2 plume and/or brine crossflow from injection zones to top of UCCZ
	Indirect, geophysical techniques per 40 CFR 146.90(g)(2)	Time-lapse seismic surveys, or equivalent technologies	CO_2 Plume Area	From surface to base of Frio Sand 2	No.	Surface Seismic Survey Event #1 (Survey Event #1) is the baseline event conducted prior to injection. Survey Event #2 will be performed within the first 3 years after injection, Survey Event #3 within 6 to 8 years of injection, Survey Event #4 in year 13 at	Detection monitoring for presence of CO_2 plume above UCCZ Detection monitoring and evaluation of trends in water quality and geotechnical parameters

Target Zone	Requirement	Technology	Placement Location	Target Depths	Phased/Triggered Approach	Monitoring Frequency	Data Evaluation Objectives
						cessation of injection. Additional survey events if necessary, during PISC, as approved by UIC Program Director.	
USDW	Direct per 40 CFR 146.90(d)	Fluid Sampling	USDW Monitoring Wells No. 01, No. 02, No. 03	Groundwater samples collected just below the typical total depth of water wells completed in the area (e.g., 300 to 350 feet below ground level).	Yes, three USDW monitoring wells prior to start of injection and additional USDW monitoring wells depending on the results of CO_2 plume and pressure front tracking as discussed in AoR reevaluations	Pre-Operational Phase – Quarterly Operational Phase – Quarterly	Detection monitoring and evaluation of trends in water quality and geotechnical parameters
Soil Gas Monitoring	Direct per 40 CFR 146.90(h)	Soil gas samples collected from the unsaturated zone	Contingent on confirmed release to USDW				
Air Monitoring	Direct per 40 CFR 146.90(h)	Portable and/or stationary CO_2 detectors monitor record ambient CO_2 concentrations	Contingent on confirmed release to USDW				
AoR = Area of Review; CFR = Code of Federal Regulations; CO_2 = carbon dioxide; PISC = post-injection site care; UCCZ = upper composite confining zone; UIC = Underground Injection Control; USDW = underground source of drinking water							

7.0 Assessment of Expected Baselines [40 CFR 98.448(a)(4)]

ExxonMobil has developed a comprehensive pre-injection (baseline) Testing and Monitoring Plan to develop reference conditions against which future data will be compared throughout the operational phase of the Project. Baseline data collection has been completed or is underway, and comparisons to these baseline conditions will be used to evaluate any deviations that may occur during injection activities. The following summarizes the key elements of baseline data collection:

- Groundwater Sampling—ExxonMobil has collected baseline groundwater quality and geochemical samples from the Above-Zone Monitoring Well No. 1 (Bead Farm Co. #1) installed in the formation directly above the UCCZ and from the three USDW monitoring wells at the Project site.
- Continuous Pressure/Temperature Monitoring—Reservoir temperatures and pressures will be monitored using a downhole gauge installed in the tubing above the production packer. At In-Zone Monitoring Well No. 01, a tubing encapsulated conductor cable with in-line pressure/temperature gauges will be installed. Baseline measurements will be collected prior to the start of injection to establish reference operating conditions.
- Seismic Survey—A seismic survey to monitor the CO_2 plume extent is planned to take place four times throughout the life of the Project. The baseline survey was conducted using the data purchased and reprocessed in 2024/2025 for site characterization.
- Visual Inspection—Prior to operations, surface equipment will be inspected and tested to confirm proper function and integrity.
- Soil Gas and Air Monitoring—Soil gas and air monitoring are proposed only as responses to triggering events. However, baseline samples of each have been collected.

8.0 Mass Balance Equations [40 CFR 98.448(a)(5)]

CO_2 will be injected into saline aquifers via three injection wells at the Project site. To accommodate the anticipated injection volume, two separate flowlines will be utilized at the central pad (Figure 3-2). Each flowline will be equipped with a mass flow meter to continuously measure and record the quantity of CO_2 injected. ExxonMobil will utilize the two flow meters to estimate CO_2 injected for the Project. All CO_2 injected will be sourced from a single pipeline that enters the central pad.

8.1 CO_2 Injected (CO_{2I})

The CO_2 stream received will be wholly injected into the storage complex. Therefore, pursuant to 40 CFR 98.444(a)(4) and 98.444(b), the annual CO_2 received will be equivalent to the annual CO_2 injected. The point of measurement for CO_2 injected is the mass flow meters located at the central pad. CO_2 will be measured through two-meter runs, each equipped with a mass flow meter. These meter runs will merge at a single point, from which the CO_2 is distributed to the three injection wells via flowlines.

The annual CO_2 injected at each well will be calculated using Equation RR-4 from 40 CFR 98, Subpart RR:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_2,p,u}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tonnes) as measured by flow meter u.
$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tonnes per quarter).
$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flow meter.

The sum of the mass of CO_2 injected through the two mass flow meters will be calculated using Equation RR-6:

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

Where:

CO_{2I} = Total annual CO_2 mass injected (metric tonnes) through all injection wells.
$CO_{2,u}$ = Annual CO_2 mass injected (metric tonnes) as measured by flow meter u.
u = Flow meter.

8.2 Mass of CO_2 Emitted by Surface Leakage (CO_{2E})

In addition to the mass of CO_2 received, injection into the subsurface, emitted from equipment leaks, and sequestered in subsurface geologic formations, ExxonMobil will monitor and report the total estimated CO_2 emitted in the event of surface leakage using the strategies and procedures for quantifying leakage in accordance with 40 CFR 98.444(d). The quantification approach will be adaptable to the specific characteristics of each leakage scenario, with methods selected based on site conditions and the nature of the release. These methods may include direct monitoring data, engineering-based calculations, or the application of established emission factors.

Although the specific types of leaks cannot be anticipated ahead of time, quantification methods will adhere to accepted engineering standards and best practices, with example approaches for different leak types. If anomalies of the monitored parameters (i.e., injection zone pressure, etc.) are detected, field personnel will investigate to identify the issue. For minor problems, repairs will be completed promptly and any resulting CO_2 emissions will be documented in the Subpart RR report. In cases requiring more extensive repairs, ExxonMobil will evaluate the best method for estimating the leaked CO_2 based on relevant factors such as leakage rate, concentration, and duration.

Issues such as anomalies in annular pressure or other concerns identified during maintenance activities will be addressed using the same protocol. Field personnel will examine the affected equipment to assess the problem. If the issue is minor, repairs will be completed promptly during the inspection and any associated CO_2 emissions will be recorded in the Subpart RR report. For more significant repairs, the well will be shut-in until the necessary work can be completed. In such cases, ExxonMobil will evaluate the best method for estimating the leaked CO_2 based on relevant factors such as leakage rate, concentration, and duration.

Should a surface leakage event occur, ExxonMobil will document and report the estimated mass of CO_2 released in the annual Subpart RR submission, along with a summary of the measurement or estimation techniques employed. Data and supporting documentation will be retained to ensure regulatory compliance and transparency.

The total annual mass of CO_2 emitted from all leakage pathways will be calculated using Equation RR-10:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tonnes) in the reporting year.
$CO_{2,x}$ = Annual CO_2 mass emitted (metric tonnes) at leakage pathway x in the reporting year.
x = Leakage pathway.

8.3 Mass of CO2 Emitted from Equipment Leaks and Vented Emissions (CO2FI)

The annual mass of CO_2 emitted from equipment leakage and vented emissions between the injection flow meter and wellhead will be measured and reported in accordance with the requirements of 40 CFR 98.444(d)/Subpart W.

8.4 Mass of CO2 Sequestered in Geologic Formations (CO2)

The total annual mass of CO_2 sequestered in geologic formations for the reporting year will be calculated and reported using Equation RR-12:

$$CO_2 = CO_{2I} – CO_{2E} – CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tonnes) at the facility in the reporting year.
CO_{2I} = Total annual CO_2 mass injected (metric tonnes) in the well or group of wells covered by this source category in the reporting year.
CO_{2E} = Total annual CO_2 mass emitted (metric tonnes) by surface leakage in the reporting year.
CO_{2FI} = Total annual CO_2 mass emitted (metric tonnes) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98.

9.0 Estimated Schedule for Implementation of MRV Plan [40 CFR 98.448(a)(7)]

Implementation of the MRV Plan will commence immediately following the effectiveness of the permit. The MRV data collection activities will be initiated prior to the start of injection to develop baseline conditions and will continue throughout the operational phase of the Project and into the PISC period, until the EPA approves the cessation of Subpart RR reporting. Key milestones include completion of baseline monitoring, commissioning of monitoring equipment, and initiation of data collection and reporting systems. In the event of material changes to the Project, the Plan will be resubmitted to and approved by the EPA prior to injection, in accordance with 40 CFR 98.448(d).

Data collection and implementation of this MRV Plan is proposed on October 1, 2025 and upon the EPA's approval of this MRV Plan.

10.0 Quality Assurance Program [40 CFR 98.444]

ExxonMobil has designed its monitoring plan and network to meet the quality assurance and quality control requirements of 40 CFR 98.444 of Subpart RR.

10.1 Measurement of CO2 Concentration

The CO_2 injection stream will be measured with a gas chromatograph and will be sampled quarterly at the central pad. Sufficient mixing and residence time in the system will have occurred at this sampling point for the sample to be representative of the injected CO_2 stream to meet the requirements of 40 CFR 146.91(a). The sampling station will be equipped with the ability to purge and collect a gas sample into a sealed container. The central pad is the connection point between the CO_2 pipeline and the sequestration field's distribution system.

The sample will be collected by site representatives following established company sampling procedures. It will then be transferred to a certified or accredited laboratory, where analysis will be performed using industry standard methods for CO2 based on the minimum regulations at the time the analysis is completed.

Each sample will be accompanied by a facility or contract laboratory Chain-of-Custody (COC) form that provides a record of sample handling, starting with sample acquisition, documenting the sample transfer process up to laboratory analysis. Samples taken are to be logged in the field using the COC form. Sample transfer containers (e.g., coolers) will be sealed and delivered to the laboratory with a COC form. The COC form shall provide the following items recorded by the sampler:

1. Sample ID including code or name, in addition to date and time;
2. Name of sample collector (including sampling company name if not site personnel);
3. Sample collection method;
4. Sample collection date;
5. Sample collection point; and
6. Sample presentation technique, as applicable.

Standard laboratory COC forms that document the times and dates of all personnel handling the sample, along with standard labels and container seals sufficient to distinguish between samples and prevent tampering, will be acceptable. Sample COC will be followed at all times during the sampling and subsequent analysis. COC will be used to document the handling and control necessary to identify and trace a sample from collection to final analytical results.

10.2 Measurement of CO_2 Mass

To meet the requirements of 40 CFR 98.444(e), ExxonMobil will conduct the following activities for operation and maintenance of meters associated with the Project:

- Flow meters will be operated continuously except as necessary for maintenance and calibration.

- Flow meters will be calibrated to measure quantities reported in 40 CFR 98.446 according to the calibration and accuracy requirements in 40 CFR 98.3(i).
- Measurement devices will be operated according to an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute, the American Gas Association, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.
- Assess flow meter calibrations performed are traceable by the National Institute of Standards and Technology.

10.3 Estimating Missing Data

ExxonMobil will follow all quality assurance and quality control procedures to record the mass of CO_2 injected. In the event ExxonMobil is unable to collect the necessary data for greenhouse gas (GHG) reporting, the following procedures will be followed to estimate missing injection data as required by 40 CFR 98.445. Generally, the methods include:

- A quarterly quantity of CO_2 flow rate that is missing will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures will follow those specified in subpart W of this part.
- A quarterly concentration value that is missing will be estimated using a representative concentration value from the nearest previous time period. If the CO_2 stream was sampled by the capture facility in the same time period, sales contract data may be used.
- A quarterly quantity of CO_2 injected that is missing will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

11.0 Reporting [40 CFR 98.442]

ExxonMobil will submit reports consistent with 40 CFR 98.442.

12.0 Records Retention [40 CFR 98.447]

ExxonMobil will retain the following documents and records to remain in compliance with 40 CFR 98.447(a) and 98.3(g), including but not limited to:

- A list of all units, operations, processes, and activities for which GHG emission were calculated. The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):
    - The GHG emissions calculations and methods used. For data required by § 98.5(b) to be entered into verification software specified in § 98.5(b), maintain the

  entered data in the format generated by the verification software according to § 98.5(b).
  - Analytical results for the development of site-specific emissions factors.
  - Any facility operating data or process information used for the GHG emission calculations.

- The annual GHG reports.
- Missing data computations. For each missing data event, also retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
- A written GHG Monitoring Plan.
- The results of required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
- Maintenance records for continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
- Quarterly records of CO_2 received, including mass flow rate of contents of containers (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams. No CO_2 received is anticipated for the facility as all CO_2 received is wholly injected and not mixed with any other supply of CO_2.
- Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams. No produced CO_2 is anticipated for the facility.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.
- Other records as specified for retention in the EPA-approved MRV Plan.

12.1 Revisions to the MRV Plan

In accordance with 40 CFR 98.448(d), ExxonMobil will revise and submit the MRV Plan within 180 days to the Administrator for approval if any of the following applies:

- A material change was made to monitoring and/or operational parameters that was not anticipated in the original MRV Plan. Examples of material changes include but are not limited to:
  - Significant changes in the volume of CO_2 injected;
  - The construction of new injection wells not identified in the MRV Plan;
  - Failures of the monitoring system including monitoring system sensitivity, performance, location, or baseline;
  - Changes to surface land use that affects baseline or operational conditions;
  - Observed CO_2 plume location that differs significantly from the predicted CO_2 plume area used for developing the MRV Plan;
  - A change in the MMA or AMA;
  - Or a change in monitoring technology that would result in coverage or detection capability different from the MRV Plan.
- A change in the permit class of the Underground Injection Control Permit.
- If ExxonMobil is notified by EPA of substantive errors in the MRV Plan or monitoring report.
- If the MRV Plan must be changed for any other reason in any reporting year.

ExxonMobil will include the reason(s) for the revisions in the MRV Plan submittal.

Appendices

Appendix A: References

Carr, D.L., K.J. Wallace, A.J. Nicholson, and C. Yang, 2017, Regional CO_2 Static Capacity Estimate Offshore Saline Aquifers, Texas State Waters, Geological CO_2 Sequestration Atlas of Miocene Strata, Offshore Texas State Waters, Report of Investigations No. 283, Bureau of Economic Geology, University of Texas at Austin, Austin

Galloway, W.E., 2008, Depositional Evolution of the Gulf of Mexico Sedimentary Basin, Chapter 15, The Sedimentary Basins of the United States and Canada, Elsevier, The Netherlands, pp. 505-549.

Roberts-Ashby, T.L., S.T. Brennan, M.L. Buursink, J.A. Covault, W.H. Craddock, R.M. Drake II, M.D. Merrill, E.R. Slucher, P.D. Warwick, M.S. Blondes, M.A. Gosai, P.A. Freeman, S.M. Cahan, C.A. DeVera, and C.D. Lohr, 2014, Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources - U.S. Gulf Coast, Chapter H, U. S. Geological Survey, Open-File Report 2012-1024-H, Reston, VA.

Gosai, P.A. Freeman, S.M. Cahan, C.A. DeVera, and C.D. Lohr, 2014, Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources - U.S. Gulf Coast, Chapter H, U. S. Geological Survey, Open-File Report 2012-1024-H, Reston, VA.

Swanson, S.M., A.W. Karlsen, and B.J. Valentine, 2013, Geologic Assessment of Undiscovered Oil and Gas Resources-Oligocene Frio and Anahuac Formations, United States Gulf of Mexico Coastal Plain and State Waters, Open-File Report 2013-1257, U.S. Geological Survey, Reston.

Treviño, R.H., and J.-L.T. Rhatigan, 2017, Regional Geology of the Gulf of Mexico and the Miocene Section of the Texas Near-Offshore Waters, Geological CO_2 Sequestration Atlas of Miocene Strata, Offshore Texas State Waters, Report of Investigations No. 283, Chapter 1, Bureau of Economic Geology, University of Texas at Austin, Austin, TX.

Request for Additional Information: Rose Carbon Capture and Sequestration Facility
August 21, 2025

Instructions: Please enter responses into this table and make corresponding revisions to the MRV Plan as necessary. Any long responses, references, or supplemental information may be attached to the end of the table as an appendix. This table may be uploaded to the Electronic Greenhouse Gas Reporting Tool (e-GGRT) in addition to any MRV Plan resubmissions.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	There is a lack of consistency with hyphens, bolding, quotation marks, spelling, and capitalization throughout the MRV plan. Examples include but are not limited to: • CO2 vs. CO_2 • Tonnes vs. tons We recommend reviewing the formatting in the MRV plan for consistency. Furthermore, we recommend doing an additional review for spelling, grammar, etc.	We have reviewed the MRV Plan and standardized terminology, formatting, spelling, grammar, and style throughout the document for consistency.
2.	3.2	14	"The Project area is suitable for CO_2 injection into the proposed injection intervals of the Fleming and Upper Frio Formations." Figure 3-3 does not include the Fleming Formation or the Anahuac formation. We recommend reviewing the MRV plan to ensure that the stratigraphic column is consistent with the geologic discussion.	We have updated Figure 3-3 with additional annotation to identify the Fleming and Anahuac Formations.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	3.2	14	"Both the upper composite confining zone (UCCZ) and Anahuac Shale are thick, continuous sealing intervals across the AoR…" Please clarify in the MRV plan whether the upper composite confining zone (UCCZ) and Anahuac Shale are continuous sealing intervals across the larger MMA, or just the AoR. In general, please review the MRV plan to ensure that the MMA is discussed where applicable.	We have added additional clarification to the text to indicate the extent and nature of the seals.
4.	3.3	17	"The wells outside the AoR and within the MMA do not trigger specific CO_2 plume and pressure front monitoring." Please clarify what is meant by "do not trigger specific CO2 plume and pressure front monitoring" in the context of this subpart RR MRV plan.	The wells identified in the MMA but outside of the boundary of the stabilized CO_2 plume are not anticipated to come into contact with the CO_2 plume or pressure front. Therefore, these wells are not anticipated to require direct CO_2 plume and pressure front monitoring. As discussed in Section 5.2, time-lapse seismic surveys will be conducted at the specified intervals to monitor for unexpected lateral or vertical CO_2 plume migration above the UCCZ and the corrective action plan will be updated accordingly. The above text has been added to Section 3.3.
5.	3.4	22	"Superimposing the stabilized CO_2 plume and critical-pressure boundaries, **Figure -1** shows the AoR boundary for the Project." The statement above from the MRV plan appears to include an incomplete reference. Please review the MRV plan to ensure that all references within the text match up to the correct figure, table, etc.	The figure reference was updated. We have also reviewed the MRV Plan for consistency of references between text, tables, and figures.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
6.	4.0	22	The MRV plan defines the MMA/AMA as the AoR plus the half-mile buffer. However, Section 5.0 is inconsistent in that some leakage pathways are discussed in the context of the AoR and some are in the context of the larger MMA. Please clarify whether the identified potential leakage pathways were evaluated throughout the entire MMA and not just the AoR. If necessary, please review and revise section 5.0 accordingly.	This section has been updated to consistently discuss leakage pathways within the MMA. All leakage pathway evaluations are in terms of the MMA.
7.	4.2	22	Per 40 CFR 98.449, the boundary of the active monitoring area (AMA) is established by superimposing two areas: (1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile. (2) The area projected to contain the free phase CO_2 plume at the end of year t + 5. While the MRV plan defines the AMA, please provide further explanation of whether the AMA meets the definitions in 40 CFR 98.449. For example, please specify whether this delineation contains the free phase CO_2 plume at the end of year t+5 as required by criterion (2).	The definition of AMA is functionally equivalent to MMA and encompasses an area of the stabilized plume plus a one-half-mile buffer. Since we are using the stabilized CO_2 plume, the area satisfies the t+5 criteria. Section 4.2 has been amended to provide clarity.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
8.	5.0	27	40 CFR 98.448(a)(2) requires the MRV plan to include an "Identification of potential surface leakage pathways for CO_2 in the maximum monitoring area and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways." Please ensure that each of the listed potential leakage pathways contains a characterization of the likelihood of leakage. Furthermore, while the MRV plan discusses existing wells that penetrate the upper composite confining zone (UCCZ) within the MMA, it does not discuss these parameters for existing wells that were completed above the UCCZ within the MMA. Please clarify whether there are wells completed above the UCCZ within the MMA, and discuss the likelihood, magnitude, and timing of leakage through these wells if applicable. Please revise Sections 5.0 and 6.0 as necessary. Furthermore, we recommend discussing the likelihood, magnitude, and timing of leakage due to potential lateral migration outside the injection zone and future drilling through the injection zone.	The first paragraph in Section 5 states each of the pathways in that section are low likelihood; however, additional likelihood language is added for each pathway. Section 5.2 was updated to include the wells within MMA that do not penetrate the UCCZ. This section also includes the scenario for lateral migration outside the MMA. Section 5.2 has been updated to include mitigations in place to reduce potential for CO2 leakage from future drilling activities within the MMA.
9.	5.4	29	We recommend either expanding the discussions for potential surface leakage through the upper composite confining zone (UCCZ) and faults and fractures in the MRV plan or discussing the pathways separately. Additionally, we recommend characterizing the likelihood, magnitude, and timing of surface leakage through each of these pathways.	We have added additional clarification to Section 5.4 to address the recommendations.
10.	7.0	37	The MRV plan discusses monitoring strategies that require an established baseline to compare monitoring results against. For example, Table 6-3 references soil gas monitoring, but soil gas monitoring is not included in Section 7.0. Please clarify whether soil gas monitoring should be included as a baseline in Section 7.	Section 7 was revised to clarify that soil gas and air monitoring are proposed only as responses to triggering events. However, baseline samples of each have been collected.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
11.	8.0	37	Please revise the title to section 8.0 "Site-Specific Modifications to the Mass Balance Equation [40 CFR 98.445(a)(5)]" as modifications cannot be made to the equations in subpart RR. Note that subpart RR does allow for "considerations you intend to use to calculate site-specific variables for the mass balance equation."	This section title has been revised.
12.	8.2	38	"In addition to the mass of CO_2 received, injection into the subsurface, emitted from equipment leaks, and sequestered in subsurface geologic formations, ExxonMobil will monitor and report the total estimated CO_2 emitted in the event of surface leakage using the strategies and procedures for quantifying leakage detailed in Section 6..." The statement above from the MRV plan references strategies for quantifying leakage detailed in Section 6.0, but Section 6.0 does not discuss surface leakage quantification. Please either revise the statement above or adjust Section 6.0 accordingly. Furthermore, we recommend including additional examples of quantification strategies that may be used in the event of a surface leak in either Section 6 or Section 8.2.	This text has been updated accordingly, and additional quantification strategies are now included in 8.2.
13.	10.1	39	"The sample will be collected by site representatives following established company sampling procedures. It will then be transferred to a certified or accredited laboratory, where analysis will be performed using industry-standard methods for CO2 that comply with the minimum current EPA regulations." We recommend that this sentence end with "based on the minimum regulations at the time the analysis is completed."	This text has been updated accordingly.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
14.	N/A	N/A	Please clarify whether the MRV plan contains a "Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart. This date must be after expected baselines as required by paragraph (a)(4) of this section are established and the leakage detection and quantification strategy as required by paragraph (a)(3) of this section is implemented in the initial AMA." See 40 CFR 98.448(a)(7).	Section 9 has been updated to include that data collection and implementation of this MRV Plan is proposed on October 1, 2025 and upon the EPA's approval of this MRV Plan.

Rose Carbon Capture and Sequestration Facility

Facility (GHGRP) ID: 590420

MONITORING, REPORTING, AND VERIFICATION PLAN

Rose Carbon Capture and Storage Facility

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

June 2025

TABLE OF CONTENTS

List of Tables

List of Figures

List of Acronyms and Abbreviations

Name	Definition
%	percent
AMA	active monitoring area
AoR	Area of Review
API	American Petroleum Institute
CCS	carbon capture and sequestration or carbon capture and storage
CFR	Code of Federal Regulations
CO2	carbon dioxide
CO_{2I}	carbon dioxide injected
CO_{2E}	carbon dioxide emitted via surface leakage
CO_{2FI}	mass of CO2 emitted from equipment leaks and vented emissions
COC	Chain-of-Custody
DTS	Distributed Temperature Sensing
EPA	U.S. Environmental Protection Agency
ExxonMobil	ExxonMobil Low Carbon Solutions Onshore Storage LLC
GHG	greenhouse gas
KB	Kelly bushing

Name	Definition
LCZ	Lower Confining Zone
mD	millidarcy
MMA	maximum monitoring area
MRV	Monitoring, Reporting, and Verification
PISC	post-injection site care
Project	Rose Carbon Capture and Sequestration Project or Rose Carbon Capture and Storage Project
RRC	Railroad Commission of Texas
Storage	Sequestration
TVD	true vertical depth
UCCZ	upper composite confining zone
UIC	Underground Injection Control
USDW	underground sources of drinking water

Distribution Sheet

This Monitoring, Reporting, and Verification Plan was prepared and approved by ExxonMobil for use in collecting information for the reporting of greenhouse gases received and injected by the Rose Carbon Capture and Sequestration Project. ExxonMobil will incorporate the monitoring and reporting actions described in this document into the standard ExxonMobil operating program, as appropriate, for the control of work associated with the scope of data quality and detection monitoring for the Project.

Revision History for MRV Plan.

Version	Date	Description of Change
Version 1.0	June, 2025	Initial submission of MRV Plan for EPA Review.

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1.0 Introduction

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is submitting a Monitoring, Reporting, and Verification (MRV) Plan in accordance with Title 40 of the Code of Federal Regulations, Part 98, Sections 440–449 (40 CFR 98.440-449 [Subpart RR]). This Plan details the MRV activities for ExxonMobil's Rose Carbon Capture and Sequestration Facility (Project or Rose Carbon Capture and Storage Project) in Jefferson County, Texas. The proposed Project site consists of three injection wells injecting carbon dioxide (CO2) sources received by a single pipeline from multiple industrial emitters.

The Project is designed to collect, transport, and sequester a maximum of 5 million metric tonnes per annum of CO2. ExxonMobil plans to sequester a total of approximately 53 million metric tonnes of CO2 over a 13-year injection period into the Fleming and Upper Frio Formations.

An application has been submitted in accordance with the requirements of the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Sequestration Wells promulgated in 40 CFR 146.81-146.95. Until Texas receives primacy, U.S. Environmental Protection Agency (EPA) Region 6 is responsible for processing the federal Class VI permit application.

The objective of this MRV Plan is to satisfy the requirements of Subpart RR as applicable to MRV plans.

Pursuant to 40 CFR 98.448, this MRV Plan meets the content requirements and otherwise satisfies the key data collection and monitoring activities, including the following seven major components:

- Delineation of the maximum monitoring area (MMA) and active monitoring areas (AMAs) (40 CFR 98.448(a)(1));
- Identification of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing of surface leakage of CO2 through these pathways (40 CFR 98.448(a)(2));
- Strategy for detection and quantification of surface leakage of CO2 (40 CFR 98.448(a)(3));
- Approach for establishing the expected baselines for monitoring CO2 surface leakage (40 CFR 98.448(a)(4)); and
- Considerations made to calculate site-specific variables for the mass balance equation (40 CFR 98.448(a)(5));
- Identification numbers for wells (see section 2 below) (40 CFR 98.448(a)(6));
- Timing of data collection (see Section 9 below) (40 CFR 98.448(a)(7)).

2.0 Facility Information [40 CFR § 98.448(a)(6)]

The following are registration numbers associated with the Project:

- Project Site Name – ExxonMobil's Rose Carbon Capture and Sequestration Facility
- Greenhouse Gas Reporting Program ID number – 590420
- EPA UIC Class VI Permits for Rose Carbon Capture and Storage Project Injection Wells No. 01, No. 02, and No. 03 – Under Review

Table 2-1 provides the location of the three injection wells. A map showing the injection wells, monitoring wells, artificial penetrations, and the Area of Review (AoR) is provided in Figure 3-1. The AoR represents the furthest extent of the modeled free phase CO_2 plume and critical pressure front as described in Section 3.4.2.

Table 2-1: Injection Well Locations

Well Name and Number	API	Location	Latitude (NAD83)	Longitude (NAD83)
LaBelle Properties Ltd #1 (Rose CCS Project Injection Well No. 01)	4224532913	RRC District 3, Section 42, Abstract 874	29° 59' 58.84" 29.999678	-94° 17' 6.39" -94.285108
Bead Farm Co. #2 (Rose CCS Project Injection Well No. 02)	4224532911	RRC District 3, Section 41, Abstract 266	29° 59' 27.66" 29.991017	-94° 17' 52.93" -94.298036
Bead Farm #3 (Rose CCS Project Injection Well No. 03)	4224532912	RRC District 3, Section 8, Abstract 658	30° 00' 42.40" 30.011778	-94° 17' 52.29" -94.297858
API = American Petroleum Institute; CCS = carbon capture and sequestration; RRC = Railroad Commission of Texas				

3.0 Project Description

The Project is located in Jefferson County, Texas, within the Gulf Coast Basin, an area known for its favorable geologic formations for CO_2 injection and containment. The Project site is ideally suited for the sequestration of CO_2 within the proposed injection zone in the Fleming and Upper Frio Formations. The selected injection intervals within these formations exhibit high porosity and permeability that are ideal for CO_2 storage and are of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of CO_2 stream. The CO_2 is derived from multiple industrial sources, where industrial, atmospheric emission points under long-term contract will be captured and compressed for transportation to the Project area.

As part of the Project, ExxonMobil drilled a stratigraphic well in October and November 2023 (Bead Farm Co. #1; American Petroleum Institute 4224532908) and implemented a data acquisition program. The data acquisition program for the stratigraphic well produced a significant amount of site-specific information. Field observations were made of the core samples, geological logging data were collected through the injection and confining zones, injectivity testing yielded measurements of injection zone permeability, and numerous laboratory tests were performed on core and fluid samples for refining the site characterization and geochemical model. As a result, an AoR model and injection strategy were developed and well designs made to align with the site characterization data. Sufficient geologic characterization data are available to model the AoR, optimize the operating parameters, and identify the risks and uncertainties of the Project. The potential for uncertainty that could result in the leakage of CO_2 was addressed on a risk-by-risk basis in the operating strategy, injection well design, and the testing and monitoring program. The stratigraphic well (Bead Farm Co. #1) has since been converted to an Above-Zone Monitoring well to conduct monitoring above the confining zone and another In-Zone Monitoring well has been placed for direct monitoring, subsurface model calibration and CO2 plume and pressure front verification.

ExxonMobil plans to utilize three injection wells to sequester approximately 53 million metric tonnes of CO2 over a 13-year period. Each well will inject into the Fleming and Upper Frio formations in multiple intervals as part of a staged approach. The project includes a comprehensive monitoring network (Figure 3-1) consisting of an Above-Zone Monitoring well, an In-Zone Monitoring well, and three shallow monitoring wells installed in the underground sources of drinking water (USDW) (i.e., the upper Chicot Aquifer) to support in-zone plume tracking, detection of potential above-zone CO2 migration, and protection of drinking water resources.

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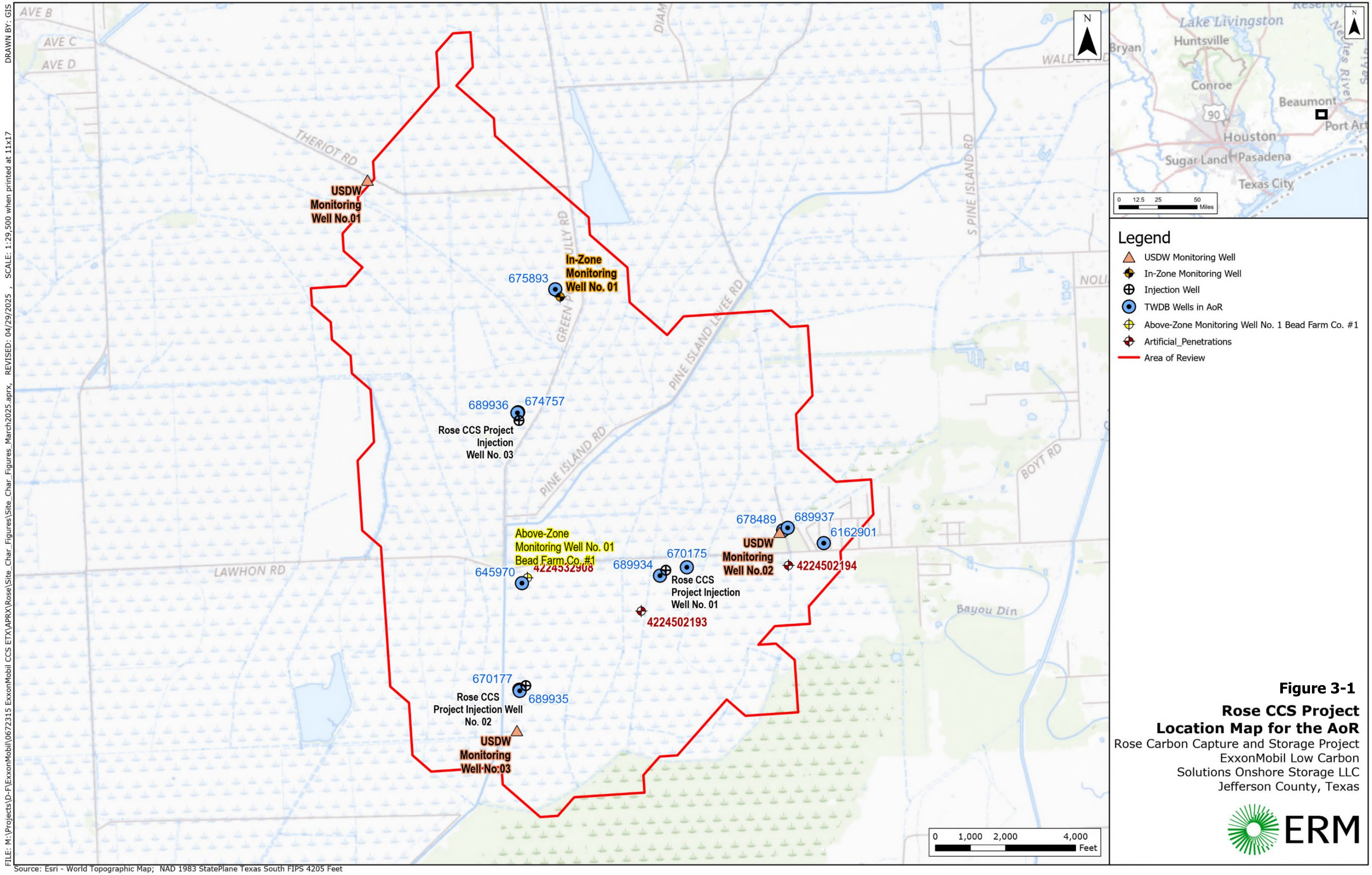
DRAWN BY: GIS
FILE: M:\Projects\D-F\ExxonMobil\0672315 ExxonMobil CCS ETX\APRX\Rose\Site_Char_Figures\Site_Char_Figures_March2025.aprx, REVISED: 04/29/2025 , SCALE: 1:29,500 when printed at 11x17
USDW Monitoring Well No.01
In-Zone Monitoring Well No. 01
675893
689936
674757
Rose CCS Project Injection Well No. 03
Above-Zone Monitoring Well No. 01 Bead Farm Co. #1
4224532908
645970
689934
670175
Rose CCS Project Injection Well No. 01
678489
689937
6162901
USDW Monitoring Well No.02
4224502194
4224502193
670177
689935
Rose CCS Project Injection Well No. 02
USDW Monitoring Well No:03
THERIOT RD
LAWHON RD
PINE ISLAND RD
PINE ISLAND LEVEE RD
S PINE ISLAND RD
BOYT RD
Bayou Din
0 1,000 2,000 4,000 Feet
Lake Livingston
Huntsville
Bryan
Conroe
Beaumont
Port Arthur
Houston
Sugar Land
Pasadena
Texas City
0 12.5 25 50 Miles
Legend
USDW Monitoring Well
In-Zone Monitoring Well
Injection Well
TWDB Wells in AoR
Above-Zone Monitoring Well No. 1 Bead Farm Co. #1
Artificial_Penetrations
Area of Review
Figure 3-1
Rose CCS Project
Location Map for the AoR
Rose Carbon Capture and Storage Project
ExxonMobil Low Carbon
Solutions Onshore Storage LLC
Jefferson County, Texas
Source: Esri - World Topographic Map; NAD 1983 StatePlane Texas South FIPS 4205 Feet

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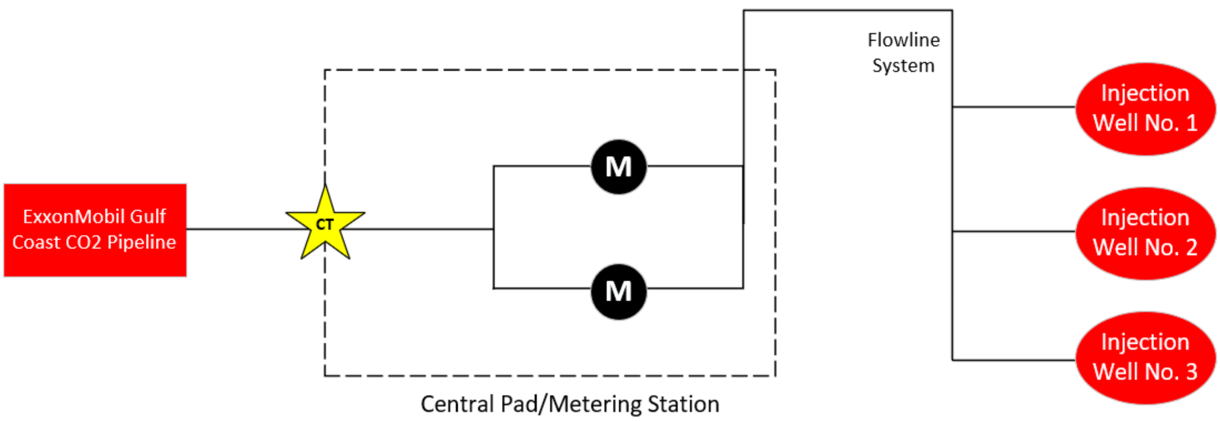
3.1 Injection Process

Figure 3-2 shows a simplified diagram of the injection process, following the flow of CO_2 from its source to each of the three injection wells. The black "M" points represent flow meters that will be utilized to measure CO_2 injected. The yellow star represents the point of custody transfer from the single CO_2 pipeline. The dotted line represents the central pad where metering will be conducted prior to injection. The central pad is co-located with the Above-Zone Monitoring Well No. 01/Bead Farm Co. #1 pad. All CO_2 sequestered will be metered at the central pad.

Figure 3-2: Simplified Facilities Flow Diagram for Project Rose.



The source of CO_2 will come from multiple high concentration industrial sources, including clean hydrogen and ammonia production facilities, direct reduced iron plants, natural gas treatment facilities, and other industrial sources that feed directly into ExxonMobil's Gulf Coast CO_2 pipeline network. The pipeline network maintains a CO_2 composition of >97 percent (%) CO_2, <1% hydrogen, and <3% methane.

CO_2 will arrive at the central pad via pipeline in a supercritical state. At the central pad, CO_2 will pass through a gas chromatograph before a flowline system will transport the CO_2 to each of the three injection wells. Three injection wells will be used to sequester the CO_2 at the Project site. The names and location of each well are provided in Table 2-1.

Each injection well was completed with a single completion string and assembly consisting of injection packer, nipple profile, safety injection valve, pressure/temperature gauges, and tubing. Upon permit approval, injection will start based on a staged bottoms-up injection approach. A total of seven injection stages within the four formation intervals are planned for each well. Once the target injection volume of CO_2 is attained, that injection stage will be plugged back to isolate that interval from subsequent injection intervals. The next injection interval will then be completed and accessed through additional perforations to establish communication with the reservoir. CO_2 will continue into that new injection interval until the target CO_2 storage amount has been achieved for that interval.

3.2 Geologic Setting

The Project is located within the Houston Embayment of the Gulf Basin. On shore and near-shore, the Gulf Basin is referred to as the Gulf Coast region. The stratigraphic column of the Houston Embayment is presented in Figure 3-3 (Treviño and Rhatigan, 1995). The Gulf Basin was formed by crustal extension and seafloor spreading during the breakup of Pangea that took place in the Mesozoic Era. A regional unconformity at the base of the sedimentary section is marked by the base of an evaporite layer (Galloway, 2008). These substantial evaporitic deposits (up to 4 kilometers thick) became a defining characteristic for later structural evolution of the Basin. Salt deposition ceased at the end of the Late Jurassic Era, as continued rifting produced oceanic crust.

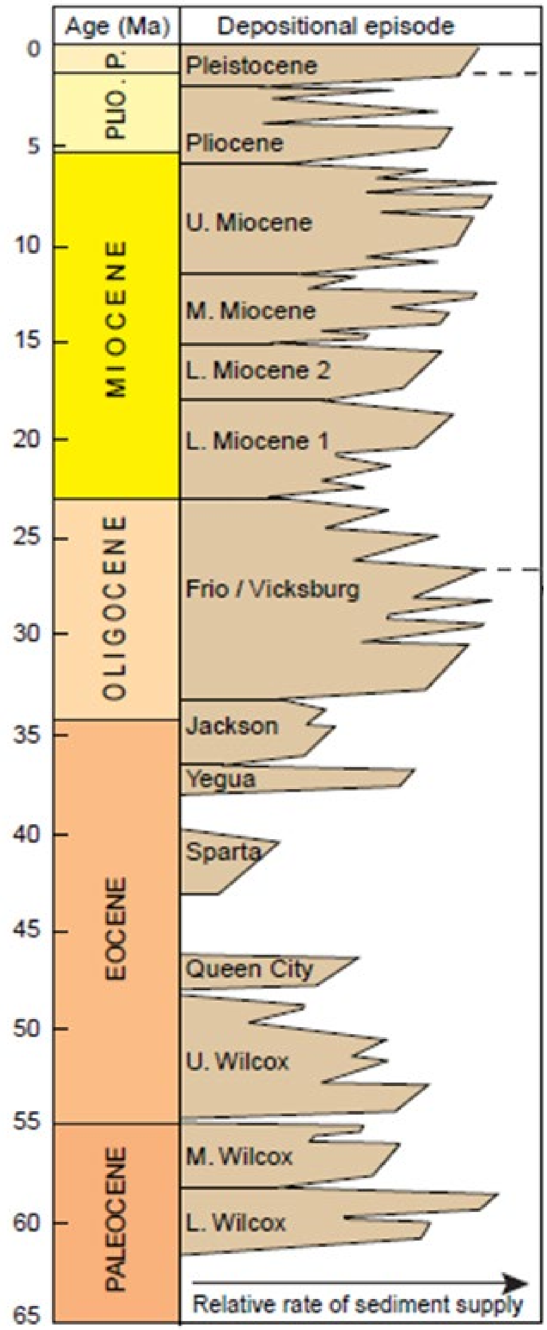
The outline and morphology of the present-day Gulf Basin was sculpted by subsidence and rimming carbonate platform formation by the Early Cretaceous Era (Galloway, 2008). The Cenozoic Era depositional episodes along the northwestern Gulf Basin are fluvial-deltaic and shore-zone dominated, which reflect major phases of adjacent North American structural events (Galloway, 2008).

The Project area is suitable for CO2 injection into the proposed injection intervals of the Fleming and Upper Frio Formations. The sands within these formations exhibit high porosity and permeability that are ideal for CO2 storage and are “of sufficient areal extent, thickness porosity and permeability to receive the total anticipated volume of the CO2 stream” [40 CFR 146.83(a)(1)]. Both the upper composite confining zone (UCCZ) and Anahuac Shale are thick, continuous sealing intervals across the AoR and are sufficient to “contain the injected CO2 stream and displaced formation fluids and allow injection at proposed maximum pressure and volumes without initiating or propagating fractures in the confining zone” [40 CFR 146.83(a)(2). The major stratigraphic units, from deepest moving shallower, are detailed below:

- Lower Confining Zone (LCZ): The LCZ is comprised of over 3,000 feet of thick Frio sediments, dominated by fine-grained lithologies (shales), which underlie the Upper Frio injection interval. A limited number of wells have log data to verify the gross thickness of this interval near the site. ExxonMobil relied on seismic data to assess the occurrence and lateral continuity of LCZ.
- Upper Frio: The Upper Frio Formation consists of alternating shales and sands, stemming from progradational shore-zone systems of the Gulf coastal plain. Specifically, in the Houston area and during the Early Oligocene, deposition of large volumes of sand from the fluvially dominated Houston and Central Mississippi deltas occurred, with subsequent wave reworking resulting in thick, sand-rich prograding shore-zone systems fronted by muddy shelf sequences. Regionally, the reservoir quality of the Frio in the Houston Embayment area exhibits porosities ranging from 16 to 36% and permeabilities of approximately 50 to 3,000 millidarcies (mD) (Swanson et al., 2013). The analysis of core data from the stratigraphic well showed porosity values to be generally consistent with regional data.
- Anahuac Formation: The Anahuac Formation is located within the injection zone, overlying the Frio Formation, and underlying the Fleming Formation. It is a thick, continuous shale interval. The Anahuac Formation (Anahuac Shale) was deposited during a transgressive event following Frio deposition (Galloway, 2008). Prograding Miocene intervals, including the Fleming Formation, cap the Anahuac transgression (Swanson et al., 2013).

- Fleming Formation: The Lower Miocene was characterized by high sediment supply rates and general deltaic progradation in the Project area. Some transgressive sequences interrupted the Lower Miocene deposition, but the Lower Miocene is mainly bracketed by the underlying Anahuac Shale and overlying UCCZ that include the Amph 'B' Shale as the major transgressive sequence. South of the Project site, the estimated porosities of the Miocene reservoirs range from 5 to 38%, with an average of 28% (Carr et al., 2017). A review of available literature also indicated that permeabilities range from 16 to 1,600 mD with an average of 338 mD (Carr et al., 2017). Analysis of the Lower Miocene core samples from the stratigraphic well demonstrate consistent reservoir characteristics.
- UCCZ: The UCCZ is a thick, muddy sequence that includes the Middle Miocene Amph 'B' Shale, a regionally continuous, transgressive marine unit (Galloway, 2008), that is recognized by the U.S. Geological Survey National Assessment of Carbon Dioxide Storage Resources to be a good sealing unit and, therefore, a competent confining zone as required for CO2 sequestration project sites (Roberts-Ashby et al., 2014).

Figure 3-3: Gulf Basin Stratigraphic Column.



Source: Treviño and Rhatigan, 2017

3.3 Artificial Penetrations in the AoR

As outlined in the Project Rose Class VI Application and in accordance with 40 CFR 146.82(a)(4) and 40 CFR 146.84(c)(2), a search was conducted to identify and assess the occurrence of artificial penetrations within the AoR. A summary of artificial penetrations identified is provided in Table 3-1. Based on available data, other than the project injection and monitoring wells drilled in 2024, two artificial penetrations were identified to intersect the UCCZ: one legacy well (Broussard JE Jr-1) and the Project's stratigraphic test well (Bead Farm Co. #1). Details for each well are provided in Table 3-1.

Pursuant to 40 CFR § 146.84(c)(3), corrective actions were undertaken for both penetrations to prevent fluid movement that could endanger USDWs. Each well was re-entered and appropriate barriers were installed at critical intervals. Barriers were installed at the UCCZ, surface casing shoe, base of the lowermost USDW, and the wellhead for the legacy well. A barrier at the UCCZ was installed in Bead Farm Co. #1 in order to remain open for above zone monitoring. For each well, the barrier at the UCCZ was constructed using CO_2-compatible material, as required by 40 CFR § 146.84(d).

The Broussard JE Jr-1 legacy well was re-entered and plugged and abandoned on March 14, 2025. The Bead Farm Co. #1 stratigraphic test well was converted into the above-zone monitoring well on February 7, 2025, to support the Project's testing and monitoring program.

The artificial penetrations reviewed for corrective action and monitoring were identified based on 40 CFR § 146.84. The wells outside the AoR and within the MMA do not trigger specific CO_2 plume and pressure front monitoring. These wells are not anticipated to come in contact with the CO_2 plume or the critical pressure front.

Table 3-2 summarizes the additional wells identified within the MMA and outside the AoR, which includes a half-mile buffer that extends beyond the stabilized CO_2 plume.

Table 3-1: Summary of Artificial Penetrations within AoR

Well Name	State/ Federal Well ID (API Number)	Well Type	Well Status	Date Drilled	Depth (ft KB)	Latitude, Longitude (NAD83)	Penetrates UCCZ?
Above-Zone Monitoring Well No. 01 Bead Farm Co. #1	4224532908	Project Monitoring Well	Active	10/15/2023 Recompleted 02/07/2025	8,664	29.999222, -94.297364	Yes
Broussard JE Jr-1	4224502193	Dry Hole	P&A	2/10/1958	9,050	29.996539, -94.287435	Yes
Broussard J. E. Etal-1	4224502194	Dry Hole	P&A	Unknown	2,518**	29.999730, -94.274070	No
BFC-1 Rig Supply Water Well #1	645970	Water Rig Supply	In Use	8/11/2023	290*	29.999028, -94.298056	No
D. S. Wier	Not Available	Water Supply	P&A	1941	7*	30.001389, -94.270833	No
Labelle Properties Ltd #1	4224532913	Project Injection Well No. 01	Active	06/23/204	8,672	29.999678, -94.285108	Yes
Bead Farm Co. #2	4224532911	Project Injection Well No. 2	Active	07/15/2024	8,752	29.991017, -94.298036	Yes
Bead Farm #3	4224532912	Project Injection Well No. 3	Active	08/05/2024	8,565	30.011778, -94.297858	Yes
Bead Farm Company #4	4224532914	Project Monitoring Well	Active	08/31/2024	8,383	30.021558, -94.293978	Yes
Rose Rig Supply Water Well #1	670175	Water Rig Supply	Active	6/14/2024	300*	29.999857, -94.28321	No
Rose Rig Supply Water Well #2	670177	Water Rig Supply	Active	7/2/2024	300*	29.990716, -94.298632	No
Rose Rig Supply Water Well #3	674757	Water Rig Supply	Active	7/19/2024	300*	30.012428, -94.297908	No
Rose Rig Supply Water Well #4	675893	Water Rig Supply	Active	8/15/2024	300*	30.021947, -94.294199	No
USDW Monitoring Well No. 1	678487	USDW Monitoring Well	Active	8/20/2024	330*	30.030833, -94.310556	No

Well Name	State/ Federal Well ID (API Number)	Well Type	Well Status	Date Drilled	Depth (ft KB)	Latitude, Longitude (NAD83)	Penetrates UCCZ?
USDW Monitoring Well No. 2	678489	USDW Monitoring Well	P&A***	8/20/2024	440*	30.0025, -94.274444	No
USDW Monitoring Well No. 3	678491	USDW Monitoring Well	Active	8/20/2024	330*	29.9875, -94.298889	No
USDW Monitoring Well No. 2R	683826	USDW Monitoring Well	Active	11/9/2024	320*	30.0025, -94.274444	No
Shallow Groundwater Well #1	689934	Monitoring Well	Active	9/19/2024	25*	29.99927, -9428565	No
Shallow Groundwater Well #2	689935	Monitoring Well	Active	9/17/2024	25*	29.99062, -94.2986	No
Shallow Groundwater Well #3	689936	Monitoring Well	Active	9/17/2024	25*	30.01238, -94.29797	No
Shallow Groundwater Well #4	689937	Monitoring Well	Active	9/18/2024	20*	30.00268, -94.27403	No

Notes:
API = American Petroleum Institute; ID = identification; KB = Kelly bushing; UCCZ = upper composite confining zone; USDW = underground sources of drinking water
*Water well datum is below ground level
**KB not available in historical records
***Casing collapsed above water table, couldn't collect sample, redrilled as 2R in same location

Table 3-2: List of Wells Within Half-Mile Buffer of the MMA and Outside of AoR

Well Name	API Number or State Well ID	Surface Location Latitude, Longitude (NAD83)	Status	Date Drilling or Recompletion Complete	Well Depth (ft TVD)	Penetrates the UCCZ?
Walter Co. 1	24532667	30.0479207, -94.2960335	Gas Well	1/6/2011	15,577	Yes
Walter Co. 2	24532736	30.0450865, -94.2979686	Gas Well	1/1/2019	15,248	Yes
Sunset Unit 1H	24532729	30.01374, -94.25681	Oil Well	4/27/2018	8,231	Yes
Broussard Unit 1	24532862	29.99733669, -94.26210890	Dry Hole	3/7/2018	8,300	Yes
Vaughan 1	24532799	29.99424, -94.26941	Plugged Gas Well	3/18/2014	14,500	Yes
Burrell Estate 1	24532125	29.98283161, -94.28273884	Dry Hole	4/15/1996	9,100	Yes
Broussard, Et Al 1	24531254	29.97798666, -94.29521881	Dry Hole	2/5/1979	8,366	Yes
Walter Co. 'C' 1	24531720	29.977486, -94.3012888	Plugged Oil Well	12/3/1983	9,000	Yes
Walter Co. 2	24531452	29.97873115, -94.30382344	Plugged	3/27/1981	8,702	Yes
Walter Company 1	24531387	29.98137196, -94.30693397	Plugged Oil Well	7/7/1980	9,000	Yes
Walter Co. 'B' 1	24531488	29.98006035, -94.31094003	Dry Hole	5/11/1981	8,815	Yes
Walter Company 1WD	24531848	29.98183461, -94.3075098	Dry Hole	7/3/1985	2,800	No
Walter Co. 1	24531725	30.02038438, -94.32145035	Plugged Gas Well	12/8/1983	16,000	Yes
Beaumont Farms 1	24500109	30.03063294, -94.29401318	Dry Hole	1/31/1956	8,517	Yes
Broussard Tr 1	24500111	30.01214737, -94.26244721	Dry Hole	6/13/1937	7,360	Yes
Broussard Trust Co. 1	24502191	29.99958128, -94.31390135	Dry Hole	12/23/1949	9,010	Yes
Broussard Unit #1	469176	29.993983, -94.26965	Plugged Rig Supply Well	12/28/2017	330	No
Vaughan #1	355705	29.994167, -94.269444	Plugged Rig Supply Well	1/4/2014	332	No
Bright Edge #1	165222	29.978889, -94.306667	Rig Supply Well	2/28/2005	325	No
API = American Petroleum Institute; TVD = true vertical depth; UCCZ= upper composite confining zone						

3.4 Reservoir Characterization and Modeling

The Fleming and Upper Frio Formations were assessed to characterize the sealing effects of the confining zone and reservoir heterogeneity within the injection zone. Based on the analysis and understanding of the Project area, a three-dimensional geologic model was developed to estimate the storage potential for the CO2 and evaluate its confinement, both laterally and vertically.

3.4.1 Modeling Background

Schlumberger's Petrel™ Software was chosen to create the detailed geologic model for the Project. This software is used worldwide and combines information from logs and seismic data to build a sophisticated representation of underground reservoirs. The Petrel™ developed geologic model for the Project incorporates the available data for all relevant subsurface layers of the site.

The geologic model developed in Petrel™ was used as an input into the Schlumberger Eclipse-300™ numerical reservoir simulator. Eclipse-300™ is a widely recognized tool used for modeling both compositional and unconventional reservoirs. The simulator uses advanced computational methods and equation-of-state algorithms to produce a reliable prediction for CO2 sequestration projects. The software has modules and options specifically intended to allow the study of CO2 injection activities, can handle large data sets and multiple grids, and offers various tools for data management, visualization, and uncertainty analysis.

3.4.2 AoR Delineation Based on Model Results

The Eclipse-300™ model was used to generate projections of CO2 plume and pressure front migration versus time over the anticipated life of the Project. Each well's operational plan was incorporated into the modeling and followed the staged approach outlined in Section 3.1, beginning with initial completion and progressing through successive recompletions in incrementally shallower sections of the injection intervals. For each injection interval, as the volume of CO2 injected increases the areal extent of CO2 within that zone expands. Eventually, the CO2 plumes from each injection well commingle within the layers of each distinct injection interval. The combined effects of relative permeability, capillary pressure, and limited structural dip, ultimately arrest the extent of migration of the CO2 plume within each injection interval up-dip to the northwest.

The areal extent of the aggregate CO2 plume is expected to grow rapidly during injection and slow after injection ceases. The areal growth rate is expected to reach a stability threshold, which is defined conservatively at less than 0.25% per year, 39 years after the start of injection, demonstrating plume stability. The stabilized CO2 plume is shown in Figure 4-1.

In accordance with 40 CFR 146.84, the AoR is delineated via the maximum areal extents within the injection interval of both the CO2 plume and critical pressure front at any time interval or depth. Critical pressure is the increase in reservoir pressure that has a potential to create crossflow of brine from the injection zone into the lowermost USDW, assuming the presence of a hypothetical bridging conduit such as an unplugged borehole. The first step to predict the pressure front of interest is to calculate the critical pressure for each completion stage. Once critical pressure is estimated, a numerical simulation is used to predict the size and shape of the critical-pressure front defined by this pressure contour. The critical-pressure front represents the

maximum areal cone of influence and combines results from the seven completion intervals for each of the three injection wells.

Superimposing the stabilized CO2 plume and critical-pressure boundaries, Figure -1 shows the AoR boundary for the Project.

4.0 Delineation of Monitoring Areas [40 CFR § 98.448(a)(1)]

Reservoir simulator modeling (Section 3.4), informed by site characterization data, was conducted to delineate the maximum areal extent of the plume area for the life of the Project and to identify the MMA and AMA. ExxonMobil will reevaluate the AoR (including free phase CO2 plume), MMA, and AMA based on site specific monitoring data at the minimum frequency of five years in accordance with 40 CFR 146.84. Information gathered from testing and monitoring activities will be used to evaluate whether a more frequent review period is warranted based on the observed conditions of CO2 plume and pressure front migration.

ExxonMobil will not cease post-injection monitoring until the non-endangerment demonstration pursuant to 40 CFR 146.93(b)(3) has been approved by the UIC Program Director. Pursuant to 40 CFR 146.93(b)(1), the default post-injection site care (PISC) monitoring timeframe is 50 years after cessation of injection. ExxonMobil will monitor groundwater quality and track the position of the CO2 plume and pressure front for 50 years after cessation of injection unless a lesser period of time is approved by the UIC Program Director. At the conclusion of the PISC period, a request for discontinuation of Subpart RR reporting will be submitted including a demonstration that current monitoring and modeling show that the cumulative mass of CO2 reported as sequestered is not expected to migrate in the future or encounter leakage pathways.

4.1 Maximum Monitoring Area [40 CFR § 98.449]

Subpart RR defines the MMA as the area that must be monitored under Subpart RR and is defined as equal to or greater than the area expected to contain the free phase CO2 plume until the CO2 plume has stabilized, plus an all-around buffer zone of at least one-half mile. ExxonMobil has simulated the maximum plume extent to occur 26 years post injection (39 years after the start of injection). Figure 4-1 shows the extent of the stabilized CO2 plume with a half-mile buffer area.

4.2 Active Monitoring Area [40 CFR § 98.449]

The AMA is the portion of the MMA where monitoring is actively conducted at any given time during the injection and post-injection phases (Orange dash line in Figure 4-1). The AMA is composed of two combined areas:

- The area projected to contain the free phase CO2 plume at the end of year "t", plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile; and
- The area projected to contain the free phase CO2 plume at the end of year t+5.

Based on the definition above, ExxonMobil has assumed an active monitoring timeframe of t = 39 years post start-up, aligning with the expected stabilization of the CO2 plume. For the Rose project, this AMA is controlled by the 39-year plume plus the one-half mile buffer.

ExxonMobil has established one AMA boundary for 39 years and does not anticipate expansion of the monitoring area under 40 CFR 98.448 based on the currently planned operating conditions. Given the definitions used to delineate the MMA and the AMA, the AMA is functionally equivalent to the MMA. Monitoring the entire MMA boundary provides maximum operational flexibility.

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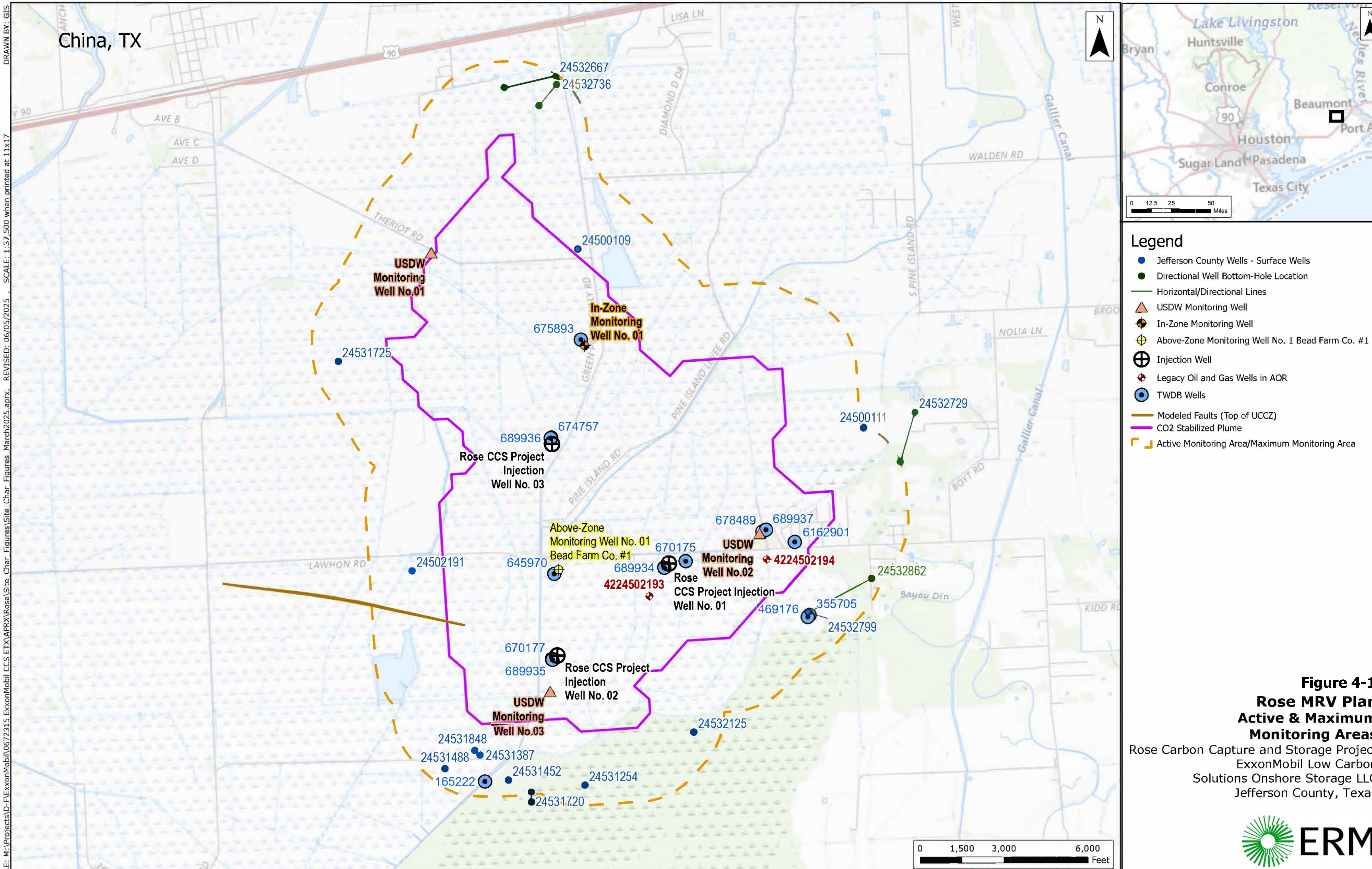

Figure 4-1
Rose MRV Plan
Active & Maximum Monitoring Areas
Rose Carbon Capture and Storage Project
ExxonMobil Low Carbon Solutions Onshore Storage LLC
Jefferson County, Texas

ERM

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5.0 Identification of Potential Leakage Pathways [40 CFR 98.448(a)(2)]

ExxonMobil identified the following scenarios as potential leakage pathways for the Project through a risk assessment process. Each of the identified leakage pathways carries a low likelihood of occurrence due to the engineering design of the Project, mitigating measures taken, and implementation of the Testing and Monitoring Plan developed as part of the Class VI application process.

The potential leakage pathways described in Sections 5.1 through 5.6 are summarized below:

- Integrity of Injection or Monitoring Well Casing or Cement Seal;
- Integrity of Legacy Well Casing or Cement Seal;
- Injection Well Monitoring Equipment Failure;
- Integrity of the UCCZ;
- Induced or Natural Seismic Event; and
- Integrity of Surface Equipment.

5.1 Integrity of Injection or Monitor Well Casing or Cement Seal

Corrosion of the mechanical components or casing cement are two hypothetical release mechanisms identified for the injection and monitoring wells that have the potential for a release of CO2. For example, CO2 detected at an injection or monitoring well potentially implies that internal or external mechanical integrity of a well may have been compromised causing release of CO2. Potentially, CO2 or brine could be released at an injection or monitoring well due to subsurface cement degradation or annular space defects in cement completion. In the case of either of these hypothetical examples, the likelihood of surface leakage due to a breakdown of materials in injection or monitoring wells is very low because of the CO2 compatible materials used and the continuous monitoring techniques deployed.

Hypothetical Release Mechanism: mechanical integrity failure at an injection or monitoring well resulting in release of CO2
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Proper wellbore design and construction of the project wells, which will utilize CO2 compatible materials for cement, casing, and tubing.
• Routine inspection of the well casing and cement integrity to identify potential corrosion or deficiencies.
Detection methods:
• Well casing and cement bond logs conducted on injection wells during shut-ins to assess loss decay or corrosion more than acceptable limits via distributed temperature sensing (DTS) as described in Table 6-2.
• Deficiency identified during pressure falloff tests and annulus pressure tests.
• Wellhead pressure exceeds the maximum pressure specified in the permit.
• Annulus pressure indicates a loss of external or internal integrity/containment.
• CO2 plume and pressure front tracking above UCCZ indicates a change in conditions.

• Fluid samples from above the UCCZ and/or USDW indicate a statistically significant change in conditions.
• Mechanical integrity testing identifies a potential issue in the integrity of the well.
Magnitude: Should a leakage result from the injection or monitoring wellbores and into the atmosphere, the volume of CO2 released will be quantified based on operating conditions at the time of release, as described in Section 6.0.

5.2 Integrity of Legacy Well Casing or Cement Seal

Consistent with the potential for CO2 to leak at an injection well, artificial penetrations of the UCCZ from legacy oil and gas activities may represent a similar risk scenario. Legacy wells were identified within the AoR that penetrate the UCCZ. The plugging of one legacy well was completed as a corrective action prior to operation, the other legacy well was recompleted as an above zone monitoring well for the Project. The objective of this risk scenario is to provide the response actions in the event that unknown legacy wells are identified and suspected of being within the pathway of CO2 plume or brine due to unexpected lateral migration, causing CO2 leakage due to potential casing or cement integrity issues. To further reduce this unlikely risk in the AoR, an aeromagnetic survey was conducted on September 2023 to assess the AoR for undocumented artificial penetrations. No additional artificial penetrations were identified.

As a part of the MMA, additional legacy wells were identified that penetrate the UCCZ (Table 3-2). However, current reservoir models predict no migration of CO2 plume nor brine to reach the identified wells.

Hypothetical Release Mechanism: CO2 leaks at an artificial penetration as detected within the AoR.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Compliance with CO2 plume and brine tracking systems.
• Time-lapse seismic surveys will be conducted at the intervals specified in Tables 6-2 and 6-3 to monitor for any indication of unexpected lateral or vertical CO2 plume migration above the UCCZ.
• CO2 Plume reservoir model forecast updates to predict pressure front changes that may impact legacy wells outside of the AoR and adjust timing of monitoring and phased-corrective action.
Detection methods:
• CO2 plume and pressure front tracking indicates potential impact.
• Fluid samples from above the UCCZ and/or USDW indicate a statistically significant change in conditions.
• Legacy well re-entry to collect casing and cement bond logs to assess integrity and well completion materials.
Magnitude: Should a leakage result from a legacy well and into the atmosphere, the volume of CO2 released will be quantified based on operating conditions at the time of release, as described in Section 6.0.

5.3 Injection Well Monitoring Equipment Failure

Loss of mechanical integrity of well pressure equipment may occur during operation of the injection wells. A pressure gauge malfunction or other similar equipment could create a shut-off valve malfunction and result in an uncontrolled pressure situation and CO2/brine crossflow to USDW by fault or fracture activation or well casing and/or cement failure in the vicinity of the production casing perforations.

Hypothetical Release Mechanism: Loss of mechanical integrity of well pressure equipment could trigger a shut-off valve malfunction and result in an uncontrolled pressure situation and CO2 release by near wellbore fault or fracture activation or by well casing and/or cement failure in the vicinity of the production casing perforations.
Timing of event: Injection phase and/or post-injection phase.
Avoidance measures:
• Routine equipment inspection and maintenance to identify potential integrity issues that may be a result of equipment failure.
• Routine inspections and calibration of monitoring equipment in accordance with manufacturer's recommended procedures.
• Consistent fluid sampling throughout the detection monitoring well network to detect a release above the UCCZ.
• Redundant pressure and temperature measurements in the injection zones to maintain compliance with permitted operating conditions.
Detection methods:
• Anomalies in pressure and rate monitoring, pressure falloff tests, and annulus pressure tests.
Magnitude: Anticipated CO2 leakage is negligible.

5.4 Integrity of the UCCZ

Several potential risk scenarios were considered that involve a hypothetical release through naturally occurring faults and fractures or other penetrations of the UCCZ, creating a migration pathway for CO2. For example, CO2 could hypothetically leak through seismically visible faults or fractures in the UCCZ within the AMA or CO2 or brine could hypothetically migrate horizontally to artificial penetrations within the AMA that are not sealed at the UCCZ and result in a release of CO2. Based on ExxonMobil's assessment of the subsurface one visible fault was identified that extends through the UCCZ within the AMA. The displacement on this fault is minor compared to the thickness of the UCCZ. Seal analysis indicates high sealing properties such that integrity of the UCCZ should not be compromised and this is not a likely leakage pathway for CO2.

CO2 and brine leaks through shales due to mechanical fracturing were not considered a potential concern for the Project because of the physical nature of the confining shale materials. Above the UCCZ is approximately 3,000 feet of saturated shale, mudstone, and sand. A release through the UCCZ would likely be detected by the groundwater monitoring program prior to release to the surface.

The following actions were developed to mitigate the potential for releases through the UCCZ:

Hypothetical Release Mechanism: release through naturally occurring faults and fractures or penetration of the UCCZ, creating an unexpected migration pathway for CO2.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Time-lapse seismic surveys will be conducted at the intervals specified in Tables 6-2 and 6-3 to monitor for any indication of CO2 plume migration above the UCCZ.
• Compliance with CO2 plume and brine tracking systems.
Detection methods:

• CO2 plume and pressure front tracking indicates a potential impact.
• Fluid samples from above the UCCZ and/or USDW indicate a statistically significant change in conditions.
• Third-party direct or indirect data identify a potential impact to subsurface outside of AMA.
Magnitude: As described above, anticipated leakage magnitude is negligible.

5.5 Induced or Natural Seismic Event

Based on the projected operating conditions and regional and local geologic conditions, injection operations are not expected to result in an induced seismic event mandating a response action. Induced or natural seismic events would be monitored at a minimum during the injection phase. ExxonMobil has installed a permanent seismicity monitoring system onsite, which is being monitored by a third party to detect seismic activity prior to and during injection operations. This array has been recording baseline data since 1 July 2024. The design of the array consists of a near-surface network of seismometers with continuous data sampling, incorporation of publicly available data, and telemetry to cloud-based storage. Near-real-time, high-resolution signal processing and quality assurance will be implemented for event detection, magnitude, and location accuracy. ExxonMobil will additionally receive notifications from the United States Geological Survey of recorded seismicity events for the site and surrounding area, should an event occur. If a review of the data indicates that a magnitude 2 or larger seismic event was within a 5.6 mi radius of an injector, ExxonMobil will notify the UIC Program Director to jointly assess if the events are likely to be associated with the operations, and, if so, implement response actions for seismic events. As described in this section, anticipated leakage magnitude is negligible.

5.6 Integrity of Surface Equipment

The surface components of the injection system include the CO2 injection wellheads and the associated surface piping that transports CO2 from the mass flow meters located on the central pad to the wellheads. A data management system, or a suitable equivalent, will be used to facilitate the continuous collection of key operational parameters, including:

- Intake pressure at the central pad transfer point;
- Pressure within the distribution system to each injection well; and
- Pressure at each injection wellhead.

Two Coriolis flow meters, installed at the central pad, will be used to directly measure the mass flow rate of the injected fluid. The Coriolis meters will be calibrated in accordance with the manufacturer’s specifications.

During injection, ExxonMobil will review and interpret continuously monitored parameters against permitted limits. This review will also include trend analyses to assess maintenance, recalibration, or system optimization opportunities.

To mitigate the potential for surface leakage of CO2 from equipment, ExxonMobil will implement the following measures:

- Adherence to Class VI regulatory requirements for well construction (40 CFR 146.86), well operation (40 CFR 146.88), and testing and monitoring of surface facilities (40 CFR 146.90).

- Continuous monitoring via a Supervisory Control and Data Acquisition system monitored remotely by ExxonMobil's Operations Control Center. Surface equipment pressure and flow rates (as noted above and in Section 3.1) are included in the Supervisory Control and Data Acquisition system.
- Routine visual inspections and preventative maintenance of all surface components.
- Surface equipment will be inspected, tested, and calibrated in accordance with manufacturer specifications prior to commissioning.

The likelihood of CO2 leakage from surface equipment during injection operations is considered to be very low. In the unlikely event of a release, the volume would be limited to the amount of CO2 contained within the surface piping and equipment due to automatic shutoff devices. The quantification approach will be adaptable to the specific characteristics of each leakage scenario, with methods selected based on site conditions and the nature of the release.

6.0 Detection, Verification and Quantification of Leakage [40 CFR 98.448(a)(3)]

ExxonMobil installed and will use continuous measurement devices to monitor injection pressure, temperature, rate, and mass injected; the pressure on the annulus between the tubing and the long-string casing; and the temperature of the CO2 stream, as required under [40 CFR 146.88(e)(1), 146.89(b), and 146.90(b)]. Data will also be collected to document the addition or removal of any fluid from the annulus system. Data interfaces will be created for equipment that is not linked directly to a data management system or suitable equivalent, and will be integrated into a unique surveillance platform. In the monitoring program, the sensors, transducers, and controllers will be connected in a central platform to monitor the operating conditions, set alarms for alerting operations of malfunction, and maintain safety protocols in case of abnormal conditions. Alarms will be set for pressures outside described tolerances (generally 90% of fracture gradient and prescribed wellhead pressures), and changes in annular pressure and fluid.

Instrument calibration standards, precision, and tolerances will be maintained based on manufacturer recommendations. The automated control system data will be monitored for anomalies on a regular basis. Average values will be compared to baseline and predicted values to assess if there are any significant deviations relevant to integrity or containment.

The operating parameters, monitoring values, laboratory results, reports, and surveillance documents for the Project will be stored in a database to support AoR and AMA reviews, quality assurance / quality control review programs, and routine reporting. Table 6-1 provides a summary of the typical sampling devices, locations, and data storage frequencies for the continuous monitoring program.

Table 6-1: Sampling Devices, Locations, and Data Frequencies for Continuous Monitoring

Continuous Sampling Parameter	Device(s)	Location	Estimated Min. Sampling Frequency	Estimated Min. Recording Frequency
Surface Injection Pressure	Wellhead Pressure Logger	Surface, injection well piping	5 seconds	5 minutes
Downhole pressure gauge	Pressure Gauges	Injection Unit	5 seconds	5 minutes

Continuous Sampling Parameter	Device(s)	Location	Estimated Min. Sampling Frequency	Estimated Min. Recording Frequency
Injection rate	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Injectate density	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Total mass injected	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Annular pressure	Pressure Gauge	Well Head	5 seconds	5 minutes
Annulus fluid volume	Level Transmitter	Annulus System Tank	5 seconds	5 minutes
Carbon dioxide stream temperature	Coriolis Meter/Wellhead Pressure Logger	Well Head, injection well flowing	5 seconds	5 minutes
Note: The word “continuous” is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument’s normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application. Measurements that are collected “continuously” will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.				

Additionally, as part of its Class VI well permit application, ExxonMobil developed a comprehensive testing and monitoring strategy for the Project using a risk-based approach. The monitoring frequency is outlined in Table 6-2 and the monitoring strategy is outlined in Table 6-3. The monitoring program aligns with the three operational phases of the Project: (1) pre-operational baseline data collection phase; (2) the operational phase for the three injectors; and (3) the PISC phase. During the pre- and early-operational phases, a selection of technologies will be used to develop baseline seismic response, pressure, temperature, and certain geochemical parameters needed to monitor the CO2 plume and pressure front.

This testing and monitoring information will also be used to assess the predictive modeling results and refine the model as necessary. During the operational phase, the frequency of direct monitoring data collection activities will be aligned with the initiation of injection into each new stage of the injection intervals as described in Section 3.1. The accuracy of the model at predicting the CO2 plume and pressure front migration will inform the frequency of indirect monitoring data collection. Upon assessment of the predictive capabilities of the model, the frequency of indirect monitoring activities listed in Table 6-2 may be reduced as justified by the rates of change and variations observed by the monitoring results, which are subject to approval by the UIC Program Director and incorporation into the Class VI permit. The data generated from the implementation of this Plan provides the basis to assess the confinement of the CO2 in the permitted injection formations during the active injection phase of the Project.

Section 5 of this Plan details the detection methods in place for each leakage pathway. Consistent with EPA guidance, the monitoring program is intended to be a flexible approach using appropriate technologies and techniques that are refined and adapted based on site-specific information over time. ExxonMobil will continue to assess the feasibility of emerging technologies and conduct performance evaluations to continue to improve the performance of the testing and monitoring program.

Table 6-2: Testing and Monitoring Plan Measurements and Frequency

Equipment / Measurement	Regulation	Objective	Frequency
Coriolis flow meter	146.90b	Measure mass flow rate	Continuously
Corrosion coupon	146.90c	Measure corrosion levels on the types of metal used in the Project	Quarterly
Injection stream sampling	146.90a	Provide more detailed analysis via periodic lab analysis of injection stream	Quarterly
Central pad temperature gauge	146.90a	Measure temperature of the total injection stream at the pad before partitioning to injections	Continuously
Injection wellhead tubing Pressure gauge	146.90a	Measure downstream of choke	Continuously
Injection wellhead annulus Pressure gauge	146.90b	Verify annulus pressure maintained	Continuously
Injection annulus pressure test	146.89b	Verify absence of leak in annulus	Annually
Injection Well downhole pressure and temperature gauge for active/open injection interval	146.90b	Measure downhole pressure and temperature (injection mass to volume conversion, verifying that it is not exceeding maximum pressure)	Continuously
	146.90f	Measure fall-off of pressure after abandoning injection stage and before initiating injection in next stage above	At the end of every injection stage
	146.90g(1)	Direct measurement of pressure, sensitive to pressure from other injections, especially when injection intervals are staggered between wells	Continuously
Time-lapse surface seismic survey	146.90g(2)	Indirect method to monitor CO2 plume growth in the subsurface over time	Frequency from start of operations: Survey Event #1: completed; Survey Event #2: one to three years; Survey Event #3: six to eight years; Survey Event #4: 13 years. Contingent additional survey events as needed and approved by UIC Program Director.

Equipment / Measurement	Regulation	Objective	Frequency
	146.87a(3)(ii)	DTS for cement long portion of long-string casing where fiber is cemented in place	One-time event
	146.90e	DTS to assess potential flow through channels through or along cement	Annually
Injection well casing inspection log	146.90e	Through-tubing log to detect loss of metal mass in casing due to corrosion	Baseline only; repeat survey is triggered if risk of leakage is apparent or upon request by UIC Program Director
In-zone monitoring well downhole pressure and temperature gauges	Not required 146.90g(1)	Collect pressure and temperature measurements for evaluating the rate of CO2 plume and pressure front movement	Continuously
Above-zone monitoring well fluid sampling from above UCCZ	146.90d	Above UCCZ fluid collection is recommended by guidelines	Quarterly
USDW fluid sampling	146.90d	Sample fluids from the Chicot Aquifer which is the most prolific USDW aquifer within the AoR, as recommended by guidelines, and analyze composition	Quarterly
DTS = Distributed Temperature Sensing; UCCZ = upper composite confining zone; UIC = Underground Injection Control; USDW = underground source of drinking water Note: The word “continuous” is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument’s normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application. Measurements that are collected “continuously” will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.			

Table 6-3: Summary of Monitoring Technologies for Direct and Indirect CO_2 Plume and Pressure Front Tracking

Target Zone	Requirement	Technology	Placement Location	Target Depths	Phased/Triggered Approach	Monitoring Frequency	Data Evaluation Objectives
Injection Zone	Direct per 40 CFR 146.90(g)(1)	Downhole tubing mounted pressure and temperature gauge	Injection Wells No. 01, No. 02, and No. 03	Four injection intervals in Fleming and Upper Frio Formations	No	Continuous monitoring during injection operations for each injection interval Annual pressure fall-off test during well shut-ins	Identify pressure differential and location of pressure front for the four injection intervals
		Tubing encapsulated conductor cable with in-line pressure/ temperature gauges	In-Zone Monitoring Well No. 01	Four injection intervals in Fleming and Upper Frio Formations	No	Continuous monitoring	CO_2 plume and pressure front tracking
	Indirect, geophysical techniques per 40 CFR 146.90(g)(2)	Time-lapse seismic surveys, or equivalent technologies	CO_2 Plume Area	Four injection intervals in the Upper Frio and Fleming Formations	No	Surface Seismic Survey Event #1 (Survey Event #1) is the baseline event conducted prior to injection. Survey Event #2 will be performed within the first three years after injection, Survey Event #3 within six to eight years after injection, Survey Event #4 in year 13 at cessation of injection. Additional survey events if necessary, during PISC, as approved by UIC Program Director.	Monitor CO_2 plume growth in the subsurface over time
		Passive Seismicity Monitor Station Array	Selected locations within AoR	Surface	Yes, contingent on triggering seismic events	Continuous monitoring	AoR-specific seismicity data collection and event analyses
Above UCCZ	Direct per 40 CFR 146.90(g)(1)	Fluid sampling protocol using converted Bead Farm Co. #1 collected through tubing	Above-Zone Monitoring Well - Bead Farm Co. #1	First laterally continuous water-bearing zone above UCCZ	No	Quarterly samples	Detection monitoring for CO_2 plume and/or brine crossflow from injection zones to top of UCCZ
	Indirect, geophysical techniques per 40 CFR 146.90(g)(2)	Time-lapse seismic surveys, or equivalent technologies	CO_2 Plume Area	From surface to base of Frio Sand 2	No.	Surface Seismic Survey Event #1 (Survey Event #1) is the baseline event conducted prior to injection. Survey Event #2 will be performed within the first three years after injection, Survey Event #3 within six to eight years of injection, Survey Event	Detection monitoring for presence of CO_2 plume above UCCZ Detection monitoring and evaluation of trends in water quality and geotechnical parameters

Target Zone	Requirement	Technology	Placement Location	Target Depths	Phased/Triggered Approach	Monitoring Frequency	Data Evaluation Objectives
						#4 in year 13 at cessation of injection. Additional survey events if necessary, during PISC, as approved by UIC Program Director.	
USDW	Direct per 40 CFR 146.90(d)	Fluid Sampling	USDW Monitoring Wells No. 01, No. 02, No. 03	Groundwater samples collected just below the typical total depth of water wells completed in the area (e.g., 300 to 350 feet below ground level).	Yes, three USDW monitoring wells prior to start of injection and additional USDW monitoring wells depending on the results of CO2 plume and pressure front tracking as discussed in AoR reevaluations	Pre-Operational Phase – Quarterly Operational Phase – Quarterly	Detection monitoring and evaluation of trends in water quality and geotechnical parameters
Soil Gas Monitoring	Direct per 40 CFR 146.90(h)	Soil gas samples collected from the unsaturated zone	Contingent on confirmed release to USDW				
Air Monitoring	Direct per 40 CFR 146.90(h)	Portable and/or stationary CO2 detectors monitor record ambient CO2 concentrations	Contingent on confirmed release to USDW				
AoR = Area of Review; CFR = Code of Federal Regulations; CO2 = carbon dioxide; PISC = post-injection site care; UCCZ = upper composite confining zone; UIC = Underground Injection Control; USDW = underground source of drinking water							

7.0 Assessment of Expected Baselines [40 CFR 98.448(a)(4)]

ExxonMobil has developed a comprehensive pre-injection (baseline) testing and monitoring plan to develop reference conditions against which future data will be compared throughout the operational phase of the Project. Baseline data collection has been completed or is underway, and comparisons to these baseline conditions will be used to evaluate any deviations that may occur during injection activities. The following summarizes the key elements of baseline data collection:

- Groundwater Sampling—ExxonMobil has collected baseline groundwater quality and geochemical samples from the above-zone monitoring well (Bead Farm Co. #1) installed in the formation directly above the UCCZ and from the three USDW monitoring wells at the Project site.
- Continuous Pressure/Temperature Monitoring—Reservoir temperatures and pressures will be monitored using a downhole gauge installed in the tubing above the production packer. At In-Zone Monitoring Well No. 01, a tubing encapsulated conductor cable with in-line pressure/ temperature gauges will be installed. Baseline measurements will be collected prior to the start of injection to establish reference operating conditions.
- Seismic Survey—A seismic survey to monitor the CO2 plume extent is planned to take place four times throughout the life of the Project. The baseline survey was conducted using the data purchased and reprocessed in 2024/2025 for site characterization.
- Visual Inspection—Prior to operations, surface equipment will be inspected and tested to confirm proper function and integrity.

8.0 Site-Specific Modifications to the Mass Balance Equation [40 CFR 98.448(a)(5)]

CO2 will be injected into saline aquifers via three injection wells at the Project site. To accommodate the anticipated injection volume, two separate flowlines will be utilized at the central pad (Figure 3-2). Each flowline will be equipped with a mass flow meter to continuously measure and record the quantity of CO2 injected. ExxonMobil will utilize the two flow meters to estimate CO2 injected for the Project. All CO2 injected will be sourced from a single pipeline that enters the central pad.

8.1 CO2 Injected (CO_{2I})

The CO2 stream received will be wholly injected into the storage complex. Therefore, pursuant to 40 CFR 98.444(a)(4) and 98.444(b), the annual CO2 received will be equivalent to the annual CO2 injected. The point of measurement for CO2 injected is the mass flow meters located at the central pad. CO2 will be measured through two-meter runs, each equipped with a mass flow meter. These meter runs will merge at a single point, from which the CO2 is distributed to the three injection wells via flowlines.

The annual CO2 injected at each well will be calculated using Equation RR-4 from 40 CFR Part 98, Subpart RR:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_2,p,u}$$

Where:

$CO_{2,u}$ = Annual CO2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).
$C_{CO2,p,u}$ = Quarterly CO2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flow meter.

The sum of the mass of CO2 injected through the two mass flow meters will be calculated using Equation RR-6:

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u}$$

Where:

CO_{2I} = Total annual CO2 mass injected (metric tons) through all injection wells.
$CO_{2,u}$ = Annual CO2 mass injected (metric tons) as measured by flow meter u.
u = Flow meter.

8.2 Mass of CO_2 Emitted by Surface Leakage (CO_{2E})

In addition to the mass of CO2 received, injection into the subsurface, emitted from equipment leaks, and sequestered in subsurface geologic formations, ExxonMobil will monitor and report the total estimated CO2 emitted in the event of surface leakage using the strategies and procedures for quantifying leakage detailed in Section 6 (Detection, Verification and Quantification of Leakage) of this MRV Plan and in accordance with 40 CFR 98.444(d). The quantification approach will be adaptable to the specific characteristics of each leakage scenario, with methods selected based on site conditions and the nature of the release. These methods may include direct monitoring data, engineering-based calculations, or the application of established emission factors.

Quantification methods will adhere to accepted engineering standards and best practices, with example approaches for different leak types outlined in Section 6. Should a surface leakage event occur, ExxonMobil will document and report the estimated mass of CO2 released in the annual Subpart RR submission, along with a summary of the measurement or estimation techniques employed. Data and supporting documentation will be retained to ensure regulatory compliance and transparency.

The total annual mass of CO2 emitted from all leakage pathways will be calculated using Equation RR-10:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.
$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.
x = Leakage pathway.

8.3 Mass of CO2 Emitted from Equipment Leaks and Vented Emissions (CO_{2FI})

The annual mass of CO2 emitted from equipment leakage and vented emissions between the injection flow meter and wellhead will be measured and reported in accordance with the requirements of 40 CFR 98.444(d)/Subpart W.

8.4 Mass of CO2 Sequestered in Geologic Formations (CO_2)

The total annual mass of CO2 sequestered in geologic formations for the reporting year will be calculated and reported using Equation RR-12:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98.

9.0 Estimated Schedule for Implementation of MRV Plan [40 CFR 98.448(a)(7)]

Implementation of the MRV Plan will commence immediately following the effectiveness of the permit. The MRV activities will be initiated prior to the start of injection to develop baseline conditions and will continue throughout the operational phase of the Project and into the PISC period, until the EPA approves the cessation of Subpart RR reporting. Key milestones include completion of baseline monitoring, commissioning of monitoring equipment, and initiation of data collection and reporting systems. In the event of material changes to the Project, the plan will be resubmitted to and approved by the EPA prior to injection, in accordance with 40 CFR 98.448(d).

10.0 Quality Assurance Program [40 CFR 98.444]

ExxonMobil has designed its monitoring plan and network to meet the quality assurance and quality control requirements of 40 CFR 98.444 of Subpart RR.

10.1 Measurement of CO2 Concentration

The CO2 injection stream will be measured with a gas chromatograph and will be sampled quarterly at the central pad. Sufficient mixing and residence time in the system will have occurred at this sampling point for the sample to be representative of the injected CO2 stream to meet the requirements of 40 CFR 146.91(a). The sampling station will be equipped with the ability to purge and collect a gas sample into a sealed container. The central pad is the connection point between the CO2 pipeline and the sequestration field's distribution system.

The sample will be collected by site representatives following established company sampling procedures. It will then be transferred to a certified or accredited laboratory, where analysis will be performed using industry-standard methods for CO2 that comply with the minimum current EPA regulations.

Each sample will be accompanied by a facility or contract laboratory Chain-of-Custody (COC) form that provides a record of sample handling, starting with sample acquisition, documenting the sample transfer process up to laboratory analysis. Samples taken are to be logged in the field using the COC form. Sample transfer containers (e.g., coolers) will be sealed and delivered to the laboratory with a COC form. The COC form shall provide the following items recorded by the sampler:

1. Sample ID including code or name, in addition to date and time;
2. Name of sample collector; (include sampling company name if not site personnel);
3. Sample collection method;
4. Sample collection date;
5. Sample collection point; and
6. Sample presentation technique, as applicable.

Standard laboratory COC forms that document the times and dates of all personnel handling the sample, along with standard labels and container seals sufficient to distinguish between samples and prevent tampering, will be acceptable. Sample COC will be followed at all times during the sampling and subsequent analysis. COC will be used to document the handling and control necessary to identify and trace a sample from collection to final analytical results.

10.2 Measurement of CO2 Mass

To meet the requirements of 40 CFR 98.444(e), ExxonMobil will conduct the following activities for operation and maintenance of meters associated with the Project:

- Flow meters will be operated continuously except as necessary for maintenance and calibration.
- Flow meters will be calibrated to measure quantities reported in 40 CFR 98.446 according to the calibration and accuracy requirements in 40 CFR 98.3(i).
- Measurement devices will be operated according to an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute, the American Gas Association, the American Society of Mechanical Engineers, the American Petroleum Institute, and the North American Energy Standards Board.
- Assess flow meter calibrations performed are traceable by the National Institute of Standards and Technology.

10.3 Estimating Missing Data

ExxonMobil will follow all quality assurance and quality control procedures to record the mass of CO2 injected. In the event ExxonMobil is unable to collect the necessary data for greenhouse gas (GHG) reporting, the following procedures will be followed to estimate missing injection data as required by 40 CFR 98.445. Generally, the methods include:

- A quarterly quantity of CO2 flow rate that is missing will be estimated using a representative quantity of CO2 injected from the nearest previous period of time at a similar injection pressure.
- Values associated with CO2 emissions from equipment leaks and vented emissions of CO2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures will follow those specified in subpart W of this part.
- A quarterly concentration value that is missing will be estimated using a representative concentration value from the nearest previous time period. If the CO2 stream was sampled by the capture facility in the same time period, sales contract data may be used.
- A quarterly quantity of CO2 injected that is missing will be estimated using a representative quantity of CO2 injected from the nearest previous period of time at a similar injection pressure.

11.0 Reporting [40 CFR 98.442]

ExxonMobil will submit reports consistent with 40 CFR 98.442.

12.0 Records Retention [40 CFR 98.447]

ExxonMobil will retain the following documents and records to remain in compliance with 40 CFR 98.447(a) and 98.3(g), including but not limited to:

- A list of all units, operations, processes, and activities for which GHG emission were calculated. The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):
- The GHG emissions calculations and methods used. For data required by § 98.5(b) to be entered into verification software specified in § 98.5(b), maintain the entered data in the format generated by the verification software according to § 98.5(b).
- Analytical results for the development of site-specific emissions factors.
- Any facility operating data or process information used for the GHG emission calculations.
- The annual GHG reports.
- Missing data computations. For each missing data event, also retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
- A written GHG Monitoring Plan.
- The results of required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
- Maintenance records for continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

- Quarterly records of CO_2 received, including mass flow rate of contents of containers (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams. No CO_2 received is anticipated for the facility as all CO_2 received is wholly injected and not mixed with any other supply of CO_2.
- Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams. No produced CO_2 is anticipated for the facility.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.
- Other records as specified for retention in the EPA-approved MRV Plan.

12.1 <u>Revisions to the MRV Plan</u>

In accordance with 40 CFR 98.448(d), ExxonMobil will revise and submit the MRV Plan within 180 days to the Administrator for approval if any of the following applies:

- A material change was made to monitoring and/or operational parameters that was not anticipated in the original MRV Plan. Examples of material changes include but are not limited to:
  - Significant changes in the volume of CO_2 injected;
  - The construction of new injection wells not identified in the MRV Plan;
  - Failures of the monitoring system including monitoring system sensitivity, performance, location, or baseline;
  - Changes to surface land use that affects baseline or operational conditions;
  - Observed CO_2 plume location that differs significantly from the predicted CO_2 plume area used for developing the MRV Plan;
  - A change in the MMA or AMA;
  - Or a change in monitoring technology that would result in coverage or detection capability different from the MRV Plan.
- A change in the permit class of the Underground Injection Control Permit.
- If ExxonMobil is notified by EPA of substantive errors in the MRV Plan or monitoring report.

- If the MRV Plan must be changed for any other reason in any reporting year.

ExxonMobil will include the reason(s) for the revisions in the MRV Plan submittal.

Appendices

Appendix A: References

Carr, D.L., K.J. Wallace, A.J. Nicholson, and C. Yang, 2017, Regional CO2 Static Capacity Estimate Offshore Saline Aquifers, Texas State Waters, Geological CO2 Sequestration Atlas of Miocene Strata, Offshore Texas State Waters, Report of Investigations No. 283, Bureau of Economic Geology, University of Texas at Austin, Austin

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Roberts-Ashby, T.L., S.T. Brennan, M.L. Buursink, J.A. Covault, W.H. Craddock, R.M. Drake II, M.D. Merrill, E.R. Slucher, P.D. Warwick, M.S. Blondes, M.A. Gosai, P.A. Freeman, S.M. Cahan, C.A. DeVera, and C.D. Lohr, 2014, Geologic Framework for the National Assessment of Carbon Dioxide Storage Resources - U.S. Gulf Coast, Chapter H, U. S. Geological Survey, Open-File Report 2012-1024-H, Reston, VA.

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