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OFFICE OF AIR AND RADIATION
WASHINGTON, D.C. 20460

February 22, 2024

Mr. Travis Hurst
Director
California Resources Corporation
28590 CA 119
Tupman, California 93276

Re: Monitoring, Reporting and Verification (MRV) Plan for CTV/CRC Elk Hills Carbon Project

Dear Mr. Hurst:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for CTV/CRC Elk Hills Carbon Project, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by CTV/CRC Elk Hills Carbon Project on January 12, 2024, as the final MRV plan. The MRV Plan Approval Number is 1014435-1. This decision is effective February 27, 2024 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78. In conjunction with this MRV plan approval, we recommend reviewing the Subpart PP regulations to determine whether your facility may also be required to report data as a supplier of carbon dioxide. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

If you have any questions regarding this determination, please contact me or Melinda Miller of the Greenhouse Gas Reporting Branch at miller.melinda@epa.gov.

Sincerely,

Julius Banks,
Chief, Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for the CTV/CRC Elk Hills Carbon Project (EHCP)

February 2024

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 California Resources Corporation's CTV/CRC Elk Hills Carbon Project (EHCP) for its carbon dioxide (CO_2) capture and storage (CCS) project located in Kern County, California. Note that this evaluation pertains only to the Subpart RR MRV plan for the EHCP, 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

The MRV plan states that Carbon TerraVault (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), intends to inject and store a measurable quantity of CO_2 in subsurface formations at the EHCP, located within the Elk Hills Oil Field (EHOF), for a term of 27 years referred to as the "Specified Period". During this Specified Period, EHCP states that they will inject CO_2 from anthropogenic sources such as the Elk Hills 550 megawatt (MW) natural gas combined cycle power plant (EHPP), bio-diesel refineries, and other sources in the EHOF area.

The MRV plan states that existing wells in the EHOF including production, injection, and monitoring wells are permitted by California Geologic Energy Management Division (CalGEM) through California Public Resources Code Division 3. EHCP states that wells injecting CO_2 for geologic storage will be permitted with the EPA's UIC program for Class VI injection. The list of wells as of March 2023 associated with the geologic storage at the EHCP are included in Appendix 11.5 of the MRV plan. EHCP states that any new wells or changes to wells will be indicated in the annual report.

The EHCP is located 20 miles southwest of Bakersfield in western Kern County, California. It lies within the EHOF, which was discovered in 1911. Since then, the EHOF has become one of the most productive fields in the United States by producing over 2 billion barrels of oil equivalent (BOE) from multiple stacked reservoirs.

EHCP states that the potential CO_2 stored over the project duration is up to 48 million metric tons. Furthermore, EHCP describes that, for accounting purposes, the amount stored will be the difference between the amount injected less any CO_2 that i) leaks to the surface, or ii) is released through surface equipment leakage or malfunction.

The CO_2 will be injected into the Monterey Formation A1-A2 and 26R reservoirs for dedicated geologic storage. The Monterey Formation is the most prolific reservoir in the more than 24,000 feet (ft) of sediment deposited during the Tertiary period surrounding the EHCP. Individual layers within the Monterey Formation are primarily interbedded sandstone and shale. The MRV plan states that the combination of multiple porous and permeable sandstone reservoirs interbedded with impermeable shale seals makes the EHOF one of the most suitable locations in North America for the extraction of hydrocarbons and the sequestration of CO_2.

EHCP states that the Monterey Formation was buried under more than 750 ft of impermeable silty and sandy shale that comprise the confining Reef Ridge shale. The Reef Ridge shale serves as the primary confining layer because it effectively seals underlying fluids from the overlying formations.

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 maximum monitoring area 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 active monitoring area 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.

EHCP states that reservoir modeling was used to predict the size and location of the plume, as well as how the plume migrates over time. The reservoir model incorporated geologic data collected from wells, seismic data, and historic production and injection data. Using this model, EHCP defines the MMA by the extent of the CO_2 plume at 100 years post-injection for geologic sequestration plus one-half mile.

The MRV plan states that the AMA boundary was established by superimposing two areas:

1. Area #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. Area #2: The area projected to contain the free phase CO_2 plume at the end of year t + 5.

The MRV plan states that the A1-A2 and 26R reservoirs are depleted and CO_2 is predicted to reach the edges of the reservoir within the first two to three years of injection. For this reason, the MRV plan states that the area projected to contain the free phrase CO_2 is similar during the majority of the Specified Period. The MRV plan states that the AMA boundary was determined for the time period ("t") corresponding to three years after the end of injection (30 years after the beginning of injection). Area #1 was taken as the plume area plus an all-around buffer zone of one-half mile. Area #2 is smaller or equal in all directions for both project plume areas (A1-A2 and 26R) than Area #1, and therefore the final AMA was defined as Area #1. Therefore, EHCP states that the AMA is assumed to be functionally equivalent to the MMA. EHCP states that leveraging the MMA boundary for the AMA also provides maximum operational flexibility. Figure 8 in the MRV plan shows the delineations of the AMA and MMA.

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 timing of surface leakage of CO_2 through these pathways pursuant to 40 CFR 98.448(a)(2). In section 4 of their MRV plan, EHCP identified the following potential leakage pathways that require consideration:

- Existing wellbores,
- Faults and fractures,
- Natural and induced seismic activity,
- Previous operations,
- Pipeline/surface equipment,
- Lateral migration outside the EHOF,
- Drilling through the CO_2 area, and
- Diffuse leakage through the seal.

3.1 Existing Wellbores

The MRV plan states that the likelihood of leakage through existing wellbores is considered low at the EHCP. The risk of leakage through existing wellbores is greatest after the CO_2 has reached the wellbore and when pressure is greatest, which is generally towards the end of the project injection time period. The MRV plan also states that leakage through existing wellbores is mitigated by adhering to CalGem regulatory requirements for well drilling and testing; implementing best practices developed through extensive operating experience; monitoring injection/production performance, wellbores, and the surface; and maintaining surface equipment. Therefore, EHCP believes that leakage mass is predicted to be less than one percent of total injection (less than 0.5 million metric tons).

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through existing wellbores at the EHCP.

3.2 Faults and Fractures

The MRV plan states that there are no faults or fractures penetrating the confining layer of the Reef Ridge shale that would provide a potential upward pathway for fluid flow. EHCP further states that the presence of oil, especially oil with a gas cap, is indicative of a competent natural seal. Therefore, places where oil and gas remain trapped in the deep subsurface over millions of years, as is the case in the EHCP, prove that faults or fractures do not provide a pathway for upward migration out of the CO_2 flooding interval.

Therefore, for these reasons, EHCP concludes that the likelihood and magnitude of leakage through faults and fractures is considered negligible throughout the entire duration of the project. EHCP conducted a seismic survey to characterize the formations and provide information for the reservoir models used for development planning. This study revealed the location of four high angle faults that have remained inactive for millions of years since their formation. EHCP states that the faults penetrate the lowest portions of the Monterey Formation but do not continue through the injection interval to the Reef Ridge confining layer.

Furthermore, EHCP states that the operating history of the EHOF confirms there are no faults or fractures penetrating the Reef Ridge shale that allow fluid migration. Water and gas have been successfully injected into the Monterey Formation since 1976, and there is no evidence of new or existing faults or fractures.

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

3.3 Natural or Induced Seismic Activity

The MRV plan states that the likelihood of induced seismicity is low, and the magnitude of possible leakage is negligible. The MRV plan states that the risk of induced seismicity is highest when operating pressures are greatest at the end of the injection period. EHCP states that the published data and over 100 years of operational experience show that there is no evidence that natural seismic activity poses a significant risk for loss of CO_2 for the project. The MRV plan states that this is due, in part, to the thickness, ductility, and predominance of clay in the primary confining layer, the Reef Ridge shale. EHCP states that the State Geologist of the California Division of Mines and Geology (CDMG) has not identified any active faults in the EHCP area. Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west, beyond the Temblor Range) and the White Wolf Fault (25 miles southeast from the EHOF).

Furthermore, EHCP states that based on historical seismic data from the Southern California Earthquake Data Center (SCEDC) dating back to 1932, there have been no earthquakes recorded greater than a 3.0 magnitude in the A1-A2 and 26R MMA. This data also showed that there have been eleven earthquakes with a magnitude of 5.0 or greater within a 30-mile buffer around the EHOF administrative boundary. The MRV plan states that there have been 518 earthquakes with a magnitude between 3.0 and 5.0 within the 30-mile EHOF buffer. EHCP states that the average depth of earthquakes with a magnitude greater than 3.0 is 4.5 miles, while the storage reservoirs are one mile below the surface.

The MRV plan states that induced seismicity will be mitigated operationally by keeping reservoir pressure at or below the discovery pressure and by keeping injection pressure lower than the failure pressure of the confining Reef Ridge shale.

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

3.4 Previous Operations

EHCP states that the likelihood of leakage via this pathway is considered low, but that the leakage risk is greatest when pressures are highest (generally during the end of the injection period). The MRV plan states that any possible leakages are predicted to be less than one percent of total mass injected (less than 0.5 million metric tons). The MRV plan also states that all the existing wells at the EHCP have been permitted through CalGEM (and predecessor California agencies) under rules that require detailed information about the character of the geologic setting, the construction and operation of the wells, and other information used to assess the suitability of the site. EHCP has assessed internal databases as well as CalGEM information to identify and confirm wells within the project area. Furthermore, the MRV plan states that there have been no undocumented historical wells found during the development history of the reservoir, including wells used for injection of water and gas. EHCP's operational experience verifies that there are no unknown wells within the EHCP. EHCP asserts that they have sufficiently mitigated the possibility of migration from older wells by continuously checking for the presence of old, unknown wells throughout the EHCP. Therefore, the practices ensure that identified wells are sufficiently isolated and do not interfere with ongoing operations and reservoir pressure management.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected from previous operations.

3.5 Pipeline/Surface Equipment

EHCP states that the likelihood of leakage via pipeline and surface equipment is classified as low throughout the project time period. EHCP states that unplanned leakage from surface facilities will be mitigated to the maximum extent practicable by relying on the use of prevailing design and construction practices and maintaining compliance with applicable regulations. The MRV plan states that the facilities and pipelines will be constructed of materials and managed using control processes that are standard for CO_2 injection projects. Furthermore, the MRV plan states that CO_2 delivery to the complex will comply with all applicable regulations, including any pipeline regulations that are updated in the future.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through pipeline/surface equipment.

3.6 Lateral Migration

The MRV plan states that it is not anticipated that injected CO_2 will migrate downdip and laterally outside the EHCP because of the buoyant properties of supercritical CO_2, the nature of the geologic structure, and the planned injection approach. The MRV plan states while leakage through lateral migration is not anticipated, the risk is greatest when pressures are highest at the end of the injection period. The MRV plan states that the magnitude of any leakage is considered negligible due to the above listed reasons. EHCP's strategy to minimize the lateral migration risk is to ensure that the CO_2 plume and surrounding fluids will be at or below the initial reservoir pressure at the time of discovery. Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through lateral migration.

3.7 Drilling through the CO_2 Area

EHCP states that the possibility of leakage caused by drilling through the CO_2 area is extremely low, but that the leakage risk is greatest during future time periods if drilling through the Reef Ridge confining zone were to occur. The MRV plan states that the magnitude of any leakage is considered negligible. The MRV plan also states that drilling through the Reef Ridge confining zone and into the Monterey Formation may occur at some point in the future. EHCP believes that the possibility of this activity creating a leakage pathway is extremely low for three reasons:

1. Future well drilling would be regulated by CalGEM (oil and gas wells) or EPA UIC (Class VI injection wells) and will therefore be subject to requirements that fluids be contained in strata in which they are encountered;
2. As sole operators and owners of the EHOF, CRC and CTV control the placement and timing of new drilling operations; and
3. There are no oil and gas targets beneath the Monterey Formation. Leakage via this pathway is not anticipated; however, leakage risk is greatest during future time periods if drilling through the Reef Ridge confining zone were to occur.

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

3.8 Diffuse Leakage through the Seal

The MRV plan states that diffuse leakage through the Reef Ridge confining layer is highly unlikely, and that the magnitude of any leakage is considered negligible. EHCP states that while leakage through the seal is not anticipated, the risk is greatest at the end of the injection period when pressures are highest. EHCP believes that the leakage through the seal is mitigated by ensuring that post injection reservoir pressure will be at or below the initial reservoir pressure at the time of discovery. The MRV also plan states that the injection monitoring program described in section 5 of the MRV plan assures that no breach of the seal will be created. Furthermore, the MRV plan states that the leakage risk will be reduced as the relative amount of CO_2 in the supercritical phase will decrease as CO_2 dissolves into the brine. Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected from diffuse leakage through the seal.

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

Under the provisions of 40 CFR 98.448(a)(3) an MRV plan requires a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Sections 4 and 5 of the MRV plan discuss the strategies EHCP will employ for monitoring 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)(3-4). Section 6 of the MRV plan discusses the strategies that EHCP will use for establishing expected baselines for CO_2 leakage. Monitoring will occur during the planned 27-year injection period, or otherwise the cessation of operations, plus a proposed 2-3 year post-injection period. A summary table of EHCP's response plan for CO_2 leakage or loss can be found in Table 4 of the MRV plan and copied below. A summary table of EHCP's injection monitoring strategy summary can be found in Table 5 of the MRV plan and copied below.

Risk	Monitoring Plan	Response Plan	Parallel Reporting (if any)
Loss of well control			
Tubing leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days	
Casing leak	Routine field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days	CalGEM or EPA UIC
Wellhead leak	Routine field inspection and continuous SCADA monitoring	Workover crews respond within days	
Loss of bottom-hole pressure control	Blowout during well operations	Maintain well-kill procedures; shut-in offset injectors prior to drilling	CalGEM or EPA UIC
Loss of seal in abandoned wells	Anomalous pressure or gas composition from productive shallower zones	Re-enter and reseal abandoned wells	CalGEM or EPA UIC
Leaks in surface facilities			
Pumps, valves, etc.	Routine field inspection and remote monitoring	Workover crews respond within days	Subpart W
Subsurface leaks			
Leakage along faults	Monitoring of zones above sequestration reservoir	Shut-in injectors near faults	EPA UIC
Leakage through induced fractures	Induced seismicity monitoring with seismometers	Comply with rules for keeping pressures below parting pressure	EPA UIC
Leakage due to a seismic event	Induced seismicity monitoring with seismometers	Shut-in injectors near seismic event	EPA UIC

Monitoring Activity	Frequency/Location
MIT (Internal and External)	Annual
SAPT	Initially; any time the packer is replaced or reset
Injection rate, pressure, and temperature	Continuous
Seismicity	Induced seismicity monitoring via seismometers
Underground sources of drinking water (USDWs) and reservoirs between USDWs and sequestration reservoir	Monitoring wells with pressure, temperature, fluid composition, and periodic cased-hole logs
Stream analysis	Continuous
Corrosion monitoring (coupons, casing integrity)	Well materials, pipelines, and other surface equipment
Sequestration reservoir monitoring	Dedicated wells monitoring sequestration reservoir with pressure, temperature, fluid composition, and periodic cased hole logs

The MRV plan states that existing operations are centrally monitored and controlled by the extensive and sophisticated Central Control Facility (CCF). The CCF uses a Supervisory Control and Data Acquisition (SCADA) software system to implement operational control decisions on a real-time basis throughout the EHCP to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits. Furthermore, the MRV plan states that flow rates, pressures, gas compositions, and other data will be collected at key points and stored in a centralized data management system. EHCP states that qualified technicians monitor these data 24 hours a day. These technicians follow response and reporting protocols when the system delivers notifications that data exceed predetermined statistically acceptable limits.

As stated in the MRV plan, potential sources of leakage include routine issues such as problems with surface equipment (pumps, valves, etc.), subsurface equipment, and unique events such as induced fractures. If leakage occurs, EHCP states that they plan to determine the most appropriate methods for quantifying the mass of CO_2 leaked and will report it as required as part of the annual Subpart RR submissions. The MRV plan states that any mass of CO_2 detected leaking to surface will be quantified using acceptable emissions factors such as those found in 40 CFR 98.230-238 (Subpart W), or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as frequency of inspection.

4.1 Detection of Leakage through Existing Wellbores

The MRV plan states that EHCP will continuously monitor wellbores for leakage in the following ways:

1. The MRV plan states that injection well pressure is continuously monitored throughout the EHCP using a SCADA system. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such excursions occur, EHCP would investigate and address these changes.

2. The MRV plan states that experience gained over time allows for a strategic approach to well maintenance and workovers. For example, EHCP states that well classifications by age and construction method inform planning for monitoring and updating wells. EHCP will use all available information, including pattern performance and well characteristics, to determine well maintenance schedules.

3. The MRV plan states that a corrosion protection program for CO_2 operations will be implemented to mitigate both internal and external corrosion of casing in wells in the EHCP. Procedures will be performed to prevent and monitor for corrosion.

4. The MRV plan states that Mechanical Integrity Test (MIT) requirements implemented by CalGEM and/or EPA UIC (as applicable) will be followed to periodically inspect wells and surface facilities to ensure that all wells and related surface equipment are in good repair, leak-free, and that all aspects of the site and equipment conform with existing relations and permit conditions. All active injection wells undergo MIT before injection, after any workover, or per time periods specified in the UIC approval. If a well fails the MIT, the operator must immediately shut the well in and provide notice to CalGEM. Casing leaks must be successfully repaired within 180 days and re-tested, or the well must be plugged and abandoned after submitting a formal notice and obtaining approval from CalGEM.

5. The MRV plan states that field inspections are conducted on a routine basis by field personnel. Leaking CO_2 is very cold and leads to the formation of bright white clouds and ice that are easily spotted. All field personnel will be trained to identify leaking CO_2 and other potential problems in the field and to safely remedy the issue.

6. The MRV plan states that Corrective Action assessment pursuant to the Class VI regulation includes the generation and detailed review of wellbore/casing diagrams for each well in the project area.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, EHCP concludes that it will mitigate CO_2 leakage through wellbores by detecting problems as they arise and quantifying any leakage that does occur by use of local surface air monitoring in the vicinity of the leaking wellbore.

Thus, the MRV plan provides adequate characterization of EHCP's approach to detect potential leakage through existing wellbores as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through Faults and Fractures

The MRV plan states that the operating history of the EHCP confirms that there are no faults or fractures penetrating the Reef Ridge shale that allows fluid migration. Nevertheless, EHCP states that they will monitor zones above the sequestration reservoir to monitor for leakage along faults. EHCP will also monitor induced seismicity with seismometers to monitor leakage through induced fractures.

Thus, the MRV plan provides adequate characterization of EHCP's approach to detect potential leakage through faults and fractures as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage through Natural or Induced Seismic Activity

The MRV plan states that there is no evidence that natural seismic activity poses a significant risk for loss of CO_2 for the EHCP. Furthermore, induced seismicity will be mitigated by maintaining a reservoir pressure at or beneath the discovery pressure and by keeping the injection pressure lower than the failure pressure of the confining Reef Ridge shale. However, the MRV plan states that seismometers will be installed at the surface to detect seismicity induced by injection operations.

Thus, the MRV plan provides adequate characterization of EHCP's approach to detect potential leakage through natural or induced seismic activity as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage from Previous Operations

EHCP states that they have sufficiently mitigated the possibility of migration from older wells by checking for the presence of old, unknown wells throughout the EHCP. Therefore, the MRV plan states that leakage via this pathway is not anticipated. Nevertheless, EHCP states that they will use anomalous pressures or gas compositions from productive shallower zones to monitor for loss of seal in abandoned wells.

Thus, the MRV plan provides adequate characterization of EHCP's approach to detect potential leakage from previous operations as required by 40 CFR 98.448(a)(3).

4.5 Detection of Leakage through Pipeline and Surface Equipment

The MRV plan states that unplanned leakage from surface facilities will be mitigated to the maximum extent practicable by relying on the use of prevailing design and construction practices and maintaining compliance with applicable regulations. EHCP states that instrumentation will be installed on pipelines and facilities that allow the operation's staff at the CCF to monitor the process 24/7 and potentially spots leaks. The MRV plan also states that frequent and routine visual inspections of surface facilities by field staff provides an additional means to detect leaks. Both manual and automatic shutdowns will be installed in the complex to ensure that leaks are addressed in a timely manner. Should leakage be detected from pipeline or surface equipment, EHCP states that it will quantify the mass of released CO_2 following the requirements of 40 CFR 98.230-238 (Subpart W).

Thus, the MRV plan provides adequate characterization of EHCP's approach to detect potential leakage through pipeline and surface equipment as required by 40 CFR 98.448(a)(3).

4.6 Detection of Leakage through Lateral Migration

The MRV plan states that CO_2 leakage through lateral migration is highly improbable. Even so, the MRV plan states that monitoring wells to measure pressure, temperature, and fluid composition will be dedicated to geologic sequestration. These dedicated wells will monitor the sequestration reservoir, zones above the sequestration reservoir, and the underground source of drinking water (USDW). The MRV plan also states that measured increases in CO_2 in groundwater above the Storage Complex will be used to develop groundwater isoconcentration maps and to quantify CO_2 leakage rates.

Thus, the MRV plan provides adequate characterization of EHCP's approach to detect potential leakage through lateral migration as required by 40 CFR 98.448(a)(3).

4.7 Detection of Leakage from Drilling through the CO_2 Area

The MRV plan states that it is possible that at some point in the future, drilling through the Reef Ridge confining zone and into the Monterey Formation may occur. While the MRV plan states that the possibility of this activity creating a leakage pathway is extremely low, EHCP will still have ways to detect leakage from drilling through the CO_2 area through ongoing regulation of all drilling activities. The MRV plan states that blowouts during well operations will be used to detect loss of bottom-hole pressure control.

Thus, the MRV plan provides adequate characterization of EHCP's approach to detect potential leakage through the CO_2 area as required by 40 CFR 98.448(a)(3).

4.8 Detection of Leakage through the Seal

The MRV plan states that diffuse leakage through the Reef Ridge confining layer is highly unlikely. The MRV plan also states that monitoring wells to measure pressure, temperature, and fluid composition will be dedicated to geologic sequestration. These dedicated wells will monitor the sequestration reservoir, zones above the sequestration reservoir, and the USDW. Any deviation from the baseline analysis will be assessed for potential indications of leakage. A measured increase in CO_2 in groundwater above the Storage Complex will be used to develop groundwater isoconcentration maps and quantify CO_2 leakage rates.

Thus, the MRV plan provides adequate characterization of EHCP's approach to detect potential leakage through the seal as required by 40 CFR 98.448(a)(3).

4.9 Determination of Baselines

Section 6 of the MRV plan identifies the strategies that EHCP will use to establish the baselines for monitoring CO_2 surface leakage per §98.448(a)(4). EHCP will use automatic data systems to identify and investigate deviations from expected performance that could indicate CO_2 leakage. The MRV plan states that these data systems are used primarily for operational control and monitoring, and as such, are set to capture more information than is necessary for reporting in the Annual Subpart RR Report. EHCP will develop necessary system guidelines to capture the information that is relevant to identify CO_2 leakage.

Visual Inspections

The MRV plan states that methods to capture work orders that involve activities that could potentially involve CO_2 leakage will be developed, if not currently in place. Examples of such work orders might include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. The MRV plan also states that each incident will be flagged for review by the person responsible for MRV documentation. Consequently, the MRV plan states that the Annual Subpart RR Report will include an estimate of the amount of CO_2 leakage.

Personal Gas Monitors

The MRV plan states that CO_2 gas monitors are worn by all field personnel (detection value of 1,000 parts per million (ppm) or lower). Such a monitor alarm will trigger an immediate response to ensure personnel are not at risk and to verify the monitor is working properly. If a fugitive leak is discovered, EHCP states that it would quantify the leak and determine needed mitigation actions. The MRV plan also states that the person responsible for MRV documentation will receive notices of all incidents where gas is confirmed to be present. As such, the Annual Subpart RR Report will provide an estimate of the amount of CO_2 emitted from any such incidents.

Monitoring Wells

The MRV plan states that baseline data will be collected from each monitoring well during well construction to provide a baseline. Baseline data will also be collected on sequestration zone fluid chemistry and pressure, and above confining zone water chemistry and pressure at monitoring well locations. Data will be acquired that is characteristic of the subsurface after showing data stabilization. Quarterly fluid sampling and continuous pressure/temperature monitoring will be conducted at groundwater monitoring wells above the confining zone during the baseline period. In the injection zone fluid chemistry sampling will occur once at each location and temperature/pressure will be monitored continuously during the baseline period.

Seismic Baseline

The MRV plan states that the seismic monitoring network will be installed during the construction phase. Baseline seismicity data will be collected from the seismic monitoring network for at least 12 months prior to first injection to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. The MRV plan states that these data will help establish historical natural seismic event depth, magnitude, and frequency to distinguish between naturally occurring seismicity and induced seismicity resulting from the CO_2 injection.

Injection Rates, Pressures, and Mass

The MRV plan states that target injection rates and pressures will be developed for each injector, based on the results of ongoing modeling and permitted limits. EHCP programs high and low set-points into the controllers, and flags are identified whenever statistically significant deviations from the targeted ranges are identified. The MRV plan states that flags (or excursions) will be screened to determine if they could also lead to CO_2 leakage to the surface. The MRV plan states that the person responsible for MRV documentation will receive notice of excursions and related work orders that could potentially involve CO_2 leakage. As such, the Annual Subpart RR Report will provide an estimate of the amount of CO_2 emitted from any such incidents.

Thus, the EHCP provides an acceptable approach for establishing expected baselines in accordance with 40 CFR 98.448(a)(4).

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

Section 7 of the MRV plan provides the equations that EHCP will use to calculate sequestration masses.

5.1 Calculation of Mass of CO_2 Received

EHCP states that Equation RR-1, as indicated in 40 CFR 98.443, will be used to calculate the mass of CO_2 received from each custody-transfer meter immediately downstream of the source(s).

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \qquad \text{(Eq. RR-1)}$$

Where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).

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

p = Quarter of the year.

r = Receiving flow meter.

The MRV plan states that given EHCP's method of receiving CO_2 and the requirements of 40 CFR 98.444(a):

- All delivery to the EHCP is used, so quarterly flow redelivered, $S_{r,p}$, is zero ("0") and will not be included in the equation.
- CRC and CTV will sum to total mass of CO_2 Received using Equation RR-3 in 40 CFR 98.443:

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \text{ (Eq. RR-3)}$$

Where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 for flow meter r.

r = Receiving flow meter.

EHCP provides an acceptable approach for calculating the mass of CO_2 received under Subpart RR.

5.2 Calculation of Mass of CO_2 Injected into the Subsurface

The MRV plan states that the annual mass of CO_2 injected into the subsurface at the EHCP at each injection well will be calculated with Equation RR-4:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \text{ (Eq. RR-4)}$$

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 MRV plan states that the aggregated injection at all injection wells will be calculated with Equation RR-6:

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \quad \text{(Eq. RR-6)}$$

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.

EHCP provides an acceptable approach for calculating the mass of CO_2 injected into the subsurface.

5.3 Calculation of Mass of CO_2 Emitted by Equipment Leakage

The MRV plan states EHCP will calculate and report the total annual mass of CO_2 emitted by equipment leakage using an approach that is tailored to specific leakage events and relies on 40 CFR 98.230-238 (Subpart W) equipment leakage reports. The MRV plan states that estimates of the amount of equipment leakage will depend on several site-specific factors including measurements, engineering estimates, and emissions factors depending on the source and nature of the leakage.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

The MRV plan states that the process for quantifying surface leakage will entail using best engineering principles or emissions factors. The MRV plan also states that, in the event leakage to the surface occurs, the quantity and leakage amounts will be reported, and records retained that describe the methods used to estimate or measure the mass leaked as reported in the Annual Subpart RR Report.

The MRV plan states that Equation RR-10 in 40 CFR 98.443 will be used to calculate and report the mass of CO_2 emitted by surface leakage.

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \text{ (Eq. RR-10)}$$

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.

EHCP provides an acceptable approach for calculating the mass of CO_2 emitted by surface leakage under Subpart RR.

5.5 Calculation of Mass of CO_2 Sequestered in Subsurface Geologic Formations

The MRV plan states that Equation RR-12 in 40 CFR 98.443 will be used to calculate the mass of CO_2 sequestered in subsurface geologic formations in the reporting year as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \text{ (Eq. RR-12)}$$

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 by surface leakage (metric tons) 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.

EHCP provides an acceptable approach for calculating the mass of CO_2 sequestered in subsurface geologic formations.

5.6 Calculation of Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formations

The MRV plan states that a sum of the total annual mass obtained using RR-12 in 40 CFR 98.443 will be used to calculate the cumulative mass of CO_2 sequestered in subsurface geologic formations.

6 Summary of Findings

The Subpart RR MRV plan for California Resources Corporation's CTV/CRC Elk Hills Carbon Project facility meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in EHCP's MRV plan.

Subpart RR MRV Plan Requirement	EHCP MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 3 of the MRV plan delineates and describes the MMA and AMA. The MMA is defined by the extent of the CO_2 plume at 100 years post injection for geologic sequestration plus one-half mile. The AMA is assumed to be functionally equivalent to the MMA since the CO_2 is predicted to reach the edges of the reservoir within the first two to three years of injection.
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 4 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: existing wellbores, faults and fractures, natural and induced seismic activity, previous operations, pipeline/surface equipment, lateral migrations outside the EHCP, drilling through the CO_2 area, and diffuse leakage through the seal. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Sections 4 and 5 of the MRV plan describe the strategies that EHCP will use to detect and quantify potential CO_2 leakage to the surface should it occur. The MRV plan identifies the following quantification strategies: MITs, SCADA monitoring, routine field

	inspections, and induced seismicity monitoring. The MRV plan states that the process for quantifying leakage will entail using the best engineering principles or emission factors.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 6 of the MRV plan describes the strategies for establishing baselines against which monitoring results will be compared to assess potential surface leakage. EHCP will use automatic data systems to identify and investigate deviations from expected performance that could indicate CO_2 leakage. EHCP's approach to collecting information for the determination of baselines includes visual inspections; personal gas monitors; monitoring wells, seismic baselines, and the monitoring of injection rates, pressures, and mass of CO_2.
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 7 of the MRV plan describes EHCP's approach to determining the total amount of CO_2 sequestered using the Subpart RR mass balance equations, including calculation of total annual mass emitted by equipment leakage.
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 11.5 of the MRV plan identifies the injection and monitoring wells used in the EHCP. The EHCP has submitted a Class VI UIC permit application.
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 8 of the MRV plan states that it is anticipated that the EHCP will be implemented as early as the first quarter (Q1) of 2025 pending appropriate permit approvals and an available CO_2 source, or within 90 days of EPA approval, whichever occurs later.

Appendix A: Final MRV Plan

Elk Hills A1-A2 and 26R CO_2 Subpart RR Monitoring, Reporting, and Verification Plan

Version Date: 11/29/2023

1 Contents

Overview

The Elk Hills Oil Field (EHOF), covering 75 square miles, was discovered in 1911 and has produced over 2 billion barrels of oil equivalent (BOE), making it one of the most productive fields in the United States. California Resources Corporation (CRC) and Carbon TerraVault (CTV; a CRC wholly owned subsidiary), owns 100% of the surface, mineral, and pore space rights at the EHOF.

CTV intends to inject and store a measurable quantity of carbon dioxide (CO_2) in subsurface geologic formations at the EHOF, for a term of 27 years referred to as the "Specified Period." During the Specified Period, CO_2 will be injected from anthropogenic sources such as the Elk Hills 550 megawatt (MW) natural gas combined cycle power plant (EHPP), bio-diesel refineries, and other sources in the EHOF area.

The CO_2 will be injected into the Monterey Formation A1-A2 and 26R reservoirs for dedicated geologic storage. The Elk Hills storage complex will be pre-certified and monitored to verify permanent CO_2 sequestration. Class VI applications have been submitted for the A1-A2 and 26R reservoir.

This EHOF monitoring, reporting, and verification (MRV) plan is based on decades of subsurface characterization and simulation of the targeted Monterey Formation. This empirically driven analysis indicates that the natural geologic seal that overlays the entire EHOF, known as the Reef Ridge shale, will provide a physical trap that will permanently prevent injected CO_2 from migrating to the surface.

This MRV plan documents the following in accordance with 40 CFR 98.440-449 (Subpart RR):

- Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA), 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,
- Strategy for detecting and quantifying any surface leakage of CO_2,
- Strategy for establishing the expected baselines for monitoring CO_2 surface leakage,
- Summary of considerations for calculating EHOF-specific variables for the mass balance equation, and
- Proposed date to begin collecting data for calculating total CO_2 sequestered.

1 Facility Information

i. Reporter number – 582061

ii. Existing wells in the EHOF including production, injection, and monitoring wells are permitted by California Geologic Energy Management Division (CalGEM) through California Public Resources Code Division 3.[1]

iii. Wells injecting CO_2 for geologic storage will be permitted with the United States Environmental Protection Agency (EPA) Underground Injection Control (UIC) program for Class VI injection.

[1] Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

iv. Wells in the EHOF are identified by name, American Petroleum Institute (API) number, status, and type. The list of wells as of March 2023 associated with the geologic storage projects is included in Appendix 11.5. Any new wells or changes to wells will be indicated in the annual report.

2 Project Description

The EHOF is one of the largest oil and natural gas fields in the United States, with production from multiple vertically stacked reservoirs. Turbidite sand deposits of the Miocene Monterey Formation will serve as the injection targets in two separate anticlinal structures, Northwest Stevens (NWS) and 31S (Figures 1a, 1b).

Numerous aspects of the geology, facilities, equipment, and operational procedures for A1-A2 and 26R are consistent throughout the field. As such, one MRV report will satisfy the 26R and A1-A2 reservoirs as shown in Table 1. The A1-A2 and 26R reservoir and well locations within the field are shown in Figure 1a.

Structure	Reservoir	Sequestration Type	Number of Injectors
31S	26R	Geologic : Class VI	4
NWS	A1-A2	Geologic : Class VI	2

Table 1: Reservoirs within the EHOF and sequestration type.

2.1 Project Characteristics

The potential CO_2 stored over the project duration is up to 48 million metric tons (refer to Table 2 for breakdown). For accounting purposes, the amount stored is the difference between the amount injected less any CO_2 that i) leaks to the surface, or ii) is released through surface equipment leakage or malfunction. Actual amounts stored during the Specified Period of reporting will be calculated as described in Section 7 of this MRV Plan.

2.2 Environmental Setting

The project site for this MRV plan is the EHOF, located in the San Joaquin Basin, California (Figure 2).

2.2.1 Geology of Elk Hills Oil Field

The EHOF is located 20 miles southwest of Bakersfield in western Kern County, producing oil and gas from several vertically stacked reservoirs formed in the Tertiary period (65 million to 2 million years ago). Of the more than 24,000 feet (ft) of sediment deposited, the most prolific reservoir is the Miocene epoch Monterey Formation that is the target CO_2 sequestration reservoir.

Individual layers within the Monterey Formation are primarily interbedded sandstone and shale. These layers have been folded, resulting in anticlinal structures containing hydrocarbons formed from the deposition of organic material approximately 33 million to 5 million years ago (during the Oligocene and Miocene epochs). The combination of multiple porous and permeable sandstone reservoirs interbedded with impermeable shale seals makes the EHOF one of the most suitable locations in North America for the extraction of hydrocarbons and the sequestration of CO_2.

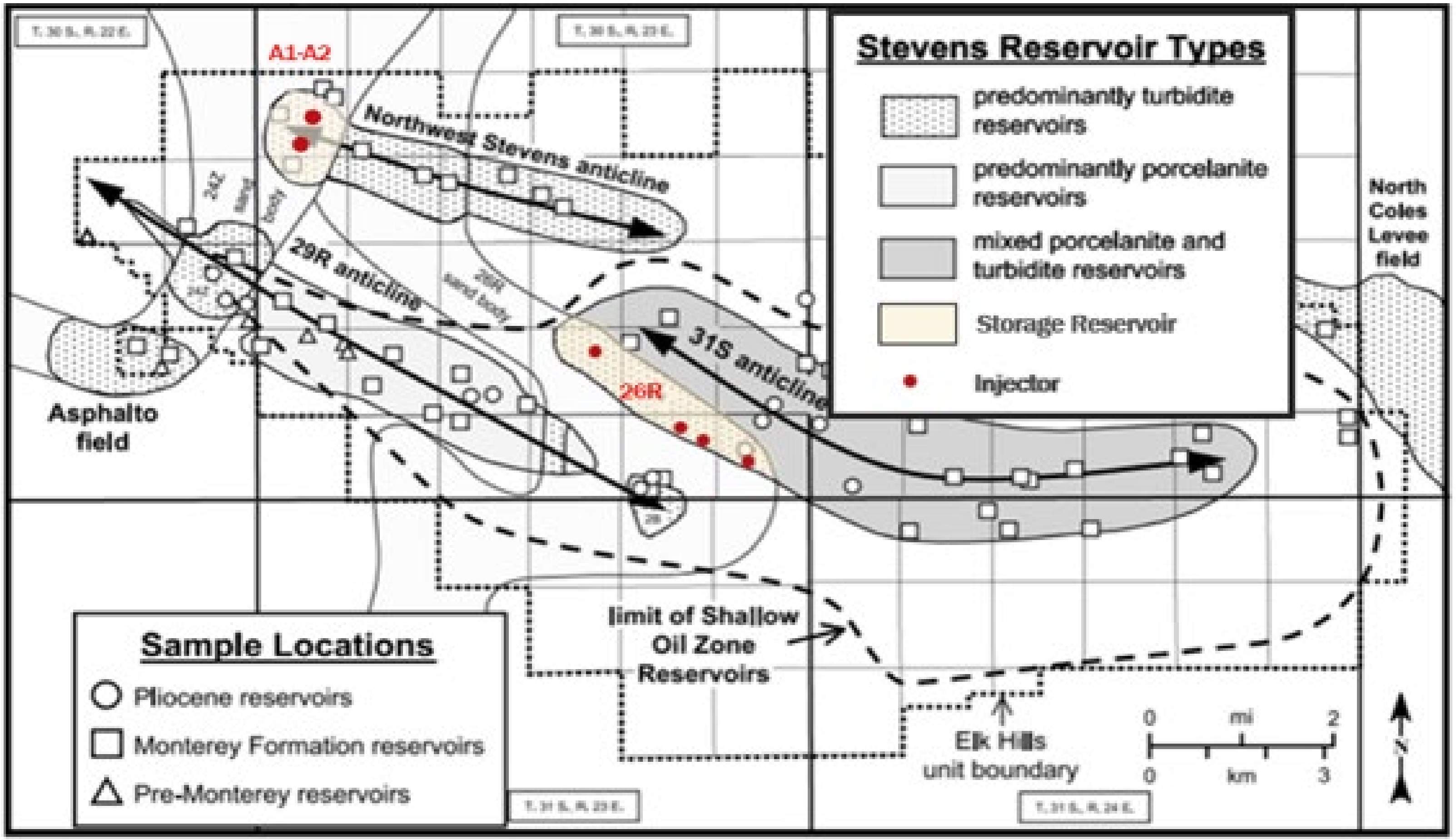


Figure 1a: EHOF map of injection target and injection well locations.

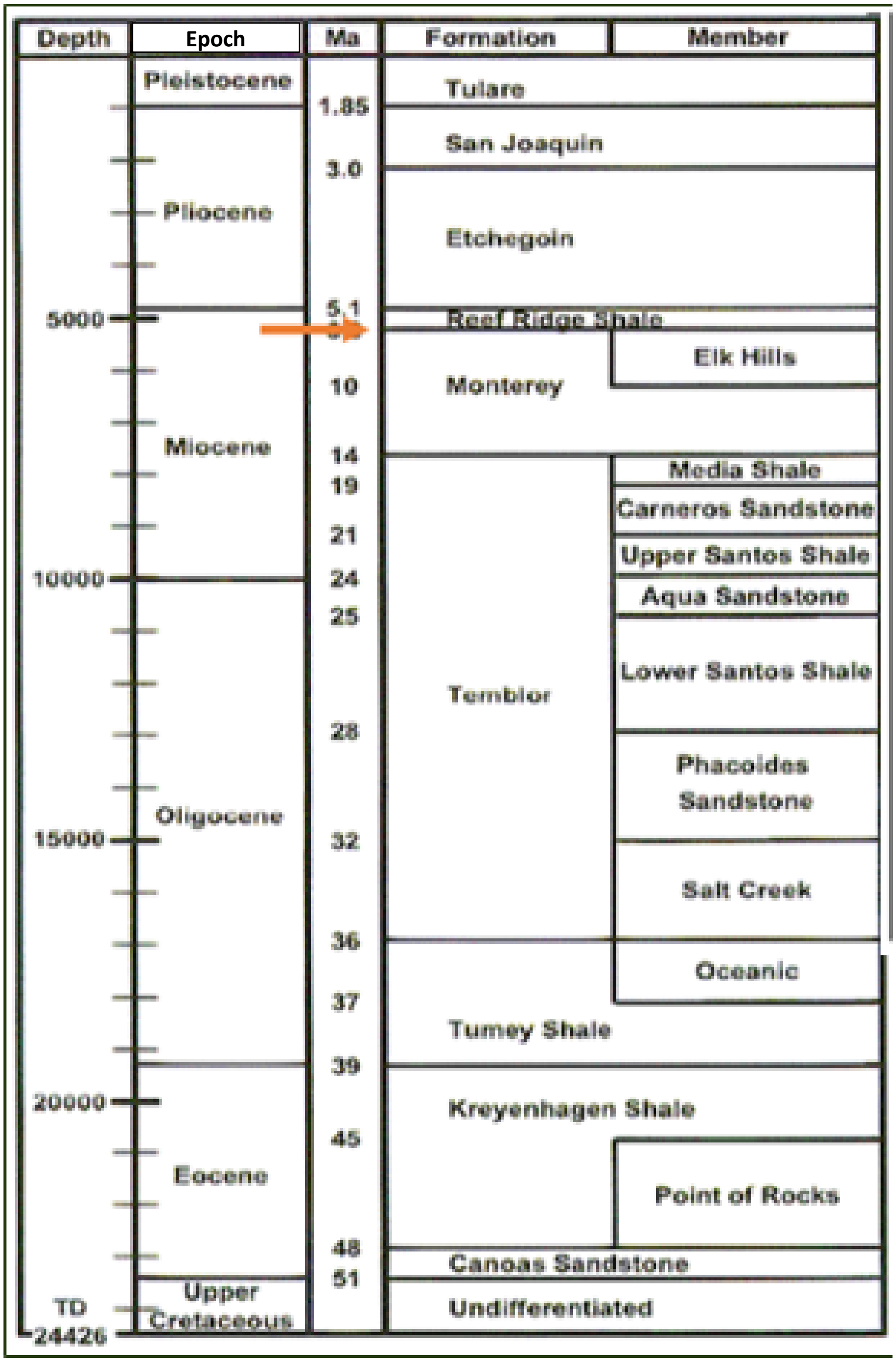


Figure 1b: EHOF stratigraphic column.

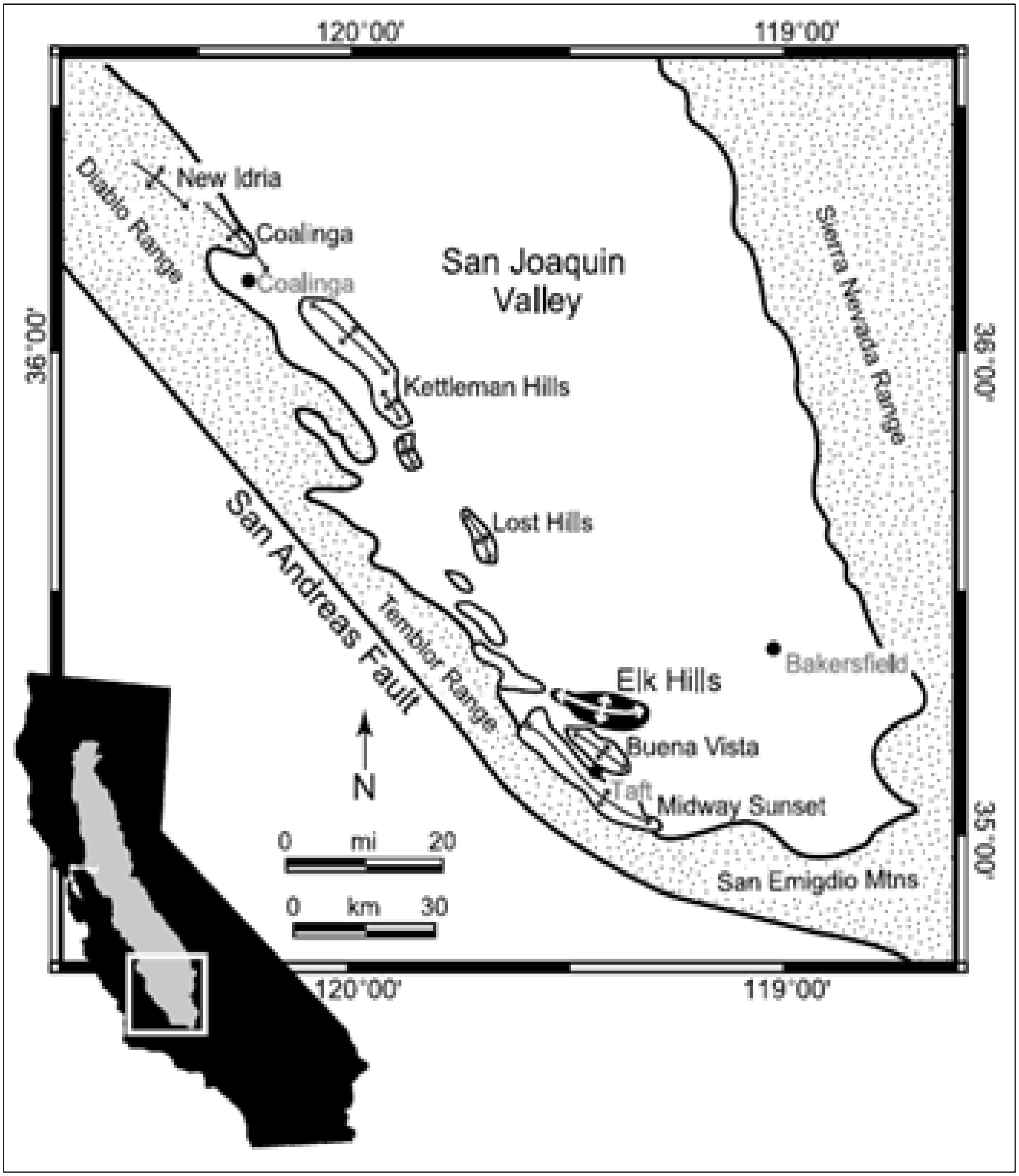


Figure 2: Location of Elk Hills Oil Field, San Joaquin Basin, California.

Following its deposition, Monterey Formation sediments were buried under more than 750 ft of impermeable silty and sandy shale that comprise the confining Reef Ridge shale. The Reef Ridge shale serves as the primary confining layer over the Monterey because it effectively seals underlying fluids from the overlying formations. Above the Reef Ridge lies several alternating sand-shale sequences of the Pliocene Etchegoin and San Joaquin Formations and Pleistocene Tulare Formation. These formations are highlighted in the cross-section in Figure 3.

As indicated in Figure 1a, the 31S and NWS structures represent structural highs, or anticlines, within the EHOF. The elevated areas form a natural trap for oil and gas that migrated from below over millions of years. Once trapped at these high points, the oil and gas has remained in place. In the case of the EHOF, the oil and gas has been trapped in the reservoir for more than 6 million years.

Based on physical site characterization and analysis of historic operating records from the Monterey Formation, there is sufficient reservoir capacity and flow properties to inject and store the entire volume of CO_2 proposed as determined by computational modeling (Table 2).

	Volume (million metric tons)
A1-A2 geologic storage	10
26R geologic storage	38
Total storage capacity	48

Table 2: Calculation of cumulative net fluid volume produced for the Monterey Formation sequestration reservoir.

Stored CO_2 will be contained securely within the EHOF Monterey Formation as demonstrated by 1) preservation of hydrocarbon accumulations over geologic time; 2) subsequent water and gas injection operations; 3) competency of the Reef Ridge confining zone over millions of years and throughout decades of primary and secondary operations; and 4) ample storage capacity of the A1-A2 and 26R reservoir. Confinement within the project area and in the reservoir will be ensured by limiting the pressure of the reservoir post-injection at or below the initial pressure of the reservoir at time of discovery.

2.2.2 Elk Hills Oil Field Operational History

McJannet (1996) reports on the early operating history of EHOF. By Executive Order, in 1912 President Taft designated the area surrounding EHOF as a naval oil reserve. Intended to ensure a secure supply of fuel for the Navy's oil-burning ships, the Executive Order defined "Naval Petroleum Reserve No. 1" (NPR-1). In 1977, President Carter signed the U.S. Department of Energy (DOE) Organization Act which transferred NPR-1 to the DOE. Nearly 20 years later, the DOE was directed to sell the assets of NPR-1. Occidental Petroleum ("Occidental") provided a winning bid of $3.65 billion, and on February 10, 1998, Occidental took over official ownership and operation of EHOF. In December 2014, Occidental Petroleum spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC.

The EHOF unit boundary is shown in orange below in Figure 4.

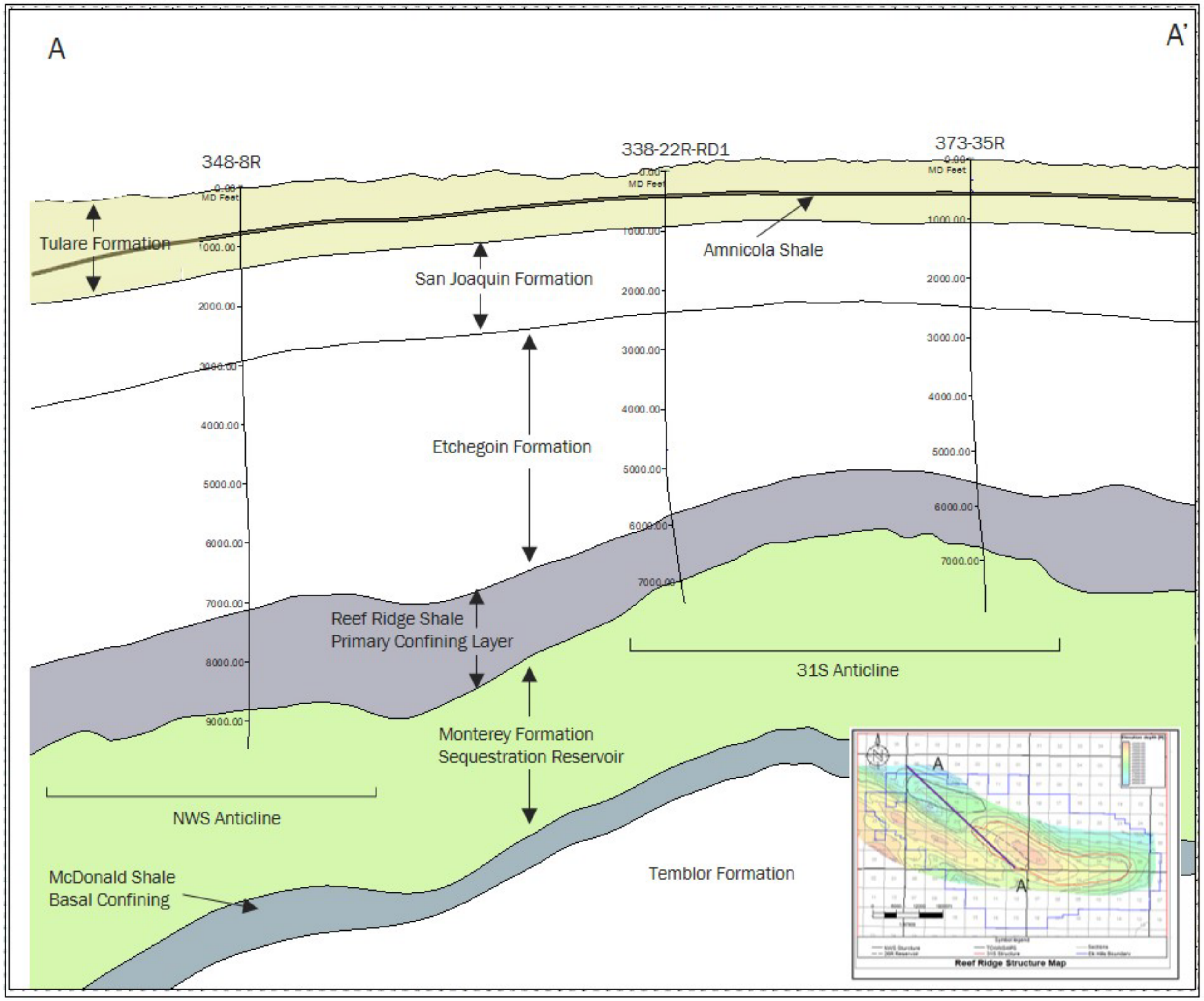


Figure 3: Stratigraphic schematic highlighting the NWS and 31S anticlines.

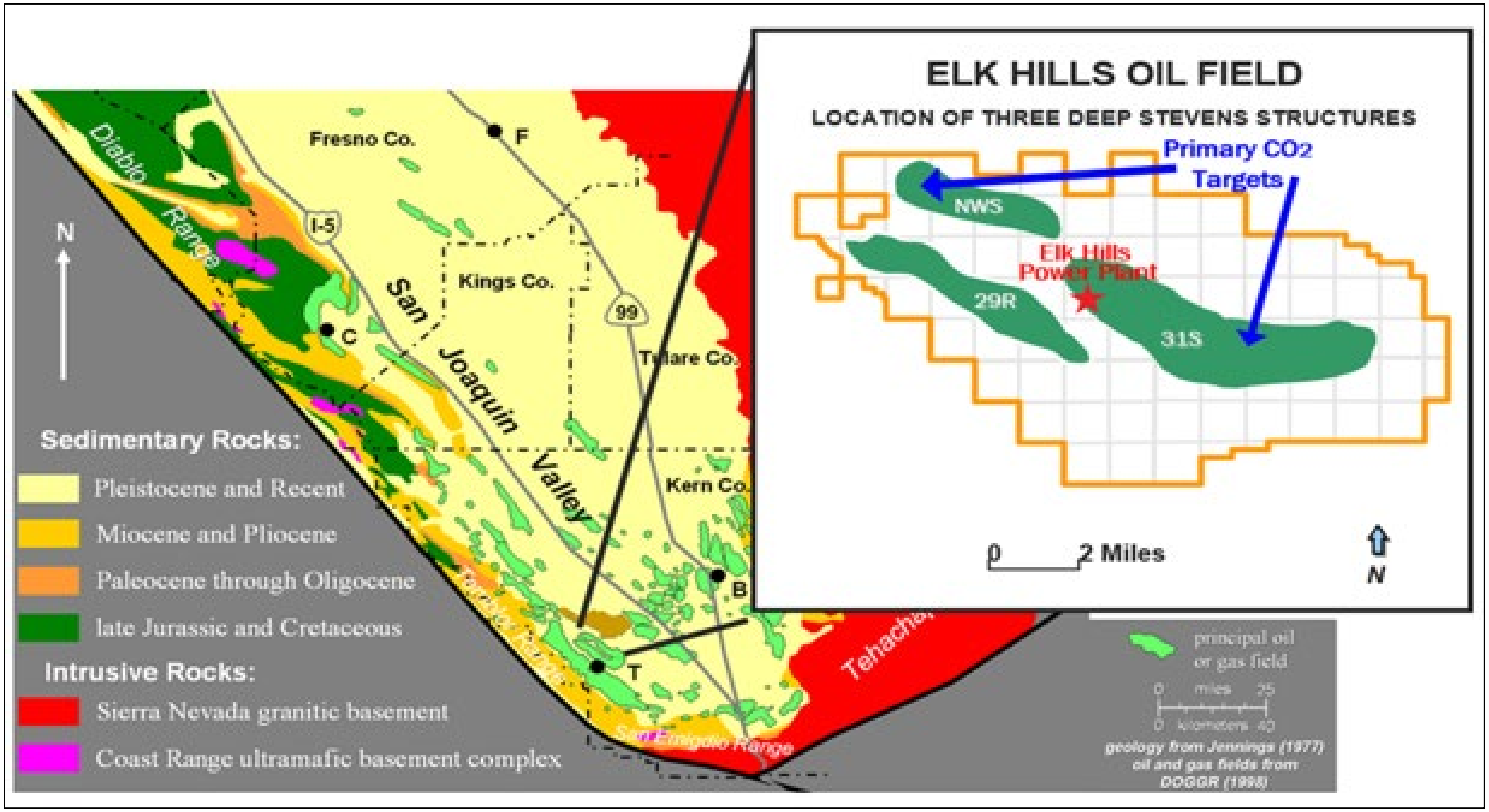


Figure 4: Location of Elk Hills Oil Field within San Joaquin Basin, California.

Development History

Selected primary drilling in the Monterey Formation began in the early 1940s, with concerted drilling and production operations commencing with the DOE's oversight in the late 1970s. To support reservoir pressure and maximize the oil recovery factor, extensive water and gas injection has occurred.

A successful CO_2 injection pilot was implemented in the Monterey Formation in 2005. Data from the four-month pilot confirmed the formation as an attractive target for CO_2 sequestration. This project assessed how much oil could be mobilized from the conventional sand reservoirs, how much CO_2 would be required to mobilize that oil, and how quickly the oil would be produced. Production performance and data collected before, during, and after the pilot operations showed that Monterey Formation reservoirs selected are ideal for CO_2 sequestration.

In addition, past development of the shallow Etchegoin Formation oil reservoirs and Monterey Formation has created a large pressure differential across the Reef Ridge shale, further demonstrating the lack of communication between the reservoirs.

2.3 Description of Facilities and Injection Process

A simplified flow diagram of surface facilities can be seen in Figure 5. This includes facilities outside the scope of the MRV including CO_2 source(s), and the subsequent metering locations between the MRV scope and those facilities. All facilities will be designed and built to ensure integrity and compatibility with CO_2. The subsequent parts of this section will review each of the following:

- CO_2 source,
- CO_2 distribution and injection, and
- Wells in the Class VI defined area of review (AoR) penetrating the Reef Ridge shale.

Facilities associated with dedicated geologic sequestration will be relatively simple as field production and re-compression process flows are unnecessary.

2.3.1 CO_2 Source

CTV plans to construct a carbon capture and sequestration (CCS) "hub" project (i.e., a project that captures CO_2 from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC-permitted injection well). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The anthropogenic CO_2 will be sourced from an onsite blue hydrogen plant (up to 200,000 metric tons per annum), with additional potential CO_2 from the EHPP, direct air capture (DAC), renewable diesel refineries, and/or other sources in the area.

All CO_2 sources will have custody-transfer metering to ensure accurate accounting of both the mass rate and impurities in the CO_2 stream. Anticipated hydrogen sulfide (H_2S) concentration in the injectate is 0.001 to 0.014%.

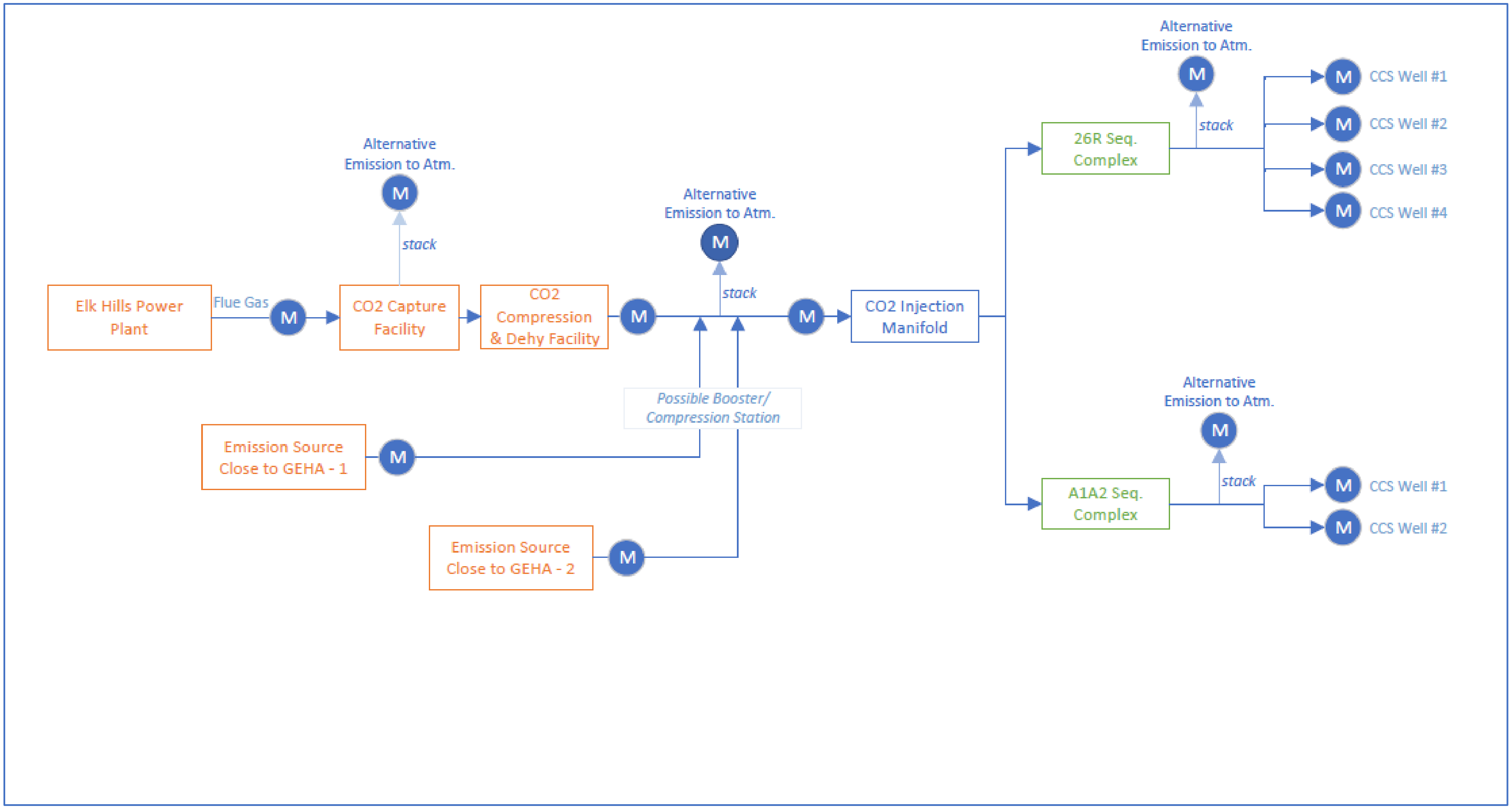


Figure 5: Facilities flow diagram for Carbon TerraVault carbon capture and sequestration project. Blue "M" symbols denote meter locations.

2.3.2 CO_2 Distribution and Injection

CO_2 from the sources previously discussed will be distributed throughout the field through a combination of new and existing infrastructure. This distribution infrastructure will allow CO_2 to be injected into CO_2 wells completed within the Monterey Formation at A1-A2 and 26R.

Each CO_2 injection well will have automated controls that provide for both control and measurement of the mass flow rate and pressure.

2.3.3 Wells in the AoR Penetrating the Reef Ridge Shale

CalGEM regulations govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields (other than UIC Class VI CO_2 injection wells that are regulated by the EPA UIC program). Current CalGEM rules require, among other provisions, the following conditions.

- Fluids must be constrained in the strata in which they are encountered.
- Activities governed by the regulations cannot result in the pollution of subsurface or surface waters.
- Wells must adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata in which they are encountered into strata with oil and gas, or into subsurface and surface waters.
- Operators must file a completion report including basic electric log (e.g., a density, sonic, or resistivity log acquired from the wellbore).
- Wells must follow plugging procedures that require advance approval from CalGEM and allow consideration of the suitability of the cement based on the use of the well, location and setting of plugs.

Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM at time of drilling and as part of the existing Class II UIC permit applications. Wells penetrating the Reef Ridge confining layer and storage reservoir are shown in Figure 6, and are listed in Table 3 categorized in groups that relate to the well status for each reservoir.

Completion Date	A1-A2 Reservoir Count	26R Reservoir Count
Oil and gas producing wells	79	145
Class II injection/disposal wells	32	22
Observation wells	0	2
Plugged and abandoned	39	35
TOTAL	**150**	**204**

Table 3: Wells penetrating Reef Ridge shale for each reservoir by status.

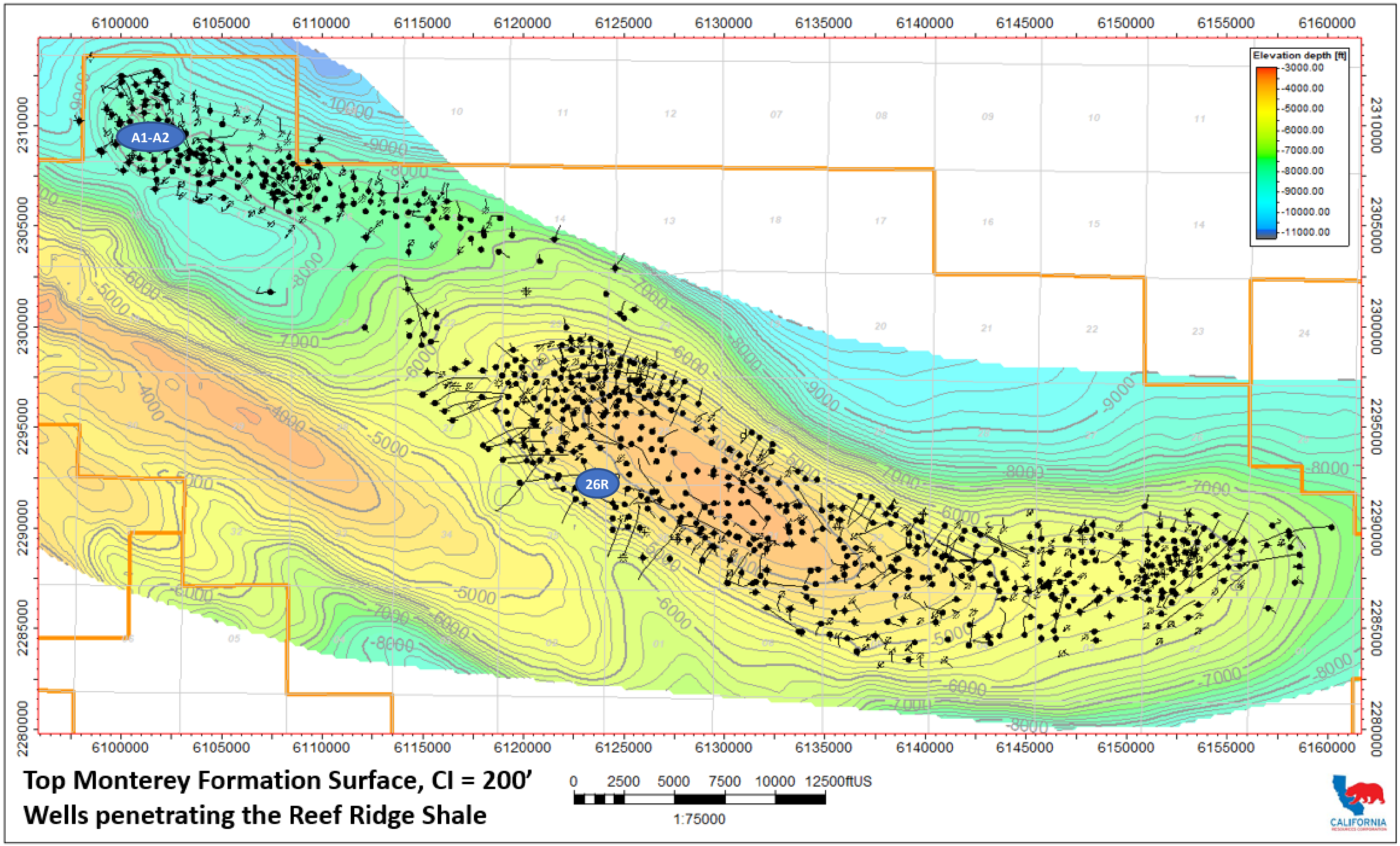


Figure 6: Wells penetrating the Reef Ridge shale. Project locations are shown at blue ovals.

Wells that penetrate the Reef Ridge shale (Table 3) were drilled between 1948 and 2014. Corrective action assessment of existing wellbores for the Class VI applications included the generation and detailed review of wellbore/casing diagrams for each well from CalGEM records. Information used in the review included depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top-of-cement determination supported the review for annular isolation.

Existing wellbores within the project areas will, where necessary and as approved by the UIC Director in the Class VI permit, be pressure tested, abandoned, re-abandoned, or have a technical demonstration of adequate zonal confinement. Corrective action will occur prior to the commencement of CO_2 injection or on an approved phased schedule after CO_2 injection commences if conditions allow.

Project injection and monitoring wells are listed in Section 11.5. Well workover crews are on-call to maintain active wells and to respond to any wellbore issues that arise. Incidents are detected by monitoring changes in the surface pressure of injection wells and by conducting Mechanical Integrity Tests (MITs) that include, but are not limited to, Radioactive Tracer Surveys (RTSs) and Standard Annular Pressure Tests (SAPTs).

All existing oil and gas wells, including both injection and production wells are regulated by CalGEM under Public Resources Code Division 3.

2.4 Reservoir Modeling

Numerical reservoir simulation is used for many purposes, including optimizing reservoir management, forecasting hydrocarbon and water production, predicting the behavior of injected fluids such as CO_2, and assessing CO_2 plume development and confinement.

2.4.1 Reservoir Model for Operational Design and Economic Evaluation

Reservoir modeling workflow begins with the development of a three-dimensional (3-D) representation of the subsurface geology (“static model”). Static model development leverages all available well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces and faults (if present) into a geocellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. CRC used Schlumberger Petrel, an industry-standard geocellular modeling software, to build and maintain the EHOF static model.

The static model becomes “dynamic” in the reservoir simulator with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon phase,
- Liquid and gas relative permeability,
- Capillary pressure data, and
- Fluid injection and/or extraction rates.

2.4.2 Performance Prediction

One objective of the simulation models is to develop an injection plan that maximizes CO_2 storage and minimizes associated costs. The injection plan includes injection wells and appropriate injection rate and pressure for each well that adheres to regulatory requirements.

2.4.3 Plume Model for CO_2 Storage Capacity, Containment, and Predicted Plume Migration

Full-field plume models confirm reservoir capacity and CO_2 containment within the 26R and A1-A2 reservoir. These models were built using a dynamic reservoir simulation application known as the Equation-of-State (EOS) Compositional Simulator (GEM), developed by Computer Modelling Group Ltd. (CMG). Figure 7 shows the results of the modeling for the 26R and A1-A2 storage reservoir. The plume models were used to evaluate: (1) the quantity of CO_2 stored for geological sequestration, and (2) the lateral movement of CO_2 to define the MMA and demonstrate vertical confinement by the Reef Ridge shale.

2.4.4 Geomechanical Modeling of Reef Ridge Shale

In addition to the plume models, a simpler GEM-based model was coupled with a finite element geomechanical module, GEOMECH, to model cap rock failure in the Reef Ridge shale as a function of cap rock mechanical properties and reservoir pressure immediately below the cap rock. This model was used to assess the pressure at which the Reef Ridge shale would shear through tensile failure.

The plume modeling effort confirms the Monterey Formation's ability to permanently store the planned project CO_2 volumes under the Reef Ridge shale over the project's life. The results of the plume models are discussed in greater detail below.

3 Delineation of Monitoring Area and Timeframes

3.1 Maximum Monitoring Area

The MMA is defined in 40 CFR 98.449 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. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data as described above, was used to predict the size and location of the plume, as well as understand how the plume migrates over time.

The MMA, shown by the blue line Figure 8 , is defined by the extent of the CO_2 plume at 100 years post-injection for geologic sequestration plus one-half mile.

3.2 Active Monitoring Area

The AMA boundary was established by superimposing two areas (40 CFR 98.449):

- Area #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.
- Area #2: The area projected to contain the free phase CO_2 plume at the end of year $t + 5$.

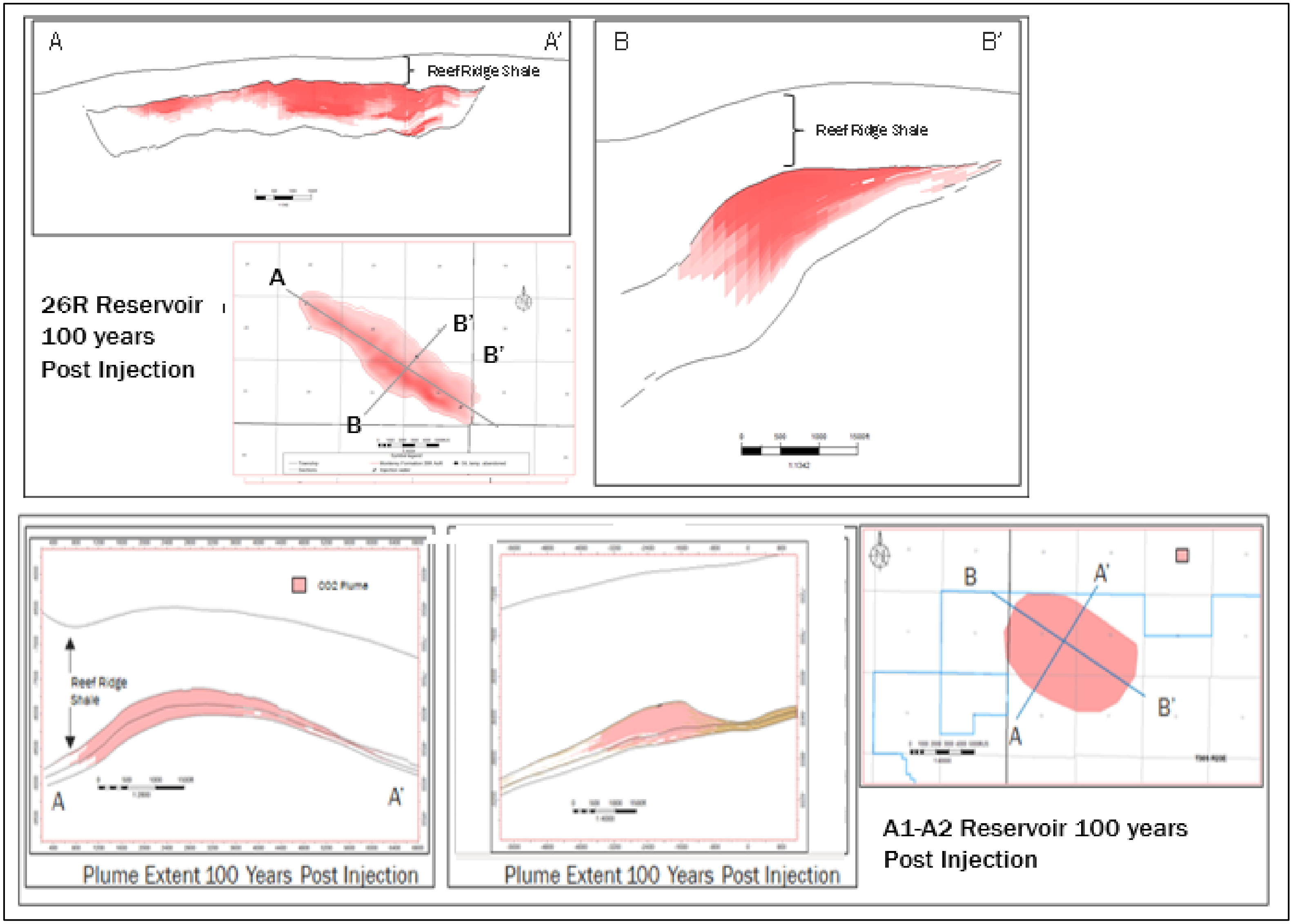


Figure 7: CO_2 plume modeling results.

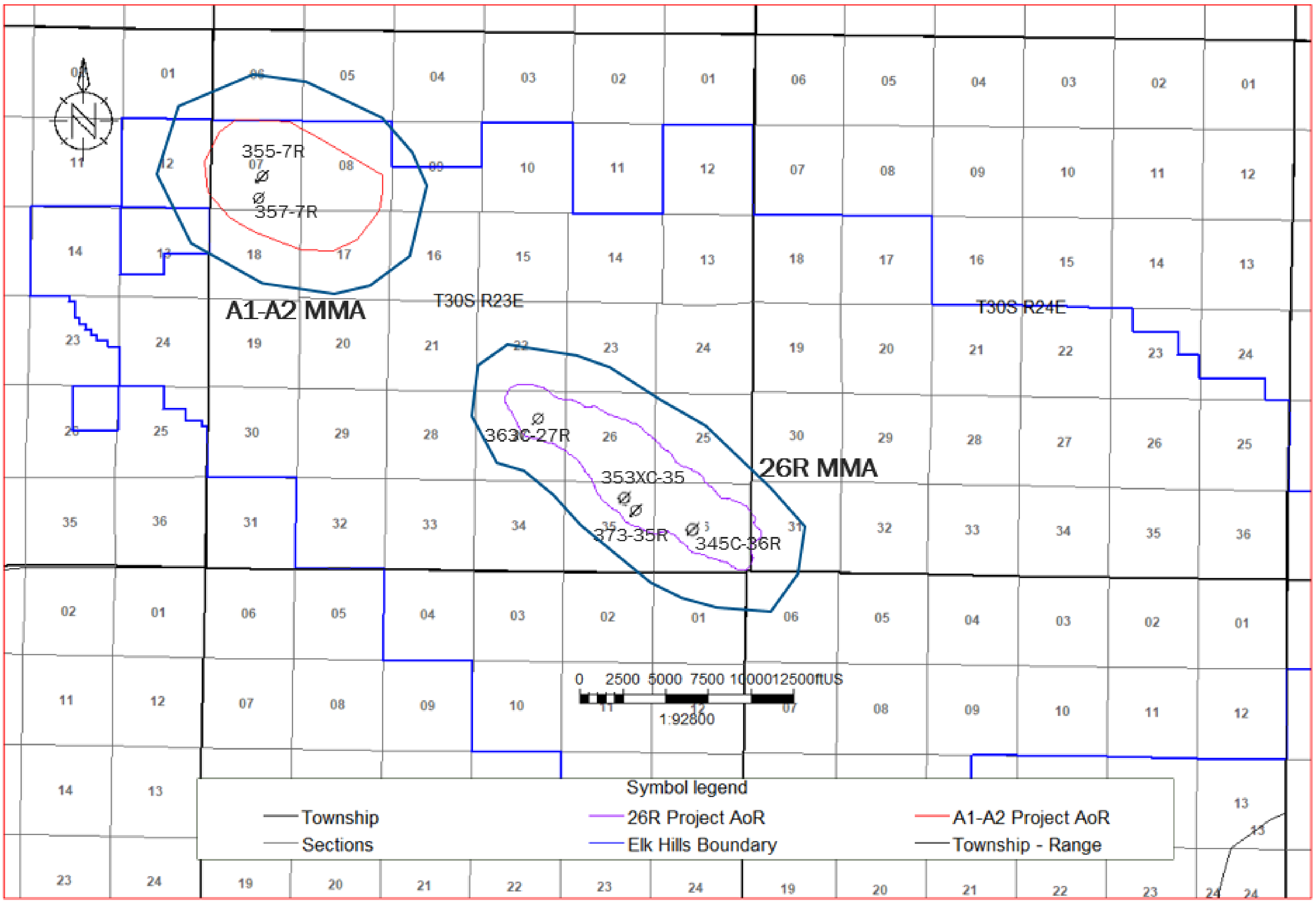


Figure 8: Injector well locations, EPA AoR (final CO_2 plume boundaries; orange and purple lines) and AMA - MMA (blue line). Scale bar units are feet.

The A1-A2 and 26R reservoirs are depleted and CO_2 is predicted to reach the edges of the reservoir within the first two to three years of injection (see Figures 9a, 9b). For this reason the area projected to contain free phase CO_2 is similar during the majority of the Specified Period.

The AMA boundary was determined for the time period ("*t*") corresponding to three years after the end of injection (30 years after the beginning of injection). Area #1, above, was taken as the plume area plus an all-around buffer zone of one-half mile. Area #2 is smaller or equal in all directions for both projects than Area #1, and therefore the final AMA was defined as Area #1 (Figure 8).

CTV has established one AMA boundary for 30 years and does not anticipate any expansion of the monitoring area under 40 CFR 98.448. Given the definitions used to define the MMA and AMA, AMA is also functionally equivalent to the MMA. Instituting monitoring throughout the entire MMA boundary for the Specified Period provides maximum operational flexibility. The absence of through-going faults or fractures confirms the competency of the Reef Ridge to preserve hydrocarbons within the Monterey Formation and to contain the CO_2.

3.3 Monitoring Timeframe

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted when a demonstration that current monitoring and model(s) show that the cumulative mass of CO_2 reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration within two to three years after injection for the Specified Period ceases based on predictive modeling supported by monitoring data.

4 Evaluation of Potential Pathways for Leakage to the Surface

4.1 Introduction

In the more than 100 years of the EHOF's development, the reservoir has been studied and documented extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO_2 to the surface. The following potential pathways are reviewed:

- Existing wellbores,
- Faults and fractures,
- Natural and induced seismic activity,
- Previous operations,
- Pipeline/surface equipment,
- Lateral migration outside the EHOF,
- Drilling through the CO_2 area, and
- Diffuse leakage through the seal.

Section 4.10 summarizes how CRC and CTV will monitor CO_2 leakage from various pathways and describes the response to various leakage scenarios. In addition, Section 5 describes how CRC and CTV will develop the inputs used in the Subpart RR mass-balance equation (Equation RR-12). Any incidents that result in CO_2 leakage up the wellbore and into the atmosphere will be quantified as described in Section 7.

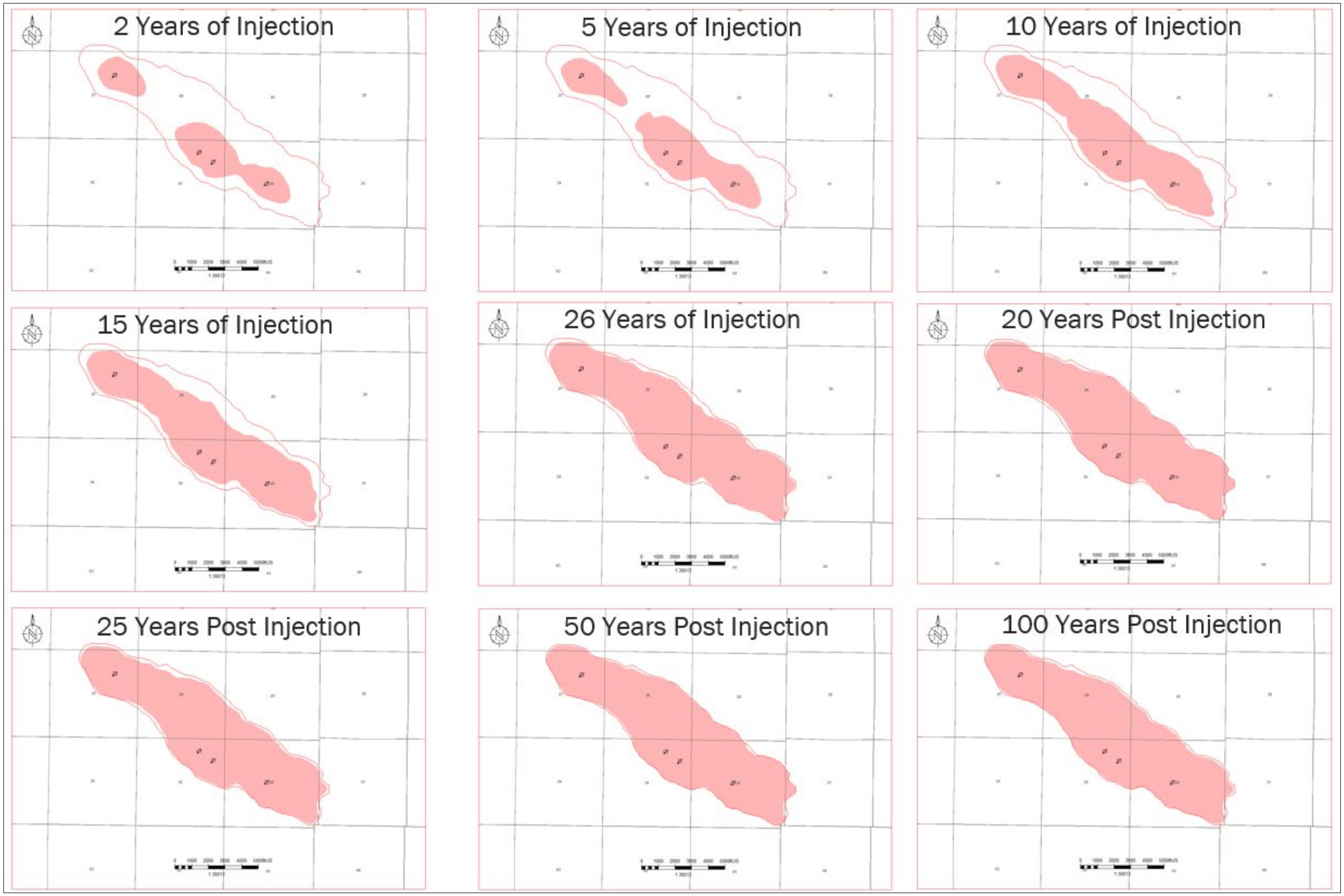


Figure 9a: Plan view showing modeled plume development through time, 26R project.

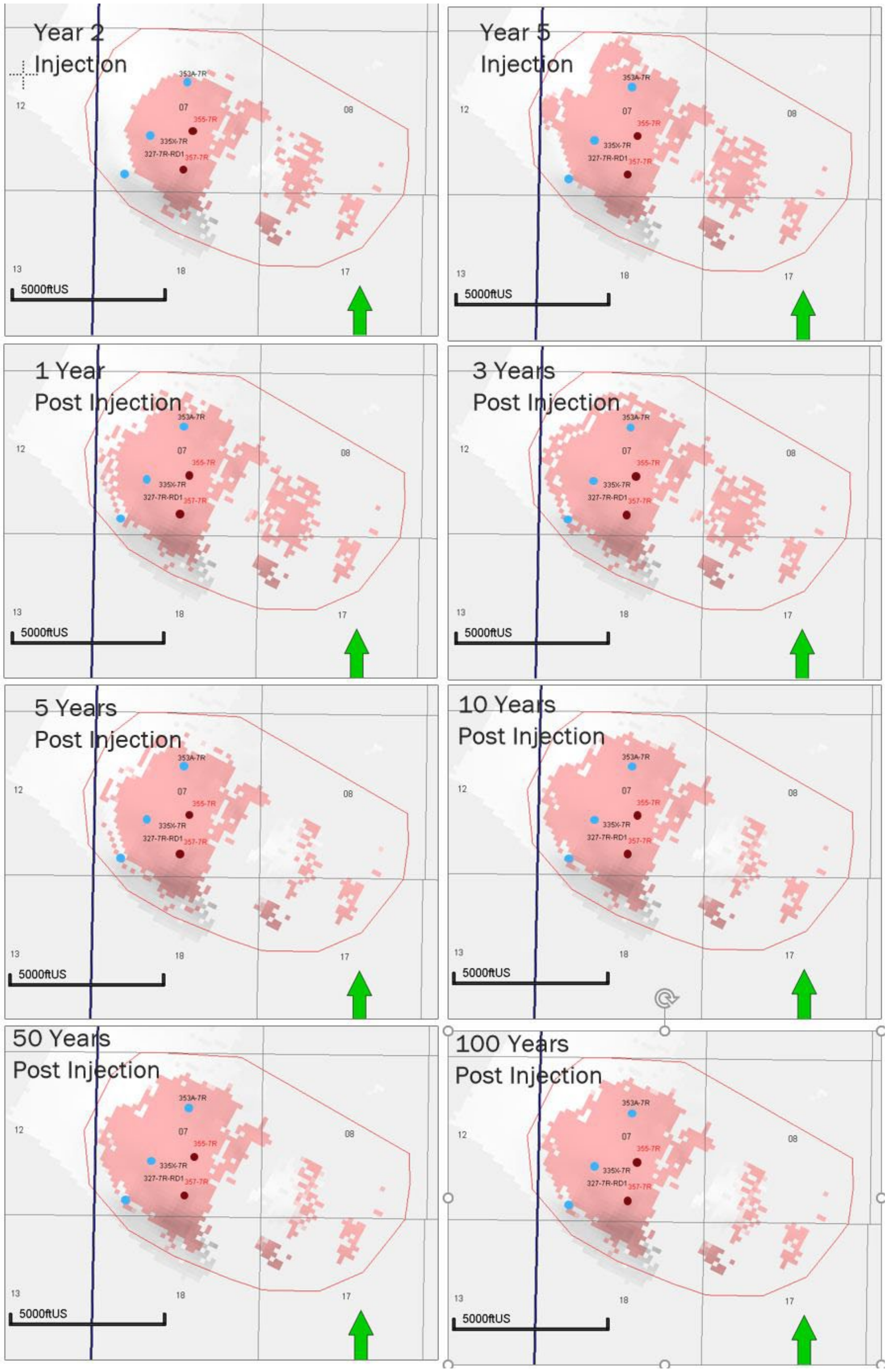


Figure 9b: Plan view showing modeled plume development through time, A1-A2 project (model layer 15). Red dots ae the injectors, Blue dots are monitoring wells.

4.2 Existing Wellbores

Leakage through existing wellbores is possible at the EHOF. However, that is mitigated by adhering to regulatory requirements for well drilling and testing; implementing best practices developed through extensive operating experience; monitoring injection/production performance, wellbores, and the surface; and maintaining surface equipment. Wells penetrating the Reef Ridge confining shale and sequestration reservoir are described in Section 2.3.3.

LIKELIHOOD: As discussed in Section 2.3.3, regulations governing the EHOF require that wells be completed and operated so that fluids are contained in the strata in which they are encountered. For this reason likelihood of leakage is considered low.

TIMING: Risk of leakage at each specific existing wellbore is greatest after CO_2 has reached that location and when pressures are greatest, which is towards the end of the project injection time period.

MAGNITUDE: Leakage mass is predicted to be less than one percent of total injection (less than 0.5 million metric tons).

MONITORING: Continual and routine monitoring and maintenance of wellbores and site operations is critical to ensure confinement in the following ways.

1. Injection well pressure is monitored continuously throughout the EHOF using a supervisory control and data acquisition (SCADA) system. Pressure and rate sensors on the injection wells are programmed to alarm and notify operations personnel when encountering values that significantly deviate from set target ranges. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such excursions occur, they are investigated and addressed.

2. Experience gained over time allows for a strategic approach to well maintenance and workovers; workover crews are onsite for this purpose. For example, the well classifications by age and construction method inform planning for monitoring and updating wells. All available information, including pattern performance and well characteristics, is used to determine well maintenance schedules.

3. A corrosion protection program for CO_2 operations will be implemented to mitigate both internal and external corrosion of casing in wells in the EHOF. In line with industry standard operations and EPA Class VI requirements for CCS, downhole equipment and the interior and exterior of wellbores will be protected using special materials (e.g., fiberglass tubing, corrosion-resistant cements, nickel-plated packers, corrosion-resistant packer fluids), and procedures will be performed to prevent and monitor for corrosion (e.g., packer placement, use of annular leakage detection devices, cement bond logs, pressure tests). These measures and procedures are typically included in the injection orders filed with CalGEM and the EPA UIC program. Corrosion protection methods and requirements may be enhanced over time in response to improvements in technology.

4. MIT requirements implemented by CalGEM and/or EPA UIC (as applicable) will be followed to periodically inspect wells and surface facilities to ensure that all wells and related surface equipment are in good repair, leak-free, and that all aspects of the site and equipment conform to existing regulations and permit conditions. All active injection wells undergo MIT before

injection, after any workover or per time periods specified in the UIC approval. Operators are required to use a pressure recorder and pressure gauge for the tests. For CalGEM regulated wells, operator's field representative must sign the pressure recorder chart and submit it with the MIT form to CalGEM. The casing-tubing annulus must be tested to maximum anticipated surface pressure (MASP) for a specified duration and with an allowable pressure loss specified in the regulations. CalGEM or EPA UIC may also approve alternative pressure monitoring programs with varying requirements at their discretion.

If a well fails the MIT, the operator must immediately shut the well in and provide notice to CalGEM. Casing leaks must be successfully repaired within 180 days and re-tested, or the well must be plugged and abandoned after submitting a formal notice and obtaining approval from CalGEM.

5. Finally, as indicated in Section 5, field inspections are conducted on a routine basis by field personnel. On any given day, there are approximately 40 personnel in the field. Leaking CO_2 is very cold and leads to formation of bright white clouds and ice that are easily spotted. All field personnel will be trained to identify leaking CO_2 and other potential problems in the field and to safely remedy the issue. Any CO_2 leakage detected will be documented and reported, quantified, and addressed as described in Section 5.

6. Corrective Action assessment performed pursuant to the Class VI regulation includes the generation and detailed review of wellbore/casing diagrams for each well in the project area. Information used in the review includes depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of cement determination supports the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface. For each well determined to require additional plugging CTV has provided the plugging procedure that will be used to abandon wells along with well-specific plugging plan tables that identify the number of plugs, placement method, cement type, density, and volume for the wells to be abandoned during pre-operational testing. The planned plugging procedures achieve all requirements of CalGEM regulations for proper abandonment of oil and gas wells.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, CRC and CTV conclude that it will mitigate CO_2 leakage through wellbores by detecting problems as they arise and quantifying any leakage that does occur by use of local surface air monitoring in the vicinity of the leaking wellbore.

4.3 Faults and Fractures

There are no faults or fractures penetrating the confining layer of the Reef Ridge shale that provide a potential upward pathway for fluid flow. First, the presence of oil, especially oil with a gas cap, is indicative of a competent natural seal. Oil, and to a greater extent gas, migrates upward over time because both are less dense than the brine found in rock formations. Places where oil and gas remain trapped in the deep

subsurface over millions of years, as is the case in the EHOF, prove that faults or fractures do not provide a pathway for upward migration out of the CO_2 flooding interval.

While developing the EHOF, a seismic survey was conducted to characterize the formations and provide information for the reservoir models used for development planning. Initial interpretations of the 3-D seismic survey were based on a conventional pre-stack time migration volume. In 2019, the 3-D seismic survey was reprocessed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 10 displays the location and extent of four faults that helped to form these anticlines beginning in the Middle Miocene, 16 million years ago (Callaway and Rennie, 1991). These faults have remained inactive for millions of years since. Offsetting the 31S and NWS structures are the 1R, 2R, and 3R high-angle reverse faults that are oriented NW-SE. The faults penetrate the lowest portions of the Monterey Formation but do not continue through the injection interval to the Reef Ridge shale confining layer.

Lastly, the operating history of the EHOF confirms there are no faults or fractures penetrating the Reef Ridge shale that allow fluid migration. Water and gas have been successfully injected into the Monterey Formation since 1976, and there is no evidence of new or existing faults or fractures. Over 1.4 billion barrels of water and 1,237 billion standard cubic feet (Bcf) of gas have been injected into the NWS and 31S structures with no reservoir confinement issues. In fact, it is the absence of faults and fractures in the Reef Ridge shale that makes the Monterey Formation such a strong candidate for water injection operations and enables field operators to maintain effective control over the injection and production processes.

LIKELIHOOD: Because there are no faults or fractures penetrating the confining layer of the Reef Ridge shale that provide a potential upward pathway for fluid flow the likelihood of leakage is considered negligible.

TIMING: No faults are present that provide a potential pathway; therefore leakage is not expected via this pathway over the entire duration of the project.

MAGNITUDE: For reasons given above, anticipated leakage magnitude is negligible.

MONITORING: Leakage via faults, if it were to occur, would be subject to detection from monitoring wells in zones above the sequestration reservoir, as described in Section 5.1.

4.4 Natural or Induced Seismicity

Based on published data and over 100 years of operational experience, there is no evidence that natural seismic activity poses a significant risk for loss of CO_2 for the project. This is due, in part, to the thickness, ductility, and predominance of clay in the primary confining layer Reef Ridge shale.

No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area. Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west, beyond the Temblor Range) and the White Wolf Fault (25 miles southeast from the EHOF).

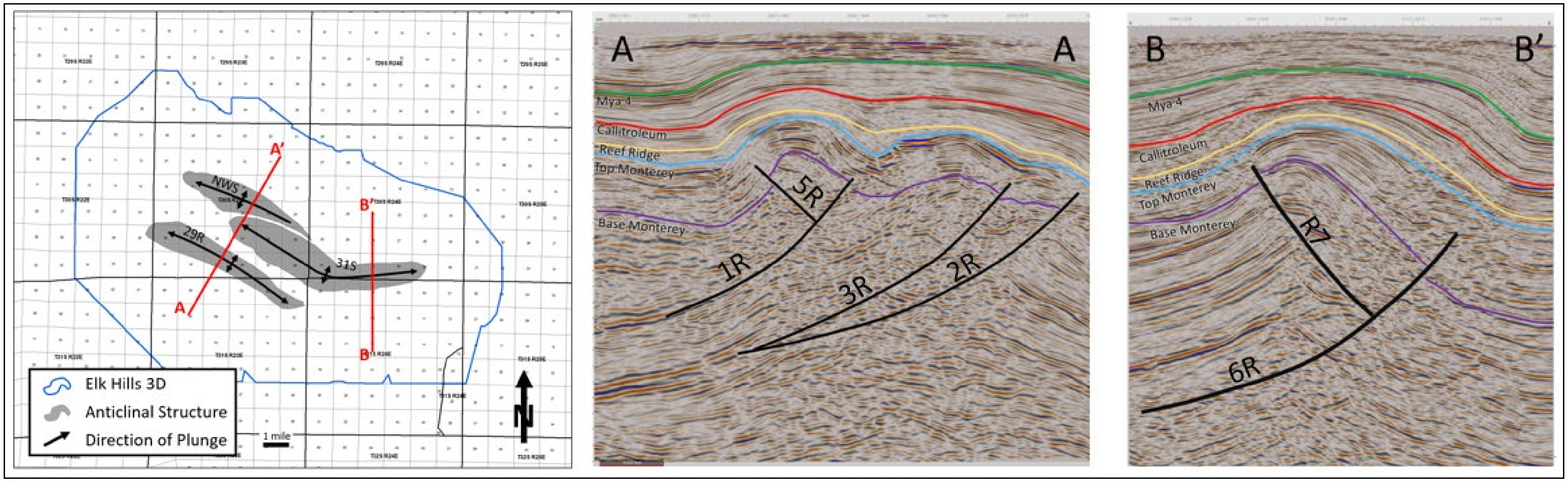


Figure 10: Outline of EHOF 3-D survey and seismic intersections across 31S and NWS structures.

Historical seismic events from 1932 to present are available from the Southern California Earthquake Data Center (SCEDC). Based on this data, there have been no earthquakes recorded greater than 3.0 in the A1-A2 and 26R MMA. In addition, there have only been eleven earthquakes with a magnitude of 5.0 or greater within a 30-mile buffer around the EHOF administrative boundary (Figure 11). There have been 518 earthquakes with a magnitude between 3 and 5 within the 30-mile EHOF buffer. The average depth of the earthquakes with magnitude greater than 3 is 4.5 miles, while the storage reservoirs are one mile below surface.

LIKELIHOOD: Induced seismicity will be mitigated operationally by the following:

1. Injection pressure will be monitored continuously and will be lower than the failure pressure of the confining Reef Ridge shale.
2. Reservoir pressure will be at or beneath the discovery pressure.
3. Seismometers will be installed at the surface to detect seismicity induced by injection operations.

Adherence to these mitigation measures will ensure that likelihood of induced seismicity is low.

TIMING: Risk of induced seismicity is highest when operating pressures are greatest at the end of the injection time period. Risk of natural seismicity is not anticipated to change during the Specified Period.

MAGNITUDE: For reasons given above, anticipated leakage magnitude is negligible.

MONITORING: Induced seismicity monitoring with seismometers, as described in Section 5.1.

4.5 Previous Operations

All of the existing wells at the EHOF have been permitted through CalGEM (and predecessor California agencies) under rules that require detailed information about the character of the geologic setting, the construction and operation of the wells, and other information used to assess the suitability of the site. CalGEM maintains a public database that contains the location, construction details, and injection-production history of each well.

CTV has assessed internal databases as well as CalGEM information to identify and confirm wells within the project area. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Therefore, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the development history of the reservoir that includes injection of water and gas.

Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest at the end of the injection period.

LIKELIHOOD: This operational experience has verified that there are no unknown wells within the EHOF. Additionally, CRC and CTV have sufficiently mitigated the possibility of migration from older wells as discussed above. Over many years, the EHOF has been continuously checked for the presence of old, unknown wells throughout the EHOF. These practices ensure that identified wells are sufficiently isolated and do not interfere with ongoing operations and reservoir pressure management. For these reasons risk of leakage via this pathway is considered low.

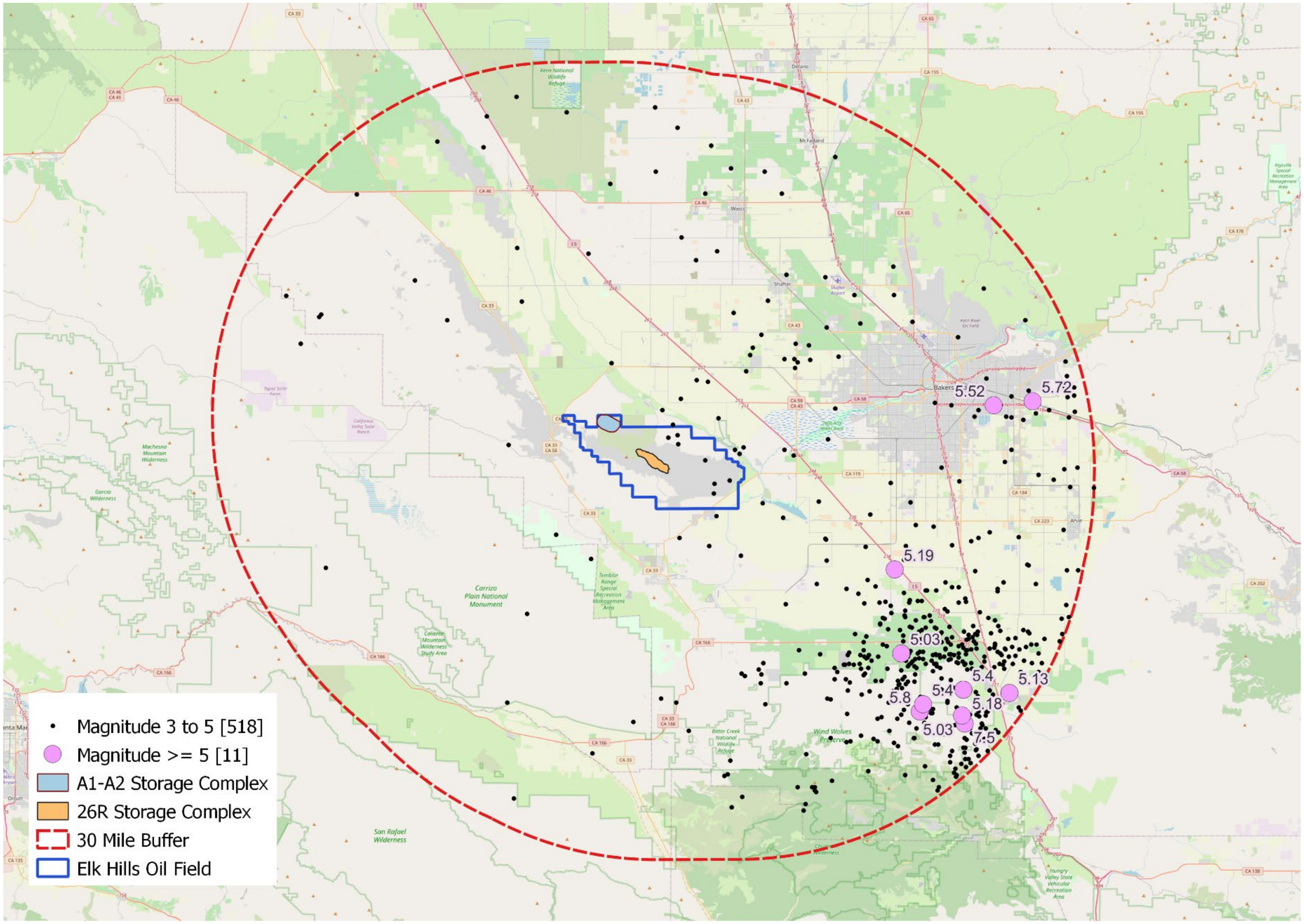


Figure 11: Earthquakes in the San Joaquin Basin with a magnitude greater than 3. Note: only 11 earthquakes have occurred within a 30-mile buffer around the EHOF administrative boundary. Earthquake data from SCEDC.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest that will be at the end of the injection period.

MAGNITUDE: Leakage mass is predicted to be less than one percent of total injection (less than 0.5 million metric tons).

MONITORING: Leakage via abandoned wells, if it were to occur, would be subject to detection from monitoring wells in zones above the sequestration reservoir, as described in Section 5.1. Additional monitoring is discussed in Section 4.2.

4.6 Pipeline/Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2. Unplanned leakage from surface facilities will be mitigated to the maximum extent practicable by relying on the use of prevailing design and construction practices and maintaining compliance with applicable regulations. The facilities and pipelines will be constructed of materials and managed using control processes that are standard for CO_2 injection projects.

CO_2 delivery to the complex will comply with all applicable regulations, including as pipeline regulations are updated in the future as applicable. Instrumentation will be installed on pipelines and facilities that allows the 24/7 operations staff at the Central Control Facility (CCF) to monitor the process and potentially spot leaks. Furthermore, frequent and routine visual inspections of surface facilities by field staff will provide an additional means to detect leaks. Both manual and automatic shutdowns will be installed in the complex to ensure that leaks are addressed in a timely manner.

LIKELIHOOD: Compliance with applicable regulations, as described above, ensures that likelihood of leakage via this pathway is low.

TIMING: Leakage risk via this pathway will be similar over the project time period.

MAGNITUDE: Should leakage be detected from pipeline or surface equipment, the mass of released CO_2 will be quantified following the requirements of 40 CFR 98.230-238 (Subpart W) of EPA's Greenhouse Gas Reporting Program (GHGRP).

MONITORING: Routine field inspection and remote monitoring will be conducted to detect any potential leakage from pipelines and surface facilities.

4.7 Lateral Migration

It is highly improbable that injected CO_2 will migrate downdip and laterally outside the EHOF because of the buoyant properties of supercritical CO_2, the nature of the geologic structure, and the planned injection approach. The strategy to minimize the lateral migration risk is to ensure that the CO_2 plume and surrounding fluids will be at or below the initial reservoir pressure at time of discovery.

LIKELIHOOD: Leakage via this pathway is not anticipated.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest at the end of the injection period.

MAGNITUDE: Leakage via this pathway is not anticipated to occur, and therefore magnitude of any leakage is considered negligible.

MONITORING: Geophysical monitoring conducted as approved in the Class VI permit will track the extent of CO_2 plume and ensure that there is not lateral migration outside of the AoR.

4.8 Drilling Through the CO_2 Area

It is possible that at some point in the future, drilling through the Reef Ridge confining zone and into the Monterey Formation may occur.

LIKELIHOOD: The possibility of this activity creating a leakage pathway is extremely low for three reasons: 1) Future well drilling would be regulated by CalGEM (oil and gas wells) or EPA UIC (Class VI injection wells) and will therefore be subject to requirements that fluids be contained in strata in which they are encountered; 2) as sole operators and owners of the EHOF, CRC and CTV control placement and timing of new drilling operations; and 3) there are no oil and gas targets beneath the Monterey Formation.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest during future time periods if drilling through the Reef Ridge confining zone were to occur.

MAGNITUDE: Leakage via this pathway is not anticipated to occur, and therefore magnitude of any leakage is considered negligible.

MONITORING: Ongoing regulation of all drilling activities by CalGEM and/or EPA will ensure future monitoring of drilling activities. See additional monitoring discussion in Section 4.2.

4.9 Leakage Through the Seal

Diffuse leakage through Reef Ridge confining layer is highly unlikely. The presence of gas caps trapped over millions of years confirms that the seal has been secure for millions of years. Leaking through the seal is mitigated by ensuring that post-injection reservoir pressure will be at or below the initial reservoir pressure at the time of discovery. The injection monitoring program referenced in Section 2.3.2 and detailed in Section 5 assures that no breach of the seal will be created.

Further, if CO_2 were to migrate through the Reef Ridge, it would migrate vertically until it encountered and was trapped by any of the additional shallower interbedded shales of the Etchegoin, San Joaquin, and Tulare Formations (more than 5,000 ft of vertical section; see Figure 3).

LIKELIHOOD: Diffuse leakage through Reef Ridge confining layer is highly unlikely.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest at the end of the injection period when pressures are highest. In addition the relative amount of CO_2 in the supercritical phase will decrease over time post-injection as CO_2 dissolves into the brine reducing leakage risk.

MAGNITUDE: Leakage via this pathway is not anticipated to occur, and therefore magnitude of any leakage is considered negligible.

MONITORING: Leakage, if it were to occur, would be subject to detection from monitoring wells in zones above sequestration reservoir, as described in Section 5.1.

4.10 Monitoring, Response and Reporting Plan for CO_2 Loss

As discussed above, the potential sources of leakage include routine issues such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment, and unique events such as induced fractures.

Table 4 summarizes some of these potential leakage scenarios, monitoring activities designed to detect those leaks, standard response, and other applicable regulatory programs requiring similar reporting.

Risk	Monitoring Plan	Response Plan	Parallel Reporting (if any)
Loss of well control			
Tubing leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days	
Casing leak	Routine field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days	CalGEM or EPA UIC
Wellhead leak	Routine field inspection and continuous SCADA monitoring	Workover crews respond within days	
Loss of bottom-hole pressure control	Blowout during well operations	Maintain well-kill procedures; shut-in offset injectors prior to drilling	CalGEM or EPA UIC
Loss of seal in abandoned wells	Anomalous pressure or gas composition from productive shallower zones	Re-enter and reseal abandoned wells	CalGEM or EPA UIC
Leaks in surface facilities			
Pumps, valves, etc.	Routine field inspection and remote monitoring	Workover crews respond within days	Subpart W
Subsurface leaks			
Leakage along faults	Monitoring of zones above sequestration reservoir	Shut-in injectors near faults	EPA UIC
Leakage through induced fractures	Induced seismicity monitoring with seismometers	Comply with rules for keeping pressures below parting pressure	EPA UIC
Leakage due to a seismic event	Induced seismicity monitoring with seismometers	Shut-in injectors near seismic event	EPA UIC

Table 4: Response plan for CO_2 leakage or loss.

Section 5.1 discusses the approaches envisioned for quantifying the mass of leaked CO_2. In the event leakage occurs, CRC and CTV plan to determine the most appropriate methods for quantifying the mass leaked and will report it as required as part of the annual Subpart RR submission.

Any mass of CO_2 detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR 98.230-238 (Subpart W) or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as frequency of inspection. As indicated in Sections 5.1 and 7, leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in the electronic environmental documentation and reporting system. Repairs requiring a work order will be documented in the electronic equipment maintenance system and well work historian. If the scope of repair work requires permitting through CalGEM or EPA UIC, a subsequent operations summary report will be provided under the conditions of the applicable permit.

4.11 Summary

The structure and stratigraphy of the Monterey Formation in the EHOF is ideally suited for injection and CO_2 storage. The CO_2 injection zone stratigraphy is porous, permeable, and very thick, providing ample capacity for long-term CO_2 storage. The overlying Reef Ridge shale forms an effective seal for Monterey Formation sequestration (see Figure 3). After assessing potential risk of release from the subsurface and steps that have been taken to prevent leaks, the potential threat of significant leakage is extremely low.

Risk of release is further reduced by the prudent operational strategy of limiting the pressure of the reservoir post-injection to at or below the initial pressure of the reservoir at time of discovery.

5 Monitoring and Considerations for Calculating Site-specific Variables

5.1 For the Mass Balance Equation

5.1.1 General Monitoring Procedures

Existing operations are centrally monitored and controlled by the extensive and sophisticated CCF. The CCF uses a SCADA software system to implement operational control decisions on a real-time basis throughout the EHOF to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Flow rates, pressures, gas composition, and other data will be collected at key points and stored in a centralized data management system. These data are monitored 24 hours a day by qualified technicians who follow response and reporting protocols when the system delivers notifications that data exceed predetermined statistically acceptable limits. The data can be accessed for immediate analysis.

Figure 5 identifies the meters that will be used to evaluate, monitor, and report on the injection project and associated plume migration described earlier in Section 2.3. A similar metering system is already installed throughout the EHOF.

As indicated in Figure 5, a custody-transfer meter will be installed at the CO_2 sources. The custody-transfer meters will measure flow rate continuously. Fluid composition will be determined on either a continuous basis or by periodic sampling depending on the specific meter; both options are accurate for purposes of commercial transactions. All meter and composition data will be recorded.

Metering protocols follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. These meters will be maintained routinely, operated continuously, and will feed data directly to the CCF. In the oil and gas industry, the accepted level of custody-transfer meter accuracy is 0.25% or better, and the meters are calibrated every 60 to 90 days. A third party is frequently used to calibrate these meters, and both parties to any transaction have rights to witness meter calibration. These custody meters provide the most accurate way to measure mass flows.

Most process streams are multi-component or multi-phase, with varying CO_2 compositions. For these streams, flow rate is the most important control parameter. Operations flow meters are used to determine the flow rates of these process streams, which allows for the monitoring of trends to identify deviations and determine if any intervention is needed. Flow meters are also used—comparing aggregate data to individual meter data—to provide a cross-check on actual operational performance.

Developing a CO_2 mass balance on multi-phase, multi-component process streams is best accomplished using custody-transfer meters rather than multiple operations meters. As noted above, in-field flow rate monitoring presents a formidable technical and maintenance challenge. Some variance is due simply to differences in factory settings and meter calibration. Additional variance is due to the operating conditions within a field. Meter elevation, changes in temperature (over the course of the day), fluid composition (especially in multi-component or multi-phase streams), or pressure will affect any in-field meter reading.

Many meters have some form of automatic adjustment for some of these factors, others utilize a conversion factor that is programmed into the meter, and still others need to be adjusted manually in the calculation process. Use of a smaller number of centrally located meters reduces the potential error that is inherent in employing multiple meters in various locations to measure the same mass of flow and gas composition.

Table 5 summarizes the CO_2 injection monitoring strategy. Figure 12 shows the location of monitoring wells.

Monitoring Activity	Frequency/Location
MIT (Internal and External)	Annual
SAPT	Initially; any time the packer is replaced or reset
Injection rate, pressure, and temperature	Continuous
Seismicity	Induced seismicity monitoring via seismometers
Underground sources of drinking water (USDWs) and reservoirs between USDWs and sequestration reservoir	Monitoring wells with pressure, temperature, fluid composition, and periodic cased-hole logs
Stream analysis	Continuous
Corrosion monitoring (coupons, casing integrity)	Well materials, pipelines, and other surface equipment
Sequestration reservoir monitoring	Dedicated wells monitoring sequestration reservoir with pressure, temperature, fluid composition, and periodic cased hole logs

Table 5: Injection monitoring strategy summary.

5.1.2 CO_2 Received

A custody-transfer meter will be used at the CO_2 source(s) to continuously measure the mass and composition of CO_2 received. The metering protocols will follow the prevailing industry standard(s) for custody transfer (as promulgated by the API and the AGA).

5.1.3 CO_2 Injected into the Subsurface

Injected CO_2 associated with geologic sequestration will be calculated using the flow meter mass at the operations/composition meter at the outlet of the recompression facilities (RCFs) and the custody-transfer meter at the CO_2 off-take points.

5.1.4 CO_2 Produced, Entrained in Products, and Recycled

No CO_2 will be produced or entrained in products or recycled.

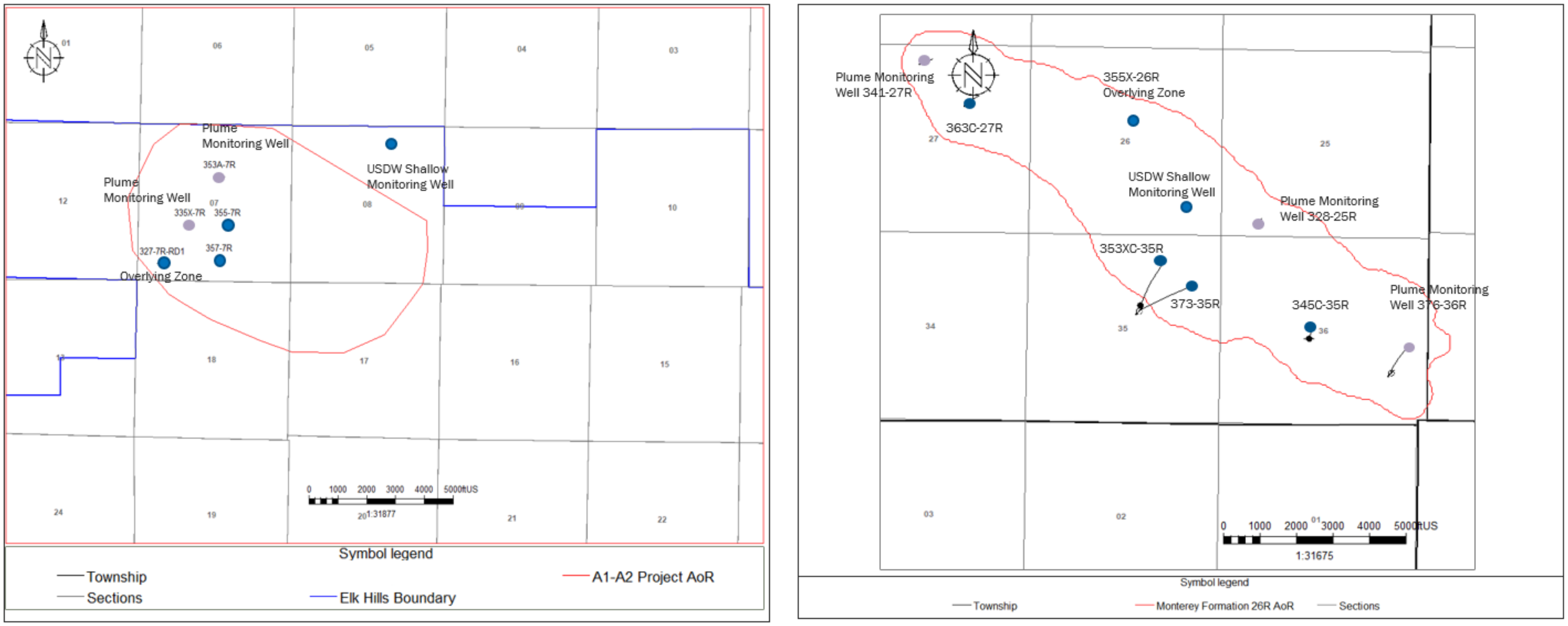


Figure 12: Map showing monitoring well locations.

5.1.5 CO_2 Emitted by Surface Leakage

40 CFR 98.230-238 (Subpart W) is used to estimate surface leaks from equipment at the EHOF. Subpart W uses a factor-driven approach to estimate equipment leakage. In addition an event-driven process will be used to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. Reporting will reconcile the Subpart W report and results from any event-driven quantification to assure that surface leaks are not double-counted.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet the following two objectives in accordance with the leakage risk assessment in Section 4: 1) to detect problems before CO_2 leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the mass of CO_2 leaked to the surface. Injection Wells

Injection well pressure, temperature, and injection rate will be monitored continuously. If injection pressure or rate measurements are beyond the specified set-points determined for each injector, a data flag is automatically triggered and field personnel will investigate and resolve the problem. These excursions will be reviewed by well-management personnel to determine if CO_2 leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or another minor action is required), and there is no threat of CO_2 leakage. In the case of issues that are not readily resolved, more detailed investigation and response would be initiated, and internal support staff would provide additional assistance and evaluation. Such issues would lead to the development of a work order in the work order management system. This record will enable the company to track progress on investigating potential leaks and, if a leak has occurred, to quantify its magnitude. To quantify leakage to the surface, an estimate of the relevant parameters (e.g., the rate, concentration, and duration of leakage) will be made to quantify the leak mass. Depending on specific circumstances, these determinations may rely on engineering estimates.

Monitoring of Wellbores

Because leaking CO_2 at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a two-part visual inspection process will be employed in the general area of the EHOF to detect unexpected releases from wellbores. First, field personnel will visit the surface facilities on a routine basis. Inspections may include tank volumes, equipment status and reliability, lube oil levels, pressures and flow rates in the facility, and valve leaks. Field personnel inspections will also check that injectors are on the proper schedule and observe the facility for visible CO_2 or fluid line leaks.

Finally, data collected by personal CO_2 gas monitors (ToxiRAE Pro CO_2 or equivalent), which will always be worn by field personnel, will be a last method to detect leakage from wellbores. The monitor's sensor range is 0 to 50,000 parts per million (ppm) and resolution is 100 ppm. The monitor alarm setting will be established to alert workers to a CO_2 concentration exceeding 1,000 ppm or a lower value. If an alarm is triggered, the first response will be to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. If the incident results in a work order, this will serve as the basis for tracking the event for greenhouse gas (GHG) reporting. Targeted point-source surface air monitoring will be conducted in the event of detected wellbore leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

Other Potential Leakage at the Surface

Routine visual inspections at surface are used to detect significant loss of CO_2 to the surface. Field personnel visit manned surface facilities daily to conduct visual inspection. Inspections may include review of equipment status, lube oil levels, pressures and flow rates in the facility, valve leaks, ensuring that injectors are on the proper schedule, and conducting a general observation of the facility for visible CO_2 or fluid line leaks. If problems are detected, field personnel would investigate and, if maintenance is required, generate a work order in the maintenance system which is tracked through completion. In addition to these visual inspections, CRC and CTV will use the results of the personal gas monitors as a supplement for smaller leaks that may escape visual detection.

If CO_2 leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, a work order will be generated in the work order management system. The work order will describe the appropriate corrective action and be used to track completion of the maintenance action. The work order will also serve as the basis for tracking the event for GHG reporting and quantifying any CO_2 emissions. Targeted surface air and/or soil gas flux monitoring will be conducted in the event of detected leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

5.1.6 Monitoring for Potential Leakage from the Injection/Production Zone

Monitoring wells to measure pressure, temperature, and fluid composition will be dedicated to geologic sequestration. These dedicated wells will monitor the sequestration reservoir, zones above the sequestration reservoir, and the USDW. Baseline analysis will be established for each of these wells. Any deviation from the baseline analysis will be assessed for potential indications of leakage. Measured increase in CO_2 in groundwater above the Storage Complex will be used to develop groundwater isoconcentration maps and quantify CO_2 leakage rates.

Monitoring well locations are shown on Figure 12, and monitoring wells are listed in Appendix 11.5. Monitoring well details including depth and chemistry monitoring parameters are listed in Appendix 11.6. Monitoring well data collection procedures will be consistent with protocols listed in the Class VI permit application.

5.1.7 Seismicity Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole. This network will be implemented to monitor seismic activity near the project site, and will consist of passive seismic monitoring to demonstrate that there are no seismic events affecting CO_2 containment.

Specifications of the network are as follows:

- Seven sensor locations (borehole and near surface) with high-sensitivity 3-component geophones.
- Borehole sensors will be deployed deeper than 1,500' to ensure a good quality signal and to minimize noise. A velocity model will be derived from vertical seismic profiles (VSPs), sonic well logs, and check shots.
- The system will be designed with capability of detecting and locating events greater than moment magnitude scale (M_w) 0.0.

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed continuously. Waveform data will be transmitted near real-time via cellular modem or other wireless means and archived in a database. Additionally, CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network.

The Class VI permit application describes actions that will be taken in the event of detected seismic events, based on the magnitude and frequency of seismic activity. In the event of a seismic event greater than M_w 2.0 and local report and confirmation of damage, an investigation will be conducted to determine of CO_2 leakage has occurred. Targeted surface air and/or soil gas flux monitoring will be conducted in the event of detected leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

5.1.8 CO_2 Emitted from Equipment Leaks and Vented Emissions of CO_2 from Surface Equipment Located Between the Injection Flow Meter and the Injection Wellhead

Monitoring efforts will evaluate and estimate leaks from equipment and vented CO_2 as required under 40 CFR 98.230-238 (Subpart W).

5.2 To Demonstrate that Injected CO_2 is not Expected to Migrate to the Surface

At the end of the Specified Period, CRC and CTV intend to cease injecting CO_2 for the subsidiary purpose of establishing the long-term storage of CO_2 in the EHOF. After the end of the Specified Period, CRC and CTV anticipate that it will submit a request to discontinue monitoring and reporting. The request will demonstrate that the amount of CO_2 reported under 40 CFR 98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage. At that time, CRC and CTV will be able to support the request with years of data collected during the Specified Period as well as two to three (or more, if needed) years of data collected after the end of the Specified Period. This demonstration will provide the information necessary for the EPA UIC Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

- Data comparing actual performance to predicted performance (injection) over the monitoring period,
- An assessment of the CO_2 leakage detected, including discussion of the estimated amount of CO_2 leaked and the distribution of emissions by leakage pathway,
- A demonstration that future operations will not release the mass of stored CO_2 to the surface,
- A demonstration that there has been no significant leakage of CO_2, and
- An evaluation of reservoir pressure in the EHOF that demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

6 Determination of Baselines

Automatic data systems will be used to identify and investigate deviations from expected performance that could indicate CO_2 leakage. These data systems are used primarily for operational control and monitoring, and as such, are set to capture more information than is necessary for reporting in the Annual

Subpart RR Report. Necessary system guidelines will be developed to capture the information that is relevant to identify CO_2 leakage. A description of the approach to collecting this information is given below.

6.1 Visual Inspections

As field personnel conduct routine inspections, work orders are generated in the electronic system for maintenance activities that cannot be immediately addressed. Methods to capture work orders that involve activities that could potentially involve CO_2 leakage will be developed, if not currently in place. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation. The responsible party will be provided in the monitoring plan, as required under 40 CFR 98.3(g) (Subpart A). The Annual Subpart RR Report will include an estimate of the amount of CO_2 leaked. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

6.2 Personal Gas Monitors

CO_2 gas monitors will be worn by all field personnel (ToxiRAE Pro CO_2 or equivalent; sensor range 0 to 50,000 ppm and resolution of 100 ppm). The monitor alarm setting will be established to alert workers to a CO_2 concentration exceeding 1,000 ppm or a lower value. Any monitor alarm will trigger an immediate response to ensure personnel are not at risk and to verify the monitor is working properly. If a fugitive leak is discovered, it would be quantified, and mitigating actions determined accordingly. The person responsible for MRV documentation will receive notice of all incidents where gas is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO_2 emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

6.3 Monitoring Wells

Baseline data will be collected from each monitoring well during well construction in order to provide a baseline. Baseline data will be collected on sequestration zone fluid chemistry and pressure, and above confining zone water chemistry and pressure at monitoring well locations. Data will be acquired that is characteristic of the subsurface after showing data stabilization. Quarterly fluid sampling and continuous pressure/temperature monitoring will be conducted at groundwater monitoring wells above the confining zone during the baseline period. In the injection zone fluid chemistry sampling will occur once at each location and temperature/pressure will be monitored continuously during the baseline period.

6.4 Seismic Baseline

The seismic monitoring network (Section 5.1.7) will be installed during the construction phase. Baseline seismicity data will be collected from the seismic monitoring network for at least 12 months prior to first injection to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

6.5 Injection Rates, Pressures, and Mass

Target injection rates and pressures will be developed for each injector, based on the results of ongoing modeling and permitted limits. High and low set-points are programmed into the controllers, and flags whenever statistically significant deviations from the targeted ranges are identified. The set-points are designed to be conservative. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO_2 leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions and related work orders that could potentially involve CO_2 leakage. The Annual Subpart RR Report will provide an estimate of CO_2 emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

7 Determination of Sequestration Mass Using Mass Balance Equations

The following sections describe how each element of the mass-balance equation (Equation RR-12) will be calculated.

7.1 Mass of CO_2 Received

CRC and CTV will use Equation RR-1 as indicated in 40 CFR 98.443 to calculate the mass of CO_2 received from each custody-transfer meter immediately downstream of the source(s).

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \qquad \text{(Eq. RR-1)}$$

Where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).
$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).
$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).
$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (wt. percent CO_2, expressed as a decimal fraction)
p = Quarter of the year.
r = Receiving flow meter.

Given CRC and CTV's method of receiving CO_2 and requirements of 40 CFR 98.444(a):

- All delivery to EHOF is used, so quarterly flow redelivered, $S_{r,p}$, is zero ("0") and will not be included in the equation
- Quarterly CO_2 concentration will be taken from the gas measurement database

CRC and CTV will sum to total mass of CO_2 Received using Equation RR-3 in 40 CFR 98.443:

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \text{ (Eq. RR-3)}$$

Where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 for flow meter r.

r = Receiving flow meter.

7.2 Mass of CO_2 Injected into the Subsurface

Mass of CO_2 injected into the subsurface at EHOF at each injection well will be calculated with Equation RR-4:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \quad \text{(Eq. RR-4)}$$

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.

Aggregated injection at all injection wells will be calculated with Equation RR-6:

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \quad \text{(Eq. RR-6)}$$

where:

CO_2. = 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.

7.3 Mass of CO_2 Emitted by Equipment Leakage

CRC and CTV will calculate and report the total annual mass of CO_2 emitted by equipment leakage using an approach that is tailored to specific leakage events and relies on 40 CFR 98.230-238 (Subpart W) equipment leakage reports. As described in Sections 4 and 5.1, the operators are prepared to address the potential for leakage in a variety of settings. Estimates of the amount of equipment leakage will depend on several site-specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

7.4 Mass of CO_2 Emitted by Surface Leakage

The process for quantifying surface leakage will entail using best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are discussed in Section 5.1. In the event leakage to the surface occurs, the quantify and leakage amounts will be reported, and records retained that describe the methods used to estimate or measure the mass leaked as reported in the Annual Subpart RR Report. Further, the Subpart W report and results from any event-driven quantification will be made to assure that surface leaks are not double-counted.

Equation RR-10 in 40 CFR 98.443 will be used to calculate and report the mass of CO_2 emitted by surface leakage:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \text{ (Eq. RR-10)}$$

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.

7.5 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Equation RR-12 in 40 CFR 98.443 will be used to calculate the mass of CO_2 sequestered in subsurface geologic formations in the reporting year as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2\,FI} \text{ (Eq. RR-12)}$$

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

Figure 5 illustrates that CO_2 supplied for geological storage will be metered between the CO_2 source and the injection meter.

7.6 Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formations

A sum of the total annual mass obtained using RR-12 in 40 CFR 98.443 will be used to calculate the cumulative mass of CO_2 sequestered in subsurface geologic formations.

8 MRV Plan Implementation Schedule

It is anticipated that this MRV plan will be implemented as early as first quarter (Q1) 2025 pending appropriate permit approvals and an available CO_2 source, or within 90 days of EPA approval, whichever occurs later. Other facility GHG reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. As described in Section 3.3 above, it is anticipated that that the MRV program will be in effect during the Specified Period, during which time the project will ensure long-term containment of a measurable quantity of CO_2 in subsurface geologic formations at the EHOF and that the project will be operated in a manner not expected to result in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be made and submission with a request to discontinue reporting under this MRV plan (see 40 CFR 98.441(b)(2)(ii)).

9 Quality Assurance Program

9.1 Monitoring QA/QC

As indicated in Section 7, the requirements of 40 CFR 98.444 (a) – (d) in the discussion of mass balance equations have been incorporated. These include the following provisions.

CO_2 Received and Injected

The quarterly flow rate of CO_2 received is measured at the receiving custody-transfer meters.

CO_2 emissions from equipment leaks and vented emissions of CO_2

These amounts are measured in conformance with the monitoring and QA/QC requirements specified in 40 CFR 98.230-238 (Subpart W).

Flow meter provisions

The flow meters used to generate data for the mass balance equations in Section 7 are:

- Operated continuously except as necessary for maintenance and calibration,
- Operated using the calibration and accuracy requirements in 40 CFR 98.3(i),
- Operated in conformance with API standards, and
- Traceable by the National Institute of Standards and Technology (NIST).

9.2 Missing Data Procedures

In the event data needed for the mass balance equations cannot be collected, procedures in 40 CFR 98.445 for estimating missing data will be used as follows:

- A quarterly flow rate of CO_2 received that is missing would be estimated using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.

- For any 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 specified in 40 CFR 98.230-238 (Subpart W) would be followed.

9.3 MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters, the MRV plan will be revised and submitted to the EPA UIC Administrator within 180 days as required in 40 CFR 98.448(d).

10 Records Retention

The record retention requirements specified by 40 CFR 98.3(g) will be followed. In addition, the requirements in 40 CFR 98.447 will be followed by maintenance of the following records for at least three years:

- Quarterly records of CO_2 received, operating temperature and pressure, and concentration of these streams,
- Quarterly records of injected CO_2 including flow rate, operating temperature and pressure, and concentration of these streams,
- 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, and
- 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.

These data will be collected as generated and aggregated as required for reporting purposes.

11 Appendices

11.1 Conversion Factors

If needed, CO_2 volumes will be reported at standard conditions of temperature and pressure as defined by the California Air Resources Board (CARB): 60° F and 14.7 pounds per square inch absolute (psia)[2].

To convert these volumes into metric tons, a density is calculated using the Span and Wagner EOS as recommended by the EPA and using the database of thermodynamic properties developed by NIST, available at [http://webbook.nist.gov/chemistry/fluid/.](http://webbook.nist.gov/chemistry/fluid/)

The conversion factor 5.29×10^{-2} metric ton per thousand cubic feet (MT/Mcf) has been used throughout to convert volumes to metric tons.

[2] See California Code of Regulations Title 17 Section 95102 (General Requirements of Greenhouse Gas Reporting, Definitions)

11.2 Acronyms

3-D – three-dimensional
AGA – American Gas Association
AMA – active monitoring area
AoR – area of review
API – American Petroleum Institute
Bcf – billion standard cubic feet
BOE - barrel of oil equivalent
CalGEM – California Geologic Energy Management Division
CARB – California Air Resources Board
CCF – Central Control Facility
CCS – carbon capture and sequestration
CDMG – California Division of Mines and Geology
CMG - Computer Modeling Group Ltd.
CO_2 – carbon dioxide
CRC - California Resources Corporation
CTV - Carbon TerraVault
DAC – direct air capture
DOE – U.S. Department of Energy
EHOF – Elk Hills Oil Field
EHPP – Elk Hills Power Plant
EOS - equation of state
EPA – U.S. Environmental Protection Agency
GEM – geochemical equation compositional model
GHG – greenhouse gas
GHGRP -- Greenhouse Gas Reporting Program
GPA – Gas Processors Association
H_2S – Hydrogen sulfide
MASP - maximum anticipated surface pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MRV –monitoring, reporting, and verification
MT/Mcf – metric ton per thousand cubic feet
MW - megawatt
NIST -- National Institute of Standards and Technology
NWS – Northwest Stevens
ppm – parts per million
RTS – radioactive tracer survey
RCF – recompression facility
SAPT – standard annual pressure test
SCADA – supervisory control and data acquisition
SCEDC – Southern California Earthquake Data Center

UIC – underground injection control
USDW – underground source of drinking water
VSPs – vertical seismic profiles

11.3 References

Callaway, D.C. and E.W. Rennie, Jr. 1991. *San Joaquin Basin, California*, in Gluskoter, H.J., D.D.Rice, and R.B. Taylor, eds. Economic geology, U.S.: Boulder, Colorado. Geological Society of America. The Geology of North America, v. P-2: 417-430.

McJannet, G.S. 1996. *General Overview of the Elk Hills Field*. Society of Petroleum Engineers. doi:10.2118/35670-MS.

11.4 Glossary of Terms

This glossary describes some of the technical terms as they are used in this MRV plan. For additional glossaries please see the U.S. EPA Glossary of UIC Terms (http://water.epa.gov/type/groundwater/uic/glossary.cfm), and the Schlumberger Oilfield Glossary (http://www.glossary.oilfield.slb.com/).

Anticline – an arch-shaped fold in the rock layers in a geologic formation in which the layers are upwardly convex, forming something like a dome or bell shape. Anticlines form excellent hydrocarbon traps, particularly in folds that have rocks with high injectivity in their core and high impermeability in the outer layers of the fold.

Contain/containment –the effect of keeping fluids located within in a specified portion of a geologic formation.

Dip – the angle of the rock layer relative to the horizontal plane. Buoyant fluids will tend to move up the dip, or *updip*, and heavy fluids will tend to move down the dip, or *downdip*. Moving higher up structure is moving updip. Moving lower is downdip. Perpendicular to dip is *strike*. Moving perpendicular along a constant depth is moving along strike.

Downdip – see *dip*.

Flooding pattern – also known as an injection pattern; the geometric arrangement of production and injection wells to sweep oil efficiently and effectively from a reservoir.

Formation – a body of rock that is sufficiently distinctive and continuous that it can be mapped.

Injectivity – the ability of an injection well to receive injected fluid (both rate and pressure) without fracturing the formation in which the well is completed. Injectivity is a function of the porosity and permeability of the rock formation and the reservoir pressure in which the injection well is completed.

Infill drilling – the drilling of additional wells within existing patterns. These additional wells decrease average well spacing. This practice both accelerates expected recovery and increases estimated ultimate recovery in heterogeneous reservoirs by improving the continuity between injectors and producers. As well spacing is decreased, shifting flow paths lead to increased sweep to areas where greater hydrocarbon saturations remain.

Permeability – the measure of a rock's ability to transmit fluids. Rocks that transmit fluids readily, such as sandstones, are described as permeable and tend to have many large, well-connected pores. Impermeable formations, such as shales and siltstones, tend to be finer grained or of a mixed-grain size, with smaller, fewer, or less-interconnected pores.

Phase – a region of space throughout which all physical properties of a material are uniform. Fluids that don't mix segregate themselves into phases. Oil, for example, does not mix with water and forms a separate phase.

Pore space – see *porosity*.

Porosity – the fraction of a rock that is not occupied by solid grains or minerals. All rocks have spaces between rock crystals or grains that is available to be filled with a fluid, such as water, oil, or gas. This space is called *pore space*.

Primary recovery – the first stage of hydrocarbon production, in which natural reservoir energy, such as gas drive, water drive, or gravity drainage, displaces hydrocarbons from the reservoir into the wellbore and up to surface. Initially, the reservoir pressure is higher than the bottom-hole pressure inside the wellbore. This high natural differential pressure drives hydrocarbons toward the well and up to surface. However, as the reservoir pressure declines because of production, so does the differential pressure. To reduce the bottom-hole pressure or increase the differential pressure to increase hydrocarbon production, it is necessary to implement an artificial lift system, such as a rod pump, an electrical submersible pump, or a gas-lift installation. Production using artificial lift is considered primary recovery. The primary recovery stage reaches its limit either when the reservoir pressure is so low that the production rates are not economic, or when the proportions of gas or water in the production stream are too high. During primary recovery, only a small percentage of the initial hydrocarbons in place are produced, typically 10%-12% for oil reservoirs. Primary recovery is also called *primary production*.

Saturation – the fraction of pore space occupied by a given fluid. Oil saturation, for example, is the fraction of pore space occupied by oil.

Seal – a geologic layer (or multiple layers) of impermeable rock that serves as a barrier to prevent fluids from moving upwards to the surface.

Secondary recovery – the second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are immiscible gas injection and waterflooding.

Sedimentary rocks – rocks formed at the Earth's surface through deposition of sediments derived from weathered rocks, biogenic activity, or precipitation from solution. There are three main types of rocks: igneous, metamorphic, and sedimentary.

Stratigraphic section – a sequence of layers of rocks in the order they were deposited.

Strike – see *dip.*

Updip – see *dip.*

11.5 Well List

The following tables present the well name and well type for the project.

26R Project Wells

Injectors	363C-27R 353XC-35R 373-35R 345C-35R	
Monitoring wells	341-27R	Plume monitoring
	328-25R	Plume monitoring
	374-36R	Plume monitoring
	355X-26R	Above-zone monitoring well
	USDW monitoring well	USDW monitoring

A1-A2 Project Wells

Injectors	355-7R 357-7R	
Monitoring wells	353A-7R	Plume monitoring
	335X-7R	Plume monitoring
	327-7R-RD1	Above-zone monitoring well
	USDW monitoring well	USDW monitoring

11.6 Monitoring Well Details

26R Project monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage of Depth	Frequency (Injection Phase)
Tulare Formation	Fluid Sampling	Shallow Water Monitoring Well	Pump	–400’ - 450' MD/VD	Quarterly
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’ - 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’ - 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	400' - 500' MD/VD in each well	Continuous
Etchegoin Formation	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Quarterly
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' 4788' - 4811' 4205' - 4226' (all MD/VD)	Continuous

A1-A2 Project monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	USDW Monitoring Well	Pump	940' - 960' MD/VD	Baseline, Quarterly
	Pressure	USDW Monitoring Well	Pressure Gauge	940' - 960' MD/VD	Continuous
	Temperature	USDW Monitoring Well	Temperature Sensor	940' - 960' MD/VD	Continuous
	Temperature	327-7R-RD1 353A-7R 335X-7R	Fiberoptic cable (DTS)	849' MD/VD 961' MD/VD 854' MD/VD	Continuous
Etchegoin	Fluid Sampling	327-7R-RD1	Sampling Device	3782' - 3934' MD 3780' - 3932' VD	Baseline, Quarterly
	Pressure	327-7R-RD1	Pressure Gauge	3782' - 3934' MD 3780' - 3932' VD	Continuous
	Temperature	327-7R-RD1	Temperature Sensor	3782' - 3934' MD 3780' - 3932' VD	Continuous
	Temperature	353A-7R 335X-7R	Fiberoptic cable (DTS)	4100' - 4220' 3850' - 3990' (all MD/VD)	Continuous

Summary of analytical and field parameters for groundwater samples above the confining zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO_3, SO_4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Dissolved CH_4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

11.7 Summary of Key Regulations Referenced in MRV Plan

Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b).

Appendix B: Submissions and Responses to Requests for Additional Information

Elk Hills A1-A2 and 26R CO_2 Subpart RR Monitoring, Reporting, and Verification Plan

Version Date: 11/29/2023

1 Contents

Overview

The Elk Hills Oil Field (EHOF), covering 75 square miles, was discovered in 1911 and has produced over 2 billion barrels of oil equivalent (BOE), making it one of the most productive fields in the United States. California Resources Corporation (CRC) and Carbon TerraVault (CTV; a CRC wholly owned subsidiary), owns 100% of the surface, mineral, and pore space rights at the EHOF.

CTV intends to inject and store a measurable quantity of carbon dioxide (CO_2) in subsurface geologic formations at the EHOF, for a term of 27 years referred to as the "Specified Period." During the Specified Period, CO_2 will be injected from anthropogenic sources such as the Elk Hills 550 megawatt (MW) natural gas combined cycle power plant (EHPP), bio-diesel refineries, and other sources in the EHOF area.

The CO_2 will be injected into the Monterey Formation A1-A2 and 26R reservoirs for dedicated geologic storage. The Elk Hills storage complex will be pre-certified and monitored to verify permanent CO_2 sequestration. Class VI applications have been submitted for the A1-A2 and 26R reservoir.

This EHOF monitoring, reporting, and verification (MRV) plan is based on decades of subsurface characterization and simulation of the targeted Monterey Formation. This empirically driven analysis indicates that the natural geologic seal that overlays the entire EHOF, known as the Reef Ridge shale, will provide a physical trap that will permanently prevent injected CO_2 from migrating to the surface.

This MRV plan documents the following in accordance with 40 CFR 98.440-449 (Subpart RR):

- Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA), 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,
- Strategy for detecting and quantifying any surface leakage of CO_2,
- Strategy for establishing the expected baselines for monitoring CO_2 surface leakage,
- Summary of considerations for calculating EHOF-specific variables for the mass balance equation, and
- Proposed date to begin collecting data for calculating total CO_2 sequestered.

1 Facility Information

i. Reporter number – 582061

ii. Existing wells in the EHOF including production, injection, and monitoring wells are permitted by California Geologic Energy Management Division (CalGEM) through California Public Resources Code Division 3.[1]

iii. Wells injecting CO_2 for geologic storage will be permitted with the United States Environmental Protection Agency (EPA) Underground Injection Control (UIC) program for Class VI injection.

[1] Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

iv. Wells in the EHOF are identified by name, American Petroleum Institute (API) number, status, and type. The list of wells as of March 2023 associated with the geologic storage projects is included in Appendix 11.5. Any new wells or changes to wells will be indicated in the annual report.

2 Project Description

The EHOF is one of the largest oil and natural gas fields in the United States, with production from multiple vertically stacked reservoirs. Turbidite sand deposits of the Miocene Monterey Formation will serve as the injection targets in two separate anticlinal structures, Northwest Stevens (NWS) and 31S (Figures 1a, 1b).

Numerous aspects of the geology, facilities, equipment, and operational procedures for A1-A2 and 26R are consistent throughout the field. As such, one MRV report will satisfy the 26R and A1-A2 reservoirs as shown in Table 1. The A1-A2 and 26R reservoir and well locations within the field are shown in Figure 1a.

Structure	Reservoir	Sequestration Type	Number of Injectors
31S	26R	Geologic : Class VI	4
NWS	A1-A2	Geologic : Class VI	2

Table 1: Reservoirs within the EHOF and sequestration type.

2.1 Project Characteristics

The potential CO_2 stored over the project duration is up to 48 million metric tons (refer to Table 2 for breakdown). For accounting purposes, the amount stored is the difference between the amount injected less any CO_2 that i) leaks to the surface, or ii) is released through surface equipment leakage or malfunction. Actual amounts stored during the Specified Period of reporting will be calculated as described in Section 7 of this MRV Plan.

2.2 Environmental Setting

The project site for this MRV plan is the EHOF, located in the San Joaquin Basin, California (Figure 2).

2.2.1 Geology of Elk Hills Oil Field

The EHOF is located 20 miles southwest of Bakersfield in western Kern County, producing oil and gas from several vertically stacked reservoirs formed in the Tertiary period (65 million to 2 million years ago). Of the more than 24,000 feet (ft) of sediment deposited, the most prolific reservoir is the Miocene epoch Monterey Formation that is the target CO_2 sequestration reservoir.

Individual layers within the Monterey Formation are primarily interbedded sandstone and shale. These layers have been folded, resulting in anticlinal structures containing hydrocarbons formed from the deposition of organic material approximately 33 million to 5 million years ago (during the Oligocene and Miocene epochs). The combination of multiple porous and permeable sandstone reservoirs interbedded with impermeable shale seals makes the EHOF one of the most suitable locations in North America for the extraction of hydrocarbons and the sequestration of CO_2.

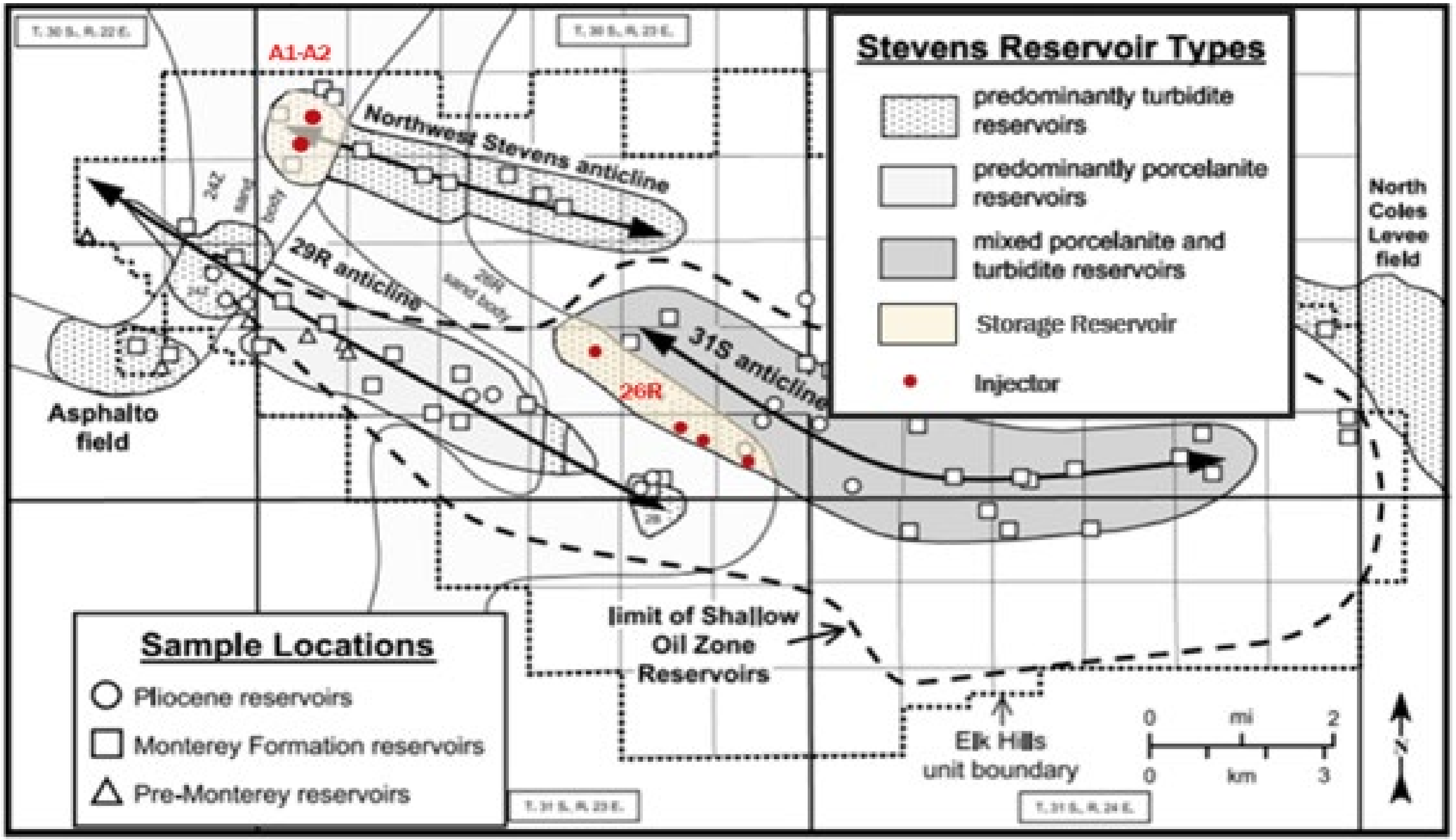


Figure 1a: EHOF map of injection target and injection well locations.

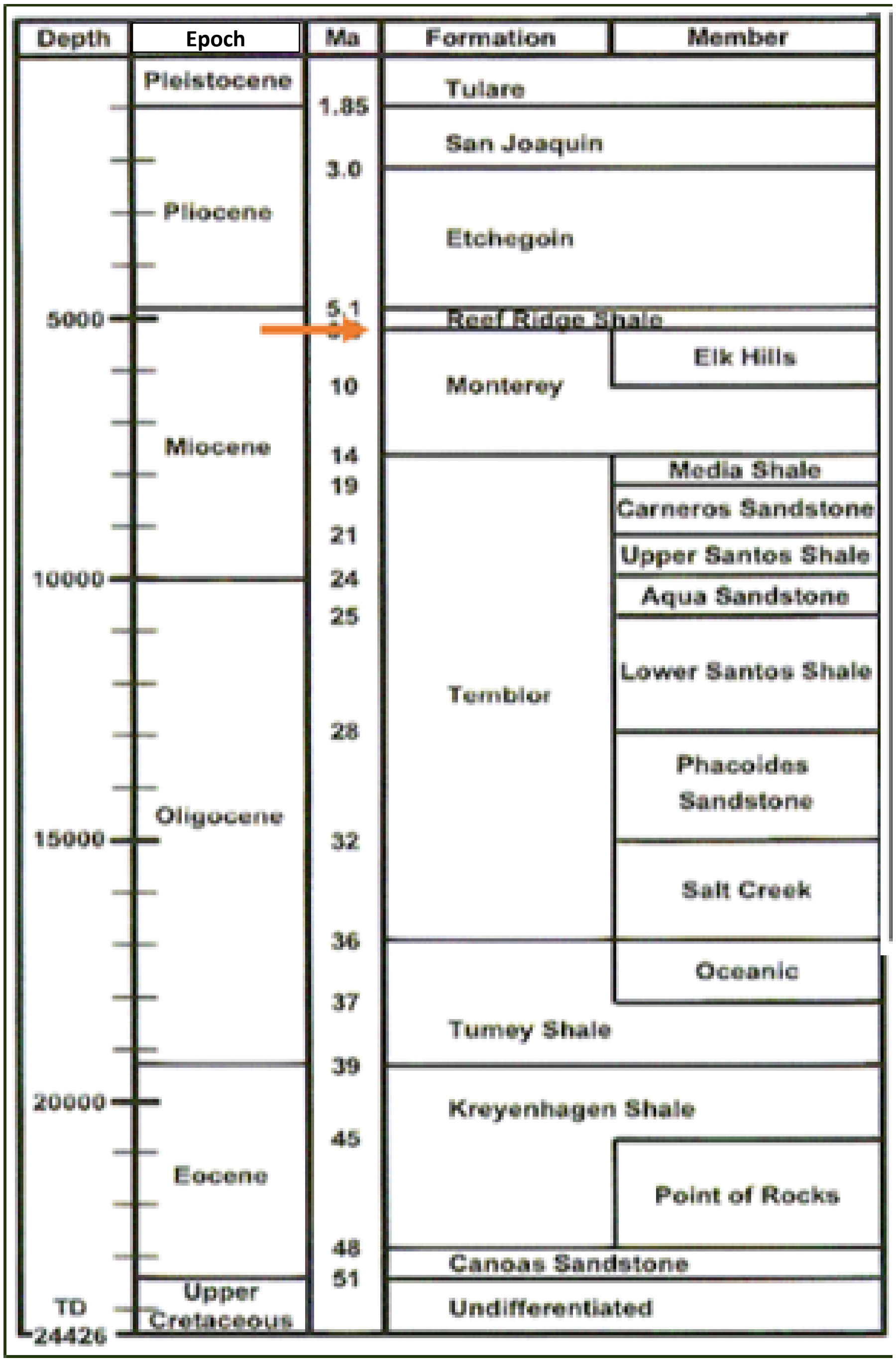


Figure 1b: EHOF stratigraphic column.

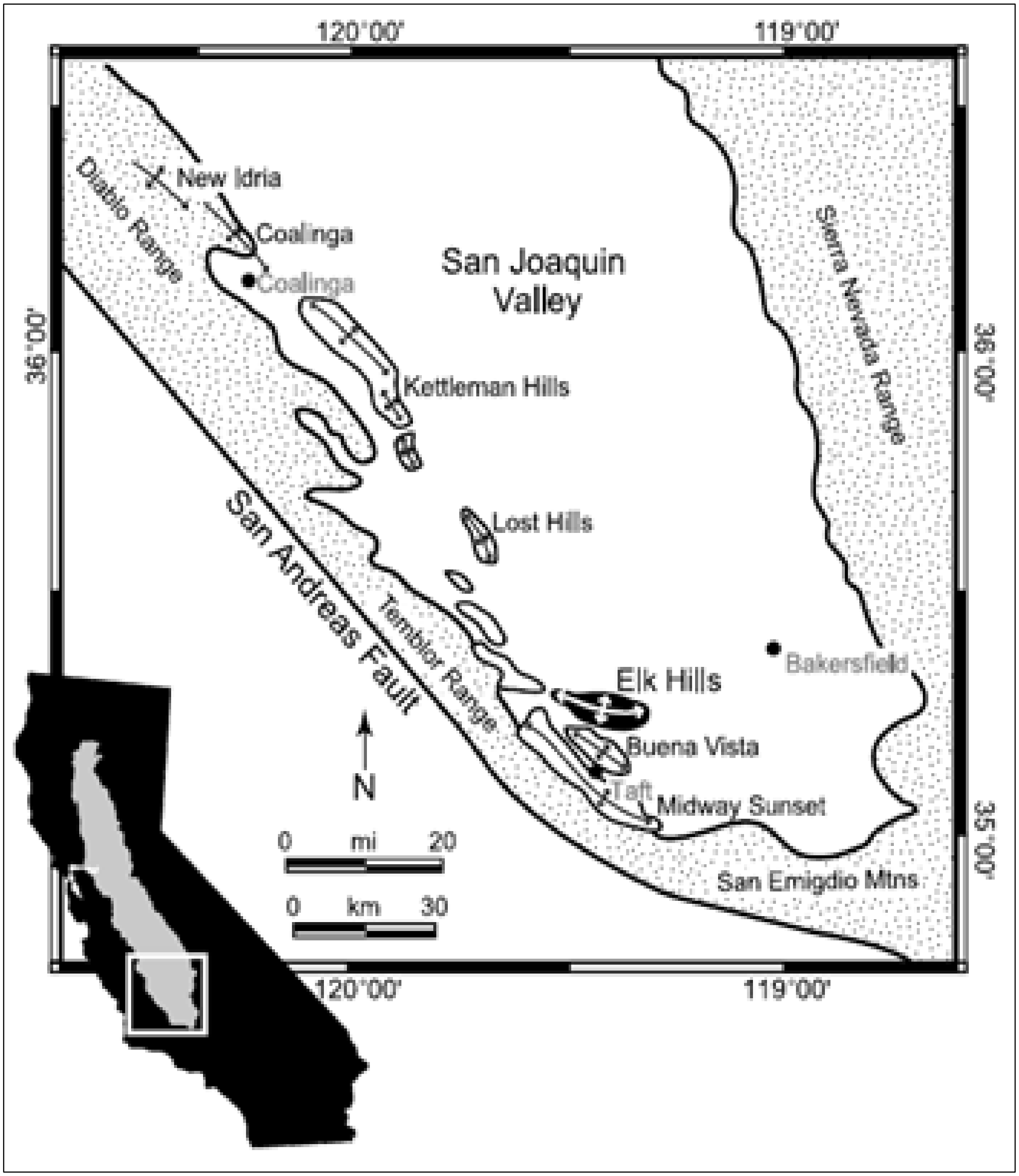


Figure 2: Location of Elk Hills Oil Field, San Joaquin Basin, California.

Following its deposition, Monterey Formation sediments were buried under more than 750 ft of impermeable silty and sandy shale that comprise the confining Reef Ridge shale. The Reef Ridge shale serves as the primary confining layer over the Monterey because it effectively seals underlying fluids from the overlying formations. Above the Reef Ridge lies several alternating sand-shale sequences of the Pliocene Etchegoin and San Joaquin Formations and Pleistocene Tulare Formation. These formations are highlighted in the cross-section in Figure 3.

As indicated in Figure 1a, the 31S and NWS structures represent structural highs, or anticlines, within the EHOF. The elevated areas form a natural trap for oil and gas that migrated from below over millions of years. Once trapped at these high points, the oil and gas has remained in place. In the case of the EHOF, the oil and gas has been trapped in the reservoir for more than 6 million years.

Based on physical site characterization and analysis of historic operating records from the Monterey Formation, there is sufficient reservoir capacity and flow properties to inject and store the entire volume of CO_2 proposed as determined by computational modeling (Table 2).

	Volume (million metric tons)
A1-A2 geologic storage	10
26R geologic storage	38
Total storage capacity	48

Table 2: Calculation of cumulative net fluid volume produced for the Monterey Formation sequestration reservoir.

Stored CO_2 will be contained securely within the EHOF Monterey Formation as demonstrated by 1) preservation of hydrocarbon accumulations over geologic time; 2) subsequent water and gas injection operations; 3) competency of the Reef Ridge confining zone over millions of years and throughout decades of primary and secondary operations; and 4) ample storage capacity of the A1-A2 and 26R reservoir. Confinement within the project area and in the reservoir will be ensured by limiting the pressure of the reservoir post-injection at or below the initial pressure of the reservoir at time of discovery.

2.2.2 Elk Hills Oil Field Operational History

McJannet (1996) reports on the early operating history of EHOF. By Executive Order, in 1912 President Taft designated the area surrounding EHOF as a naval oil reserve. Intended to ensure a secure supply of fuel for the Navy's oil-burning ships, the Executive Order defined "Naval Petroleum Reserve No. 1" (NPR-1). In 1977, President Carter signed the U.S. Department of Energy (DOE) Organization Act which transferred NPR-1 to the DOE. Nearly 20 years later, the DOE was directed to sell the assets of NPR-1. Occidental Petroleum ("Occidental") provided a winning bid of $3.65 billion, and on February 10, 1998, Occidental took over official ownership and operation of EHOF. In December 2014, Occidental Petroleum spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC.

The EHOF unit boundary is shown in orange below in Figure 4.

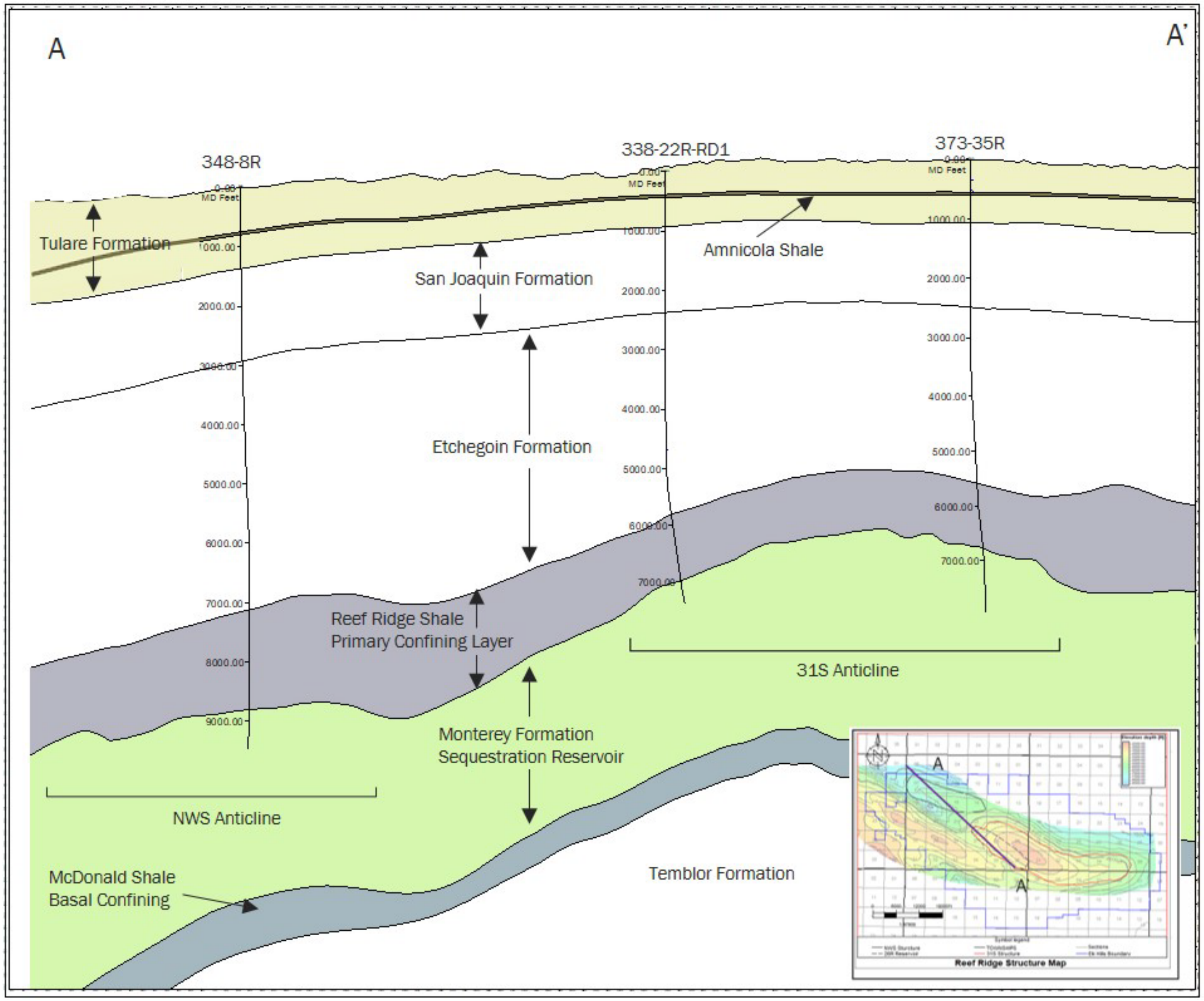


Figure 3: Stratigraphic schematic highlighting the NWS and 31S anticlines.

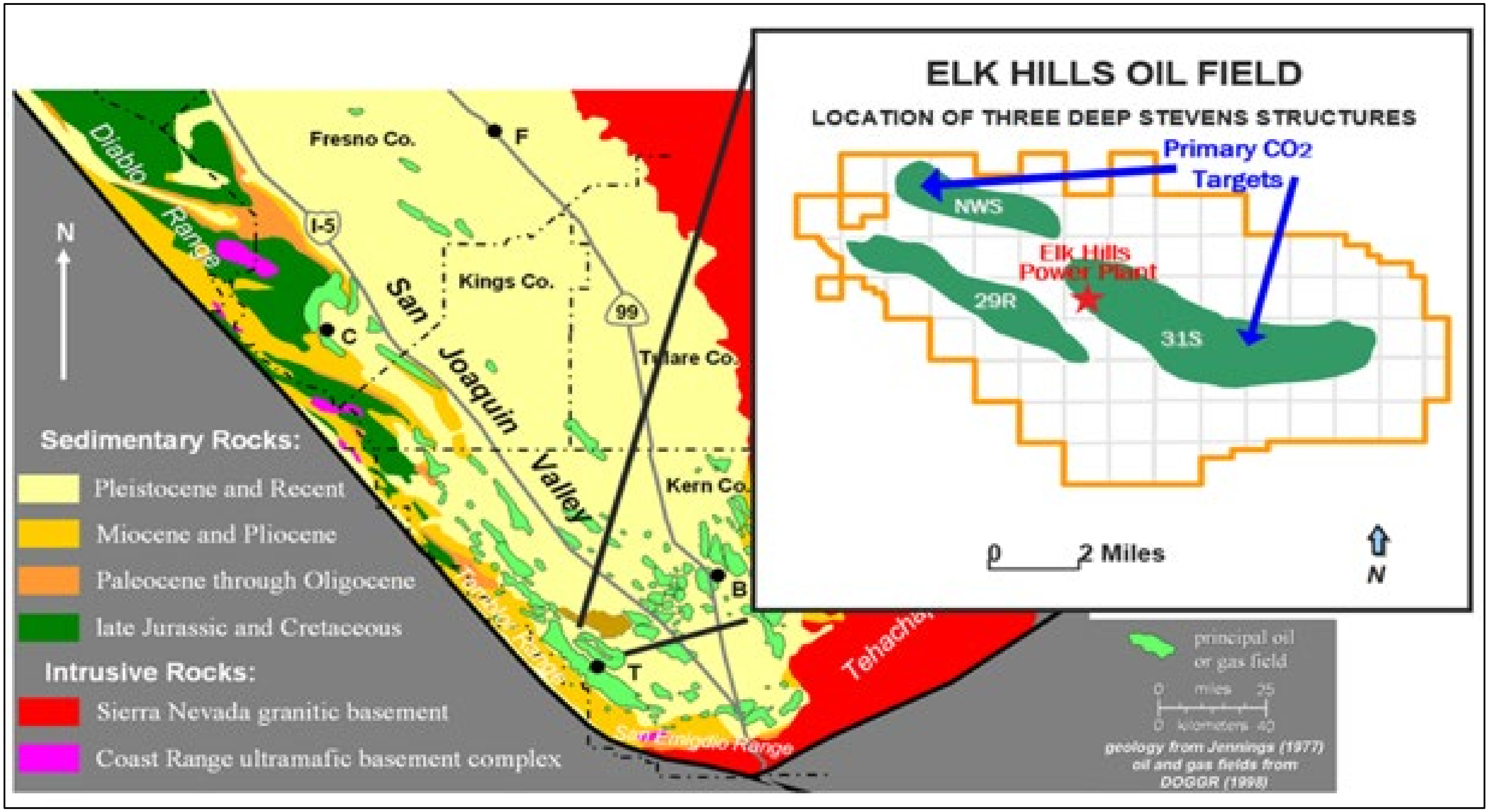


Figure 4: Location of Elk Hills Oil Field within San Joaquin Basin, California.

Development History

Selected primary drilling in the Monterey Formation began in the early 1940s, with concerted drilling and production operations commencing with the DOE's oversight in the late 1970s. To support reservoir pressure and maximize the oil recovery factor, extensive water and gas injection has occurred.

A successful CO_2 injection pilot was implemented in the Monterey Formation in 2005. Data from the four-month pilot confirmed the formation as an attractive target for CO_2 sequestration. This project assessed how much oil could be mobilized from the conventional sand reservoirs, how much CO_2 would be required to mobilize that oil, and how quickly the oil would be produced. Production performance and data collected before, during, and after the pilot operations showed that Monterey Formation reservoirs selected are ideal for CO_2 sequestration.

In addition, past development of the shallow Etchegoin Formation oil reservoirs and Monterey Formation has created a large pressure differential across the Reef Ridge shale, further demonstrating the lack of communication between the reservoirs.

2.3 Description of Facilities and Injection Process

A simplified flow diagram of surface facilities can be seen in Figure 5. This includes facilities outside the scope of the MRV including CO_2 source(s), and the subsequent metering locations between the MRV scope and those facilities. All facilities will be designed and built to ensure integrity and compatibility with CO_2. The subsequent parts of this section will review each of the following:

- CO_2 source,
- CO_2 distribution and injection, and
- Wells in the Class VI defined area of review (AoR) penetrating the Reef Ridge shale.

Facilities associated with dedicated geologic sequestration will be relatively simple as field production and re-compression process flows are unnecessary.

2.3.1 CO_2 Source

CTV plans to construct a carbon capture and sequestration (CCS) "hub" project (i.e., a project that captures CO_2 from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC-permitted injection well). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The anthropogenic CO_2 will be sourced from an onsite blue hydrogen plant (up to 200,000 metric tons per annum), with additional potential CO_2 from the EHPP, direct air capture (DAC), renewable diesel refineries, and/or other sources in the area.

All CO_2 sources will have custody-transfer metering to ensure accurate accounting of both the mass rate and impurities in the CO_2 stream. Anticipated hydrogen sulfide (H_2S) concentration in the injectate is 0.001 to 0.014%.

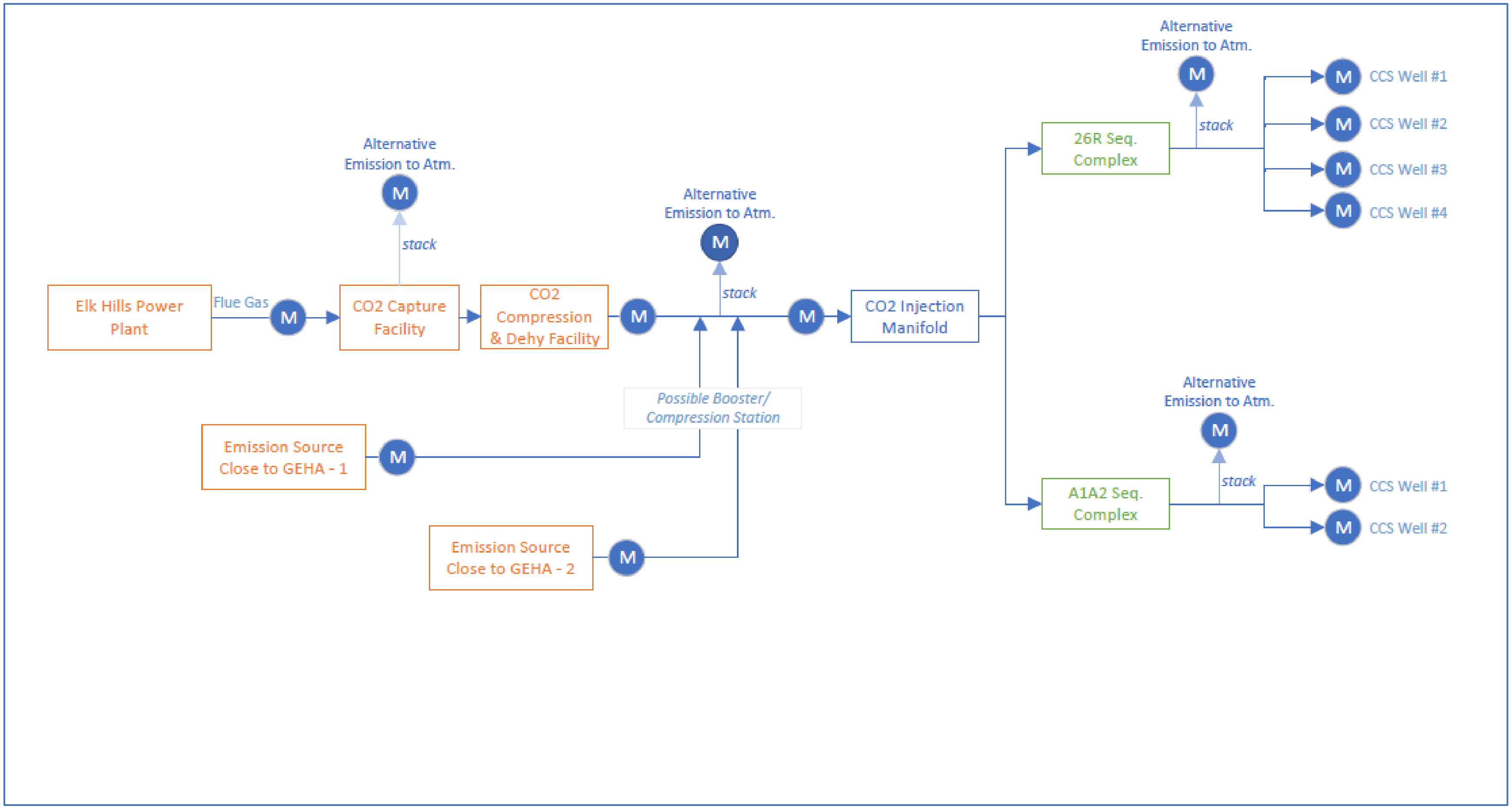


Figure 5: Facilities flow diagram for Carbon TerraVault carbon capture and sequestration project. Blue "M" symbols denote meter locations.

2.3.2 CO_2 Distribution and Injection

CO_2 from the sources previously discussed will be distributed throughout the field through a combination of new and existing infrastructure. This distribution infrastructure will allow CO_2 to be injected into CO_2 wells completed within the Monterey Formation at A1-A2 and 26R.

Each CO_2 injection well will have automated controls that provide for both control and measurement of the mass flow rate and pressure.

2.3.3 Wells in the AoR Penetrating the Reef Ridge Shale

CalGEM regulations govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields (other than UIC Class VI CO_2 injection wells that are regulated by the EPA UIC program). Current CalGEM rules require, among other provisions, the following conditions.

- Fluids must be constrained in the strata in which they are encountered.
- Activities governed by the regulations cannot result in the pollution of subsurface or surface waters.
- Wells must adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata in which they are encountered into strata with oil and gas, or into subsurface and surface waters.
- Operators must file a completion report including basic electric log (e.g., a density, sonic, or resistivity log acquired from the wellbore).
- Wells must follow plugging procedures that require advance approval from CalGEM and allow consideration of the suitability of the cement based on the use of the well, location and setting of plugs.

Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM at time of drilling and as part of the existing Class II UIC permit applications. Wells penetrating the Reef Ridge confining layer and storage reservoir are shown in Figure 6, and are listed in Table 3 categorized in groups that relate to the well status for each reservoir.

Completion Date	A1-A2 Reservoir Count	26R Reservoir Count
Oil and gas producing wells	79	145
Class II injection/disposal wells	32	22
Observation wells	0	2
Plugged and abandoned	39	35
TOTAL	**150**	**204**

Table 3: Wells penetrating Reef Ridge shale for each reservoir by status.

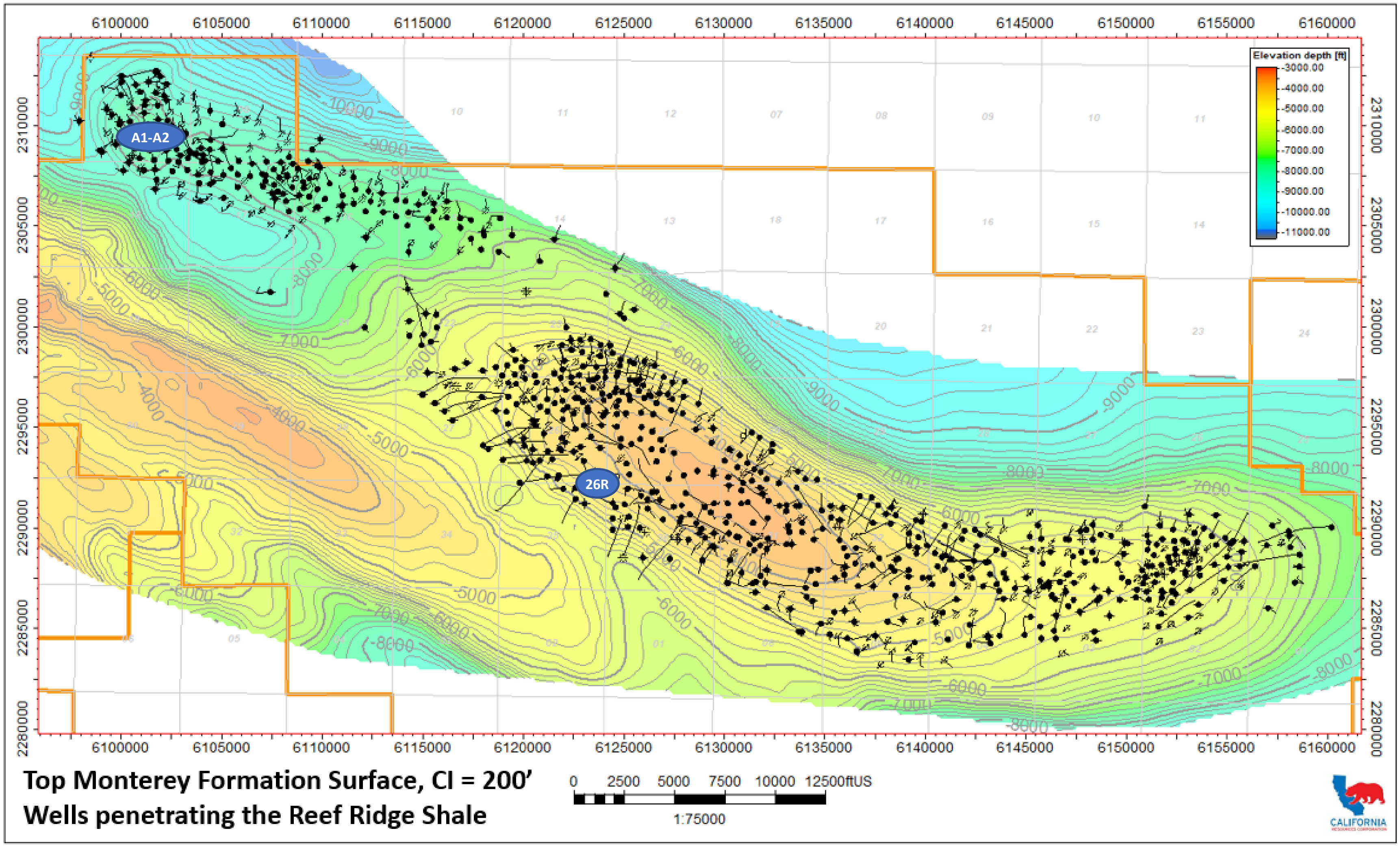


Figure 6: Wells penetrating the Reef Ridge shale. Project locations are shown at blue ovals.

Wells that penetrate the Reef Ridge shale (Table 3) were drilled between 1948 and 2014. Corrective action assessment of existing wellbores for the Class VI applications included the generation and detailed review of wellbore/casing diagrams for each well from CalGEM records. Information used in the review included depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top-of-cement determination supported the review for annular isolation.

Existing wellbores within the project areas will, where necessary and as approved by the UIC Director in the Class VI permit, be pressure tested, abandoned, re-abandoned, or have a technical demonstration of adequate zonal confinement. Corrective action will occur prior to the commencement of CO_2 injection or on an approved phased schedule after CO_2 injection commences if conditions allow.

Project injection and monitoring wells are listed in Section 11.5. Well workover crews are on-call to maintain active wells and to respond to any wellbore issues that arise. Incidents are detected by monitoring changes in the surface pressure of injection wells and by conducting Mechanical Integrity Tests (MITs) that include, but are not limited to, Radioactive Tracer Surveys (RTSs) and Standard Annular Pressure Tests (SAPTs).

All existing oil and gas wells, including both injection and production wells are regulated by CalGEM under Public Resources Code Division 3.

2.4 Reservoir Modeling

Numerical reservoir simulation is used for many purposes, including optimizing reservoir management, forecasting hydrocarbon and water production, predicting the behavior of injected fluids such as $CO_{2,}$ and assessing CO_2 plume development and confinement.

2.4.1 Reservoir Model for Operational Design and Economic Evaluation

Reservoir modeling workflow begins with the development of a three-dimensional (3-D) representation of the subsurface geology ("static model"). Static model development leverages all available well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces and faults (if present) into a geocellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. CRC used Schlumberger Petrel, an industry-standard geocellular modeling software, to build and maintain the EHOF static model.

The static model becomes "dynamic" in the reservoir simulator with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon phase,
- Liquid and gas relative permeability,
- Capillary pressure data, and
- Fluid injection and/or extraction rates.

2.4.2 Performance Prediction

One objective of the simulation models is to develop an injection plan that maximizes CO_2 storage and minimizes associated costs. The injection plan includes injection wells and appropriate injection rate and pressure for each well that adheres to regulatory requirements.

2.4.3 Plume Model for CO_2 Storage Capacity, Containment, and Predicted Plume Migration

Full-field plume models confirm reservoir capacity and CO_2 containment within the 26R and A1-A2 reservoir. These models were built using a dynamic reservoir simulation application known as the Equation-of-State (EOS) Compositional Simulator (GEM), developed by Computer Modelling Group Ltd. (CMG). Figure 7 shows the results of the modeling for the 26R and A1-A2 storage reservoir. The plume models were used to evaluate: (1) the quantity of CO_2 stored for geological sequestration, and (2) the lateral movement of CO_2 to define the MMA and demonstrate vertical confinement by the Reef Ridge shale.

2.4.4 Geomechanical Modeling of Reef Ridge Shale

In addition to the plume models, a simpler GEM-based model was coupled with a finite element geomechanical module, GEOMECH, to model cap rock failure in the Reef Ridge shale as a function of cap rock mechanical properties and reservoir pressure immediately below the cap rock. This model was used to assess the pressure at which the Reef Ridge shale would shear through tensile failure.

The plume modeling effort confirms the Monterey Formation's ability to permanently store the planned project CO_2 volumes under the Reef Ridge shale over the project's life. The results of the plume models are discussed in greater detail below.

3 Delineation of Monitoring Area and Timeframes

3.1 Maximum Monitoring Area

The MMA is defined in 40 CFR 98.449 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. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data as described above, was used to predict the size and location of the plume, as well as understand how the plume migrates over time.

The MMA, shown by the blue line Figure 8 , is defined by the extent of the CO_2 plume at 100 years post-injection for geologic sequestration plus one-half mile.

3.2 Active Monitoring Area

The AMA boundary was established by superimposing two areas (40 CFR 98.449):

- Area #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.
- Area #2: The area projected to contain the free phase CO_2 plume at the end of year $t + 5$.

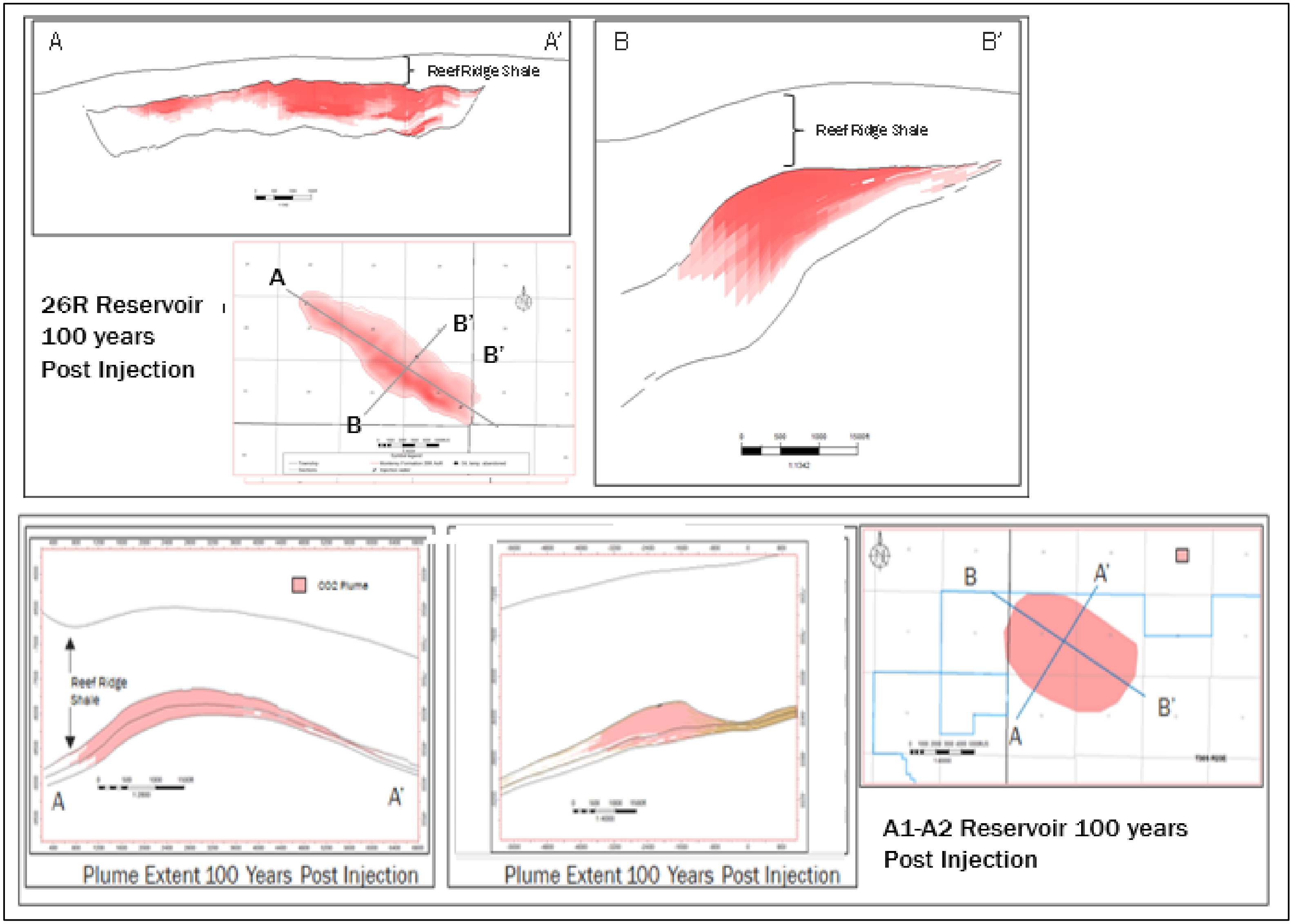


Figure 7: CO_2 plume modeling results.

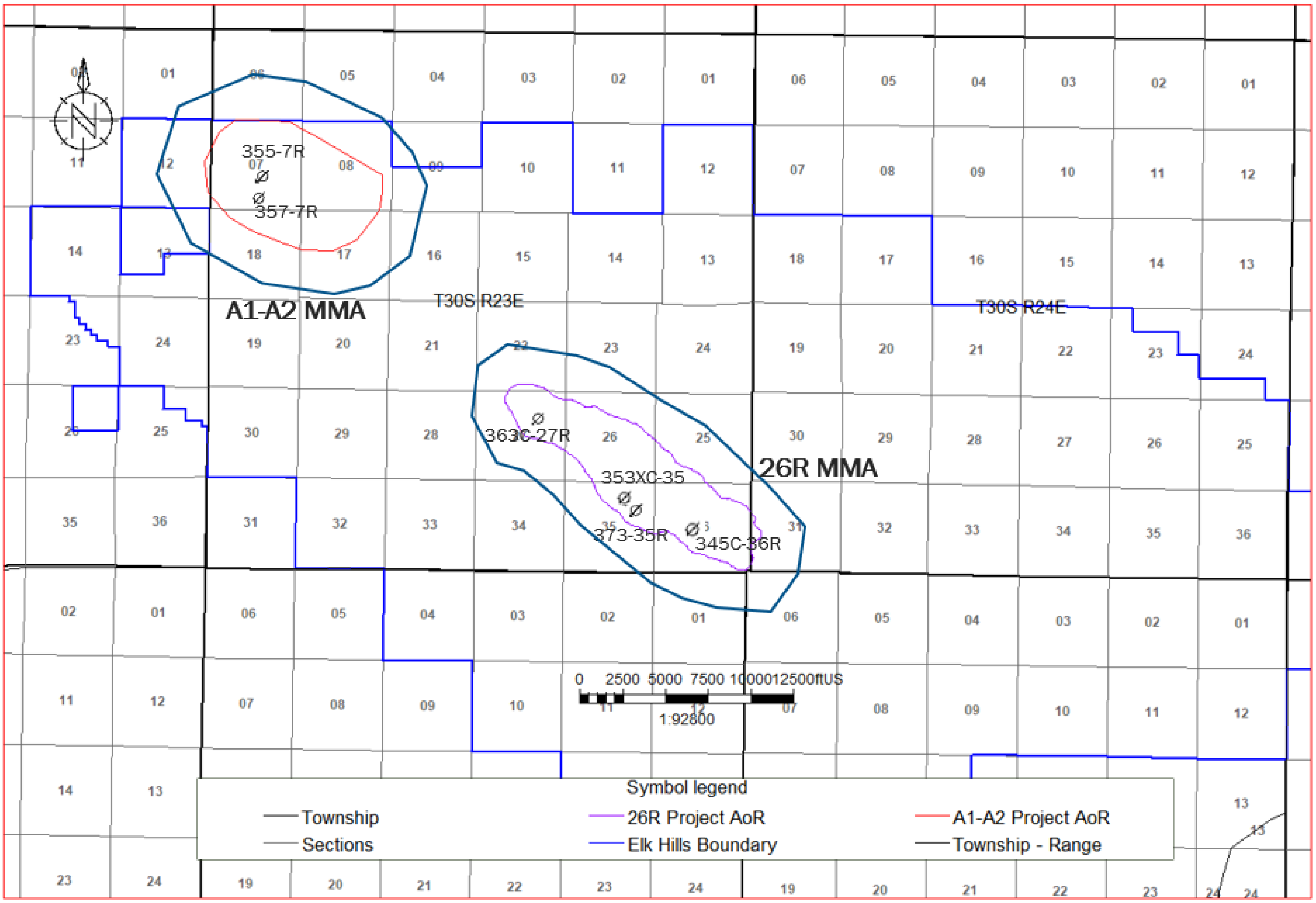


Figure 8: Injector well locations, EPA AoR (final CO_2 plume boundaries; orange and purple lines) and AMA - MMA (blue line). Scale bar units are feet.

The A1-A2 and 26R reservoirs are depleted and CO_2 is predicted to reach the edges of the reservoir within the first two to three years of injection (see Figures 9a, 9b). For this reason the area projected to contain free phase CO_2 is similar during the majority of the Specified Period.

The AMA boundary was determined for the time period ("*t*") corresponding to three years after the end of injection (30 years after the beginning of injection). Area #1, above, was taken as the plume area plus an all-around buffer zone of one-half mile. Area #2 is smaller or equal in all directions for both projects than Area #1, and therefore the final AMA was defined as Area #1 (Figure 8).

CTV has established one AMA boundary for 30 years and does not anticipate any expansion of the monitoring area under 40 CFR 98.448. Given the definitions used to define the MMA and AMA, AMA is also functionally equivalent to the MMA. Instituting monitoring throughout the entire MMA boundary for the Specified Period provides maximum operational flexibility. The absence of through-going faults or fractures confirms the competency of the Reef Ridge to preserve hydrocarbons within the Monterey Formation and to contain the CO_2.

3.3 Monitoring Timeframe

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted when a demonstration that current monitoring and model(s) show that the cumulative mass of CO_2 reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration within two to three years after injection for the Specified Period ceases based on predictive modeling supported by monitoring data.

4 Evaluation of Potential Pathways for Leakage to the Surface

4.1 Introduction

In the more than 100 years of the EHOF's development, the reservoir has been studied and documented extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO_2 to the surface. The following potential pathways are reviewed:

- Existing wellbores,
- Faults and fractures,
- Natural and induced seismic activity,
- Previous operations,
- Pipeline/surface equipment,
- Lateral migration outside the EHOF,
- Drilling through the CO_2 area, and
- Diffuse leakage through the seal.

Section 4.10 summarizes how CRC and CTV will monitor CO_2 leakage from various pathways and describes the response to various leakage scenarios. In addition, Section 5 describes how CRC and CTV will develop the inputs used in the Subpart RR mass-balance equation (Equation RR-12). Any incidents that result in CO_2 leakage up the wellbore and into the atmosphere will be quantified as described in Section 7.

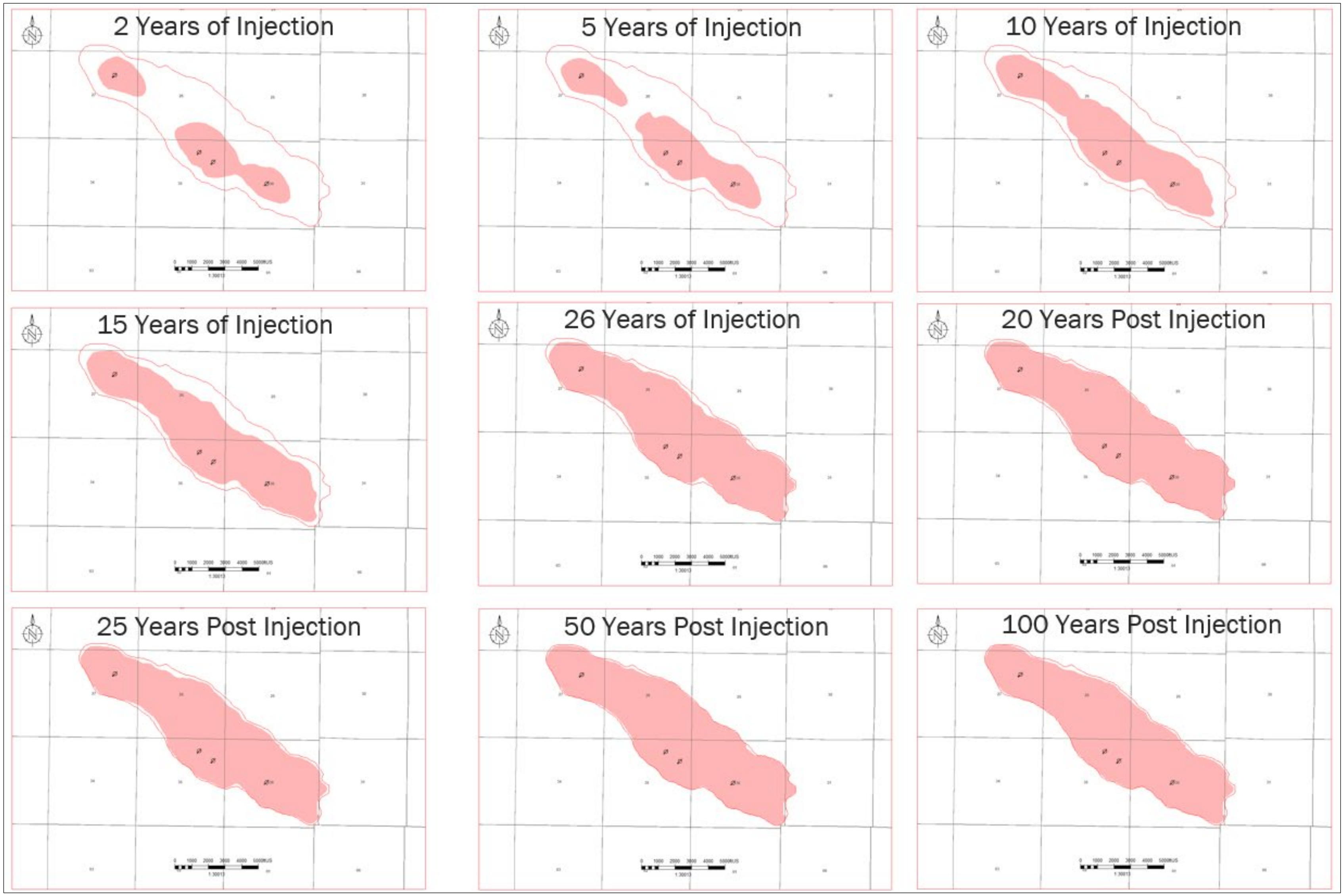


Figure 9a: Plan view showing modeled plume development through time, 26R project.

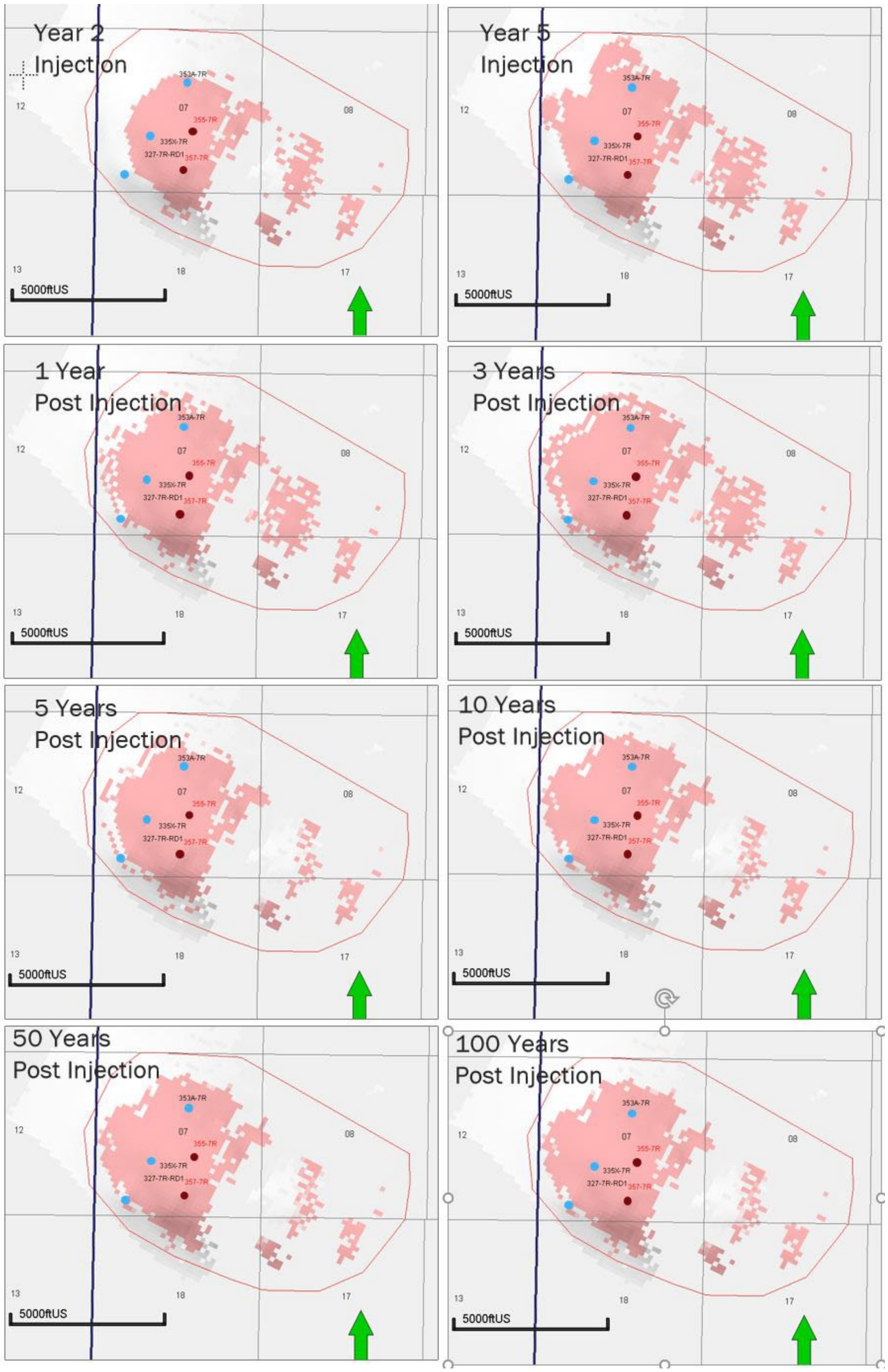


Figure 9b: Plan view showing modeled plume development through time, A1-A2 project (model layer 15). Red dots ae the injectors, Blue dots are monitoring wells.

4.2 Existing Wellbores

Leakage through existing wellbores is possible at the EHOF. However, that is mitigated by adhering to regulatory requirements for well drilling and testing; implementing best practices developed through extensive operating experience; monitoring injection/production performance, wellbores, and the surface; and maintaining surface equipment. Wells penetrating the Reef Ridge confining shale and sequestration reservoir are described in Section 2.3.3.

LIKELIHOOD: As discussed in Section 2.3.3, regulations governing the EHOF require that wells be completed and operated so that fluids are contained in the strata in which they are encountered. For this reason likelihood of leakage is considered low.

TIMING: Risk of leakage at each specific existing wellbore is greatest after CO_2 has reached that location and when pressures are greatest, which is towards the end of the project injection time period.

MAGNITUDE: Leakage mass is predicted to be less than one percent of total injection (less than 0.5 million metric tons).

MONITORING: Continual and routine monitoring and maintenance of wellbores and site operations is critical to ensure confinement in the following ways.

1. Injection well pressure is monitored continuously throughout the EHOF using a supervisory control and data acquisition (SCADA) system. Pressure and rate sensors on the injection wells are programmed to alarm and notify operations personnel when encountering values that significantly deviate from set target ranges. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such excursions occur, they are investigated and addressed.

2. Experience gained over time allows for a strategic approach to well maintenance and workovers; workover crews are onsite for this purpose. For example, the well classifications by age and construction method inform planning for monitoring and updating wells. All available information, including pattern performance and well characteristics, is used to determine well maintenance schedules.

3. A corrosion protection program for CO_2 operations will be implemented to mitigate both internal and external corrosion of casing in wells in the EHOF. In line with industry standard operations and EPA Class VI requirements for CCS, downhole equipment and the interior and exterior of wellbores will be protected using special materials (e.g., fiberglass tubing, corrosion-resistant cements, nickel-plated packers, corrosion-resistant packer fluids), and procedures will be performed to prevent and monitor for corrosion (e.g., packer placement, use of annular leakage detection devices, cement bond logs, pressure tests). These measures and procedures are typically included in the injection orders filed with CalGEM and the EPA UIC program. Corrosion protection methods and requirements may be enhanced over time in response to improvements in technology.

4. MIT requirements implemented by CalGEM and/or EPA UIC (as applicable) will be followed to periodically inspect wells and surface facilities to ensure that all wells and related surface equipment are in good repair, leak-free, and that all aspects of the site and equipment conform to existing regulations and permit conditions. All active injection wells undergo MIT before

injection, after any workover or per time periods specified in the UIC approval. Operators are required to use a pressure recorder and pressure gauge for the tests. For CalGEM regulated wells, operator's field representative must sign the pressure recorder chart and submit it with the MIT form to CalGEM. The casing-tubing annulus must be tested to maximum anticipated surface pressure (MASP) for a specified duration and with an allowable pressure loss specified in the regulations. CalGEM or EPA UIC may also approve alternative pressure monitoring programs with varying requirements at their discretion.

If a well fails the MIT, the operator must immediately shut the well in and provide notice to CalGEM. Casing leaks must be successfully repaired within 180 days and re-tested, or the well must be plugged and abandoned after submitting a formal notice and obtaining approval from CalGEM.

5. Finally, as indicated in Section 5, field inspections are conducted on a routine basis by field personnel. On any given day, there are approximately 40 personnel in the field. Leaking CO_2 is very cold and leads to formation of bright white clouds and ice that are easily spotted. All field personnel will be trained to identify leaking CO_2 and other potential problems in the field and to safely remedy the issue. Any CO_2 leakage detected will be documented and reported, quantified, and addressed as described in Section 5.

6. Corrective Action assessment performed pursuant to the Class VI regulation includes the generation and detailed review of wellbore/casing diagrams for each well in the project area. Information used in the review includes depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of cement determination supports the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface. For each well determined to require additional plugging CTV has provided the plugging procedure that will be used to abandon wells along with well-specific plugging plan tables that identify the number of plugs, placement method, cement type, density, and volume for the wells to be abandoned during pre-operational testing. The planned plugging procedures achieve all requirements of CalGEM regulations for proper abandonment of oil and gas wells.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, CRC and CTV conclude that it will mitigate CO_2 leakage through wellbores by detecting problems as they arise and quantifying any leakage that does occur by use of local surface air monitoring in the vicinity of the leaking wellbore.

4.3 Faults and Fractures

There are no faults or fractures penetrating the confining layer of the Reef Ridge shale that provide a potential upward pathway for fluid flow. First, the presence of oil, especially oil with a gas cap, is indicative of a competent natural seal. Oil, and to a greater extent gas, migrates upward over time because both are less dense than the brine found in rock formations. Places where oil and gas remain trapped in the deep

subsurface over millions of years, as is the case in the EHOF, prove that faults or fractures do not provide a pathway for upward migration out of the CO_2 flooding interval.

While developing the EHOF, a seismic survey was conducted to characterize the formations and provide information for the reservoir models used for development planning. Initial interpretations of the 3-D seismic survey were based on a conventional pre-stack time migration volume. In 2019, the 3-D seismic survey was reprocessed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 10 displays the location and extent of four faults that helped to form these anticlines beginning in the Middle Miocene, 16 million years ago (Callaway and Rennie, 1991). These faults have remained inactive for millions of years since. Offsetting the 31S and NWS structures are the 1R, 2R, and 3R high-angle reverse faults that are oriented NW-SE. The faults penetrate the lowest portions of the Monterey Formation but do not continue through the injection interval to the Reef Ridge shale confining layer.

Lastly, the operating history of the EHOF confirms there are no faults or fractures penetrating the Reef Ridge shale that allow fluid migration. Water and gas have been successfully injected into the Monterey Formation since 1976, and there is no evidence of new or existing faults or fractures. Over 1.4 billion barrels of water and 1,237 billion standard cubic feet (Bcf) of gas have been injected into the NWS and 31S structures with no reservoir confinement issues. In fact, it is the absence of faults and fractures in the Reef Ridge shale that makes the Monterey Formation such a strong candidate for water injection operations and enables field operators to maintain effective control over the injection and production processes.

LIKELIHOOD: Because there are no faults or fractures penetrating the confining layer of the Reef Ridge shale that provide a potential upward pathway for fluid flow the likelihood of leakage is considered negligible.

TIMING: No faults are present that provide a potential pathway; therefore leakage is not expected via this pathway over the entire duration of the project.

MAGNITUDE: For reasons given above, anticipated leakage magnitude is negligible.

MONITORING: Leakage via faults, if it were to occur, would be subject to detection from monitoring wells in zones above the sequestration reservoir, as described in Section 5.1.

4.4 Natural or Induced Seismicity

Based on published data and over 100 years of operational experience, there is no evidence that natural seismic activity poses a significant risk for loss of CO_2 for the project. This is due, in part, to the thickness, ductility, and predominance of clay in the primary confining layer Reef Ridge shale.

No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area. Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west, beyond the Temblor Range) and the White Wolf Fault (25 miles southeast from the EHOF).

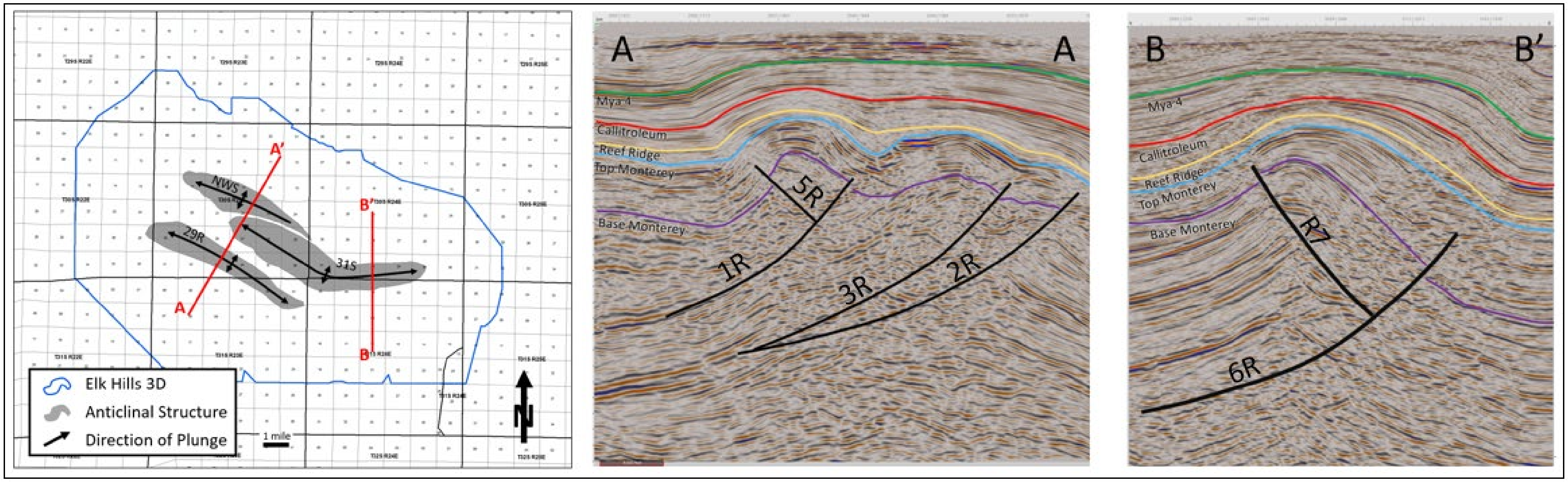


Figure 10: Outline of EHOF 3-D survey and seismic intersections across 31S and NWS structures.

Historical seismic events from 1932 to present are available from the Southern California Earthquake Data Center (SCEDC). Based on this data, there have been no earthquakes recorded greater than 3.0 in the A1-A2 and 26R MMA. In addition, there have only been eleven earthquakes with a magnitude of 5.0 or greater within a 30-mile buffer around the EHOF administrative boundary (Figure 11). There have been 518 earthquakes with a magnitude between 3 and 5 within the 30-mile EHOF buffer. The average depth of the earthquakes with magnitude greater than 3 is 4.5 miles, while the storage reservoirs are one mile below surface.

LIKELIHOOD: Induced seismicity will be mitigated operationally by the following:

1. Injection pressure will be monitored continuously and will be lower than the failure pressure of the confining Reef Ridge shale.
2. Reservoir pressure will be at or beneath the discovery pressure.
3. Seismometers will be installed at the surface to detect seismicity induced by injection operations.

Adherence to these mitigation measures will ensure that likelihood of induced seismicity is low.

TIMING: Risk of induced seismicity is highest when operating pressures are greatest at the end of the injection time period. Risk of natural seismicity is not anticipated to change during the Specified Period.

MAGNITUDE: For reasons given above, anticipated leakage magnitude is negligible.

MONITORING: Induced seismicity monitoring with seismometers, as described in Section 5.1.

4.5 Previous Operations

All of the existing wells at the EHOF have been permitted through CalGEM (and predecessor California agencies) under rules that require detailed information about the character of the geologic setting, the construction and operation of the wells, and other information used to assess the suitability of the site. CalGEM maintains a public database that contains the location, construction details, and injection-production history of each well.

CTV has assessed internal databases as well as CalGEM information to identify and confirm wells within the project area. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Therefore, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the development history of the reservoir that includes injection of water and gas.

Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest at the end of the injection period.

LIKELIHOOD: This operational experience has verified that there are no unknown wells within the EHOF. Additionally, CRC and CTV have sufficiently mitigated the possibility of migration from older wells as discussed above. Over many years, the EHOF has been continuously checked for the presence of old, unknown wells throughout the EHOF. These practices ensure that identified wells are sufficiently isolated and do not interfere with ongoing operations and reservoir pressure management. For these reasons risk of leakage via this pathway is considered low.

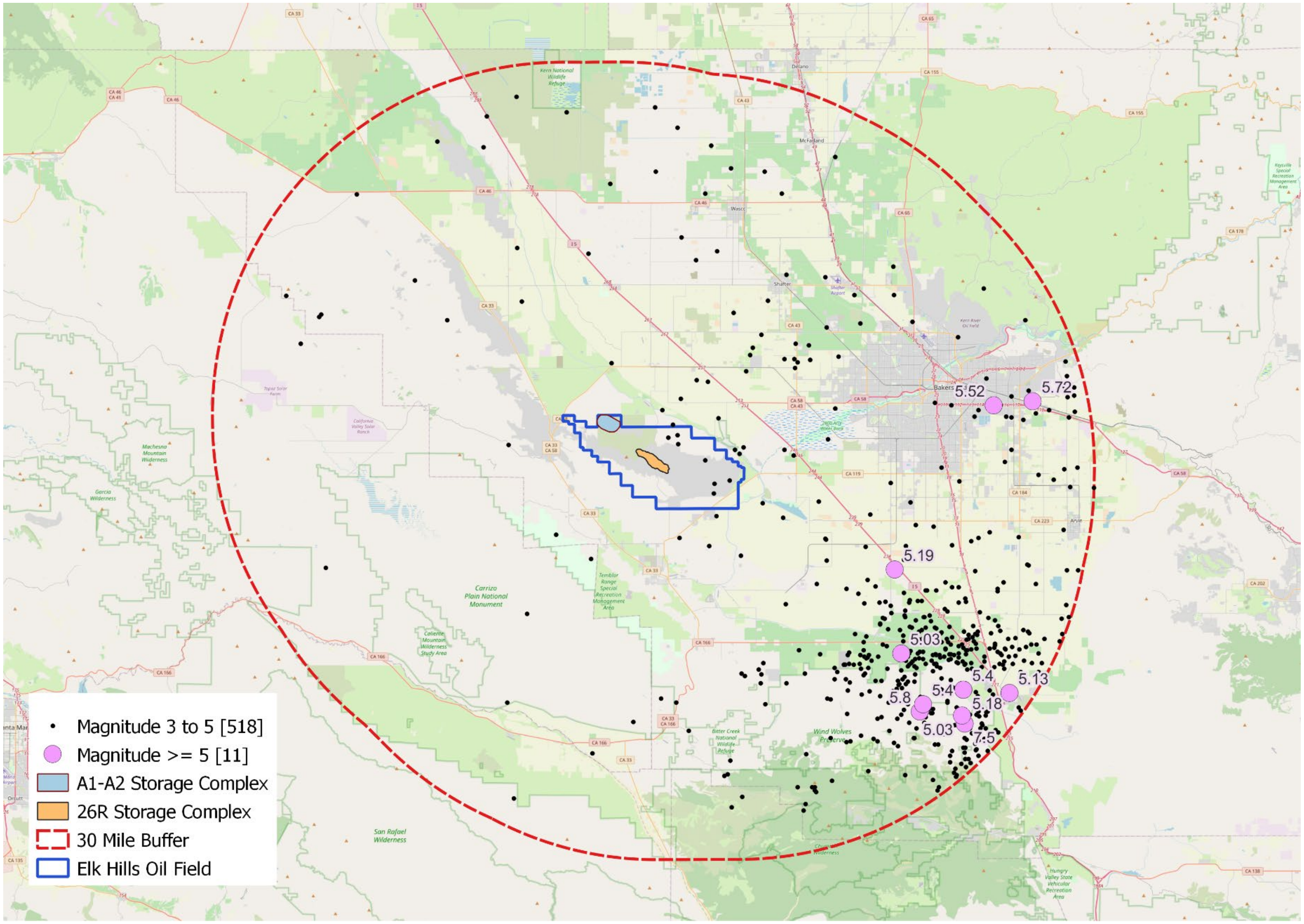


Figure 11: Earthquakes in the San Joaquin Basin with a magnitude greater than 3. Note: only 11 earthquakes have occurred within a 30-mile buffer around the EHOF administrative boundary. Earthquake data from SCEDC.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest that will be at the end of the injection period.

MAGNITUDE: Leakage mass is predicted to be less than one percent of total injection (less than 0.5 million metric tons).

MONITORING: Leakage via abandoned wells, if it were to occur, would be subject to detection from monitoring wells in zones above the sequestration reservoir, as described in Section 5.1. Additional monitoring is discussed in Section 4.2.

4.6 Pipeline/Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2. Unplanned leakage from surface facilities will be mitigated to the maximum extent practicable by relying on the use of prevailing design and construction practices and maintaining compliance with applicable regulations. The facilities and pipelines will be constructed of materials and managed using control processes that are standard for CO_2 injection projects.

CO_2 delivery to the complex will comply with all applicable regulations, including as pipeline regulations are updated in the future as applicable. Instrumentation will be installed on pipelines and facilities that allows the 24/7 operations staff at the Central Control Facility (CCF) to monitor the process and potentially spot leaks. Furthermore, frequent and routine visual inspections of surface facilities by field staff will provide an additional means to detect leaks. Both manual and automatic shutdowns will be installed in the complex to ensure that leaks are addressed in a timely manner.

LIKELIHOOD: Compliance with applicable regulations, as described above, ensures that likelihood of leakage via this pathway is low.

TIMING: Leakage risk via this pathway will be similar over the project time period.

MAGNITUDE: Should leakage be detected from pipeline or surface equipment, the mass of released CO_2 will be quantified following the requirements of 40 CFR 98.230-238 (Subpart W) of EPA's Greenhouse Gas Reporting Program (GHGRP).

MONITORING: Routine field inspection and remote monitoring will be conducted to detect any potential leakage from pipelines and surface facilities.

4.7 Lateral Migration

It is highly improbable that injected CO_2 will migrate downdip and laterally outside the EHOF because of the buoyant properties of supercritical CO_2, the nature of the geologic structure, and the planned injection approach. The strategy to minimize the lateral migration risk is to ensure that the CO_2 plume and surrounding fluids will be at or below the initial reservoir pressure at time of discovery.

LIKELIHOOD: Leakage via this pathway is not anticipated.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest at the end of the injection period.

MAGNITUDE: Leakage via this pathway is not anticipated to occur, and therefore magnitude of any leakage is considered negligible.

MONITORING: Geophysical monitoring conducted as approved in the Class VI permit will track the extent of CO_2 plume and ensure that there is not lateral migration outside of the AoR.

4.8 Drilling Through the CO_2 Area

It is possible that at some point in the future, drilling through the Reef Ridge confining zone and into the Monterey Formation may occur.

LIKELIHOOD: The possibility of this activity creating a leakage pathway is extremely low for three reasons: 1) Future well drilling would be regulated by CalGEM (oil and gas wells) or EPA UIC (Class VI injection wells) and will therefore be subject to requirements that fluids be contained in strata in which they are encountered; 2) as sole operators and owners of the EHOF, CRC and CTV control placement and timing of new drilling operations; and 3) there are no oil and gas targets beneath the Monterey Formation.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest during future time periods if drilling through the Reef Ridge confining zone were to occur.

MAGNITUDE: Leakage via this pathway is not anticipated to occur, and therefore magnitude of any leakage is considered negligible.

MONITORING: Ongoing regulation of all drilling activities by CalGEM and/or EPA will ensure future monitoring of drilling activities. See additional monitoring discussion in Section 4.2.

4.9 Leakage Through the Seal

Diffuse leakage through Reef Ridge confining layer is highly unlikely. The presence of gas caps trapped over millions of years confirms that the seal has been secure for millions of years. Leaking through the seal is mitigated by ensuring that post-injection reservoir pressure will be at or below the initial reservoir pressure at the time of discovery. The injection monitoring program referenced in Section 2.3.2 and detailed in Section 5 assures that no breach of the seal will be created.

Further, if CO_2 were to migrate through the Reef Ridge, it would migrate vertically until it encountered and was trapped by any of the additional shallower interbedded shales of the Etchegoin, San Joaquin, and Tulare Formations (more than 5,000 ft of vertical section; see Figure 3).

LIKELIHOOD: Diffuse leakage through Reef Ridge confining layer is highly unlikely.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest at the end of the injection period when pressures are highest. In addition the relative amount of CO_2 in the supercritical phase will decrease over time post-injection as CO_2 dissolves into the brine reducing leakage risk.

MAGNITUDE: Leakage via this pathway is not anticipated to occur, and therefore magnitude of any leakage is considered negligible.

MONITORING: Leakage, if it were to occur, would be subject to detection from monitoring wells in zones above sequestration reservoir, as described in Section 5.1.

4.10 Monitoring, Response and Reporting Plan for CO_2 Loss

As discussed above, the potential sources of leakage include routine issues such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment, and unique events such as induced fractures.

Table 4 summarizes some of these potential leakage scenarios, monitoring activities designed to detect those leaks, standard response, and other applicable regulatory programs requiring similar reporting.

Risk	Monitoring Plan	Response Plan	Parallel Reporting (if any)
Loss of well control			
Tubing leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days	
Casing leak	Routine field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days	CalGEM or EPA UIC
Wellhead leak	Routine field inspection and continuous SCADA monitoring	Workover crews respond within days	
Loss of bottom-hole pressure control	Blowout during well operations	Maintain well-kill procedures; shut-in offset injectors prior to drilling	CalGEM or EPA UIC
Loss of seal in abandoned wells	Anomalous pressure or gas composition from productive shallower zones	Re-enter and reseal abandoned wells	CalGEM or EPA UIC
Leaks in surface facilities			
Pumps, valves, etc.	Routine field inspection and remote monitoring	Workover crews respond within days	Subpart W
Subsurface leaks			
Leakage along faults	Monitoring of zones above sequestration reservoir	Shut-in injectors near faults	EPA UIC
Leakage through induced fractures	Induced seismicity monitoring with seismometers	Comply with rules for keeping pressures below parting pressure	EPA UIC
Leakage due to a seismic event	Induced seismicity monitoring with seismometers	Shut-in injectors near seismic event	EPA UIC

Table 4: Response plan for CO_2 leakage or loss.

Section 5.1 discusses the approaches envisioned for quantifying the mass of leaked CO_2. In the event leakage occurs, CRC and CTV plan to determine the most appropriate methods for quantifying the mass leaked and will report it as required as part of the annual Subpart RR submission.

Any mass of CO_2 detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR 98.230-238 (Subpart W) or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as frequency of inspection. As indicated in Sections 5.1 and 7, leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in the electronic environmental documentation and reporting system. Repairs requiring a work order will be documented in the electronic equipment maintenance system and well work historian. If the scope of repair work requires permitting through CalGEM or EPA UIC, a subsequent operations summary report will be provided under the conditions of the applicable permit.

4.11 Summary

The structure and stratigraphy of the Monterey Formation in the EHOF is ideally suited for injection and CO_2 storage. The CO_2 injection zone stratigraphy is porous, permeable, and very thick, providing ample capacity for long-term CO_2 storage. The overlying Reef Ridge shale forms an effective seal for Monterey Formation sequestration (see Figure 3). After assessing potential risk of release from the subsurface and steps that have been taken to prevent leaks, the potential threat of significant leakage is extremely low.

Risk of release is further reduced by the prudent operational strategy of limiting the pressure of the reservoir post-injection to at or below the initial pressure of the reservoir at time of discovery.

5 Monitoring and Considerations for Calculating Site-specific Variables

5.1 For the Mass Balance Equation

5.1.1 General Monitoring Procedures

Existing operations are centrally monitored and controlled by the extensive and sophisticated CCF. The CCF uses a SCADA software system to implement operational control decisions on a real-time basis throughout the EHOF to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Flow rates, pressures, gas composition, and other data will be collected at key points and stored in a centralized data management system. These data are monitored 24 hours a day by qualified technicians who follow response and reporting protocols when the system delivers notifications that data exceed predetermined statistically acceptable limits. The data can be accessed for immediate analysis.

Figure 5 identifies the meters that will be used to evaluate, monitor, and report on the injection project and associated plume migration described earlier in Section 2.3. A similar metering system is already installed throughout the EHOF.

As indicated in Figure 5, a custody-transfer meter will be installed at the CO_2 sources. The custody-transfer meters will measure flow rate continuously. Fluid composition will be determined on either a continuous basis or by periodic sampling depending on the specific meter; both options are accurate for purposes of commercial transactions. All meter and composition data will be recorded.

Metering protocols follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. These meters will be maintained routinely, operated continuously, and will feed data directly to the CCF. In the oil and gas industry, the accepted level of custody-transfer meter accuracy is 0.25% or better, and the meters are calibrated every 60 to 90 days. A third party is frequently used to calibrate these meters, and both parties to any transaction have rights to witness meter calibration. These custody meters provide the most accurate way to measure mass flows.

Most process streams are multi-component or multi-phase, with varying CO_2 compositions. For these streams, flow rate is the most important control parameter. Operations flow meters are used to determine the flow rates of these process streams, which allows for the monitoring of trends to identify deviations and determine if any intervention is needed. Flow meters are also used—comparing aggregate data to individual meter data—to provide a cross-check on actual operational performance.

Developing a CO_2 mass balance on multi-phase, multi-component process streams is best accomplished using custody-transfer meters rather than multiple operations meters. As noted above, in-field flow rate monitoring presents a formidable technical and maintenance challenge. Some variance is due simply to differences in factory settings and meter calibration. Additional variance is due to the operating conditions within a field. Meter elevation, changes in temperature (over the course of the day), fluid composition (especially in multi-component or multi-phase streams), or pressure will affect any in-field meter reading.

Many meters have some form of automatic adjustment for some of these factors, others utilize a conversion factor that is programmed into the meter, and still others need to be adjusted manually in the calculation process. Use of a smaller number of centrally located meters reduces the potential error that is inherent in employing multiple meters in various locations to measure the same mass of flow and gas composition.

Table 5 summarizes the CO_2 injection monitoring strategy. Figure 12 shows the location of monitoring wells.

Monitoring Activity	Frequency/Location
MIT (Internal and External)	Annual
SAPT	Initially; any time the packer is replaced or reset
Injection rate, pressure, and temperature	Continuous
Seismicity	Induced seismicity monitoring via seismometers
Underground sources of drinking water (USDWs) and reservoirs between USDWs and sequestration reservoir	Monitoring wells with pressure, temperature, fluid composition, and periodic cased-hole logs
Stream analysis	Continuous
Corrosion monitoring (coupons, casing integrity)	Well materials, pipelines, and other surface equipment
Sequestration reservoir monitoring	Dedicated wells monitoring sequestration reservoir with pressure, temperature, fluid composition, and periodic cased hole logs

Table 5: Injection monitoring strategy summary.

5.1.2 CO_2 Received

A custody-transfer meter will be used at the CO_2 source(s) to continuously measure the mass and composition of CO_2 received. The metering protocols will follow the prevailing industry standard(s) for custody transfer (as promulgated by the API and the AGA).

5.1.3 CO_2 Injected into the Subsurface

Injected CO_2 associated with geologic sequestration will be calculated using the flow meter mass at the operations/composition meter at the outlet of the recompression facilities (RCFs) and the custody-transfer meter at the CO_2 off-take points.

5.1.4 CO_2 Produced, Entrained in Products, and Recycled

No CO_2 will be produced or entrained in products or recycled.

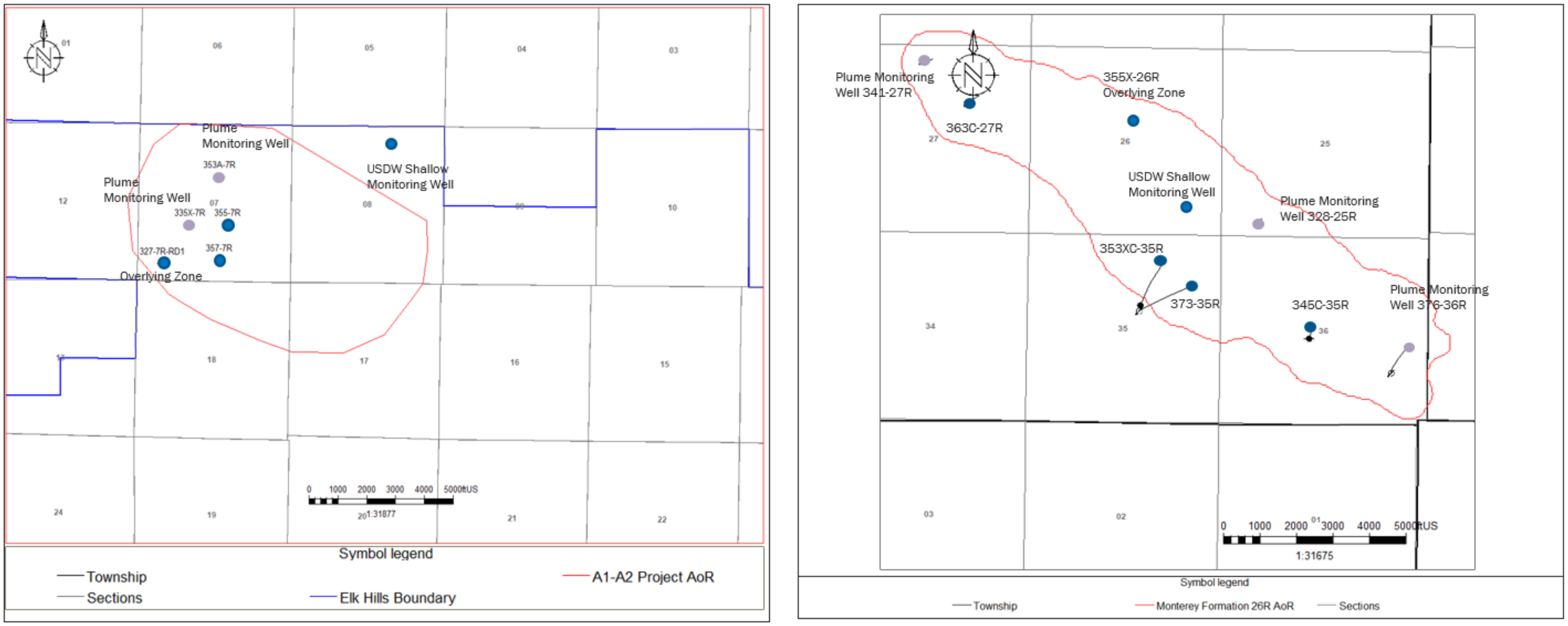


Figure 12: Map showing monitoring well locations.

5.1.5 CO_2 Emitted by Surface Leakage

40 CFR 98.230-238 (Subpart W) is used to estimate surface leaks from equipment at the EHOF. Subpart W uses a factor-driven approach to estimate equipment leakage. In addition an event-driven process will be used to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. Reporting will reconcile the Subpart W report and results from any event-driven quantification to assure that surface leaks are not double-counted.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet the following two objectives in accordance with the leakage risk assessment in Section 4: 1) to detect problems before CO_2 leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the mass of CO_2 leaked to the surface. Injection Wells

Injection well pressure, temperature, and injection rate will be monitored continuously. If injection pressure or rate measurements are beyond the specified set-points determined for each injector, a data flag is automatically triggered and field personnel will investigate and resolve the problem. These excursions will be reviewed by well-management personnel to determine if CO_2 leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or another minor action is required), and there is no threat of CO_2 leakage. In the case of issues that are not readily resolved, more detailed investigation and response would be initiated, and internal support staff would provide additional assistance and evaluation. Such issues would lead to the development of a work order in the work order management system. This record will enable the company to track progress on investigating potential leaks and, if a leak has occurred, to quantify its magnitude. To quantify leakage to the surface, an estimate of the relevant parameters (e.g., the rate, concentration, and duration of leakage) will be made to quantify the leak mass. Depending on specific circumstances, these determinations may rely on engineering estimates.

Monitoring of Wellbores

Because leaking CO_2 at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a two-part visual inspection process will be employed in the general area of the EHOF to detect unexpected releases from wellbores. First, field personnel will visit the surface facilities on a routine basis. Inspections may include tank volumes, equipment status and reliability, lube oil levels, pressures and flow rates in the facility, and valve leaks. Field personnel inspections will also check that injectors are on the proper schedule and observe the facility for visible CO_2 or fluid line leaks.

Finally, data collected by personal CO_2 gas monitors (ToxiRAE Pro CO_2 or equivalent), which will always be worn by field personnel, will be a last method to detect leakage from wellbores. The monitor's sensor range is 0 to 50,000 parts per million (ppm) and resolution is 100 ppm. The monitor alarm setting will be established to alert workers to a CO_2 concentration exceeding 1,000 ppm or a lower value. If an alarm is triggered, the first response will be to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. If the incident results in a work order, this will serve as the basis for tracking the event for greenhouse gas (GHG) reporting. Targeted point-source surface air monitoring will be conducted in the event of detected wellbore leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

Other Potential Leakage at the Surface

Routine visual inspections at surface are used to detect significant loss of CO_2 to the surface. Field personnel visit manned surface facilities daily to conduct visual inspection. Inspections may include review of equipment status, lube oil levels, pressures and flow rates in the facility, valve leaks, ensuring that injectors are on the proper schedule, and conducting a general observation of the facility for visible CO_2 or fluid line leaks. If problems are detected, field personnel would investigate and, if maintenance is required, generate a work order in the maintenance system which is tracked through completion. In addition to these visual inspections, CRC and CTV will use the results of the personal gas monitors as a supplement for smaller leaks that may escape visual detection.

If CO_2 leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, a work order will be generated in the work order management system. The work order will describe the appropriate corrective action and be used to track completion of the maintenance action. The work order will also serve as the basis for tracking the event for GHG reporting and quantifying any CO_2 emissions. Targeted surface air and/or soil gas flux monitoring will be conducted in the event of detected leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

5.1.6 Monitoring for Potential Leakage from the Injection/Production Zone

Monitoring wells to measure pressure, temperature, and fluid composition will be dedicated to geologic sequestration. These dedicated wells will monitor the sequestration reservoir, zones above the sequestration reservoir, and the USDW. Baseline analysis will be established for each of these wells. Any deviation from the baseline analysis will be assessed for potential indications of leakage. Measured increase in CO_2 in groundwater above the Storage Complex will be used to develop groundwater isoconcentration maps and quantify CO_2 leakage rates.

Monitoring well locations are shown on Figure 12, and monitoring wells are listed in Appendix 11.5. Monitoring well details including depth and chemistry monitoring parameters are listed in Appendix 11.6. Monitoring well data collection procedures will be consistent with protocols listed in the Class VI permit application.

5.1.7 Seismicity Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole. This network will be implemented to monitor seismic activity near the project site, and will consist of passive seismic monitoring to demonstrate that there are no seismic events affecting CO_2 containment.

Specifications of the network are as follows:

- Seven sensor locations (borehole and near surface) with high-sensitivity 3-component geophones.
- Borehole sensors will be deployed deeper than 1,500' to ensure a good quality signal and to minimize noise. A velocity model will be derived from vertical seismic profiles (VSPs), sonic well logs, and check shots.
- The system will be designed with capability of detecting and locating events greater than moment magnitude scale (M_w) 0.0.

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed continuously. Waveform data will be transmitted near real-time via cellular modem or other wireless means and archived in a database. Additionally, CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network.

The Class VI permit application describes actions that will be taken in the event of detected seismic events, based on the magnitude and frequency of seismic activity. In the event of a seismic event greater than M_w 2.0 and local report and confirmation of damage, an investigation will be conducted to determine of CO_2 leakage has occurred. Targeted surface air and/or soil gas flux monitoring will be conducted in the event of detected leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

5.1.8 CO_2 Emitted from Equipment Leaks and Vented Emissions of CO_2 from Surface Equipment Located Between the Injection Flow Meter and the Injection Wellhead

Monitoring efforts will evaluate and estimate leaks from equipment and vented CO_2 as required under 40 CFR 98.230-238 (Subpart W).

5.2 To Demonstrate that Injected CO_2 is not Expected to Migrate to the Surface

At the end of the Specified Period, CRC and CTV intend to cease injecting CO_2 for the subsidiary purpose of establishing the long-term storage of CO_2 in the EHOF. After the end of the Specified Period, CRC and CTV anticipate that it will submit a request to discontinue monitoring and reporting. The request will demonstrate that the amount of CO_2 reported under 40 CFR 98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage. At that time, CRC and CTV will be able to support the request with years of data collected during the Specified Period as well as two to three (or more, if needed) years of data collected after the end of the Specified Period. This demonstration will provide the information necessary for the EPA UIC Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

- Data comparing actual performance to predicted performance (injection) over the monitoring period,
- An assessment of the CO_2 leakage detected, including discussion of the estimated amount of CO_2 leaked and the distribution of emissions by leakage pathway,
- A demonstration that future operations will not release the mass of stored CO_2 to the surface,
- A demonstration that there has been no significant leakage of CO_2, and
- An evaluation of reservoir pressure in the EHOF that demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

6 Determination of Baselines

Automatic data systems will be used to identify and investigate deviations from expected performance that could indicate CO_2 leakage. These data systems are used primarily for operational control and monitoring, and as such, are set to capture more information than is necessary for reporting in the Annual

Subpart RR Report. Necessary system guidelines will be developed to capture the information that is relevant to identify CO_2 leakage. A description of the approach to collecting this information is given below.

6.1 Visual Inspections

As field personnel conduct routine inspections, work orders are generated in the electronic system for maintenance activities that cannot be immediately addressed. Methods to capture work orders that involve activities that could potentially involve CO_2 leakage will be developed, if not currently in place. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation. The responsible party will be provided in the monitoring plan, as required under 40 CFR 98.3(g) (Subpart A). The Annual Subpart RR Report will include an estimate of the amount of CO_2 leaked. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

6.2 Personal Gas Monitors

CO_2 gas monitors will be worn by all field personnel (ToxiRAE Pro CO_2 or equivalent; sensor range 0 to 50,000 ppm and resolution of 100 ppm). The monitor alarm setting will be established to alert workers to a CO_2 concentration exceeding 1,000 ppm or a lower value. Any monitor alarm will trigger an immediate response to ensure personnel are not at risk and to verify the monitor is working properly. If a fugitive leak is discovered, it would be quantified, and mitigating actions determined accordingly. The person responsible for MRV documentation will receive notice of all incidents where gas is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO_2 emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

6.3 Monitoring Wells

Baseline data will be collected from each monitoring well during well construction in order to provide a baseline. Baseline data will be collected on sequestration zone fluid chemistry and pressure, and above confining zone water chemistry and pressure at monitoring well locations. Data will be acquired that is characteristic of the subsurface after showing data stabilization. Quarterly fluid sampling and continuous pressure/temperature monitoring will be conducted at groundwater monitoring wells above the confining zone during the baseline period. In the injection zone fluid chemistry sampling will occur once at each location and temperature/pressure will be monitored continuously during the baseline period.

6.4 Seismic Baseline

The seismic monitoring network (Section 5.1.7) will be installed during the construction phase. Baseline seismicity data will be collected from the seismic monitoring network for at least 12 months prior to first injection to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

6.5 Injection Rates, Pressures, and Mass

Target injection rates and pressures will be developed for each injector, based on the results of ongoing modeling and permitted limits. High and low set-points are programmed into the controllers, and flags whenever statistically significant deviations from the targeted ranges are identified. The set-points are designed to be conservative. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO_2 leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions and related work orders that could potentially involve CO_2 leakage. The Annual Subpart RR Report will provide an estimate of CO_2 emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

7 Determination of Sequestration Mass Using Mass Balance Equations

The following sections describe how each element of the mass-balance equation (Equation RR-12) will be calculated.

7.1 Mass of CO_2 Received

CRC and CTV will use Equation RR-1 as indicated in 40 CFR 98.443 to calculate the mass of CO_2 received from each custody-transfer meter immediately downstream of the source(s).

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \qquad \text{(Eq. RR-1)}$$

Where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).
$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).
$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).
$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (wt. percent CO_2, expressed as a decimal fraction)
p = Quarter of the year.
r = Receiving flow meter.

Given CRC and CTV's method of receiving CO_2 and requirements of 40 CFR 98.444(a):

- All delivery to EHOF is used, so quarterly flow redelivered, $S_{r,p}$, is zero ("0") and will not be included in the equation
- Quarterly CO_2 concentration will be taken from the gas measurement database

CRC and CTV will sum to total mass of CO_2 Received using Equation RR-3 in 40 CFR 98.443:

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \text{ (Eq. RR-3)}$$

Where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-1 for flow meter r.

r = Receiving flow meter.

7.2 Mass of CO_2 Injected into the Subsurface

Mass of CO_2 injected into the subsurface at EHOF at each injection well will be calculated with Equation RR-4:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \quad \text{(Eq. RR-4)}$$

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.

Aggregated injection at all injection wells will be calculated with Equation RR-6:

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \quad \text{(Eq. RR-6)}$$

where:

CO_2. = 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.

7.3 Mass of CO_2 Emitted by Equipment Leakage

CRC and CTV will calculate and report the total annual mass of CO_2 emitted by equipment leakage using an approach that is tailored to specific leakage events and relies on 40 CFR 98.230-238 (Subpart W) equipment leakage reports. As described in Sections 4 and 5.1, the operators are prepared to address the potential for leakage in a variety of settings. Estimates of the amount of equipment leakage will depend on several site-specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

7.4 Mass of CO_2 Emitted by Surface Leakage

The process for quantifying surface leakage will entail using best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are discussed in Section 5.1. In the event leakage to the surface occurs, the quantify and leakage amounts will be reported, and records retained that describe the methods used to estimate or measure the mass leaked as reported in the Annual Subpart RR Report. Further, the Subpart W report and results from any event-driven quantification will be made to assure that surface leaks are not double-counted.

Equation RR-10 in 40 CFR 98.443 will be used to calculate and report the mass of CO_2 emitted by surface leakage:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \text{ (Eq. RR-10)}$$

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.

7.5 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Equation RR-12 in 40 CFR 98.443 will be used to calculate the mass of CO_2 sequestered in subsurface geologic formations in the reporting year as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \text{ (Eq. RR-12)}$$

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

Figure 5 illustrates that CO_2 supplied for geological storage will be metered between the CO_2 source and the injection meter.

7.6 Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formations

A sum of the total annual mass obtained using RR-12 in 40 CFR 98.443 will be used to calculate the cumulative mass of CO_2 sequestered in subsurface geologic formations.

8 MRV Plan Implementation Schedule

It is anticipated that this MRV plan will be implemented as early as first quarter (Q1) 2025 pending appropriate permit approvals and an available CO_2 source, or within 90 days of EPA approval, whichever occurs later. Other facility GHG reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. As described in Section 3.3 above, it is anticipated that that the MRV program will be in effect during the Specified Period, during which time the project will ensure long-term containment of a measurable quantity of CO_2 in subsurface geologic formations at the EHOF and that the project will be operated in a manner not expected to result in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be made and submission with a request to discontinue reporting under this MRV plan (see 40 CFR 98.441(b)(2)(ii)).

9 Quality Assurance Program

9.1 Monitoring QA/QC

As indicated in Section 7, the requirements of 40 CFR 98.444 (a) – (d) in the discussion of mass balance equations have been incorporated. These include the following provisions.

CO_2 Received and Injected

The quarterly flow rate of CO_2 received is measured at the receiving custody-transfer meters.

CO_2 emissions from equipment leaks and vented emissions of CO_2

These amounts are measured in conformance with the monitoring and QA/QC requirements specified in 40 CFR 98.230-238 (Subpart W).

Flow meter provisions

The flow meters used to generate data for the mass balance equations in Section 7 are:

- Operated continuously except as necessary for maintenance and calibration,
- Operated using the calibration and accuracy requirements in 40 CFR 98.3(i),
- Operated in conformance with API standards, and
- Traceable by the National Institute of Standards and Technology (NIST).

9.2 Missing Data Procedures

In the event data needed for the mass balance equations cannot be collected, procedures in 40 CFR 98.445 for estimating missing data will be used as follows:

- A quarterly flow rate of CO_2 received that is missing would be estimated using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.

- For any 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 specified in 40 CFR 98.230-238 (Subpart W) would be followed.

9.3 MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters, the MRV plan will be revised and submitted to the EPA UIC Administrator within 180 days as required in 40 CFR 98.448(d).

10 Records Retention

The record retention requirements specified by 40 CFR 98.3(g) will be followed. In addition, the requirements in 40 CFR 98.447 will be followed by maintenance of the following records for at least three years:

- Quarterly records of CO_2 received, operating temperature and pressure, and concentration of these streams,
- Quarterly records of injected CO_2 including flow rate, operating temperature and pressure, and concentration of these streams,
- 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, and
- 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.

These data will be collected as generated and aggregated as required for reporting purposes.

11 Appendices

11.1 Conversion Factors

If needed, CO_2 volumes will be reported at standard conditions of temperature and pressure as defined by the California Air Resources Board (CARB): 60° F and 14.7 pounds per square inch absolute (psia)[2].

To convert these volumes into metric tons, a density is calculated using the Span and Wagner EOS as recommended by the EPA and using the database of thermodynamic properties developed by NIST, available at http://webbook.nist.gov/chemistry/fluid/.

The conversion factor 5.29×10^{-2} metric ton per thousand cubic feet (MT/Mcf) has been used throughout to convert volumes to metric tons.

[2] See California Code of Regulations Title 17 Section 95102 (General Requirements of Greenhouse Gas Reporting, Definitions)

11.2 Acronyms

3-D – three-dimensional
AGA – American Gas Association
AMA – active monitoring area
AoR – area of review
API – American Petroleum Institute
Bcf – billion standard cubic feet
BOE - barrel of oil equivalent
CalGEM – California Geologic Energy Management Division
CARB – California Air Resources Board
CCF – Central Control Facility
CCS – carbon capture and sequestration
CDMG – California Division of Mines and Geology
CMG - Computer Modeling Group Ltd.
CO_2 – carbon dioxide
CRC - California Resources Corporation
CTV - Carbon TerraVault
DAC – direct air capture
DOE – U.S. Department of Energy
EHOF – Elk Hills Oil Field
EHPP – Elk Hills Power Plant
EOS - equation of state
EPA – U.S. Environmental Protection Agency
GEM – geochemical equation compositional model
GHG – greenhouse gas
GHGRP -- Greenhouse Gas Reporting Program
GPA – Gas Processors Association
H_2S – Hydrogen sulfide
MASP - maximum anticipated surface pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MRV –monitoring, reporting, and verification
MT/Mcf – metric ton per thousand cubic feet
MW - megawatt
NIST -- National Institute of Standards and Technology
NWS – Northwest Stevens
ppm – parts per million
RTS – radioactive tracer survey
RCF – recompression facility
SAPT – standard annual pressure test
SCADA – supervisory control and data acquisition
SCEDC – Southern California Earthquake Data Center

UIC – underground injection control
USDW – underground source of drinking water
VSPs – vertical seismic profiles

11.3 References

Callaway, D.C. and E.W. Rennie, Jr. 1991. *San Joaquin Basin, California*, in Gluskoter, H.J., D.D.Rice, and R.B. Taylor, eds. Economic geology, U.S.: Boulder, Colorado. Geological Society of America. The Geology of North America, v. P-2: 417-430.

McJannet, G.S. 1996. *General Overview of the Elk Hills Field*. Society of Petroleum Engineers. doi:10.2118/35670-MS.

11.4 Glossary of Terms

This glossary describes some of the technical terms as they are used in this MRV plan. For additional glossaries please see the U.S. EPA Glossary of UIC Terms (http://water.epa.gov/type/groundwater/uic/glossary.cfm), and the Schlumberger Oilfield Glossary (http://www.glossary.oilfield.slb.com/).

Anticline – an arch-shaped fold in the rock layers in a geologic formation in which the layers are upwardly convex, forming something like a dome or bell shape. Anticlines form excellent hydrocarbon traps, particularly in folds that have rocks with high injectivity in their core and high impermeability in the outer layers of the fold.

Contain/containment –the effect of keeping fluids located within in a specified portion of a geologic formation.

Dip – the angle of the rock layer relative to the horizontal plane. Buoyant fluids will tend to move up the dip, or *updip*, and heavy fluids will tend to move down the dip, or *downdip*. Moving higher up structure is moving updip. Moving lower is downdip. Perpendicular to dip is *strike*. Moving perpendicular along a constant depth is moving along strike.

Downdip – see *dip*.

Flooding pattern – also known as an injection pattern; the geometric arrangement of production and injection wells to sweep oil efficiently and effectively from a reservoir.

Formation – a body of rock that is sufficiently distinctive and continuous that it can be mapped.

Injectivity – the ability of an injection well to receive injected fluid (both rate and pressure) without fracturing the formation in which the well is completed. Injectivity is a function of the porosity and permeability of the rock formation and the reservoir pressure in which the injection well is completed.

Infill drilling – the drilling of additional wells within existing patterns. These additional wells decrease average well spacing. This practice both accelerates expected recovery and increases estimated ultimate recovery in heterogeneous reservoirs by improving the continuity between injectors and producers. As well spacing is decreased, shifting flow paths lead to increased sweep to areas where greater hydrocarbon saturations remain.

Permeability – the measure of a rock's ability to transmit fluids. Rocks that transmit fluids readily, such as sandstones, are described as permeable and tend to have many large, well-connected pores. Impermeable formations, such as shales and siltstones, tend to be finer grained or of a mixed-grain size, with smaller, fewer, or less-interconnected pores.

Phase – a region of space throughout which all physical properties of a material are uniform. Fluids that don't mix segregate themselves into phases. Oil, for example, does not mix with water and forms a separate phase.

Pore space – see *porosity*.

Porosity – the fraction of a rock that is not occupied by solid grains or minerals. All rocks have spaces between rock crystals or grains that is available to be filled with a fluid, such as water, oil, or gas. This space is called *pore space*.

Primary recovery – the first stage of hydrocarbon production, in which natural reservoir energy, such as gas drive, water drive, or gravity drainage, displaces hydrocarbons from the reservoir into the wellbore and up to surface. Initially, the reservoir pressure is higher than the bottom-hole pressure inside the wellbore. This high natural differential pressure drives hydrocarbons toward the well and up to surface. However, as the reservoir pressure declines because of production, so does the differential pressure. To reduce the bottom-hole pressure or increase the differential pressure to increase hydrocarbon production, it is necessary to implement an artificial lift system, such as a rod pump, an electrical submersible pump, or a gas-lift installation. Production using artificial lift is considered primary recovery. The primary recovery stage reaches its limit either when the reservoir pressure is so low that the production rates are not economic, or when the proportions of gas or water in the production stream are too high. During primary recovery, only a small percentage of the initial hydrocarbons in place are produced, typically 10%-12% for oil reservoirs. Primary recovery is also called *primary production*.

Saturation – the fraction of pore space occupied by a given fluid. Oil saturation, for example, is the fraction of pore space occupied by oil.

Seal – a geologic layer (or multiple layers) of impermeable rock that serves as a barrier to prevent fluids from moving upwards to the surface.

Secondary recovery – the second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are immiscible gas injection and waterflooding.

Sedimentary rocks – rocks formed at the Earth's surface through deposition of sediments derived from weathered rocks, biogenic activity, or precipitation from solution. There are three main types of rocks: igneous, metamorphic, and sedimentary.

Stratigraphic section – a sequence of layers of rocks in the order they were deposited.

Strike – see *dip.*

Updip – see *dip.*

11.5 Well List

The following tables present the well name and well type for the project.

26R Project Wells

Injectors	363C-27R 353XC-35R 373-35R 345C-35R	
Monitoring wells	341-27R	Plume monitoring
	328-25R	Plume monitoring
	374-36R	Plume monitoring
	355X-26R	Above-zone monitoring well
	USDW monitoring well	USDW monitoring

A1-A2 Project Wells

Injectors	355-7R 357-7R	
Monitoring wells	353A-7R	Plume monitoring
	335X-7R	Plume monitoring
	327-7R-RD1	Above-zone monitoring well
	USDW monitoring well	USDW monitoring

11.6 Monitoring Well Details

26R Project monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage of Depth	Frequency (Injection Phase)
Tulare Formation	Fluid Sampling	Shallow Water Monitoring Well	Pump	–400’ - 450' MD/VD	Quarterly
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’ - 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’ - 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	400' - 500' MD/VD in each well	Continuous
Etchegoin Formation	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Quarterly
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' 4788' - 4811' 4205' - 4226' (all MD/VD)	Continuous

A1-A2 Project monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	USDW Monitoring Well	Pump	940' - 960' MD/VD	Baseline, Quarterly
	Pressure	USDW Monitoring Well	Pressure Gauge	940' - 960' MD/VD	Continuous
	Temperature	USDW Monitoring Well	Temperature Sensor	940' - 960' MD/VD	Continuous
	Temperature	327-7R-RD1 353A-7R 335X-7R	Fiberoptic cable (DTS)	849' MD/VD 961' MD/VD 854' MD/VD	Continuous
Etchegoin	Fluid Sampling	327-7R-RD1	Sampling Device	3782' - 3934' MD 3780' - 3932' VD	Baseline, Quarterly
	Pressure	327-7R-RD1	Pressure Gauge	3782' - 3934' MD 3780' - 3932' VD	Continuous
	Temperature	327-7R-RD1	Temperature Sensor	3782' - 3934' MD 3780' - 3932' VD	Continuous
	Temperature	353A-7R 335X-7R	Fiberoptic cable (DTS)	4100' - 4220' 3850' - 3990' (all MD/VD)	Continuous

Summary of analytical and field parameters for groundwater samples above the confining zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO_3, SO_4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Dissolved CH_4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

11.7 Summary of Key Regulations Referenced in MRV Plan

Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b).

Request for Additional Information: CTV/CRC Elk Hills Carbon Project
November 7, 2023

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.	NA	NA	We recommend checking the MRV plan once more for consistency with formatting and section/figure names throughout the MRV plan. Examples include but are not limited to: Figure 1a vs. Figure 2b Figure 7 on page 12 vs. Figure 7 on page 15.	
2.	5.1.5	32	"Finally, data collected by the **personal CO_2 gas monitors, which are always worn by all field personnel, are a last method to detect leakage from wellbores. The monitor's detection limit is 10 parts per million (ppm);** if an alarm is triggered, the first response is to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. If the incident results in a work order, this will serve as the basis for tracking the event for greenhouse gas (GHG) reporting. Targeted point-source surface air monitoring will be conducted in the event of detected wellbore leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration." It is our understanding that ambient air is on average greater than 400 ppm CO_2. Most of the CO_2 meters that we aware of sound at approximately 5,000 ppm CO_2 and have a sensitivity of 100 ppm CO_2. However, we are aware that most H_2S monitors have a low alarm of 10 ppm. Please clarify in the MRV plan whether these are CO_2 or H_2S monitors, or provide additional explanation as appropriate.	

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	7.4	38	Section 7.3 states that "CRC and CTV will calculate and report the total annual mass of CO_2 emitted by surface leakage using an approach that is tailored to specific leakage events and relies on 40 CFR 98.230-238 (Subpart W) reports of equipment leakage." Please note that surface leakage (variable CO_{2E} in equation RR-12) is separate from the equipment leaks (variable CO_{2FI} in equation RR-12) that are calculated per procedures in subpart W. Please clarify and expand this section or add a separate section for equipment leaks to make this distinction.	

Elk Hills A1-A2 and 26R CO_2 Subpart RR Monitoring, Reporting, and Verification Plan

Version Date: 9/12/2023

Table of Contents

Overview

The Elk Hills Oil Field (EHOF), covering 75 square miles, was discovered in 1911 and has produced over 2 billion barrels of oil equivalent (BOE), making it one of the most productive fields in the United States. California Resources Corporation (CRC) and Carbon TerraVault (CTV; a CRC wholly owned subsidiary), owns 100% of the surface, mineral, and pore space rights at the EHOF.

CTV intends to inject and store a measurable quantity of carbon dioxide (CO_2) in subsurface geologic formations at the EHOF, for a term of 27 years referred to as the "Specified Period." During the Specified Period, CO_2 will be injected from anthropogenic sources such as the Elk Hills 550 megawatt (MW) natural gas combined cycle power plant (EHPP), bio-diesel refineries, and other sources in the EHOF area.

The CO_2 will be injected into the Monterey Formation A1-A2 and 26R reservoirs for dedicated geologic storage. The Elk Hills storage complex will be pre-certified and monitored to verify permanent CO_2 sequestration. Class VI applications have been submitted for the A1-A2 and 26R reservoir.

This EHOF monitoring, reporting, and verification (MRV) plan is based on decades of subsurface characterization and simulation of the targeted Monterey Formation. This empirically driven analysis indicates that the natural geologic seal that overlays the entire EHOF, known as the Reef Ridge shale, will provide a physical trap that will permanently prevent injected CO_2 from migrating to the surface.

This MRV plan documents the following in accordance with 40 CFR 98.440-449 (Subpart RR):

- Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA), 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,
- Strategy for detecting and quantifying any surface leakage of CO_2,
- Strategy for establishing the expected baselines for monitoring CO_2 surface leakage,
- Summary of considerations for calculating EHOF-specific variables for the mass balance equation, and
- Proposed date to begin collecting data for calculating total CO_2 sequestered.

1 Facility Information

i. Reporter number – 582061

ii. Existing wells in the EHOF including production, injection, and monitoring wells are permitted by California Geologic Energy Management Division (CalGEM) through California Public Resources Code Division 3.[1]

iii. Wells injecting CO_2 for geologic storage will be permitted with the United States Environmental Protection Agency (EPA) Underground Injection Control (UIC) program for Class VI injection.

[1] Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

iv. Wells in the EHOF are identified by name, American Petroleum Institute (API) number, status, and type. The list of wells as of March 2023 associated with the geologic storage projects is included in Appendix 11.5. Any new wells or changes to wells will be indicated in the annual report.

2 Project Description

The EHOF is one of the largest oil and natural gas fields in the United States, with production from multiple vertically stacked reservoirs. Turbidite sand deposits of the Miocene Monterey Formation will serve as the injection targets in two separate anticlinal structures, Northwest Stevens (NWS) and 31S (Figures 1a, 1b).

Numerous aspects of the geology, facilities, equipment, and operational procedures for A1-A2 and 26R are consistent throughout the field. As such, one MRV report will satisfy the 26R and A1-A2 reservoirs as shown in Table 1. The A1-A2 and 26R reservoir and well locations within the field are shown in Figure 1a.

Structure	Reservoir	Sequestration Type	Number of Injectors
31S	26R	Geologic : Class VI	4
NWS	A1-A2	Geologic : Class VI	2

Table 1: Reservoirs within the EHOF and sequestration type.

2.1 Project Characteristics

The potential CO_2 stored over the project duration is up to 48 million metric tons (refer to Table 2 for breakdown). For accounting purposes, the amount stored is the difference between the amount injected less any CO_2 that i) leaks to the surface, or ii) is released through surface equipment leakage or malfunction. Actual amounts stored during the Specified Period of reporting will be calculated as described in Section 7 of this MRV Plan.

2.2 Environmental Setting

The project site for this MRV plan is the EHOF, located in the San Joaquin Basin, California (Figure 2).

2.2.1 Geology of Elk Hills Oil Field

The EHOF is located 20 miles southwest of Bakersfield in western Kern County, producing oil and gas from several vertically stacked reservoirs formed in the Tertiary period (65 million to 2 million years ago). Of the more than 24,000 feet (ft) of sediment deposited, the most prolific reservoir is the Miocene epoch Monterey Formation that is the target CO_2 sequestration reservoir.

Individual layers within the Monterey Formation are primarily interbedded sandstone and shale. These layers have been folded, resulting in anticlinal structures containing hydrocarbons formed from the deposition of organic material approximately 33 million to 5 million years ago (during the Oligocene and Miocene epochs). The combination of multiple porous and permeable sandstone reservoirs interbedded with impermeable shale seals makes the EHOF one of the most suitable locations in North America for the extraction of hydrocarbons and the sequestration of CO_2.

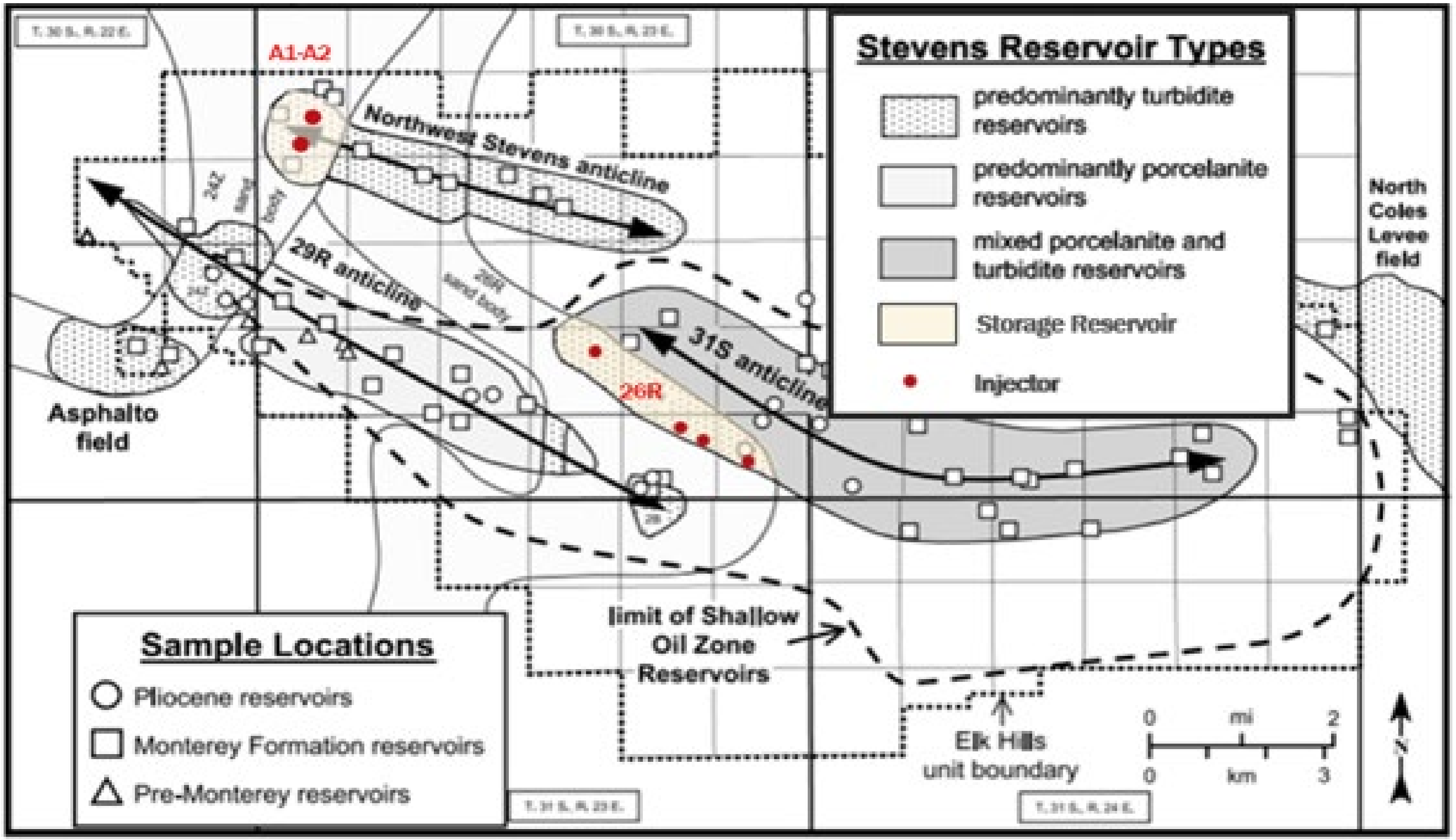


Figure 1a: EHOF map of injection target and injection well locations.

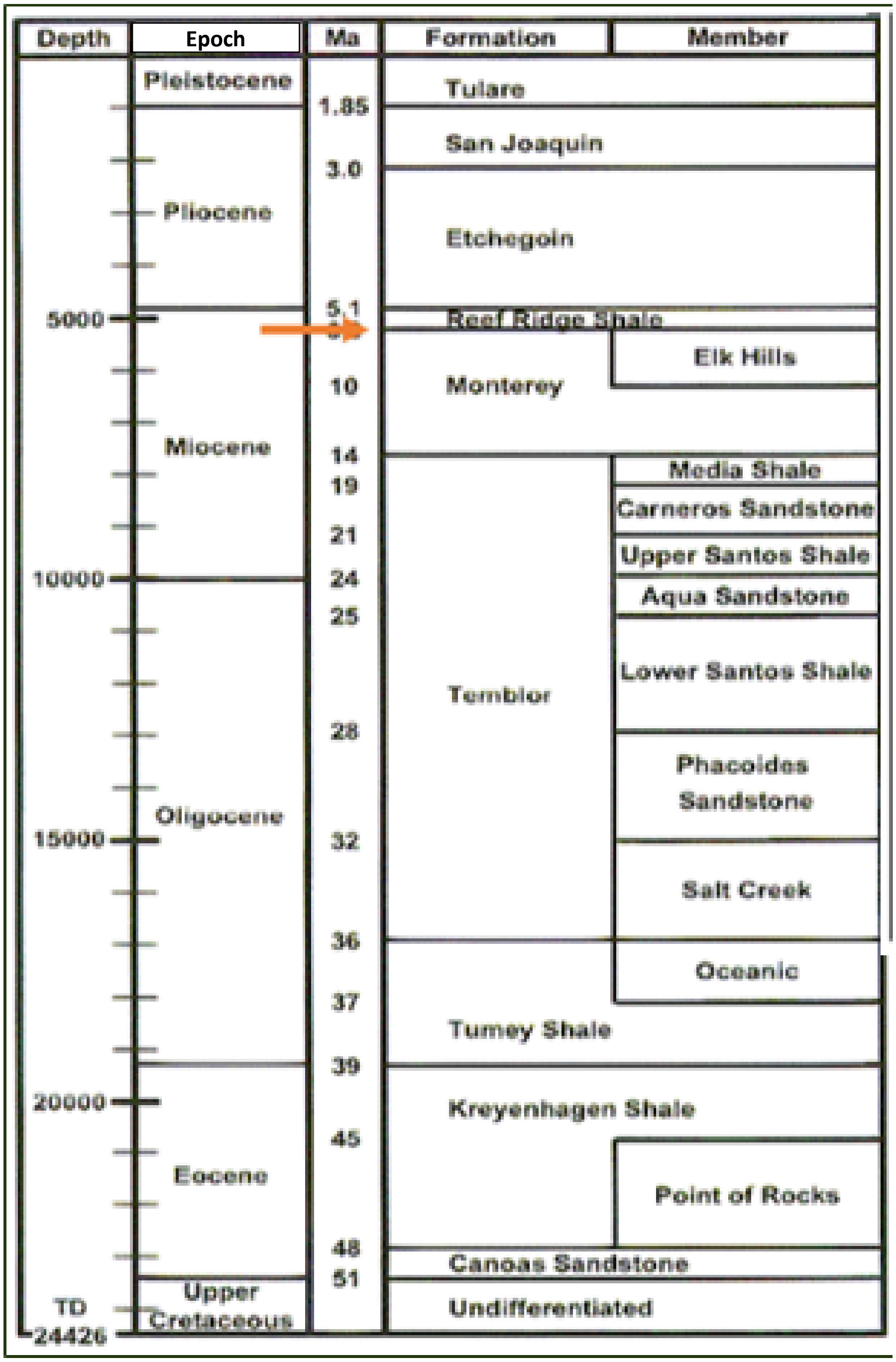


Figure 2b: EHOF stratigraphic column.

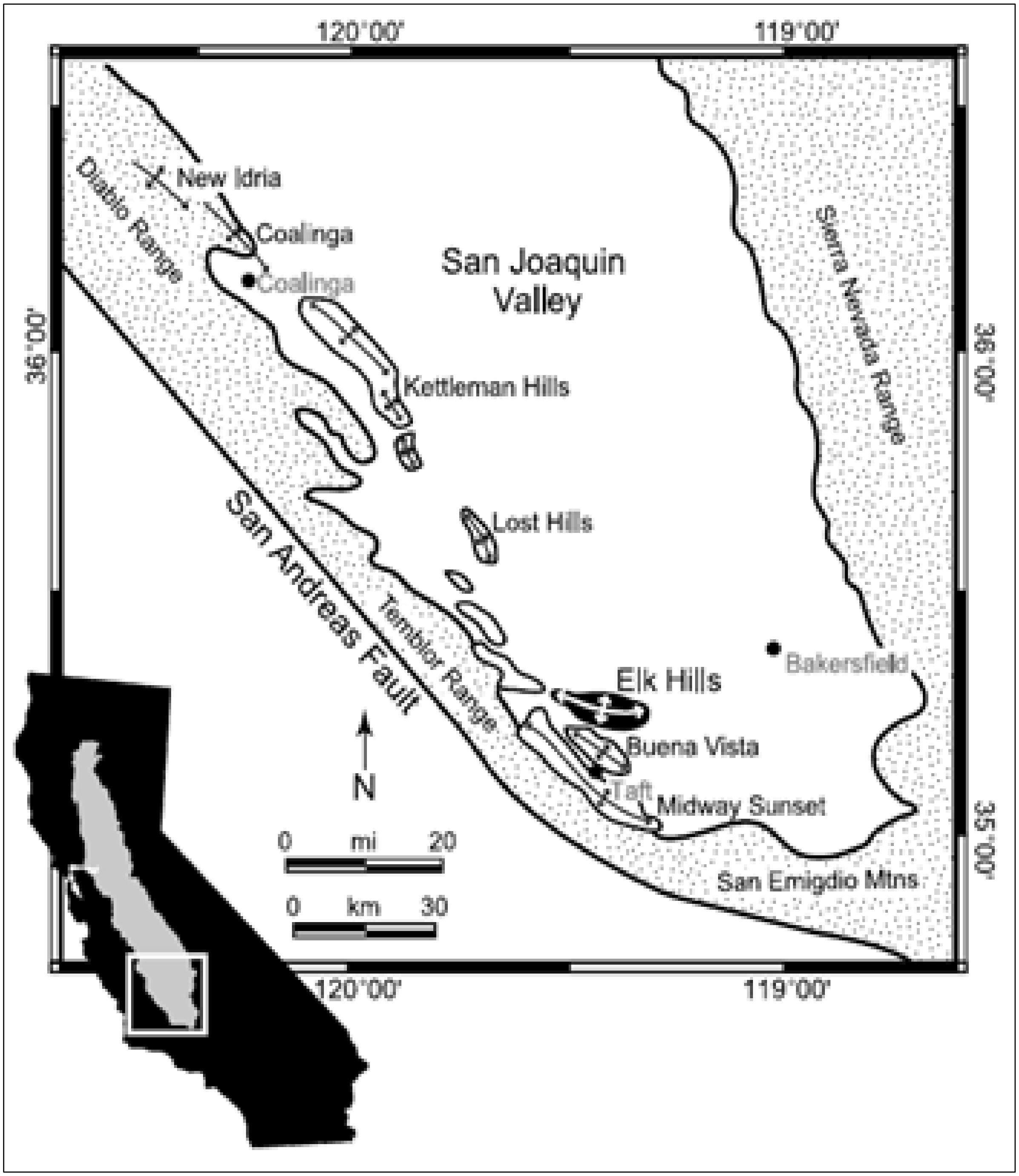


Figure 3: Location of Elk Hills Oil Field, San Joaquin Basin, California.

Following its deposition, Monterey Formation sediments were buried under more than 750 ft of impermeable silty and sandy shale that comprise the confining Reef Ridge shale. The Reef Ridge shale serves as the primary confining layer over the Monterey because it effectively seals underlying fluids from the overlying formations. Above the Reef Ridge lies several alternating sand-shale sequences of the Pliocene Etchegoin and San Joaquin Formations and Pleistocene Tulare Formation. These formations are highlighted in the cross-section in Figure 3.

As indicated in Figure 1a, the 31S and NWS structures represent structural highs, or anticlines, within the EHOF. The elevated areas form a natural trap for oil and gas that migrated from below over millions of years. Once trapped at these high points, the oil and gas has remained in place. In the case of the EHOF, the oil and gas has been trapped in the reservoir for more than 6 million years.

Based on physical site characterization and analysis of historic operating records from the Monterey Formation, there is sufficient reservoir capacity and flow properties to inject and store the entire volume of CO_2 proposed as determined by computational modeling (Table 2).

	Volume (million metric tons)
A1-A2 geologic storage	10
26R geologic storage	38
Total storage capacity	48

Table 2: Calculation of cumulative net fluid volume produced for the Monterey Formation sequestration reservoir.

Stored CO_2 will be contained securely within the EHOF Monterey Formation as demonstrated by 1) preservation of hydrocarbon accumulations over geologic time; 2) subsequent water and gas injection operations; 3) competency of the Reef Ridge confining zone over millions of years and throughout decades of primary and secondary operations; and 4) ample storage capacity of the A1-A2 and 26R reservoir. Confinement within the project area and in the reservoir will be ensured by limiting the pressure of the reservoir post-injection at or below the initial pressure of the reservoir at time of discovery.

2.2.2 Elk Hills Oil Field Operational History

McJannet (1996) reports on the early operating history of EHOF. By Executive Order, in 1912 President Taft designated the area surrounding EHOF as a naval oil reserve. Intended to ensure a secure supply of fuel for the Navy's oil-burning ships, the Executive Order defined "Naval Petroleum Reserve No. 1" (NPR-1). In 1977, President Carter signed the U.S. Department of Energy (DOE) Organization Act which transferred NPR-1 to the DOE. Nearly 20 years later, the DOE was directed to sell the assets of NPR-1. Occidental Petroleum ("Occidental") provided a winning bid of $3.65 billion, and on February 10, 1998, Occidental took over official ownership and operation of EHOF. In December 2014, Occidental Petroleum spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC.

The EHOF unit boundary is shown in orange below in Figure 4.

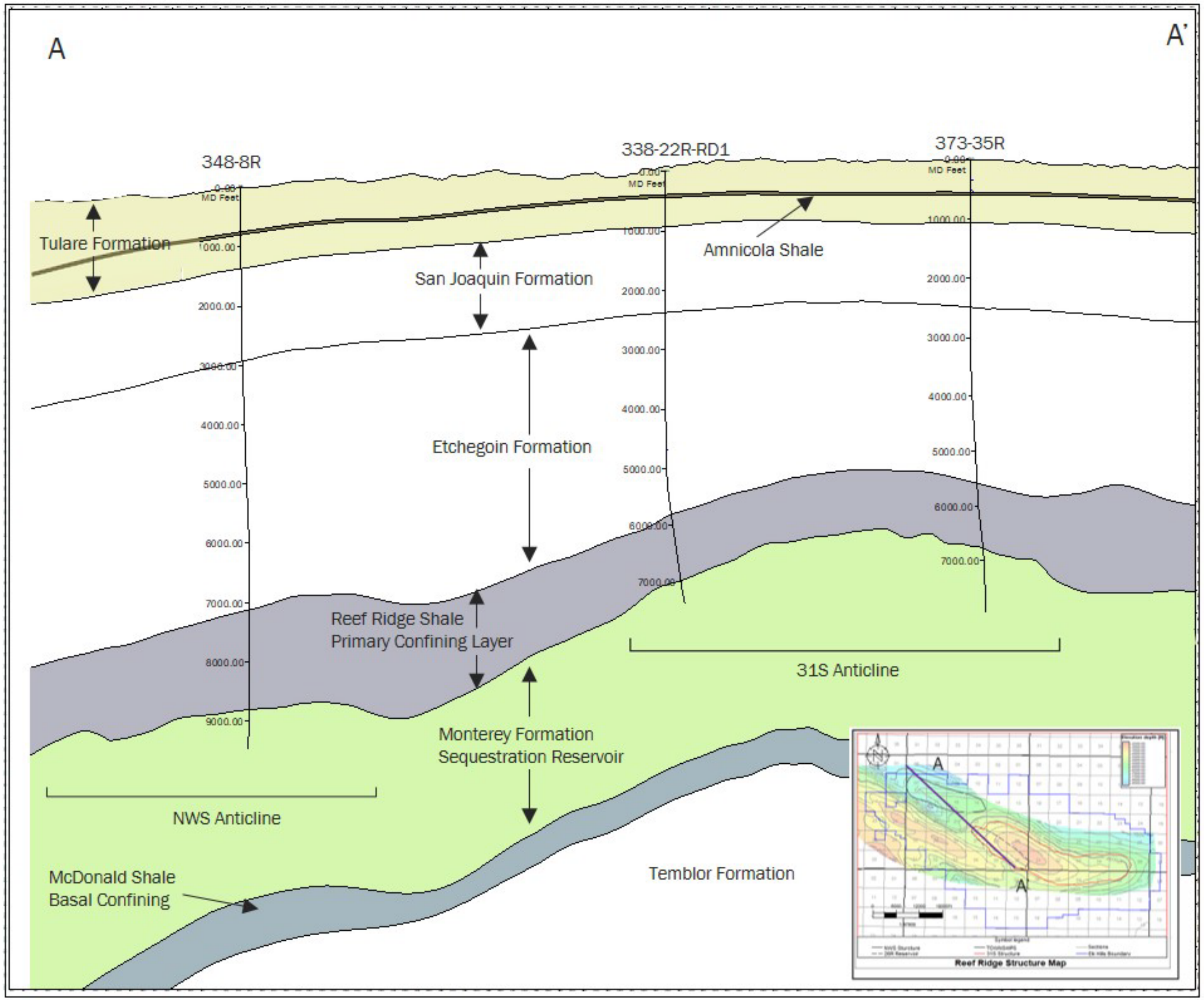


Figure 4: Stratigraphic schematic highlighting the NWS and 31S anticlines.

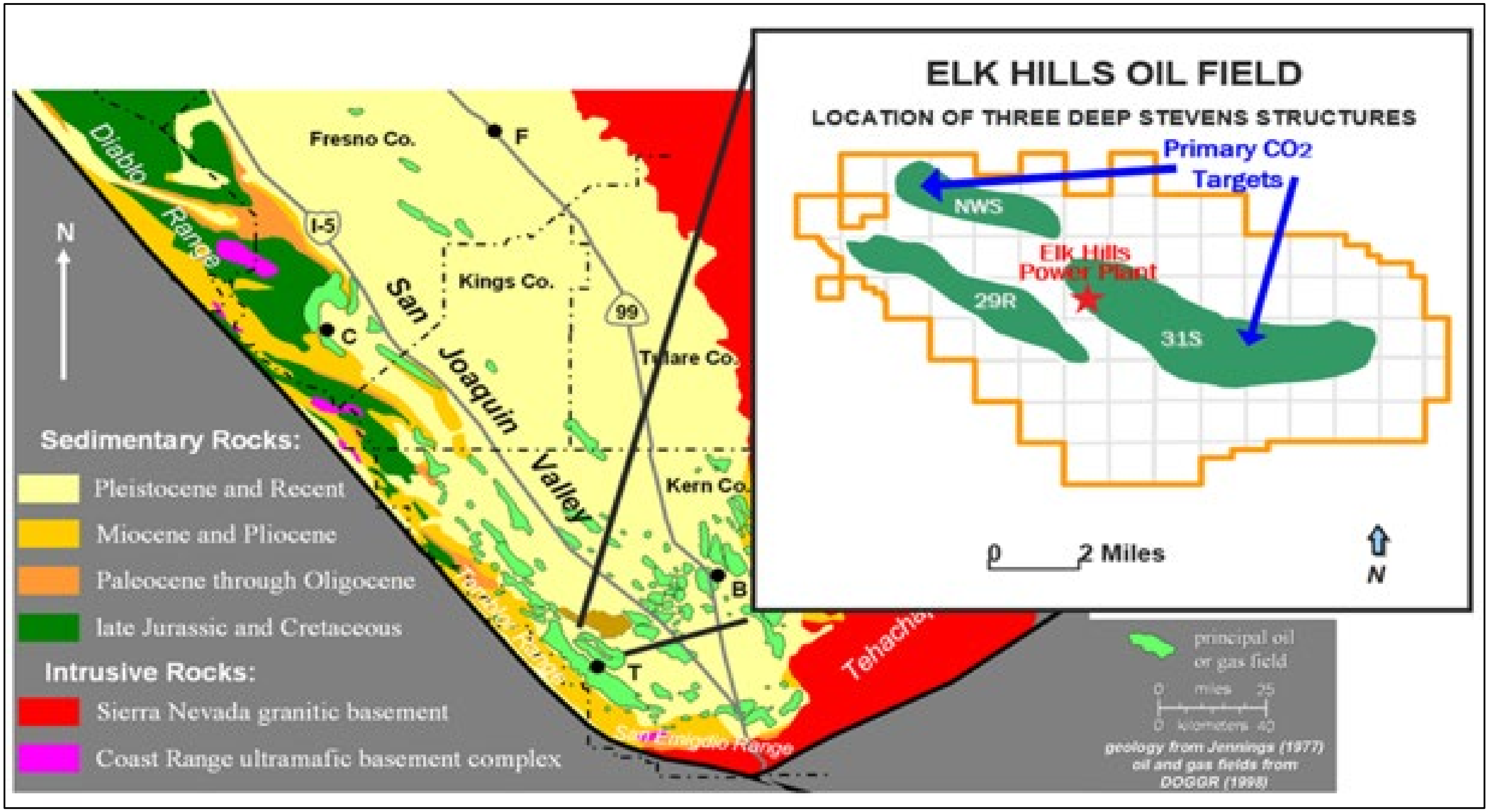


Figure 5: Location of Elk Hills Oil Field within San Joaquin Basin, California.

Development History

Selected primary drilling in the Monterey Formation began in the early 1940s, with concerted drilling and production operations commencing with the DOE's oversight in the late 1970s. To support reservoir pressure and maximize the oil recovery factor, extensive water and gas injection has occurred.

A successful CO_2 injection pilot was implemented in the Monterey Formation in 2005. Data from the four-month pilot confirmed the formation as an attractive target for CO_2 sequestration. This project assessed how much oil could be mobilized from the conventional sand reservoirs, how much CO_2 would be required to mobilize that oil, and how quickly the oil would be produced. Production performance and data collected before, during, and after the pilot operations showed that Monterey Formation reservoirs selected are ideal for CO_2 sequestration.

In addition, past development of the shallow Etchegoin Formation oil reservoirs and Monterey Formation has created a large pressure differential across the Reef Ridge shale, further demonstrating the lack of communication between the reservoirs.

2.3 Description of Facilities and Injection Process

A simplified flow diagram of surface facilities can be seen in Figure 5. This includes facilities outside the scope of the MRV including CO_2 source(s), and the subsequent metering locations between the MRV scope and those facilities. All facilities will be designed and built to ensure integrity and compatibility with CO_2. The subsequent parts of this section will review each of the following:

- CO_2 source,
- CO_2 distribution and injection, and
- Wells in the Class VI defined area of review (AoR) penetrating the Reef Ridge shale.

Facilities associated with dedicated geologic sequestration will be relatively simple as field production and re-compression process flows are unnecessary.

2.3.1 CO_2 Source

CTV plans to construct a carbon capture and sequestration (CCS) "hub" project (i.e., a project that captures CO_2 from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC-permitted injection well). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The anthropogenic CO_2 will be sourced from an onsite blue hydrogen plant (up to 200,000 metric tons per annum), with additional potential CO_2 from the EHPP, direct air capture (DAC), renewable diesel refineries, and/or other sources in the area.

All CO_2 sources will have custody-transfer metering to ensure accurate accounting of both the mass rate and impurities in the CO_2 stream. Anticipated hydrogen sulfide (H_2S) concentration in the injectate is 0.001 to 0.014%.

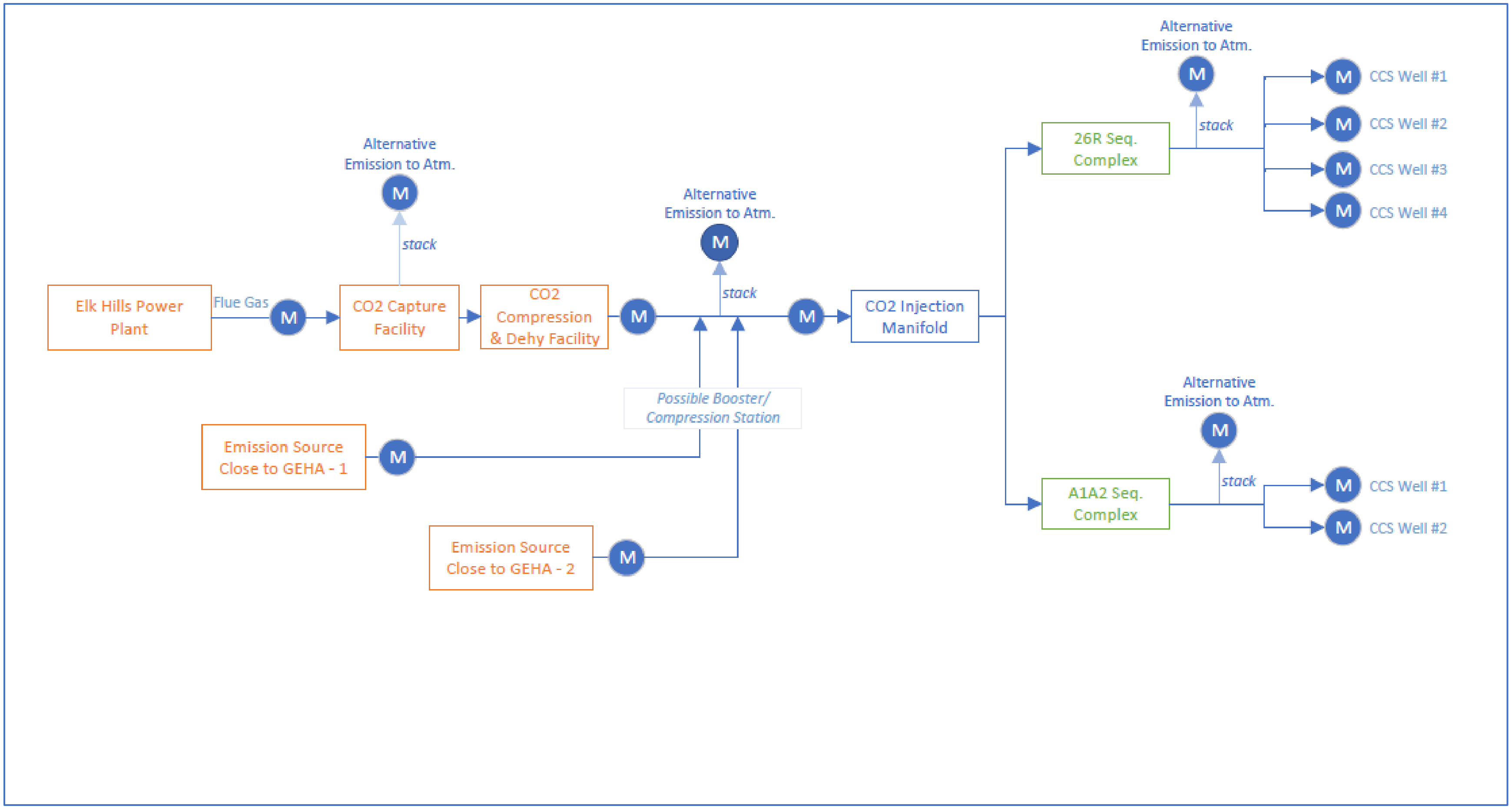


Figure 6: Facilities flow diagram for Carbon TerraVault carbon capture and sequestration project. Blue "M" symbols denote meter locations.

2.3.2 CO_2 Distribution and Injection

CO_2 from the sources previously discussed will be distributed throughout the field through a combination of new and existing infrastructure. This distribution infrastructure will allow CO_2 to be injected into CO_2 wells completed within the Monterey Formation at A1-A2 and 26R.

Each CO_2 injection well will have automated controls that provide for both control and measurement of the mass flow rate and pressure.

2.3.3 Wells in the AoR Penetrating the Reef Ridge Shale

CalGEM regulations govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields (other than UIC Class VI CO_2 injection wells that are regulated by the EPA UIC program). Current CalGEM rules require, among other provisions, the following conditions.

- Fluids must be constrained in the strata in which they are encountered.
- Activities governed by the regulations cannot result in the pollution of subsurface or surface waters.
- Wells must adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata in which they are encountered into strata with oil and gas, or into subsurface and surface waters.
- Operators must file a completion report including basic electric log (e.g., a density, sonic, or resistivity log acquired from the wellbore).
- Wells must follow plugging procedures that require advance approval from CalGEM and allow consideration of the suitability of the cement based on the use of the well, location and setting of plugs.

Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM at time of drilling and as part of the existing Class II UIC permit applications. Wells penetrating the Reef Ridge confining layer and storage reservoir are shown in Figure 6, and are listed in Table 3 categorized in groups that relate to the well status for each reservoir.

Completion Date	**A1-A2 Reservoir Count**	**26R Reservoir Count**
Oil and gas producing wells	79	145
Class II injection/disposal wells	32	22
Observation wells	0	2
Plugged and abandoned	39	35
TOTAL	**150**	**204**

Table 3: Wells penetrating Reef Ridge shale for each reservoir by status.

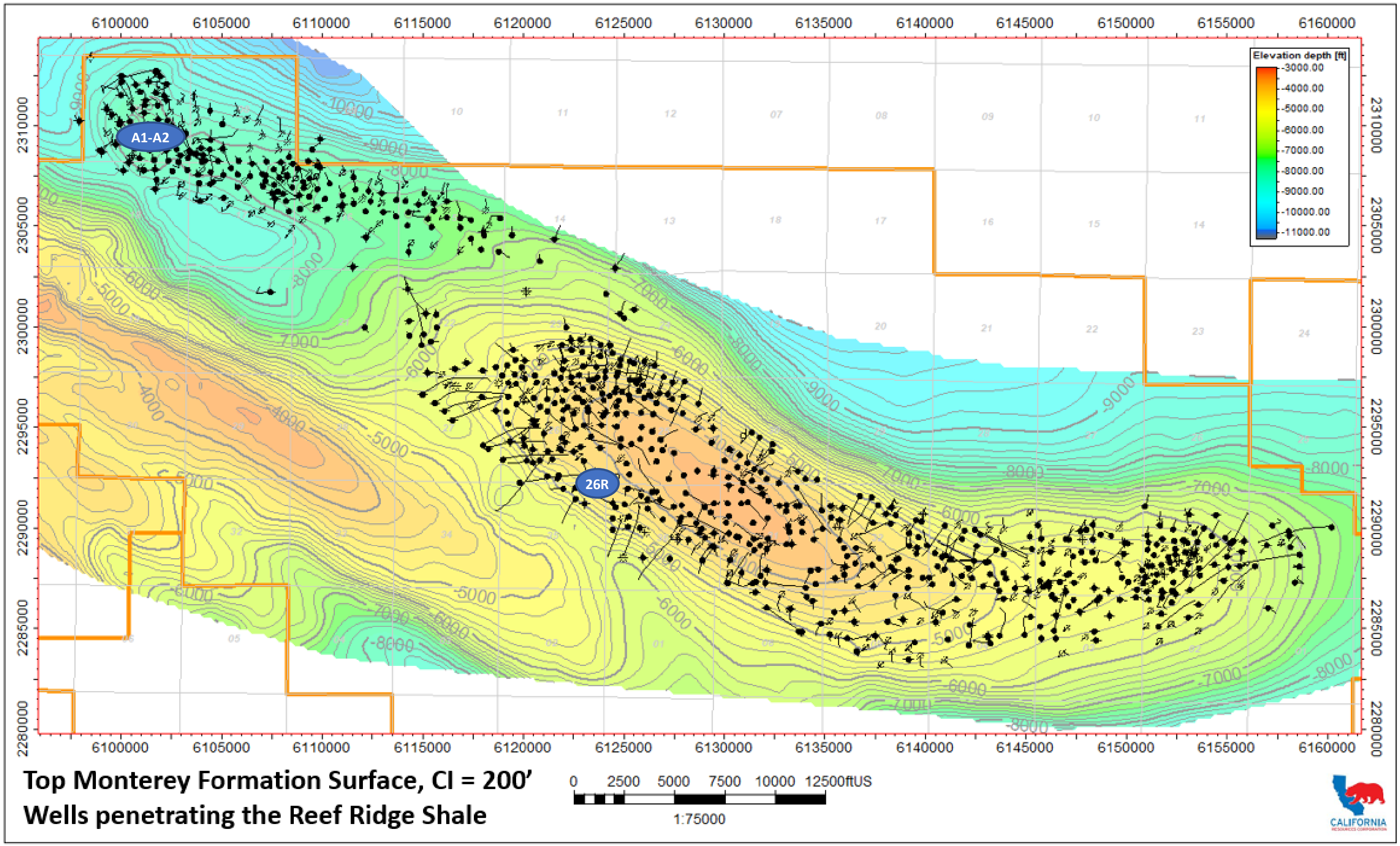


Figure 7: Wells penetrating the Reef Ridge shale. Project locations are shown at blue ovals.

Wells that penetrate the Reef Ridge shale (Table 3) were drilled between 1948 and 2014. Corrective action assessment of existing wellbores for the Class VI applications included the generation and detailed review of wellbore/casing diagrams for each well from CalGEM records. Information used in the review included depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top-of-cement determination supported the review for annular isolation.

Existing wellbores within the project areas will, where necessary and as approved by the UIC Director in the Class VI permit, be pressure tested, abandoned, re-abandoned, or have a technical demonstration of adequate zonal confinement. Corrective action will occur prior to the commencement of CO_2 injection or on an approved phased schedule after CO_2 injection commences if conditions allow.

Project injection and monitoring wells are listed in Section 11.5. Well workover crews are on-call to maintain active wells and to respond to any wellbore issues that arise. Incidents are detected by monitoring changes in the surface pressure of injection wells and by conducting Mechanical Integrity Tests (MITs) that include, but are not limited to, Radioactive Tracer Surveys (RTSs) and Standard Annular Pressure Tests (SAPTs).

All existing oil and gas wells, including both injection and production wells are regulated by CalGEM under Public Resources Code Division 3.

2.4 Reservoir Modeling

Numerical reservoir simulation is used for many purposes, including optimizing reservoir management, forecasting hydrocarbon and water production, predicting the behavior of injected fluids such as $CO_{2,}$ and assessing CO_2 plume development and confinement.

2.4.1 Reservoir Model for Operational Design and Economic Evaluation

Reservoir modeling workflow begins with the development of a three-dimensional (3-D) representation of the subsurface geology (“static model”). Static model development leverages all available well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces and faults (if present) into a geocellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. CRC used Schlumberger Petrel, an industry-standard geocellular modeling software, to build and maintain the EHOF static model.

The static model becomes “dynamic” in the reservoir simulator with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon phase,
- Liquid and gas relative permeability,
- Capillary pressure data, and
- Fluid injection and/or extraction rates.

2.4.2 Performance Prediction

One objective of the simulation models is to develop an injection plan that maximizes CO_2 storage and minimizes associated costs. The injection plan includes injection wells and appropriate injection rate and pressure for each well that adheres to regulatory requirements.

2.4.3 Plume Model for CO_2 Storage Capacity, Containment, and Predicted Plume Migration

Full-field plume models confirm reservoir capacity and CO_2 containment within the 26R and A1-A2 reservoir. These models were built using a dynamic reservoir simulation application known as the Equation-of-State (EOS) Compositional Simulator (GEM), developed by Computer Modelling Group Ltd. (CMG). Figure 7 shows the results of the modeling for the 26R and A1-A2 storage reservoir. The plume models were used to evaluate: (1) the quantity of CO_2 stored for geological sequestration, and (2) the lateral movement of CO_2 to define the MMA and demonstrate vertical confinement by the Reef Ridge shale.

2.4.4 Geomechanical Modeling of Reef Ridge Shale

In addition to the plume models, a simpler GEM-based model was coupled with a finite element geomechanical module, GEOMECH, to model cap rock failure in the Reef Ridge shale as a function of cap rock mechanical properties and reservoir pressure immediately below the cap rock. This model was used to assess the pressure at which the Reef Ridge shale would shear through tensile failure.

The plume modeling effort confirms the Monterey Formation's ability to permanently store the planned project CO_2 volumes under the Reef Ridge shale over the project's life. The results of the plume models are discussed in greater detail below.

3 Delineation of Monitoring Area and Timeframes

3.1 Maximum Monitoring Area

The MMA is defined in 40 CFR 98.449 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. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data as described above, was used to predict the size and location of the plume, as well as understand how the plume migrates over time.

The MMA, shown by the blue line Figure 8 , is defined by the extent of the CO_2 plume at 100 years post-injection for geologic sequestration plus one-half mile.

3.2 Active Monitoring Area

The AMA boundary was established by superimposing two areas (40 CFR 98.449):

- Area #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.
- Area #2: The area projected to contain the free phase CO_2 plume at the end of year *t* + 5.

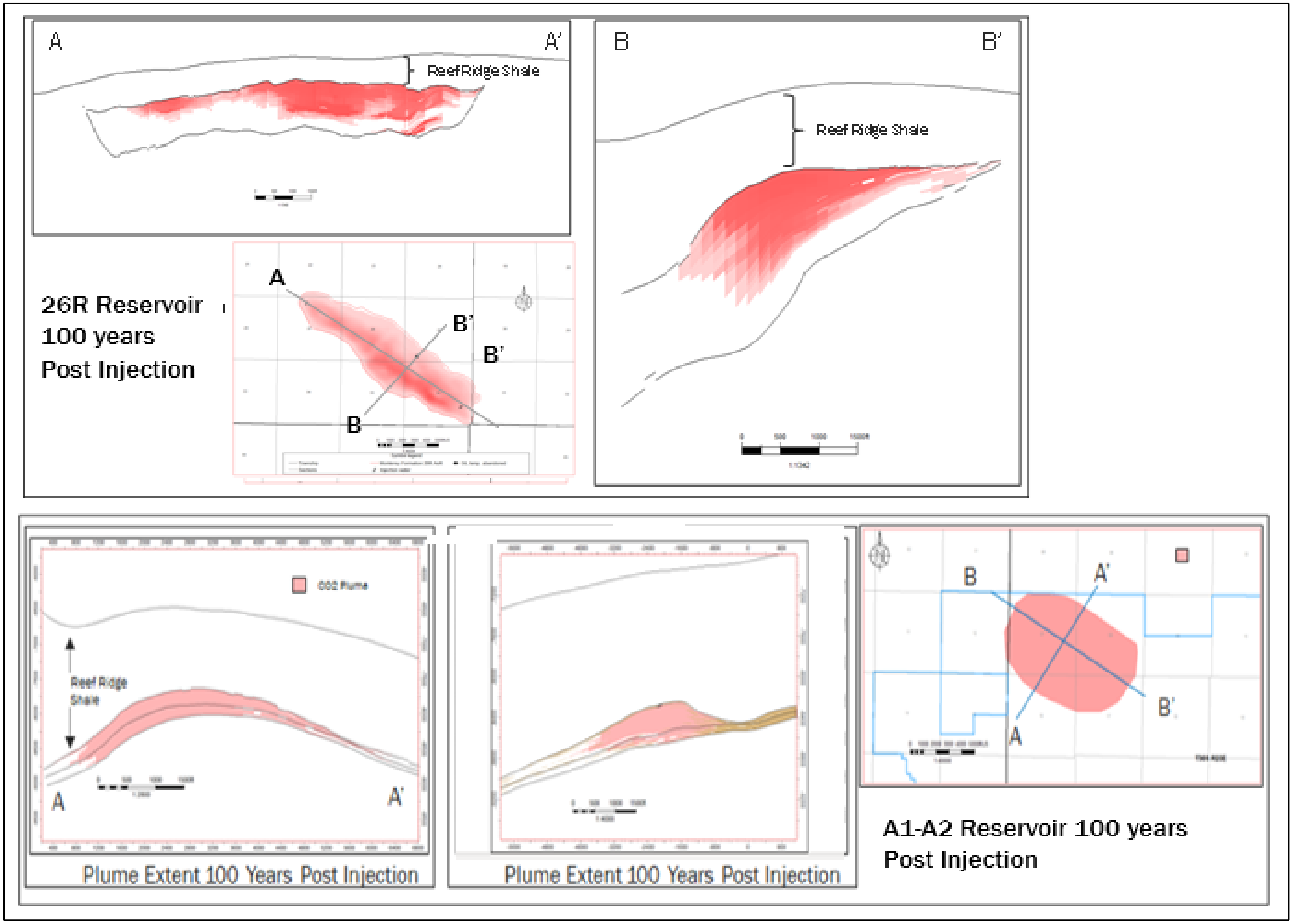


Figure 7: CO_2 plume modeling results.

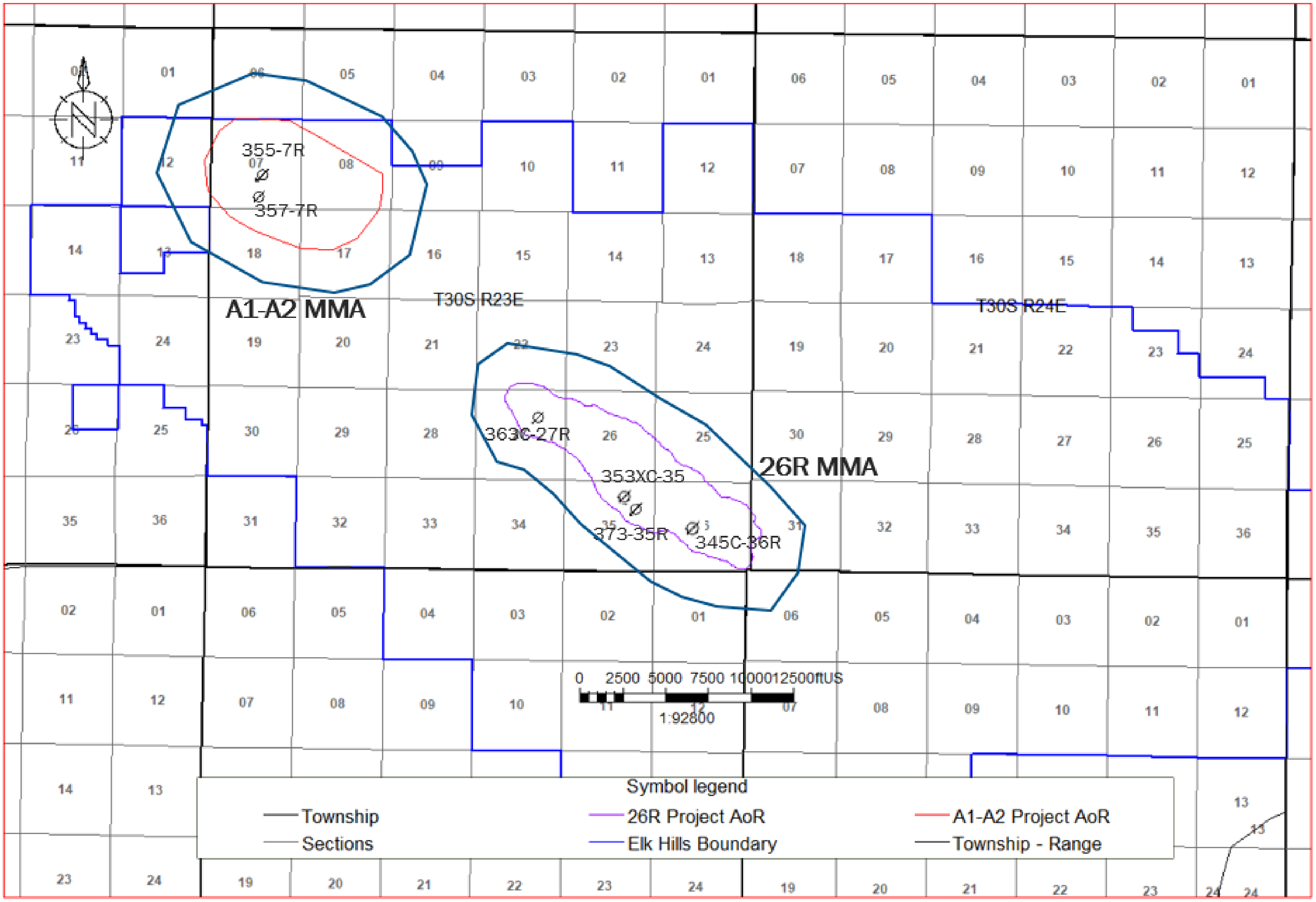


Figure 8: Injector well locations, EPA AoR (final CO_2 plume boundaries; orange and purple lines) and AMA - MMA (blue line). Scale bar units are feet.

The A1-A2 and 26R reservoirs are depleted and CO_2 is predicted to reach the edges of the reservoir within the first two to three years of injection (see Figures 9a, 9b). For this reason the area projected to contain free phase CO_2 is similar during the majority of the Specified Period.

The AMA boundary was determined for the time period ("*t*") corresponding to three years after the end of injection (30 years after the beginning of injection). Area #1, above, was taken as the plume area plus an all-around buffer zone of one-half mile. Area #2 is smaller or equal in all directions for both projects than Area #1, and therefore the final AMA was defined as Area #1 (Figure 8).

CTV has established one AMA boundary for 30 years and does not anticipate any expansion of the monitoring area under 40 CFR 98.448. Given the definitions used to define the MMA and AMA, AMA is also functionally equivalent to the MMA. Instituting monitoring throughout the entire MMA boundary for the Specified Period provides maximum operational flexibility. The absence of through-going faults or fractures confirms the competency of the Reef Ridge to preserve hydrocarbons within the Monterey Formation and to contain the CO_2.

3.3 Monitoring Timeframe

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted when a demonstration that current monitoring and model(s) show that the cumulative mass of CO_2 reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration within two to three years after injection for the Specified Period ceases based on predictive modeling supported by monitoring data.

4 Evaluation of Potential Pathways for Leakage to the Surface

4.1 Introduction

In the more than 100 years of the EHOF's development, the reservoir has been studied and documented extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO_2 to the surface. The following potential pathways are reviewed:

- Existing wellbores,
- Faults and fractures,
- Natural and induced seismic activity,
- Previous operations,
- Pipeline/surface equipment,
- Lateral migration outside the EHOF,
- Drilling through the CO_2 area, and
- Diffuse leakage through the seal.

Section 4.10 summarizes how CRC and CTV will monitor CO_2 leakage from various pathways and describes the response to various leakage scenarios. In addition, Section 5 describes how CRC and CTV will develop the inputs used in the Subpart RR mass-balance equation (Equation RR-12). Any incidents that result in CO_2 leakage up the wellbore and into the atmosphere will be quantified as described in Section 7.

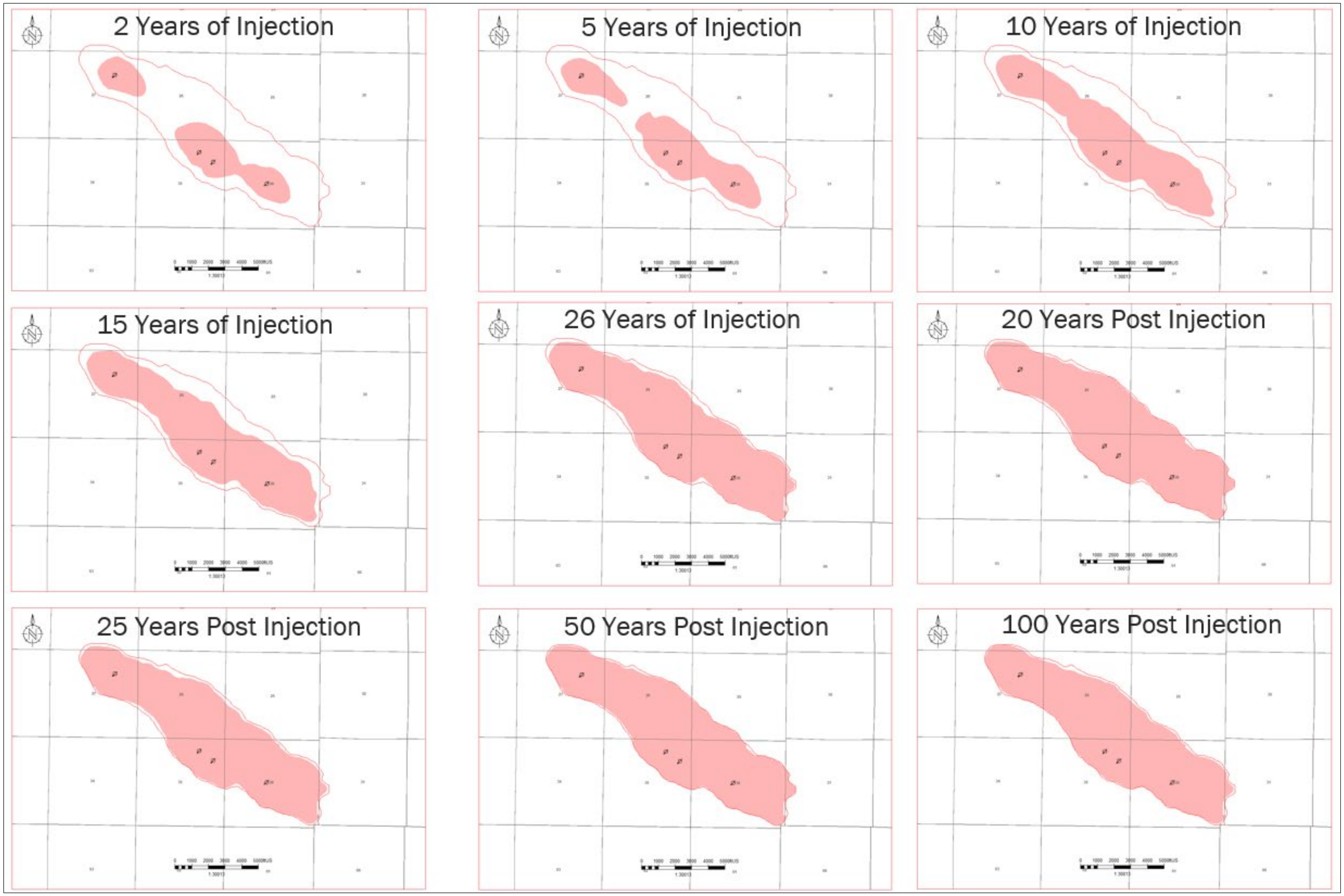


Figure 9a: Plan view showing modeled plume development through time, 26R project.

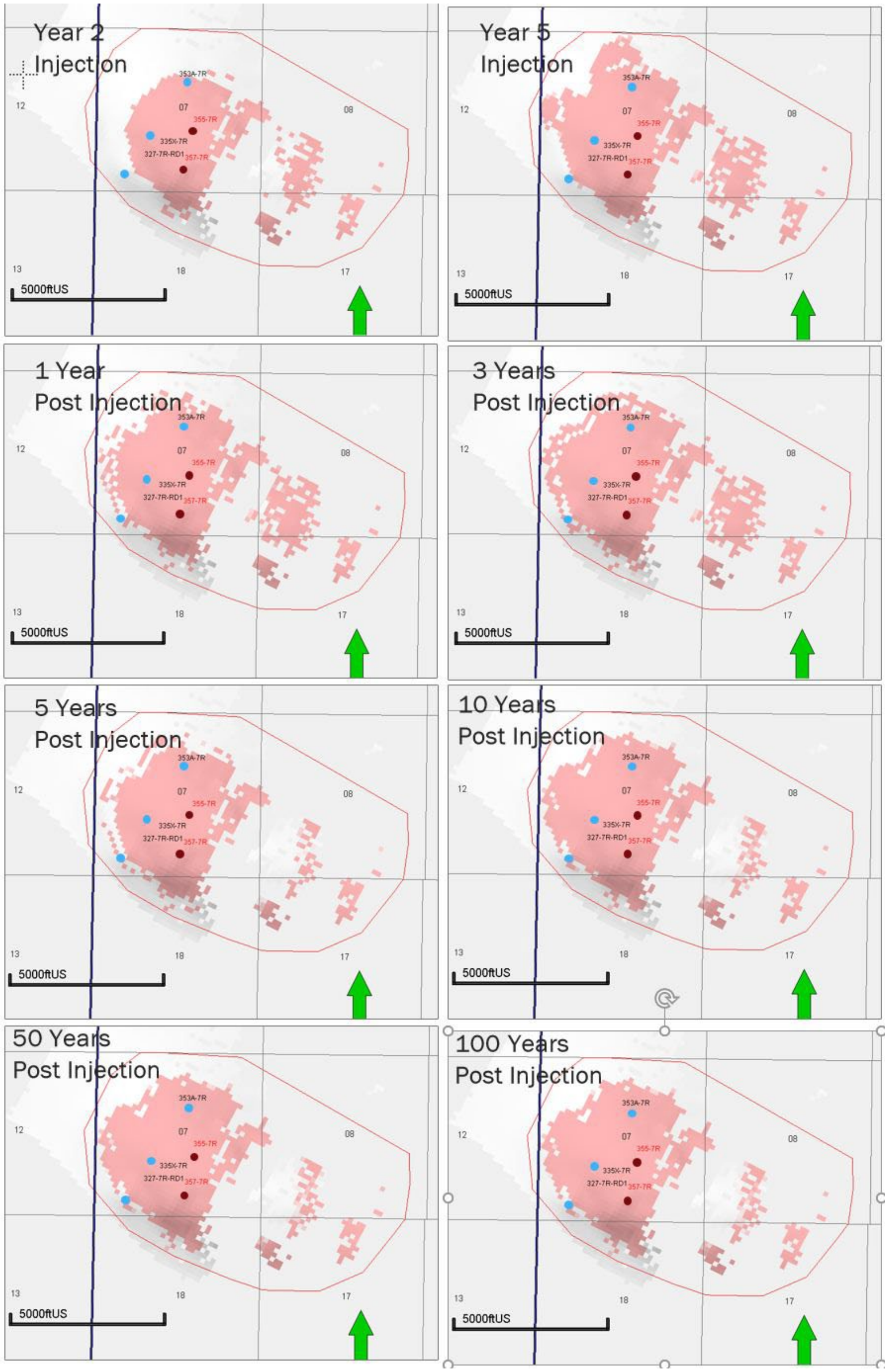


Figure 9b: Plan view showing modeled plume development through time, A1-A2 project (model layer 15). Red dots ae the injectors, Blue dots are monitoring wells.

4.2 Existing Wellbores

Leakage through existing wellbores is possible at the EHOF. However, that is mitigated by adhering to regulatory requirements for well drilling and testing; implementing best practices developed through extensive operating experience; monitoring injection/production performance, wellbores, and the surface; and maintaining surface equipment. Wells penetrating the Reef Ridge confining shale and sequestration reservoir are described in Section 2.3.3.

LIKELIHOOD: As discussed in Section 2.3.3, regulations governing the EHOF require that wells be completed and operated so that fluids are contained in the strata in which they are encountered. For this reason likelihood of leakage is considered low.

TIMING: Risk of leakage at each specific existing wellbore is greatest after CO_2 has reached that location and when pressures are greatest, which is towards the end of the project injection time period.

MAGNITUDE: Leakage volumes are predicted to be less than one percent of total injection (less than 0.5 million metric tons).

MONITORING: Continual and routine monitoring and maintenance of wellbores and site operations is critical to ensure confinement in the following ways.

1. Injection well pressure is monitored continuously throughout the EHOF using a supervisory control and data acquisition (SCADA) system. Pressure and rate sensors on the injection wells are programmed to alarm and notify operations personnel when encountering values that significantly deviate from set target ranges. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such excursions occur, they are investigated and addressed.

2. Experience gained over time allows for a strategic approach to well maintenance and workovers; workover crews are onsite for this purpose. For example, the well classifications by age and construction method inform planning for monitoring and updating wells. All available information, including pattern performance and well characteristics, is used to determine well maintenance schedules.

3. A corrosion protection program for CO_2 operations will be implemented to mitigate both internal and external corrosion of casing in wells in the EHOF. In line with industry standard operations and EPA Class VI requirements for CCS, downhole equipment and the interior and exterior of wellbores will be protected using special materials (e.g., fiberglass tubing, corrosion-resistant cements, nickel-plated packers, corrosion-resistant packer fluids), and procedures will be performed to prevent and monitor for corrosion (e.g., packer placement, use of annular leakage detection devices, cement bond logs, pressure tests). These measures and procedures are typically included in the injection orders filed with CalGEM and the EPA UIC program. Corrosion protection methods and requirements may be enhanced over time in response to improvements in technology.

4. MIT requirements implemented by CalGEM and/or EPA UIC (as applicable) will be followed to periodically inspect wells and surface facilities to ensure that all wells and related surface equipment are in good repair, leak-free, and that all aspects of the site and equipment conform to existing regulations and permit conditions. All active injection wells undergo MIT before

injection, after any workover or per time periods specified in the UIC approval. Operators are required to use a pressure recorder and pressure gauge for the tests. For CalGEM regulated wells, operator's field representative must sign the pressure recorder chart and submit it with the MIT form to CalGEM. The casing-tubing annulus must be tested to maximum anticipated surface pressure (MASP) for a specified duration and with an allowable pressure loss specified in the regulations. CalGEM or EPA UIC may also approve alternative pressure monitoring programs with varying requirements at their discretion.

If a well fails the MIT, the operator must immediately shut the well in and provide notice to CalGEM. Casing leaks must be successfully repaired within 180 days and re-tested, or the well must be plugged and abandoned after submitting a formal notice and obtaining approval from CalGEM.

5. Finally, as indicated in Section 5, field inspections are conducted on a routine basis by field personnel. On any given day, there are approximately 40 personnel in the field. Leaking CO_2 is very cold and leads to formation of bright white clouds and ice that are easily spotted. All field personnel will be trained to identify leaking CO_2 and other potential problems in the field and to safely remedy the issue. Any CO_2 leakage detected will be documented and reported, quantified, and addressed as described in Section 5.

6. Corrective Action assessment performed pursuant to the Class VI regulation includes the generation and detailed review of wellbore/casing diagrams for each well in the project area. Information used in the review includes depths and dimensions of all hole sections, casing strings, cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of cement determination supports the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface. For each well determined to require additional plugging CTV has provided the plugging procedure that will be used to abandon wells along with well-specific plugging plan tables that identify the number of plugs, placement method, cement type, density, and volume for the wells to be abandoned during pre-operational testing. The planned plugging procedures achieve all requirements of CalGEM regulations for proper abandonment of oil and gas wells.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, CRC and CTV conclude that it will mitigate CO_2 leakage through wellbores by detecting problems as they arise and quantifying any leakage that does occur by use of local surface air monitoring in the vicinity of the leaking wellbore.

4.3 Faults and Fractures

There are no faults or fractures penetrating the confining layer of the Reef Ridge shale that provide a potential upward pathway for fluid flow. First, the presence of oil, especially oil with a gas cap, is indicative of a competent natural seal. Oil, and to a greater extent gas, migrates upward over time because both are less dense than the brine found in rock formations. Places where oil and gas remain trapped in the deep

subsurface over millions of years, as is the case in the EHOF, prove that faults or fractures do not provide a pathway for upward migration out of the CO_2 flooding interval.

While developing the EHOF, a seismic survey was conducted to characterize the formations and provide information for the reservoir models used for development planning. Initial interpretations of the 3-D seismic survey were based on a conventional pre-stack time migration volume. In 2019, the 3-D seismic survey was reprocessed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 10 displays the location and extent of four faults that helped to form these anticlines beginning in the Middle Miocene, 16 million years ago (Callaway and Rennie, 1991). These faults have remained inactive for millions of years since. Offsetting the 31S and NWS structures are the 1R, 2R, and 3R high-angle reverse faults that are oriented NW-SE. The faults penetrate the lowest portions of the Monterey Formation but do not continue through the injection interval to the Reef Ridge shale confining layer.

Lastly, the operating history of the EHOF confirms there are no faults or fractures penetrating the Reef Ridge shale that allow fluid migration. Water and gas have been successfully injected into the Monterey Formation since 1976, and there is no evidence of new or existing faults or fractures. Over 1.4 billion barrels of water and 1,237 billion standard cubic feet (Bcf) of gas have been injected into the NWS and 31S structures with no reservoir confinement issues. In fact, it is the absence of faults and fractures in the Reef Ridge shale that makes the Monterey Formation such a strong candidate for water injection operations and enables field operators to maintain effective control over the injection and production processes.

LIKELIHOOD: Because there are no faults or fractures penetrating the confining layer of the Reef Ridge shale that provide a potential upward pathway for fluid flow the likelihood of leakage is considered negligible.

TIMING: No faults are present that provide a potential pathway; therefore leakage is not expected via this pathway over the entire duration of the project.

MAGNITUDE: For reasons given above, anticipated leakage magnitude is negligible.

MONITORING: Leakage via faults, if it were to occur, would be subject to detection from monitoring wells in zones above the sequestration reservoir, as described in Section 5.1.

4.4 Natural or Induced Seismicity

Based on published data and over 100 years of operational experience, there is no evidence that natural seismic activity poses a significant risk for loss of CO_2 for the project. This is due, in part, to the thickness, ductility, and predominance of clay in the primary confining layer Reef Ridge shale.

No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area. Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west, beyond the Temblor Range) and the White Wolf Fault (25 miles southeast from the EHOF).

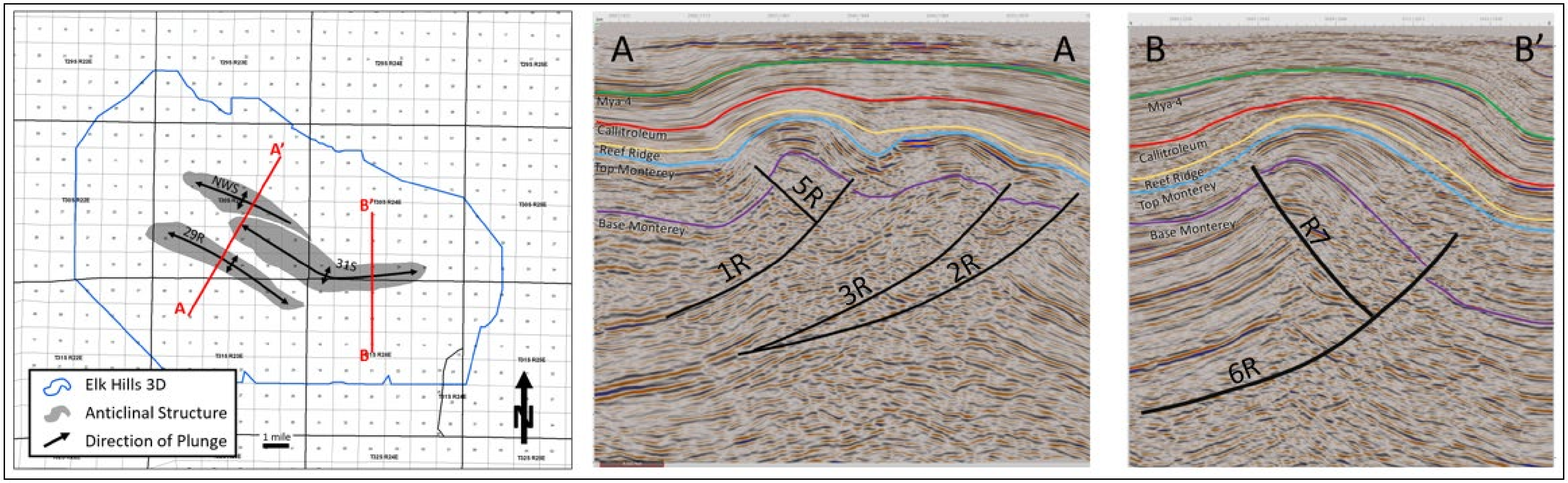


Figure 10: Outline of EHOF 3-D survey and seismic intersections across 31S and NWS structures.

Historical seismic events from 1932 to present are available from the Southern California Earthquake Data Center (SCEDC). Based on this data, there have been no earthquakes recorded greater than 3.0 in the A1-A2 and 26R MMA. In addition, there have only been eleven earthquakes with a magnitude of 5.0 or greater within a 30-mile buffer around the EHOF administrative boundary (Figure 11). There have been 518 earthquakes with a magnitude between 3 and 5 within the 30-mile EHOF buffer. The average depth of the earthquakes with magnitude greater than 3 is 4.5 miles, while the storage reservoirs are one mile below surface.

LIKELIHOOD: Induced seismicity will be mitigated operationally by the following:

1. Injection pressure will be monitored continuously and will be lower than the failure pressure of the confining Reef Ridge shale.
2. Reservoir pressure will be at or beneath the discovery pressure.
3. Seismometers will be installed at the surface to detect seismicity induced by injection operations.

Adherence to these mitigation measures will ensure that likelihood of induced seismicity is low.

TIMING: Risk of induced seismicity is highest when operating pressures are greatest at the end of the injection time period. Risk of natural seismicity is not anticipated to change during the Specified Period.

MAGNITUDE: For reasons given above, anticipated leakage magnitude is negligible.

MONITORING: Induced seismicity monitoring with seismometers, as described in Section 5.1.

4.5 Previous Operations

All of the existing wells at the EHOF have been permitted through CalGEM (and predecessor California agencies) under rules that require detailed information about the character of the geologic setting, the construction and operation of the wells, and other information used to assess the suitability of the site. CalGEM maintains a public database that contains the location, construction details, and injection-production history of each well.

CTV has assessed internal databases as well as CalGEM information to identify and confirm wells within the project area. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Therefore, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the development history of the reservoir that includes injection of water and gas.

Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest at the end of the injection period.

LIKELIHOOD: This operational experience has verified that there are no unknown wells within the EHOF. Additionally, CRC and CTV have sufficiently mitigated the possibility of migration from older wells as discussed above. Over many years, the EHOF has been continuously checked for the presence of old, unknown wells throughout the EHOF. These practices ensure that identified wells are sufficiently isolated and do not interfere with ongoing operations and reservoir pressure management. For these reasons risk of leakage via this pathway is considered low.

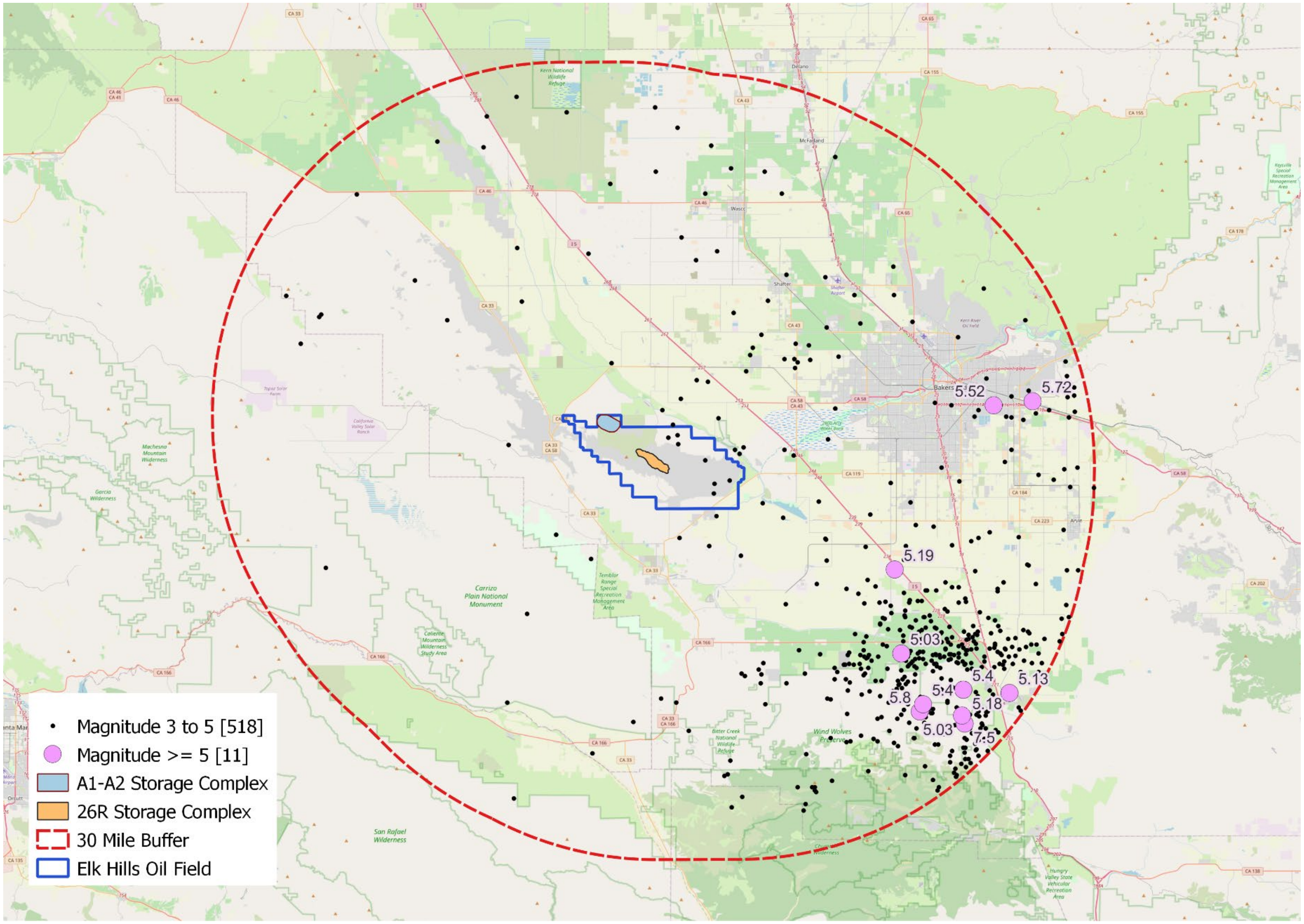


Figure 11: Earthquakes in the San Joaquin Basin with a magnitude greater than 3. Note: only 11 earthquakes have occurred within a 30-mile buffer around the EHOF administrative boundary. Earthquake data from SCEDC.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest that will be at the end of the injection period.

MAGNITUDE: Leakage volumes are predicted to be less than one percent of total injection (less than 0.5 million metric tons).

MONITORING: Leakage via abandoned wells, if it were to occur, would be subject to detection from monitoring wells in zones above the sequestration reservoir, as described in Section 5.1. Additional monitoring is discussed in Section 4.2.

4.6 Pipeline/Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2. Unplanned leakage from surface facilities will be mitigated to the maximum extent practicable by relying on the use of prevailing design and construction practices and maintaining compliance with applicable regulations. The facilities and pipelines will be constructed of materials and managed using control processes that are standard for CO_2 injection projects.

CO_2 delivery to the complex will comply with all applicable regulations, including as pipeline regulations are updated in the future as applicable. Instrumentation will be installed on pipelines and facilities that allows the 24/7 operations staff at the Central Control Facility (CCF) to monitor the process and potentially spot leaks. Furthermore, frequent and routine visual inspections of surface facilities by field staff will provide an additional means to detect leaks. Both manual and automatic shutdowns will be installed in the complex to ensure that leaks are addressed in a timely manner.

LIKELIHOOD: Compliance with applicable regulations, as described above, ensures that likelihood of leakage via this pathway is low.

TIMING: Leakage risk via this pathway will be similar over the project time period.

MAGNITUDE: Should leakage be detected from pipeline or surface equipment, the volume of released CO_2 will be quantified following the requirements of 40 CFR 98.230-238 (Subpart W) of EPA's Greenhouse Gas Reporting Program (GHGRP).

MONITORING: Routine field inspection and remote monitoring will be conducted to detect any potential leakage from pipelines and surface facilities.

4.7 Lateral Migration

It is highly improbable that injected CO_2 will migrate downdip and laterally outside the EHOF because of the buoyant properties of supercritical CO_2, the nature of the geologic structure, and the planned injection approach. The strategy to minimize the lateral migration risk is to ensure that the CO_2 plume and surrounding fluids will be at or below the initial reservoir pressure at time of discovery.

LIKELIHOOD: Leakage via this pathway is not anticipated.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest at the end of the injection period.

MAGNITUDE: Leakage via this pathway is not anticipated to occur, and therefore magnitude of any leakage is considered negligible.

MONITORING: Geophysical monitoring conducted as approved in the Class VI permit will track the extent of CO_2 plume and ensure that there is not lateral migration outside of the AoR.

4.8 Drilling Through the CO_2 Area

It is possible that at some point in the future, drilling through the Reef Ridge confining zone and into the Monterey Formation may occur.

LIKELIHOOD: The possibility of this activity creating a leakage pathway is extremely low for three reasons: 1) Future well drilling would be regulated by CalGEM (oil and gas wells) or EPA UIC (Class VI injection wells) and will therefore be subject to requirements that fluids be contained in strata in which they are encountered; 2) as sole operators and owners of the EHOF, CRC and CTV control placement and timing of new drilling operations; and 3) there are no oil and gas targets beneath the Monterey Formation.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest during future time periods if drilling through the Reef Ridge confining zone were to occur.

MAGNITUDE: Leakage via this pathway is not anticipated to occur, and therefore magnitude of any leakage is considered negligible.

MONITORING: Ongoing regulation of all drilling activities by CalGEM and/or EPA will ensure future monitoring of drilling activities. See additional monitoring discussion in Section 4.2.

4.9 Leakage Through the Seal

Diffuse leakage through Reef Ridge confining layer is highly unlikely. The presence of gas caps trapped over millions of years confirms that the seal has been secure for millions of years. Leaking through the seal is mitigated by ensuring that post-injection reservoir pressure will be at or below the initial reservoir pressure at the time of discovery. The injection monitoring program referenced in Section 2.3.2 and detailed in Section 5 assures that no breach of the seal will be created.

Further, if CO_2 were to migrate through the Reef Ridge, it would migrate vertically until it encountered and was trapped by any of the additional shallower interbedded shales of the Etchegoin, San Joaquin, and Tulare Formations (more than 5,000 ft of vertical section; see Figure 3).

LIKELIHOOD: Diffuse leakage through Reef Ridge confining layer is highly unlikely.

TIMING: Leakage via this pathway is not anticipated; however, leakage risk is greatest at the end of the injection period when pressures are highest. In addition the relative amount of CO_2 in the supercritical phase will decrease over time post-injection as CO_2 dissolves into the brine reducing leakage risk.

MAGNITUDE: Leakage via this pathway is not anticipated to occur, and therefore magnitude of any leakage is considered negligible.

MONITORING: Leakage, if it were to occur, would be subject to detection from monitoring wells in zones above sequestration reservoir, as described in Section 5.1.

4.10 Monitoring, Response and Reporting Plan for CO_2 Loss

As discussed above, the potential sources of leakage include routine issues such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment, and unique events such as induced fractures.

Table 4 summarizes some of these potential leakage scenarios, monitoring activities designed to detect those leaks, standard response, and other applicable regulatory programs requiring similar reporting.

Risk	Monitoring Plan	Response Plan	Parallel Reporting (if any)
Loss of well control			
Tubing leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days	
Casing leak	Routine field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days	CalGEM or EPA UIC
Wellhead leak	Routine field inspection and continuous SCADA monitoring	Workover crews respond within days	
Loss of bottom-hole pressure control	Blowout during well operations	Maintain well-kill procedures; shut-in offset injectors prior to drilling	CalGEM or EPA UIC
Loss of seal in abandoned wells	Anomalous pressure or gas composition from productive shallower zones	Re-enter and reseal abandoned wells	CalGEM or EPA UIC
Leaks in surface facilities			
Pumps, valves, etc.	Routine field inspection and remote monitoring	Workover crews respond within days	Subpart W
Subsurface leaks			
Leakage along faults	Monitoring of zones above sequestration reservoir	Shut-in injectors near faults	EPA UIC
Leakage through induced fractures	Induced seismicity monitoring with seismometers	Comply with rules for keeping pressures below parting pressure	EPA UIC
Leakage due to a seismic event	Induced seismicity monitoring with seismometers	Shut-in injectors near seismic event	EPA UIC

Table 4: Response plan for CO_2 leakage or loss.

Section 5.1 discusses the approaches envisioned for quantifying the volumes of leaked CO_2. In the event leakage occurs, CRC and CTV plan to determine the most appropriate methods for quantifying the volume leaked and will report it as required as part of the annual Subpart RR submission.

Any volume of CO_2 detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR 98.230-238 (Subpart W) or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as frequency of inspection. As indicated in Sections 5.1 and 7, leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in the electronic environmental documentation and reporting system. Repairs requiring a work order will be documented in the electronic equipment maintenance system and well work historian. If the scope of repair work requires permitting through CalGEM or EPA UIC, a subsequent operations summary report will be provided under the conditions of the applicable permit.

4.11 Summary

The structure and stratigraphy of the Monterey Formation in the EHOF is ideally suited for injection and CO_2 storage. The CO_2 injection zone stratigraphy is porous, permeable, and very thick, providing ample capacity for long-term CO_2 storage. The overlying Reef Ridge shale forms an effective seal for Monterey Formation sequestration (see Figure 3). After assessing potential risk of release from the subsurface and steps that have been taken to prevent leaks, the potential threat of significant leakage is extremely low.

Risk of release is further reduced by the prudent operational strategy of limiting the pressure of the reservoir post-injection to at or below the initial pressure of the reservoir at time of discovery.

5 Monitoring and Considerations for Calculating Site-specific Variables

5.1 For the Mass Balance Equation

5.1.1 General Monitoring Procedures

Existing operations are centrally monitored and controlled by the extensive and sophisticated CCF. The CCF uses a SCADA software system to implement operational control decisions on a real-time basis throughout the EHOF to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Flow rates, pressures, gas composition, and other data will be collected at key points and stored in a centralized data management system. These data are monitored 24 hours a day by qualified technicians who follow response and reporting protocols when the system delivers notifications that data exceed predetermined statistically acceptable limits. The data can be accessed for immediate analysis.

Figure 5 identifies the meters that will be used to evaluate, monitor, and report on the injection project and associated plume migration described earlier in Section 2.3. A similar metering system is already installed throughout the EHOF.

As indicated in Figure 5, a custody-transfer meter will be installed at the CO_2 sources. The custody-transfer meters will measure flow rate continuously. Fluid composition will be determined on either a continuous basis or by periodic sampling depending on the specific meter; both options are accurate for purposes of commercial transactions. All meter and composition data will be recorded.

Metering protocols follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. These meters will be maintained routinely, operated continuously, and will feed data directly to the CCF. In the oil and gas industry, the accepted level of custody-transfer meter accuracy is 0.25% or better, and the meters are calibrated every 60 to 90 days. A third party is frequently used to calibrate these meters, and both parties to any transaction have rights to witness meter calibration. These custody meters provide the most accurate way to measure mass flows.

Most process streams are multi-component or multi-phase, with varying CO_2 compositions. For these streams, flow rate is the most important control parameter. Operations flow meters are used to determine the volumetric flow rates of these process streams, which allows for the monitoring of trends to identify deviations and determine if any intervention is needed. Flow meters are also used—comparing aggregate data to individual meter data—to provide a cross-check on actual operational performance.

Developing a CO_2 mass balance on multi-phase, multi-component process streams is best accomplished using custody-transfer meters rather than multiple operations meters. As noted above, in-field flow rate monitoring presents a formidable technical and maintenance challenge. Some variance is due simply to differences in factory settings and meter calibration. Additional variance is due to the operating conditions within a field. Meter elevation, changes in temperature (over the course of the day), fluid composition (especially in multi-component or multi-phase streams), or pressure will affect any in-field meter reading.

Many meters have some form of automatic adjustment for some of these factors, others utilize a conversion factor that is programmed into the meter, and still others need to be adjusted manually in the calculation process. Use of a smaller number of centrally located meters reduces the potential error that is inherent in employing multiple meters in various locations to measure the same volume of flow and gas composition.

Table 5 summarizes the CO_2 injection monitoring strategy. Figure 12 shows the location of monitoring wells.

Monitoring Activity	Frequency/Location
MIT (Internal and External)	Annual
SAPT	Initially; any time the packer is replaced or reset
Injection rate, pressure, and temperature	Continuous
Seismicity	Induced seismicity monitoring via seismometers
Underground sources of drinking water (USDWs) and reservoirs between USDWs and sequestration reservoir	Monitoring wells with pressure, temperature, fluid composition, and periodic cased-hole logs
Stream analysis	Continuous
Corrosion monitoring (coupons, casing integrity)	Well materials, pipelines, and other surface equipment
Sequestration reservoir monitoring	Dedicated wells monitoring sequestration reservoir with pressure, temperature, fluid composition, and periodic cased hole logs

Table 5: Injection monitoring strategy summary.

5.1.2 CO_2 Received

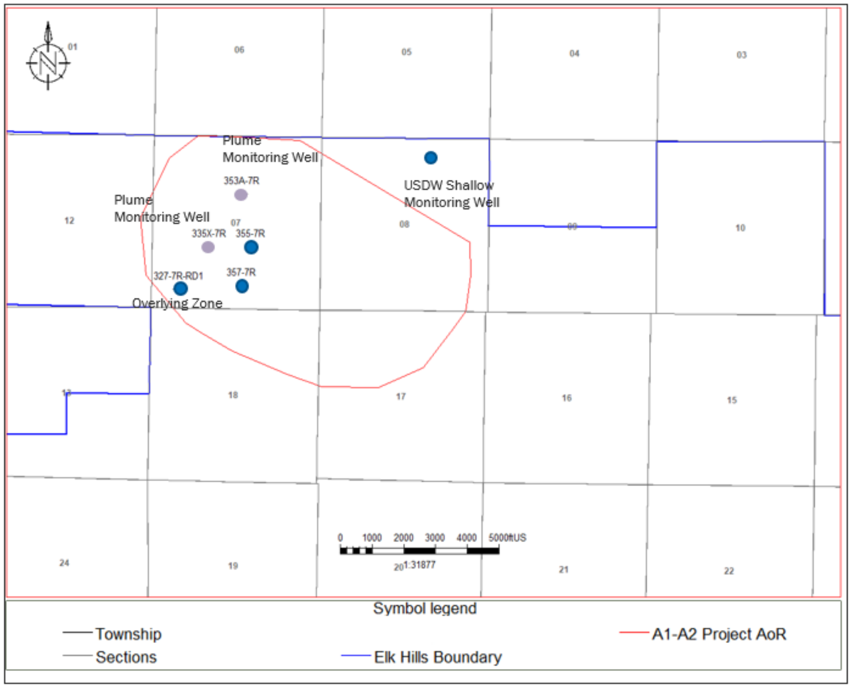
A custody-transfer meter will be used at the CO_2 source(s) to continuously measure the volume and composition of CO_2 received. The metering protocols will follow the prevailing industry standard(s) for custody transfer (as promulgated by the API and the AGA).

5.1.3 CO_2 Injected into the Subsurface

Injected CO_2 associated with geologic sequestration will be calculated using the flow meter volumes at the operations/composition meter at the outlet of the recompression facilities (RCFs) and the custody-transfer meter at the CO_2 off-take points.

5.1.4 CO_2 Produced, Entrained in Products, and Recycled

No CO_2 will be produced or entrained in products or recycled.



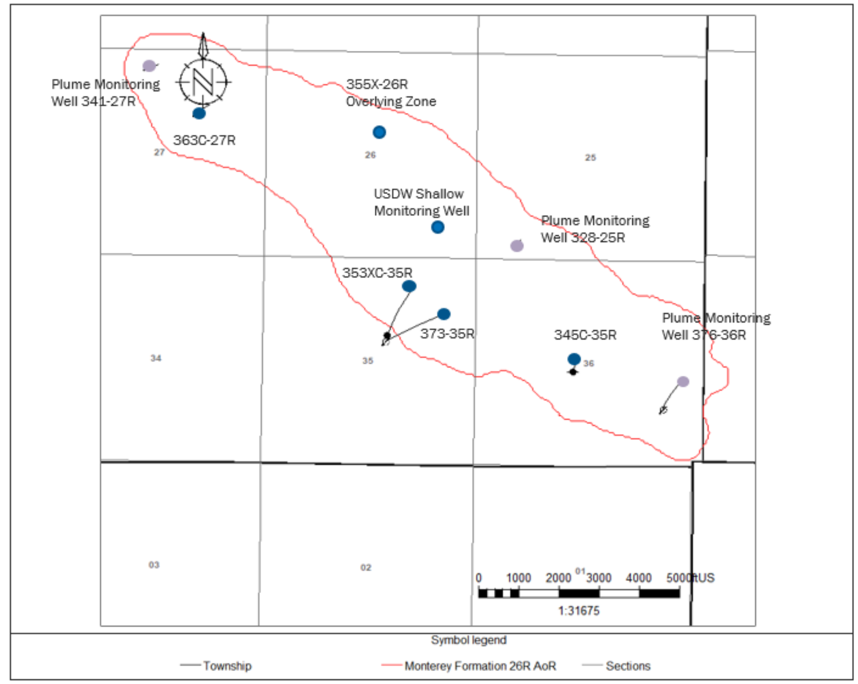


Figure 12: Map showing monitoring well locations.

5.1.5 CO_2 Emitted by Surface Leakage

40 CFR 98.230-238 (Subpart W) is used to estimate surface leaks from equipment at the EHOF. Subpart W uses a factor-driven approach to estimate equipment leakage. In addition an event-driven process will be used to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. Reporting will reconcile the Subpart W report and results from any event-driven quantification to assure that surface leaks are not double-counted.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet the following two objectives in accordance with the leakage risk assessment in Section 4: 1) to detect problems before CO_2 leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the volumes of CO_2 leaked to the surface. Injection Wells

Injection well pressure, temperature, and injection rate will be monitored continuously. If injection pressure or rate measurements are beyond the specified set-points determined for each injector, a data flag is automatically triggered and field personnel will investigate and resolve the problem. These excursions will be reviewed by well-management personnel to determine if CO_2 leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or another minor action is required), and there is no threat of CO_2 leakage. In the case of issues that are not readily resolved, more detailed investigation and response would be initiated, and internal support staff would provide additional assistance and evaluation. Such issues would lead to the development of a work order in the work order management system. This record will enable the company to track progress on investigating potential leaks and, if a leak has occurred, to quantify its magnitude. To quantify leakage to the surface, an estimate of the relevant parameters (e.g., the rate, concentration, and duration of leakage) will be made to quantify the leak volume. Depending on specific circumstances, these determinations may rely on engineering estimates.

Monitoring of Wellbores

Because leaking CO_2 at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a two-part visual inspection process will be employed in the general area of the EHOF to detect unexpected releases from wellbores. First, field personnel will visit the surface facilities on a routine basis. Inspections may include tank volumes, equipment status and reliability, lube oil levels, pressures and flow rates in the facility, and valve leaks. Field personnel inspections will also check that injectors are on the proper schedule and observe the facility for visible CO_2 or fluid line leaks.

Finally, data collected by the personal CO_2 gas monitors, which are always worn by all field personnel, are a last method to detect leakage from wellbores. The monitor's detection limit is 10 parts per million (ppm); if an alarm is triggered, the first response is to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. If the incident results in a work order, this will serve as the basis for tracking the event for greenhouse gas (GHG) reporting. Targeted point-source surface air monitoring will be conducted in the event of detected wellbore leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

Other Potential Leakage at the Surface

Routine visual inspections at surface are used to detect significant loss of CO_2 to the surface. Field personnel visit manned surface facilities daily to conduct visual inspection. Inspections may include review of equipment status, lube oil levels, pressures and flow rates in the facility, valve leaks, ensuring that injectors are on the proper schedule, and conducting a general observation of the facility for visible CO_2 or fluid line leaks. If problems are detected, field personnel would investigate and, if maintenance is required, generate a work order in the maintenance system which is tracked through completion. In addition to these visual inspections, CRC and CTV will use the results of the personal gas monitors as a supplement for smaller leaks that may escape visual detection.

If CO_2 leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, a work order will be generated in the work order management system. The work order will describe the appropriate corrective action and be used to track completion of the maintenance action. The work order will also serve as the basis for tracking the event for GHG reporting and quantifying any CO_2 emissions. Targeted surface air and/or soil gas flux monitoring will be conducted in the event of detected leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

5.1.6 Monitoring for Potential Leakage from the Injection/Production Zone

Monitoring wells to measure pressure, temperature, and fluid composition will be dedicated to geologic sequestration. These dedicated wells will monitor the sequestration reservoir, zones above the sequestration reservoir, and the USDW. Baseline analysis will be established for each of these wells. Any deviation from the baseline analysis will be assessed for potential indications of leakage. Measured increase in CO_2 in groundwater above the Storage Complex will be used to develop groundwater isoconcentration maps and quantify CO_2 leakage rates.

Monitoring well locations are shown on Figure 12, and monitoring wells are listed in Appendix 11.5. Monitoring well details including depth and chemistry monitoring parameters are listed in Appendix 11.6. Monitoring well data collection procedures will be consistent with protocols listed in the Class VI permit application.

5.1.7 Seismicity Monitoring

CTV will monitor seismicity with a network of surface and shallow borehole. This network will be implemented to monitor seismic activity near the project site, and will consist of passive seismic monitoring to demonstrate that there are no seismic events affecting CO_2 containment.

Specifications of the network are as follows:

- Seven sensor locations (borehole and near surface) with high-sensitivity 3-component geophones.
- Borehole sensors will be deployed deeper than 1,500’ to ensure a good quality signal and to minimize noise. A velocity model will be derived from vertical seismic profiles (VSPs), sonic well logs, and check shots.
- The system will be designed with capability of detecting and locating events greater than moment magnitude scale (M_w) 0.0.

Throughout the injection phase, monitoring for natural and induced seismic activity will be performed continuously. Waveform data will be transmitted near real-time via cellular modem or other wireless means and archived in a database. Additionally, CTV will monitor data from nearby (~5-8mi) existing broadband seismometers and strong motion accelerometers of the Southern California Seismic Network.

The Class VI permit application describes actions that will be taken in the event of detected seismic events, based on the magnitude and frequency of seismic activity. In the event of a seismic event greater than M_w 2.0 and local report and confirmation of damage, an investigation will be conducted to determine of CO_2 leakage has occurred. Targeted surface air and/or soil gas flux monitoring will be conducted in the event of detected leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

5.1.8 CO_2 Emitted from Equipment Leaks and Vented Emissions of CO_2 from Surface Equipment Located Between the Injection Flow Meter and the Injection Wellhead

Monitoring efforts will evaluate and estimate leaks from equipment and vented CO_2 as required under 40 CFR 98.230-238 (Subpart W).

5.2 To Demonstrate that Injected CO_2 is not Expected to Migrate to the Surface

At the end of the Specified Period, CRC and CTV intend to cease injecting CO_2 for the subsidiary purpose of establishing the long-term storage of CO_2 in the EHOF. After the end of the Specified Period, CRC and CTV anticipate that it will submit a request to discontinue monitoring and reporting. The request will demonstrate that the amount of CO_2 reported under 40 CFR 98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage. At that time, CRC and CTV will be able to support the request with years of data collected during the Specified Period as well as two to three (or more, if needed) years of data collected after the end of the Specified Period. This demonstration will provide the information necessary for the EPA UIC Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

- Data comparing actual performance to predicted performance (injection) over the monitoring period,
- An assessment of the CO_2 leakage detected, including discussion of the estimated amount of CO_2 leaked and the distribution of emissions by leakage pathway,
- A demonstration that future operations will not release the volume of stored CO_2 to the surface,
- A demonstration that there has been no significant leakage of CO_2, and
- An evaluation of reservoir pressure in the EHOF that demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

6 Determination of Baselines

Automatic data systems will be used to identify and investigate deviations from expected performance that could indicate CO_2 leakage. These data systems are used primarily for operational control and monitoring, and as such, are set to capture more information than is necessary for reporting in the Annual

Subpart RR Report. Necessary system guidelines will be developed to capture the information that is relevant to identify CO_2 leakage. A description of the approach to collecting this information is given below.

6.1 Visual Inspections

As field personnel conduct routine inspections, work orders are generated in the electronic system for maintenance activities that cannot be immediately addressed. Methods to capture work orders that involve activities that could potentially involve CO_2 leakage will be developed, if not currently in place. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation. The responsible party will be provided in the monitoring plan, as required under 40 CFR 98.3(g) (Subpart A). The Annual Subpart RR Report will include an estimate of the amount of CO_2 leaked. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

6.2 Personal Gas Monitors

CO_2 gas monitors are worn by all field personnel (detection limit 10 ppm). Any monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the monitor is working properly. If a fugitive leak is discovered, it would be quantified, and mitigating actions determined accordingly. The person responsible for MRV documentation will receive notice of all incidents where gas is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO_2 emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

6.3 Monitoring Wells

Baseline data will be collected from each monitoring well during well construction in order to provide a baseline. Baseline data will be collected on sequestration zone fluid chemistry and pressure, and above confining zone water chemistry and pressure at monitoring well locations. Data will be acquired that is characteristic of the subsurface after showing data stabilization. Quarterly fluid sampling and continuous pressure/temperature monitoring will be conducted at groundwater monitoring wells above the confining zone during the baseline period. In the injection zone fluid chemistry sampling will occur once at each location and temperature/pressure will be monitored continuously during the baseline period.

6.4 Seismic Baseline

The seismic monitoring network (Section 5.1.7) will be installed during the construction phase. Baseline seismicity data will be collected from the seismic monitoring network for at least 12 months prior to first injection to establish an understanding of baseline seismic activity within the area of the project. Historical seismicity data from the Southern California Seismic Network will be reviewed to assist in establishing the baseline. This data will help establish historical natural seismic event depth, magnitude, and frequency in order to distinguish between naturally occurring seismicity and induced seismicity resulting from CO_2 injection.

6.5 Injection Rates, Pressures, and Volumes

Target injection rates and pressures will be developed for each injector, based on the results of ongoing modeling and permitted limits. High and low set-points are programmed into the controllers, and flags whenever statistically significant deviations from the targeted ranges are identified. The set-points are designed to be conservative. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO_2 leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions and related work orders that could potentially involve CO_2 leakage. The Annual Subpart RR Report will provide an estimate of CO_2 emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

7 Determination of Sequestration Volumes Using Mass Balance Equations

The following sections describe how each element of the mass-balance equation (Equation RR-12) will be calculated.

7.1 Mass of CO_2 Received

CRC and CTV will use Equation RR-2 as indicated in 40 CFR 98.443 to calculate the mass of CO_2 received from each custody-transfer meter immediately downstream of the source(s). The volumetric flow at standard conditions will be multiplied by the CO_2 concentration and the density of CO_2 at standard conditions to determine the mass.

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \text{ (Eq. RR-2)}$$

Where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).
$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).
$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into a site well in quarter p (standard cubic meters).
D = density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682
$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (volume percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
r = Receiving flow meters.

Given CRC and CTV's method of receiving CO_2 and requirements of 40 CFR 98.444(a):

- All delivery to EHOF is used, so quarterly flow redelivered, $S_{r,p}$, is zero ("0") and will not be included in the equation
- Quarterly CO_2 concentration will be taken from the gas measurement database

CRC and CTV will sum to total mass of CO_2 Received using Equation RR-3 in 40 CFR 98.443:

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \text{ (Eq. RR-3)}$$

Where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-2 for flow meter r.

r = Receiving flow meter.

7.2 Mass of CO_2 Injected into the Subsurface

Mass of CO_2 injected into the subsurface at EHOF at each injection well will be calculated with Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \quad \text{(Eq. RR-5)}$$

where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

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

p = Quarter of the year.

u = Flow meter.

Aggregated injection at all injection wells will be calculated with Equation RR-6:

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \quad \text{(Eq. RR-6)}$$

where:

CO_2. = 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.

7.3 Mass of CO_2 Emitted by Surface Leakage

CRC and CTV will calculate and report the total annual mass of CO_2 emitted by surface leakage using an approach that is tailored to specific leakage events and relies on 40 CFR 98.230-238 (Subpart W) reports of equipment leakage. As described in Sections 4 and 5.1, the operators are prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO_2 leaked to the surface will depend on several site-specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

The process for quantifying leakage will entail using best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are discussed in Section 5.1. In the event leakage to the surface occurs, the quantify and leakage amounts will be reported, and records retained that describe the methods used to estimate or measure the volume leaked as reported in the Annual Subpart RR Report. Further, the Subpart W report and results from any event-driven quantification will be made to assure that surface leaks are not double-counted.

Equation RR-10 in 40 CFR 98.443 will be used to calculate and report the mass of CO_2 emitted by surface leakage:

$$\mathrm{CO}_{2E} = \sum_{x=1}^{X} \mathrm{CO}_{2,x} \text{ (Eq. RR-10)}$$

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.

7.4 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Equation RR-12 in 40 CFR 98.443 will be used to calculate the mass of CO_2 sequestered in subsurface geologic formations in the reporting year as follows:

$$\mathrm{CO}_2 = \mathrm{CO}_{2I} - \mathrm{CO}_{2E} - \mathrm{CO}_{2\,\mathrm{FI}} \text{ (Eq. RR-12)}$$

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

Figure 5 illustrates that CO_2 supplied for geological storage will be metered between the CO_2 source and the injection meter.

7.5 Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formations

A sum of the total annual volumes obtained using RR-12 in 40 CFR 98.443 will be used to calculate the cumulative mass of CO_2 sequestered in subsurface geologic formations.

8 MRV Plan Implementation Schedule

It is anticipated that this MRV plan will be implemented as early as first quarter (Q1) 2025 pending appropriate permit approvals and an available CO_2 source, or within 90 days of EPA approval, whichever occurs later. Other facility GHG reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. As described in Section 3.3 above, it is anticipated that that the MRV program will be in effect during the Specified Period, during which time the project will ensure long-term containment of a measurable quantity of CO_2 in subsurface geologic formations at the EHOF and that the project will be operated in a manner not expected to result in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be made and submission with a request to discontinue reporting under this MRV plan (see 40 CFR 98.441(b)(2)(ii)).

9 Quality Assurance Program

9.1 Monitoring QA/QC

As indicated in Section 7, the requirements of 40 CFR 98.444 (a) – (d) in the discussion of mass balance equations have been incorporated. These include the following provisions.

CO_2 Received and Injected

The quarterly flow rate of CO_2 received is measured at the receiving custody-transfer meters.

CO_2 emissions from equipment leaks and vented emissions of CO_2

These volumes are measured in conformance with the monitoring and QA/QC requirements specified in 40 CFR 98.230-238 (Subpart W).

Flow meter provisions

The flow meters used to generate data for the mass balance equations in Section 7 are:

- Operated continuously except as necessary for maintenance and calibration,
- Operated using the calibration and accuracy requirements in 40 CFR 98.3(i),
- Operated in conformance with API standards, and
- Traceable by the National Institute of Standards and Technology (NIST).

Concentration of CO_2

As indicated in Appendix 1 (Section 11.1), CO_2 density is measured using an appropriate standard method. Further, all measured volumes of CO_2 have been converted to standard cubic meters at a temperature of 60 degrees Fahrenheit (°F) and at an absolute pressure of 1 atmosphere, including those used in Equations RR-2, RR-5, and RR-8 in Section 7.

9.2 Missing Data Procedures

In the event data needed for the mass balance equations cannot be collected, procedures in 40 CFR 98.445 for estimating missing data will be used as follows:

- A quarterly flow rate of CO_2 received that is missing would be estimated using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.
- For any 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 specified in 40 CFR 98.230-238 (Subpart W) would be followed.

9.3 MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters, the MRV plan will be revised and submitted to the EPA UIC Administrator within 180 days as required in 40 CFR 98.448(d).

10 Records Retention

The record retention requirements specified by 40 CFR 98.3(g) will be followed. In addition, the requirements in 40 CFR 98.447 will be followed by maintenance of the following records for at least three years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams,
- Quarterly records of injected CO_2 including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams,
- 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, and
- 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.

These data will be collected as generated and aggregated as required for reporting purposes.

11 Appendices

11.1 Conversion Factors

CO_2 volumes will be reported at standard conditions of temperature and pressure as defined by the California Air Resources Board (CARB): 60° F and 14.7 pounds per square inch absolute (psia)[2].

To convert these volumes into metric tons, a density is calculated using the Span and Wagner EOS as recommended by the EPA and using the database of thermodynamic properties developed by NIST, available at http://webbook.nist.gov/chemistry/fluid/.

The conversion factor 5.29×10^{-2} metric ton per thousand cubic feet (MT/Mcf) has been used throughout to convert volumes to metric tons.

[2] See California Code of Regulations Title 17 Section 95102 (General Requirements of Greenhouse Gas Reporting, Definitions)

11.2 Acronyms

3-D – three-dimensional
AGA – American Gas Association
AMA – active monitoring area
AoR – area of review
API – American Petroleum Institute
Bcf – billion standard cubic feet
BOE - barrel of oil equivalent
CalGEM – California Geologic Energy Management Division
CARB – California Air Resources Board
CCF – Central Control Facility
CCS – carbon capture and sequestration
CDMG – California Division of Mines and Geology
CMG - Computer Modeling Group Ltd.
CO_2 – carbon dioxide
CRC - California Resources Corporation
CTV - Carbon TerraVault
DAC – direct air capture
DOE – U.S. Department of Energy
EHOF – Elk Hills Oil Field
EHPP – Elk Hills Power Plant
EOS - equation of state
EPA – U.S. Environmental Protection Agency
GEM – geochemical equation compositional model
GHG – greenhouse gas
GHGRP -- Greenhouse Gas Reporting Program
GPA – Gas Processors Association
H_2S – Hydrogen sulfide
MASP - maximum anticipated surface pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MRV –monitoring, reporting, and verification
MT/Mcf – metric ton per thousand cubic feet
MW - megawatt
NIST -- National Institute of Standards and Technology
NWS – Northwest Stevens
ppm – parts per million
RTS – radioactive tracer survey
RCF – recompression facility
SAPT – standard annual pressure test
SCADA – supervisory control and data acquisition
SCEDC – Southern California Earthquake Data Center

UIC – underground injection control
USDW – underground source of drinking water
VSPs – vertical seismic profiles

11.3 References

Callaway, D.C. and E.W. Rennie, Jr. 1991. *San Joaquin Basin, California*, in Gluskoter, H.J., D.D.Rice, and R.B. Taylor, eds. Economic geology, U.S.: Boulder, Colorado. Geological Society of America. The Geology of North America, v. P-2: 417-430.

McJannet, G.S. 1996. *General Overview of the Elk Hills Field*. Society of Petroleum Engineers. doi:10.2118/35670-MS.

11.4 Glossary of Terms

This glossary describes some of the technical terms as they are used in this MRV plan. For additional glossaries please see the U.S. EPA Glossary of UIC Terms (http://water.epa.gov/type/groundwater/uic/glossary.cfm), and the Schlumberger Oilfield Glossary (http://www.glossary.oilfield.slb.com/).

Anticline – an arch-shaped fold in the rock layers in a geologic formation in which the layers are upwardly convex, forming something like a dome or bell shape. Anticlines form excellent hydrocarbon traps, particularly in folds that have rocks with high injectivity in their core and high impermeability in the outer layers of the fold.

Contain/containment –the effect of keeping fluids located within in a specified portion of a geologic formation.

Dip – the angle of the rock layer relative to the horizontal plane. Buoyant fluids will tend to move up the dip, or *updip*, and heavy fluids will tend to move down the dip, or *downdip*. Moving higher up structure is moving updip. Moving lower is downdip. Perpendicular to dip is *strike*. Moving perpendicular along a constant depth is moving along strike.

Downdip – see *dip*.

Flooding pattern – also known as an injection pattern; the geometric arrangement of production and injection wells to sweep oil efficiently and effectively from a reservoir.

Formation – a body of rock that is sufficiently distinctive and continuous that it can be mapped.

Injectivity – the ability of an injection well to receive injected fluid (both rate and pressure) without fracturing the formation in which the well is completed. Injectivity is a function of the porosity and permeability of the rock formation and the reservoir pressure in which the injection well is completed.

Infill drilling – the drilling of additional wells within existing patterns. These additional wells decrease average well spacing. This practice both accelerates expected recovery and increases estimated ultimate recovery in heterogeneous reservoirs by improving the continuity between injectors and producers. As well spacing is decreased, shifting flow paths lead to increased sweep to areas where greater hydrocarbon saturations remain.

Permeability – the measure of a rock's ability to transmit fluids. Rocks that transmit fluids readily, such as sandstones, are described as permeable and tend to have many large, well-connected pores. Impermeable formations, such as shales and siltstones, tend to be finer grained or of a mixed-grain size, with smaller, fewer, or less-interconnected pores.

Phase – a region of space throughout which all physical properties of a material are uniform. Fluids that don't mix segregate themselves into phases. Oil, for example, does not mix with water and forms a separate phase.

Pore space – see *porosity*.

Porosity – the fraction of a rock that is not occupied by solid grains or minerals. All rocks have spaces between rock crystals or grains that is available to be filled with a fluid, such as water, oil, or gas. This space is called *pore space*.

Primary recovery – the first stage of hydrocarbon production, in which natural reservoir energy, such as gas drive, water drive, or gravity drainage, displaces hydrocarbons from the reservoir into the wellbore and up to surface. Initially, the reservoir pressure is higher than the bottom-hole pressure inside the wellbore. This high natural differential pressure drives hydrocarbons toward the well and up to surface. However, as the reservoir pressure declines because of production, so does the differential pressure. To reduce the bottom-hole pressure or increase the differential pressure to increase hydrocarbon production, it is necessary to implement an artificial lift system, such as a rod pump, an electrical submersible pump, or a gas-lift installation. Production using artificial lift is considered primary recovery. The primary recovery stage reaches its limit either when the reservoir pressure is so low that the production rates are not economic, or when the proportions of gas or water in the production stream are too high. During primary recovery, only a small percentage of the initial hydrocarbons in place are produced, typically 10%-12% for oil reservoirs. Primary recovery is also called *primary production*.

Saturation – the fraction of pore space occupied by a given fluid. Oil saturation, for example, is the fraction of pore space occupied by oil.

Seal – a geologic layer (or multiple layers) of impermeable rock that serves as a barrier to prevent fluids from moving upwards to the surface.

Secondary recovery – the second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are immiscible gas injection and waterflooding.

Sedimentary rocks – rocks formed at the Earth's surface through deposition of sediments derived from weathered rocks, biogenic activity, or precipitation from solution. There are three main types of rocks: igneous, metamorphic, and sedimentary.

Stratigraphic section – a sequence of layers of rocks in the order they were deposited.

Strike – see *dip.*

Updip – see *dip.*

11.5 Well List

The following tables present the well name and well type for the project.

26R Project Wells

Injectors	363C-27R 353XC-35R 373-35R 345C-35R	
Monitoring wells	341-27R	Plume monitoring
	328-25R	Plume monitoring
	374-36R	Plume monitoring
	355X-26R	Above-zone monitoring well
	USDW monitoring well	USDW monitoring

A1-A2 Project Wells

Injectors	355-7R 357-7R	
Monitoring wells	353A-7R	Plume monitoring
	335X-7R	Plume monitoring
	327-7R-RD1	Above-zone monitoring well
	USDW monitoring well	USDW monitoring

11.6 Monitoring Well Details

26R Project monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage of Depth	Frequency (Injection Phase)
Tulare Formation	Fluid Sampling	Shallow Water Monitoring Well	Pump	–400’ - 450' MD/VD	Quarterly
	Pressure	Shallow Water Monitoring Well	Pressure Gauge	400’ - 450' MD/VD	Continuous
	Temperature	Shallow Water Monitoring Well	Temperature Sensor	400’ - 450' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	400' - 500' MD/VD in each well	Continuous
Etchegoin Formation	Fluid Sampling	355X-26R	Sampling Device	4063' - 4087' MD/VD	Quarterly
	Pressure	355X-26R	Pressure Gauge	4063' - 4087' MD/VD	Continuous
	Temperature	355X-26R	Temperature Sensor	4063' - 4087' MD/VD	Continuous
	Temperature	328-25R 341-27R 376-36R	Fiberoptic cable (DTS)	3961' - 3987' 4788' - 4811' 4205' - 4226' (all MD/VD)	Continuous

A1-A2 Project monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Data Collection Location(s)	Device	Spatial Coverage or Depth	Frequency (Injection Phase)
Tulare	Fluid Sampling	USDW Monitoring Well	Pump	940' - 960' MD/VD	Baseline, Quarterly
	Pressure	USDW Monitoring Well	Pressure Gauge	940' - 960' MD/VD	Continuous
	Temperature	USDW Monitoring Well	Temperature Sensor	940' - 960' MD/VD	Continuous
	Temperature	327-7R-RD1 353A-7R 335X-7R	Fiberoptic cable (DTS)	849' MD/VD 961' MD/VD 854' MD/VD	Continuous
Etchegoin	Fluid Sampling	327-7R-RD1	Sampling Device	3782' - 3934' MD 3780' - 3932' VD	Baseline, Quarterly
	Pressure	327-7R-RD1	Pressure Gauge	3782' - 3934' MD 3780' - 3932' VD	Continuous
	Temperature	327-7R-RD1	Temperature Sensor	3782' - 3934' MD 3780' - 3932' VD	Continuous
	Temperature	353A-7R 335X-7R	Fiberoptic cable (DTS)	4100' - 4220' 3850' - 3990' (all MD/VD)	Continuous

Summary of analytical and field parameters for groundwater samples above the confining zone.

Parameters	Analytical Methods
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Zn, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO_3, SO_4)	Ion Chromatography, EPA Method 300.0
Dissolved CO_2	Coulometric titration, ASTM D513-11
Dissolved CH_4 (Methane)	SM 6211 B or 6211 C
Dissolved Oxygen (field)	APHA 2005
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
Total Dissolved Solids	Gravimetry; Method 2540 C
Oxygen, Argon, and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	APHA 2510
Temperature (field)	Thermocouple
Water Density (field)	Oscillating body method

11.7 Summary of Key Regulations Referenced in MRV Plan

Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b).

Request for Additional Information: CTV/CRC Elk Hills Carbon Project
August 23, 2023

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.	2.3.3	13	"There wells were drilled between 1948 and 2014, are **generally** completed with three strings of casing, **typically** cemented to the surface. A perforated production liner was typically installed to the top of the producing interval…" Per the previous RFAI, we recommended adding clarification to what these instances of "generally" and "typically" refer to. For example, are you aware of wells that may not have been completed to these standards? Would such wells require additional monitoring?	This section was revised to summarize the process that was used to assess each wellbore for potential corrective action, and state that corrective action will be performed on existing wellbores as necessary to ensure zonal isolation per the Class VI permit. The terms "generally" and "typically" were removed.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
2.	3.2	14	"The A1-A2 and 26R reservoirs are depleted and CO_2 is **predicated** to reach the edges of the reservoir within the first two to three years of injection; therefore, the AMA is assumed to be functionally equivalent to the MMA." Per 40 CFR 98.449, active monitoring area is defined 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. While the MRV plan identifies the AMA and acknowledges the definitions in 40 CFR 98.449, please provide further explanation on how the AMA meets the boundary definitions above. For example, what is the predicted plume boundary at year t and year t+5? The sentence does not explain why CO2 reaching the edges of the reservoir in two to three years of injection would justify the AMA being equal to the MMA. Additionally, please clarify whether "predicated" should be "predicted" in this sentence.	This section was edited to clarify the period of the AMA, provide additional explanation, and add maps showing plume evolution over time for both projects. The word "predicated" was removed.
3.	4	NA	In addition to listing the possible leakage pathways and their monitoring strategies, please provide a characterization of the likelihood magnitude, and timing of leakage for each potential leakage pathway. For example, Sections 4.3, 4.4, and 4.6 do not directly/fully explain the likelihood, magnitude, and timing of potential leakage.	These sections were revised to add specific statements regarding likelihood, magnitude, timing, and monitoring of potential leakage as requested.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	4.4/5	22	"Based on this data, there have been no earthquakes recorded greater than 3.0 in the A1-A2 and 26R MMA. In addition, there have only been eleven earthquakes with a magnitude of 5.0 or greater within a 30-mile buffer around the EHOF administrative boundary (Figure 10). **There have been 518 earthquakes with a magnitude between 3 and 5 within the 30-mile EHOF buffer**. The average depth of the earthquakes with magnitude greater than 3 is 4.5 miles, while the storage reservoirs are one mile below surface." The number of 3M-5M earthquakes within the 30-mile EHOF buffer seems substantial. We recommend including more information about monitoring for seismicity and associated potential leakage here or in section 5.	Section 5.1.7 has been added to provide additional information on the seismic monitoring network. Section 6.4 has been added to provide additional information on seismic baseline data collection.
5.	6.2	31	**Gas monitors** are worn by all field personnel (detection limit 10 ppm). Any monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the monitor is working properly. If **a fugitive leak is discovered**, it would be quantified, and mitigating actions determined accordingly. Section 6.2 describes how gas monitors will be used to detect leakage. It is not specified in this section whether the monitors detect CO_2 or another gas. Please clarify what type of gas these monitors detect and what kind of leakage would be detected. In other words, is this section suggesting that H_2S be used as a proxy for CO_2 leakage? Furthermore, in the response to our previous request for information, you indicated that the "anticipated H2S concentration in the injectate is 0.001 to 0.014%." Please add this information to the MRV plan itself.	Clarification has been added that these are CO_2 gas monitors. Anticipated hydrogen sulfide concentration has been added to Section 2.3.1.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
6.	5.1.5	29	"Monitoring wells to measure pressure, temperature, and fluid composition will be dedicated to geologic sequestration… Baseline analysis will be established for each of these wells." Please provide more information about the monitoring wells here. E.g., how many are there, what is their depth, and what chemistry will be monitored? Furthermore, the above sentence appears to indicate that monitoring wells will be used in setting baselines. Therefore, we recommend including monitoring wells in section 6.	Figure 12 already showed monitoring well locations and Appendix 11.5 already listed monitoring wells for each project. Section 5.1.6 and Appendix 11.6 have been added to provide additional monitoring well information. Section 6.3 has been added to address baseline monitoring well data collection.
7.	7.4	32-34	"CO_2 = Total net annual mass of CO_2 sequestered (metric tons)" In Equation RR-12, this variable is "CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year." Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	This edit was made as requested.

Elk Hills A1-A2 and 26R CO_2 Subpart RR Monitoring, Reporting, and Verification Plan

Version Date: 7/11/2023

Table of Contents

Overview

The Elk Hills Oil Field (EHOF), covering 75 square miles, was discovered in 1911 and has produced over 2 billion barrels of oil equivalent (BOE), making it one of the most productive fields in the United States. California Resources Corporation (CRC) and Carbon TerraVault (CTV; a CRC wholly owned subsidiary), owns 100% of the surface, mineral, and pore space rights at the EHOF.

CTV intends to inject and store a measurable quantity of carbon dioxide (CO_2) in subsurface geologic formations at the EHOF, for a term of 27 years referred to as the "Specified Period." During the Specified Period, CO_2 will be injected from anthropogenic sources such as the Elk Hills 550 megawatt (MW) natural gas combined cycle power plant (EHPP), bio-diesel refineries, and other sources in the EHOF area.

The CO_2 will be injected into the Monterey Formation A1-A2 and 26R reservoirs for dedicated geologic storage. The Elk Hills storage complex will be pre-certified and monitored to verify permanent CO_2 sequestration. Class VI applications have been submitted for the A1-A2 and 26R reservoir.

This EHOF monitoring, reporting, and verification (MRV) plan is based on decades of subsurface characterization and simulation of the targeted Monterey Formation. This empirically driven analysis indicates that the natural geologic seal that overlays the entire EHOF, known as the Reef Ridge shale, will provide a physical trap that will permanently prevent injected CO_2 from migrating to the surface.

This MRV plan documents the following in accordance with 40 CFR 98.440-449 (Subpart RR):

- Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA), 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,
- Strategy for detecting and quantifying any surface leakage of CO_2,
- Strategy for establishing the expected baselines for monitoring CO_2 surface leakage,
- Summary of considerations for calculating EHOF-specific variables for the mass balance equation, and
- Proposed date to begin collecting data for calculating total CO_2 sequestered.

1 Facility Information

i. Reporter number – 582061

ii. Existing wells in the EHOF including production, injection, and monitoring wells are permitted by California Geologic Energy Management Division (CalGEM) through California Public Resources Code Division 3.[1]

iii. Wells injecting CO_2 for geologic storage will be permitted with the United States Environmental Protection Agency (EPA) Underground Injection Control (UIC) program for Class VI injection.

[1] Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

iv. Wells in the EHOF are identified by name, American Petroleum Institute (API) number, status, and type. The list of wells as of March 2023 associated with the geologic storage projects is included in Appendix 11.5. Any new wells or changes to wells will be indicated in the annual report.

2 Project Description

The EHOF is one of the largest oil and natural gas fields in the United States, with production from multiple vertically stacked reservoirs. Turbidite sand deposits of the Miocene Monterey Formation will serve as the injection targets in two separate anticlinal structures, Northwest Stevens (NWS) and 31S (Figures 1a, 1b).

Numerous aspects of the geology, facilities, equipment, and operational procedures for A1-A2 and 26R are consistent throughout the field. As such, one MRV report will satisfy the 26R and A1-A2 reservoirs as shown in Table 1. The A1-A2 and 26R reservoir and well locations within the field are shown in Figure 1.

Structure	Reservoir	Sequestration Type	Number of Injectors
31S	26R	Geologic : Class VI	4
NWS	A1-A2	Geologic : Class VI	2

Table 1: Reservoirs within the EHOF and sequestration type.

2.1 Project Characteristics

The potential CO_2 stored over the project duration is up to 48 million metric tons (refer to Table 2 for breakdown). For accounting purposes, the amount stored is the difference between the amount injected less any CO_2 that i) leaks to the surface, or ii) is released through surface equipment leakage or malfunction. Actual amounts stored during the Specified Period of reporting will be calculated as described in Section 7 of this MRV Plan.

2.2 Environmental Setting

The project site for this MRV plan is the EHOF, located in the San Joaquin Basin, California (Figure 2).

2.2.1 Geology of Elk Hills Oil Field

The EHOF is located 20 miles southwest of Bakersfield in western Kern County, producing oil and gas from several vertically stacked reservoirs formed in the Tertiary period (65 million to 2 million years ago). Of the more than 24,000 feet (ft) of sediment deposited, the most prolific reservoir is the Miocene epoch Monterey Formation that is the target CO_2 sequestration reservoir.

Individual layers within the Monterey Formation are primarily interbedded sandstone and shale. These layers have been folded, resulting in anticlinal structures containing hydrocarbons formed from the deposition of organic material approximately 33 million to 5 million years ago (during the Oligocene and Miocene epochs). The combination of multiple porous and permeable sandstone reservoirs interbedded with impermeable shale seals makes the EHOF one of the most suitable locations in North America for the extraction of hydrocarbons and the sequestration of CO_2.

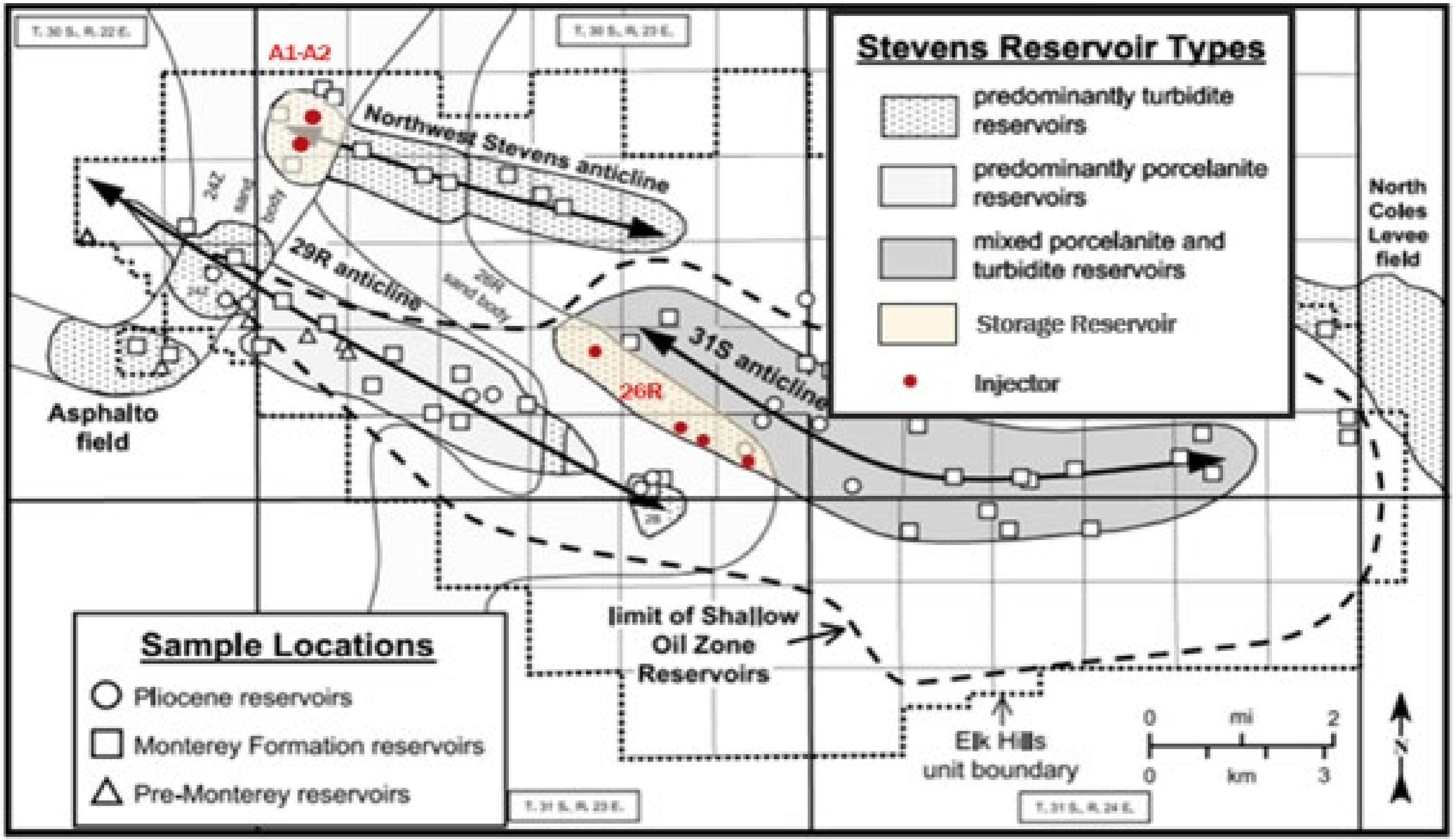


Figure 1a: EHOF map of injection target and injection well locations.

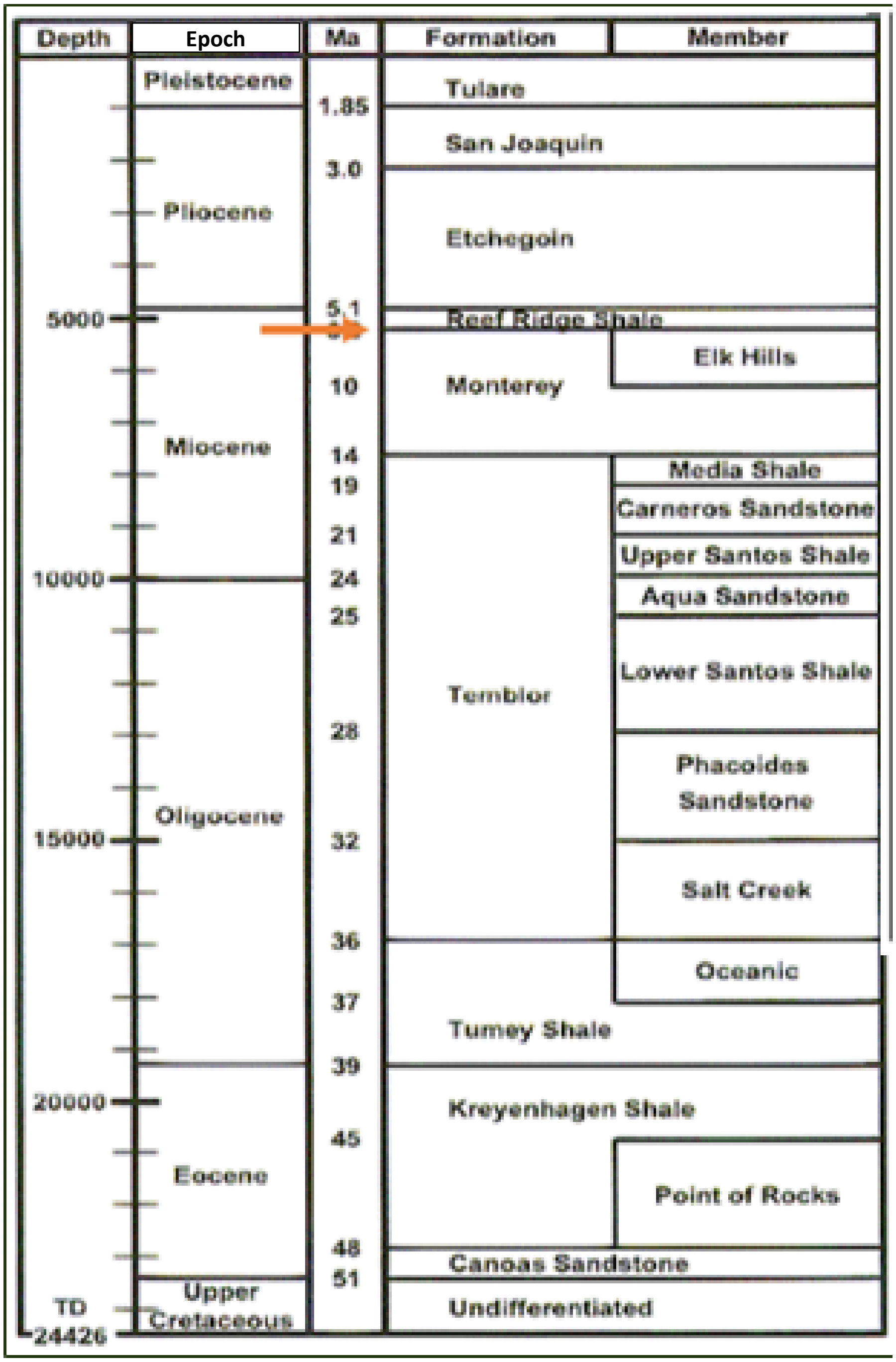


Figure 2b: EHOF stratigraphic column.

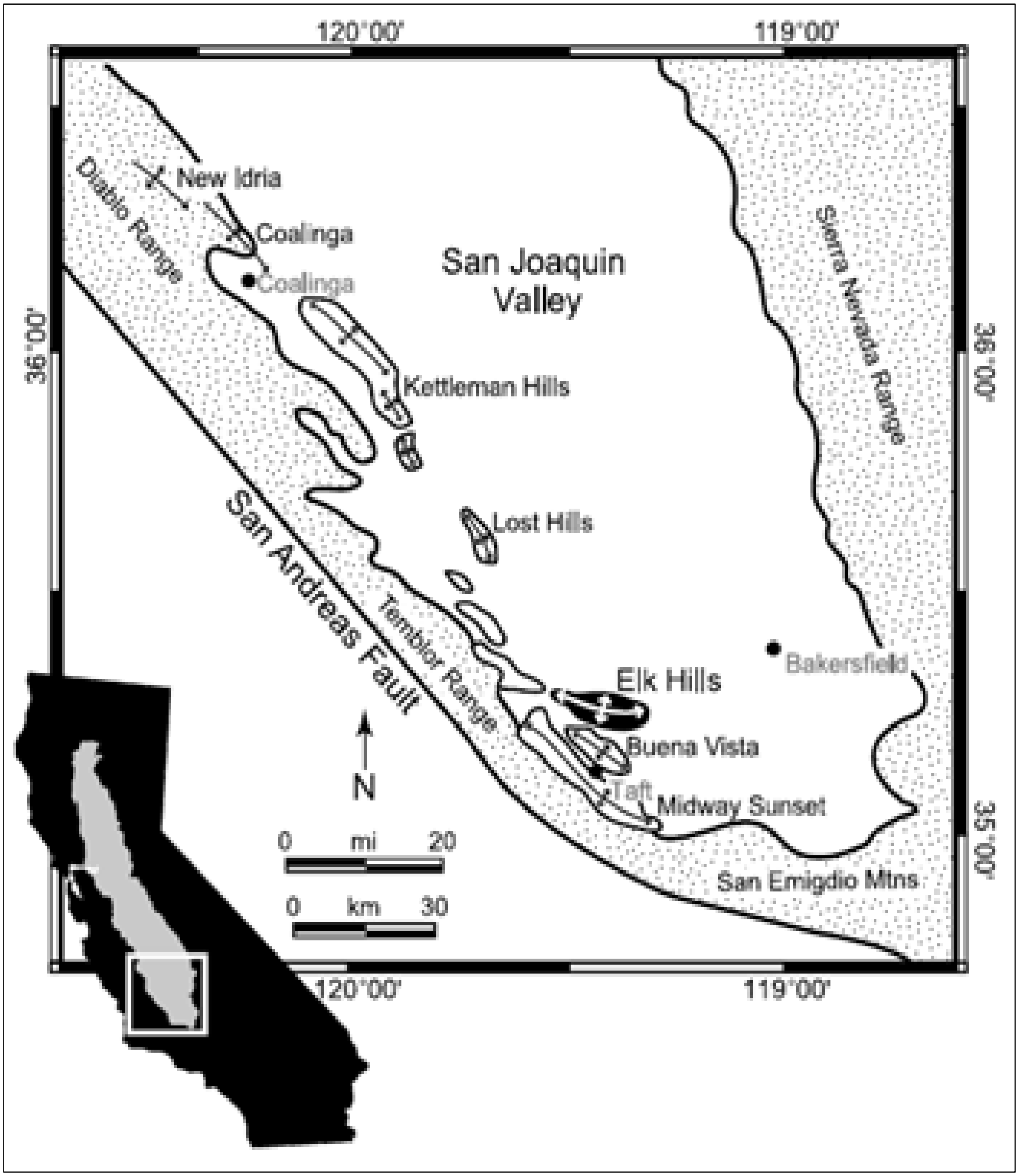


Figure 3: Location of Elk Hills Oil Field, San Joaquin Basin, California.

Following its deposition, Monterey Formation sediments were buried under more than 750 ft of impermeable silty and sandy shale that comprise the confining Reef Ridge shale. The Reef Ridge shale serves as the primary confining layer over the Monterey because it effectively seals underlying fluids from the overlying formations. Above the Reef Ridge lies several alternating sand-shale sequences of the Pliocene Etchegoin and San Joaquin Formations and Pleistocene Tulare Formation. These formations are highlighted in the cross-section in Figure 3.

As indicated in Figure 1, the 31S and NWS structures represent structural highs, or anticlines, within the EHOF. The elevated areas form a natural trap for oil and gas that migrated from below over millions of years. Once trapped at these high points, the oil and gas has remained in place. In the case of the EHOF, the oil and gas has been trapped in the reservoir for more than 6 million years.

Based on physical site characterization and analysis of historic operating records from the Monterey Formation, there is sufficient reservoir capacity and flow properties to inject and store the entire volume of CO_2 proposed as determined by computational modeling (Table 2).

	Volume (million metric tons)
A1-A2 geologic storage	10
26R geologic storage	38
Total storage capacity	48

Table 2: Calculation of cumulative net fluid volume produced for the Monterey Formation sequestration reservoir.

Stored CO_2 will be contained securely within the EHOF Monterey Formation as demonstrated by 1) preservation of hydrocarbon accumulations over geologic time; 2) subsequent water and gas injection operations; 3) competency of the Reef Ridge confining zone over millions of years and throughout decades of primary and secondary operations; and 4) ample storage capacity of the A1-A2 and 26R reservoir. Confinement within the project area and in the reservoir will be ensured by limiting the pressure of the reservoir post-injection at or below the initial pressure of the reservoir at time of discovery.

2.2.2 Elk Hills Oil Field Operational History

McJannet (1996) reports on the early operating history of EHOF. By Executive Order, in 1912 President Taft designated the area surrounding EHOF as a naval oil reserve. Intended to ensure a secure supply of fuel for the Navy's oil-burning ships, the Executive Order defined "Naval Petroleum Reserve No. 1" (NPR-1). In 1977, President Carter signed the U.S. Department of Energy (DOE) Organization Act which transferred NPR-1 to the DOE. Nearly 20 years later, the DOE was directed to sell the assets of NPR-1. Occidental Petroleum ("Occidental") provided a winning bid of $3.65 billion, and on February 10, 1998, Occidental took over official ownership and operation of EHOF. In December 2014, Occidental Petroleum spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC.

The EHOF unit boundary is shown in orange below in Figure 4.

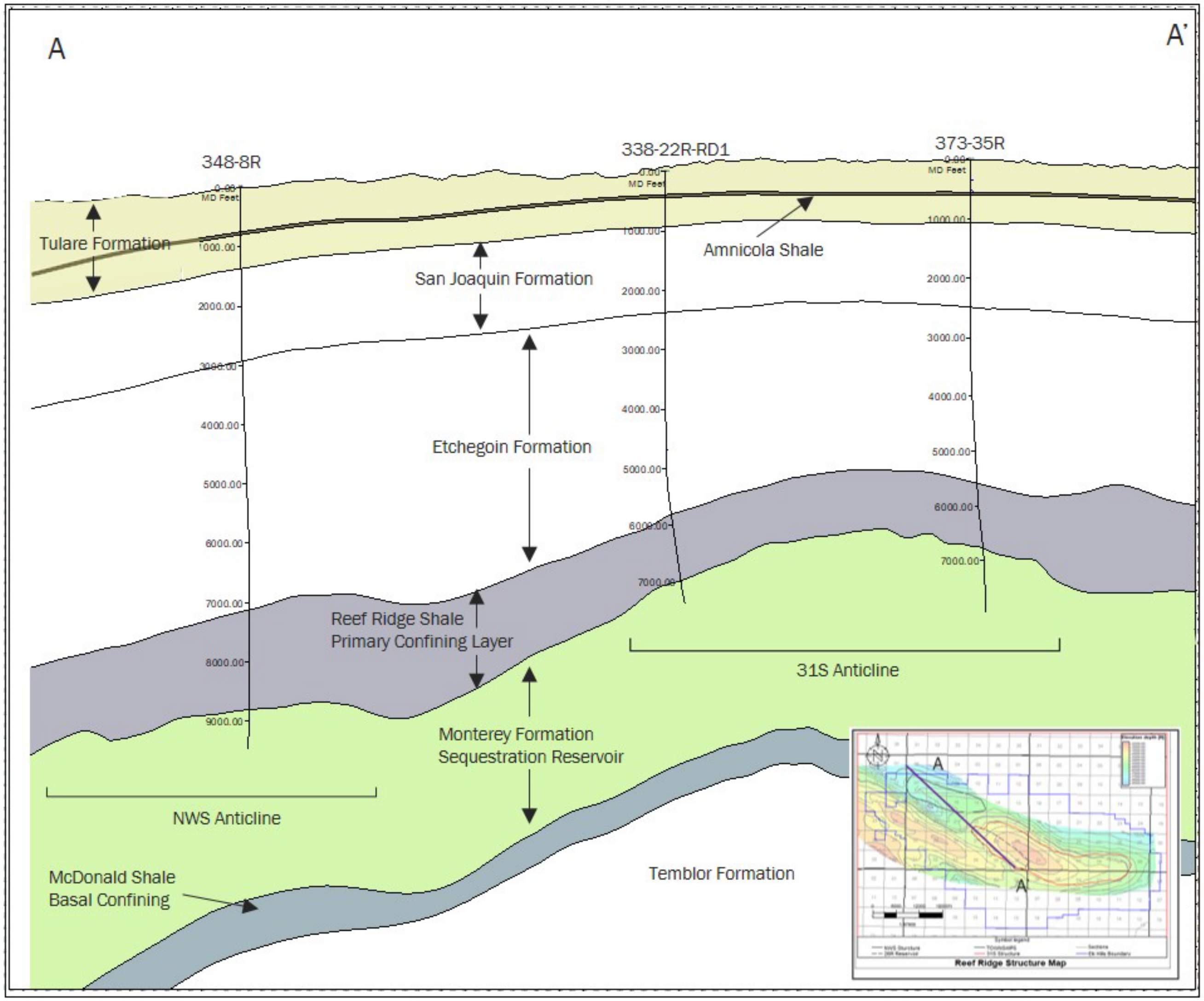


Figure 4: Stratigraphic schematic highlighting the NWS and 31S anticlines.

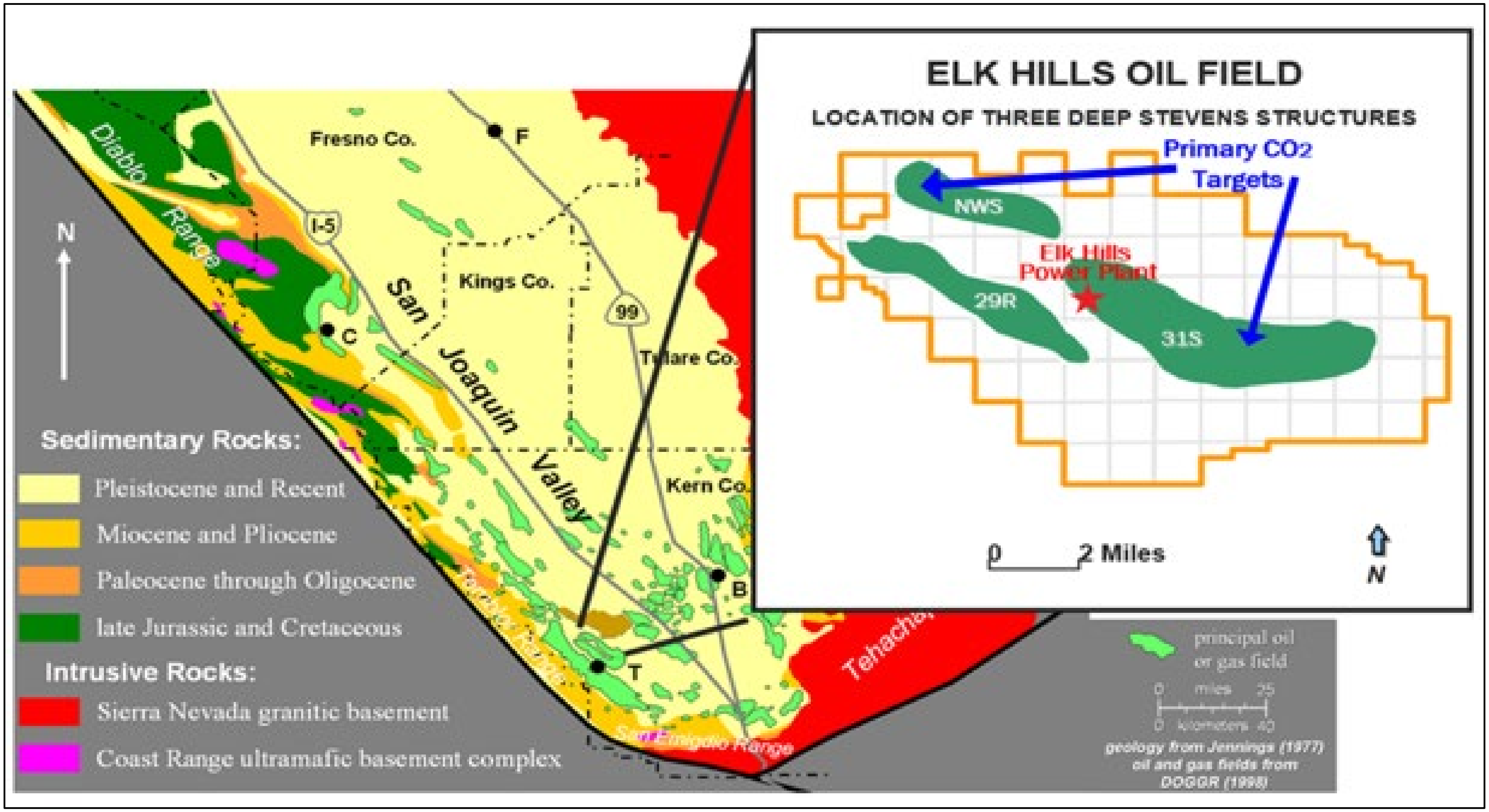


Figure 5: Location of Elk Hills Oil Field within San Joaquin Basin, California.

Development History

Selected primary drilling in the Monterey Formation began in the early 1940s, with concerted drilling and production operations commencing with the DOE's oversight in the late 1970s. To support reservoir pressure and maximize the oil recovery factor, extensive water and gas injection has occurred.

A successful CO_2 injection pilot was implemented in the Monterey Formation in 2005. Data from the four-month pilot confirmed the formation as an attractive target for CO_2 sequestration. This project assessed how much oil could be mobilized from the conventional sand reservoirs, how much CO_2 would be required to mobilize that oil, and how quickly the oil would be produced. Production performance and data collected before, during, and after the pilot operations showed that Monterey Formation reservoirs selected are ideal for CO_2 sequestration.

In addition, past development of the shallow Etchegoin Formation oil reservoirs and Monterey Formation has created a large pressure differential across the Reef Ridge shale, further demonstrating the lack of communication between the reservoirs.

2.3 Description of Facilities and Injection Process

A simplified flow diagram of surface facilities can be seen in Figure 5. This includes facilities outside the scope of the MRV including CO_2 source(s), and the subsequent metering locations between the MRV scope and those facilities. All facilities will be designed and built to ensure integrity and compatibility with CO_2. The subsequent parts of this section will review each of the following:

- CO_2 source,
- CO_2 distribution and injection, and
- Wells in the Class VI defined area of review (AOR) penetrating the Reef Ridge shale.

Facilities associated with dedicated geologic sequestration will be relatively simple as field production and re-compression process flows are unnecessary.

2.3.1 CO_2 Source

CTV plans to construct a carbon capture and sequestration (CCS) "hub" project (i.e., a project that captures CO_2 from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC-permitted injection well). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The anthropogenic CO_2 will be sourced from an onsite blue hydrogen plant (up to 200,000 metric tons per annum), with additional potential CO_2 from the EHPP, direct air capture (DAC), renewable diesel refineries, and/or other sources in the area.

All CO_2 sources will have custody-transfer metering to ensure accurate accounting of both the mass rate and impurities in the CO_2 stream.

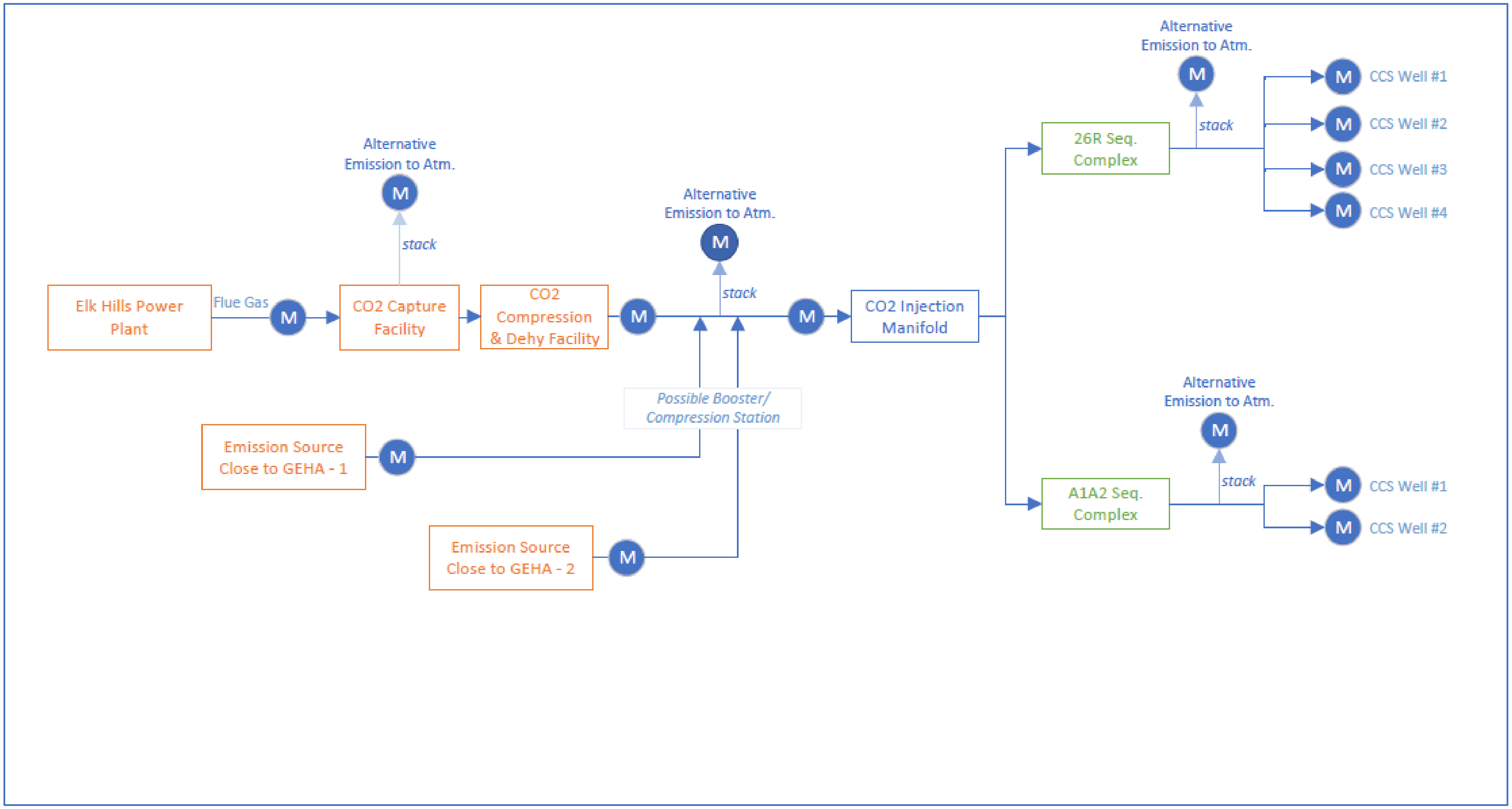


Figure 6: Facilities flow diagram for Carbon TerraVault geological sequestration and CalCapture enhanced oil recovery (EOR). Meter placement will ensure that volume of CO_2 from source to both geologic sequestration and EOR will be measured separately. Blue "M" symbols denote meter locations.

2.3.2 CO_2 Distribution and Injection

CO_2 from the sources previously discussed will be distributed throughout the field through a combination of new and existing infrastructure. This distribution infrastructure will allow CO_2 to be injected into CO_2 wells completed within the Monterey Formation at A1-A2 and 26R.

Each CO_2 injection well will have automated controls that provide for both control and measurement of the mass flow rate and pressure.

2.3.3 Wells in the AOR Penetrating the Reef Ridge Shale

CalGEM regulations govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields (other than UIC Class VI CO_2 injection wells that are regulated by the EPA UIC program). Current CalGEM rules require, among other provisions, the following conditions.

- Fluids must be constrained in the strata in which they are encountered.
- Activities governed by the regulations cannot result in the pollution of subsurface or surface waters.
- Wells must adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata in which they are encountered into strata with oil and gas, or into subsurface and surface waters.
- Operators must file a completion report including basic electric log (e.g., a density, sonic, or resistivity log acquired from the wellbore).
- Wells must follow plugging procedures that require advance approval from CalGEM and allow consideration of the suitability of the cement based on the use of the well, location and setting of plugs.

Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM at time of drilling and as part of the existing Class II UIC permit applications. Wells penetrating the Reef Ridge confining layer and storage reservoir are shown in Figure 6.

Completion Date	A1-A2 Reservoir Count	26R Reservoir Count
Oil and gas producing wells	79	145
Class II injection/disposal wells	32	22
Observation wells	0	2
Plugged and abandoned	39	35
TOTAL	150	204

Table 3: Wells penetrating Reef Ridge shale for each reservoir by status.

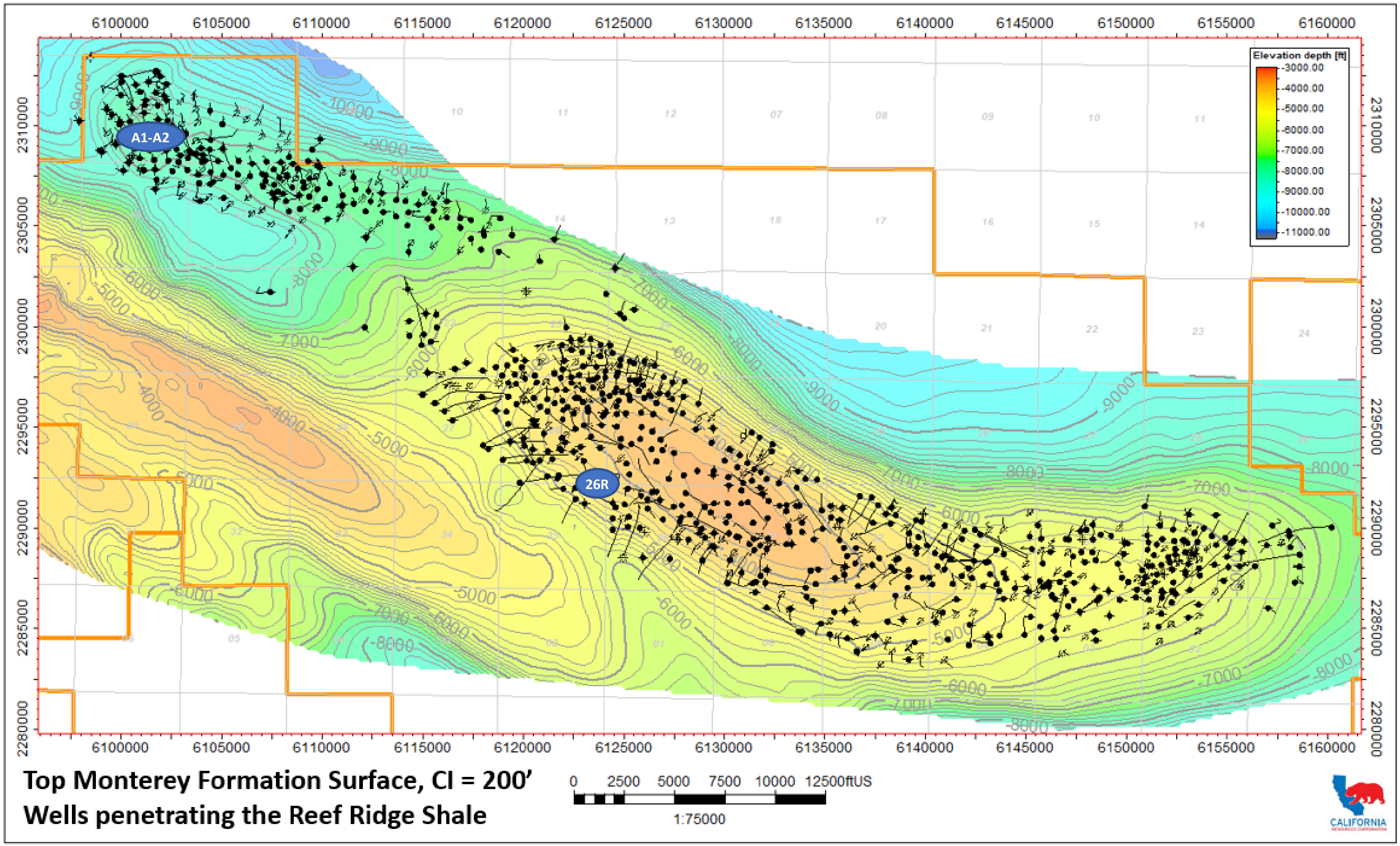


Figure 7: Wells penetrating the Reef Ridge shale. Project locations are shown at blue ovals.

The wells in Table 3 are categorized in groups that relate to the well status for each reservoir. These wells were drilled between 1948 and 2014, are generally completed with three strings of casing, and are typically cemented to the surface. A perforated production liner was typically installed to the top of the producing interval, with completion tubing hung just above the perforations. Cement bond logs (CBL) or temperature surveys that can identify cement top were typically run on these wells.

Wells that are not associated with the EPA Class VI project that penetrate the Reef Ridge will be abandoned to ensure that the CO_2 injectate is confined in the storage reservoir. Project wells are listed in Section 11.5.

Well workover crews are on-call to maintain active wells and to respond to any wellbore issues that arise. Incidents are detected by monitoring changes in the surface pressure of injection wells and by conducting Mechanical Integrity Tests (MITs) that include, but are not limited to, Radioactive Tracer Surveys (RTSs) and Standard Annular Pressure Tests (SAPTs).

All existing oil and gas wells, including both injection and production wells are regulated by CalGEM under Public Resources Code Division 3.

2.4 Reservoir Modeling

Numerical reservoir simulation is used for many purposes, including optimizing reservoir management, forecasting hydrocarbon and water production, predicting the behavior of injected fluids such as $CO_{2,}$ and assessing CO_2 plume development and confinement.

2.4.1 Reservoir Model for Operational Design and Economic Evaluation

Reservoir modeling workflow begins with the development of a three-dimensional (3-D) representation of the subsurface geology (“static model”). Static model development leverages all available well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces and faults (if present) into a geocellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. CRC used Schlumberger Petrel, an industry-standard geocellular modeling software, to build and maintain the EHOF static model.

The static model becomes “dynamic” in the reservoir simulator with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon phase,
- Liquid and gas relative permeability,
- Capillary pressure data, and
- Fluid injection and/or extraction rates.

2.4.2 Performance Prediction

One objective of the simulation models is to develop an injection plan that maximizes CO_2 storage and minimizes associated costs. The injection plan includes injection wells and appropriate injection rate and pressure for each well that adheres to regulatory requirements.

2.4.3 Plume Model for CO_2 Storage Capacity, Containment, and Predicted Plume Migration

Full-field plume models confirm reservoir capacity and CO_2 containment within the 26R and A1-A2 reservoir. These models were built using a dynamic reservoir simulation application known as the Equation-of-State (EOS) Compositional Simulator (GEM), developed by Computer Modelling Group Ltd. (CMG). Figure 7 shows the results of the modeling for the 26R and A1-A2 storage reservoir. The plume models were used to evaluate: (1) the quantity of CO_2 stored for geological sequestration, and (2) the lateral movement of CO_2 to define the MMA and demonstrate vertical confinement by the Reef Ridge shale.

2.4.4 Geomechanical Modeling of Reef Ridge Shale

In addition to the plume models, a simpler GEM-based model was coupled with a finite element geomechanical module, GEOMECH, to model cap rock failure in the Reef Ridge shale as a function of cap rock mechanical properties and reservoir pressure immediately below the cap rock. This model was used to assess the pressure at which the Reef Ridge shale would shear through tensile failure.

The plume modeling effort confirms the Monterey Formation's ability to permanently store the planned project CO_2 volumes under the Reef Ridge shale over the project's life. The results of the plume models are discussed in greater detail below.

3 Delineation of Monitoring Area and Timeframes

3.1 Maximum Monitoring Area

The MMA is defined in 40 CFR 98.449 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. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data as described above, was used to predict the size and location of the plume, as well as understand how the plume migrates over time.

The MMA, shown by the blue line Figure 8 , is defined by the extent of the CO_2 plume at 100 years post-injection for geologic sequestration plus one-half mile.

3.2 Active Monitoring Area

The following factors were considered in defining this boundary (40 CFR 98.449):

- 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.
- The area projected to contain the free phase CO2 plume at the end of year t + 5.

The A1-A2 and 26R reservoirs are depleted and CO_2 is predicated to reach the edges of the reservoir within the first two to three years of injection; therefore, the AMA is assumed to be functionally equivalent to the MMA. Leveraging the MMA boundary for the AMA also provides maximum operational flexibility. The absence of through-going faults or fractures confirms the competency of the Reef Ridge to preserve hydrocarbons within the Monterey Formation and to contain the CO_2.

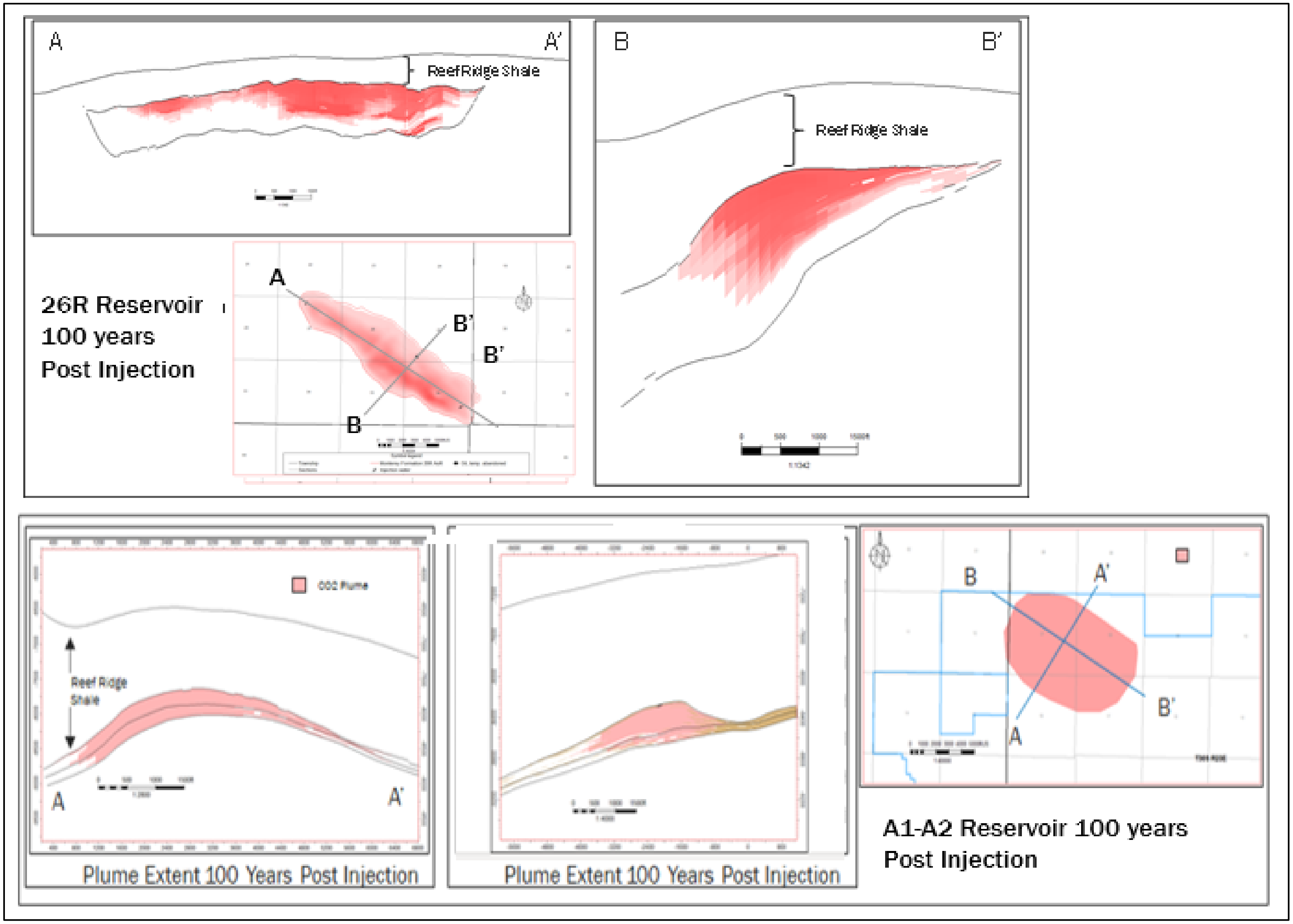


Figure 7: CO_2 plume modeling results.

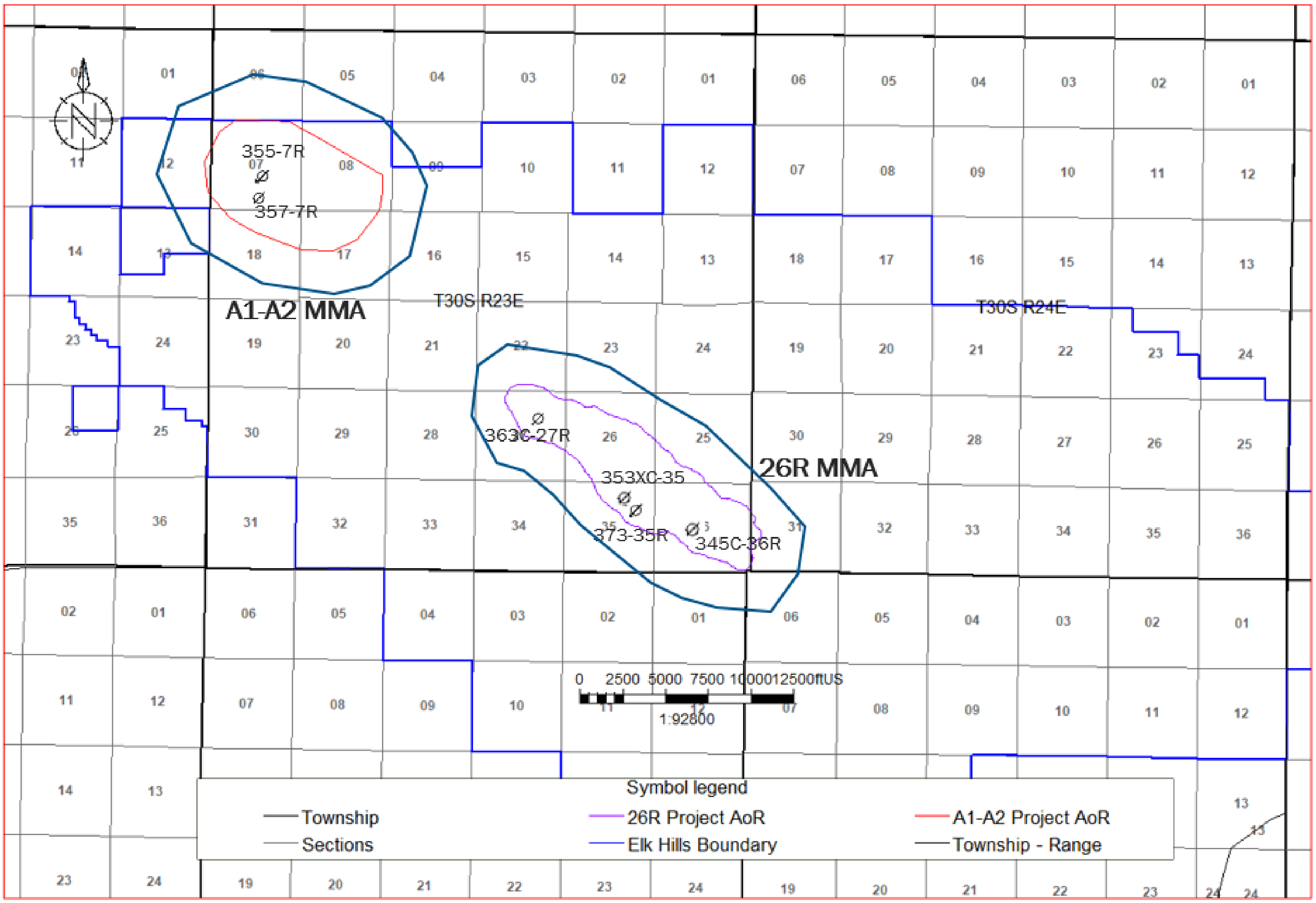


Figure 8: Injector well locations, EPA AoR (final CO_2 plume boundaries; orange and purple lines) and AMA - MMA (blue line). Scale bar units are feet.

3.3 Monitoring Timeframe

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted when a demonstration that current monitoring and model(s) show that the cumulative mass of CO_2 reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration within two to three years after injection for the Specified Period ceases based on predictive modeling supported by monitoring data.

4 Evaluation of Potential Pathways for Leakage to the Surface

4.1 Introduction

In the more than 100 years of the EHOF's development, the reservoir has been studied and documented extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO_2 to the surface. The following potential pathways are reviewed:

- Existing wellbores,
- Faults and fractures,
- Natural and induced seismic activity,
- Previous operations,
- Pipeline/surface equipment,
- Lateral migration outside the EHOF,
- Drilling through the CO_2 area, and
- Diffuse leakage through the seal.

4.2 Existing Wellbores

Leakage through existing wellbores is possible at the EHOF. However, that is mitigated by adhering to regulatory requirements for well drilling and testing; implementing best practices developed through extensive operating experience; monitoring injection/production performance, wellbores, and the surface; and maintaining surface equipment. Wells penetrating the Reef Ridge confining shale and sequestration reservoir are described in Section 2.3.2. Risk of leakage at each specific existing wellbore is greatest after CO_2 has reached that location and when pressures are greatest, which is generally towards the end of the project injection time period. Leakage volumes are predicted to be less than one percent of total injection (less than 0.5 million metric tons).

As discussed in Section 2.3.3, regulations governing the EHOF require that wells be completed and operated so that fluids are contained in the strata in which they are encountered.

Continual and routine monitoring and maintenance of wellbores and site operations is critical to ensure confinement in the following ways.

1. Injection well pressure is monitored continuously throughout the EHOF using a supervisory control and data acquisition (SCADA) system. Pressure and rate sensors on the injection wells are programmed to alarm and notify operations personnel when encountering values that significantly deviate from set target ranges. Leakage on the inside or outside of the injection

wellbore would affect pressure and be detected through this approach. If such excursions occur, they are investigated and addressed.

2. Experience gained over time allows for a strategic approach to well maintenance and workovers; workover crews are onsite for this purpose. For example, the well classifications by age and construction method inform planning for monitoring and updating wells. All available information, including pattern performance and well characteristics, is used to determine well maintenance schedules.

3. A corrosion protection program for CO_2 operations will be implemented to mitigate both internal and external corrosion of casing in wells in the EHOF. In line with industry standard operations and EPA Class VI requirements for CCS, downhole equipment and the interior and exterior of wellbores will be protected using special materials (e.g., fiberglass tubing, corrosion-resistant cements, nickel-plated packers, corrosion-resistant packer fluids), and procedures will be performed to prevent and monitor for corrosion (e.g., packer placement, use of annular leakage detection devices, cement bond logs, pressure tests). These measures and procedures are typically included in the injection orders filed with CalGEM and the EPA UIC program. Corrosion protection methods and requirements may be enhanced over time in response to improvements in technology.

4. MIT requirements implemented by CalGEM and/or EPA UIC (as applicable) will be followed to periodically inspect wells and surface facilities to ensure that all wells and related surface equipment are in good repair, leak-free, and that all aspects of the site and equipment conform to existing regulations and permit conditions. All active injection wells undergo MIT before injection, after any workover or per time periods specified in the UIC approval. Operators are required to use a pressure recorder and pressure gauge for the tests. For CalGEM regulated wells, operator's field representative must sign the pressure recorder chart and submit it with the MIT form to CalGEM. The casing-tubing annulus must be tested to maximum anticipated surface pressure (MASP) for a specified duration and with an allowable pressure loss specified in the regulations. CalGEM or EPA UIC may also approve alternative pressure monitoring programs with varying requirements at their discretion.

   If a well fails the MIT, the operator must immediately shut the well in and provide notice to CalGEM. Casing leaks must be successfully repaired within 180 days and re-tested, or the well must be plugged and abandoned after submitting a formal notice and obtaining approval from CalGEM.

5. Finally, as indicated in Section 5, field inspections are conducted on a routine basis by field personnel. On any given day, there are approximately 40 personnel in the field. Leaking CO_2 is very cold and leads to formation of bright white clouds and ice that are easily spotted. All field personnel will be trained to identify leaking CO_2 and other potential problems in the field and to safely remedy the issue. Any CO_2 leakage detected will be documented and reported, quantified, and addressed as described in Section 5.

6. Corrective Action assessment performed pursuant to the Class VI regulation includes the generation and detailed review of wellbore/casing diagrams for each well in the project area. Information used in the review includes depths and dimensions of all hole sections, casing strings,

cement plugs, and other wellbore equipment that isolates portions of the wellbore or otherwise establishes plugback depth. Perforated intervals are described with depth and status of perforations. Top of cement determination supports the review for annular isolation. Depths to relevant geologic features such as formation tops and injection zone are provided in both measured and true vertical depths. The depth of the confining zone in each of the wells penetrating the Reef Ridge shale is determined through open-hole well logs and utilized the deviation survey to convert measured depth along the borehole to true vertical depth from surface. For each well determined to require additional plugging CTV has provided the plugging procedure that will be used to abandon wells along with well-specific plugging plan tables that identify the number of plugs, placement method, cement type, density, and volume for the wells to be abandoned during pre-operational testing. The planned plugging procedures achieve all requirements of CalGEM regulations for proper abandonment of oil and gas wells.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, CRC and CTV conclude that it will mitigate CO_2 leakage through wellbores by detecting problems as they arise and quantifying any leakage that does occur by use of local surface air monitoring in the vicinity of the leaking wellbore. Section 4.10 summarizes how CRC and CTV will monitor CO_2 leakage from various pathways and describes the response to various leakage scenarios. In addition, Section 5 describes how CRC and CTV will develop the inputs used in the Subpart RR mass-balance equation (Equation RR-12). Any incidents that result in CO_2 leakage up the wellbore and into the atmosphere will be quantified as described in Section 7.4.

4.3 Faults and Fractures

There are no faults or fractures penetrating the confining layer of the Reef Ridge shale that provide a potential upward pathway for fluid flow. First, the presence of oil, especially oil with a gas cap, is indicative of a competent natural seal. Oil, and to a greater extent gas, migrates upward over time because both are less dense than the brine found in rock formations. Places where oil and gas remain trapped in the deep subsurface over millions of years, as is the case in the EHOF, prove that faults or fractures do not provide a pathway for upward migration out of the CO_2 flooding interval.

While developing the EHOF, a seismic survey was conducted to characterize the formations and provide information for the reservoir models used for development planning. Initial interpretations of the 3-D seismic survey were based on a conventional pre-stack time migration volume. In 2019, the 3-D seismic survey was reprocessed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 9 displays the location and extent of four faults that helped to form these anticlines beginning in the Middle Miocene, 16 million years ago (Callaway and Rennie, 1991). These faults have remained inactive for millions of years since. Offsetting the 31S and NWS structures are the 1R, 2R, and 3R high-angle reverse faults that are oriented NW-SE. The faults penetrate the lowest portions of the Monterey Formation but do not continue through the injection interval to the Reef Ridge shale confining layer.

Lastly, the operating history of the EHOF confirms there are no faults or fractures penetrating the Reef Ridge shale that allow fluid migration. Water and gas have been successfully injected into the Monterey Formation since 1976, and there is no evidence of new or existing faults or fractures. Over 1.4 billion

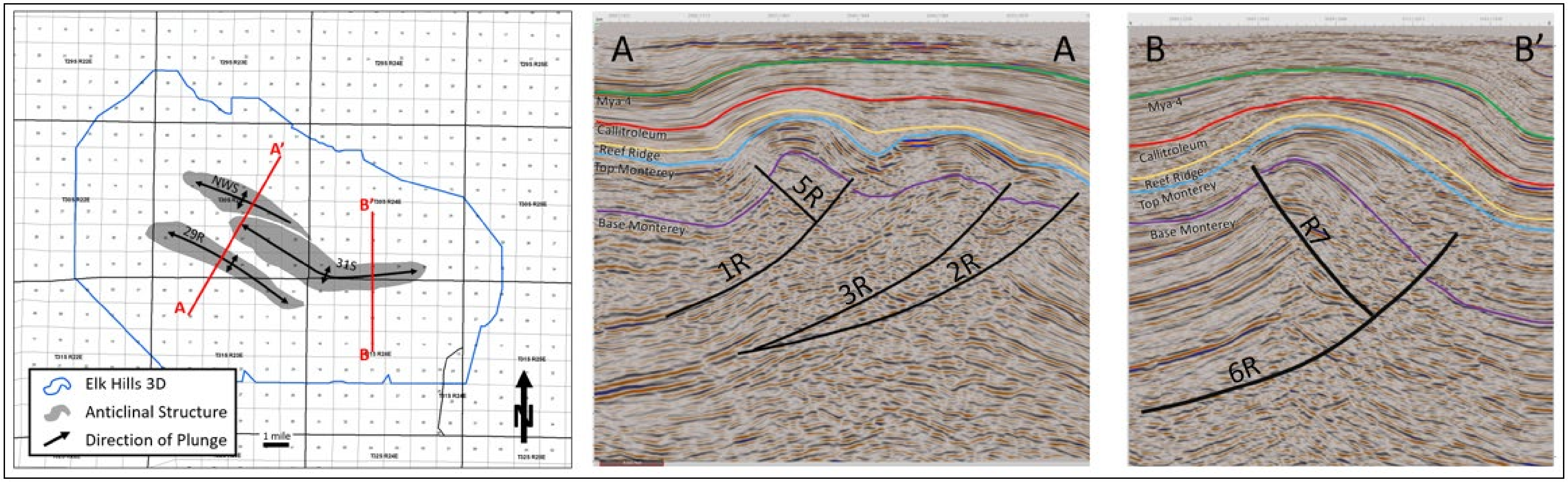


Figure 9: Outline of EHOF 3-D survey and seismic intersections across 31S and NWS structures.

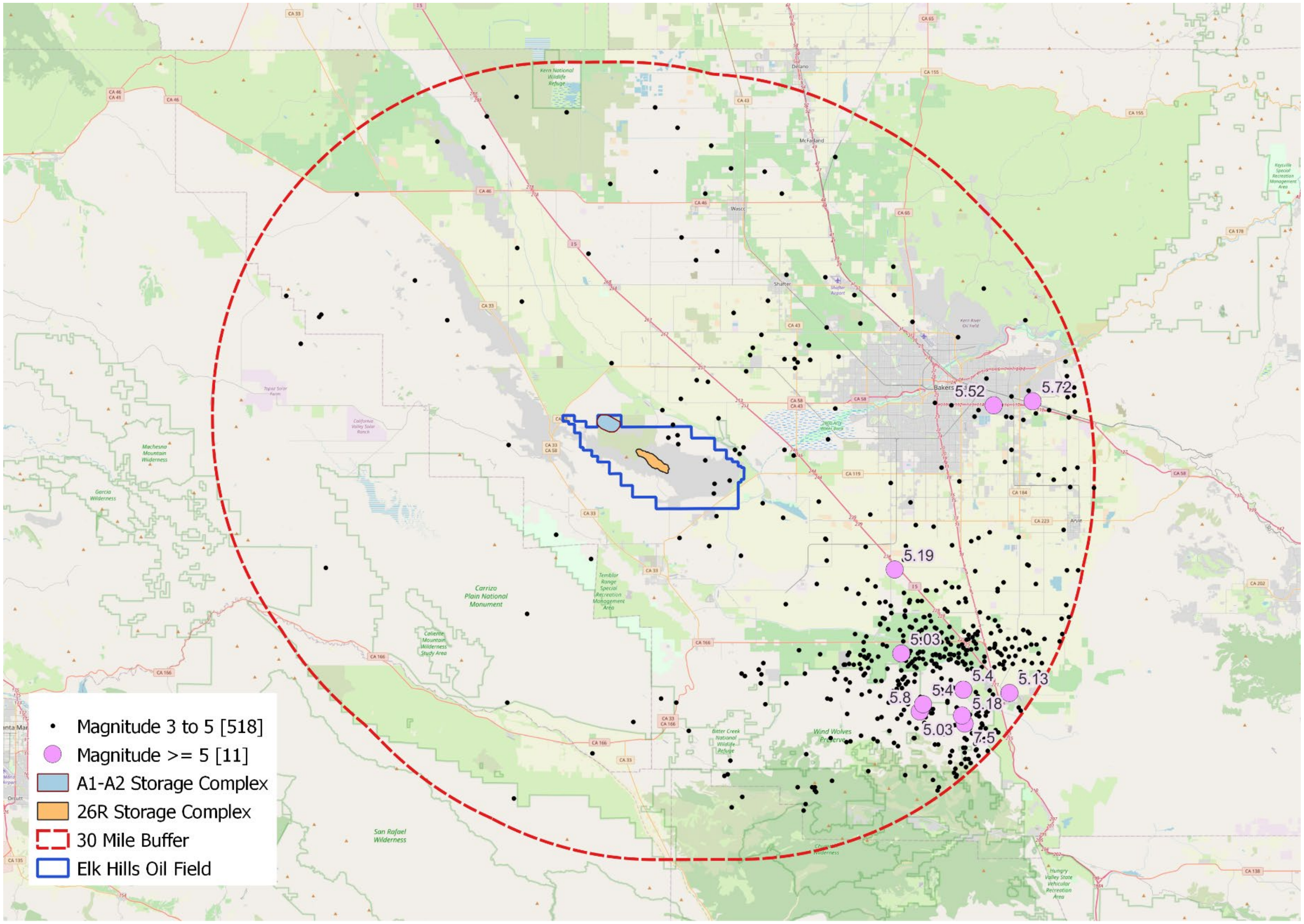


Figure 10: Earthquakes in the San Joaquin Basin with a magnitude greater than 3. Note: only 11 earthquakes have occurred within a 30-mile buffer around the EHOF administrative boundary. Earthquake data from SCEDC.

barrels of water and 1,237 billion standard cubic feet (Bcf) of gas have been injected into the NWS and 31S structures with no reservoir confinement issues. In fact, it is the absence of faults and fractures in the Reef Ridge shale that makes the Monterey Formation such a strong candidate for water injection operations and enables field operators to maintain effective control over the injection and production processes.

4.4 Natural or Induced Seismicity

Based on published data and over 100 years of operational experience, there is no evidence that natural seismic activity poses a significant risk for loss of CO_2 for the project. This is due, in part, to the thickness, ductility, and predominance of clay in the primary confining layer Reef Ridge shale.

No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area. Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west, beyond the Temblor Range) and the White Wolf Fault (25 miles southeast from the EHOF).

Historical seismic events from 1932 to present are available from the Southern California Earthquake Data Center (SCEDC). Based on this data, there have been no earthquakes recorded greater than 3.0 in the A1-A2 and 26R MMA. In addition, there have only been eleven earthquakes with a magnitude of 5.0 or greater within a 30-mile buffer around the EHOF administrative boundary (Figure 10). There have been 518 earthquakes with a magnitude between 3 and 5 within the 30-mile EHOF buffer. The average depth of the earthquakes with magnitude greater than 3 is 4.5 miles, while the storage reservoirs are one mile below surface.

Induced seismicity will be mitigated operationally by the following:

1. Injection pressure will be monitored continuously and will be lower than the failure pressure of the confining Reef Ridge shale.
2. Reservoir pressure will be at or beneath the discovery pressure.
3. Seismometers will be installed at the surface to detect seismicity induced by injection operations.

4.5 Previous Operations

All of the existing wells at the EHOF have been permitted through CalGEM (and predecessor California agencies) under rules that require detailed information about the character of the geologic setting, the construction and operation of the wells, and other information used to assess the suitability of the site. CalGEM maintains a public database that contains the location, construction details, and injection/production history of each well.

CTV has assessed internal databases as well as CalGEM information to identify and confirm wells within the project area. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Therefore, there are excellent records for wells drilled in the field. There have been no undocumented historical wells found during the development history of the reservoir that includes injection of water and gas.

This operational experience has verified that there are no unknown wells within the EHOF. Additionally, CRC and CTV have sufficiently mitigated the possibility of migration from older wells as discussed above. Over many years, the EHOF has been continuously checked for the presence of old, unknown wells throughout the EHOF. These practices ensure that identified wells are sufficiently isolated and do not interfere with ongoing operations and reservoir pressure management.

Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest that will generally be at the end of the injection period.

4.6 Pipeline/Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2. Unplanned leakage from surface facilities will be mitigated to the maximum extent practicable by relying on the use of prevailing design and construction practices and maintaining compliance with applicable regulations. The facilities and pipelines will be constructed of materials and managed using control processes that are standard for CO_2 injection projects.

CO_2 delivery to the complex will comply with all applicable regulations, including as pipeline regulations are updated in the future as applicable. Instrumentation will be installed on pipelines and facilities that allows the 24/7 operations staff at the Central Control Facility (CCF) to monitor the process and potentially spot leaks. Furthermore, frequent and routine visual inspections of surface facilities by field staff will provide an additional means to detect leaks. Both manual and automatic shutdowns will be installed in the complex to ensure that leaks are addressed in a timely manner. Should leakage be detected from pipeline or surface equipment, the volume of released CO_2 will be quantified following the requirements of 40 CFR 98.230-238 (Subpart W) of EPA's Greenhouse Gas Reporting Program (GHGRP). Leakage risk via this pathway will generally be similar over the project time period.

4.7 Lateral Migration

It is highly improbable that injected CO_2 will migrate downdip and laterally outside the EHOF because of the buoyant properties of supercritical CO_2, the nature of the geologic structure, and the planned injection approach. The strategy to minimize the lateral migration risk is to ensure that the CO_2 plume and surrounding fluids will be at or below the initial reservoir pressure at time of discovery. Leakage via this pathway is not anticipated; however, leakage risk is greatest when pressures are highest that will generally be at the end of the injection period.

4.8 Drilling Through the CO_2 Area

It is possible that at some point in the future, drilling through the Reef Ridge confining zone and into the Monterey Formation may occur. The possibility of this activity creating a leakage pathway is extremely low for three reasons: 1) Future well drilling would be regulated by CalGEM (oil and gas wells) or EPA UIC (Class VI injection wells) and will therefore be subject to requirements that fluids be contained in strata in which they are encountered; 2) as sole operators and owners of the EHOF, CRC and CTV control placement and timing of new drilling operations; and 3) there are no oil and gas targets beneath the Monterey Formation. Leakage via this pathway is not anticipated; however, leakage risk is greatest during future time periods if drilling through the Reef Ridge confining zone were to occur.

4.9 Leakage Through the Seal

Diffuse leakage through Reef Ridge confining layer is highly unlikely. The presence of gas caps trapped over millions of years confirms that the seal has been secure for millions of years. Leaking through the seal is mitigated by ensuring that post-injection reservoir pressure will be at or below the initial reservoir pressure at the time of discovery. The injection monitoring program referenced in Section 2.3.1 and detailed in Section 5 assures that no breach of the seal will be created.

Further, if CO_2 were to migrate through the Reef Ridge, it would migrate vertically until it encountered and was trapped by any of the additional shallower interbedded shales of the Etchegoin, San Joaquin, and Tulare Formations (more than 5,000 ft of vertical section; see Figure 3).

Leakage via this pathway is not anticipated; however, leakage risk is greatest at the end of the injection period when pressures are highest. In addition the relative amount of CO_2 in the supercritical phase will decrease over time post-injection as CO_2 dissolves into the brine reducing leakage risk.

4.10 Monitoring, Response and Reporting Plan for CO_2 Loss

As discussed above, the potential sources of leakage include routine issues such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment, and unique events such as induced fractures. Table 4 summarizes some of these potential leakage scenarios, monitoring activities designed to detect those leaks, standard response, and other applicable regulatory programs requiring similar reporting.

Sections 5.1.5 to 5.1.6 discuss the approaches envisioned for quantifying the volumes of leaked CO_2. In the event leakage occurs, CRC and CTV plan to determine the most appropriate methods for quantifying the volume leaked and will report it as required as part of the annual Subpart RR submission.

Any volume of CO_2 detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR 98.230-238 (Subpart W) or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as frequency of inspection. As indicated in Sections 5.1 and 7.4, leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in the electronic environmental documentation and reporting system. Repairs requiring a work order will be documented in the electronic equipment maintenance system and well work historian. If the scope of repair work requires permitting through CalGEM or EPA UIC, a subsequent operations summary report will be provided under the conditions of the applicable permit.

4.11 Summary

The structure and stratigraphy of the Monterey Formation in the EHOF is ideally suited for injection and CO_2 storage. The CO_2 injection zone stratigraphy is porous, permeable, and very thick, providing ample capacity for long-term CO_2 storage. The overlying Reef Ridge shale forms an effective seal for Monterey Formation sequestration (see Figure 3). After assessing potential risk of release from the subsurface and steps that have been taken to prevent leaks, the potential threat of significant leakage is extremely low. Risk of release is further reduced by the prudent operational strategy of limiting the pressure of the reservoir post-injection to at or below the initial pressure of the reservoir at time of discovery.

Risk	Monitoring Plan	Response Plan	Parallel Reporting (if any)
Loss of well control			
Tubing leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days	
Casing leak	Routine field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days	CalGEM or EPA UIC
Wellhead leak	Routine field inspection and continuous SCADA monitoring	Workover crews respond within days	
Loss of bottom-hole pressure control	Blowout during well operations	Maintain well-kill procedures; shut-in offset injectors prior to drilling	CalGEM or EPA UIC
Loss of seal in abandoned wells	Anomalous pressure or gas composition from productive shallower zones	Re-enter and reseal abandoned wells	CalGEM or EPA UIC
Leaks in surface facilities			
Pumps, valves, etc.	Routine field inspection and remote monitoring	Workover crews respond within days	Subpart W
Subsurface leaks			
Leakage along faults	Monitoring of zones above sequestration reservoir	Shut-in injectors near faults	
Leakage through induced fractures	Induced seismicity monitoring with seismometers	Comply with rules for keeping pressures below parting pressure	
Leakage due to a seismic event	Induced seismicity monitoring with seismometers	Shut-in injectors near seismic event	

Table 4: Response plan for CO_2 leakage or loss.

5 Monitoring and Considerations for Calculating Site-specific Variables

5.1 For the Mass Balance Equation

5.1.1 General Monitoring Procedures

Existing operations are centrally monitored and controlled by the extensive and sophisticated CCF. The CCF uses a SCADA software system to implement operational control decisions on a real-time basis throughout the EHOF to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Flow rates, pressures, gas composition, and other data will be collected at key points and stored in a centralized data management system. These data are monitored 24 hours a day by qualified technicians who follow response and reporting protocols when the system delivers notifications that data exceed predetermined statistically acceptable limits. The data can be accessed for immediate analysis.

Figure 5 identifies the meters that will be used to evaluate, monitor, and report on the flood and associated plume migration described earlier in Section 2.3. A similar metering system is already installed throughout the EHOF.

As indicated in Figure 5, a custody-transfer meter will be installed at the CO_2 sources. The custody-transfer meters will measure flow rate continuously. Fluid composition will be determined on either a continuous basis or by periodic sampling depending on the specific meter; both options are accurate for purposes of commercial transactions. All meter and composition data will be recorded.

Metering protocols follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. These meters will be maintained routinely, operated continuously, and will feed data directly to the CCF. In the oil and gas industry, the accepted level of custody-transfer meter accuracy is 0.25% or better, and the meters are calibrated every 60 to 90 days. A third party is frequently used to calibrate these meters, and both parties to any transaction have rights to witness meter calibration. These custody meters provide the most accurate way to measure mass flows.

Most process streams are multi-component or multi-phase, with varying CO_2 compositions. For these streams, flow rate is the most important control parameter. Operations flow meters are used to determine the volumetric flow rates of these process streams, which allows for the monitoring of trends to identify deviations and determine if any intervention is needed. Flow meters are also used—comparing aggregate data to individual meter data—to provide a cross-check on actual operational performance.

Developing a CO_2 mass balance on multi-phase, multi-component process streams is best accomplished using custody-transfer meters rather than multiple operations meters. As noted above, in-field flow rate monitoring presents a formidable technical and maintenance challenge. Some variance is due simply to differences in factory settings and meter calibration. Additional variance is due to the operating conditions within a field. Meter elevation, changes in temperature (over the course of the day), fluid composition (especially in multi-component or multi-phase streams), or pressure will affect any in-field meter reading. Many meters have some form of automatic adjustment for some of these factors, others utilize a conversion factor that is programmed into the meter, and still others need to be adjusted manually in the calculation process. Use of a smaller number of centrally located meters reduces the potential error that is inherent in employing multiple meters in various locations to measure the same volume of flow and gas composition.

Table 5 summarizes the CO_2 injection monitoring strategy. Figure 11 shows the location of monitoring wells.

5.1.2 CO_2 Received

A custody-transfer meter will be used at the CO_2 source(s) to continuously measure the volume and composition of CO_2 received. The metering protocols will follow the prevailing industry standard(s) for custody transfer (as promulgated by the API and the AGA).

Monitoring Activity	Frequency/Location
MIT (Internal and External)	Annual
SAPT	Initially; any time the packer is replaced or reset
Injection rate, pressure, and temperature	Continuous
Seismicity	Induced seismicity monitoring via seismometers
Underground sources of drinking water (USDWs) and reservoirs between USDWs and sequestration reservoir	Monitoring wells with pressure, temperature, fluid composition, and periodic cased-hole logs
Stream analysis	Continuous
Corrosion monitoring (coupons, casing integrity)	Well materials, pipelines, and other surface equipment
Sequestration reservoir monitoring	Dedicated wells monitoring sequestration reservoir with pressure, temperature, fluid composition, and periodic cased hole logs

Table 5: Injection monitoring strategy summary.

5.1.3 CO_2 Injected into the Subsurface

Injected CO_2 associated with geologic sequestration will be calculated using the flow meter volumes at the operations/composition meter at the outlet of the recompression facilities (RCFs) and the custody-transfer meter at the CO_2 off-take points.

5.1.4 CO_2 Produced, Entrained in Products, and Recycled

No CO_2 will be produced or entrained in products or recycled.

5.1.5 CO_2 Emitted by Surface Leakage

As discussed in Section 5.1.6 below, 40 CFR 98.230-238 (Subpart W) is used to estimate surface leaks from equipment at the EHOF. Subpart W uses a factor-driven approach to estimate equipment leakage. In addition an event-driven process will be used to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. Reporting will reconcile the Subpart W report and results from any event-driven quantification to assure that surface leaks are not double-counted.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet the following two objectives in accordance with the leakage risk assessment in Section 4: 1) to detect problems before CO_2 leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the volumes of CO_2 leaked to the surface.

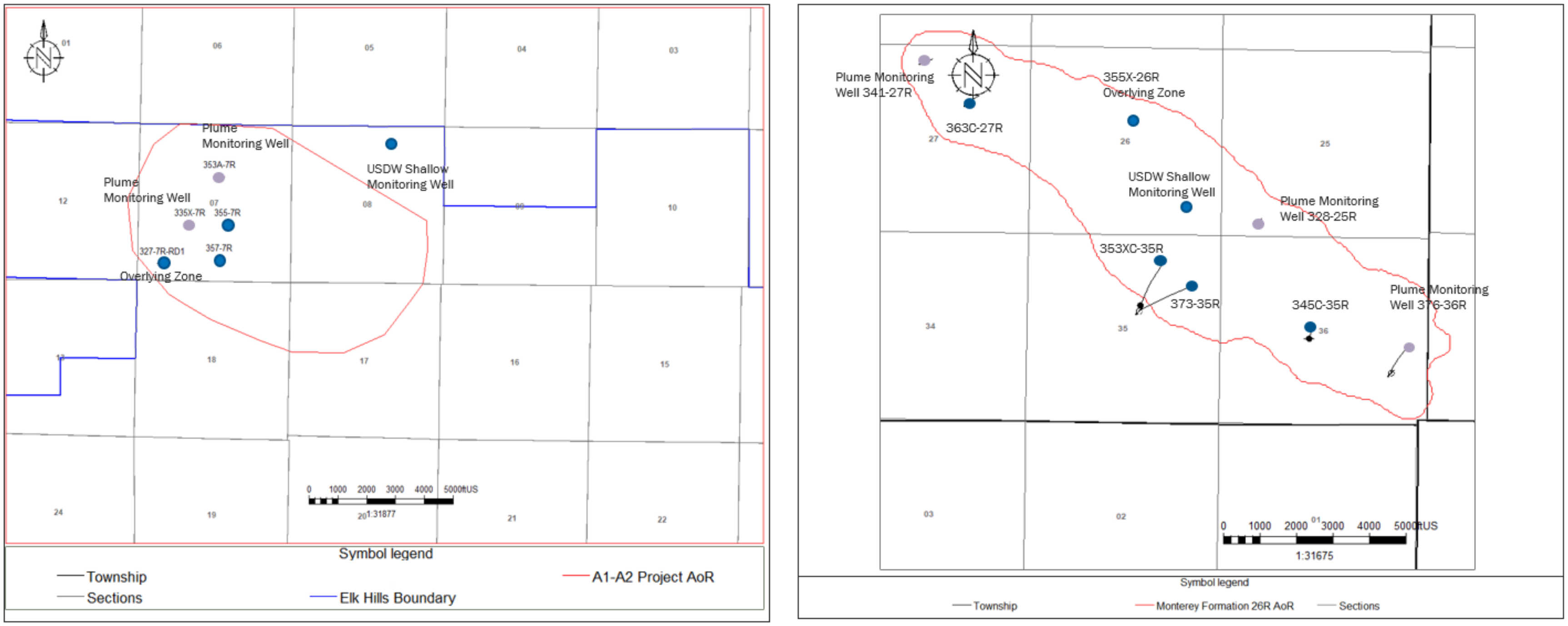


Figure 11: Map showing monitoring well locations.

Monitoring for Potential Leakage from the Injection/Production Zone

1. Monitoring Wells

   Monitoring wells to measure pressure, temperature, and fluid composition will be dedicated to geologic sequestration. These dedicated wells will monitor the sequestration reservoir, zones above the sequestration reservoir, and the USDW. Baseline analysis will be established for each of these wells. Any deviation from the baseline analysis will be assessed for potential indications of leakage. Measured increase in CO_2 in groundwater above the Storage Complex will be used to develop groundwater isoconcentration maps and quantify CO2 leakage rates.

2. Injection Wells

   Injection well pressure, temperature, and injection rate will be monitored continuously. If injection pressure or rate measurements are beyond the specified set-points determined for each injector, a data flag is automatically triggered and field personnel will investigate and resolve the problem. These excursions will be reviewed by well-management personnel to determine if CO_2 leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or another minor action is required), and there is no threat of CO_2 leakage. In the case of issues that are not readily resolved, more detailed investigation and response would be initiated, and internal support staff would provide additional assistance and evaluation. Such issues would lead to the development of a work order in the work order management system. This record will enable the company to track progress on investigating potential leaks and, if a leak has occurred, to quantify its magnitude. To quantify leakage to the surface, an estimate of the relevant parameters (e.g., the rate, concentration, and duration of leakage) will be made to quantify the leak volume. Depending on specific circumstances, these determinations may rely on engineering estimates.

Monitoring of Wellbores

Because leaking CO_2 at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a two-part visual inspection process will be employed in the general area of the EHOF to detect unexpected releases from wellbores. First, field personnel will visit the surface facilities on a routine basis. Inspections may include tank volumes, equipment status and reliability, lube oil levels, pressures and flow rates in the facility, and valve leaks. Field personnel inspections will also check that injectors are on the proper schedule and observe the facility for visible CO_2 or fluid line leaks.

Finally, data collected by the personal gas monitors, which are always worn by all field personnel, are a last method to detect leakage from wellbores. The monitor's detection limit is 10 parts per million (ppm); if an alarm is triggered, the first response is to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. If the incident results in a work order, this will serve as the basis for tracking the event for greenhouse gas (GHG) reporting. Targeted point-source surface air monitoring will be conducted in the event of detected wellbore leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

Other Potential Leakage at the Surface

Routine visual inspections at surface are used to detect significant loss of CO_2 to the surface. Field personnel visit manned surface facilities daily to conduct visual inspection. Inspections may include review of equipment status, lube oil levels, pressures and flow rates in the facility, valve leaks, ensuring that injectors are on the proper schedule, and conducting a general observation of the facility for visible CO_2 or fluid line leaks. If problems are detected, field personnel would investigate and, if maintenance is required, generate a work order in the maintenance system which is tracked through completion. In addition to these visual inspections, CRC and CTV will use the results of the personal gas monitors as a supplement for smaller leaks that may escape visual detection.

If CO_2 leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, a work order will be generated in the work order management system. The work order will describe the appropriate corrective action and be used to track completion of the maintenance action. The work order will also serve as the basis for tracking the event for GHG reporting and quantifying any CO_2 emissions. Targeted surface air and/or soil gas flux monitoring will be conducted in the event of detected leakage, and leakage will be quantified based on leak flow rate and CO_2 gas concentration.

5.1.6 CO_2 Emitted from Equipment Leaks and Vented Emissions of CO_2 from Surface Equipment Located Between the Injection Flow Meter and the Injection Wellhead

Monitoring efforts will evaluate and estimate leaks from equipment and vented CO_2 as required under 40 CFR 98.230-238 (Subpart W).

5.2 To Demonstrate that Injected CO_2 is not Expected to Migrate to the Surface

At the end of the Specified Period, CRC and CTV intend to cease injecting CO_2 for the subsidiary purpose of establishing the long-term storage of CO_2 in the EHOF. After the end of the Specified Period, CRC and CTV anticipate that it will submit a request to discontinue monitoring and reporting. The request will demonstrate that the amount of CO_2 reported under 40 CFR 98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage. At that time, CRC and CTV will be able to support the request with years of data collected during the Specified Period as well as two to three (or more, if needed) years of data collected after the end of the Specified Period. This demonstration will provide the information necessary for the EPA UIC Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

- Data comparing actual performance to predicted performance (injection) over the monitoring period,
- An assessment of the CO_2 leakage detected, including discussion of the estimated amount of CO_2 leaked and the distribution of emissions by leakage pathway,
- A demonstration that future operations will not release the volume of stored CO_2 to the surface,
- A demonstration that there has been no significant leakage of CO_2, and

- An evaluation of reservoir pressure in the EHOF that demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

6 Determination of Baselines

Automatic data systems will be used to identify and investigate deviations from expected performance that could indicate CO_2 leakage. These data systems are used primarily for operational control and monitoring, and as such, are set to capture more information than is necessary for reporting in the Annual Subpart RR Report. Necessary system guidelines will be developed to capture the information that is relevant to identify CO_2 leakage. A description of the approach to collecting this information is given below.

6.1 Visual Inspections

As field personnel conduct routine inspections, work orders are generated in the electronic system for maintenance activities that cannot be immediately addressed. Methods to capture work orders that involve activities that could potentially involve CO_2 leakage will be developed, if not currently in place. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation. The responsible party will be provided in the monitoring plan, as required under 40 CFR 98.3(g) (Subpart A). The Annual Subpart RR Report will include an estimate of the amount of CO_2 leaked. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

6.2 Personal Gas Monitors

Gas monitors are worn by all field personnel (detection limit 10 ppm). Any monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the monitor is working properly. If a fugitive leak is discovered, it would be quantified, and mitigating actions determined accordingly. The person responsible for MRV documentation will receive notice of all incidents where gas is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO_2 emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

6.3 Injection Rates, Pressures, and Volumes

Target injection rates and pressures will be developed for each injector, based on the results of ongoing modeling and permitted limits. High and low set-points are programmed into the controllers, and flags whenever statistically significant deviations from the targeted ranges are identified. The set-points are designed to be conservative. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO_2 leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions and related work orders that could potentially involve CO_2 leakage. The Annual Subpart RR Report will provide an estimate of CO_2 emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

7 Determination of Sequestration Volumes Using Mass Balance Equations

The following sections describe how each element of the mass-balance equation (Equation RR-12) will be calculated.

7.1 Mass of CO_2 Received

CRC and CTV will use Equation RR-2 as indicated in 40 CFR 98.443 to calculate the mass of CO_2 received from each custody-transfer meter immediately downstream of the source(s). The volumetric flow at standard conditions will be multiplied by the CO_2 concentration and the density of CO_2 at standard conditions to determine the mass.

$$\mathrm{CO}_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{\mathrm{CO}_{2,p,r}} \text{ (Eq. RR-2)}$$

Where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons)
$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters)
$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into a site well in quarter p (standard cubic meters)
D = density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682
$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (volume percent CO_2, expressed as a decimal fraction)
p = Quarter of the year
r = Receiving flow meters

Given CRC and CTV's method of receiving CO_2 and requirements of 40 CFR 98.444(a):

- All delivery to EHOF is used, so quarterly flow redelivered, $S_{r,p}$, is zero ("0") and will not be included in the equation
- Quarterly CO_2 concentration will be taken from the gas measurement database

CRC and CTV will sum to total mass of CO_2 Received using Equation RR-3 in 40 CFR 98.443:

$$\mathrm{CO}_2 = \sum_{r=1}^{R} \mathrm{CO}_{2T,r} \text{ (Eq. RR-3)}$$

Where:

CO_2 = Total net annual mass of CO_2 received (metric tons)
$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-2 for flow meter r
r = Receiving flow meter

7.2 Mass of CO_2 Injected into the Subsurface

Mass of CO_2 injected into the subsurface at EHOF at each injection well will be calculated with Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \quad \text{(Eq. RR-5)}$$

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.
$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).
D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.
$C_{CO2,p,u}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flow meter.

Aggregated injection at all injection wells will be calculated with Equation RR-6:

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \quad \text{(Eq. RR-6)}$$

where:

CO_2. = 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.

7.3 Mass of CO_2 Emitted by Surface Leakage

CRC and CTV will calculate and report the total annual mass of CO_2 emitted by surface leakage using an approach that is tailored to specific leakage events and relies on 40 CFR 98.230-238 (Subpart W) reports of equipment leakage. As described in Sections 4 and 5.1.5 to 5.1.6, the operators are prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO_2 leaked to the surface will depend on several site-specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

The process for quantifying leakage will entail using best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are discussed in Sections 5.1.5 to 5.1.6. In the event leakage to the surface occurs, the quantify and leakage amounts will be reported, and records retained that describe the methods used to estimate or measure the volume leaked as reported in the Annual Subpart RR Report. Further, the Subpart

W report and results from any event-driven quantification will be made to assure that surface leaks are not double-counted.

Equation RR-10 in 40 CFR 98.443 will be used to calculate and report the mass of CO_2 emitted by surface leakage:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \text{ (Eq. RR-10)}$$

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

7.4 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Equation RR-12 in 40 CFR 98.443 will be used to calculate the mass of CO_2 sequestered in subsurface geologic formations in the reporting year as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2\,FI} \text{ (Eq. RR-12)}$$

Where:

CO_2 = Total net annual mass of CO2 sequestered (metric tons)
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 by surface leakage (metric tons) 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

Figure 5 illustrates that CO_2 supplied for geological storage will be metered between the CO_2 source and the injection meter.

7.5 Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formations

A sum of the total annual volumes obtained using RR-12 in 40 CFR 98.443 will be used to calculate the cumulative mass of CO_2 sequestered in subsurface geologic formations.

8 MRV Plan Implementation Schedule

It is anticipated that this MRV plan will be implemented as early as first quarter (Q1) 2025 pending appropriate permit approvals and an available CO_2 source, or within 90 days of EPA approval, whichever occurs later. Other facility GHG reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. As described in Section 3.3 above, it is anticipated that that the MRV program will be in effect during the Specified Period, during which time the project will ensure long-term containment of a measurable quantity of CO_2 in subsurface geologic formations at the EHOF and that the project will be operated in a manner not expected to result in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be made and submission with a request to discontinue reporting under this MRV plan (see 40 CFR 98.441(b)(2)(ii)).

9 Quality Assurance Program

9.1 Monitoring QA/QC

As indicated in Section 7, the requirements of 40 CFR 98.444 (a) – (d) in the discussion of mass balance equations have been incorporated. These include the following provisions.

CO_2 Received and Injected

The quarterly flow rate of CO_2 received is measured at the receiving custody-transfer meters.

CO_2 emissions from equipment leaks and vented emissions of CO_2

These volumes are measured in conformance with the monitoring and QA/QC requirements specified in 40 CFR 98.230-238 (Subpart W).

Flow meter provisions

The flow meters used to generate data for the mass balance equations in Section 7 are:

- Operated continuously except as necessary for maintenance and calibration,
- Operated using the calibration and accuracy requirements in 40 CFR 98.3(i),
- Operated in conformance with API standards, and
- Traceable by the National Institute of Standards and Technology (NIST).

Concentration of CO_2

As indicated in Appendix 1 (Section 11.1), CO_2 density is measured using an appropriate standard method. Further, all measured volumes of CO_2 have been converted to standard cubic meters at a temperature of 60 degrees Fahrenheit (°F) and at an absolute pressure of 1 atmosphere, including those used in Equations RR-2, RR-5, and RR-8 in Section 7.

9.2 Missing Data Procedures

In the event data needed for the mass balance equations cannot be collected, procedures in 40 CFR 98.445 for estimating missing data will be used as follows:

- A quarterly flow rate of CO_2 received that is missing would be estimated using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.

- For any 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 specified in 40 CFR 98.230-238 (Subpart W) would be followed.

9.3 MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters, the MRV plan will be revised and submitted to the EPA UIC Administrator within 180 days as required in 40 CFR 98.448(d).

10 Records Retention

The record retention requirements specified by 40 CFR 98.3(g) will be followed. In addition, the requirements in 40 CFR 98.447 will be followed by maintenance of the following records for at least three years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams,
- Quarterly records of injected CO_2 including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams,
- 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, and
- 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.

These data will be collected as generated and aggregated as required for reporting purposes.

11 Appendices

11.1 Conversion Factors

CO_2 volumes will be reported at standard conditions of temperature and pressure as defined by the California Air Resources Board (CARB): 60° F and 14.7 pounds per square inch absolute (psia)[2].

To convert these volumes into metric tons, a density is calculated using the Span and Wagner EOS as recommended by the EPA and using the database of thermodynamic properties developed by NIST, available at http://webbook.nist.gov/chemistry/fluid/.

The conversion factor 5.29×10^{-2} metric ton per thousand cubic feet (MT/Mcf) has been used throughout to convert volumes to metric tons.

[2] See California Code of Regulations Title 17 Section 95102 (General Requirements of Greenhouse Gas Reporting, Definitions)

11.2 Acronyms

3-D – three-dimensional
AGA – American Gas Association
AMA – active monitoring area
AoR – area of review
API – American Petroleum Institute
ASP – alkaline surfactant polymer
Bcf – billion standard cubic feet
BOE - barrel of oil equivalent
CalGEM – California Geologic Energy Management Division
CARB – California Air Resources Board
CBL - cement bond logs
CCF – Central Control Facility
CCS – carbon capture and storage
CDMG – California Division of Mines and Geology
CMG - Computer Modeling Group Ltd.
CO_2 – carbon dioxide
CRC - California Resources Corporation
CTV - Carbon TerraVault
DAC – direct air capture
DOE - U.S. Department of Energy
EHOF – Elk Hills Oil Field
EHPP – Elk Hills Power Plant
EOR – enhanced oil recovery
EOS - equation of state
EPA – U.S. Environmental Protection Agency
GEM – geochemical equation compositional model
GHG – greenhouse gas
GHGRP -- Greenhouse Gas Reporting Program
GPA – Gas Processors Association
MASP - maximum anticipated surface pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MRV –monitoring, reporting, and verification
MT/Mcf – metric ton per thousand cubic feet
MW - megawatt
NIST -- National Institute of Standards and Technology
NWS – Northwest Stevens
ppm – parts per million
RTS – radioactive tracer survey
RCF – recompression facility
SAPT – standard annual pressure test

SCADA – supervisory control and data acquisition
SCEDC – Southern California Earthquake Data Center
UIC – underground injection control
USDW – underground source of drinking water

11.3 References

Callaway, D.C. and E.W. Rennie, Jr. 1991. *San Joaquin Basin, California*, in Gluskoter, H.J., D.D.Rice, and R.B. Taylor, eds. Economic geology, U.S.: Boulder, Colorado. Geological Society of America. The Geology of North America, v. P-2: 417-430.

McJannet, G.S. 1996. *General Overview of the Elk Hills Field*. Society of Petroleum Engineers. doi:10.2118/35670-MS.

11.4 Glossary of Terms

This glossary describes some of the technical terms as they are used in this MRV plan. For additional glossaries please see the U.S. EPA Glossary of UIC Terms (http://water.epa.gov/type/groundwater/uic/glossary.cfm), and the Schlumberger Oilfield Glossary (http://www.glossary.oilfield.slb.com/).

Anticline – an arch-shaped fold in the rock layers in a geologic formation in which the layers are upwardly convex, forming something like a dome or bell shape. Anticlines form excellent hydrocarbon traps, particularly in folds that have rocks with high injectivity in their core and high impermeability in the outer layers of the fold.

Contain/containment –the effect of keeping fluids located within in a specified portion of a geologic formation.

Dip – the angle of the rock layer relative to the horizontal plane. Buoyant fluids will tend to move up the dip, or *updip*, and heavy fluids will tend to move down the dip, or *downdip*. Moving higher up structure is moving updip. Moving lower is downdip. Perpendicular to dip is *strike*. Moving perpendicular along a constant depth is moving along strike.

Downdip – see *dip*.

Enhanced oil recovery (EOR) – a method of enhancing the recovery of the original oil in place through a combination of restoring or increasing pressure in an oil field and/or altering the chemical properties of that oil. Its purpose is to improve oil displacement or fluid flow in the reservoir. There are several types of EOR in use today including chemical flooding using alkaline surfactant polymer (ASP), immiscible and miscible displacement (CO_2), and thermal recovery (steamflood). The optimal application of each type depends on reservoir temperature, pressure, depth, net pay, permeability, residual oil and water saturations, porosity, and fluid properties such as oil API gravity and viscosity.

Flooding pattern – also known as an injection pattern; the geometric arrangement of production and injection wells to sweep oil efficiently and effectively from a reservoir.

Formation – a body of rock that is sufficiently distinctive and continuous that it can be mapped.

Injectivity – the ability of an injection well to receive injected fluid (both rate and pressure) without fracturing the formation in which the well is completed. Injectivity is a function of the porosity and permeability of the rock formation and the reservoir pressure in which the injection well is completed.

Infill drilling – the drilling of additional wells within existing patterns. These additional wells decrease average well spacing. This practice both accelerates expected recovery and increases estimated ultimate recovery in heterogeneous reservoirs by improving the continuity between injectors and producers. As well spacing is decreased, shifting flow paths lead to increased sweep to areas where greater hydrocarbon saturations remain.

Permeability – the measure of a rock's ability to transmit fluids. Rocks that transmit fluids readily, such as sandstones, are described as permeable and tend to have many large, well-connected pores. Impermeable formations, such as shales and siltstones, tend to be finer grained or of a mixed-grain size, with smaller, fewer, or less-interconnected pores.

Phase – a region of space throughout which all physical properties of a material are uniform. Fluids that don't mix segregate themselves into phases. Oil, for example, does not mix with water and forms a separate phase.

Pore space – see *porosity*.

Porosity – the fraction of a rock that is not occupied by solid grains or minerals. All rocks have spaces between rock crystals or grains that is available to be filled with a fluid, such as water, oil, or gas. This space is called *pore space*.

Primary recovery – the first stage of hydrocarbon production, in which natural reservoir energy, such as gas drive, water drive, or gravity drainage, displaces hydrocarbons from the reservoir into the wellbore and up to surface. Initially, the reservoir pressure is higher than the bottom-hole pressure inside the wellbore. This high natural differential pressure drives hydrocarbons toward the well and up to surface. However, as the reservoir pressure declines because of production, so does the differential pressure. To reduce the bottom-hole pressure or increase the differential pressure to increase hydrocarbon production, it is necessary to implement an artificial lift system, such as a rod pump, an electrical submersible pump, or a gas-lift installation. Production using artificial lift is considered primary recovery. The primary recovery stage reaches its limit either when the reservoir pressure is so low that the production rates are not economic, or when the proportions of gas or water in the production stream are too high. During primary recovery, only a small percentage of the initial hydrocarbons in place are produced, typically 10%-12% for oil reservoirs. Primary recovery is also called *primary production*.

Saturation – the fraction of pore space occupied by a given fluid. Oil saturation, for example, is the fraction of pore space occupied by oil.

Seal – a geologic layer (or multiple layers) of impermeable rock that serves as a barrier to prevent fluids from moving upwards to the surface.

Secondary recovery – the second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are immiscible gas injection and waterflooding.

Sedimentary rocks – rocks formed at the Earth's surface through deposition of sediments derived from weathered rocks, biogenic activity, or precipitation from solution. There are three main types of rocks: igneous, metamorphic, and sedimentary.

Stratigraphic section – a sequence of layers of rocks in the order they were deposited.

Strike – see *dip.*

Updip – see *dip.*

11.5 Well List

The following tables present the well name and well type for the project.

26R Project Wells

Injectors	363C-27R 353XC-35R 373-35R 345C-35R	
Monitoring wells	341-27R	Plume monitoring
	328-25R	Plume monitoring
	374-36R	Plume monitoring
	355X-26R	Above-zone monitoring well
	USDW monitoring well	USDW monitoring

A1-A2 Project Wells

Injectors	355-7R 357-7R	
Monitoring wells	353A-7R	Plume monitoring
	335X-7R	Plume monitoring
	327-7R-RD1	Above-zone monitoring well
	USDW monitoring well	USDW monitoring

11.6 Summary of Key Regulations Referenced in MRV Plan

Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b).

Request for Additional Information: CTV/CRC Elk Hills Carbon Project
May 15, 2023

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.	NA	NA	Please review the Figures included in the MRV plan to ensure that all text is legible, scale bars and legends are scaled appropriately, etc. For example, some of the text in Figure 1 is difficult to read.	All figures have been enlarged for readability, and we also confirm that all scale bars are scaled appropriately.
2.	NA	NA	The MRV plan mentions a "Specified Period of reporting". Please clarify what timeline this is referring to.	The report (p.1) has been revised to clarify that the injection period will be 27 years.
3.	NA	NA	We recommend checking the MRV plan once more for consistency with hyphens, bolding, quotations marks, capitalization, and spacing throughout the MRV plan. Examples include but are not limited to: CO2 vs CO_2 NPR1 vs NPR-1 Punctuations in bulleted lists Post injection vs post-injection Furthermore, we recommend doing an additional review of the entire plan for spelling, grammar, etc.	The report has been edited as requested, including review by a technical editor.
4.	NA	NA	Please ensure that all acronyms are defined during the first use within the MRV plan. For example, "MASP" is not defined within the text.	The report has been edited as requested.
5.	1	4	The MRV plan states that the Reporter number is "TBD". However, the facility that submitted the MRV plan, CTV/CRC Elk Hills Carbon Project, has a GHGRP ID. Please update as necessary.	Report number has been added, as requested.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
6.	2.2.1	6	Section 2.2.1 mentions various geologic epochs and ages. However, several epochs are referenced as ages within this section. Please ensure that all references to the geologic timescale are consistent.	The report has been edited as requested.
7.	2.3	9	We recommend adding a legend to Figure 5 so that readers can easily identify what "M" means. Additionally, the Figure states: "Three Metering Locations: Emissions Point / Pipeline / Sequestration Well" This could be read to contradict the number of meters seen in the figure itself. Please adjust for clarity.	The Figure caption was edited to add the definition of the "M" symbols. The referenced text has been removed from the figure for clarity.
8.	2.3.3	11	We recommend adding icons on Figure 6 to show the location of the project.	Project locations have been added to the figure as requested.
9.	2.3.3	11	Please ensure that the 26R Reservoir Count total in Table 3 is accurate.	The well count in Table 3 has been updated for 26R as requested.
10.	2.3.3	11	"There wells were **generally** completed with three strings of casing, **typically** cemented to the surface. A perforated production liner was typically installed to the top of the producing interval…" We recommend adding clarification to what these instances of "generally" and "typically" refer to. With the field beginning production in 1911, it is difficult to imagine that such general statements can be made on the integrity of wells. Are you aware of wells that may not have been completed to these standards? Please clarify.	These statements are correct. Wells within these specific project areas (a subarea of the larger EHOF) were drilled beginning in 1948. The text has been edited to clarify this.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
11.	3.1-3.2	13-14	Per 40 CFR 98.449, active monitoring area is defined 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. While the MRV plan includes the subpart RR definition of MMA, it does not include the above definition of AMA. Please clarify in the plan what boundaries would be covered by the above definition and whether the current AMA satisfies this definition.	The report was edited to add citation to the 40 CFR 98.449 and clarify why the AMA is assumed equal to the MMA.
12.	Figure 8	14	Per 40 CFR 98.449, the MMA is defined 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. Please improve the clarity of this Figure 8 by enlarging/zooming in on the project and by enlarging or otherwise fixing the scale bar so that the units are readable. As the plan states that the MMA is based on the predicted plume boundary at 100 years, please also add this plume boundary to the figure (or clarify if it is already represented).	The figure was enlarged as requested. The figure caption was edited to clarify that the plume boundaries are shown, and also to clarify that the scale bar units are in feet.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
13.	4	NA	In addition to listing the possible leakage pathways and their monitoring strategies, please provide a characterization of the likelihood magnitude, and timing of leakage for each potential leakage pathway. For example, the format of such a characterization might look like: "leakage from XYZ pathway is unlikely but possible. If it did occur, it would be most likely when pressures are highest during XYZ timeframe, and the leakage could result in XYZ kgs/metric tons before being addressed…"	Timing of each potential leakage pathway has been added to applicable sections as requested and potential leakage volume has been included for the existing wellbore case, the only case that it has been quantified.
14.	4	NA	Please elaborate how potential CO_2 leakage would be quantified from the identified potential surface leakage pathways. Please note that subpart W procedures apply only to equipment leaks, and quantification strategies for other types of leakage pathways should be identified in the MRV plan.	Quantification methods are included in Section 5, and Section 4 provides a reference to Section 5 to clarify this. Additional clarification regarding quantification methods were added to Section 5.1.5.
15.	4.4	17	"Based on this data, there have been no earthquakes recorded greater than 3.0 in the A1A2 and 26R MMA. In addition, there have only been nine earthquakes with a magnitude of 5.0 or greater within a 30-mile radius around the EHOF (Figure 10)." The above statement does not address magnitude 3-5 earthquakes within the 30-mile radius around the EHOF. Please elaborate.	Figure 10 has been revised to show all earthquakes with magnitude greater than 3, and the text has been revised to give the number of earthquakes magnitude 3 to 5 as requested.
16.	4.5	18	"Operational experience has verified that there are no unknown wells within the EOHF. Additionally, CRC and CTV have sufficiently mitigated the possibility of migration from older wells." Please clarify what methods were used to verify that there are no unknown wells. Furthermore, please elaborate on what steps have been taken to mitigate migration from older wells.	Section 4.5 has been edited to clarify how the potential for unknown wells has been assessed; Section 4.2 addresses what steps are taken to mitigate migration from older existing wells.
17.	6.2	26	Section 6.2 described how gas monitors will be used to detect leakage. Please clarify what the gas monitors can detect and their detection limits, etc. Please clarify whether there is any H_2S in the injected CO_2, and if so, clarify the approximate concentration.	The monitor's detection limit is 10 parts per million (ppm), and this is stated in Section 5.1.5, it has been added again to Section 6.2 as requested. Anticipated H_2S concentration in the injectate is 0.001 to 0.014%.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
18.	7	26	"The following sections describe how each element of the mass-balance equation (Equation RR-11) will be calculated." Please review the subpart RR equations and clarify whether RR-11 is applicable to this project: https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-RR#p-98.443(f).	Equation RR-11 was changed to Equation RR-12.
19.	7	26-28	Please ensure that all subpart RR equations applicable to this project have been identified in the MRV plan. For example, how will the facility calculate CO2 injected (40 CFR 98.443(c))?	The report has been edited to reference Equations RR-5 and RR-6 as requested.

Elk Hills A1-A2 and 26R CO_2 Subpart RR Monitoring, Reporting and Verification Plan

Version Date: 3/8/2023

Table of Contents

Overview

The Elk Hills Oil Field (EHOF), covering 75 square miles, was discovered in 1911 and has produced over 2 billion barrels of oil equivalent (BOE) making it one of the most productive fields in the United States. California Resources Corporation (CRC) and Carbon TerraVault (CTV; a CRC wholly owned subsidiary), owns 100% of the surface, mineral and pore space rights at the EHOF.

CTV intends to inject and store a measurable quantity of carbon dioxide (CO_2) in subsurface geologic formations at the EHOF for a term referred to as the "Specified Period." During the Specified Period CO_2 will be injected from anthropogenic sources such as the Elk Hills 550 megawatt (MW) natural gas combined cycle power plant, bio-diesel refineries, and other sources in the EHOF area.

The CO_2 will be injected into the Monterey Formation A1-A2 and 26R reservoirs for dedicated geologic storage. The Elk Hills storage complex will be pre-certified and monitored to verify permanent CO_2 sequestration. Class VI applications have been submitted for the A1-A2 and 26R reservoir.

This EHOF monitoring, reporting, and verification (MRV) plan is based on decades of subsurface characterization and simulation of the targeted Monterey Formation. This empirically driven analysis indicates that the natural geologic seal that overlays the entire EHOF known as the Reef Ridge Shale will provide a physical trap that will permanently prevent injected CO_2 from migrating to the surface.

This MRV plan documents the following in accordance with 40 CFR §98.440-449 (Subpart RR):

- Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA)
- 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,
- A strategy for detecting and quantifying any surface leakage of CO_2,
- A strategy for establishing the expected baselines for monitoring CO_2 surface leakage,
- A summary of considerations for calculating EHOF-specific variables for the mass balance equation,
- Proposed date to begin collecting data for calculating total CO_2 sequestered.

1 Facility Information

i. Reporter number – TBD (once we submit)

ii. Existing wells in the EHOF including production, injection, and monitoring wells are permitted by CalGEM through California Public Resources Code Division 3.[1]

iii. Wells injecting CO_2 for geologic storage will be permitted with the United States Environmental Protection Agency (EPA) Underground Injection Control (UIC) program for Class VI injection.

iv. Wells in the EHOF are identified by name, American Petroleum Institute (API) number, status, and type. The list of wells as of March 2023 associated with the geologic storage projects is included in Appendix 11.5. Any new wells or changes to wells will be indicated in the annual report.

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[1] Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

2 Project Description

The EHOF is one of the largest oil and natural gas fields in the United States with production from multiple vertically stacked reservoirs. Turbidite sand deposits of the Miocene Monterey Formation will serve as the injection targets in two separate anticlinal structures, Northwest Stevens (NWS) and 31S (Figure 1).

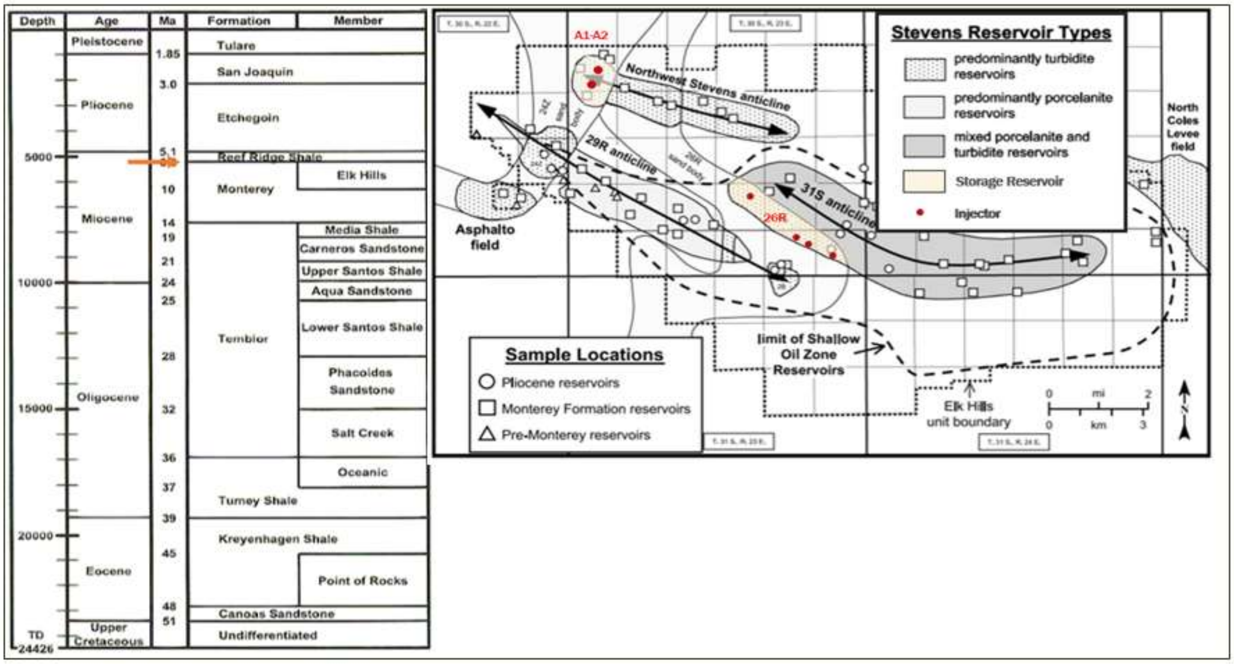

Figure 1: EHOF Stratigraphic Column and Map of Injection Target, and Injection Well Locations.

Numerous aspects of the geology, facilities, equipment, and operational procedures for A1-A2 and 26R are consistent throughout the field. As such, one MRV report will satisfy the 26R and A1A2 reservoirs as shown in Table 1. The A1-A2 and 26R reservoir and well locations within the field are shown in Figure 1.

Structure	Reservoir	Sequestration Type	Number of Injectors
31S	26R	Geologic : Class VI	4
NWS	A1-A2	Geologic : Class VI	2

Table 1: Reservoirs within the EHOF and sequestration type.

2.1 Project Characteristics

The potential CO_2 stored over the project duration is up to 48 million metric tons (refer to Table 2 for breakdown). For accounting purposes, the amount stored is the difference between the amount injected less any CO_2 that i) leaks to the surface, or ii) is released through surface equipment leakage or malfunction. Actual amounts stored during the Specified Period of reporting will be calculated as described in Section 7 of this MRV Plan.

2.2 Environmental Setting

The project site for this MRV plan is the EHOF, located in the San Joaquin Basin, California (Figure 2).

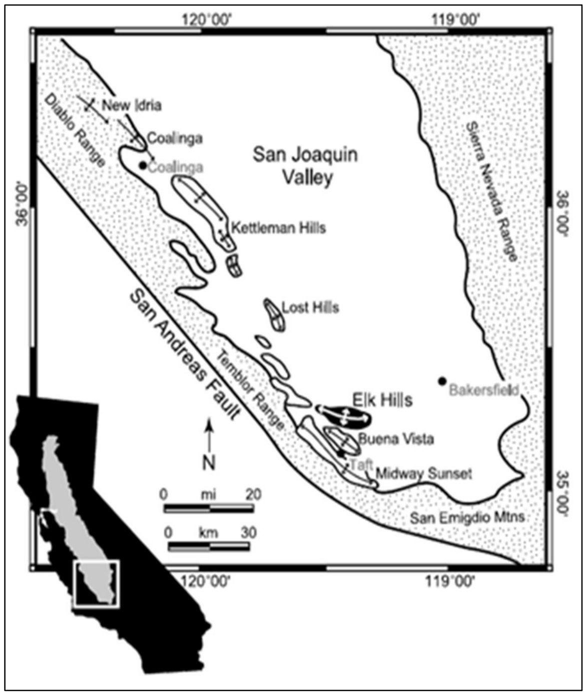

Figure 2: Location of Elk Hills Oil Field, San Joaquin Basin, California

2.2.1 Geology of Elk Hills Oil Field

The EHOF is located 20 miles southwest of Bakersfield in western Kern County and produces oil and gas from several vertically stacked reservoirs formed in the Tertiary age (65 million to 2 million years ago). Of the more than 24,000 feet (ft) of sediment deposited, the most prolific reservoir is the Miocene aged Monterey Formation which is the target CO_2 sequestration reservoir.

Individual layers within the Monterey Formation are primarily interbedded sandstone and shale. These layers have been folded resulting in anticlinal structures containing hydrocarbons formed from the deposition of organic material approximately 33 million to 5 million years ago (during the Oligocene and Miocene age). The combination of multiple porous and permeable sandstone reservoirs interbedded with impermeable shale seals make the EHOF one of the most suitable locations in North America for the extraction of hydrocarbons and the sequestration of CO_2.

Following its deposition, Monterey Formation sediments were buried under more than 750 ft of impermeable silty and sandy shale that comprise the confining Reef Ridge Shale. The Reef Ridge Shale serves as the primary confining layer over the Monterey because it effectively seals underlying fluids from the overlying formations. Above the Reef Ridge lies several alternating sand-shale sequences of the Pliocene Etchegoin and San Joaquin Formations and Pleistocene Tulare Formation. These formations are highlighted in the cross section in Figure 3.

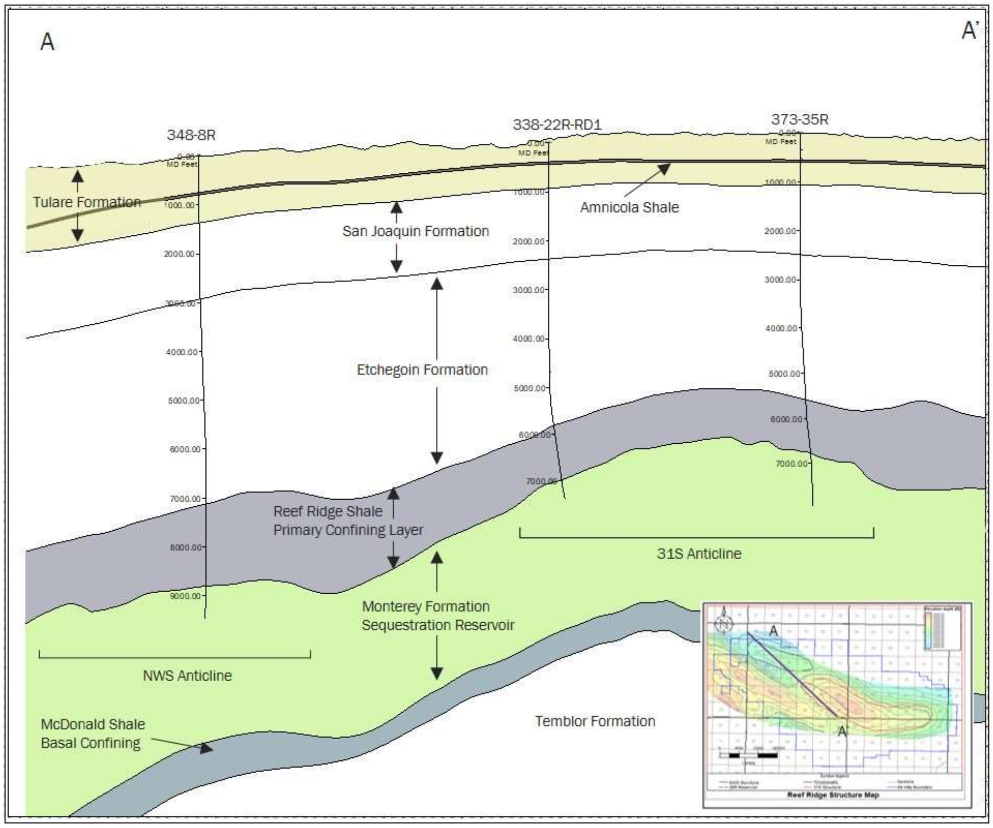

Figure 3: Stratigraphic schematic highlighting the NWS and 31S anticlines.

As indicated in Figure 1, the 31S and NWS structures represent structural highs, or anticlines, within the EHOF. The elevated areas form a natural trap for oil and gas that migrated from below over millions of years. Once trapped at these high points, the oil and gas has remained in place. In the case of the EHOF, this oil and gas has been trapped in the reservoir for more than 6 million years.

Based on physical site characterization and analysis of historic operating records from the Monterey Formation, there is sufficient reservoir capacity and flow properties to inject and store the entire volume of CO_2 proposed as determined by computational modeling (Table 2).

	Volume (million metric tons)
A1-A2 Geologic Storage	10
26R Geologic Storage	38
Total Storage Capacity	48

Table 2: Calculation of cumulative net fluid volume produced for the Monterey Formation sequestration reservoir.

Stored CO_2 will be contained securely within the EHOF Monterey Formation as demonstrated by 1) preservation of hydrocarbon accumulations over geologic time; 2) subsequent water and gas injection operations; 3) competency of the Reef Ridge confining zone over millions of years and throughout decades of primary and secondary operations; and 4) the A1-A2 and 26R reservoir has ample storage capacity.

Confinement within the project area and in the reservoir will be ensured by limiting the pressure of the reservoir post injection at or below the initial pressure of the reservoir at time of discovery.

2.2.2 Elk Hills Oil Field Operational History

McJannet (1996) reports on the early operating history of EHOF. In 1912 President Taft designated the area surrounding EHOF as a naval oil reserve by Executive Order. Intended to ensure a secure supply of fuel for the Navy's oil-burning ships, the Executive Order defined "Naval Petroleum Reserve No. 1" (NPR-1). In 1977, President Carter signed the Department of Energy Organization Act which transferred NPR-1 to the US Department of Energy (DOE). Nearly 20 years later, the DOE was directed to sell the assets of NPR-1. Occidental Petroleum ("Occidental") provided a winning bid of \$3.65 billion and on February 10, 1998, Occidental took over official ownership and operation of EHOF. In December 2014, Occidental Petroleum spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC.

The EHOF unit boundary is shown in orange below in Figure 4.

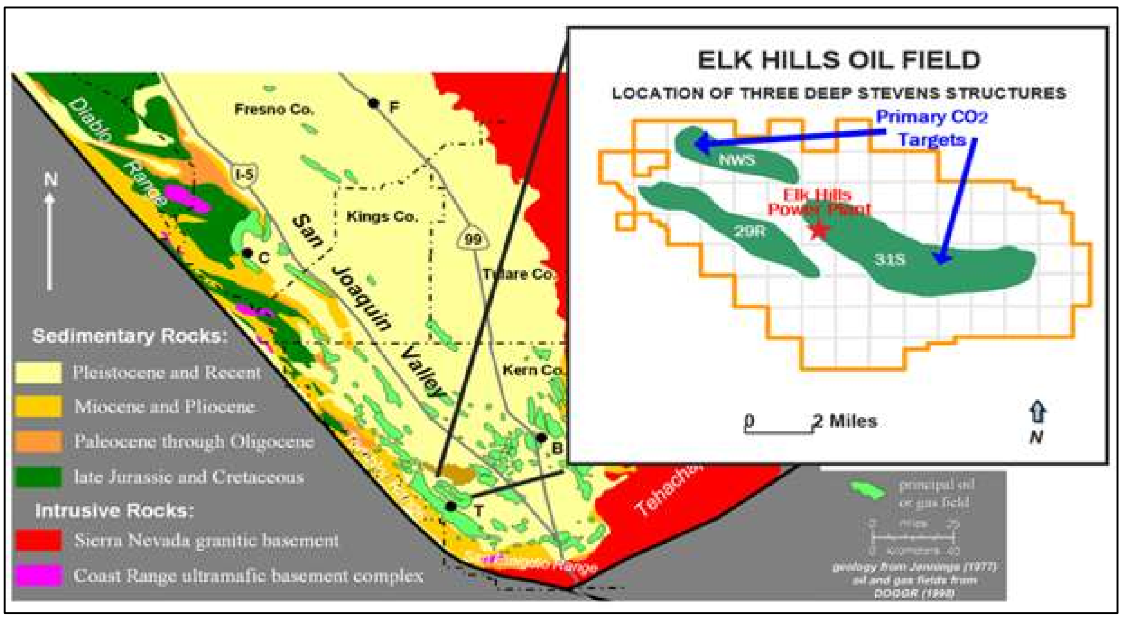

Figure 4: Location of Elk Hills Oil Field within San Joaquin Basin, California

Development History

Selected primary drilling in the Monterey Formation began in the early 1940s, with concerted drilling and production operations commencing with the DOE's oversight in the late 1970s. To support reservoir pressure and maximize the oil recovery factor extensive water and gas injection has occurred.

A successful CO_2-injection pilot was implemented in the Monterey Formation in 2005. Data from the four-month pilot confirmed the formation as an attractive target for CO_2 sequestration. This project assessed how much oil could be mobilized from the conventional sand reservoirs, how much CO_2 would be required to mobilize that oil, and how quickly the oil would be produced. Production performance and data collected before, during and after the pilot operations showed that Monterey Formation reservoirs selected are ideal for CO_2 sequestration.

In addition, past development of the shallow Etchegoin Formation oil reservoirs and Monterey Formation has created a large pressure differential across the Reef Ridge Shale, further demonstrating the lack of communication between the reservoirs.

2.3 Description of Facilities and Injection Process

A simplified flow diagram of surface facilities can be seen in Figure 5. This includes facilities outside the scope of the MRV including CO_2 source(s), and the subsequent metering locations between the MRV scope and those facilities. All facilities will be designed and built to ensure integrity and compatibility with CO_2. The subsequent parts of this section will review each of the following:

- CO_2 Source
- CO_2 Distribution and Injection
- Wells in the Area of Review (AOR) Penetrating the Reef Ridge Shale

Facilities associated with dedicated geologic sequestration will be relatively simple as field production and re-compression process flows are unnecessary.

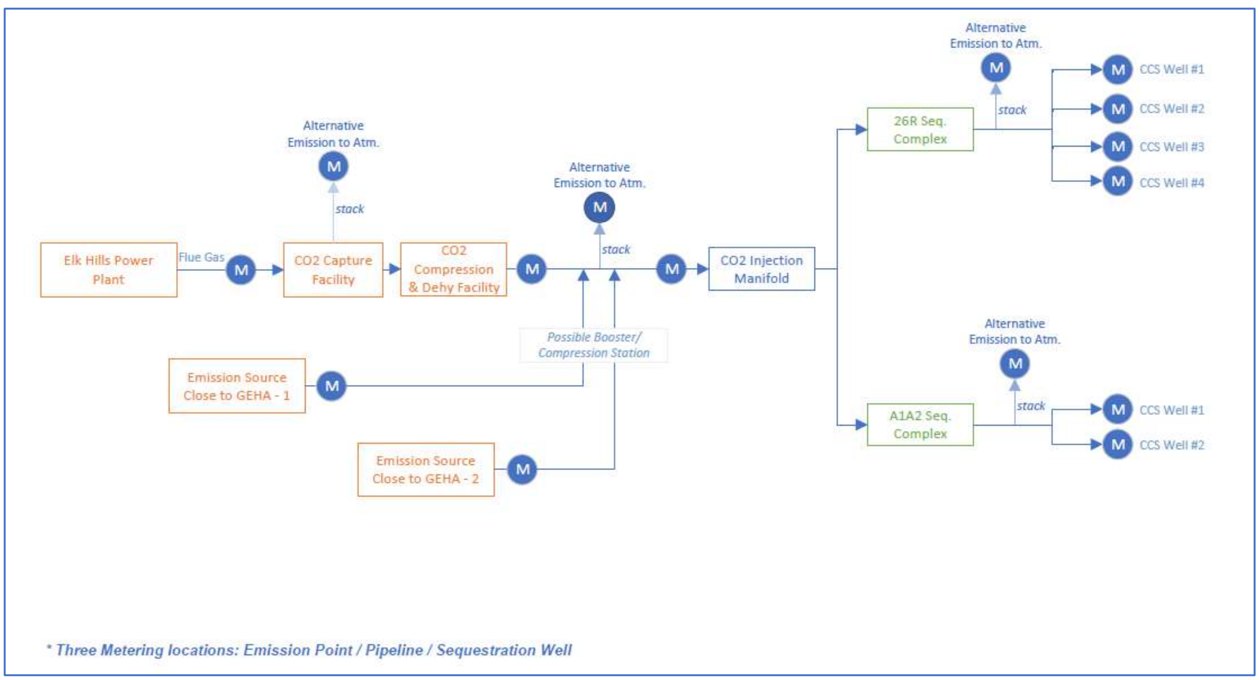

Figure 5: Facilities Flow Diagram for Carbon TerraVault geological sequestration and CalCapture EOR. Meter placement will ensure that the volume of CO2 from source to both georgical sequestration and EOR will be measured separately.

2.3.1 CO_2 Source

CTV is planning to construct a carbon capture and sequestration "hub" project (i.e., a project that CO_2 from multiple sources over time and injects the CO2 stream(s) via a Class VI UIC permitted injection well). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. The anthropogenic CO_2 will be sourced from an onsite blue hydrogen plant (up to 200,000 metric tons per annum) with additional potential CO_2 from the Elk Hills 550 MW natural gas combined cycle power plant (EHPP), direct air capture (DAC), renewable diesel refineries, and/or other sources in the area.

All CO_2 sources will have custody transfer metering to ensure accurate accounting of both the mass rate and impurities in the CO_2 stream.

2.3.2 CO_2 Distribution and Injection

CO_2 from the sources previously discussed will be distributed throughout the field through a combination of new and existing infrastructure. This distribution infrastructure will allow CO_2 to be injected into CO_2 wells completed within the Monterey Formation at A1-A2 and 26R.

Each CO_2 injection well will have automated controls that provide for both control and measurement of the mass flow rate and pressure.

2.3.3 Wells in the AOR Penetrating the Reef Ridge Shale

CalGEM regulations govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields (other than UIC Class VI CO_2 injection wells that are regulated by the EPA UIC program). Current CalGEM rules require, among other provisions, that:

- Fluids be constrained in the strata in which they are encountered
- Activities governed by the regulations cannot result in the pollution of subsurface or surface waters
- Wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface waters
- Operators file a completion report including basic electric log (e.g., a density, sonic, or resistivity log acquired from the wellbore)
- Wells follow plugging procedures that require advance approval from CalGEM and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.

Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM at time of drilling and as part of the existing Class II UIC permit applications. Wells penetrating the Reef Ridge Confining layer and storage reservoir are shown in Figure 6.

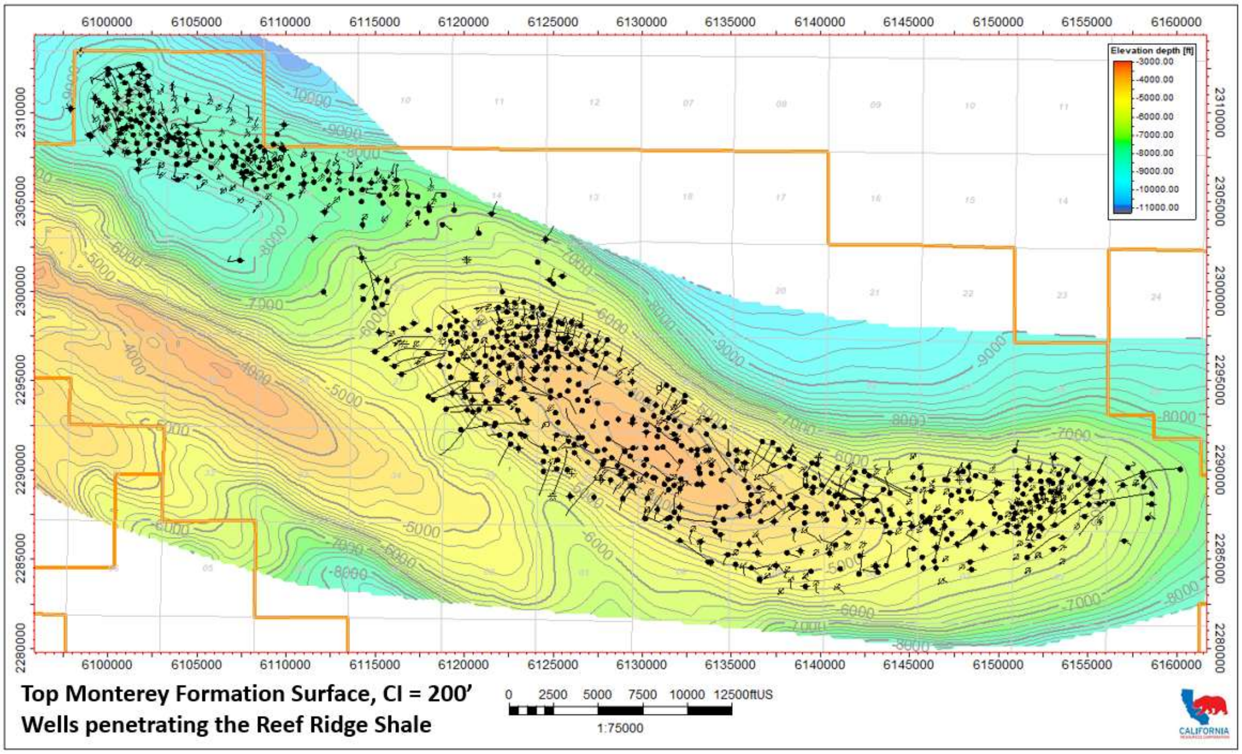

Figure 6: Wells penetrating the Reef Ridge Shale

Completion Date	A1-A2 Reservoir Count	26R Reservoir Count
Oil and Gas Producing Wells	79	145
Class II Injection/Disposal Wells	32	22
Observation Wells	0	2
Plugged and Abandoned	39	35
TOTAL	150	205

Table 3: Wells Penetrating Reef Ridge Shale for each reservoir by status.

The wells in Table 3 are categorized in groups that relate to the well status for each reservoir. These wells were generally completed with three strings of casing, typically cemented to the surface. A perforated production liner was typically installed to the top of the producing interval, with completion tubing hung just above the perforations. Cement bond logs (CBL) or temperature surveys that can identify cement top were typically run on these wells.

Wells that are not associated with the EPA Class VI project that penetrate the Reef Ridge will be abandoned to ensure that the CO2 injectate is confined in the storage reservoir. Project wells are shown in Figure 11 and listed in Section 11.5.

Well workover crews are on call to maintain active wells and to respond to any wellbore issues that arise. Incidents are detected by monitoring changes in the surface pressure of injection wells and by conducting

Mechanical Integrity Tests (MITs) that include, but not limited to, Radioactive Tracer Surveys (RA Surveys) and Standard Annular Pressure Tests (SAPTs).

All existing oil and gas wells, including both injection and production wells are regulated by CalGEM under Public Resources Code Division 3.

2.4 Reservoir Modeling

Numerical reservoir simulation is used for many purposes including optimizing reservoir management, forecasting hydrocarbon and water production, predicting the behavior of injected fluids such as CO_2 and assessing CO_2 plume development and confinement.

2.4.1 Reservoir Model for Operational Design and Economic Evaluation

Reservoir modeling workflow begins with the development of a three dimensional representation of the subsurface geology ("static model"). Static model development leverages all available well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces and faults (if present) into a geocellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. CRC used Schlumberger Petrel, an industry-standard geocellular modeling software, to build and maintain the EHOF static model.

The static model becomes "dynamic" in the reservoir simulator with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon phase
- Liquid and gas relative permeability
- Capillary pressure data
- Fluid injection and/or extraction rates

2.4.2 Performance Prediction

One objective of the simulation models is to develop an injection plan that maximizes CO_2 storage and minimizes associated costs. The injection plan includes injection wells and appropriate injection rate and pressure for each that adheres to regulatory requirements.

2.4.3 Plume Model for CO_2 Storage Capacity, Containment and Predicted Plume Migration

Full-field plume models confirm reservoir capacity and CO_2 containment within the 26R and A1-A2 reservoir. These models were built using a dynamic reservoir simulation application known as the Equation-of-State Compositional Simulator (GEM), developed by Computer Modelling Group Ltd. (CMG). Figure 7 shows the results on the modeling for the 26R and A1-A2 storage reservoir. The plume models were used to evaluate the following:

- Quantity of CO_2 stored for geological sequestration
- Lateral movement of CO_2 to define the MMA and demonstrate vertical confinement by the Reef Ridge shale

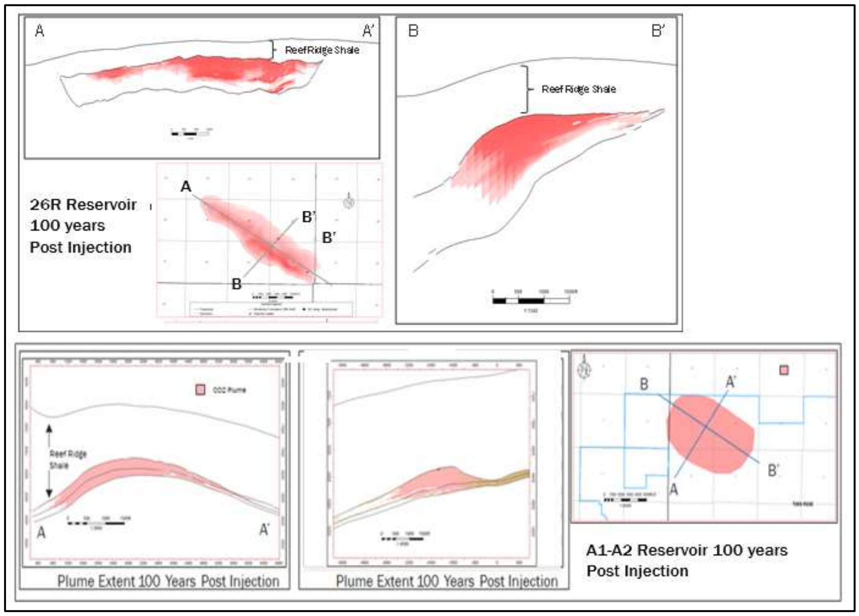

Figure 7: Injector well locations, EPA AoR and AMA - MMA (blue line).

2.4.4 Geomechanical Modeling of Reef Ridge Shale

In addition to the plume models, a simpler GEM-based model was coupled with a finite element geomechanical module, GEOMECH, to model cap rock failure in the Reef Ridge Shale as a function of cap rock mechanical properties and reservoir pressure immediately below the cap rock. This model was used to assess the pressure at which the Reef Ridge Shale would shear through tensile failure.

The plume modeling effort confirms the Monterey Formation's ability to permanently store the planned project CO_2 volumes under the Reef Ridge Shale over the project's life. The results of the plume models are discussed in greater detail below.

3 Delineation of Monitoring Area and Timeframes

3.1 Maximum Monitoring Area

The MMA is defined in §98.440-449 (Subpart RR) 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. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data as described above was used to predict the size and location of the plume, as well as understand how the plume migrates over time.

The MMA, shown in Figure 8 below in the blue line, is defined by the extent of the CO_2 plume at 100 years post injection for geologic sequestration plus one-half mile.

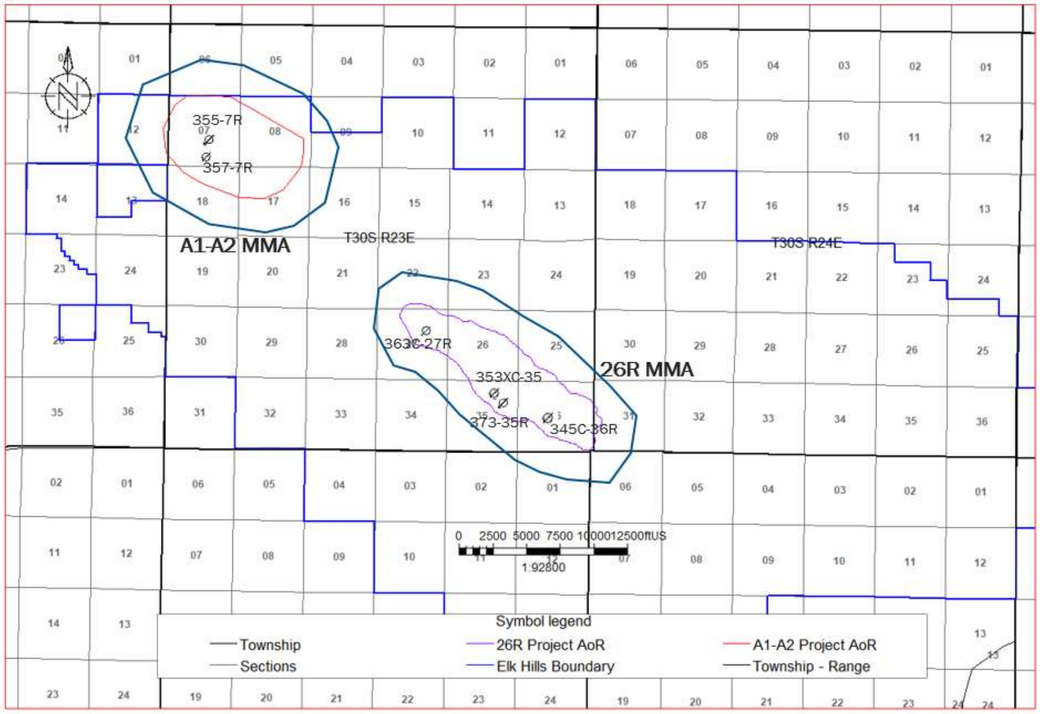

Figure 8: Injector well locations, EPA AoR and AMA - MMA (blue line).

3.2 Active Monitoring Area

The AMA will be the same boundary as the MMA. The following factors were considered in defining this boundary:

- The A1-A2 and 26R reservoirs are depleted. CO2 reaches the edges of the reservoir within the first couple years of injection. Leveraging the MMA boundary for the AMA provides maximum operational flexibility.
- The absence of through-going faults or fractures confirms the competency of the Reef Ridge to preserve hydrocarbons within the Monterey Formation and to contain the CO_2.

3.3 Monitoring Timeframe

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted when a demonstration that current monitoring and model(s) show that the cumulative mass of CO_2 reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration within two to three years after injection for the Specified Period ceases based on predictive modeling supported by monitoring data.

4 Evaluation of Potential Pathways for Leakage to the Surface

4.1 Introduction

In the more than 100 years since the EHOF has been developed, the reservoir has been studied and documented extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO_2 to the surface. The following potential pathways are reviewed:

1. Existing Wellbores
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the EHOF
7. Drilling Through the CO_2 Area
8. Diffuse Leakage Through the Seal

4.2 Existing Wellbores

Leakage through existing wellbores is possible at the EHOF. However, that is mitigated by adhering to regulatory requirements for well drilling and testing; implementing best practices developed through its extensive operating experience; monitoring injection/production performance, wellbores, and the surface; and maintaining surface equipment. Wells penetrating the Reef Ridge confining shale and sequestration reservoir is described in Section 2.3.2.

As discussed in Section 2.3.3, regulations governing wells in the EHOF require that wells be completed and operated so that fluids are contained in the strata in which they are encountered.

Continual and routine monitoring and maintenance of wellbores and site operations is critical to ensure confinement as follows:

- Injection well pressure is monitored continuously throughout the EHOF using a supervisory control and data acquisition (SCADA) system. Pressure and rate sensors on the injection wells are programmed to alarm and notify operations personnel when values that significantly deviate from set target ranges. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such excursions occur, they are investigated and addressed.

- Experience gained over time to strategically approach well maintenance and workovers and maintain workover crews onsite for this purpose. For example, the well classifications by age and construction method inform planning for monitoring and updating wells. All available information including pattern performance and well characteristics is used to determine well maintenance schedules.

- A corrosion protection program for CO_2 operations will be implemented to mitigate both internal and external corrosion of casing in wells in the EHOF. In line with industry standard operations and EPA Class VI requirements for CCS, downhole equipment and the interior and exterior of wellbores will be protected using special materials (e.g., fiberglass tubing, corrosion resistant cements, nickel plated packers, corrosion resistant packer fluids) and procedures will be performed to prevent and monitor for corrosion (e.g., packer placement, use of annular leakage detection devices, cement bond logs, pressure tests). These measures and procedures are typically included in the injection orders filed with CalGEM and the EPA UIC program. Corrosion protection methods and requirements may be enhanced over time in response to improvements in technology.

- MIT requirements implemented by CalGEM and/or EPA UIC (as applicable) will be followed to periodically inspect wells and surface facilities to ensure that all wells and related surface equipment are in good repair, leak-free, and that all aspects of the site and equipment conform to existing regulations and permit conditions. All active injection wells undergo MIT before injection, after any workover or per time periods specified in the UIC approval. Operators are required to use a pressure recorder and pressure gauge for the tests. For CalGEM regulated wells operator's field representative must sign the pressure recorder chart and submit it with the MIT form to CalGEM. The casing-tubing annulus must be tested to MASP for a specified duration and with an allowable pressure loss specified in the regulations. CalGEM or EPA UIC may also approve Alternative Pressure Monitoring Programs with varying requirements at their discretion.

  If a well fails the MIT, the operator must immediately shut the well in and provide notice to CalGEM. Casing leaks must be successfully repaired within 180-days and re-tested or the well must be plugged and abandoned after submitting a formal notice and obtaining approval from CalGEM.

- Finally, as indicated in Section 5, field inspections are conducted on a routine basis by field personnel. On any given day, there are approximately 40 personnel in the field. Leaking CO_2 is very cold and leads to formation of bright white clouds and ice that are easily spotted. All field personnel will be trained to identify leaking CO_2 and other potential problems in the field and safely remedy the issue. Any CO_2 leakage detected will be documented and reported, quantified, and addressed as described in Section 5.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, CRC and CTV conclude that it will mitigate CO_2 leakage through wellbores by detecting problems as they arise and quantifying any leakage that does occur. Section 4.10 summarizes how CRC and CTV will monitor CO_2 leakage from various pathways and describes the response to various leakage scenarios. In addition, Section 5 describes how CRC and CTV will develop the inputs used in the Subpart RR mass-balance equation (Equation RR-11 and Equation RR-12). Any incidents that result in CO_2 leakage up the wellbore and into the atmosphere will be quantified as described in Section 7.4.

4.3 Faults and Fractures

There are no faults or fractures penetrating the confining layer of the Reef Ridge Shale that provide a potential upward pathway for fluid flow. First, the presence of oil, especially oil with a gas cap, is indicative of a competent natural seal. Oil, and to a greater extent gas, migrates upward over time because both are less dense than the brine found in rock formations. Places where oil and gas remain trapped in the deep subsurface over millions of years, as is the case in the EHOF, prove that faults or fractures do not provide a pathway for upward migration out of the CO_2 flooding interval.

While developing the EHOF, a seismic survey was conducted to characterize the formations and provide information for the reservoir models used for development planning. Initial interpretations of the three-dimensional (3-D) seismic survey were based on a conventional pre-stack time migration volume. In 2019, the 3-D seismic survey was re-processed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 9 displays the location and extent of four faults that helped to form these anticlines beginning in the Middle Miocene, 16 million years ago (Callaway and Rennie, 1991). These faults have remained inactive for millions of years since. Offsetting the 31S and NWS structures are the 1R, 2R and 3R high angle reverse faults that are oriented NW-SE. The faults penetrate the lowest portions of the Monterey Formation but do not continue through the injection interval to the Reef Ridge Shale confining layer.

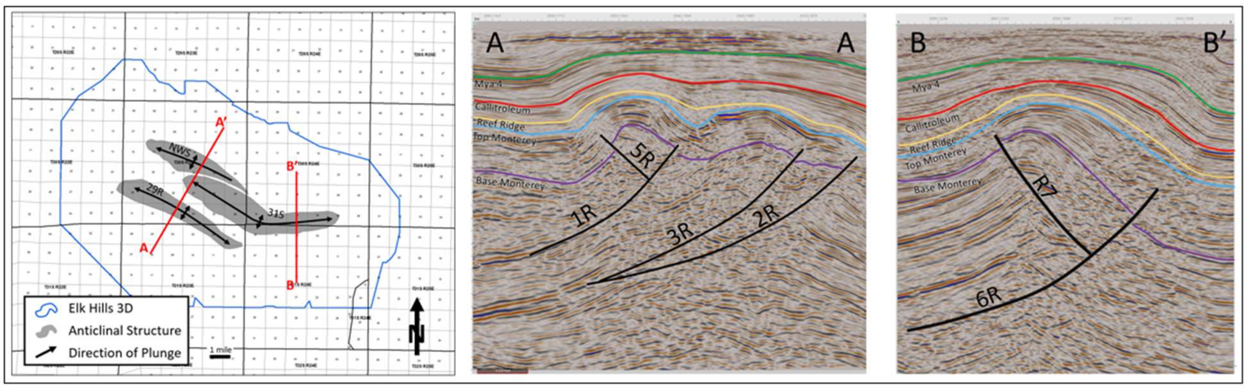

Figure 9: Outline of EHOF 3-D Survey and Seismic Intersections Across 31S and NWS Structures

Lastly, the operating history of the EHOF confirms there are no faults or fractures penetrating the Reef Ridge Shale that allow fluid migration. Water and gas have been successfully injected into the Monterey Formation since 1976, and there is no evidence of new or existing faults or fractures. Over 1.4 billion barrels of water and 1,237 billion standard cubic feet of gas have been injected into the NWS and 31S structures with no reservoir confinement issues. In fact, it is the absence of faults and fractures in the Reef Ridge Shale that makes the Monterey Formation such a strong candidate for water injection operations and enables field operators to maintain effective control over the injection and production processes.

4.4 Natural or Induced Seismicity

Based on published data and over 100 years of operational experience, there is no evidence that natural seismic activity poses a significant risk for loss of CO_2 for the project. This is due, in part, to the thickness, ductility and predominance of clay in the primary confining layer Reef Ridge Shale.

No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area. Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west, beyond the Temblor Range) and the White Wolf Fault (25 miles southeast from the EHOF).

Historical seismic events from 1932 to present are available from the Southern California Earthquake Data Center (SCEDC). Based on this data, there have been no earthquakes recorded greater than 3.0 in the A1-A2 and 26R MMA. In addition, there have only been nine earthquakes with a magnitude of 5.0 or greater within a 30-mile radius around the EHOF (Figure 10). The average depth of these earthquakes is 6.3 miles, while the storage reservoirs are one mile below surface.

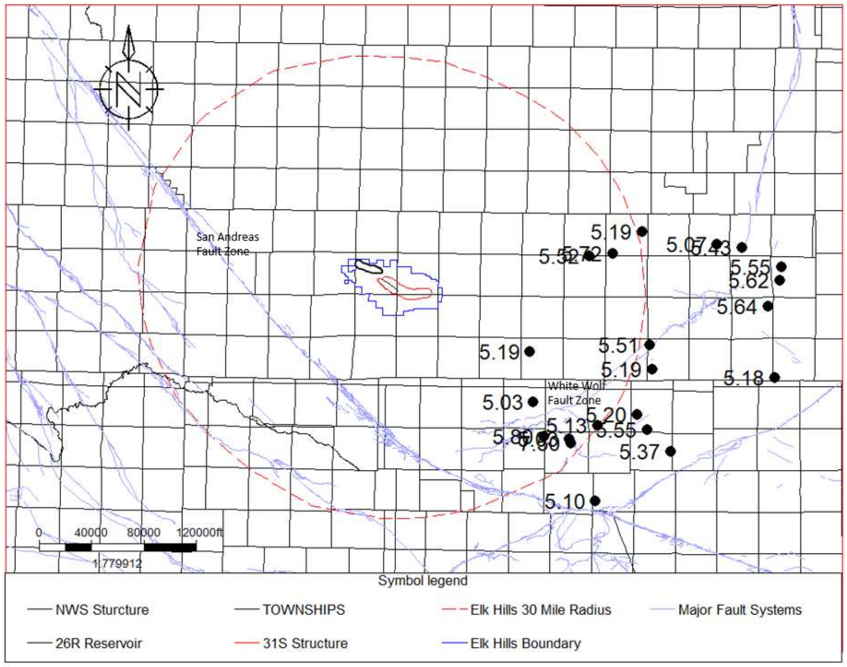

Figure 10: Earthquakes in the San Joaquin Basin with a magnitude greater than 5. Note, only 9 earthquakes have occurred within a 30-mile radius around the EHOF.

Induced seismicity will be mitigated operationally by the following:

1. Injection pressure will be monitored continuously and will be lower than the failure pressure of the confining Reef Ridge Shale.
2. Reservoir pressure will be at or beneath the discovery pressure.
3. Seismometers will be installed at the surface to detect seismicity induced by injection operations.

4.5 Previous Operations

All of the existing wells at the EHOF have been permitted through CalGEM (and predecessor California agencies) under rules that require detailed information about the character of the geologic setting, the construction and operation of the wells, and other information used to assess the suitability of the site. CalGEM maintains a public database that contains the location, construction details and injection/production history of each well.

Operational experience has verified that there are no unknown wells within the EOHF. Additionally, CRC and CTV have sufficiently mitigated the possibility of migration from older wells. Over many years, the EHOF has been continuously checked for the presence of old, unknown wells throughout the EHOF. These practices ensure that identified wells are sufficiently isolated and do not interfere with ongoing operations and reservoir pressure management.

4.6 Pipeline/Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO_2. Unplanned leakage from surface facilities will be mitigated to the maximum extent practicable by relying on the use of prevailing design and construction practices and maintaining compliance with applicable regulations. The facilities and pipelines will be constructed of materials and managed using control processes that are standard for CO_2 injection projects.

CO_2 delivery to the complex will comply with all applicable regulations including as pipeline regulations are updated in the future as applicable. Instrumentation will be installed on pipelines and facilities that allow the 24/7 operations staff at the central control facility to monitor the process and potentially spot leaks. Furthermore, frequent and routine visual inspections of surface facilities by field staff will provide an additional means to detect leaks. Both manual and automatic shutdowns will be installed in the complex to ensure that leaks are addressed in a timely manner. Should leakage be detected from pipeline or surface equipment, the volume of released CO_2 will be quantified following the requirements of Subpart W of EPA's Greenhouse Gas Reporting Program (GHGRP).

4.7 Lateral Migration

It is highly improbable that injected CO_2 will migrate downdip and laterally outside the EHOF because of the buoyant properties of supercritical CO_2, the nature of the geologic structure and the planned injection approach. The strategy to minimize the lateral migration risk is to ensure that the CO_2 plume and surrounding fluids will be at or below the initial reservoir pressure at time of discovery.

4.8 Drilling Through the CO_2 Area

It is possible that at some point in the future drilling through the Reef Ridge confining zone and into the Monterey Formation may occur. The possibility of this activity creating a leakage pathway is extremely low for three reasons: 1) Future well drilling would be regulated by CalGEM (oil and gas wells) or EPA UIC (Class VI injection wells) and will therefore be subject to requirements that fluids be contained in strata in which they are encountered, 2) As sole operators and owners of the EHOF, CRC and CTV control placement and timing of new drilling operations, and 3) There are no oil and gas targets beneath the Monterey Formation.

4.9 Leakage Through the Seal

Diffuse leakage through Reef Ridge confining layer is highly unlikely. The presence of gas caps trapped over millions of years confirms that the seal has been secure for millions of years. Leaking through the seal is mitigated by ensuring that post injection reservoir pressure will be at or below the initial reservoir pressure at the time of discovery. The injection monitoring program referenced in Section 2.3.1 and detailed in Section 5 assures that no breach of the seal will be created.

Further, if CO_2 were to migrate through the Reef Ridge, it would migrate vertically until it encountered and was trapped by any of the additional shallower interbedded shales of the Etchegoin, San Joaquin and Tulare Formations (more than 5,000 ft. of vertical section; see Figure 3).

4.10 Monitoring, Response and Reporting Plan for CO_2 Loss

As discussed above, the potential sources of leakage include routine issues, as such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment, and unique events such as induced fractures. Table 4 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, standard response, and other applicable regulatory programs requiring similar reporting.

Sections 5.1.5 to 5.1.7 discuss the approaches envisioned for quantifying the volumes of leaked CO_2. In the event leakage occurs, CRC and CTV plan to determine the most appropriate methods for quantifying the volume leaked and will report it as required as part of the annual Subpart RR submission.

Any volume of CO_2 detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as frequency of inspection. As indicated in Sections 5.1 and 7.4, leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in the electronic environmental documentation and reporting system. Repairs requiring a work order will be documented in the electronic equipment maintenance system and well work historian. If the scope of repair work requires permitting through CalGEM or EPA UIC, a subsequent operations summary report will be provided under the conditions of the applicable permit.

4.11 Summary

The structure and stratigraphy of the Monterey Formation in the EHOF is ideally suited for the injection and CO_2 storage. The CO_2 injection zone stratigraphy is porous, permeable, and very thick, providing ample capacity for long-term CO_2 storage. The overlying Reef Ridge Shale forms an effective seal for Monterey Formation sequestration (see Figure 3). After assessing potential risk of release from the subsurface and steps that have been taken to prevent leaks, the potential threat of significant leakage is extremely low. Risk of release is further reduced by the prudent operational strategy of limiting the pressure of the reservoir post-injection to at or below the initial pressure of the reservoir at time of discovery.

Risk	Monitoring Plan	Response Plan	Parallel Reporting (if any)
Loss of well control			
Tubing Leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days	
Casing Leak	Routine field inspection; MIT for injectors; extra attention to high risk wells	Workover crews respond within days	CalGEM or EPA UIC
Wellhead Leak	Routine field inspection and continuous SCADA monitoring	Workover crews respond within days	
Loss of bottom-hole pressure control	Blowout during well operations	Maintain well kill procedures; shut-in offset injectors prior to drilling	CalGEM or EPA UIC
Loss of seal in abandoned wells	Anomalous pressure or gas composition from productive shallower zones	Re-enter and reseal abandoned wells	CalGEM or EPA UIC
Leaks in surface facilities			
Pumps, valves, etc.	Routine field inspection and remote monitoring	Workover crews respond within days	Subpart W
Subsurface leaks			
Leakage along faults	Monitoring of zones above sequestration reservoir	Shut in injectors near faults	
Leakage through induced fractures	Induced seismicity monitoring with seismometers	Comply with rules for keeping pressures below parting pressure	
Leakage due to a seismic event	Induced seismicity monitoring with seismometers	Shut in injectors near seismic event	

Table 4: Response Plan for CO_2 leakage or loss

5 Monitoring and Considerations for Calculating Site Specific Variables

5.1 For the Mass Balance Equation

5.1.1 General Monitoring Procedures

Existing operations are centrally monitored and controlled by an extensive and sophisticated system referred to as the Central Control Facility (CCF). The CCF uses a SCADA software system to implement operational control decisions on a real-time basis throughout the EHOF to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Flow rates, pressures, gas composition and other data will be collected at key points and stored in a centralized data management system. These data are monitored 24 hours a day by qualified technicians who follow response and reporting protocols when the system delivers notifications that data exceed pre-determined statistically acceptable limits. The data can be accessed for immediate analysis.

Figure 5 identifies the meters that will be used to evaluate, monitor, and report on the flood and associated plume migration described earlier in Section 2.3. A similar metering system is already installed throughout the EHOF.

As indicated in Figure 5, a custody-transfer meter will be installed at the CO_2 sources. The custody-transfer meters will measure flow rate continuously. Fluid composition will be determined on either a continuous basis or by periodic sampling depending on the specific meter; both options are accurate for purposes of commercial transactions. All meter and composition data will be recorded.

Metering protocols follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. These meters will be maintained routinely, operated continuously, and will feed data directly to the CCF. In the oil and gas industry, the accepted level of custody transfer meter accuracy is 0.25% or better and the meters are calibrated every 60-90 days. A third party is frequently used to calibrate these meters and both parties to any transaction have rights to witness meter calibration. These custody meters provide the most accurate way to measure mass flows.

Most process streams are multi-component or multi-phase, with varying CO_2 compositions. For these streams, flow rate is the most important control parameter. Operations flow meters are used to determine the volumetric flow rates of these process streams, which allows for the monitoring of trends to identify deviations and determine if any intervention is needed. Flow meters are also used—comparing aggregate data to individual meter data—to provide a cross-check on actual operational performance.

Developing a CO_2 mass balance on multi-phase, multi-component process streams is best accomplished using custody-transfer meters rather than multiple operations meters. As noted above, in-field flow rate monitoring presents a formidable technical and maintenance challenge. Some variance is due simply to differences in factory settings and meter calibration. Additional variance is due to the operating conditions within a field. Meter elevation, changes in temperature (over the course of the day), fluid composition (especially in multi-component or multi-phase streams), or pressure will each affect any in-field meter reading. Many meters have some form of automatic adjustment for some of these factors, while others utilize a conversion factor that is programmed into the meter, and still others need to be adjusted manually in the calculation process. Use of a smaller number of centrally located meters reduces the potential error that is inherent in employing multiple meters in various locations to measure the same volume of flow and gas composition.

Table 5 below summarizes the CO_2 injection monitoring strategy.

Monitoring Activity	Frequency/Location
MIT (Internal and External ME)	Annual
SAPT	Initially, any time the packer is replaced or reset
Injection Rate, Pressure and Temperature	Continuous
Seismicity	Induced seismicity monitoring via seismometers
USDW and reservoirs between USDW and sequestration reservoir	Monitoring wells with pressure, temperature, fluid composition and periodic cased-hole logs.
Stream Analysis	Continuous
Corrosion Monitoring (coupons, casing integrity)	Well materials, pipelines, and other surface equipment.
Sequestration reservoir monitoring	Dedicated wells monitoring sequestration reservoir with pressure, temperature, fluid composition and periodic cased hole logs.

Table 5: Injection Monitoring Strategy Summary

Figure 11 below shows the location of monitoring wells.

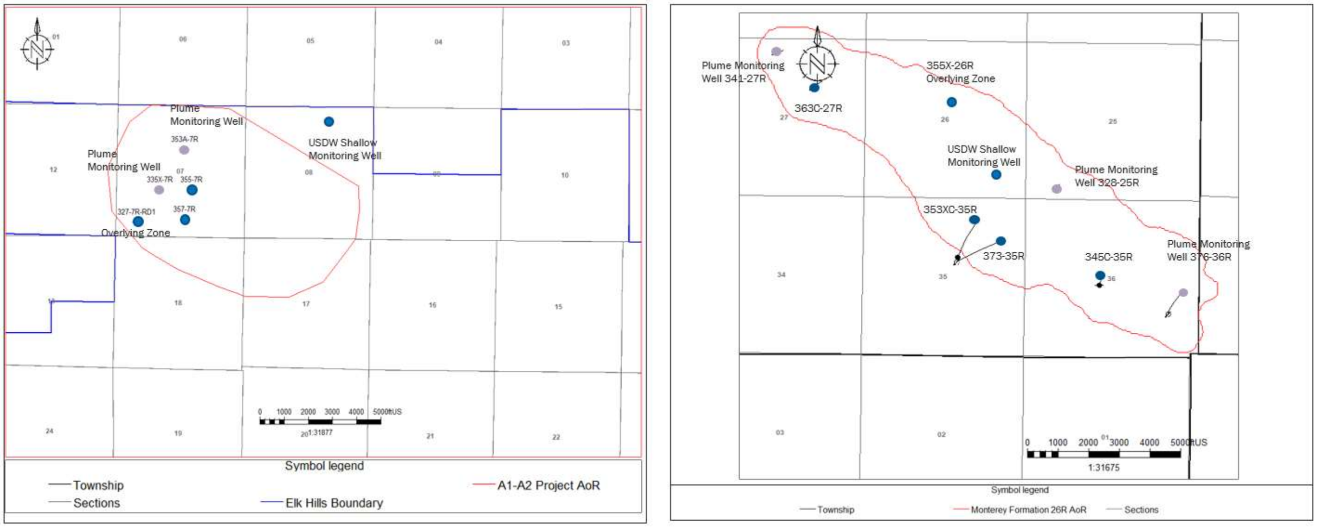

Figure 11: Map showing monitoring well locations.

5.1.2 CO_2 Received

A custody transfer meter will be used at the CO_2 source(s) to continuously measure the volume and composition of CO_2 received. The metering protocols will follow the prevailing industry standard(s) for custody transfer (as promulgated by the API and the AGA).

5.1.3 CO_2 Injected into the Subsurface

Injected CO_2 associated with geologic sequestration will be calculated using the flow meter volumes at the operations/composition meter at the outlet of the recompression facilities (RCFs) and the custody transfer meter at the CO_2 off-take points.

5.1.4 CO_2 Produced, Entrained in Products and Recycled

No CO_2 will be produced or entrained in products or recycled.

5.1.5 CO_2 Emitted by Surface Leakage

As discussed in Section 5.1.6 and 5.1.7 below, 40 CFR Part 98 Subpart W is used to estimate surface leaks from equipment at the EHOF. Subpart W uses a factor-driven approach to estimate equipment leakage. In addition an event-driven process will be used to assess, address, track, and if applicable quantify potential CO_2 leakage to the surface. Reporting will reconcile the Subpart W report and results from any event-driven quantification to assure that surface leaks are not double counted.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet two objectives in accordance with the leakage risk assessment in Section 4: 1) to detect problems before CO_2 leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the volumes of CO_2 leaked to the surface.

Monitoring for Potential Leakage from the Injection/Production Zone:

1. Monitoring Wells

Monitoring wells that will measure pressure, temperature and fluid composition will be dedicated to geologic sequestration. These dedicated wells will monitor the sequestration reservoir, zones above the sequestration reservoir and the underground source of drinking water (USDW). Baseline analysis will be established for each of these wells. Any deviation from the baseline analysis will be assessed for potential indications of leakage.

2. Injection Wells

Injection well pressure, temperature and injection rate will be monitored continuously. If injection pressure or rate measurements are beyond the specified set points determined for each injector, a data flag is automatically triggered and field personnel will investigate and resolve the problem. These excursions will be reviewed by well-management personnel to determine if CO_2 leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or some other minor action is required), and there is no threat of CO_2 leakage. In the case of issues that are not readily resolved, more detailed investigation and response would be initiated, and internal support staff would provide additional assistance and evaluation. Such issues would lead to the development of a work order in the work order management system. This record will enable the company to track progress on investigating potential leaks and, if a leak has occurred, to quantify its magnitude. To quantify leakage to the surface, an estimate of the relevant parameters (e.g., the rate, concentration, and duration of leakage) will be made to quantify the leak volume. Depending on specific circumstances, these determinations may rely on engineering estimates.

Monitoring of Wellbores

Because leaking CO_2 at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a two-part visual inspection process will be employed in the general area of the EHOF to detect unexpected releases from wellbores. First, field personnel will visit the surface facilities on a routine basis. Inspections may include tank volumes, equipment status and reliability, lube oil levels, pressures and flow rates in the facility, and valve leaks. Field personnel inspections will also check that injectors are on the proper schedule and observe the facility for visible CO_2 or fluid line leaks.

Finally, data collected by the personal gas monitors, which are always worn by all field personnel are a last method to detect leakage from wellbores. The monitor's detection limit is 10 parts per million (ppm); if an alarm is triggered, the first response is to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. If the incident results in a work order, this will serve as the basis for tracking the event for greenhouse gas (GHG) reporting.

Other Potential Leakage at the Surface

Routine visual inspections at surface are used to detect significant loss of CO_2 to the surface. Field personnel visit manned surface facilities daily to conduct a visual inspection. Inspections may include review of equipment status, lube oil levels, pressures and flow rates in the facility, valve leaks, ensuring that injectors are on the proper schedule, and conducting a general observation of the facility for visible

CO_2 or fluid line leaks. If problems are detected, field personnel would investigate and, if maintenance is required, generate a work order in the maintenance system which is tracked through completion. In addition to these visual inspections, CRC and CTV will use the results of the personal gas monitors as a supplement for smaller leaks that may escape visual detection.

If CO_2 leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, a work order will be generated in the work order management system. The work order will describe the appropriate corrective action and be used to track completion of the maintenance action. The work order will also serve as the basis for tracking the event for GHG reporting and quantifying any CO_2 emissions.

5.1.6 CO_2 Emitted from Equipment Leaks and Vented Emissions of CO_2 from Surface Equipment Located Between the Injection Flow Meter and the Injection Wellhead

Monitoring efforts will evaluate and estimate leaks from equipment and vented CO_2 as required under 40 CFR Part 98 Subpart W.

5.2 To Demonstrate that Injected CO_2 is not Expected to Migrate to the Surface

At the end of the Specified Period, CRC and CTV intend to cease injecting CO_2 for the subsidiary purpose of establishing the long-term storage of CO_2 in the EHOF. After the end of the Specified Period, CRC and CTV anticipate that it will submit a request to discontinue monitoring and reporting. The request will demonstrate that the amount of CO_2 reported under 40 CFR §98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage. At that time, CRC and CTV will be able to support the request with years of data collected during the Specified Period as well as two to three (or more, if needed) years of data collected after the end of the Specified Period. This demonstration will provide the information necessary for the EPA Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

1. Data comparing actual performance to predicted performance (injection) over the monitoring period
2. An assessment of the CO_2 leakage detected, including discussion of the estimated amount of CO_2 leaked and the distribution of emissions by leakage pathway
3. A demonstration that future operations will not release the volume of stored CO_2 to the surface
4. A demonstration that there has been no significant leakage of CO_2 and,
5. An evaluation of reservoir pressure in the EHOF that demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

6 Determination of Baselines

Automatic data systems will be used to identify and investigate deviations from expected performance that could indicate CO_2 leakage. These data systems are used primarily for operational control and monitoring and as such are set to capture more information than is necessary for reporting in the Annual Subpart RR Report. Necessary system guidelines will be developed to capture the information that is relevant to identify CO_2 leakage. The following describes the approach to collecting this information.

6.1 Visual Inspections

As field personnel conduct routine inspections, work orders are generated in the electronic system for maintenance activities that cannot be immediately addressed. Methods to capture work orders that involve activities that could potentially involve CO_2 leakage will be developed, if not currently in place. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation. The responsible party will be provided in the monitoring plan, as required under Subpart A, 98.3(g). The Annual Subpart RR Report will include an estimate of the amount of CO_2 leaked. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

6.2 Personal Gas Monitors

Gas monitors are worn by all field personnel. Any monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the monitor is working properly. If a fugitive leak is discovered, it would be quantified, and mitigating actions determined accordingly. The person responsible for MRV documentation will receive notice of all incidents where gas is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO_2 emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

6.3 Injection Rates, Pressures and Volumes

Target injection rates and pressures will be developed for each injector, based on the results of ongoing modeling and permitted limits. High and low set points are programmed into the controllers, and flags whenever statistically significant deviations from the targeted ranges are identified. The set points are designed to be conservative. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO_2 leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions and related work orders that could potentially involve CO_2 leakage. The Annual Subpart RR Report will provide an estimate of CO_2 emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

7 Determination of Sequestration Volumes Using Mass Balance Equations

The following sections describe how each element of the mass-balance equation (Equation RR-11) will be calculated.

7.1 Mass of CO_2 Received

CRC and CTV will use equation RR-2 as indicated in Subpart RR §98.443 to calculate the mass of CO_2 received from each custody transfer meter immediately downstream of the source(s). The volumetric flow at standard conditions will be multiplied by the CO_2 concentration and the density of CO_2 at standard conditions to determine the mass.

$$\mathrm{CO}_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{\mathrm{CO}_{2,p,r}} \text{ (Eq. RR-2)}$$

Where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons)
$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters)
$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into a site well in quarter p (standard cubic meters)
D = density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682
$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (volume percent CO_2, expressed as a decimal fraction).
p = Quarter of the year
r = Receiving flow meters

Given CRC and CTV's method of receiving CO_2 and requirements of Subpart RR §98.444(a):

- All delivery to EHOF is used, so quarterly flow redelivered, $S_{r,p}$, is zero ("0") and will not be included in the equation.
- Quarterly CO_2 concentration will be taken from the gas measurement database

CRC and CTV will sum to total Mass of CO_2 Received using equation RR-3 in §98.443:

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \text{ (Eq. RR-3)}$$

Where:

CO_2 = Total net annual mass of CO_2 received (metric tons)
$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-2 for flow meter r
r = Receiving flow meter

7.2 Mass of CO_2 Injected into the Subsurface

Mass of CO_2 injected into the subsurface at EHOF is equal to the sum of the mass of CO_2 received as calculated in RR-3 of 98.443 (as described in Section 7.1).

7.3 Mass of CO_2 Emitted by Surface Leakage

CRC and CTV will calculate and report the total annual mass of CO_2 emitted by surface leakage using an approach that is tailored to specific leakage events and relies on 40 CFR Part 98 Subpart W reports of equipment leakage. As described in Sections 4 and 5.1.5 to 5.1.7, the operators are prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO_2 leaked to the surface will depend on several site-specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

The process for quantifying leakage will entail using best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are discussed in Section 5.1.5 to 5.1.7. In the event leakage to the surface occurs the quantify and leakage amounts will be reported, and records retained that describe the methods used to estimate or measure the volume leaked as reported in the Annual Subpart RR Report. Further, the Subpart

W report and results from any event-driven quantification will be made to assure that surface leaks are not double counted.

Equation RR-10 in §98.443 will be used to calculate and report the Mass of CO_2 emitted by Surface Leakage:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \text{ (Eq. RR-10)}$$

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

7.4 Mass of CO_2 Sequestered in Subsurface Geologic Formations

Equation RR-12 in §98.443 will be used to calculate the mass of CO_2 sequestered in subsurface geologic formations in the Reporting Year as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2\,FI} \text{ (Eq. RR-12)}$$

Where:

CO_2 = Total net annual mass of CO2 sequestered (metric tons)
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 by surface leakage (metric tons) 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 this part

Figure 5 illustrates that CO_2 supplied for geological storage will be metered between the CO_2 source and the injection meter.

7.5 Cumulative Mass of CO2 Reported as Sequestered in Subsurface Geologic Formations

A sum of the total annual volumes obtained using RR-11 in §98.443 will be used to calculate the cumulative mass of CO_2 sequestered in subsurface geologic formations.

8 MRV Plan Implementation Schedule

It is anticipated that this MRV plan will be implemented as early as first quarter (Q1) 2025 pending appropriate permit approvals and an available CO_2 source or within 90 days of EPA approval, whichever occurs later. Other facility GHG reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. As described in Section 3.3 above, it is anticipated that that the MRV program will be in effect during the Specified Period, during which time the project will ensure long-term containment of a measurable quantity of CO_2 in subsurface geologic formations at the EHOF and that the project will be operated in a manner not expected to result in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be made and submission with a request to discontinue reporting under this MRV plan (see 40 C.F.R. § 98.441(b)(2)(ii)).

9 Quality Assurance Program

9.1 Monitoring QA/QC

As indicated in Section 7, the requirements of §98.444 (a) – (d) in the discussion of mass balance equations have been incorporated. These include the following provisions.

CO_2 Received and Injected

The quarterly flow rate of CO_2 received is measured at the receiving custody transfer meters.

CO_2 emissions from equipment leaks and vented emissions of CO_2

These volumes are measured in conformance with the monitoring and QA/QC requirements specified in subpart W of 40 CFR §98.

Flow meter provisions

The flow meters used to generate data for the mass balance equations in Section 7 are:

- Operated continuously except as necessary for maintenance and calibration
- Operated using the calibration and accuracy requirements in 40 CFR §98.3(i).
- Operated in conformance with API standards.
- National Institute of Standards and Technology (NIST) traceable.

Concentration of CO_2

As indicated in Appendix 1 (Section 11.1), CO_2 density is measured using an appropriate standard method. Further, all measured volumes of CO_2 have been converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere, including those used in Equations RR-2, RR-5, and RR-8 in Section 7.

9.2 Missing Data Procedures

In the event data needed for the mass balance equations cannot be collected, procedures for estimating missing data in §98.445 will be used as follows:

- A quarterly flow rate of CO_2 received that is missing would be estimated using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.

- For any 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 specified in subpart W of 40 CFR Part 98 would be followed.

9.3 MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in §98.448(d).

10 Records Retention

The record retention requirements specified by §98.3(g) will be followed. In addition, it will follow the requirements in Subpart RR §98.447 by maintaining the following records for at least three years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO_2 including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- 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.

These data will be collected as generated and aggregated as required for reporting purposes.

11 Appendices

11.1 Conversion Factors

CO_2 volumes will be reported at standard conditions of temperature and pressure as defined by the California Air Resources Board (CARB): 60° F and 14.7 psia[2].

To convert these volumes into metric tons, a density is calculated using the Span and Wagner equation of state as recommended by the EPA and using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST), available at http://webbook.nist.gov/chemistry/fluid/.

The conversion factor 5.29×10^{-2} metric ton per thousand cubic feet (MT/Mcf) has been used throughout to convert volumes to metric tons.

[2] See § 95102. Definitions

11.2 Acronyms

3-D – Three-dimensional
AMA – Active monitoring area
AGA – American Gas Association
AoR – Area of Review
API – American Petroleum Institute
ASP – Alkaline Surfactant Polymer
CalGEM – California Geologic Energy Management Division
CARB – California Air Resources Board
CCF – Central Control Facility
CCS – Carbon Capture and Storage
CDMG – California Division of Mines and Geology
CO_2 – Carbon Dioxide
DAC – Direct Air Capture
EHOF – Elk Hills Oil Field
EHPP – Elk Hills Power Plant
EPA – U.S. Environmental Protection Agency
EOR – Enhanced Oil Recovery
GEM – Geochemical Equation Compositional Model
GHG – Greenhouse Gas
GHGRP -- Greenhouse Gas Reporting Program
GPA – Gas Processors Association
MCF – thousand cubic feet
MMA – Maximum monitoring area
mmscfd – Million standard cubic feet per day
MITs – Mechanical Integrity Tests
MRV – Monitoring, Reporting, and Verification
NIST -- National Institute of Standards and Technology
NWS – Northwest Stevens
OD – Outer diameter
ppm – parts per million
RA Survey – Radioactive Tracer Survey
RCF – Recompression Facility
SAPT – Standard Annular Pressure Tests
SCADA – Supervisory Control and Data Acquisition
SCEDC – Southern California Earthquake Data Center
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water

11.3 References

Callaway, D.C., and Rennie, E.W., Jr., 1991, San Joaquin Basin, California, in Gluskoter, H.J., Rice, D.D., and Taylor, R. B., eds., Economic geology, U.S.: Boulder, Colorado, Geological Society of America, The Geology of North America, v. P-2, p. 417-430.

McJannet, G. S. 1996. *General Overview of the Elk Hills Field*. Society of Petroleum Engineers. doi:10.2118/35670-MS.

11.4 Glossary of Terms

This glossary describes some of the technical terms as they are used in this MRV plan. For additional glossaries please see the U.S. EPA Glossary of UIC Terms (http://water.epa.gov/type/groundwater/uic/glossary.cfm) and the Schlumberger Oilfield Glossary (http://www.glossary.oilfield.slb.com/).

Anticline – an arch-shaped fold in the rock layers in a geologic formation in which the layers are upwardly convex, forming something like a dome or bell shape. Anticlines form excellent hydrocarbon traps, particularly in folds that have rocks with high injectivity in their core and high impermeability in the outer layers of the fold.

Contain/Containment – having the effect of keeping fluids located within in a specified portion of a geologic formation.

Dip – the angle between of the rock layer relative to the horizontal plane. Buoyant fluids will tend to move up the dip, or up dip, and heavy fluids will tend to move down the dip, or down dip. Moving higher up structure is moving "updip." Moving lower is "downdip." Perpendicular to dip is "strike." Moving perpendicular along a constant depth is moving along strike.

Downdip – see "dip."

Enhanced oil recovery (EOR) – a method of enhancing the recovery of the original oil in place through a combination of restoring or increasing pressure in an oil field and/or altering the chemical properties of that oil. Its purpose is to improve oil displacement or fluid flow in the reservoir. There are several types of EOR in use today including chemical flooding (ASP), immiscible and miscible displacement (CO_2), and thermal recovery (steamflood). The optimal application of each type depends on reservoir temperature, pressure, depth, net pay, permeability, residual oil and water saturations, porosity, and fluid properties such as oil API gravity and viscosity.

Flooding pattern – also known as an injection pattern, it is the geometric arrangement of production and injection wells to sweep oil efficiently and effectively from a reservoir.

Formation – a body of rock that is sufficiently distinctive and continuous that it can be mapped.

Injectivity – the ability of an injection well to receive injected fluid (both rate and pressure) without fracturing the formation in which the well is completed. Injectivity is a function of the porosity and permeability of the rock formation and the reservoir pressure in which the injection well is completed.

Infill Drilling – the drilling of additional wells within existing patterns. These additional wells decrease average well spacing. This practice both accelerates expected recovery and increases estimated ultimate recovery in heterogeneous reservoirs by improving the continuity between injectors and producers. As well spacing is decreased, the shifting flow paths lead to increased sweep to areas where greater hydrocarbon saturations remain.

Permeability – the measure of a rock's ability to transmit fluids. Rocks that transmit fluids readily, such as sandstones, are described as permeable and tend to have many large, well-connected pores. Impermeable formations, such as shales and siltstones, tend to be finer grained or of a mixed grain size, with smaller, fewer, or less interconnected pores.

Phase – a region of space throughout which all physical properties of a material are uniform. Fluids that don't mix segregate themselves into phases. Oil, for example, does not mix with water and forms a separate phase.

Pore Space – see porosity.

Porosity – the fraction of a rock that is not occupied by solid grains or minerals. All rocks have spaces between rock crystals or grains that is available to be filled with a fluid, such as water, oil, or gas. This space is called "pore space."

Primary recovery – the first stage of hydrocarbon production, in which natural reservoir energy, such as gas drive, water drive or gravity drainage, displaces hydrocarbons from the reservoir, into the wellbore and up to surface. Initially, the reservoir pressure is higher than the bottomhole pressure inside the wellbore. This high natural differential pressure drives hydrocarbons toward the well and up to surface. However, as the reservoir pressure declines because of production, so does the differential pressure. To reduce the bottomhole pressure or increase the differential pressure to increase hydrocarbon production, it is necessary to implement an artificial lift system, such as a rod pump, an electrical submersible pump, or a gas-lift installation. Production using artificial lift is considered primary recovery. The primary recovery stage reaches its limit either when the reservoir pressure is so low that the production rates are not economic, or when the proportions of gas or water in the production stream are too high. During primary recovery, only a small percentage of the initial hydrocarbons in place are produced, typically 10%-12% for oil reservoirs. Primary recovery is also called primary production.

Saturation – the fraction of pore space occupied by a given fluid. Oil saturation, for example, is the fraction of pore space occupied by oil.

Seal – a geologic layer (or multiple layers) of impermeable rock that serve as a barrier to prevent fluids from moving upwards to the surface.

Secondary recovery – the second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are immiscible gas injection and waterflooding.

Sedimentary Rocks – rocks formed at the Earth's surface through deposition of sediments derived from weathered rocks, biogenic activity, or precipitation from solution. There are three main types of rocks – igneous, metamorphic, and sedimentary.

Stratigraphic section – a sequence of layers of rocks in the order they were deposited.

Strike – See "dip."

Updip – See "dip."

11.5 Well List

The following table presents the well name, and well type for the project.

26R Project Wells:

Injectors	363C-27R 353XC-35R 373-35R 345C-35R	
Monitoring Wells	341-27R	Plume Monitoring
	328-25R	Plume Monitoring
	374-36R	Plume Monitoring
	355X-26R	Above Zone Monitoring Well
	USDW Monitoring Well	USDW Monitoring

A1-A2 Project Wells:

Injectors	355-7R 357-7R	
Monitoring Wells	353A-7R	Plume Monitoring
	335X-7R	Plume Monitoring
	327-7R-RD1	Above Zone Monitoring Well
	USDW Monitoring Well	USDW Monitoring

11.6 Summary of Key Regulations Referenced in MRV Plan

Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b).

Request for Additional Information: CTV/CRC Elk Hills Carbon Project

June 8, 2022

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

1. Determination of MMA and AMA, plume modeling, and planned operations

40 CFR 98.448 specifies that operators are required to develop and submit for approval a proposed MRV plan for the facility. As described in 40 CFR 98.448(a)(1), the MRV plan must contain a "… Delineation of the maximum monitoring area and the active monitoring areas."

Based on the MRV plan, it is our understanding that there is no CO_2 enhanced oil recovery (EOR) currently taking place in the Elk Hills Oil Field (EHOF). What is the basis for long-term containment with respect to CO_2 EOR? All that is stated in the draft plan is as follows:

> "Initial volume estimates are between 25 – 100 million standard cubic feet per day (mmscfd) or 0.5 - 1.9 million tonnes (MMt) per year of CO_2 being delivered to the storage complex over a 15+ year period."

Please provide additional information in the MRV plan on how the storage capacity determinations in Section 2 and the plume size determinations for defining the AMA and MMA in Section 3 were established. Specifically, provide information such as the assumed rate of injection, the volume of injection, the time period of injection, and the time period of post injection. In addition, it is not clear what was assumed in the plume modeling. For example, is the extent of the plume based on the high end or the low end of the range?

Furthermore, we would generally expect the following:

- Simulation modeling should demonstrate whether the planned injection volumes will stay within those boundaries, when injected for the planned time period for injection.
- Injection volumes and time frames should be explicit both for injection and post-injection for purposes of plume modeling.
- Identification numbers of wells should be provided as required by 40 CFR 98.448(a)(6).

In the MRV plan, the assumed volumes and injection rates associated with the plume sizes for the MMA and AMA shown in Figure 14 for both EOR and for geologic sequestration are not stated. Are these the stated rates in Table 2, and the stated volumes in Table 3? The plan should more clearly describe any assumptions. Do the identified MMA and AMA define the extent of the modeled plume, or the extent of the structure and the formations within the structure into which CO_2 will be injected?

The plumes shown in Figure 14 represent the situation 100 years post-injection, but nowhere does the MRV plan state how long actual injection takes place for purposes of defining the plume size. Nor does the plan give the rate of injection over this period. Relatedly, if Tables 2 and 3 are the basis for estimating plume size, what happens if the distribution (if there is an assumed distribution) of CO_2 injected into the two options (EOR vs. geologic sequestration) changes from that shown in Table 3? What if the volumes injected per targeted reservoir change? Does the MMA (and thus the AMA) account for such variability?

Please also address whether there would be situations where changes in the injection plan (injection pattern sizes and geometry, cycle length and WAG ratio to inject water or CO_2 into the WAG process, and rates and pressures for each injection phase) would materially change the current delineations of the MMAs.

The Technical Support Document (TSD) for subparts RR and UU[1] provides further background that you may find useful.[2]

2. Differentiation between CO2 EOR-related storage and storage in deep saline aquifers

In the Overview section of the draft MRV Plan, it states that "The CO_2 will be injected into the Monterey Formation for ***either*** [emphasis added] enhanced oil recovery (EOR), before being permanently sequestered or for dedicated geological storage. The Elk Hills storage complex will be pre-certified and monitored to verify permanent CO_2 sequestration." However, most of the major sections of the MRV plan are based on the premise of what takes place in an EOR operation, and very little pertains specifically or uniquely to saline injection. The MRV Plan

[1] GENERAL TECHNICAL SUPPORT DOCUMENT FOR INJECTION AND GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE: SUBPARTS RR AND UU GREENHOUSE GAS REPORTING PROGRAM, Office of Air and Radiation, U.S. Environmental Protection Agency, November 2010 https://www.epa.gov/sites/default/files/2015-07/documents/subpart-rr-uu_tsd.pdf

[2] For example, Page 50 of the TSD states, "The MRV plan must include a delineation of the area that will be monitored. The maximum areal extent of the plume area of the life of the project should be determined using a reservoir simulator model informed by site characterization data and monitoring results. Reservoir modeling or simulation is a powerful mathematical tool that is used to evaluate the movement of injected CO_2 in the reservoir, to predict the size and location of the plume, and is an integral aspect of project design, planning, site characterization, and monitoring program design. An initial model can be used to forecast how the plume is expected to move and change. After the beginning of injection, the data from the injection well and data from the other types of monitoring should be used to calibrate and history-match the model." Page 52 of the TSD states, "In order to determine the MMA, the reporter should estimate, by modeling, the future area of the free-phase plume. The geometry of the free-phase plume will be a function of the amount and rate of CO_2 injected, as well as the geologic characteristics of the IZ [injection zone] including the CZ [confining zone] geometry, IZ thickness, permeability, and porosity, and the amount of anisotropy within the IZ. The resolution of the reservoir model used to predict plume behavior will also influence the delineation of the area of free-phase CO_2. A model that can predict characteristics of thin layers at the upper boundary of the IZ, or predict the presence of lower CO_2 saturations, may be able to resolve a larger area of free-phase CO_2. The reporter should describe the rationale for defining the free-phase plume boundary by presenting the results of the reservoir simulation including the minimum CO_2 saturation that defines free-phase, and the thickness of the zone over which the saturation is estimated. The determination of both minimum saturation and saturated thickness help define the plume edge."

appears to assume that all considerations (e.g., leakage pathways, operations, monitoring activities, quantification procedures) are the same for both EOR and saline storage. Please ensure each requirement at 40 CFR 98.448(a) is clearly addressed for both EOR and saline storage in the MRV plan. If considerations are determined to be the same for both types of storage, please state this explicitly and provide justification in the MRV plan. Where considerations are different, please provide discussion of these differences.

3. It is requested that the MRV Plan document add page numbers.

It is difficult to prepare specific comments or editorial suggestions without the ability to reference page numbers in the MRV Plan document.

Elk Hills Monitoring, Reporting and Verification (MRV) Plan

4-25-2022

Submitted to:

U.S. Environmental Protection Agency

Prepared by:

CALIFORNIA RESOURCES CORPORATION | CARBON TERRAVAULT

Table of Contents

Overview

The Elk Hills Oil Field (EHOF), covering 75 square miles, was discovered in 1911 and has produced over 2 billion barrels of oil equivalent (BOE) making it one of the most productive fields in the United States. CRC and Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary, owns 100% of the surface, mineral and pore space rights at the EHOF.

CRC and CTV intend to inject and store a measurable quantity of CO2 in subsurface geological formations at the EHOF for a term referred to as the "Specified Period". During the Specified Period, CO2 will be injected from anthropogenic sources such as the Elk Hills 550 MW natural gas combined cycle power plant, bio-diesel refineries, and other sources in the EHOF area.

The CO2 will be injected into the Monterey Formation for either enhanced oil recovery (EOR), before being permanently sequestered, or for dedicated geological storage. The Elk Hills storage complex will be pre-certified and monitored to verify permanent CO2 sequestration.

The EHOF monitoring, reporting, and verification (MRV) plan is based on decades of subsurface characterization and simulation of the targeted Monterey Formation. This empirically driven analysis indicates that the natural geologic seal that overlays the entire EHOF known as the Reef Ridge Shale will provide a physical trap that will permanently prevent injected CO_2 from migrating to the surface.

This monitoring, reporting and verification (MRV) plan in accordance with 40 CFR §98.440-449 (Subpart RR) documents the following:

- Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA)
- 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
- A strategy for detecting and quantifying any surface leakage of CO_2
- A strategy for establishing the expected baselines for monitoring CO_2 surface leakage
- A summary of considerations for calculating EHOF-specific variables for the mass balance equation
- Proposed date to begin collecting data for calculating total CO_2 sequestered

1 Facility Information

i. Reporter number – TBD (once we submit)

ii. Wells in the Elk Hills Oil Field including production, injection, and monitoring wells are permitted by CalGEM through California Public Resources Code Division 3.1 In addition, CalGEM has state

1 Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

and federal authority to oversee the Underground Injection Control (UIC) for Class II injection wells.

Wells injecting CO_2 for geological storage will be permitted with the Environmental Protection Agency (EPA) for Class VI injection.

iii. Wells in the EHOF are identified by name, API number, status, and type. The list of wells as of February 2022 associated with the EOR and geologic storage projects is included in Appendix 11.5. Any new wells or changes to wells will be indicated in the annual report.

2 Project Description

The EHOF is one of the largest oil and natural gas fields in the United States with production from multiple vertically stacked reservoirs. Turbidite sand deposits of the Miocene Monterey Formation will serve as the injection targets in two separate anticlinal structures, Northwest Stevens (NWS) and 31S (Figure 1).

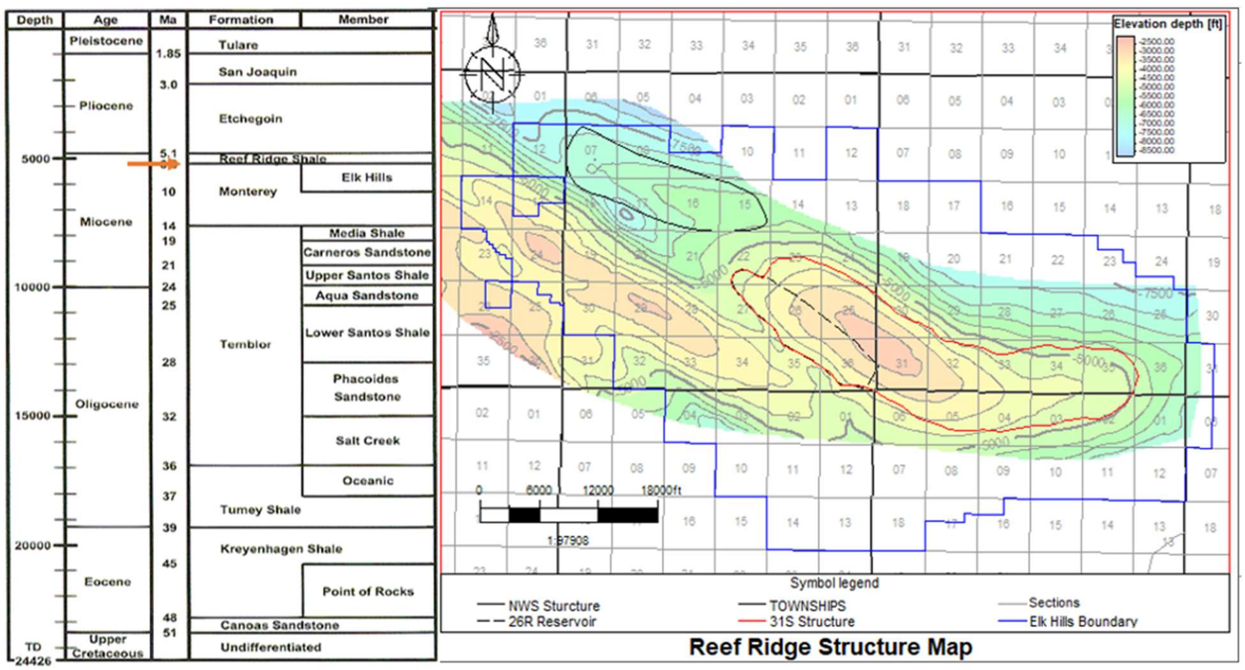

Figure 1: EHOF Stratigraphic Column and Depth Map of Injection Target, Monterey Formation showing the NWS and 31S structures

Numerous aspects of the geology, facilities, equipment, and operational procedures at the EHOF are consistent throughout the field. As such, one MRV will satisfy the NWS and 31S structures as well as CO_2 geological sequestration and enhanced oil recovery (EOR) as shown in Table 1. Reservoirs for geological sequestration and EOR are not in communication, providing operational flexibility for CO_2 management.

Structure	Reservoir	Sequestration Type
31S	MBB	EOR – Class II
31S	26R	Geological – Class VI
NWS	A1-A2	Geological – Class VI
NWS	A3-A11	EOR – Class II

Table 1: Reservoirs within the EHOF and sequestration type.

2.1Project Characteristics

The potential CO_2 stored over the project duration is up to 67.5 million tonnes (refer to Table 3 for breakdown). For accounting purposes, the amount stored is the difference between the amount injected (including recycled CO_2) and the total amount produced less any CO_2 that i) leaks to the surface, ii) is released through surface equipment leakage or malfunction, or iii) is entrained or dissolved in produced oil and water that leaves the storage complex. Actual amounts stored during the Specified Period of reporting will be calculated as described in Section 7 of this MRV Plan.

2.2Environmental Setting

The project site for this MRV plan is the EHOF, located in the San Joaquin Basin, California (Figure 2).

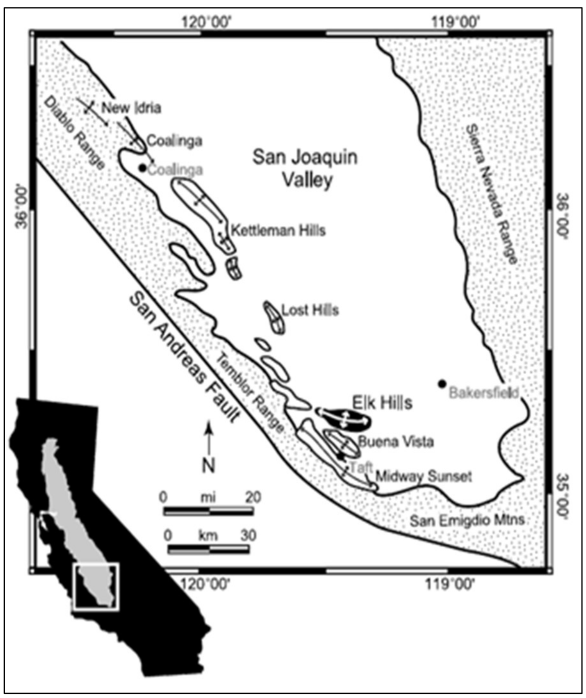

Figure 2: Location of Elk Hills Oil Field, San Joaquin Basin, California

2.2.1 Geology of Elk Hills Oil Field

The EHOF, located 20 miles southwest of Bakersfield in western Kern County, produces oil and gas from several vertically stacked reservoirs formed in the Tertiary age (65 million to 2 million years ago). Of the more than 24,000’ of sediment deposited, the most prolific reservoir is the Miocene aged Monterey Formation which is the target CO_2 sequestration reservoir.

Individual layers within the Monterey Formation are primarily interbedded sandstone and shale. These layers have been folded resulting in anticlinal structures containing hydrocarbons formed from the deposition of organic material approximately 33 million to 5 million years ago (during the Oligocene and Miocene age). The combination of multiple porous and permeable sandstone reservoirs interbedded with impermeable shale seals make the EHOF one of the most suitable locations in North America for the extraction of hydrocarbons and the sequestration of CO_2.

Following its deposition, Monterey Formation sediments were buried under more than 750’ of impermeable silty and sandy shale of the confining Reef Ridge Shale. The Reef Ridge Shale serves as a primary confining layer over the Monterey because it effectively seals underlying fluids from the overlying formations. Above the Reef Ridge lies several alternating sand-shale sequences of the Pliocene Etchegoin and San Joaquin Formations, and Pleistocene Tulare Formation. These formations are highlighted in the cross section in Figure 3.

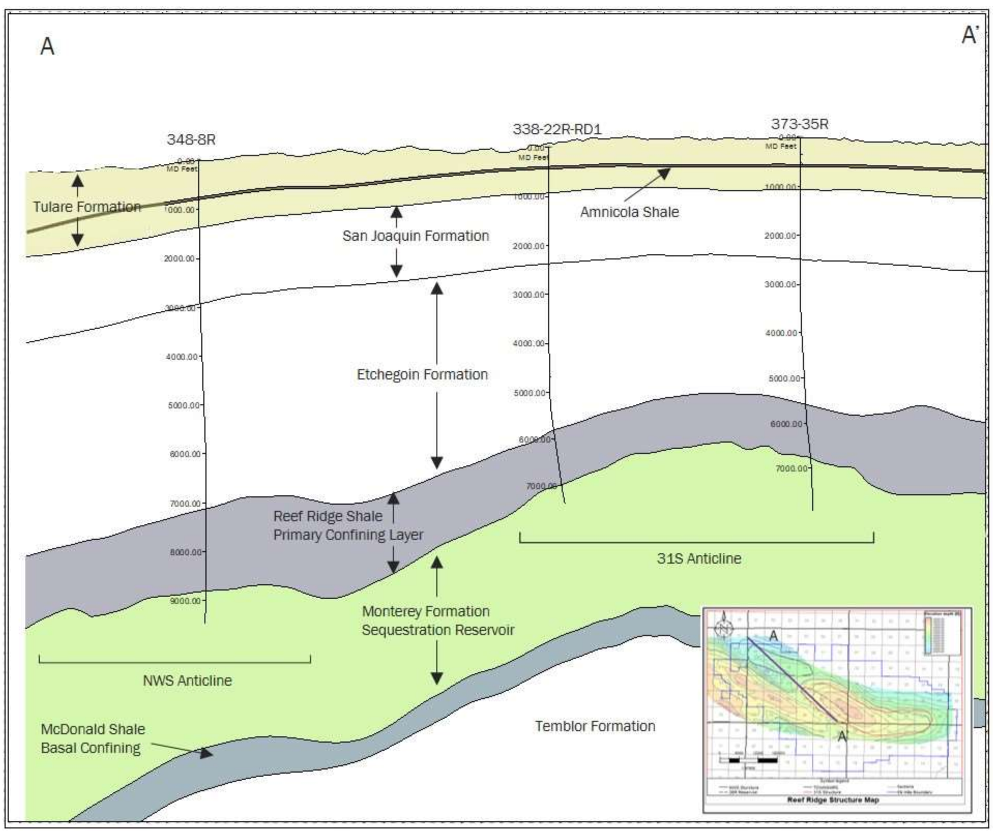

Figure 3: Stratigraphic schematic highlighting CalCapture formations, and the NWS and 31S anticlines.

As indicated in Figure 1, the 31S and NWS structures represent structural highs, or anticlines, within the EHOF. The elevated area forms a natural trap for oil and gas that migrated from below over millions of years. Once trapped at these high points, the oil and gas has remained in place. In the case of the EHOF, this oil and gas has been trapped in the reservoir for more than 6 million years.

Based on physical site characterization and analysis of historic operating records from the Monterey Formation, there is sufficient reservoir capacity and flow properties to inject and store the entire volume of CO_2 proposed:

1. Up to 120 mmscfd of CO_2 will be sequestered in the Monterey Formation daily. Historically the maximum injected daily volume of gas in the EHOF is 250 mmscfd and maximum daily water injected is 243,000 barrels of water injected per day (bwipd) as shown in Table 2.

Gas production	414 mmscfd
Gas Injection	250 mmscfd
Oil/Water Production	253,000 bpd
Water Injection	243,000 bpd

Table 2: Maximum production and injection rates for the Monterey Formation sequestration reservoir.

2. Available storage capacity determined by computational modeling is adequate for the proposed storage volume (Table 3).

	Volume (million tonnes)
31S (MBB) EOR	16
NWS EOR A3 – A11	3.5
NWS (A1-A2) Geological Storage	10
31S (26R) Geological Storage	38
Total Storage Capacity	67.5

Table 3: Calculation of cumulative net fluid volume produced for the Monterey Formation sequestration reservoir.

Stored CO_2 will be contained securely within the Monterey Formation of the EHOF given that 1) The preservation of these hydrocarbon accumulations over geologic time; 2) The subsequent water and gas injection operations; 3) The demonstrated competency of the Reef Ridge confining zone over millions of years and throughout decades of primary and secondary operations; and 4) The 31S and NWS structures ample storage capacity. Confinement within the project area and in the reservoir will be ensured by limiting the pressure of the reservoir post injection at or below the initial pressure of the reservoir at time of discovery.

2.2.2 Operational History of Elk Hills Oil Field

McJannet and other authors recorded the early operating history of EHOF. President Taft designated the area surrounding EHOF as a naval oil reserve under the Pickett Act of 1910. Intended to ensure a secure supply of fuel for the Navy's oil-burning ships, the Executive Order defined "Naval Petroleum Reserve No. 1" (NPR-1). In 1977, President Carter signed the Department of Energy Organization Act which transferred NPR-1 to the US Department of Energy (DOE). Nearly 20 years later, the DOE was directed to sell the assets of NPR-1. Occidental Petroleum provided a winning bid of $3.65 billion and on February 10, 1998, Occidental took over official ownership and operation of Elk Hills. In December 2014, Occidental Petroleum spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated California Resources Corporation (CRC).

The EHOF unit boundary is shown in orange below in Figure 4.

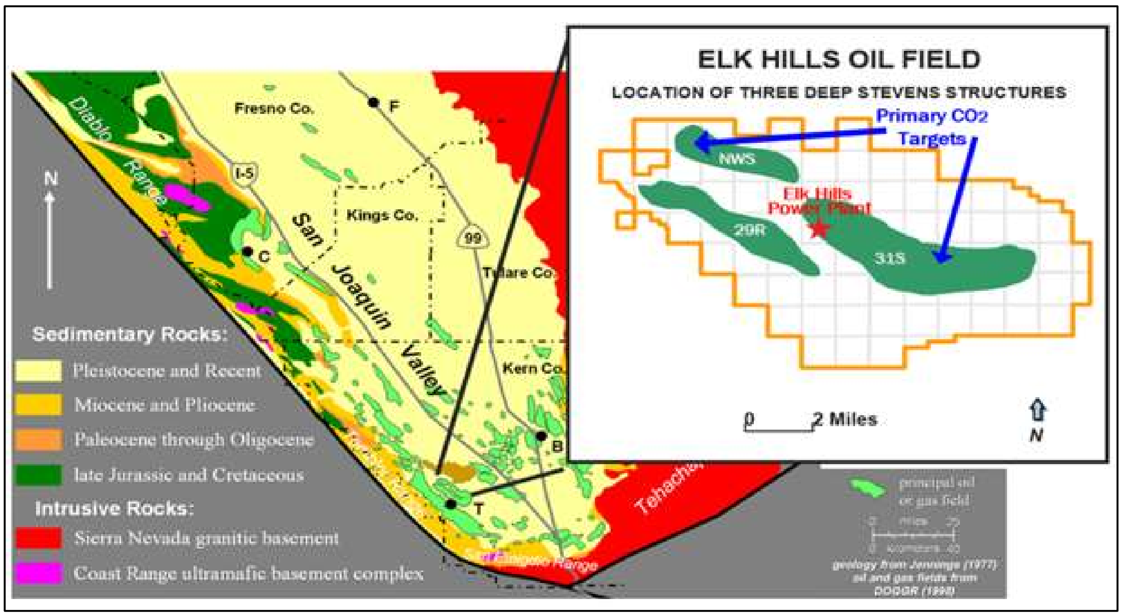

Figure 4: Location of Elk Hills Oil Field within San Joaquin Basin, California

31S and NWS Development History

Selected primary drilling in the Monterey Formation began in the early 1940s, with concerted drilling and production operations commencing with the DOE's oversight in the late 1970s. To support reservoir pressure and maximize the oil recovery factor extensive water and gas injection has occurred in NWS and 31S reservoirs through today.

A successful CO2-injection pilot project was implemented in the Monterey Formation in 2005. Data from the four-month pilot confirmed the formation as an attractive target for CO2 EOR and sequestration. This project assessed how much oil could be mobilized from the conventional sand reservoirs, how much CO2 would be required to mobilize that oil, and how quickly the oil would be produced. Production performance and data collected before, during and after the pilot operations showed that Monterey Formation reservoirs selected for CalCapture are ideal for CO2 EOR and sequestration.

Waterflooding Operations

Waterflooding is conducted under a set of Class II UIC permits issued by CalGEM. To date, more than 1.430 billion barrels of water have been injected into the Monterey Formation EOR reservoirs, with no evidence of communication across the Reef Ridge Shale. This lack of communication between the zones, is confirmed by publicly available records reported to CalGEM. The waterflood results provide meaningful evidence that the planned CO_2 injection zone is confined.

In addition, past development of the shallow Etchegoin Formation oil reservoirs and Monterey Formation has created a large pressure differential across the Reef Ridge Shale, further demonstrating the lack of communication between the reservoirs and demonstration of good isolation with cement jobs in artificial penetrations?

2.3Description of EOR Facilities and Injection Process

A simplified flow diagram of surface facilities can be seen in Figure 5. This includes facilities outside the scope of the MRV including CO_2 source(s), existing oil and gas operations and the subsequent metering locations between the MRV scope and those facilities. All facilities will be designed and built to ensure integrity and compatibility with CO_2. The subsequent parts of this section will review each of the following:

- CO_2 Source
- CO_2 Distribution and Injection
- Wells in the AOR Penetrating the Reef Ridge Shale
- Production Manifolds
- CO_2 Recompression Facilities
- Water Processing Facilities

Facilities associated with dedicated geologic sequestration will be much less complex than those associated with EOR as the entire production and re-compression process flows are unnecessary.

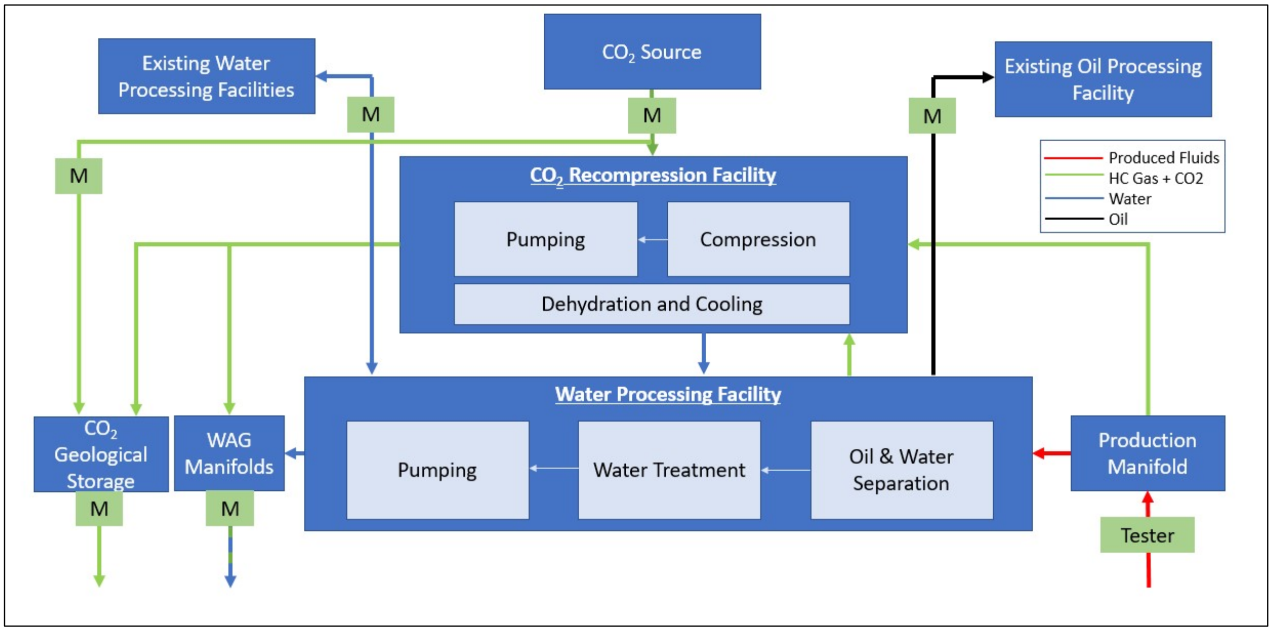

Figure 5: Facilities Flow Diagram for Carbon TerraVault geological sequestration and CalCapture EOR. Meter placement will ensure that the volume of CO2 from source to both georgical sequestration and EOR will be measured separately.

2.3.1 CO_2 Source

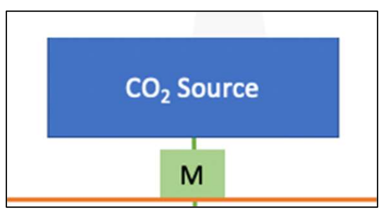

Figure 6: Anthropogenic CO_2 Source with Custody Transfer Meter

CO2 will be supplied to the EHOF from anthropogenic sources in the area. These sources may include natural gas processing, refineries, hydrogen production, and pre or post combustion capture. One of the existing sources will be from pre or post-combustion capture from Elk Hills Power Plant (EHPP).

All CO2 sources will have custody transfer metering to ensure accurate accounting of both the mass rate and impurities in the CO2 stream.

2.3.2 CO_2 Distribution and Injection

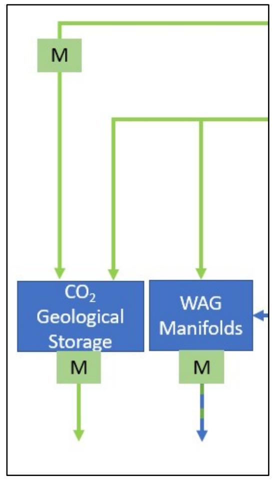

Figure 7: CO_2 Distribution & Injection

CO2 from the sources previously discussed will be distributed throughout the field through a combination of new and existing infrastructure. This distribution infrastructure will allow CO2 from both the CO2 source and the recompression facilities to be injected into CO2 geological storage wells (CO2 storage) and/or CO2 EOR Water Alternating Gas (WAG) wells for injection into the Monterey Formation.

Each CO2 injection well will have automated controls that provide for both control and measurement of the mass flow rate and pressure. The EOR WAG wells will have additional valving to allow for switching between water and CO2 injection.

2.3.3 Wells in the AOR Penetrating the Reef Ridge Shale

CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Current rules require, among other provisions, that:

- Fluids be constrained in the strata in which they are encountered
- Activities governed by the rule cannot result in the pollution of subsurface or surface waters
- Wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface waters
- Operators file a completion report including basic electric log (e.g., a density, sonic, or resistivity log acquired from the wellbore)
- Wells follow plugging procedures that require advance approval from CalGEM and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.

Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM at time of drilling and as part of the existing Class II UIC permit applications. As of November 2020, there are 574 active wells in the 31S and NWS structures; roughly 80% of these are production wells (465 wells) and the others are injection wells (109 wells). In addition, there are 259 inactive (or shut-in) wells and 131 abandoned wells 390, bringing the total number of wells currently completed in the 31S and NWS structures to 964, as reflected in Figure 9 below. Table 4 shows these well counts by status.

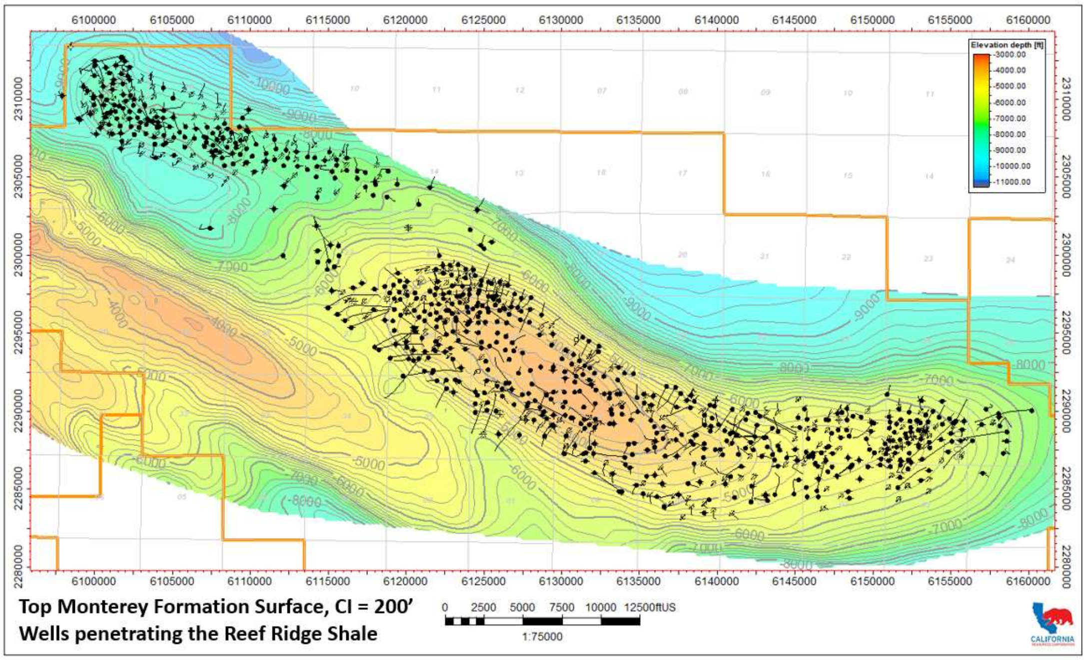

Figure 8: Wells penetrating the Reef Ridge Shale

Completion Date	Active	Shut-in	Plugged and Abandoned
Drilled & Completed Before 1953	57	38	23
Drilled 1953 - 1979	114	49	50
Completed after 1980	403	172	58
TOTAL	574	259	131

Table 4: Wells Penetrating Reef Ridge Shale by Completion Date and Status

The wells in Table 4 are categorized in groups that relate to age and completion methods. Less than 15% of these wells were drilled before 1953. These wells were generally completed with three strings of casing, with surface and intermediate strings typically cemented to the surface. A perforated production liner was typically installed to the top of the producing interval, with completion tubing hung just above the perforations.

Wells drilled from 1953 - 1979 typically have two to three strings of high-grade casing cemented to a level where the top of cement (TOC) extends above the previous casing depth. Cement bond logs (CBL) or temperature surveys that can identify this depth were typically run on these wells. This group of wells rarely has liners installed because they were completed with production casing that extended below the point of the producing oil-water contact.

The majority (66%) of wells in Table 4 were drilled after 1980. In these wellbores, the surface and production casings are cemented to the surface. As a result of well construction changes over time to optimize wellbore utility and investment returns, well design and casing sizes may vary. However, most have production casing or liners ranging from 4-1/2" to 7" OD and surface and intermediate casing sizes ranging from 7" to 13-3/8". Casing weight is determined as a result of multiple load analyses under drilling and production scenarios and considers design safety factors consistent with industry best practices. Casing load scenarios under CO2-CCS and CO2-EOR are considered benign, and the well construction of subject EHOF wells is sufficient to handle these operations.

Well workover crews are on call to maintain active wells and to respond to any wellbore issues that arise. Incidents are detected by monitoring changes in the surface pressure of injection wells and by conducting Mechanical Integrity Tests (MITs) that include, but not limited to, Radioactive Tracer Surveys (RA Surveys) and Standard Annular Pressure Tests (SAPTs).

All oil and gas wells, including both injection and production wells are regulated by CalGEM under Public Resources Code Division 3. In addition, CalGEM has state and federal authority to oversee the Underground Injection Control (UIC) Class II program for all California injection wells. A list of wells with well identification numbers is included in Appendix 11.5.

2.3.4 EOR Production Manifolds

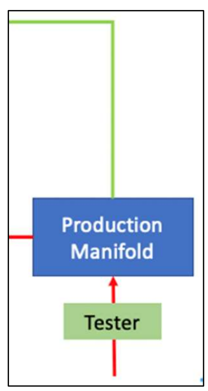

Figure 9: Production & Testing

Fluids from the EOR production wells will flow to a production manifold to be routed for processing and well testing. The production manifold sites will include two-phase liquid/gas separation at up to four different pressures, with the gas then routed to a recompression facility (RCF) and the liquids routed to a water processing facility (Figure 10). The gas streams will be a mixture of hydrocarbon gas and CO_2 at varying pressures. The liquid streams will be a water and oil mixture that will flow through pipelines to a water processing facility.

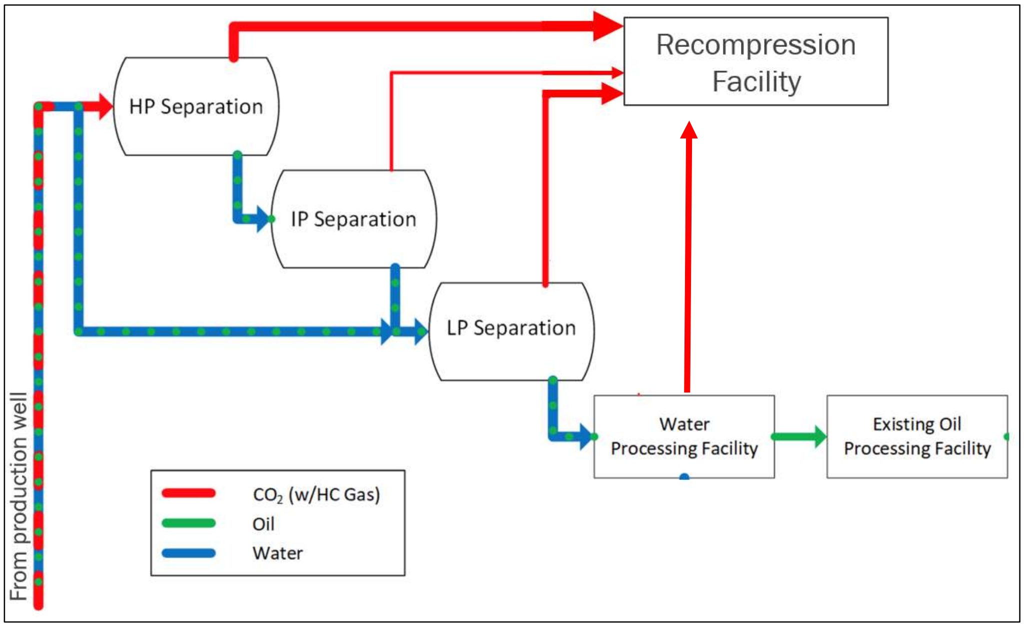

Figure 10: Current 2 phase separation design

Meters for measurement of both the gas and liquid streams will be installed where needed. In addition, the production manifolds will have well testing systems that measure oil, water, and gas rates and compositions of each production well on a rotating basis at least monthly. This measurement setup will allow for accurate monitoring of production to measure performance and optimize operations.

2.3.5 EOR Recompression Facilities (RCF)

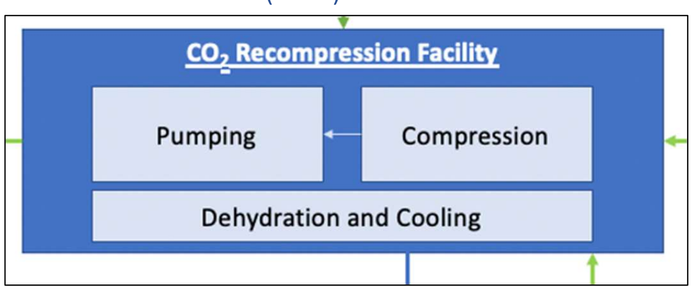

Figure 11: Recompression facility

The recompression facilities will receive gas primarily from the production manifolds but will also be capable of taking direct supply from the CO2 Source. The RCF's will also receive a small amount of gas from the water processing facilities. The CO2-rich gas from the production manifolds will flow through a compression and pumping system as shown in Figure 12. The system will include dehydration and cooling equipment, as needed. When additional CO2 is required for EOR, the CO2-rich production gas will be blended with high purity CO2 from the CO2 source. The compression systems are expected to have a capacity of up to 300 mmscfd to handle all gas from the production manifolds. The pumping systems, which boost pressure of the gas from the production manifolds and the CO2 source, will have a capacity of up to 400 mmscfd. These systems will be built and expanded over time to allow for gradual expansion of capacity consistent with the development plan. Liquids produced as part of the dehydration process will be routed to the water processing facilities.

Under current designs, CO2 dehydration will take place at the recompression facilities to lower the dew point of the injected CO2. This will be done with a ventless system to eliminate a potential emission source. Following dehydration, the dry, medium pressure CO2 is compressed further and then routed to the CO2 injection header that feeds the WAG system. The outlet from the WAG system is piped to the injection wells. A simplified cartoon of the overall processing system is shown below in figure 12.

Based on current production forecasts and facility designs, the project will include two recompression facilities. One built in the 31S and the other in NWS.

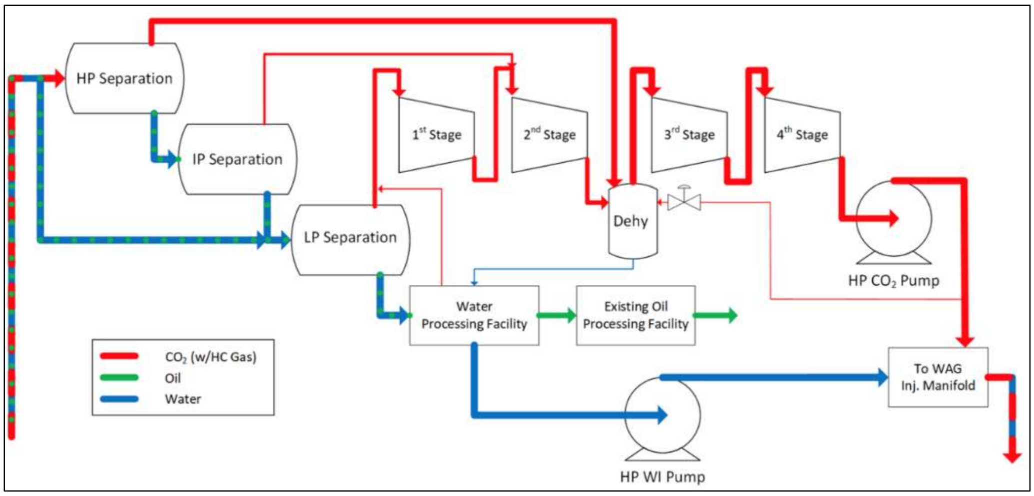

Figure 12: Simplified process flow concept

2.3.6 EOR Potential future Gas Processing Facilities

Although not part of the base plan, NGL recovery may be added to the facilities in the future. The NGL would be extracted from the produced gas from the production manifolds, after partial compression. The liquids produced would be metered and sent to existing NGL storage and sales infrastructure.

2.3.7 EOR Produced Liquids Handling

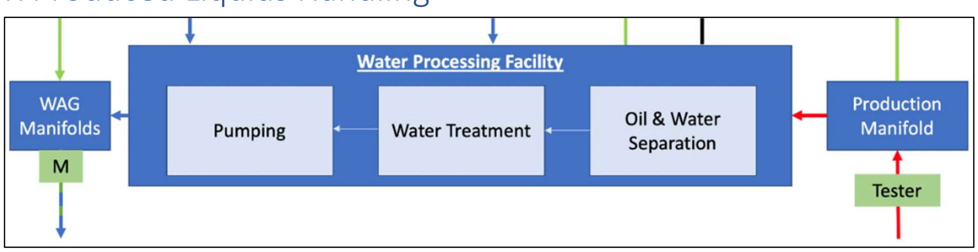

Figure 13: Water processing facility

As described above, all fluids recovered from the production wells will flow to a production manifold. From the production manifold, a mixture of oil and water with CO2 will flow to the water processing facilities. In the water processing facilities, the liquid will flow through a gas separator to remove remaining CO_2-rich hydrocarbon gas. The remaining liquid mixture will pass through an oil/water separation unit which will separate additional trace CO_2-rich hydrocarbon gas, oil, and water. The oil will be pumped to a commercial transfer point where the flow rate will be measured by a custody-transfer meter and where the stream will be sampled periodically to ensure that the oil meets pipeline quality specifications, including dissolved CO_2 concentration.

The separated water will flow to a water-treatment unit where any remaining CO_2-rich hydrocarbon gas is separated. All CO_2-rich gas will be collected and piped to the recompression facilities. An operations meter will track the flow of the CO_2-rich gas entering each Facility. Excluding fugitive and vented emissions, all CO_2 leaving the Facilities will be recycled for reinjection.

2.3.8 EOR Water Treatment and Injection

After the produced water leaves the three-phase separator at the Water Processing Facility, it is sent to the clarifier tank for water treatment. This tank allows solids in the water to drop out. From the clarifier tank, the water will enter the induced gas flotation unit for the removal of suspended matter, such as oil or solids. From the induced gas flotation unit, the water will pass through a filter unit. After the water has left the filter unit, it will enter the water surge tanks for storage before injection. From the water surge tank, the water flows through pumps to the WAG system for injection.

At the water treatment unit, additional water may be added from the make-up supply. An operations meter leading into the unit will track water flow. Water will then flow to the water-injection facility. If there is excess water, the surplus will be sent to existing water-injection or disposal wells, the remainder will be sent to the WAG manifold. Operations flow meters at both outlets from the water-injection facility will track flow. No produced water will be discharged to the surface.

2.3.9 EOR Commercial Transfer of Fluids

Oil will be pumped to an oil-shipment facility before custody is transferred to a commercial pipeline. Hydrocarbon gas and NGL's, if recovery is ultimately installed, will flow to existing facilities for additional processing and subsequent sale through existing pipelines for off-site transfers. Volumes and composition will be determined at custody transfer meters to confirm compliance with sales contracts and for financial accounting purposes.

2.4 Reservoir Modeling

Numerical reservoir simulation is used for many purposes including optimizing reservoir management, forecasting hydrocarbon and water production, predicting the behavior of injected fluids such as CO_2 and assessing CO_2 plume development and confinement.

Reservoir Model for Operational Design and Economic Evaluation

The reservoir modeling workflow begins with the development of a three dimensional representation of the subsurface geology. It leverages all available well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces and faults (if present) into a geocellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a "static model", as it reflects the reservoir at a single moment, most typically at original conditions prior to its development. Schlumberger Petrel, industry-standard geocellular modeling software, for building and maintaining static models was utilized.

The static model becomes "dynamic" in the reservoir simulator with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon phase
- Liquid and gas relative permeability
- Capillary pressure data

Performance Prediction

The reservoir modeling workflow described above is used to predict and optimize potential oil recovery for pattern development. The simulation model is tuned to match actual historical performance data collected during primary and waterflood field production. This provides confidence that the model can forecast oil, water, and CO_2 production, along with CO_2 and water injection.

One objective of the 31S and NWS simulation models is to develop an injection plan that maximizes oil recovery and minimizes the costs of the CO_2 flood. The injection plan includes:

- The injection pattern sizes and geometry
- The cycle length and WAG ratio to inject water or CO_2 in the WAG process, and
- The best rate and pressure for each injection phase

Plume Model for CO_2 Storage Capacity, Containment and Predicted Plume Migration

Full-field plume models confirm reservoir capacity and containment of CO_2 within the 31S and NWS structures. These models were built using a dynamic reservoir simulation application known as the Equation-of-State Compositional Simulator (GEM), developed by Computer Modelling Group Ltd. (CMG). The plume models were used to evaluate the following:

- Quantity of CO_2 stored for geological sequestration and EOR in the NWS and 31S reservoirs.
- Lateral movement of CO_2 to define the MMA and demonstrate vertical confinement by the Reef Ridge shale.

Geomechanical Modeling of Reef Ridge Shale

In addition to the plume models, a simpler GEM-based model was coupled with a finite element geomechanical module, GEOMECH, to model cap rock failure in the Reef Ridge Shale as a function of cap rock mechanical properties and reservoir pressure immediately below the cap rock. This model was used to assess the pressure at which the Reef Ridge Shale would shear through tensile failure.

The collective 31S and NWS plume modeling effort confirms the Monterey Formation's ability to permanently store the planned project CO_2 volumes under the Reef Ridge Shale over the project's life. The results of the plume models are discussed in greater detail below.

3 Delineation of Monitoring Area and Timeframes

3.1 Maximum Monitoring Area

The MMA is defined in §98.440-449 (Subpart RR) 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. Reservoir modeling, incorporating geologic data collected from wells, seismic data, and historic production and injection data as described above was used to predict the size and location of the plume, as well as understand how the plume migrates over time.

The MMA, shown in Figure 15 below in the dashed blue line, is defined by the extent of the CO_2 plume at 100 years post injection for geological sequestration and EOR.

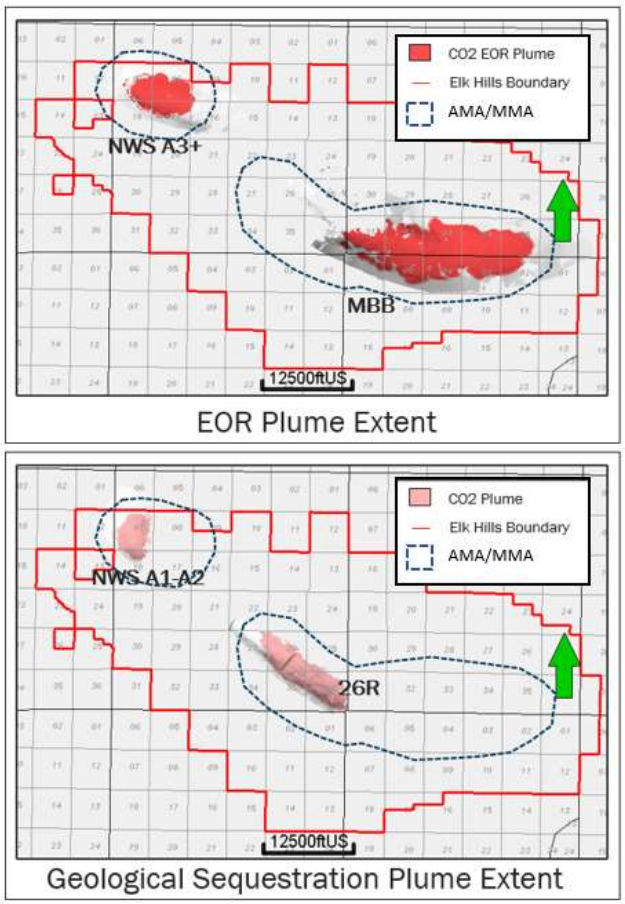

Figure 14: AMA and MMA defined by blue dashed line for geological sequestration and EOR.

3.2 Active Monitoring Area

The Active Monitoring Area (AMA) will be the same boundary as the MMA. The following factors were considered in defining this boundary:

- The injection schedule begins with the best reservoir quality sands of the 31S and NWS structures, and progressively expands into tighter reservoir quality sands. Actual field performance compared to pre-injection estimates and other business conditions (e.g., commodity pricing) will determine the rate of this expansion as well as the reservoir quality limits of the injection targets. Leveraging the MMA boundary for the AMA provides maximum operational flexibility.

- Active operations in both 31S and NWS provides pattern-level resolution monitoring (pressures, production and injection rates and volumes) concurrent with CO_2 injection.
- The absence of through-going faults or fractures confirms the competency of the Reef Ridge to preserve hydrocarbons within the Monterey Formation and to contain the CO_2.

3.3 Monitoring Timeframe

The Specified Period will be shorter than the period of injection and production from Monterey Formation. At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted when a demonstration that current monitoring and model(s) show that the cumulative mass of CO2 reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration within two to three years after injection for the Specified Period ceases based on predictive modeling supported by monitoring data.

4 Evaluation of Potential Pathways for Leakage to the Surface

4.1 Introduction

In the more than 100 years since the EHOF has been developed, the reservoir has been studied and documented extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO_2 to the surface. The following potential pathways are reviewed:

1. Existing Wellbores
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the EHOF
7. Drilling Through the CO_2 Area
8. Diffuse Leakage Through the Seal

4.2 Existing Wellbores

As of November 2020, there are 574 active wells in the 31S and NWS structures – with injectors comprising 19% of the total. In addition, there are 390 wells not in use that penetrate the Monterey Formation, as described in Section 2.3.2.

Leakage through existing wellbores is a possibility at the EHOF. However, that is mitigated by adhering to regulatory requirements for well drilling and testing; implementing best practices developed through its extensive operating experience; monitoring injection/production performance, wellbores, and the surface; and maintaining surface equipment.

As discussed in Section 2.3.3, regulations governing wells in the EHOF require that wells be completed and operated so that fluids are contained in the strata in which they are encountered.

Continual and routine monitoring and maintenance of wellbores and site operations is critical to ensure confinement as follows:

- Injection well pressure is monitored continuously throughout the EHOF using a supervisory control and data acquisition (SCADA) system. Pressure and rate sensors on the injection wells are programmed to alarm and notify operations personnel when values that significantly deviate from set target ranges. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such excursions occur, they are investigated and addressed.

- Experience gained over time to strategically approach well maintenance and workovers and maintain workover crews onsite for this purpose. For example, the well classifications by age and construction method inform planning for monitoring and updating wells. All available information including pattern performance and well characteristics to determine well maintenance schedules.

- For EOR, production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a satellite battery. There is a routine cycle for each satellite battery, with each well being tested approximately once every month. During this cycle, each production well is diverted to the well test equipment for a period of time sufficient to measure and sample produced fluids (8-12 hours). This test allows for allocation of the produced fluids measured at the satellite battery to each production well, assess the composition of produced fluids by location, and assess the performance of each well. Performance data are reviewed on a routine basis to ensure that CO_2 flooding is optimized. If production deviates from the expected/forecasted plan, it is investigated, and any identified issues are addressed.

- A corrosion protection program for CO2 operations will be implemented to mitigate both internal and external corrosion of casing in wells in the EHOF. In line with industry standard operations for CO2-CCS and CO2-EOR, downhole equipment and the interior and exterior of wellbores will be protected using special materials (e.g., fiberglass tubing, corrosion resistant cements, nickel plated packers, corrosion resistant packer fluids), as required, and procedures (e.g., packer placement, use of annular leakage detection devices, cement bond logs, pressure tests). These measures and procedures are typically included in the injection orders filed with CalGEM.

Corrosion protection methods and requirements may be enhanced over time in response to improvements in technology.

- MIT requirements implemented by CalGEM will be followed to periodically inspect wells and surface facilities to ensure that all wells and related surface equipment are in good repair, leak-free, and that all aspects of the site and equipment conform to existing rules and permit conditions. All active injection wells undergo MIT before injection, after any workover or every two years as specified in the UIC approval. Operators are required to use a pressure recorder and pressure gauge for the tests. The operator's field representative must sign the pressure recorder chart and submit it with the MIT form to CalGEM. The casing-tubing annulus must be tested to MASP for a specified duration and with an allowable pressure loss specified in the regulations. CalGEM may also approve Alternative Pressure Monitoring Programs with varying requirements at their discretion.

  If a well fails the MIT, the operator must immediately shut the well in and provide notice to CalGEM. Casing leaks must be successfully repaired within 180-days and re-tested or the well must be plugged and abandoned after submitting a formal notice and obtaining approval from CalGEM.

- Finally, as indicated in Section 5, field inspections are conducted on a routine basis by field personnel. On any given day, there are approximately 40 personnel in the field. Leaking CO_2 is very cold and leads to formation of bright white clouds and ice that are easily spotted. All field personnel will be trained to identify leaking CO_2 and other potential problems in the field and safely remedy the issue. Any CO_2 leakage detected will be documented and reported, quantified, and addressed as described in Section 5.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, CRC and CTV concludes that it is mitigating CO_2 leakage through wellbores by detecting problems as they arise and quantifying any leakage that does occur. Section 4.10 summarizes how CRC and CTV will monitor CO_2 leakage from various pathways and describes the response to various leakage scenarios. In addition, Section 5 describes how CRC and CTV will develop the inputs used in the Subpart RR mass-balance equation (Equation RR-11 and Equation RR-12). Any incidents that result in CO_2 leakage up the wellbore and into the atmosphere will be quantified as described in Section 7.4.

4.3 Faults and Fractures

There are no faults or fractures penetrating the confining layer of the Reef Ridge Shale that provide a potential upward pathway for fluid flow. First, the presence of oil, especially oil with a gas cap, is indicative of a competent natural seal. Oil, and to a greater extent gas, migrates upward over time because both are less dense than the brine found in rock formations. Places where oil and gas remain trapped in the deep subsurface over millions of years, as is the case in the EHOF, prove that faults or fractures do not provide a pathway for upward migration out of the CO_2 flooding interval.

While developing the EHOF, a seismic survey was conducted to characterize the formations and provide information for the reservoir models used for development planning. Initial interpretations of the three-dimensional (3-D) seismic survey were based on a conventional pre-stack time migration volume. In 2019, the 3-D seismic survey was re-processed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 16 displays the location and extent of four faults that helped to form these anticlines beginning in the Middle Miocene, 16 million years ago[2]. They have remained inactive for millions of years since. Offsetting the 31S and NWS structures are the 1R, 2R and 3R high angle reverse faults that are oriented NW-SE. The faults penetrate the lowest portions of the Monterey Formation but do not continue through the injection interval to the Reef Ridge Shale confining layer.

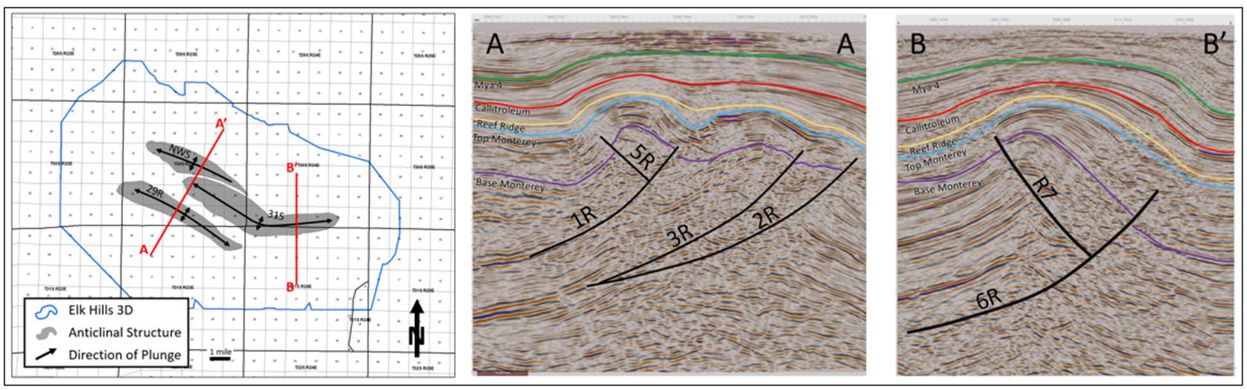

Figure 15: Outline of EHOF 3-D Survey and Seismic Intersections Across 31S and NWS Structures

Lastly, the operating history of the EHOF confirms there are no faults or fractures penetrating the Reef Ridge Shale that allow fluid migration. Water and gas have been successfully injected into the Monterey Formation since 1976, and there is no evidence of new or existing faults or fractures. Over 1.4 billion barrels of water and 1,237 billion standard cubic feet of gas have been injected into the NWS and 31S structures with no reservoir confinement issues. In fact, it is the absence of faults and fractures in the Reef Ridge Shale that makes the Monterey Formation such a strong candidate for water injection operations and enables field operators to maintain effective control over the injection and production processes.

4.4 Natural or Induced Seismicity

Based on published data and over 100 years of operational experience, there is no evidence that natural seismic activity poses a significant risk for loss of CO_2 for the project. This is due, in part, to the thickness, ductility and predominance of clay in the primary confining layer Reef Ridge Shale.

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2 Callaway and Rennie Jr., 1991

No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area. Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west, beyond the Temblor Range) and the White Wolf Fault (25 miles southeast from the EHOF).

Historical seismic events from 1932 to present are available from the Southern California Earthquake Data Center (SCEDC). There have been no earthquakes in the AoR (Figure 27). In addition, there have only been nine earthquakes with a magnitude of 5.0 or greater within a 30-mile radius around the EHOF. The average depth of these earthquakes is 6.3 miles. Through monitoring via surface and borehole seismometer installation, a baseline will be established and the reservoir will be monitored to understand seismicity.

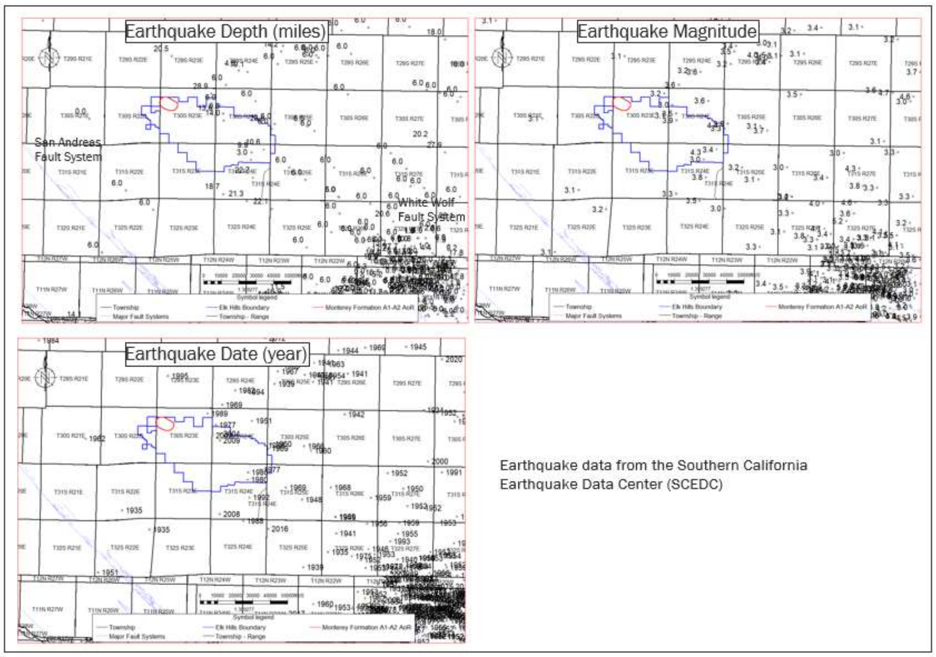

Figure 16: Earthquakes in the San Joaquin Basin. Note, only 9 earthquakes have occurred within a 30-mile radius around the EHOF.

Induced seismicity will be mitigated operationally by the following:

1. Injection pressure will be monitored continuously and will be lower than the failure pressure of the confining Reef Ridge Shale and Monterey Formation.
2. Reservoir pressure will be at or beneath the discovery pressure.
3. Seismometers will be installed to detect seismicity induced by injection operations.

4.5 Previous Operations

All of the existing wells at the EHOF have been permitted through CalGEM under rules that require detailed information about the character of the geologic setting, the construction and operation of the wells, and other information used to assess the suitability of the site. CalGEM maintains a public database that contains the location, construction details and injection/production history of each well.

Operational experience has verified that there are no unknown wells within the EOHF. Additionally, CRC and CTV have sufficiently mitigated the possibility of migration from older wells. Over many years, the EHOF has been continuously checked for the presence of old, unknown wells throughout the EHOF. These practices ensure that identified wells are sufficiently isolated and do not interfere with ongoing operations and reservoir pressure management.

4.6 Pipeline/Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO2. Unplanned leakage from surface facilities will be mitigated to the maximum extent practicable by relying on the use of prevailing design and construction practices and maintaining compliance with applicable regulations. The facilities and pipelines will be constructed of materials and managed using control processes that are standard for CO2 injection projects.

CO2 delivery to the complex will comply with all applicable regulations. Instrumentation will be installed on pipelines and facilities that allow the 24/7 operations staff at the central control facility to monitor the process and potentially spot leaks. Furthermore, frequent, and routine visual inspections of surface facilities by field staff will provide an additional means to detect leaks. Both manual and automatic shutdowns will be installed in the complex to ensure that leaks are addressed in a timely manner. Should leakage be detected from pipeline or surface equipment, the volume of released CO2 will be quantified following the requirements of Subpart W of EPA's GHGRP.

4.7 Lateral Migration Outside EHOF

It is highly improbable that injected CO2 will migrate downdip and laterally outside the EHOF because of the nature of the geologic structure and planned injection approach. As mentioned in Section 2.1.1, "Geology of Elk Hills Field", the Monterey Formation within the NWS and 31S structures form structural highs. Over extended periods, injected CO2 will tend to rise vertically toward the crest. Additionally, the planned injection volumes and active fluid management during injection operations will prevent CO2 from migrating out of the structure. The strategy to minimize the lateral migration risk is to ensure that the CO2 plume will be at or below the initial reservoir pressure at time of discovery.

4.8 Drilling Through the CO_2 Area

It is possible that at some point in the future, drilling through the Reef Ridge confining zone and into the Monterey Formation could occur. The possibility of this activity creating a leakage pathway is extremely low for three reasons: 1) All oil and gas wells drilled in California are regulated by CalGEM and are subject to requirements that fluids be contained in strata in which they are encountered, 2) As sole operators and owners of the EHOF, CRC and CTV control placement and timing of new drilling operations, and 3) There are no oil and gas targets beneath the Monterey Formation.

4.9 Leakage Through the Seal

Diffuse leakage through Reef Ridge confining layer is highly unlikely. The presence of trapped gas and oil over millions of years confirms that the seal has been secure for millions of years. Leaking through the seal is mitigated by ensuring that post injection reservoir pressure will be at or below the initial reservoir pressure at the time of discovery. The injection monitoring program referenced in Section 2.3.1 and detailed in Section 5 assures that no breach of the seal will be created.

Further, if CO_2 were to migrate through the Reef Ridge, it would migrate vertically until it encountered and was trapped by any of the additional shallower interbedded shales of the Etchegoin, San Joaquin and Tulare Formations (more than 5,000' of vertical section; see Figure 4).

4.10 Monitoring, Response and Reporting Plan for CO_2 Loss

As discussed above, the potential sources of leakage include routine issues, as such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment, and unique events such as induced fractures. Table 5 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, standard response, and other applicable regulatory programs requiring similar reporting.

Sections 5.1.5 – 5.1.7 discuss the approaches envisioned for quantifying the volumes of leaked CO2. In the event leakage occurs, CRC and CTV plan to determine the most appropriate methods for quantifying the volume leaked and will report it as required as part of the annual Subpart RR submission.

Any volume of CO2 detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as frequency of inspection. As indicated in Sections 5.1 and 7.4, leaks will be documented, evaluated, and addressed in a timely manner. Records of leakage events will be retained in the electronic environmental documentation and reporting system. Repairs requiring a work order will be documented in the electronic equipment maintenance system and well work historian. If the scope of repair work requires permitting through CalGEM, a subsequent operations summary report will be provided to CalGEM under the conditions of the permit.

Risk	Monitoring Plan	Response Plan	Parallel Reporting (if any)
Loss of well control			
Tubing Leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days	
Casing Leak	Routine field inspection; MIT for injectors; extra attention to high risk wells	Workover crews respond within days	CalGEM
Wellhead Leak	Routine field inspection and continuous SCADA monitoring	Workover crews respond within days	
Loss of bottom-hole pressure control	Blowout during well operations	Maintain well kill procedures; shut-in offset injectors prior to drilling	CalGEM

Loss of seal in abandoned wells	Anomalous pressure or gas composition from productive shallower zones	Re-enter and reseal abandoned wells	CalGEM
Leaks in surface facilities			
Pumps, valves, etc.	Routine field inspection and remote monitoring	Workover crews respond within days	Subpart W
Subsurface leaks			
Leakage along faults	Monitoring of zones above sequestration reservoir	Shut in injectors near faults	
Leakage through induced fractures	Induced seismicity monitoring with seismometers	Comply with rules for keeping pressures below parting pressure	
Leakage due to a seismic event	Induced seismicity monitoring with seismometers	Shut in injectors near seismic event	

Table 5: Response Plan for CO_2 leakage or loss

4.11 Summary

The structure and stratigraphy of the Monterey Formation in the EHOF is ideally suited for the injection and storage of CO_2. The stratigraphy within the CO_2 injection zones is porous, permeable, and very thick, providing ample capacity for long-term CO_2 storage. The overlying Reef Ridge Shale forms an effective seal for Monterey Formation sequestration (see Figure 3). After assessing potential risk of release from the subsurface and steps that have been taken to prevent leaks, the potential threat of significant leakage is extremely low. Risk of release is further reduced by the prudent operational strategy of limiting the pressure of the reservoir post-injection to at or below the initial pressure of the reservoir at time of discovery.

5 Monitoring and Considerations for Calculating Site Specific Variables

5.1 For the Mass Balance Equation

5.1.1 General Monitoring Procedures

Existing operations are centrally monitored and controlled by an extensive and sophisticated system referred to as the Central Control Facility (CCF). The CCF uses a SCADA software system to implement operational control decisions on a real-time basis throughout the EHOF to assure the safety of field operations and compliance with monitoring and reporting requirements in existing permits.

Flow rates, pressures, gas composition and other data will be collected at key points and stored in a centralized data management system. These data are monitored 24 hours a day by qualified technicians who follow response and reporting protocols when the system delivers notifications that data exceed pre-determined statistically acceptable limits. The data can be accessed for immediate analysis.

Figure 6 identifies the meters that will be used to evaluate, monitor, and report on the flood and associated plume migration described earlier in Section 2.3. A similar metering system is already installed throughout the EHOF.

As indicated in Figure 6, a custody-transfer meter will be installed at the CO_2 source and at the points at which custody of oil, liquid natural gas, and hydrocarbon gas is transferred from CRC to another party. The custody-transfer meters will measure flow rate continuously. Fluid composition will be determined on either a continuous basis or by periodic sampling depending on the specific meter; both options are accurate for purposes of commercial transactions. All meter and composition data will be recorded.

Metering protocols follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. These meters will be maintained routinely, operated continuously, and will feed data directly to the CCF. In the oil and gas industry, the accepted level of custody transfer meter accuracy is 0.25% or better and the meters are calibrated every 60-90 days. A third party is frequently used to calibrate these meters and both parties to any transaction have rights to witness meter calibration. These custody meters provide the most accurate way to measure mass flows.

Most process streams are multi-component or multi-phase, with varying CO2 compositions. For these streams, flow rate is the most important control parameter. Operations flow meters are used to determine the volumetric flow rates of these process streams, which allows for the monitoring of trends to identify deviations and determine if any intervention is needed. Flow meters are also used—comparing aggregate data to individual meter data—to provide a cross-check on actual operational performance.

Developing a CO_2 mass balance on multi-phase, multi-component process streams is best accomplished using custody-transfer meters rather than multiple operations meters. As noted above, in-field flow rate monitoring presents a formidable technical and maintenance challenge. Some variance is due simply to differences in factory settings and meter calibration. Additional variance is due to the operating conditions within a field. Meter elevation, changes in temperature (over the course of the day), fluid composition (especially in multi-component or multi-phase streams), or pressure will each affect any in-field meter reading. Many meters have some form of automatic adjustment for some of these factors, while others utilize a conversion factor that is programmed into the meter, and still others need to be adjusted manually in the calculation process. Use of a smaller number of centrally located meters reduces the potential error that is inherent in employing multiple meters in various locations to measure the same volume of flow and gas composition. Unlike in a saline formation, where there are likely to be relatively few injection wells and associated meters, at CO_2 EOR operations in the EHOF there could ultimately be upwards of 200 active injection and up to 350 production wells and a comparable number of meters, each with an acceptable range of error. This is a site-specific factor that is considered in the mass balance calculations described in Section 7.

The following table summarizes the CO2 injection monitoring strategy for both EOR and geologic storage:

	EOR (Class II)	Geologic Sequestration (Class VI)
MIT (Internal and External ME)	Annual	Annual
SAPT	At time of injection, after workover or every five years	At time of injection
Injection Rate and Pressure	Continuous	Continuous
Seismicity	Induced seismicity monitoring via seismometers	Induced seismicity monitoring via seismometers
USDW and reservoirs between USDW and sequestration reservoir	Monitoring wells with pressure, temperature, fluid composition and periodic cased-hole logs.	Monitoring wells with pressure, temperature, fluid composition and periodic cased-hole logs.
Stream Analysis	Continuous	Continuous
Corrosion Monitoring (coupons, casing integrity)	Well materials, pipelines, and other surface equipment.	Well materials, pipelines, and other surface equipment.
Sequestration reservoir monitoring	Produced fluids rates and composition from EOR production wells.	Dedicated wells monitoring sequestration reservoir with pressure, temperature fluid composition and periodic cased hole logs.
USDW and Above Zone Monitoring		Dedicated wells monitoring the USDW and zone between the USDW and sequestration reservoir. Measurements will include pressure, temperature, and fluid sampling.

5.1.2 CO_2 Received

A custody transfer meter will be used at the CO_2 source(s) to continuously measure the volume and composition of CO_2 received. The metering protocols will follow the prevailing industry standard(s) for custody transfer (as promulgated by the API and the AGA).

5.1.3 CO_2 Injected into the Subsurface

Injected CO_2 associated with geological sequestration and EOR will be calculated using the flow meter volumes at the operations/composition meter at the outlet of the RCFs and the custody transfer meter at the CO_2 off-take points.

5.1.4 CO_2 Produced, Entrained in Products and Recycled

The following measurements are used for the mass balance equations in Section 7:

CO_2 produced is calculated using the volumetric flow meters at the inlet to an RCF.

CO_2 produced is the sum of CO_2 measured at inlet to the RCF and CO_2 measured as being entrained in oil and water. The concentration of CO_2 in produced oil is measured at the custody transfer meter.

Recycled CO_2 is calculated using the volumetric flow meter and compositions at the outlet of the RCFs, which is an operations meter.

5.1.5 CO_2 Emitted by Surface Leakage

As discussed in Section 5.1.6 and 5.1.7 below, 40 CFR Part 98 Subpart W is used to estimate surface leaks from equipment at the EHOF. Subpart W uses a factor-driven approach to estimate equipment leakage. In addition an event-driven process will be used to assess, address, track, and if applicable quantify potential CO_2 leakage to the surface. Reporting will reconcile the Subpart W report and results from any event-driven quantification to assure that surface leaks are not double counted.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet two objectives in accordance with the leakage risk assessment in Section 4: 1) to detect problems before CO_2 leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the volumes of CO_2 leaked to the surface.

Monitoring for Potential Leakage from the Injection/Production Zone:

1. Monitoring Wells

Monitoring wells that will measure pressure, temperature and fluid composition will be dedicated to geologic sequestration. These dedicated wells will monitor the sequestration reservoir, zones above the sequestration reservoir and the USDW. Baseline analysis will be established for each of these wells. Any deviation from the baseline analysis will be assessed for potential indications of leakage.

2. Production Wells

A forecast of the rate and composition of produced fluids from EOR production will be established. Each producer is assigned to one satellite battery and is isolated once during each monthly cycle for a well production test. This data is reviewed on a periodic basis to confirm that production is at the level forecasted. If there is a significant deviation from the forecast, well management personnel investigate. As in the case of the injection pattern monitoring, if the investigation leads to a work order in the work order management system, this record will provide the basis for tracking the outcome of the investigation and if a leak has occurred, recording the quantity leaked to the surface. Leakage would be quantified with an appropriate method such as material balance equations that are based on known injected quantities and monitored pressures in the injection zone.

3. Injection

Injection well pressure, temperature and injection rate will be monitored continuously. If injection pressure or rate measurements are beyond the specified set points determined for each injector, a data flag is triggered, and field personnel will investigate and resolve the problem. These excursions will be reviewed by well-management personnel to determine if CO_2 leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or some other minor action is required), and there is no threat of CO_2 leakage. In the case of issues that are not readily resolved, more detailed investigation and response would be initiated, and internal support staff would provide additional assistance and evaluation. Such issues would lead to the development of a work order in the work order management system. This record will enable the company to track progress on investigating potential leaks and, if a leak has occurred, to quantify its magnitude. To quantify leakage to the surface, an estimate of the relevant parameters (e.g., the rate, concentration, and duration of leakage) will be made to quantify the leak volume. Depending on specific circumstances, these determinations may rely on engineering estimates.

Monitoring of Wellbores

Because leaking CO_2 at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a two-part visual inspection process will be employed in the general area of the EHOF to detect unexpected releases from wellbores. First, field personnel visit the surface facilities on a routine basis. Inspections may include tank volumes, equipment status and reliability, lube oil levels, pressures and flow rates in the facility, and valve leaks. Field personnel inspections will also check that injectors are on the proper WAG schedule and observe the facility for visible CO_2 or fluid line leaks.

Finally, data collected by the personal gas monitors, which are always worn by all field personnel are a last method to detect leakage from wellbores. If an alarm is triggered, the first response is to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. If the incident results in a work order, this will serve as the basis for tracking the event for GHG reporting.

Other Potential Leakage at the Surface

Routine visual inspections at surface are used to detect significant loss of CO_2 to the surface. Field personnel visit manned surface facilities daily to conduct a visual inspection. Inspections may include review of tank levels, equipment status, lube oil levels, pressures and flow rates in the facility, valve leaks, ensuring that injectors are on the proper WAG schedule, and conducting a general observation of the facility for visible CO_2 or fluid line leaks. If problems are detected, field personnel would investigate and, if maintenance is required, generate a work order in the maintenance system which is tracked through completion. In addition to these visual inspections, CRC and CTV will use the results of the personal gas monitors as a supplement for smaller leaks that may escape visual detection.

If CO_2 leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, a work order will be generated in the work order management system. The work order will describe the appropriate corrective action and be used to track completion of the maintenance action. The work order will also serve as the basis for tracking the event for GHG reporting and quantifying any CO_2 emissions.

5.1.6 CO_2 Emitted from Equipment Leaks and Vented Emissions of CO_2 from Surface Equipment Located Between the Injection Flow Meter and the Injection Wellhead

Monitoring efforts will evaluate and estimate leaks from equipment, the CO_2 content of produced oil, and vented CO_2, as required under 40 CFR Part 98 Subpart W.

5.1.7 Mass of CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2 From Surface Equipment Located Between the Production Flow Meter and the Production Wellhead

Monitoring efforts will evaluate and estimate leaks from equipment, the CO_2 content of produced oil, and vented CO_2, as required under 40 CFR Part 98 Subpart W.

5.2To Demonstrate that Injected CO_2 is not Expected to Migrate to the Surface

At the end of the Specified Period, CRC and CTV intends to cease injecting CO_2 for the subsidiary purpose of establishing the long-term storage of CO_2 in the EHOF. After the end of the Specified Period, CRC and CTV anticipate that it will submit a request to discontinue monitoring and reporting. The request will demonstrate that the amount of CO_2 reported under 40 CFR §98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage. At that time, CRC and CTV will be able to support the request with years of data collected during the Specified Period as well as two to three (or more, if needed) years of data collected after the end of the Specified Period. This demonstration will provide the information necessary for the EPA Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

i. Data comparing actual performance to predicted performance (injection, production) over the monitoring period

ii. An assessment of the CO_2 leakage detected, including discussion of the estimated amount of CO_2 leaked and the distribution of emissions by leakage pathway

iii. A demonstration that future operations will not release the volume of stored CO_2 to the surface

iv. A demonstration that there has been no significant leakage of CO_2 and,

v. An evaluation of reservoir pressure in the EHOF that demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

6 Determination of Baselines

Automatic data systems will be used to identify and investigate deviations from expected performance that could indicate CO_2 leakage. These data systems are used primarily for operational control and monitoring and as such are set to capture more information than is necessary for reporting in the Annual Subpart RR Report. Necessary system guidelines will be developed to capture the information that is relevant to identify CO_2 leakage. The following describes the approach to collecting this information.

Visual Inspections

As field personnel conduct routine inspections, work orders are generated in the electronic system for maintenance activities that cannot be immediately addressed. Methods to capture work orders that involve activities that could potentially involve CO_2 leakage will be developed, if not currently in place. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation. (The responsible party will be provided in the monitoring plan, as required under Subpart A, 98.3(g).) The Annual Subpart RR Report will include an estimate of the amount of CO_2 leaked. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

Personal Gas Monitors

Gas monitors are worn by all field personnel. Any monitor alarm triggers an immediate response to ensure personnel are not at risk and to verify the monitor is working properly. If a fugitive leak is discovered, it would be quantified, and mitigating actions determined accordingly. The person responsible for MRV documentation will receive notice of all incidents where gas is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO_2 emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

Injection Rates, Pressures and Volumes

Target injection rates and pressures will be developed for each injector, based on the results of ongoing pattern modeling, and permitted limits. The injection targets are programmed into the WAG satellite controllers. High and low set points are also programmed into the controllers, and flags whenever statistically significant deviations from the targeted ranges are identified. The set points are designed to be conservative. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO_2 leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions and related work orders that could potentially involve CO_2 leakage. The Annual Subpart RR Report will provide an estimate of CO_2 emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

Production Volumes and Compositions

A general forecast will be developed for production volumes and composition which is used to periodically evaluate performance and refine current and projected injection plans and the forecast. This information is used to make operational decisions but is not recorded in an automated data system. Sometimes this surveillance review may result in the generation of a work order in the maintenance system. The MRV plan implementation lead will review such work orders and identify those that could result in CO_2 leakage. Should such events occur, leakage volumes would be calculated following the approaches described in Sections 4 and 5. Impact to Subpart RR reporting will be addressed, if deemed necessary.

7 Determination of Sequestration Volumes Using Mass Balance Equations

To account for site conditions and complexity of a large, active CO2 injection operations, the operators propose to modify the locations for obtaining volume data for the equations in Subpart RR §98.443 as indicated below.

The modification addresses the propagation of error that would result if volume data from meters at each injection and production well were utilized. This issue arises because while each meter has a small but acceptable margin of error, this error would become significant if data were taken from all the meters within the EHOF. As such, CRC and CTV proposes to use the data from custody and operations meters on the main system pipelines to determine injection and production volumes used in the mass balance.

The following sections describe how each element of the mass-balance equation (Equation RR-11) will be calculated.

7.1Mass of CO_2 Received

CRC and CTV will use equation RR-2 as indicated in Subpart RR §98.443 to calculate the mass of CO_2 received from each custody transfer meter immediately downstream of the source(s). The volumetric flow at standard conditions will be multiplied by the CO_2 concentration and the density of CO_2 at standard conditions to determine the mass.

$$\mathrm{CO}_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{\mathrm{CO}_{2,p,r}} \text{ (Eq. RR-2)}$$

Where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons)
$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters)
$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into a site well in quarter p (standard cubic meters)
D = density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682
$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (volume percent CO_2, expressed as a decimal fraction).
p = Quarter of the year
r = Receiving flow meters

Given CRC and CTV's method of receiving CO_2 and requirements of Subpart RR §98.444(a):

- All delivery to EHOF is used, so quarterly flow redelivered, $S_{r,p}$, is zero ("0") and will not be included in the equation.
- Quarterly CO_2 concentration will be taken from the gas measurement database

CRC and CTV will sum to total Mass of CO_2 Received using equation RR-3 in 98.443:

$$\mathrm{CO}_2 = \sum_{r=1}^{R} \mathrm{CO}_{2T,r} \text{ (Eq. RR-3)}$$

Where:

CO_2 = Total net annual mass of CO_2 received (metric tons)
$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR-2 for flow meter r
r = Receiving flow meter

7.2 Mass of CO_2 Injected into the Subsurface

The equation for calculating the Mass of CO_2 injected into the subsurface at EHOF is equal to the sum of the Mass of CO_2 Received as calculated in RR-3 of 98.443 (as described in Section 7.1) and the Mass of CO_2 Recycled as calculated using measurements taken from the flow meter located at the output of the RCF.

The mass of CO_2 recycled will be determined using equation RR-5 as follows:

$$\mathrm{CO}_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \text{(Eq. RR-5)}$$

Where:

$CO_{2,u}$ = Annual CO_2 mass recycled (metric tons) as measured by flow meter u
$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter)
D = density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682
$CO_{2,p,u}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (volume percent CO_2, expressed as a decimal fraction)
p = Quarter of the year
u = Flow meter

The total Mass of CO_2 injected will be the sum of the Mass of CO_2 received (RR-3) and Mass of CO_2 recycled (modified RR-5).

$$CO_{2I} = CO_2 + CO_{2,u}$$

7.3 Mass of CO_2 Produced

The Mass of CO_2 Produced at EHOF will be calculated using the measurements from the flow meters at the inlet to the RCF and the custody transfer meter for oil sales rather than the metered data from each production well. Again, using the data at each production well would give an inaccurate estimate of total injection due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

Equation RR-8 in 98.443 will be used to calculate the mass of CO_2 produced from all production wells as follows:

$$\mathrm{CO}_{2,w} = \sum_{p=1}^{4} Q_{p,w} * D * C_{CO_{2,p,w}} \text{(Eq. RR-8)}$$

Where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons)
$Q_{p,w}$ = Volumetric gas flow rate measurement for meter w in quarter p at standard conditions (standard cubic meters)
D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682
$C_{CO2,p,w}$ = CO_2 concentration measurement in flow for meter w in quarter p (volume percent CO_2, expressed as a decimal fraction)

p = Quarter of the year
w = inlet meter to RCF

Equation RR-9 in 98.443 will be used to aggregate the mass of CO_2 produced net of the mass of CO_2 entrained in oil leaving the EHOF prior to treatment of the remaining gas fraction in the RCF as follows:

$$CO_{2P} = (1+X) * \sum_{w=1}^{W} CO_{2,w} \qquad \text{(Eq. RR-9)}$$

Where:

CO_{2P} = total annual CO_2 mass produced (metric tons) through all meters in the reporting year
$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through meter w in the reporting year
X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction).

7.4 Mass of CO_2 Emitted by Surface Leakage

CRC and CTV will calculate and report the total annual Mass of CO_2 emitted by surface leakage using an approach that is tailored to specific leakage events and relies on 40 CFR Part 98 Subpart W reports of equipment leakage. As described in Sections 4 and 5.1.5-5.1.7, the operators are prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO_2 leaked to the surface will depend on several site-specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

The process for quantifying leakage will entail using best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are discussed in Section 5.1.5-5.1.7. In the event leakage to the surface occurs the quantify and leakage amounts will be reported, and records retained that describe the methods used to estimate or measure the volume leaked as reported in the Annual Subpart RR Report. Further, the Subpart W report and results from any event-driven quantification will be made to assure that surface leaks are not double counted.

Equation RR-10 in 48.433 will be used to calculate and report the Mass of CO_2 emitted by Surface Leakage:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \text{ (Eq. RR-10)}$$

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

7.5 Mass of CO_2 Sequestered in Subsurface Geologic Formations

EOR

Equation RR-11 in 98.443 will be used to calculate the Mass of CO_2 Sequestered in Subsurface Geologic Formations for EOR in the Reporting Year as follows:

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2\,\mathrm{FI}} - CO_{2\,\mathrm{FP}} \text{ (Eq. RR-11)}$$

Where:

CO_2 = Total net annual mass of CO2 sequestered (metric tons)
CO_{2I} = Total annual CO2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year
CO_{2P} = total annual CO_2 mass produced (metric tons) through all meters in the reporting year
CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) 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 this part
CO_{2FP} = Total annual mass emitted (metric tons) 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, for which a calculation procedure is provided in subpart W of this part

Geological Storage

Equation RR-12 in 98.443 will be used to calculate the Mass of CO_2 Sequestered in Subsurface Geologic Formations for geological storage in the Reporting Year as follows for CO_2 not involved with EOR:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2\,\mathrm{FI}} \text{ (Eq. RR-12)}$$

Where:

CO_2 = Total net annual mass of CO2 sequestered (metric tons)
CO_{2I} = Total annual CO2 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 by surface leakage (metric tons) 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 this part

Figure 5 illustrates that CO2 supplied for geological storage will be metered between the CO2 source and the injection meter.

7.6 Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formations

A sum of the total annual volumes obtained using RR-11 in 98.443 to calculate the Cumulative Mass of CO_2 Sequestered in Subsurface Geologic Formations.

8 MRV Plan Implementation Schedule

It is anticipated that this MRV plan will be implemented as early as Q1-2025, pending appropriate permit approvals and an available CO_2 source, or within 90 days of EPA approval - whichever occurs later. Other GHG reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. As described in Section 3.3 above, it is anticipated that that the MRV program will be in effect during the Specified Period, during which time the project will ensure long-term containment of a measurable quantity of CO_2 in subsurface geologic formations at the EHOF and that the project will be operated in a manner not expected to result in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be made and submission with a request to discontinue reporting under this MRV plan. See 40 C.F.R. § 98.441(b)(2)(ii).

9 Quality Assurance Program

9.1 Monitoring QA/QC

As indicated in Section 7, the requirements of §98.444 (a) – (d) in the discussion of mass balance equations have been incorporated. These include the following provisions.

CO_2 Received and Injected

- The quarterly flow rate of CO_2 received is measured at the receiving custody transfer meters
- The quarterly CO_2 flow rate for recycled CO_2 is measured at the flow meter located at the RCF outlet.

CO_2 Produced

- The point of measurement for the quantity of CO_2 produced from oil or other fluid production wells is a flow meter directly downstream of each separator that sends a stream of gas into a recycle or end use system.
- The produced gas stream is sampled at least once per quarter immediately downstream of the flow meter used to measure flow rate of that gas stream and measure the CO_2 concentration of the sample.
- The quarterly flow rate of the produced gas is measured at the flow meters located at the RCF inlet.

CO_2 emissions from equipment leaks and vented emissions of CO_2

These volumes are measured in conformance with the monitoring and QA/QC requirements specified in subpart W of 40 CFR Part 98.

Flow meter provisions

The flow meters used to generate data for the mass balance equations in Section 7 are:

- Operated continuously except as necessary for maintenance and calibration
- Operated using the calibration and accuracy requirements in 40 CFR §98.3(i).
- Operated in conformance with American Petroleum Institute (API) standards.
- National Institute of Standards and Technology (NIST) traceable.

Concentration of CO_2

As indicated in Appendix 1, CO_2 density is measured using an appropriate standard method. Further, all measured volumes of CO_2 have been converted to standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere, including those used in Equations RR-2, RR-5, and RR-8 in Section 7.

9.2 Missing Data Procedures

In the event data needed for the mass balance equations cannot be collected, procedures for estimating missing data in §98.445 will be used as follows:

- A quarterly flow rate of CO_2 received that is missing would be estimated using a representative flow rate value from the nearest previous time period.
- A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.
- For any 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 specified in subpart W of 40 CFR Part 98 would be followed.
- The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

9.3 MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in §98.448(d).

10 Records Retention

The record retention requirements specified by §98.3(g) will be followed. In addition, it will follow the requirements in Subpart RR §98.447 by maintaining the following records for at least three years:

- Quarterly records of CO_2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of produced CO_2, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO_2 including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- 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.

These data will be collected as generated and aggregated as required for reporting purposes.

11 Appendices

11.1 Conversion Factors

CO_2 volumes will be reported at standard conditions of temperature and pressure as defined by CARB: 60° F and 14.7 psia[3].

To convert these volumes into metric tonnes, a density is calculated using the Span and Wagner equation of state as recommended by the EPA and using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST), available at http://webbook.nist.gov/chemistry/fluid/.

The conversion factor 5.29×10^{-2} MT/Mcf has been used throughout to convert volumes to metric tons.

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3 See § 95102. Definitions

11.2 Acronyms

AGA – American Gas Association
AoR – Area of Review
API – American Petroleum Institute
ASP – Alkaline Surfactant Polymer
bbo – Billion barrels of oil
CalGEM – California Geologic Energy Management Division
CAPUC – California Public Utilities Commission
CARB – California Air Resources Board
CCF – Central Control Facility
CCS – Carbon Capture and Storage
CDMG – California Division of Mines and Geology
CEC – California Energy Commission
CH_4 – Methane
CO_2 – Carbon Dioxide
CRP – CO_2 Removal Plant
CTB – Central Tank Battery
EHOF – Elk Hills Oil Field
EHPP – Elk Hills Power Plant
EHU – Elk Hills Unit
EOR – Enhanced Oil Recovery
GEM – Geochemical Equation Compositional Model
GHG – Greenhouse Gas
GPA – Gas Processors Association
HC – Hydrocarbon
LCFS – Low Carbon Fuel Standard
LSE – Load Serving Entity
MBB – Main Body B
mmscfd – Million standard cubic feet per day
MRV – Monitoring, Reporting, and Verification
NGL – Natural Gas Liquid
NWS – Northwest Stevens
OOIP – Original Oil in Place
RCF – Reinjection Compression Facility
SCADA – Supervisory Control and Data Acquisition
SCEDC – Southern California Earthquake Data Center
SOZ – Shallow Oil Zone
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USEPA – U.S. Environmental Protection Agency
USDW – Underground Source of Drinking Water
WAG – Water Alternating with Gas

11.3 References

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11.4 Glossary of Terms

This glossary describes some of the technical terms as they are used in this MRV plan. For additional glossaries please see the U.S. EPA Glossary of UIC Terms (http://water.epa.gov/type/groundwater/uic/glossary.cfm) and the Schlumberger Oilfield Glossary (http://www.glossary.oilfield.slb.com/).

Anticline – an arch-shaped fold in the rock layers in a geologic formation in which the layers are upwardly convex, forming something like a dome or bell shape. Anticlines form excellent hydrocarbon traps, particularly in folds that have rocks with high injectivity in their core and high impermeability in the outer layers of the fold.

Contain/Containment – having the effect of keeping fluids located within in a specified portion of a geologic formation.

Dip – the angle between of the rock layer relative to the horizontal plane. Buoyant fluids will tend to move up the dip, or up dip, and heavy fluids will tend to move down the dip, or down dip. Moving higher up structure is moving "updip." Moving lower is "downdip." Perpendicular to dip is "strike." Moving perpendicular along a constant depth is moving along strike.

Downdip – see "dip."

Enhanced oil recovery (EOR) – a method of enhancing the recovery of the original oil in place through a combination of restoring or increasing pressure in an oil field and/or altering the chemical properties of that oil. Its purpose is to improve oil displacement or fluid flow in the reservoir. There are several types of EOR in use today including chemical flooding (ASP), immiscible and miscible displacement (CO_2), and thermal recovery (steamflood). The optimal application of each type depends on reservoir temperature, pressure, depth, net pay, permeability, residual oil and water saturations, porosity, and fluid properties such as oil API gravity and viscosity.

Flooding pattern – also known as an injection pattern, it is the geometric arrangement of production and injection wells to sweep oil efficiently and effectively from a reservoir.

Formation – a body of rock that is sufficiently distinctive and continuous that it can be mapped.

Injectivity – the ability of an injection well to receive injected fluid (both rate and pressure) without fracturing the formation in which the well is completed. Injectivity is a function of the porosity and permeability of the rock formation and the reservoir pressure in which the injection well is completed.

Infill Drilling – the drilling of additional wells within existing patterns. These additional wells decrease average well spacing. This practice both accelerates expected recovery and increases estimated ultimate recovery in heterogeneous reservoirs by improving the continuity between injectors and producers. As well spacing is decreased, the shifting flow paths lead to increased sweep to areas where greater hydrocarbon saturations remain.

Permeability – the measure of a rock's ability to transmit fluids. Rocks that transmit fluids readily, such as sandstones, are described as permeable and tend to have many large, well-connected pores. Impermeable formations, such as shales and siltstones, tend to be finer grained or of a mixed grain size, with smaller, fewer, or less interconnected pores.

Phase – a region of space throughout which all physical properties of a material are uniform. Fluids that don't mix segregate themselves into phases. Oil, for example, does not mix with water and forms a separate phase.

Pore Space – see porosity.

Porosity – the fraction of a rock that is not occupied by solid grains or minerals. All rocks have spaces between rock crystals or grains that is available to be filled with a fluid, such as water, oil, or gas. This space is called "pore space."

Primary recovery – the first stage of hydrocarbon production, in which natural reservoir energy, such as gas drive, water drive or gravity drainage, displaces hydrocarbons from the reservoir, into the wellbore and up to surface. Initially, the reservoir pressure is higher than the bottomhole pressure inside the wellbore. This high natural differential pressure drives hydrocarbons toward the well and up to surface. However, as the reservoir pressure declines because of production, so does the differential pressure. To reduce the bottomhole pressure or increase the differential pressure to increase hydrocarbon production, it is necessary to implement an artificial lift system, such as a rod pump, an electrical submersible pump, or a gas-lift installation. Production using artificial lift is considered primary recovery. The primary recovery stage reaches its limit either when the reservoir pressure is so low that the production rates are not economic, or when the proportions of gas or water in the production stream are too high. During primary recovery, only a small percentage of the initial hydrocarbons in place are produced, typically 10%-12% for oil reservoirs. Primary recovery is also called primary production.

Saturation – the fraction of pore space occupied by a given fluid. Oil saturation, for example, is the fraction of pore space occupied by oil.

Seal – a geologic layer (or multiple layers) of impermeable rock that serve as a barrier to prevent fluids from moving upwards to the surface.

Secondary recovery – the second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are immiscible gas injection and waterflooding.

Sedimentary Rocks – rocks formed at the Earth's surface through deposition of sediments derived from weathered rocks, biogenic activity, or precipitation from solution. There are three main types of rocks – igneous, metamorphic, and sedimentary.

Stratigraphic section – a sequence of layers of rocks in the order they were deposited.

Strike – See "dip."

Updip – See "dip."

11.5 Well List

The following table presents the well name, number and well type for existing wells in the project as of February 2022. The table is subject to change over time as new wells are drilled, existing wells change status, or existing wells are repurposed.

Status (February 2022)

Active: refers to active wells

Inactive: refers to wells that are temporarily shut-in.

Well Type (February 2022)

PROD_OIL : refers to a Class II EOR well producing oil

INJ_H20: refers to a Class II EOR injector

CO2 Injector : Refers to a CO2 injector for Class VI

Monitoring Well : Refers to a monitoring well associated with Class VI injection

26R Reservoir Class VI Wells

Well Name	API	Well Type
373-35R	040296802800	CO2 Injector
345CI-36R	New well	CO2 Injector
353XCI-35R	New well	CO2 Injector
363CI-27R	New well	CO2 Injector
355X-26R	040303395700	Monitoring Well - Etch
376-36R	040295585300	Monitoring Well-Plume
328-25R	040295904300	Monitoring Well-Plume
341-27R	040295037600	Monitoring Well-Plume
USDW Monitoring Well	New well	Monitoring Well-USDW

A1-A2 Reservoir Class VI Wells

Well Name	API	Well Type
355-7R	040294806700	CO2 Injector
357-7R	040296215000	CO2 Injector
335X-7R	040305359200	Monitoring Well - Plume

327-7R-RD1	040301522501	Monitoring Well - Etch
353A-7R	040304641200	Monitoring Well - Plume
USDW Monitoring Well	New Well	Monitoring Well - USDW
345-7R	040296478900	Monitoring Well Fluid sampling - A3-A11
388X-7R	040300743400	Monitoring Well Fluid sampling - A3-A11
341-17R	040300280100	Monitoring Well Fluid sampling - A3-A11

31S MBB EOR Well List:

Well Name	API	Status	Type
12-312D-3G	04029290070001	ACTIVE	PROD_OIL
24-324D-5G-RD1	04029516380100	INACTIVE	PROD_OIL
25-325D-5G	04029290820002	INACTIVE	INJ_H2O
289-344D-35S-RD1	04029526830100	ACTIVE	PROD_OIL
3-655-34S	04030388190001	ACTIVE	PROD_OIL
311-2G	04029587200000	ACTIVE	PROD_OIL
311-3G	04029526930000	INACTIVE	PROD_OIL
311-4G	04029543100000	ACTIVE	PROD_OIL
311A-5G	04030238440000	ACTIVE	PROD_OIL
311H-5G-RD2	04029851550200	INACTIVE	PROD_OIL
311X-2G	04030183280000	INACTIVE	PROD_OIL
311X-5G	04030301810000	ACTIVE	PROD_OIL
311XH-4G	04030289400000	ACTIVE	PROD_OIL
312-2G	04029279800001	INACTIVE	INJ_H2O
312-4G	04030023110001	INACTIVE	PROD_OIL
312X-4G	04030171470000	INACTIVE	INJ_H2O
313-2G	04029579420000	INACTIVE	INJ_H2O
313-34S	04029583290000	ACTIVE	PROD_OIL
313-35S-RD1	04029559450100	ACTIVE	INJ_H2O
313-3G	04029542980002	ACTIVE	PROD_OIL
313-5G	04029536800000	ACTIVE	INJ_H2O
313AH-5G	04030152360000	ACTIVE	PROD_OIL
313H-4G-RD2	04029522780200	ACTIVE	PROD_OIL
314-33S	04029650230000	ACTIVE	INJ_H2O
314-34S	04029677830000	ACTIVE	PROD_OIL
314-35S	04030007390000	ACTIVE	PROD_OIL
314-3G	04029290180001	ACTIVE	PROD_OIL
314-5G	04029653810000	ACTIVE	PROD_OIL
314X-5G	04029661080000	INACTIVE	INJ_H2O
315-33S	04029532200000	ACTIVE	PROD_OIL
315-34S	04029555920000	INACTIVE	INJ_H2O

315-35S-RD1	04029811230101	ACTIVE	PROD_OIL
315-3G	04029647130001	INACTIVE	INJ_H2O
315-4G	04029556160000	ACTIVE	PROD_OIL
315A-32S	04030482320000	ACTIVE	PROD_OIL
315A-34S	04029673150002	ACTIVE	PROD_OIL
315H-33S	04030128770000	ACTIVE	PROD_OIL
315X-32S	04030256610000	ACTIVE	INJ_H2O
315X-33S-RD1	04030209150100	ACTIVE	PROD_OIL
315X-35S	04030189740000	ACTIVE	PROD_OIL
315XH-4G	04030160350000	INACTIVE	PROD_OIL
316-31S	04029274900000	INACTIVE	PROD_OIL
316-32S	04029275430001	ACTIVE	PROD_OIL
316-33S	04030277760000	ACTIVE	PROD_OIL
316-35S	04029277700000	INACTIVE	PROD_OIL
316A-32S-RD2	04030034440201	ACTIVE	INJ_H2O
316A-35S	04030203610000	ACTIVE	INJ_H2O
316H-31S	04030282740000	ACTIVE	PROD_OIL
316X-31S	04030353780000	ACTIVE	INJ_H2O
316X-32S	04030246610000	ACTIVE	PROD_OIL
316X-34S	04030171490000	INACTIVE	INJ_H2O
316X-35S	04030183850000	INACTIVE	PROD_OIL
316X-36S	04029615330001	INACTIVE	PROD_OIL
317-31S	04029557410001	ACTIVE	PROD_OIL
317-33S	04029535050000	INACTIVE	PROD_OIL
317-34S	04029529830000	ACTIVE	PROD_OIL
317-35S-RD1	04029815310100	INACTIVE	INJ_H2O
317-36S	04030670660000	ACTIVE	PROD_OIL
317A-32S	04030482330000	ACTIVE	PROD_OIL
317A-35S	04030203730000	ACTIVE	INJ_H2O
317X-33S	04030668760000	ACTIVE	PROD_OIL
317X-35S	04030183860000	INACTIVE	PROD_OIL
318-32S	04029628030004	INACTIVE	PROD_OIL
318-34S	04030034450001	ACTIVE	INJ_H2O
318-35S-RD1	04029277710102	INACTIVE	INJ_H2O
318A-32S	04030255520000	INACTIVE	PROD_OIL
318A-35S	04030207770000	INACTIVE	PROD_OIL
318X-32S	04030667360000	ACTIVE	PROD_OIL
318X-33S	04030291360000	ACTIVE	PROD_OIL
318X-35S	04030207780000	INACTIVE	PROD_OIL
321-2G	04029798580001	INACTIVE	PROD_OIL
321-5G	04029291080000	ACTIVE	PROD_OIL

321H-2G	04030255860000	ACTIVE	PROD_OIL
321H-3G-RD1	04029798930100	INACTIVE	PROD_OIL
321X-3G	04030292520000	ACTIVE	PROD_OIL
322-2G	04029279810001	INACTIVE	PROD_OIL
322-34S	04029602480000	INACTIVE	INJ_H2O
322-35S	04029575050000	INACTIVE	INJ_H2O
322A-5G	04030254630000	ACTIVE	PROD_OIL
322H-3G-RD2	04029290190200	ACTIVE	PROD_OIL
322H-4G-RD3	04029290650300	ACTIVE	PROD_OIL
322H-5G-RD2	04029291090200	ACTIVE	PROD_OIL
322XH-5G	04030193480000	ACTIVE	PROD_OIL
323-34S	04029679450000	ACTIVE	PROD_OIL
323-35S	04030210810000	ACTIVE	PROD_OIL
323-4G	04029800610000	ACTIVE	PROD_OIL
323H-32S	04030202870000	ACTIVE	PROD_OIL
323XH-4G	04030234190000	ACTIVE	PROD_OIL
324-2G	04029605910000	ACTIVE	INJ_H2O
324-32S	04029555800000	ACTIVE	PROD_OIL
324-33S	04029592510000	ACTIVE	PROD_OIL
324-34S	04029584260000	ACTIVE	INJ_H2O
324-35S	04029277720000	ACTIVE	PROD_OIL
324-3G	04029290200001	ACTIVE	PROD_OIL
324-4G	04029290660000	ACTIVE	PROD_OIL
324A-32S	04030247830000	ACTIVE	PROD_OIL
324A-33S	04029897240001	ACTIVE	PROD_OIL
324X-5G	04029664140001	ACTIVE	PROD_OIL
325-32S	04029275450001	ACTIVE	PROD_OIL
325-34S	04029673660001	INACTIVE	PROD_OIL
325-35S	04029814600002	ACTIVE	INJ_H2O
326-32S	04029275460000	ACTIVE	PROD_OIL
326-33S	04029276120000	ACTIVE	PROD_OIL
326-34S	04029276600000	ACTIVE	INJ_H2O
326-35S-RD1	04029277730100	ACTIVE	PROD_OIL
326-4G	04029607520001	ACTIVE	INJ_H2O
326A-32S	04030345770000	ACTIVE	PROD_OIL
326A-33S	04030306550000	INACTIVE	PROD_OIL
326A-35S	04030294190000	INACTIVE	PROD_OIL
326X-31S	04030300230000	ACTIVE	INJ_H2O
326X-32S	04030274590000	ACTIVE	PROD_OIL
326X-33S	04030306940000	ACTIVE	PROD_OIL
326X-35S	04030197520000	ACTIVE	PROD_OIL

326XA-32S	04030447180000	ACTIVE	PROD_OIL
327-33S	04030079140000	ACTIVE	PROD_OIL
327-34S	04029841860001	ACTIVE	INJ_H2O
327-35S-RD1	04029795210100	ACTIVE	INJ_H2O
327A-35S	04030292510000	ACTIVE	PROD_OIL
327H-32S	04030156630000	INACTIVE	PROD_OIL
327H-33S	04030118850000	ACTIVE	PROD_OIL
327X-33S	04030154070000	ACTIVE	PROD_OIL
327X-35S	04030197530000	INACTIVE	PROD_OIL
327XA-33S	04030277770001	ACTIVE	INJ_H2O
327XA-34S	04030447230000	ACTIVE	PROD_OIL
328-32S	04030007430000	ACTIVE	PROD_OIL
328-33S	04030007980000	INACTIVE	PROD_OIL
328-34S-RD1	04029544130101	INACTIVE	PROD_OIL
328-35S-RD1	04029277740100	ACTIVE	PROD_OIL
328A-31S	04029665900001	INACTIVE	PROD_OIL
328A-32S	04030175670001	ACTIVE	PROD_OIL
328H-31S-RD1	04029555780100	INACTIVE	PROD_OIL
328X-32S	04030667820000	ACTIVE	PROD_OIL
328X-33S	04030542650000	ACTIVE	PROD_OIL
328X-34S	04030291970000	INACTIVE	PROD_OIL
331-2G	04029568120001	ACTIVE	PROD_OIL
331-3G	04029532960001	ACTIVE	PROD_OIL
331-4G	04029532330001	ACTIVE	PROD_OIL
331-5G	04030243170000	ACTIVE	PROD_OIL
331X-4G	04030461240000	INACTIVE	PROD_OIL
332-4G	04030169010000	INACTIVE	INJ_H2O
332I-5G	04029796340001	INACTIVE	INJ_H2O
333-2G	04029556070000	INACTIVE	INJ_H2O
333-33S	04029604050000	INACTIVE	INJ_H2O
333-34S	04029573900000	ACTIVE	PROD_OIL
333-35S	04029590600000	ACTIVE	PROD_OIL
333-3G	04029538800001	INACTIVE	INJ_H2O
333A-34S	04029649860000	INACTIVE	PROD_OIL
333H-4G-RD1	04029545290100	INACTIVE	PROD_OIL
333H-5G-RD1	04029529240100	ACTIVE	PROD_OIL
333X-5G	04030464410001	ACTIVE	PROD_OIL
334-33S	04030210800000	INACTIVE	PROD_OIL
334-35S	04029277750000	ACTIVE	PROD_OIL
334X-33S	04030524030000	INACTIVE	PROD_OIL
335-32S	04030181880000	ACTIVE	PROD_OIL

335-33S	04029555860000	ACTIVE	INJ_H2O
335-34S	04029537150000	INACTIVE	INJ_H2O
335-35S-RD1	04029588960100	INACTIVE	PROD_OIL
335-3G	04029583120000	INACTIVE	INJ_H2O
335-4G	04029576930001	INACTIVE	PROD_OIL
335A-4G	04029648550000	ACTIVE	PROD_OIL
335A-5G	04029659790001	ACTIVE	INJ_H2O
335X-33S	04030306950000	ACTIVE	PROD_OIL
335X-4G	04030482290000	ACTIVE	PROD_OIL
335XH-5G	04030287610000	ACTIVE	PROD_OIL
336-33S	04030339810000	ACTIVE	PROD_OIL
336-35S-RD1	04029277760100	INACTIVE	INJ_H2O
336X-32S	04030223590000	ACTIVE	PROD_OIL
336X-34S	04029674030001	ACTIVE	PROD_OIL
337-33S	04029532950000	ACTIVE	PROD_OIL
337-34S	04029276610001	INACTIVE	PROD_OIL
337-35S	04029588720000	ACTIVE	PROD_OIL
337A-34S	04030289420000	INACTIVE	PROD_OIL
337HA-33S	04030118840000	INACTIVE	PROD_OIL
337X-31S-RD1	04030299020100	ACTIVE	INJ_H2O
337X-32S	04030234360000	ACTIVE	INJ_H2O
337X-33S	04030315790000	ACTIVE	PROD_OIL
337X-34S	04030202030000	ACTIVE	PROD_OIL
338-31S	04029274950000	INACTIVE	PROD_OIL
338-32S	04029275470000	ACTIVE	PROD_OIL
338-33S	04030033960000	ACTIVE	PROD_OIL
338-34S-RD1	04029850620101	ACTIVE	INJ_H2O
338-35S-RD1	04029277770100	INACTIVE	PROD_OIL
338A-34S	04030311420000	ACTIVE	PROD_OIL
338H-33S	04030118860000	ACTIVE	PROD_OIL
338X-32S	04030378110000	ACTIVE	PROD_OIL
338X-34S	04030195620000	INACTIVE	PROD_OIL
34-334D-5G	04029290860001	ACTIVE	PROD_OIL
341-3G	04030542660000	ACTIVE	PROD_OIL
341-5G	04029880940001	ACTIVE	PROD_OIL
341-6G	04030233410000	INACTIVE	PROD_OIL
341XH-4G	04030205260000	ACTIVE	PROD_OIL
341XH-5G	04030209160000	INACTIVE	PROD_OIL
342-2G	04029279820001	INACTIVE	PROD_OIL
342-34S	04029619950000	INACTIVE	INJ_H2O
342-35S	04029619220001	INACTIVE	PROD_OIL

342-3G-RD1	04029290210101	INACTIVE	PROD_OIL
342-4G	04029822070000	ACTIVE	PROD_OIL
342A-3G-RD1	04029537540102	ACTIVE	PROD_OIL
342A-6G	04029671080001	INACTIVE	PROD_OIL
342X-35S	04029775530000	INACTIVE	INJ_H2O
342X-4G	04030174420000	INACTIVE	INJ_H2O
343-34S-RD1	04029675900100	ACTIVE	PROD_OIL
343-4G	04029290670000	ACTIVE	PROD_OIL
343BX1-31S	04030511950000	ACTIVE	PROD_OIL
343X-4G	04030327460000	ACTIVE	PROD_OIL
344-33S	04029276130000	INACTIVE	PROD_OIL
344-35S	04029277780001	ACTIVE	PROD_OIL
344-3G	04029290220000	ACTIVE	INJ_H2O
344-4G	04030222570000	ACTIVE	PROD_OIL
344-5G	04029291100000	ACTIVE	INJ_H2O
344A-5G	04029651480000	INACTIVE	PROD_OIL
344H-34S-RD2	04029276620200	INACTIVE	PROD_OIL
344X-34S	04030481440000	ACTIVE	PROD_OIL
344X-35S	04030332480001	ACTIVE	INJ_H2O
345-33S	04030157600000	ACTIVE	PROD_OIL
345-34S	04029673130001	INACTIVE	PROD_OIL
345A-35S	04030210820001	ACTIVE	PROD_OIL
345X-32S	04030345780000	INACTIVE	PROD_OIL
346-31S	04029539380000	INACTIVE	PROD_OIL
346-33S	04029276140000	ACTIVE	PROD_OIL
346-34S-RD1	04029276630101	INACTIVE	PROD_OIL
346-35S	04029277790001	INACTIVE	PROD_OIL
346X-31S-RD2	04030276250200	ACTIVE	PROD_OIL
346X-35S	04030267540000	INACTIVE	PROD_OIL
347-33S	04030057790000	ACTIVE	PROD_OIL
347-34S	04029842180001	ACTIVE	INJ_H2O
347-35S-RD1	04029800600100	ACTIVE	PROD_OIL
347X-31S	04030292340000	ACTIVE	INJ_H2O
347X-32S	04030223600000	ACTIVE	PROD_OIL
347X-35S	04030294350000	INACTIVE	PROD_OIL
347XH-31S	04030281750000	ACTIVE	PROD_OIL
348-31S-RD1	04029274980101	ACTIVE	PROD_OIL
348-32S-RD2	04029275480201	INACTIVE	INJ_H2O
348-33S	04029276150000	INACTIVE	PROD_OIL
348-34S-RD1	04029276640101	ACTIVE	PROD_OIL
348-35S	04029277800000	INACTIVE	PROD_OIL

348AH-31S	04030152370000	ACTIVE	PROD_OIL
348X-33S	04030155450000	INACTIVE	PROD_OIL
348X-34S	04030203380000	INACTIVE	PROD_OIL
348XA-32S	04030442490000	ACTIVE	PROD_OIL
348XH-35S	04030248240000	ACTIVE	PROD_OIL
351-2G	04029540570001	INACTIVE	PROD_OIL
351H-5G	04029526770001	ACTIVE	PROD_OIL
351H-6G-RD1	04029540890100	ACTIVE	PROD_OIL
351I-4G	04029522760001	INACTIVE	INJ_H2O
351X-4G	04030018650000	INACTIVE	PROD_OIL
352-2G	04029682900000	INACTIVE	INJ_H2O
352-6G	04029879850000	INACTIVE	INJ_H2O
352H-3G	04030208040000	ACTIVE	PROD_OIL
352I-5G	04029291110001	ACTIVE	INJ_H2O
352X-3G	04029845290001	INACTIVE	INJ_H2O
352X-4G	04030310470000	ACTIVE	PROD_OIL
353-2G	04029581970000	INACTIVE	INJ_H2O
353-33S	04029672180000	INACTIVE	INJ_H2O
353-34S-RD1	04029602250100	ACTIVE	PROD_OIL
353-3G	04029556100000	INACTIVE	PROD_OIL
353-5G	04029557420001	ACTIVE	PROD_OIL
353A-4G	04029646140000	ACTIVE	PROD_OIL
353AH-5G-RD1	04030233000100	ACTIVE	PROD_OIL
353H-35S-RD1	04029582380101	INACTIVE	PROD_OIL
354-34S	04029675940000	ACTIVE	PROD_OIL
354-35S	04030370710000	ACTIVE	PROD_OIL
354-3G	04029290230001	INACTIVE	PROD_OIL
354AH-31S	04030306260000	INACTIVE	PROD_OIL
354X-33S	04030251860000	INACTIVE	PROD_OIL
354X-34S	04030453430000	ACTIVE	PROD_OIL
355-32S	04029544960000	ACTIVE	PROD_OIL
355-33S	04029555870000	ACTIVE	INJ_H2O
355-34S	04029559080002	ACTIVE	PROD_OIL
355-35S	04029557400001	INACTIVE	PROD_OIL
355-4G	04029583330000	INACTIVE	INJ_H2O
355A-35S	04030233500003	APPROVED	MON_PSI
355AH-5G	04030210030000	INACTIVE	PROD_OIL
355B-35S-RD1	04030233480100	DRILL	MON_PSI
355C-35S-RD1	04030233490100	DRILL	MON_PSI
355X-31S	04030321890000	ACTIVE	INJ_H2O
355X-32S	04030305620000	ACTIVE	PROD_OIL

355X-33S	04030524040000	ACTIVE	PROD_OIL
355X-5G	04029667960000	ACTIVE	INJ_H2O
356-31S	04029275000000	ACTIVE	PROD_OIL
356-32S	04030224210001	ACTIVE	INJ_H2O
356-33S	04030306930000	ACTIVE	PROD_OIL
356-34S	04029673670001	ACTIVE	INJ_H2O
356-35S	04030223190003	INACTIVE	INJ_H2O
356A-31S	04030259560000	INACTIVE	PROD_OIL
356B-31S	04030668140000	INACTIVE	PROD_OIL
356X-31S	04030274280000	ACTIVE	PROD_OIL
356X-33S	04030023100000	ACTIVE	PROD_OIL
357-32S	04029540840001	INACTIVE	PROD_OIL
357-33S	04029541440000	ACTIVE	PROD_OIL
357-34S-RD1	04029522470100	INACTIVE	PROD_OIL
357-35S	04029531140001	ACTIVE	PROD_OIL
357A-33S	04030155470000	INACTIVE	PROD_OIL
358-31S	04029897370001	INACTIVE	INJ_H2O
358-34S-RD1	04029891110100	ACTIVE	INJ_H2O
358A-33S	04030154470000	ACTIVE	PROD_OIL
358X-33S	04030133600000	ACTIVE	PROD_OIL
358X-34S-RD1	04030203390100	INACTIVE	PROD_OIL
36-336D-33S	04029275720001	ACTIVE	PROD_OIL
361-6G	04029717480001	ACTIVE	PROD_OIL
361X-4G	04030160120000	INACTIVE	PROD_OIL
361X-5G	04029893570002	ACTIVE	PROD_OIL
361XH-2G	04030259760000	ACTIVE	PROD_OIL
362-34S	04029675950000	INACTIVE	INJ_H2O
362-3G-RD1	04029290240100	INACTIVE	INJ_H2O
362-6G	04029291450001	INACTIVE	PROD_OIL
362A-3G	04029818080001	ACTIVE	PROD_OIL
362I-4G	04029290690001	INACTIVE	INJ_H2O
362I-5G	04029291120001	ACTIVE	INJ_H2O
362X-4G-RD1	04030314130100	ACTIVE	PROD_OIL
363-34S	04030186950000	ACTIVE	PROD_OIL
363-5G	04029800210000	ACTIVE	PROD_OIL
363X-33S	04029677850000	ACTIVE	INJ_H2O
363X-35S	04029672130001	ACTIVE	PROD_OIL
364-34S	04029668510000	ACTIVE	PROD_OIL
364-35S	04029584500002	ACTIVE	PROD_OIL
364-3G	04029556110001	INACTIVE	PROD_OIL
364-4G	04029290700000	ACTIVE	INJ_H2O

364-5G	04029568130000	ACTIVE	PROD_OIL
364H-32S-RD2	04029555810200	INACTIVE	PROD_OIL
364H-33S-RD1	04029611620100	ACTIVE	PROD_OIL
364X-33S	04029671660000	ACTIVE	PROD_OIL
364X-34S	04030470580000	ACTIVE	PROD_OIL
364XH-5G-RD1	04030222580100	INACTIVE	PROD_OIL
365-31S-RD1	04029275010100	ACTIVE	PROD_OIL
365-32S	04030240770000	ACTIVE	PROD_OIL
365-34S	04029672160001	INACTIVE	PROD_OIL
365-4G	04029646570003	ACTIVE	INJ_H2O
365A-31S	04030459340000	INACTIVE	PROD_OIL
365X-31S	04030321420000	ACTIVE	PROD_OIL
365X-32S	04030542640000	ACTIVE	PROD_OIL
365X-35S	04030225970002	ACTIVE	INJ_H2O
365XA-31S	04030321650000	ACTIVE	PROD_OIL
366-31S	04029275020002	INACTIVE	PROD_OIL
366-32S-RD1	04029275490100	ACTIVE	PROD_OIL
366-33S	04029276160000	ACTIVE	INJ_H2O
366-34S	04029276650001	ACTIVE	PROD_OIL
366-35S	04029277810001	INACTIVE	PROD_OIL
366A-31S	04030365850000	ACTIVE	PROD_OIL
366X-31S	04030273870000	ACTIVE	PROD_OIL
366X-32S	04030334150000	INACTIVE	PROD_OIL
366X-34S-RD2	04030317930200	INACTIVE	PROD_OIL
366X-36R	04029672680000	INACTIVE	INJ_H2O
366X-5G	04029662230000	INACTIVE	INJ_H2O
367-31S	04029611270001	ACTIVE	PROD_OIL
367-32S-RD1	04030157240100	ACTIVE	PROD_OIL
367-33S	04030133590000	ACTIVE	PROD_OIL
367-34S	04029842190001	ACTIVE	INJ_H2O
367X-32S	04030235470000	ACTIVE	INJ_H2O
367X-33S-RD1	04029897330101	ACTIVE	PROD_OIL
368-31S	04029854640001	ACTIVE	PROD_OIL
368-33S	04029529450000	ACTIVE	PROD_OIL
368-34S-RD1	04029276660100	INACTIVE	PROD_OIL
368-35S	04029277820000	ACTIVE	INJ_H2O
368A-32S	04029609550001	INACTIVE	PROD_OIL
368AH-32S-RD1	04030128380100	ACTIVE	PROD_OIL
368X-32S	04030057800000	INACTIVE	PROD_OIL
368X-34S	04030198930000	INACTIVE	PROD_OIL
368XA-32S	04030336750000	ACTIVE	PROD_OIL

371-3G	04029685000001	ACTIVE	PROD_OIL
371-4G	04029536330000	INACTIVE	PROD_OIL
371-6G	04029654800001	ACTIVE	PROD_OIL
371XA-4G	04030504820000	INACTIVE	PROD_OIL
372-4G	04030169020000	INACTIVE	INJ_H2O
372H-6G	04030284980000	ACTIVE	PROD_OIL
372X-4G	04030251870000	ACTIVE	PROD_OIL
373-32S	04029653180000	ACTIVE	INJ_H2O
373-33S	04029611200001	ACTIVE	INJ_H2O
373-34S	04029602260000	ACTIVE	INJ_H2O
373-3G	04029532410001	INACTIVE	PROD_OIL
373-4G-RD1	04029522460100	INACTIVE	PROD_OIL
373-6G	04030213350000	ACTIVE	PROD_OIL
373A-3G	04029660510002	INACTIVE	INJ_H2O
373H-31S	04030274400000	INACTIVE	PROD_OIL
373H-5G-RD1	04029528700100	INACTIVE	PROD_OIL
373X-35S	04030256500000	INACTIVE	PROD_OIL
374-32S	04030328390000	ACTIVE	PROD_OIL
374-33S	04029675540000	ACTIVE	PROD_OIL
374-34S-RD1	04029657730101	ACTIVE	PROD_OIL
374-5G	04029291130000	ACTIVE	PROD_OIL
374X-35S	04029606990003	INACTIVE	INJ_H2O
375-32S	04029555820001	ACTIVE	INJ_H2O
375-33S	04029521950001	ACTIVE	PROD_OIL
375-34S	04029544140000	ACTIVE	INJ_H2O
375-35S	04029579410001	INACTIVE	PROD_OIL
375-36R	04030261740000	INACTIVE	PROD_OIL
375-4G	04029586750000	INACTIVE	INJ_H2O
375-5G	04029588690000	ACTIVE	INJ_H2O
375X-34S	04030198940000	INACTIVE	PROD_OIL
375XA-34S-RD1	04030221940101	INACTIVE	PROD_OIL
376-31S	04030249860000	ACTIVE	PROD_OIL
376-32S	04030238880000	ACTIVE	PROD_OIL
376-33S	04029897350001	INACTIVE	INJ_H2O
376-34S	04029672320001	INACTIVE	INJ_H2O
376-36R	04029558530000	ACTIVE	INJ_H2O
377-31S	04030033970000	ACTIVE	PROD_OIL
377-32S	04030306180000	INACTIVE	PROD_OIL
377-33S	04029537310000	INACTIVE	PROD_OIL
377-35S	04029538810001	INACTIVE	PROD_OIL
377A-33S	04030239770000	INACTIVE	INJ_H2O

377H-32S	04030139670000	ACTIVE	PROD_OIL
377X-33S	04030165260001	ACTIVE	INJ_H2O
377X-34S	04030289430000	DRILL	PROD_OIL
377X-34S-RD1	04030289430100	INACTIVE	PROD_OIL
377XA-34S	04030447160000	ACTIVE	PROD_OIL
377XH-35S	04030256170000	INACTIVE	PROD_OIL
378-31S	04029275040001	ACTIVE	PROD_OIL
378-32S	04029275500000	ACTIVE	PROD_OIL
378-33S	04030007380000	ACTIVE	PROD_OIL
378-34S	04029276670001	ACTIVE	INJ_H2O
378X-31S	04030291960000	ACTIVE	INJ_H2O
378X-32S	04030426660000	ACTIVE	PROD_OIL
378X-34S	04030156640001	ACTIVE	PROD_OIL
381-4G	04029818090000	ACTIVE	PROD_OIL
381-5G	04030037620000	INACTIVE	PROD_OIL
381A-5G	04030351810000	ACTIVE	PROD_OIL
381H-6G	04030283730000	ACTIVE	PROD_OIL
381X-4G	04030171480000	ACTIVE	INJ_H2O
381X-5G	04030301870000	INACTIVE	PROD_OIL
382-33S	04029620170000	ACTIVE	INJ_H2O
382-35S	04030268170000	ACTIVE	PROD_OIL
382-3G	04029290250003	INACTIVE	PROD_OIL
382-4G	04029290710000	INACTIVE	PROD_OIL
382-6G	04029526490001	INACTIVE	PROD_OIL
382A-5G	04029841640001	ACTIVE	INJ_H2O
382A-6G	04030243180000	ACTIVE	PROD_OIL
382H-5G-RD1	04029545300100	ACTIVE	PROD_OIL
382X-4G	04030328980000	ACTIVE	PROD_OIL
383-34S	04030254180000	ACTIVE	PROD_OIL
383-5G	04029798160001	INACTIVE	INJ_H2O
384-32S	04029275510000	ACTIVE	PROD_OIL
384-33S	04029602580000	ACTIVE	PROD_OIL
384-34S	04029276680000	ACTIVE	PROD_OIL
384-36R-RD1	04029272780100	INACTIVE	PROD_OIL
384-3G	04029559470003	INACTIVE	PROD_OIL
384-4G	04029290720001	INACTIVE	INJ_H2O
384-5G	04029291140001	ACTIVE	PROD_OIL
384-6G	04029666060001	ACTIVE	PROD_OIL
384A-36R	04029599280001	ACTIVE	PROD_OIL
384X-32S	04030328580000	ACTIVE	PROD_OIL
385-32S	04030010370000	ACTIVE	PROD_OIL

385-34S	04029670970000	ACTIVE	PROD_OIL
385-35S	04030247840000	INACTIVE	PROD_OIL
385A-32S	04030332840000	ACTIVE	PROD_OIL
385X-33S	04029673460001	ACTIVE	PROD_OIL
385X-34S	04030170410000	INACTIVE	PROD_OIL
386-31S	04030256490000	ACTIVE	PROD_OIL
386-32S	04029555830002	ACTIVE	INJ_H2O
386-33S	04029276170000	ACTIVE	INJ_H2O
386-34S	04029276690000	INACTIVE	PROD_OIL
386-36R	04029727560001	ACTIVE	PROD_OIL
386-5G	04029660340001	INACTIVE	INJ_H2O
386A-33S	04030370870000	INACTIVE	PROD_OIL
386B-33S	04030370880000	ACTIVE	PROD_OIL
386X-34S-RD1	04030183510100	INACTIVE	PROD_OIL
386XH-32S	04030169730000	ACTIVE	PROD_OIL
386XH-33S	04030148640000	ACTIVE	PROD_OIL
387-31S	04029275060000	INACTIVE	PROD_OIL
387-32S	04030160110000	ACTIVE	PROD_OIL
387-33S	04029897340000	INACTIVE	PROD_OIL
387H-34S-RD3	04029819530300	ACTIVE	PROD_OIL
387X-31S	04030271120000	ACTIVE	INJ_H2O
387X-33S	04030303350000	INACTIVE	PROD_OIL
387X-34S	04030181870000	ACTIVE	PROD_OIL
388-31S	04029275070001	ACTIVE	PROD_OIL
388-32S	04029275520000	ACTIVE	PROD_OIL
388-33S-RD1	04029276180100	ACTIVE	PROD_OIL
388-34S	04029276700000	INACTIVE	PROD_OIL
388X-35S	04029618130000	INACTIVE	INJ_H2O
41-341D-4G	04029290470001	ACTIVE	PROD_OIL
47-347D-33S	04029275800001	ACTIVE	PROD_OIL
5-323H-32S-RD2	04029797320200	ACTIVE	PROD_OIL
5-377-34S	04029589160000	ACTIVE	PROD_OIL
52-352D-5G	04029290930001	ACTIVE	PROD_OIL
64-364D-32S	04029275290001	INACTIVE	PROD_OIL
64-364D-5G-RD1	04029529050100	INACTIVE	PROD_OIL
65X-365D-35S-RD1	04029559700100	INACTIVE	PROD_OIL
84-384D-6G	04029291410001	INACTIVE	PROD_OIL
9-354H-4G-RD4	04029533800400	INACTIVE	PROD_OIL

NWS A3+ EOR Well List

Well Name	API	Status	Type
311-16R	04029491300000	ACTIVE	PROD_OIL
311-17R	04029486950000	INACTIVE	PROD_OIL
311A-16R	04030313150000	ACTIVE	INJ_H2O
311A-17R	04030526720000	ACTIVE	INJ_H2O
311X-16R	04030177990000	ACTIVE	PROD_OIL
312X-16R	04030202520000	ACTIVE	PROD_OIL
313-8R-RD1	04029564400100	INACTIVE	INJ_H2O
313A-16R	04030518730000	ACTIVE	PROD_OIL
313A-17R	04029682150000	ACTIVE	INJ_H2O
313H-16R-RD1	04029531300100	ACTIVE	PROD_OIL
313X-16R	04030190010000	ACTIVE	PROD_OIL
315-16R	04029583010001	INACTIVE	INJ_H2O
315-8R	04029480860001	ACTIVE	INJ_H2O
316-8R	04030535950000	INACTIVE	PROD_OIL
317-8R	04029487700000	INACTIVE	PROD_OIL
318-8R-RD1	04030115370100	INACTIVE	PROD_OIL
318X-8R-RD1	04030023120100	INACTIVE	PROD_OIL
321-17R	04030010280000	ACTIVE	PROD_OIL
321X-16R	04030322180000	ACTIVE	INJ_H2O
322A-16R	04030518740000	ACTIVE	PROD_OIL
322H-17R-RD1	04029488710100	INACTIVE	PROD_OIL
322X-17R	04030234760000	ACTIVE	PROD_OIL
323-16R	04030477720000	ACTIVE	PROD_OIL
324AI-7R-RD1	04029671860101	ACTIVE	INJ_H2O
326-8R	04029489000000	INACTIVE	PROD_OIL
326I-7R	04029645130001	INACTIVE	INJ_H2O
328-8R	04029488130000	INACTIVE	PROD_OIL
328-9R-RD1	04029628490100	INACTIVE	PROD_OIL
331-17R	04029488120000	ACTIVE	PROD_OIL
333-17R	04029499610000	INACTIVE	PROD_OIL
333A-17R	04029683810000	INACTIVE	INJ_H2O
333A-7R	04029677650001	ACTIVE	INJ_H2O
335H-7R-RD1	04029480650100	INACTIVE	PROD_OIL
335X-7R	04030535920000	INACTIVE	PROD_OIL
336-7R	04029657040000	INACTIVE	PROD_OIL
336-9R-RD1	04030325080100	ACTIVE	PROD_OIL

337-8R-RD2	04029490410200	INACTIVE	PROD_OIL
337A-7R	04029673610000	ACTIVE	INJ_H2O
337H-7R-RD1	04029635520100	INACTIVE	PROD_OIL
341-17R	04030028010000	ACTIVE	PROD_OIL
342-17R	04029492520000	ACTIVE	PROD_OIL
344-8R	04029680920000	INACTIVE	INJ_H2O
344H-7R-RD1	04029480090100	INACTIVE	PROD_OIL
345-7R	04029647890000	ACTIVE	PROD_OIL
346H-7R-RD1	04029483640101	INACTIVE	PROD_OIL
347H-7R-RD3	04029654250301	INACTIVE	PROD_OIL
348-8R	04029490420000	INACTIVE	PROD_OIL
348A-7R-RD1	04029679460100	INACTIVE	INJ_H2O
351-17R	04029490360000	ACTIVE	PROD_OIL
351A-18R	04029680470000	ACTIVE	INJ_H2O
352X-17R	04030523020000	ACTIVE	INJ_H2O
353-17R	04029498040001	INACTIVE	INJ_H2O
353-7R	04029480660000	INACTIVE	PROD_OIL
353A-7R	04030464120000	INACTIVE	PROD_OIL
354X-17R	04029686430000	INACTIVE	INJ_H2O
354X-7R	04030372010000	INACTIVE	PROD_OIL
355-8R	04029501720001	ACTIVE	INJ_H2O
355X-7R	04030552030000	ACTIVE	INJ_H2O
356X-7R	04030372020000	INACTIVE	PROD_OIL
357-8R	04029492880001	ACTIVE	INJ_H2O
357X-7R	04030397050000	INACTIVE	PROD_OIL
358-8R	04030063720000	INACTIVE	PROD_OIL
358H-7R-RD1	04029651820101	INACTIVE	PROD_OIL
361-17R	04030035230000	ACTIVE	PROD_OIL
362-17R	04029492490000	ACTIVE	PROD_OIL
362A-17R	04030399100000	ACTIVE	PROD_OIL
362A-18R	04029679860000	ACTIVE	INJ_H2O
363-7R	04030552040001	ACTIVE	INJ_H2O
364-17R	04029503750000	INACTIVE	INJ_H2O
364-7R	04029481510001	INACTIVE	PROD_OIL
364-8R	04029681940000	ACTIVE	INJ_H2O
364X-7R	04030535930000	INACTIVE	PROD_OIL
365-7R	04029649800000	INACTIVE	PROD_OIL
366-7R	04029483690002	INACTIVE	PROD_OIL
366-8R	04029503740000	ACTIVE	INJ_H2O
366A-7R	04029648540000	ACTIVE	PROD_OIL
366X-7R	04030340240000	INACTIVE	PROD_OIL

367-7R	04029623820002	ACTIVE	INJ_H2O
367X-7R	04030262930000	ACTIVE	PROD_OIL
368-7R	04029679400002	INACTIVE	PROD_OIL
368-8R	04029492830000	INACTIVE	PROD_OIL
368A-7R	04030361320000	ACTIVE	PROD_OIL
371-17R	04029492500000	ACTIVE	PROD_OIL
371-18R	04029482720000	INACTIVE	PROD_OIL
371X-18R	04030248220000	ACTIVE	PROD_OIL
372-17R	04030073480000	ACTIVE	PROD_OIL
373-17R-RD2	04029499620200	INACTIVE	PROD_OIL
374-17R	04030150060000	INACTIVE	PROD_OIL
374-7R	04029681690000	INACTIVE	INJ_H2O
374A-7R-RD1	04030471550100	INACTIVE	PROD_OIL
375-7R	04029626260001	INACTIVE	PROD_OIL
375-8R	04029567440000	INACTIVE	INJ_H2O
375X-17R	04029687360000	ACTIVE	INJ_H2O
376-7R	04029644400000	INACTIVE	PROD_OIL
376A-7R	04030473490000	INACTIVE	PROD_OIL
377-7R	04030340230000	INACTIVE	PROD_OIL
377-8R	04029533300001	ACTIVE	INJ_H2O
377A-7R	04030535940000	INACTIVE	PROD_OIL
377X-7R	04030361330000	ACTIVE	PROD_OIL
378-7R	04029640290000	ACTIVE	PROD_OIL
378A-7R	04030399170000	INACTIVE	PROD_OIL
381-17R-RD1	04030082460100	ACTIVE	PROD_OIL
381-18R	04029659050000	INACTIVE	PROD_OIL
381A-17R	04030249430000	INACTIVE	PROD_OIL
381B-17R	04030399110000	ACTIVE	INJ_H2O
381X-17R	04030150070000	INACTIVE	PROD_OIL
382-17R	04029532550000	ACTIVE	PROD_OIL
382A-17R	04030313360000	ACTIVE	INJ_H2O
382A-18R	04029681700000	INACTIVE	INJ_H2O
382I-18R	04029485550001	ACTIVE	INJ_H2O
384-17R	04029533550000	ACTIVE	PROD_OIL
384X-7R	04029729320000	INACTIVE	INJ_H2O
385-7R	04029683590000	ACTIVE	INJ_H2O
386-17R	04029688080000	ACTIVE	INJ_H2O
386-7R-RD1	04029762160100	INACTIVE	PROD_OIL
386-8R	04029559070000	INACTIVE	INJ_H2O
387-7R	04029640530000	INACTIVE	PROD_OIL
388-8R	04029562110000	INACTIVE	PROD_OIL

388A-7R	04030526710000	INACTIVE	PROD_OIL
388X-7R	04030074340000	ACTIVE	PROD_OIL
5-346-8R	04029492870002	ACTIVE	INJ_H2O

11.6 Summary of Key Regulations Referenced in MRV Plan

Statutes & Regulations, Geologic Energy Management Division, January 2020, https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b).