Scout Energy Management, LLC

Rangely Field

Subpart RR Monitoring, Reporting and Verification (MRV) Plan

March 2024

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Roadmap to the Monitoring, Reporting and Verification (MRV) Plan

Scout Energy Management, LLC (SEM) operates the Rangely Weber Sand Unit (RWSU) and the associated Raven Ridge pipeline (RRPC), (collectively referred to as the Rangely Field) in Northwest Colorado for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) flooding. SEM has utilized, and intends to continue to utilize, injected CO_2 with a subsidiary purpose of establishing long-term containment of a measurable quantity of CO_2 in subsurface geological formations at the Rangely Field for a term referred to as the "Specified Period." The Specified Period includes all or some portion of the period 2023 to 2060. During the Specified Period, SEM will inject CO_2 that is purchased (fresh CO_2) from ExxonMobil's (XOM) Shute Creek Plant or third parties, as well as CO_2 that is recovered (recycled CO_2) from the Rangely Field's CO_2 Recycle and Compression Facilities (RCF's). SEM has developed this monitoring, reporting, and verification (MRV) plan in accordance with 40 CFR §98.440-449 (Subpart RR) to provide for the monitoring, reporting and verification of the quantity of CO_2 sequestered at the Rangely Field during the Specified Period.

SEM has chosen to submit this MRV plan to the EPA for approval according to 40 Code of Federal Regulations (CFR) 98.440(c)(1), Subpart RR of the Greenhouse Gas Reporting Program for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code.

This MRV plan contains eleven sections:

- Section 1 contains general facility information.
- Section 2 presents the project description. This section describes the planned injection volumes, the environmental setting of the Rangely Field, the injection process, and reservoir modeling. It also illustrates that the Rangely Field is well suited for secure storage of injected CO_2.
- Section 3 describes the monitoring area: the RWSU in Colorado.
- Section 4 presents the evaluation of potential pathways for CO_2 leakage to the surface. The assessment finds that the potential for leakage through pathways other than the man-made wellbores and surface equipment is minimal.
- Section 5 describes SEM's risk-based monitoring process. The monitoring process utilizes SEM's reservoir management system to identify potential CO_2 leakage indicators in the subsurface. The monitoring process also utilizes visual inspection of surface facilities and personal H_2S monitors program as applied to Rangely Field. SEM's MRV efforts will be primarily directed towards managing potential leaks through wellbores and surface facilities.
- Section 6 describes the baselines against which monitoring results will be compared to assess whether changes indicate potential leaks.
- Section 7 describes SEM's approach to determining the volume of CO_2 sequestered using the mass balance equations in 40 CFR §98.440-449, Subpart RR of the Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP). This section also describes the site-specific factors considered in this approach.
- Section 8 presents the schedule for implementing the MRV plan.
- Section 9 describes the quality assurance program to ensure data integrity.
- Section 10 describes SEM's record retention program.
- Section 11 includes several Appendices.

1. Facility Information

The Rangely Gas Plant, operated by SEM and a part of the Rangely Field, reports under Greenhouse Gas Reporting Program Identification number 537787.

The Colorado Oil and Gas Conservation Commission (COGCC)[1] regulates all oil, gas and geothermal activity in Colorado. All wells in the Rangely Field (including production, injection and monitoring wells) are permitted by COGCC through Code of Colorado Regulations (CCR) 2 CCR 404-1:301. Additionally, COGCC has primacy to implement the Underground Injection Control (UIC) Class II program in the state for injection wells. All injection wells in the Rangely Field are currently classified as UIC Class II wells.

Wells in the Rangely Field are identified by name, API number, status, and type. The list of wells as of April, 2023 is included in Appendix 5. Any new wells will be indicated in the annual report.

2. Project Description

This section describes the planned injection volumes, environmental setting of the Rangely Field, injection process, and reservoir modeling conducted.

2.1 Project Characteristics

SEM utilized historic production and injection of the RWSU in order to create a production and injection forecast, included here to provide an overview of the total amounts of CO2 anticipated to be injected, produced, and stored in the Rangely Field as a result of its current and planned CO2 EOR operations during the forecasted period. This forecast is based on historic and predicted data. Figure 1 shows the actual (historic) CO2 injection, production, and stored volumes in the Rangely Field from 1986, when Chevron initiated CO2 flooding, through 2022 (solid line) and the forecast for 2023 through 2060 (dotted line). It is important to note that this is just a forecast; actual storage data will be collected, assessed, and reported as indicated in Sections 5, 6, and 7 in this MRV Plan. The forecast does illustrate, however, the large potential storage capacity at Rangely field.

[1] Pursuant to Colorado SB21-285, effective July 1, 2023, the COGCC will become the Energy and Carbon Management Commission.

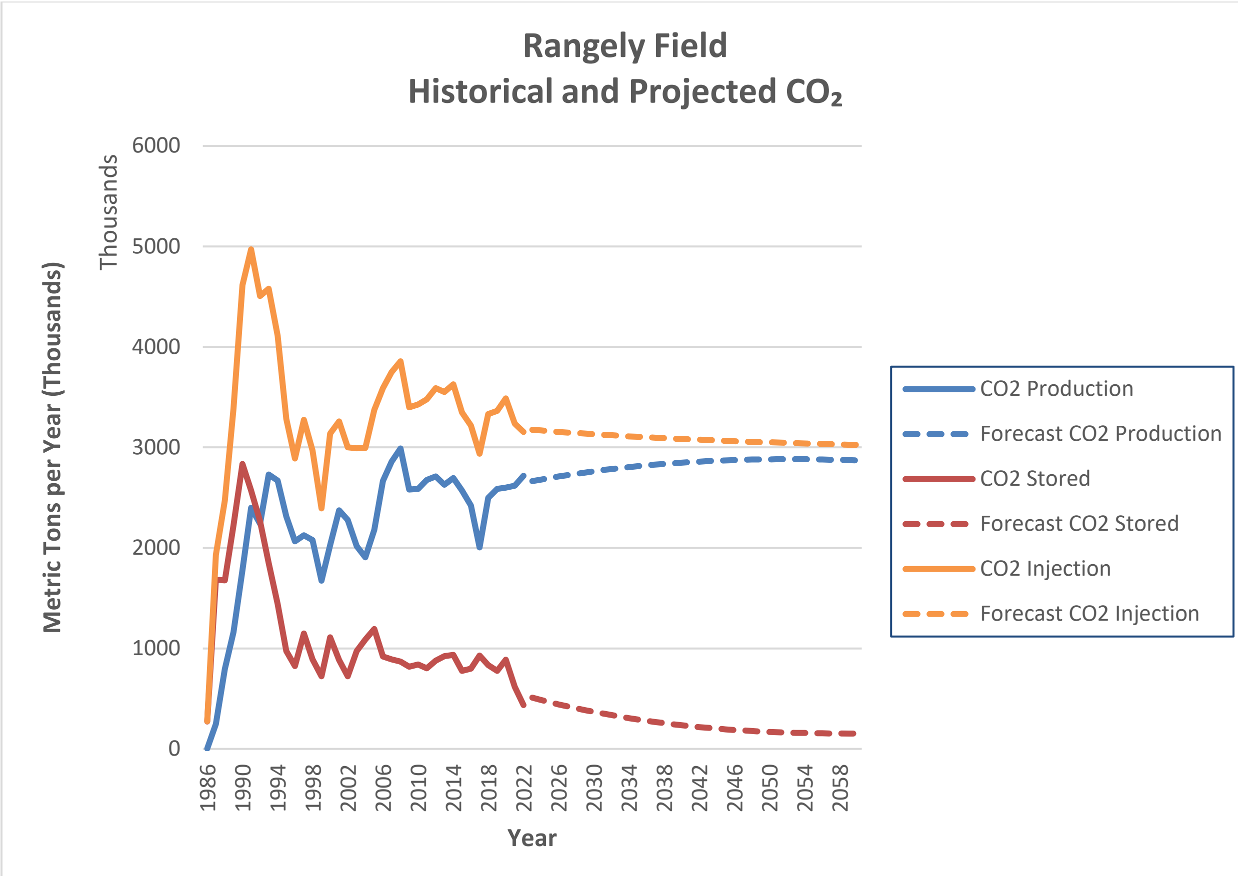

Figure 1 – Rangely Field Historic and Forecast CO2 Injection, Production, and Storage 1986-2060

The amount of CO2 injected at Rangely Field is adjusted periodically to maintain reservoir pressure and to increase recovery of oil by extending or expanding the EOR project. The amount of CO2 injected is the amount needed to balance the fluids removed from the reservoir and to increase oil recovery. While the model output shows CO2 injection and storage through 2060, this data is for planning purposes only and may not necessarily represent the actual operational life of the Rangely Field EOR project. As of the end of 2022, 2,320,000 million standard cubic feet (MMscf) (122.76 million metric tons (MMMT)) of CO2 has been injected into Rangely Field. Of that amount, 1,540,000 MMscf (81.48 MMMT) was produced and recycled.

While tons of CO2 injected and stored will be calculated using the mass balance equations described in Section 7, the forecast described above reflects that the total amount of CO2 injected and stored over the modeled injection period to be 967,000 MMscf (51.2 MMMT). This represents approximately 35.7% of the theoretical storage capacity of Rangely Field.

Figure 2 presents the cumulative annual forecasted volume of CO2 stored by year through 2060, the modeling period for the projection in Figure 1. The cumulative amount stored is equal to the sum of the annual storage volume for each year plus the sum of the total of the annual storage volume for each previous year. As is typical with CO2 EOR operations, the rate of accumulation of stored CO2 tapers over time as more recycled CO2 is used for injection. Figure 2 illustrates the total cumulative storage over the modeling period, projected to be 967,000 MMscf (51.2 MMMT) of CO2.

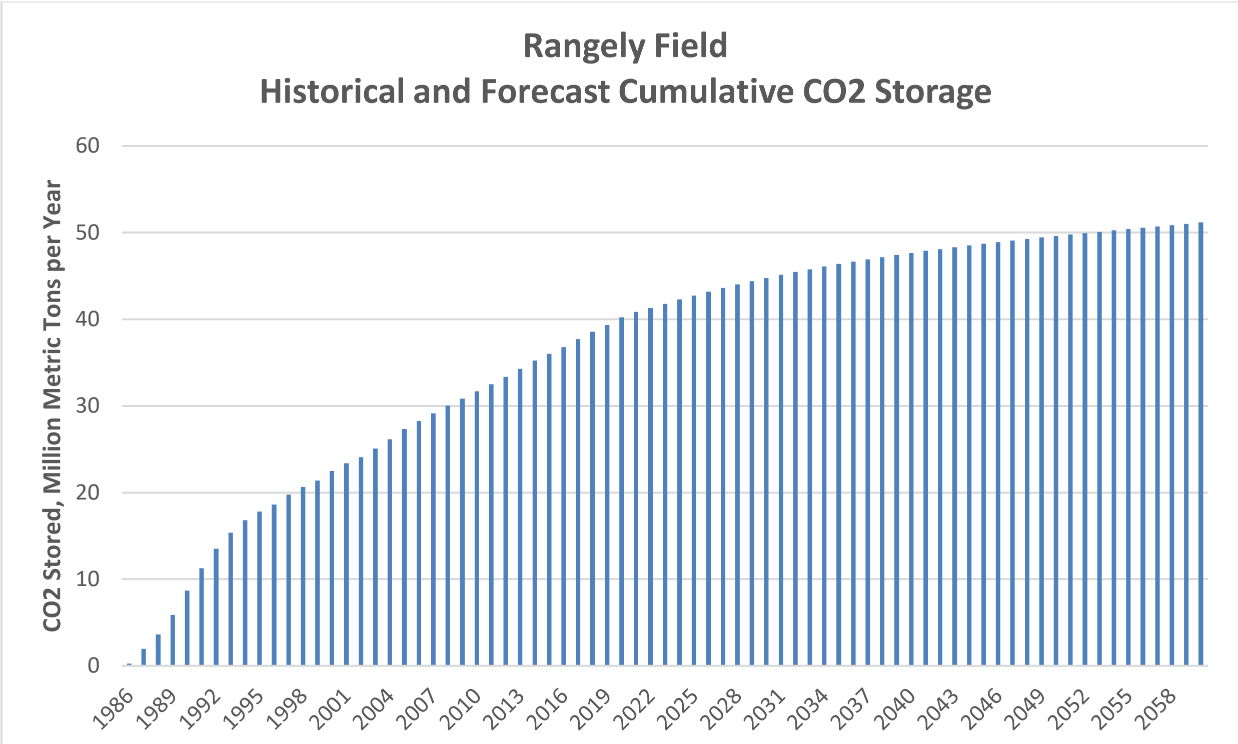

Figure 2 – Rangely Field Cumulative CO2 Storage 1986-2060

2.2 Environmental Setting

The project site for this MRV plan is the Rangely Field, located on the Douglas Creek Arch between the Uinta Basin and Piceance Basin in Colorado.

2.2.1 Geology of the Rangely Field

The Rangely Field is a Pennsylvanian-Permian age (~310-275 Mya) sandstone reservoir (Weber) located in the northwest corner of Colorado in Rio Blanco County. The field is located within the Rocky Mountain province along the structural high of the Douglas Creek Arch, which separates the Uinta Basin to the west and Piceance Basin to the east (see Figure 3). More locally, north of the Douglas Creek Arch and around the Rangely filed are a series of large thrust faults which shaped the overall structure of the subsurface. These asymmetrical anticlines are doubly plunging creating a dome shape trap allowing for the vast amounts of hydrocarbons to accumulate within.

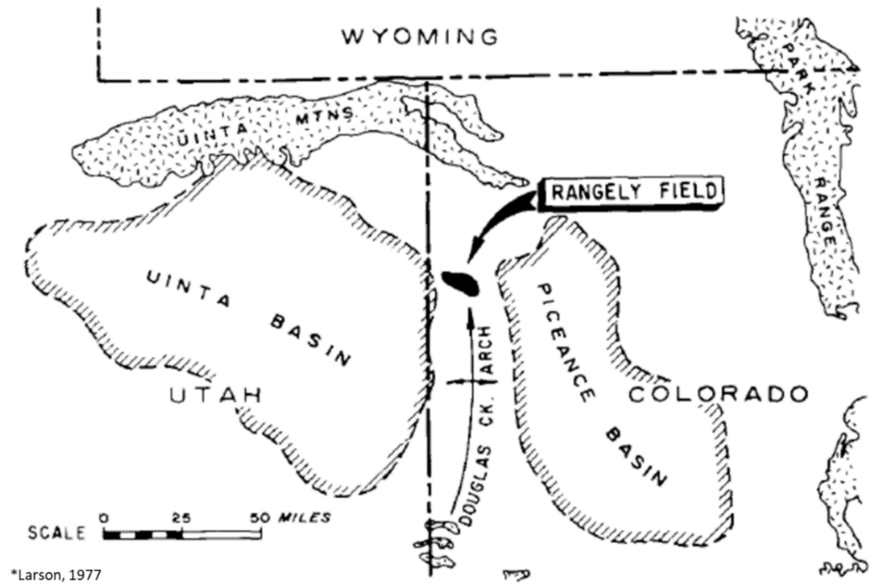

Figure 3 – Regional map showing Rangely's position between the Uinta and Piceance Basin.

The reservoir, Weber Sands, is comprised of clean eolian quartz deposited in an erg (sand sea) depositional environment. Internally, these dune sands are separated into six main packages (odd numbers, 1 to 11) with the fluvial Maroon Formation (even numbers, 2 to 10) interfingering the field from the north. The Weber Formation is underlain by the fossiliferous Desmoinesian carbonates of the Morgan Formation, and overlain by the siltstones and shales of the Phosphoria/Park City and Moenkopi Formations.

For the majority of the region, the Phosphoria Formation acts as an impermeable barrier above the Weber Formation and is a hydrocarbon source for the overlying strata. However, due to the large thrust fault south and west of the field, the Phosphoria Formation was driven down to significantly deeper depths, and below the reservoir Weber sands, allowing for maturation and expulsion of the hydrocarbons to migrate upward into stratigraphically older, but structurally shallower reservoirs sometime during the Jurassic. At Rangely, the Phosphoria Formation is almost entirely missing above the Weber Formation, but the Moenkopi Formation sits directly above the sands creating the seal for the petroleum system.

Fresh water in and around the town/field of Rangely is sourced from the quaternary creeks and rivers that cut across the region (data obtained from the Colorado Division of Water Resources). No confined fresh water aquifers are present between the reservoir rock and the surface. Safety measures are still taken to protect the shallowest of rocks that contain rain water seepage (unconfined aquifer) into the Mancos Formation (surface exposure at Rangely) illustrated by the surface casing on Figure 4. The shallowest point of the reservoir is 5,486 ft below the surface (4,986 ft below any possible fresh rain water seepage). The mere presence of hydrocarbons and the successful implication of a CO2 flood indicates the quality and effectiveness of the seal to isolate this reservoir from higher strata.

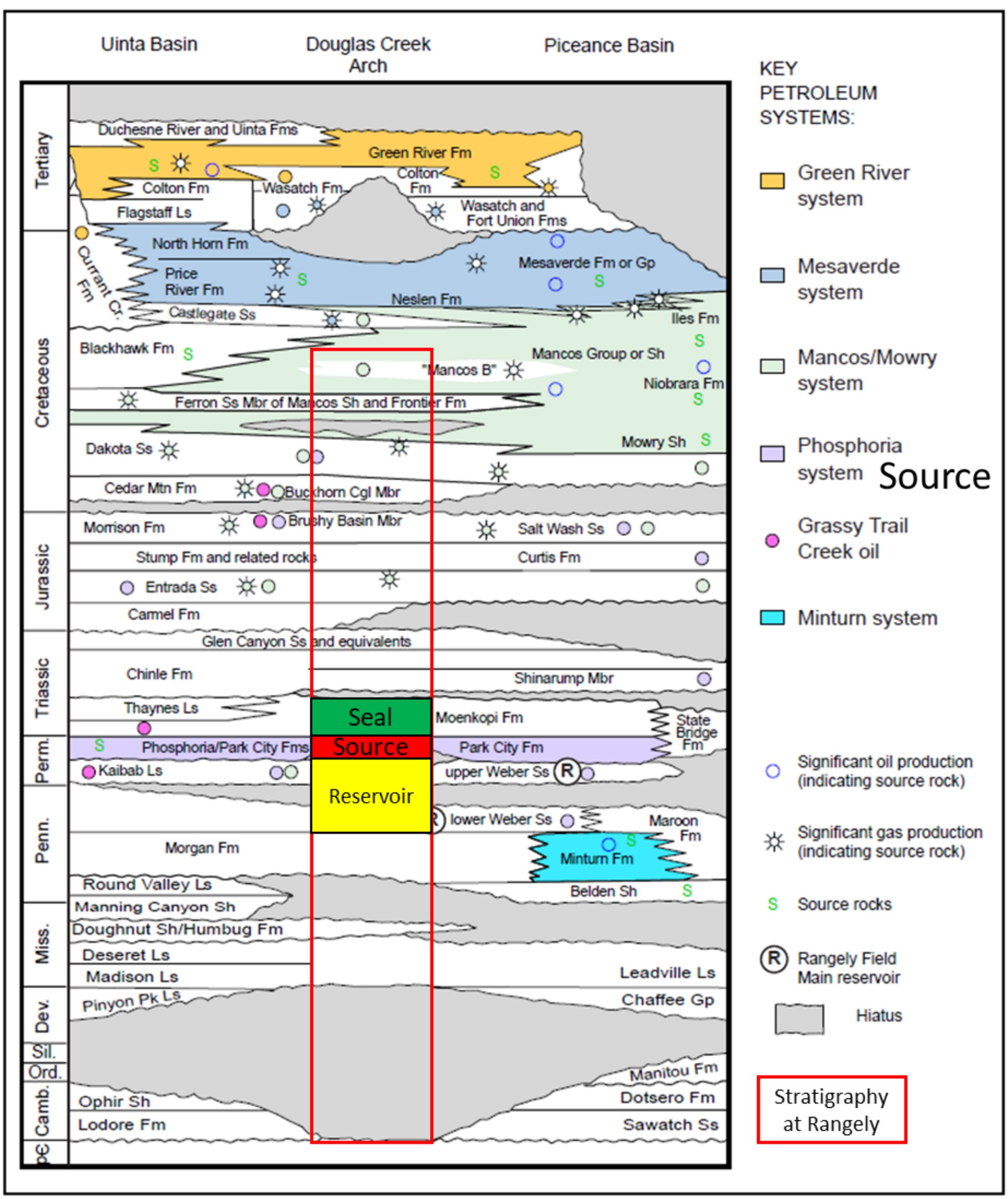

Figure 4. Stratigraphic Column of formations at the Rangely Field. Due to a large fault the source rock (Phosphoria) is stratigraphically above the reservoir rock (Weber), but structurally, the source lies below the reservoir. (from U.S. Geological Survey, 2003)

Figure 5 shows the doubly plunging anticline with the long axis along a northwest-southeast trend and the short axis along a northeast-southwest trend. In 1949 the depth of a gas cap was established at -330 ft subsea and an Oil Water Contact (OWC) at -1150 ft subsea. Many core analysis suggest that below this -1150' OWC is a transition/residual oil zone. However, for the purpose of this analysis and all volumetrics the base of the reservoir will be at the -1150’ subsea depth determined in 1949.

Geologically, the Weber Sands were deposited on top of the Morgan formation which is a combination of interbedded shale, siltstone, and cherty limestone. Few wells are drilled deep enough to penetrate the Morgan formation within the Rangely Field to gather porosity/permeability data locally. However, analysis of the Morgan formation from other fields/outcrops indicate that it is a non-reservoir rock (low porosity/permeability), and would be sufficient as a basial barrier for the field. The highest subsurface elevation of the base of the Weber Sands is deeper than the -1150’ used for the OWC. Meaning injected CO2 should not encounter the Morgan formation. Additionally, Section 4.7 explains how the Rangely Field is confined laterally through the nature of the anticline’s structure.

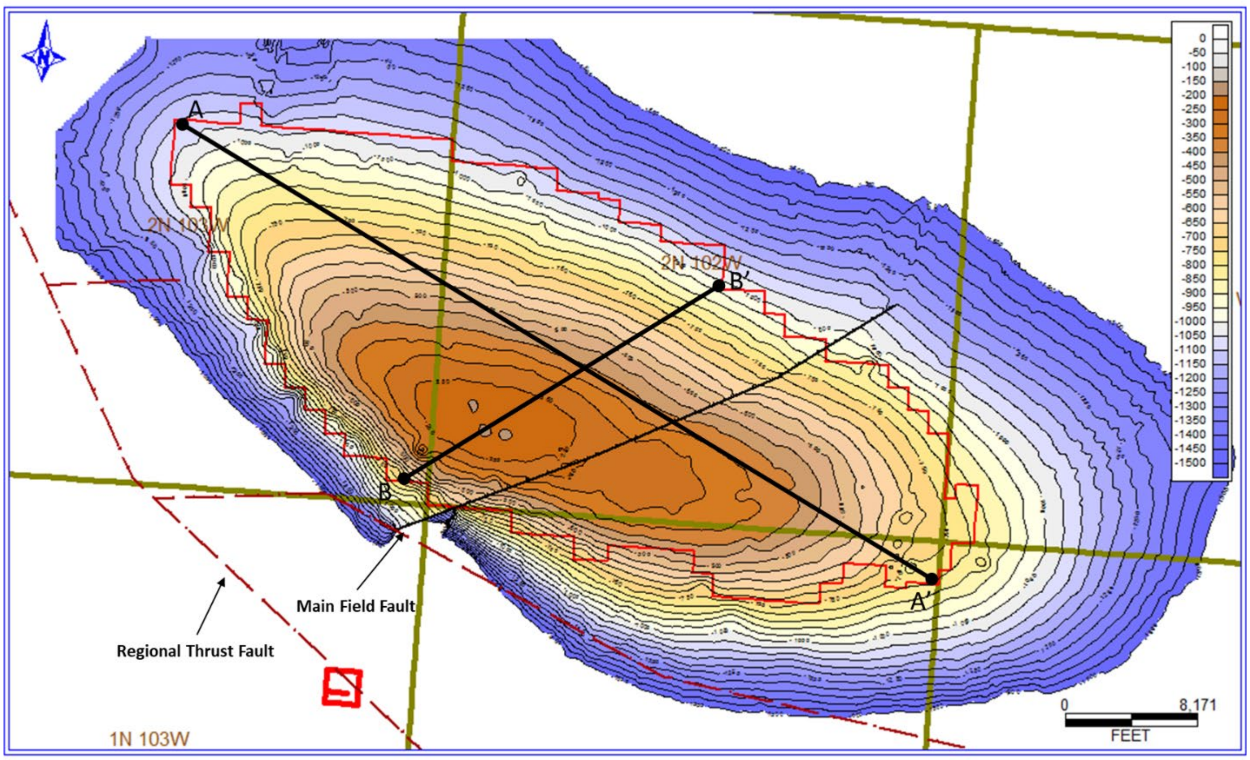

Figure 5. Structure map of the Weber 1 (top of reservoir). Colors illustrate the maximum aerial coverage of the Gas Cap (Red), Main Reservoir (Green), and Transitional Reservoir (Blue). Cross section A-A’ is predominantly along the long axis of the field and B-B’ is along the short axis.

The Rangely Field has one main field fault (MFF) and numerous smaller faults (isolated and joint) and fractures that are present throughout the stratigraphic column between the base of the Weber reservoir and surface. Faults within the reservoir were measured by well-to-well displacement, while the fractures were measured and observed as calcite veins on the surface with no displacement. The MFF has a NE-WSW trend and cuts through the reservoir interval. In the 1960’s Rangely residents began experiencing felt earthquakes. Between 1969 and 1973, a joint investigation with the USGS installed seismic monitoring stations in and around the town of Rangely and began recording activity. In 1971, a study was conducted to evaluate the stress state in the vicinity of the fault which determined a critical fluid pressure above which fault slippage may occur. Reservoir pressure was then manipulated and correlated with increases or decreases in seismic activity. This study determined that the waterflood in Rangely was inducing seismicity when reservoir pressure was raised above ~3730 psi.

In the 1990’s, field reservoir pressure had built back up leading to the largest magnitude earthquake in

Rangely which took place in 1995 (M 4.5), shortly after maximum reservoir pressure was reached in 1998. Pressure maintenance began and seismic activity dropped off after lowering the average field reservoir pressure down to ~3100 psi. No other seismic activity was recorded around the field until 2015 and 2017 when there was a total of 5 seismic events (see Figure 6) around the northeastern portion of the MFF. A new interpretation from the 3D seismic revealed a series of previously unknown joint faults (perpendicular to the MFF). Investigation into this region revealed that the ~3730 psi threshold had been crossed and triggered the seismic events. Since the 2017 seismic events, no other events have been recorded of felt magnitude and continued pressure monitoring further reduces the risk of another event.

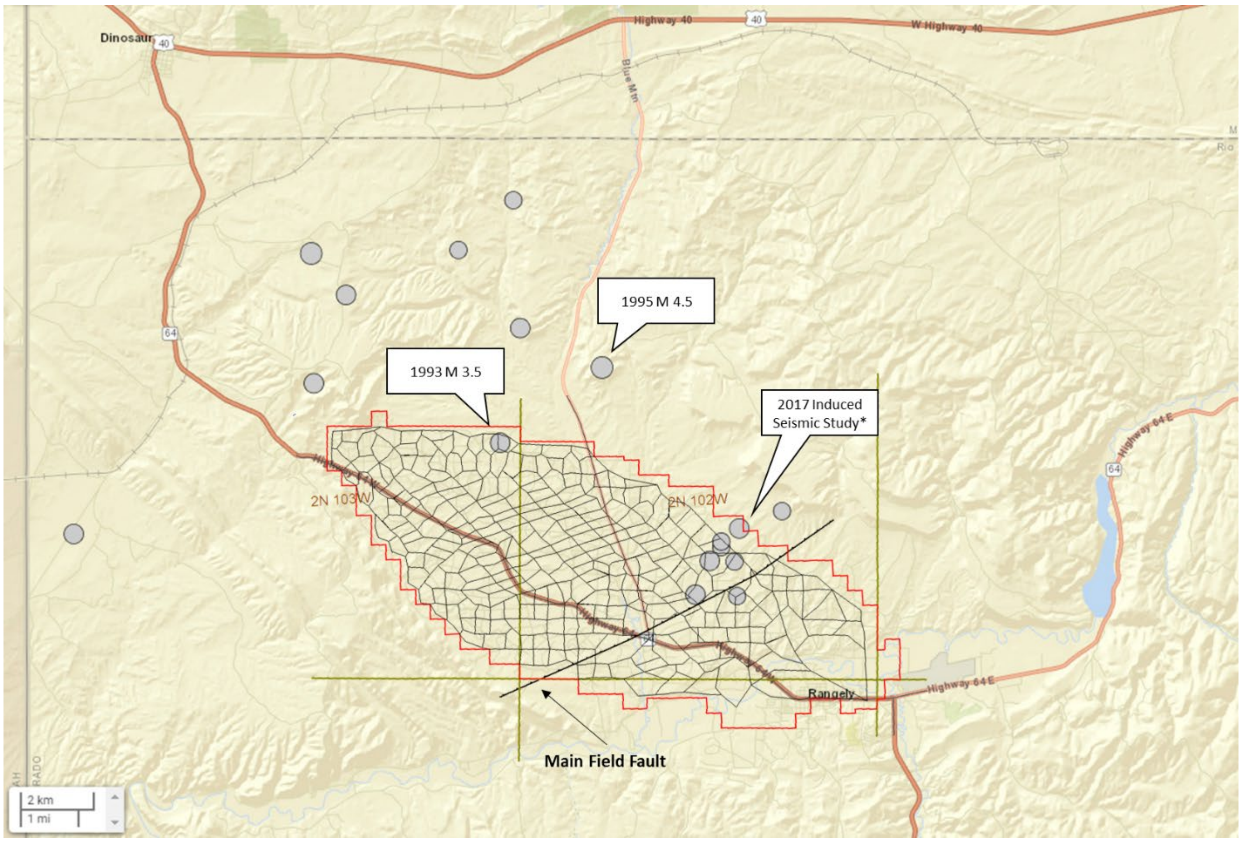

Figure 6. USGS fault history map (1900-2023). Largest earthquake was the 1995 M 4.5 north of the unit (2017 was a study to induce seismic activity along the MFF, and not caused by day-to-day operations)

The natural fractures found within the field play a significant role in fluid flow. The subsurface natural fractures are vertical and show an approximately ENE trend and their extension joints are orientated ESE. Shallower portions of the reservoir show a distinctly higher density of fractures than deeper portions. On the shallow dipping sides of the anticline, there does not appear to be a strong structural control on fracture density. Most well-to-well rapid breakthrough of injected CO2 is along these ENE fractures. It is unknown if this is from natural or induced fractures. There is no evidence that these natural fractures diminish the seals integrity.

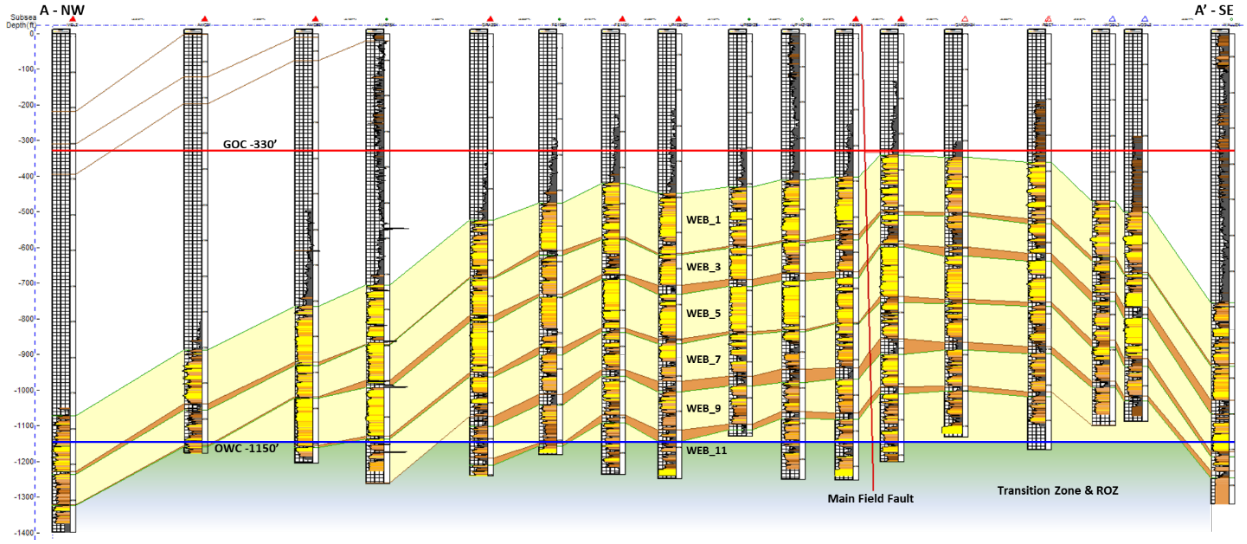

Figure 7. Cross section A-A' along the long axis of the field, and perpendicular to the MRR. The MFF does not have much displacement and is near vertical.

The Rangely Field has approximately 1.9 billion barrels of Original Oil in Place (OOIP). Since first discovered in 1933, Rangely Field has produced 920 million barrels of oil, or 48% of the OOIP. The Rangely Field has an aerial extent of approximately 19,150 acres with an average gross thickness of 650 ft. The previously mentioned 11 internal layers of the reservoir, alternating zones of Weber and Maroon Formations, can be simplified to only three sections. The Upper Weber contains intervals 1-3, the Middle Weber contains intervals 4-7, and the Lower Weber contains intervals 8-approxamently 50 ft below the 11D marker (identified by the base of the yellow in Figure 7). These interval groupings were determined by the extensive lateral continuingly and thickness of the Weber 4 and Weber 8 which easily separate the reservoir into the three zones. For the majority of the Rangely Field, the even Maroon Formations act as flow barriers between the odd Weber Formations. Average porosity within the Weber Sands dune facies is 10.3% and within the Maroon fluvial facies is 4.9%. However, the key factor that enables the Maroon Formation to be a seal is its lack of permeability. The Weber dune facies have an average permeability of 2.44 millidarcy (Md), while the Maroon fluvial facies have an average permeability of 0.03 Md.

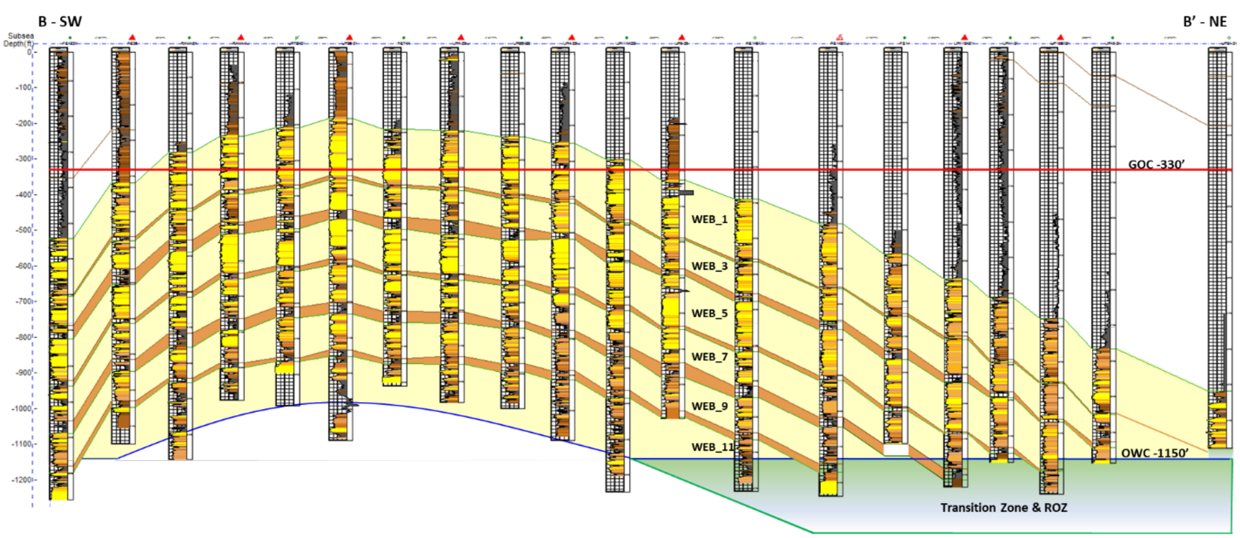

Figure 8. Cross section B-B' along the short axis of the field and parallel to the MFF. Used to illustrate the variation of the Oil Water Contact (OWC).

Given that the Rangely Field is located at the highest subsurface elevations of the structure, that the confining zone has proved competent over both millions of years and throughout decades of EOR operations, and that the Rangely Field has ample storage capacity, SEM is confident that stored CO2 will be contained securely within the Weber Sands in the Rangely Field.

2.2.2 Operational History of the Rangely Field

The Rangely Field was discovered in 1933 but subsequently ceased production until World War II when oil returned to high demand. Intensive development began, expanding from one well to 478 wells by 1949. It is located in the northwestern portion of Colorado.

The Rangely Field was originally developed by Chevron. Following the initial discover in 1933, Chevron imitated a 40-acre development in 1944, followed by hydrocarbon gas injection from 1950 to 1969. To improve efficiency, in 1957, the RWSU was formed. The boundaries of the RWSU are reflected in Figure 9.

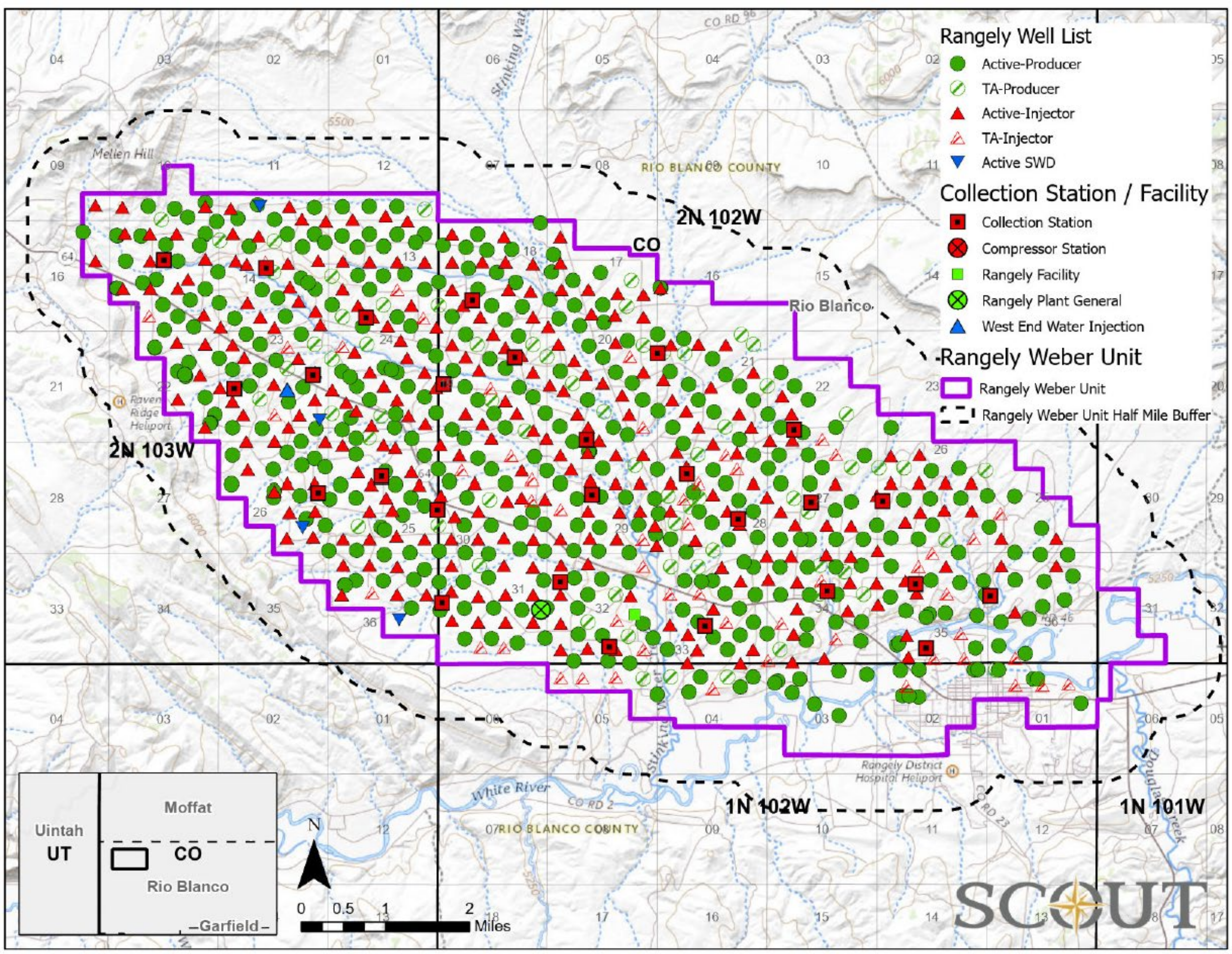

Figure 9 - Rangely Field Map

Chevron began CO2 flooding of the Rangely Field in 1986 and has continued and expanded it since that time. The experience of operating and refining the Rangely Field CO2 floods over the past decade has created a strong understanding of the reservoir and its capacity to store CO2.

2.3 Description of CO2 EOR Project Facilities and the Injection Process

Figures 10 shows a simplified flow diagram of the project facilities and equipment in the Rangely Field. CO2 is delivered to the Rangely Field via the Raven Ridge Pipeline. The CO2 injected into the Rangely Field is currently supplied by XOM's Shute Creek Plant into the pipeline system.

Once CO2 enters the Rangely Field there are four main processes involved in EOR operations. These processes are shown in Figure 10 and include:

1. **CO2 Distribution and Injection.** Purchased CO2 and recycled CO2 from the RCF is sent through the main CO2 distribution system to various CO2 injectors throughout the Field.
2. **Produced Fluids Handling.** Produced fluids gathered from the production wells are sent to collection stations for separation into a gas/CO2 mix and a produced fluids mix of water, oil, gas, and CO2. The produced fluids mix is sent to centralized water plants where oil is separated for sale into a pipeline, water is recovered for reuse, and the remaining gas/CO2 mix is merged with the output from the collection stations. The combined gas/CO2 mix is sent to the RCF and natural gas liquids (NGL) Plant. Produced oil is metered and sold; water is forwarded to the water injection plants for treatment and reinjection or disposal.
3. **Produced Gas Processing.** The gas/CO2 mix separated at the satellite batteries goes to the RCF and NGL Plant where the NGLs, and CO2 streams are separated. The NGLs move to a commercial pipeline for sale. The remaining CO2 (e.g., the recycled CO2) is returned to the CO2 distribution system for reinjection.
4. **Water Treatment and Injection.** Water separated in the tank batteries is processed at water plants to remove any remaining oil and then distributed throughout the Rangely Field for reinjection.

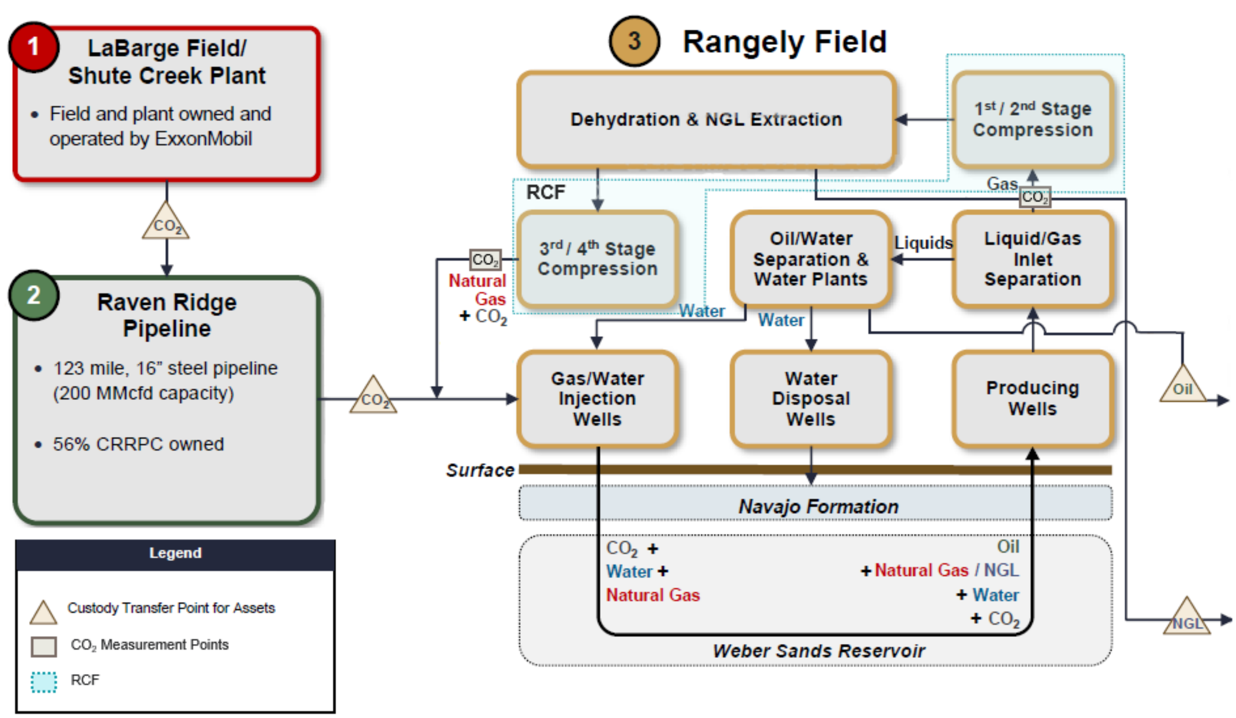

Figure 10 Rangely Field –General Production Flow Diagram

2.3.1 CO2 Distribution and Injection.

SEM purchases CO2 from XOM and receives it via the Raven Ridge Pipeline through one custody transfer metering point, as indicated in Figures 10. Purchased CO2 and recycled CO2 are sent through the CO2 trunk lines to multiple distribution lines to individual injection wells. There are volume meters at the inlet and outlet of the CO2 Reinjection Facility.

As of April 2023, SEM has approximately 280 injection wells in the Rangely Field. Approximately 160 MMscf of CO2 is injected each day, of which approximately 15% is purchased CO2, and the balance (85%) is recycled. The ratio of purchased CO2 to recycled CO2 is expected to change over time, and eventually the percentage of recycled CO2 will increase and purchases of fresh CO2 will taper off as indicated in Section 2.1.

Each injection well is connected to a water alternating gas (WAG) manifold located at the well pad. WAG manifolds are manually operated and can inject either CO2 or water at various rates and injection pressures as specified in the injection plans. The length of time spent injecting each fluid is a matter of continual optimization that is designed to maximize oil recovery and minimize CO2 utilization in each injection pattern. A WAG manifold consists of a dual-purpose flow meter used to measure the injection rate of water or CO2, depending on what is being injected. Data from these meters is sent to the Supervisory Control and Data Acquisition (SCADA) system where it is compared to the injection plan for that well. As described in Sections 5 and 7, data from the WAG manifolds, visual inspections of the injection equipment, and use of the procedures contained in 40 CFR §98.230-238 (Subpart W), will be gathered to complete the mass balance equations necessary to determine annual and cumulative volumes of stored CO2.

2.3.2 Wells in the Rangely Field

As of April 2023, there are 662 active wells that are completed in the Rangely Field, with roughly 40% injection wells and 60% producing wells, as indicated in Figure 11.[2] Table 1 shows these well counts in the Rangely Field by status.

[2] Wells that are not in use are deemed to be inactive, plugged and abandoned, temporarily abandoned, or shut in.

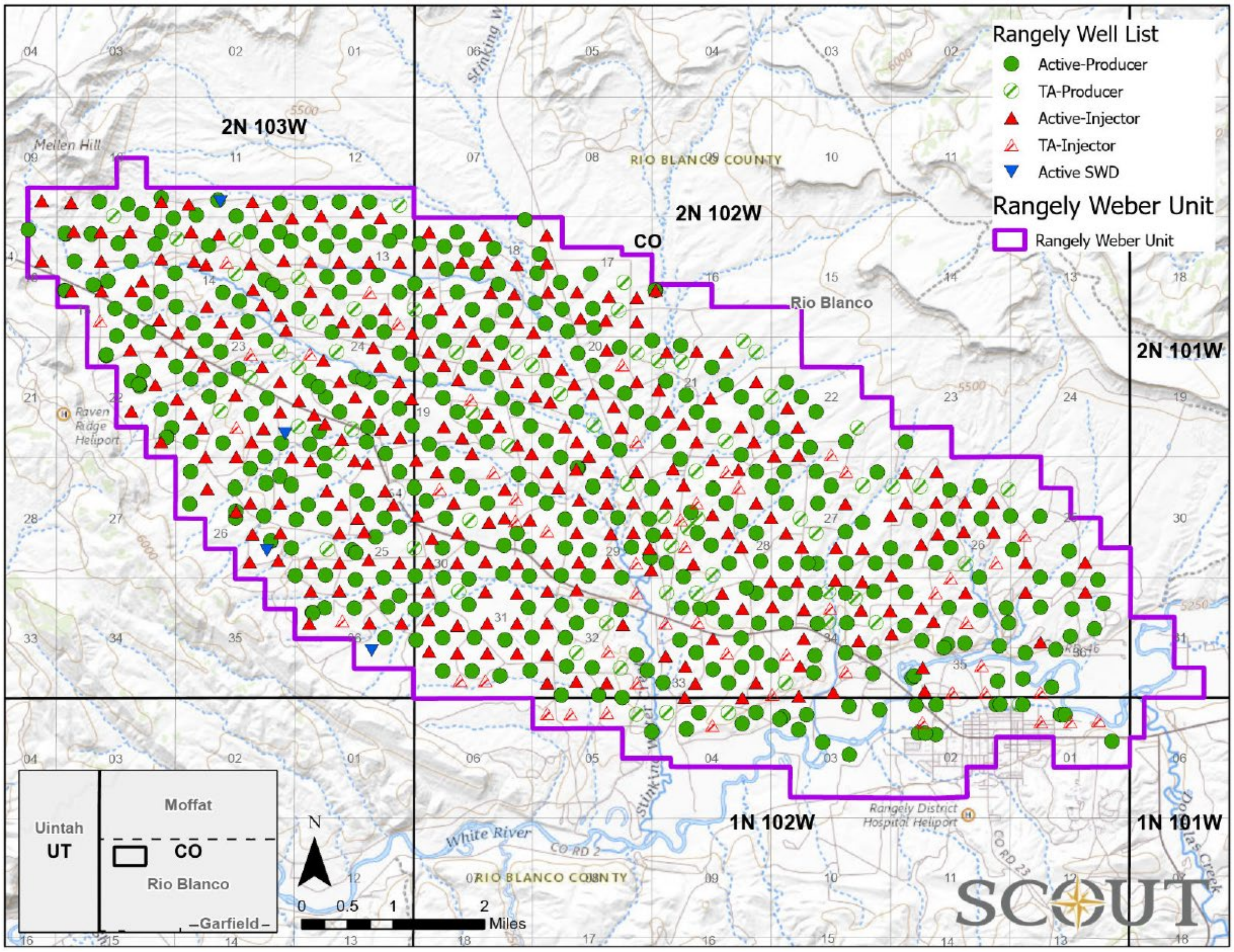

Figure 11 Rangely Field Wells – As of April 2023

Table 1 - Rangely Field Wells

Age/Completion of Well	*Active*	*Shut-in*	*Temporarily Abandoned*	*Plugged and Abandoned*
Drilled & Completed in the 1940's	265	5	55	149
Drilled 1950-1985	297	7	55	46
Completed after 1986	103	1	11	8
TOTAL	***665***	***13***	***121***	***203***

The wells in Table 1 are categorized in groups that relate to age and completion methods. Roughly 48% of these wells were drilled in the 1940's and were generally completed with three strings of casing (with surface and intermediate strings typically cemented to the surface). The production string was typically installed to the top of the producing interval, otherwise known as the main oil column (MOC), which extends to the producible oil/water contact (POWC). These wells were completed by stimulating the open hole (OH), and are not typically cased through the MOC. While implementing the water flood from 1958-1986, a partial liner would have been typically installed to allow for controlled injection intervals and this liner would have been cemented to the top of the liner (TOL) that was installed. For example, a partial liner would be installed from 5,700-6,500 ft, and the TOC would be at 5,700 ft. The casing weights used for the production string have varied between 7" 23 & 26#/ft. with 5" 18 #/ft. for the production liner.

The wells in Table 1 drilled during the period 1950-1986 typically were cased through the production interval with 7” casing. Some wells were completed with 7” casing to the top of the MOC and then completed with a 5” liner through the productive interval. The wells with liners were cemented to the TOL.

The remaining wells (roughly 12%) in Table 1 were drilled after 1986 when the CO2 flood began. All of these wells were completed with 7” casing through the POWC. Very few of these wells have experienced any wellbore issues that would dictate the need for a remedial liner.

SEM reviews these categories along with full wellbore history when planning well maintenance projects. Further, SEM keeps well workover crews on call to maintain all active wells and to respond to any wellbore issues that arise. On average, in the Rangely Field there are two to three incidents per year in which the well casing fails. SEM detects these incidents by monitoring changes in the surface pressure of wells and by conducting Mechanical Integrity Tests (MITs), as explained later in this section and in the relevant regulations cited. This rate of failure is less than 2% of wells per year and is considered extremely low.

All wells in oilfields, including both injection and production wells described in Table 1, are regulated by the COGCC under COGCC 100-1200 series rules. A list of wells, with well identification numbers, is included in Appendix 5. The injection wells are subject to additional requirements promulgated by EPA – the UIC Class II program – implementation of which has been delegated to the COGCC.

COGCC rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Current rules require, among other provisions, that:

- Class II UIC Wells will not be permitted in areas where they would inject into a formation that is separated from any Underground Source of Drinking Water by a Confining Layer with known open faults or fractures that would allow flow between the Injection Zone and Underground Source of Drinking Water within the area of review.

- Injection Zones will not be permitted within 300 feet in a vertical dimension from the top of any Precambrian basement formation.

- An Operator will not inject any Fluids or other contaminants into a UIC Aquifer that meets the definition of an Underground Source of Drinking Water unless EPA has approved a UIC Aquifer exemption as described in Rule 802.e.

In addition, SEM implements a corrosion protection program to protect and maintain the steel used in injection and production wells from any CO2-enriched fluids. SEM currently employs methods to mitigate both internal and external corrosion of casing in wells in the Rangely Field. These methods generally protect the downhole steel and the interior and exterior of wellbores through the use of special materials (e.g. fiberglass tubing, corrosion resistant cements, nickel plated packers, corrosion resistant packer fluids) 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 the COGCC. Corrosion protection methods and requirements may be enhanced over time in response to improvements in technology.

MIT
SEM complies with the MIT requirements implemented by COGCC and BLM to periodically inspect wells and surface facilities to ensure that all wells and related surface equipment are in good repair and leak-free, and that all aspects of the site and equipment conform with Division rules and permit conditions. All active injection wells undergo an MIT at the following intervals:

- Before injection operations begin

- Every 5 years as stated in the injection orders (COGCC 417.a. (1))
- After any casing repair
- After resetting the tubing or mechanical isolation device
- Or whenever the tubing or mechanical isolation device is moved during workover operations

COGCC requires that the operator notify the COGCC district office prior to conducting an MIT. 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 along with the COGCC field representative and submit it with the MIT form. The casing-tubing annulus must be tested to a minimum of 1200 psi for 15 minutes.

If a well fails an MIT, the operator must immediately shut the well in and provide notice to COGCC. Casing leaks must be successfully repaired and retested or the well plugged and abandoned after submitting a formal notice and obtaining approval from the COGCC.

Any well that fails an MIT cannot be returned to active status until it passes a new MIT

2.3.3 Produced Fluids Handling

As injected CO2 and water move through the reservoir, a mixture of oil, gas, and water ("produced fluids") flows to the production wells. Gathering lines bring the produced fluids from each production well to collection stations. SEM has approximately 382 active production wells in the Rangely Field and production from each is sent to one of 27 collection stations. Each collection station consists of a large vessel that performs a gas - liquid separation. Each collection station also has well test equipment to measure production rates of oil, water and gas from individual production wells. SEM has testing protocols for all wells connected to a collection station. Most wells are tested twice per month. Some wells are prioritized for more frequent testing because they are new or located in an important part of the Field; some wells with mature, stable flow do not need to be tested as frequently; and finally, some wells will periodically need repeat testing due to abnormal test results.

After separation, the gas phase is transported by pipeline to the CO2 reinjection facility for processing as described below. Currently the average composition of this gas mixture as it enters the facility is 92% CO2 and 800ppm H2S; this composition will change over time as CO2 EOR operations mature.

The liquid phase, which is a mixture of oil and water, is sent to one of two centralized water plants where oil is separated from water via two 3-phase separators. The water is then sent to water holding tanks where further separation is done.

The separated oil is metered through the Lease Automatic Custody Transfer (LACT) unit located at the custody transfer point between Chevron pipeline and SEM. The oil typically contains a small amount of dissolved or entrained CO2. Analysis of representative samples of oil is conducted once a year to assess CO2 content.

The water is removed from the bottom of the tanks at the water injection stations, where it is re-injected to the WAG injectors.

Any gas that is released from the liquid phase rises to the top of the tanks and is collected by a Vapor Recovery Unit (VRU) that compresses the gas and sends it to the CO2 reinjection facility for processing.

Rangely oil is slightly sour, containing small amounts of hydrogen sulfide ($H2S$), which is highly toxic. There are approximately 25 workers on the ground in the Rangely Field at any given time, and all field personnel are required to wear H2S monitors at all times. Although the primary purpose of H2S detectors is protecting employees, monitoring will also supplement SEM's CO2 leak detection practices as discussed in Sections 5 and 7.

In addition, the procedures in 40 CFR §98.230-238 (Subpart W) and the two-part visual inspection process described in Section 5 are used to detect leakage from the produced fluids handling system. As described in Sections 5 and 7, the volume of leaks, if any, will be estimated to complete the mass balance equations to determine annual and cumulative volumes of stored CO2.

2.3.4 Produced Gas Handling

Produced gas gathered from the collection stations, and water injection plants is sent to the CO2 recycling and compression facility. There is an operations meter at the facility inlet.

Once gas enters the CO2 reinjection facility, it undergoes dehydration and compression. In the RWSU an additional process separates NGLs for sale. At the end of these processes there is a CO2 rich stream that is recycled through re-injection. Meters at the CO2 recycling and compression facility outlet are used to determine the total volume of the CO2 stream recycled back into the EOR operations.

As described in Section 2.3.4, data from 40 CFR §98.230-238 (Subpart W), the two-part visual inspection process for production wells and areas described in Section 5, and information from the personal H2S monitors are used to detect leakage from the produced gas handling system. This data will be gathered to complete the mass balance equations necessary to determine annual and cumulative volumes of stored CO2 as described in Sections 5 and 7.

2.3.5 Water Treatment and Injection

Produced water collected from the collection stations is gathered through a pipeline system and moved to one of two water injection plants. Each facility consists of 3-Phase separators and 79,500-barrels of separation tanks where any remaining oil is skimmed from the water. Skimmed oil is combined with the oil from the 3-Phase separators and sent to the LACT. The water is sent to an injection pump where it is pressurized and distributed to the WAG injectors.

2.3.6 Facilities Locations

The current locations of the various facilities in the Rangely Field are shown in Figure 13. As indicated above, there are two central water plants. There are twenty-seven collections stations that gather production from surrounding wells. The two water plants are identified by the blue triangle and circle. The twenty-seven collection stations are identified by red squares. The CO2 Reinjection facility is indicated by the green circle.

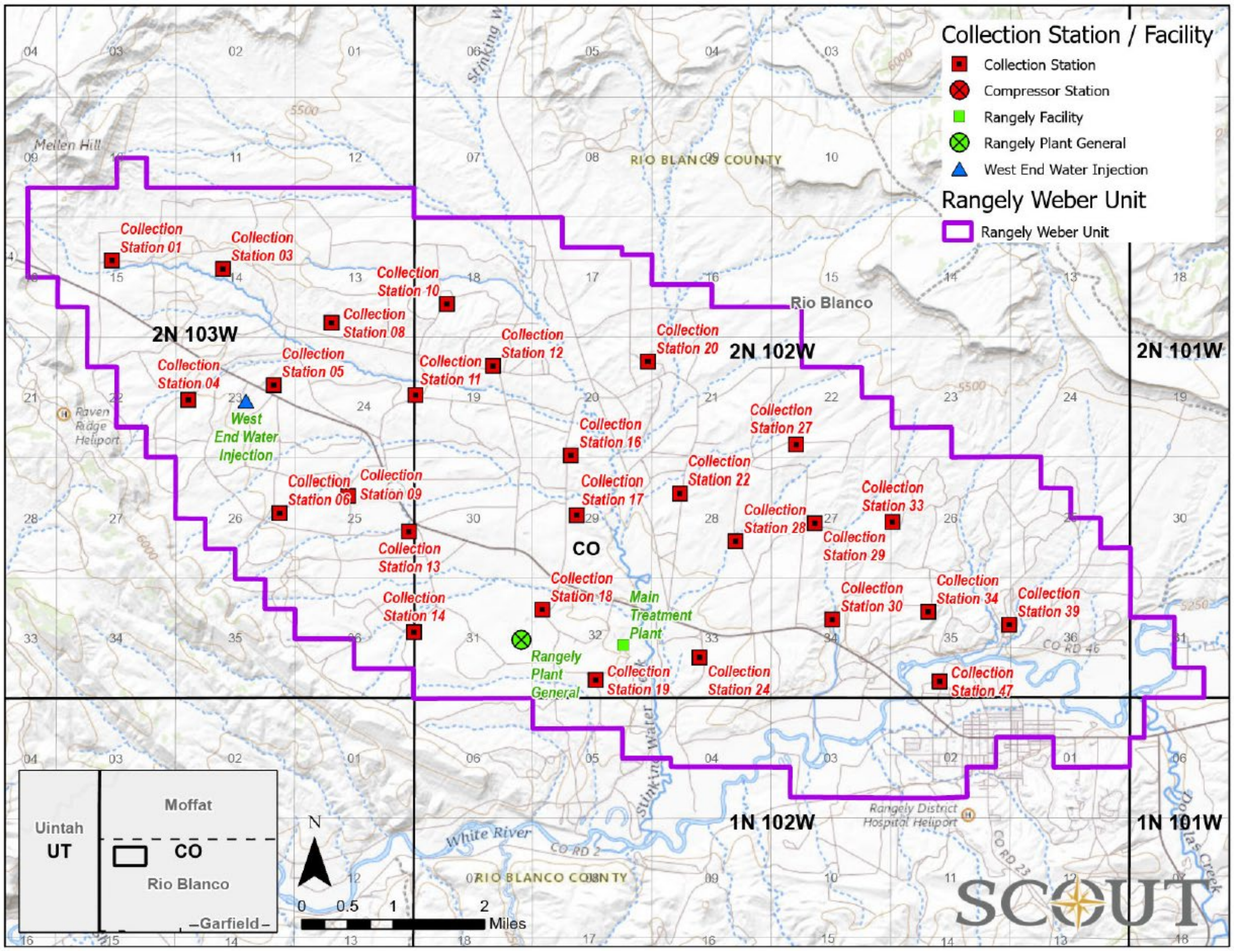

Figure 13 Location of Surface Facilities at Rangely Field

3. Delineation of Monitoring Area and Timeframes

The current active monitoring area (AMA), future AMA and monitoring time frame of the AMA are described below. Additionally, the maximum monitoring area (MMA) of the free phase CO_2 plume, its buffer zone and the monitoring time frame for the MMA are described below.

3.1 Active Monitoring Area

Because CO_2 is present throughout the Rangely Field and retained within it, the Active Monitoring Area (AMA) is defined by the boundary of the Rangely Field plus one-half mile buffer. This boundary is defined in Figure 9. The following factors were considered in defining this boundary:

- Free phase CO_2 is present throughout the Rangely Field: More than 2,320,000 MMscf (122.76 MMMT) tons of CO_2 have been injected and recycled throughout the Rangely Field since 1986 and there has been significant infill drilling in the Rangely Field, completing additional wells to further optimize production. Operational results thus far indicate that there is CO_2 throughout the Rangely Field.

- CO_2 injected into the Rangely Field remains contained within the Rangely Field AMA because of the fluid and pressure management results associated with CO_2 EOR. The maintenance of an IWR of 1.0 assures a stable reservoir pressure; managed lease line injection and production wells are used to retain fluids in the Rangely Field as indicated in Section 4.7. Implementation of these methods over the past decades have successfully contained CO_2 within the Rangely Field.

- It is highly unlikely that injected CO_2 will migrate downdip and laterally outside the Rangely Field because of the nature of the geology and the approach used for injection. As indicated in Section 2.2.1 "Geology of the Rangely Field," the Rangely Field is situated at the top of a dome structural trap, with all directions pointing down-dip from the highest point. This means that over long periods of time, injected CO_2 will tend to rise vertically towards the point in the Rangely Field with the highest elevation.

Forecasted CO_2 injection volumes, shown in Figure 1, represent SEM's plan to not increase current injection volumes and maintain an IWR of 1. Operations will not expand beyond the currently active CO_2-EOR portion of the Rangely Field; therefore, the AMA is not expected to increase. Should such expansions occur, they will be reported in the Subpart RR Annual Report for the Rangely Field, as required by section 98.446.

3.2 Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined in 40 CFR §98.440-449 (Subpart RR) as equal 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 one-half mile. Section 3.1 states that the maximum extent of the injected CO_2 is expected to be bounded by the Rangely Field Unit boundary shown in Figure 9. Therefore, the MMA is the Rangely Field Unit boundary plus the one-half mile buffer as required by 40 CFR §98.440-449 (Subpart RR).

3.3 Monitoring Timeframes

SEM's primary purpose for injecting CO_2 is to produce oil that would otherwise remain trapped in the reservoir and not, as in UIC Class VI, "specifically for the purpose of geologic storage."[3] During a Specified Period, SEM will have a subsidiary purpose of establishing the long-term containment of a measurable quantity of CO_2 in the Weber Sands in the Rangely Field. The Specified Period will be shorter than the period of production from the Rangely Field. This is in part because the purchase of new CO_2 for injection is projected to taper off significantly before production ceases at Rangely Field, which is modeled through 2060. At the conclusion of the Specified Period, SEM will submit a request for discontinuation of reporting. This request will be submitted when SEM can provide 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 upon predictive modeling supported by monitoring data. The demonstration will rely on two principles: 1) that just as is the case for the monitoring plan, the continued process of fluid management during the years of CO_2 EOR operation after the Specified Period will contain injected fluids in the Rangely Field, and 2) that the cumulative mass reported as sequestered during the Specified Period is a fraction of the theoretical storage capacity of the Rangely Field *See* 40 C.F.R. § 98.441(b)(2)(ii).

4. Evaluation of Potential Pathways for Leakage to the Surface

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

4.1 Introduction

In the 90 years since the Rangely Field was discovered in 1933, extensive reservoir monitoring and studies were performed. Based on the knowledge gained from historical practices, this section assesses the following potential pathways for leakage of CO_2 to surface within Rangely Field.

- Existing Wellbores
- Faults and Fractures
- Natural and Induced Seismic Activity
- Previous Operations
- Pipeline/Surface Equipment
- Lateral Migration Outside the Rangely Field
- Drilling Through the CO_2 Area
- Diffuse Leakage Through the Seal

Detailed analysis of these potential pathways concluded that existing wellbores and pipeline/surface equipment pose the only meaningful potential leakage pathways. Operating pressures are not expected to increase over time, therefore there is not a specific time period that would increase the likelihood of pathways for leakage. SEM identifies these potential pathways for CO_2 leakage to be low risk, i.e., less than 1% given the extensive operating history and monitoring program currently in place.

The monitoring program to detect and quantify leakage is based on the assessment discussed below.

4.2 Existing Wellbores

As of April 2023, there are approximately 662 active SEM operated wells in the Rangely Field – split roughly evenly between production and injection wells. In addition, there are approximately 135 wells not in use, as described in Section 2.3.2.

Leakage through existing wellbores is a potential risk at the Rangely Field that SEM works to prevent by adhering to regulatory requirements for well drilling and testing; implementing best practices that SEM has developed through its extensive operating experience; monitoring injection/production performance, wellbores, and the surface; and maintaining surface equipment.

As discussed in Section 2.3.2, regulations governing wells in the Rangely Field require that wells be completed and operated so that fluids are contained in the strata in which they are encountered and that well operation does not pollute subsurface and surface waters. The regulations establish the requirements that all wells (injection, production, disposal) must comply with. Depending upon the purpose of a well, the requirements can include additional standards for evaluation and MIT. SEM's best practices include pattern level analysis to guide injection pressures and performance expectations; utilizing diverse teams of experts to develop EOR projects based on specific site characteristics; and creating a culture where all field personnel are trained to look for and address issues promptly. SEM's practices, which include corrosion prevention techniques to protect the wellbore as needed, as discussed in Section 2.3.2, ensures that well completion and operation procedures are designed not only to comply with regulations but also to ensure that all fluids (e.g., oil, gas, CO_2) remain in the Rangely Field until they are produced through an SEM well.

As described in Section 5, continual and routine monitoring of SEM's wellbores and site operations will be used to detect leaks, including those from non-SEM wells, or other potential well problems, as follows:

- Well pressure in injection wells is monitored on a continual basis. The injection plans for each pattern are programmed into the injection WAG controller, as discussed in Section 2.3.1, to govern the rate and pressure of each injector. Pressure monitors on the injection wells are programmed to flag pressures that significantly deviate from the plan. 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. In the time SEM has operated the Rangely Field, there have been no CO_2 leakage events from a wellbore.

- In addition to monitoring well pressure and injection performance, SEM uses the experience gained over time to strategically approach well maintenance. SEM maintains well maintenance and workover crews onsite for this purpose. For example, the well classifications by age and construction method indicated in Table 1 inform SEM's plan for monitoring and updating wells. SEM uses all of the information at hand including pattern performance, and well characteristics to determine well maintenance schedules.

- Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a collection station. There is a routine cycle for each collection station, with each well being tested approximately twice 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 (generally 24 hours). This test allows SEM to allocate a portion of the produced fluids measured at the collection station 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 is off plan, it is investigated and any identified issues addressed. Leakage to the outside of production wells is not considered a major risk because of the reduced pressure in the casing. Further, the personal H_2S monitors are designed to detect leaked fluids around production wells.

- Finally, as indicated in Section 5, field inspections are conducted on a routine basis by field personnel. On any day, SEM has approximately 25 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 are trained to identify leaking CO_2 and other potential problems at wellbores and in the field. Any CO_2 leakage detected will be documented and reported, quantified and addressed as described in Section 5.

Based on its ongoing monitoring activities and review of the potential leakage risks posed by wellbores, SEM concludes that it is mitigating the risk of CO_2 leakage through wellbores by detecting problems as they arise and quantifying any leakage that does occur. Section 4.10 summarizes how SEM will monitor CO_2 leakage from various pathways and describes how SEM will respond to various leakage scenarios. In addition, Section 5 describes how SEM will develop the inputs used in the Subpart RR mass-balance equation (Equation RR-11). 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

After reviewing geologic, seismic, operating, and other evidence, SEM has concluded that there are no known faults or fractures that transect the entirety of the Weber Sands in the project area. As described in Section 2.2.1, the MFF is present below the reservoir and terminates within the Weber Sands without breaching the upper seal. Additional faults have been identified in formations that are stratigraphically below the Weber Sands, but this faulting has been shown not to affect the Weber Sands or to have created potential leakage pathways given that they do not contact the Upper Pennsylvanian or Permian strata (Weber Fm.).

SEM has extensive experience in designing and implementing EOR projects to ensure injection pressures will not damage the oil reservoir by inducing new fractures or creating shear. As a safeguard, injection satellites are set with automatic shutoff controls if injection pressures exceed fracture pressures.

4.4 Natural or Induced Seismicity

After reviewing literature and historic data, SEM concludes that there is no direct evidence that natural seismic activity poses a significant risk for loss of CO2 to the surface in the Rangely Field. Natural seismic events are derived from the thrust fault to the west. Historically, Figure 6 in section 2.2.1 shows nine (9) seismic events outside of the Rangely Field (including the 1993 M 3.5 event). The epicenter of these earthquakes was far below the operating depths of the Rangely Field, and are associated with the thrust fault to the west of the field. The operations of Rangely have zero impact on this thrust fault. Natural earthquakes are not predictable, but these do not pose a threat to current operations. This is evidenced by the fact that hydrocarbons are still within the anticline, meaning that there have been no major seismic events in the last few million years capable of releasing these hydrocarbons to the surface.

Induced seismic events (non-natural) are tied to the MFF and its joint faults. These can be impacted by Rangely Field operations. Section 2.2.1 explains how an increase in reservoir pressure can trigger seismic events along and near the MFF. To prevent this from occurring bottom hole pressure surveys are collected one (1) to two (2) times per year across the Rangely Field helping to monitor pressure changes along across the Rangely Field. By keeping reservoir pressure from exceeding the threshold of ~3730 psi for extended periods of time (multiple years), induced seismic events can be greatly mitigated. In the case that reservoir pressures do exceed the threshold pressure, a reduction in injected volumes in the vicinity will bring down the pressures back down gradually over a period of time.

4.5 Previous Operations

Chevron initiated CO2 flooding in the Rangely Field in 1986. SEM and the prior operators have kept records of the site and have completed numerous infill wells. SEM has not drilled any new wells in Rangely to date but their standard practice for drilling new wells includes a rigorous review of nearby wells to ensure that drilling will not cause damage to or interfere with existing wells. SEM will also follow AOR requirements under the UIC Class II program, which require identification of all active and abandoned wells in the AOR and implementation of procedures that ensure the integrity of those wells when applying for a permit for any new injection well. These practices ensure that identified wells are sufficiently isolated and do not interfere with the CO2 EOR operations and reservoir pressure management. Consequently, SEM’s operational experience supports the conclusion that there are no unknown wells within the Rangely Field that penetrate the Weber Sands and that it has sufficiently mitigated the risk of migration from older wells.

4.6 Pipeline / Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO2. SEM reduces the risk of unplanned leakage from surface facilities, 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 currently utilize and will continue to utilize materials of construction and control processes that are standard for CO_2 EOR projects in the oil and gas industry. As described above, all facilities in the Rangely Field are internally screened for proximity to the public. In the case of pipeline and surface equipment, best engineering practices call for more robust metallurgy in wellhead equipment, and pressure transducers with low pressure alarms monitored through the SCADA system to prevent and detect leakage. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. CO_2 delivery via the Raven Ridge pipeline system will continue to comply with all applicable regulations. Finally, frequent routine visual inspection of surface facilities by field staff will provide an additional way to detect leaks and further support SEM's efforts to detect and remedy any leaks 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 GHGRP.

4.7 Lateral Migration Outside the Rangely Field

It is highly unlikely that injected CO_2 will migrate downdip and laterally outside the Rangely Field because of the nature of the geology and the approach used for injection. First, as indicated in Section 2.2.1 "Geology of the Rangely Field," the Rangely Field is situated at the top of a dome structural trap, with all directions pointing down-dip from the highest point. This means that over long periods of time, injected CO_2 will tend to rise vertically towards the point in the Rangely Field with the highest elevation. Second, the planned injection volumes and active fluid management during injection operations will prevent CO_2 from migrating laterally stratigraphically (down-dip structurally) out of the structure. Finally, SEM will not be increasing the total volume of fluids in the Rangely Field.

COGCC requires that injection pressures be limited to ensure injection fluids do not migrate outside the permitted injection interval. In the Rangely Field, SEM uses two methods to contain fluids: reservoir pressure management and the careful placement and operation of wells along the outer producing limits of the units.

Reservoir pressure in the Rangely Field is managed by maintaining an injection to withdrawal ratio (IWR) of approximately 1.0. To maintain the IWR, SEM monitors fluid injection to ensure that reservoir pressure does not increase to a level that would fracture the reservoir seal or otherwise damage the oil field.

SEM also prevents injected fluids from migrating out of the injection interval by keeping injection pressure below the formation fracture pressure, which is measured using historic step-rate tests. In these tests, injection pressures are incrementally increased (e.g., in "steps") until injectivity increases abruptly, which indicates that an opening or fracture has been created in the rock. SEM manages its operations to ensure that injection pressures are kept below the formation fracture pressure so as to ensure that the valuable fluid hydrocarbons and CO_2 remain in the reservoir.

There are a few small producer wells operated by third parties outside the boundary of Rangely Field. There are currently no significant commercial operations surrounding the Rangely Field to interfere with SEM's operations.

Based on site characterization and planned and projected operations SEM estimates the total volume of stored CO_2 will be approximately 35.7% of calculated capacity.

4.8 Drilling Through the CO_2 Area

It is possible that at some point in the future, drilling through the containment zone into the Weber Sands could occur and inadvertently create a leakage pathway. SEM's review of this issue concludes that this risk is very low for two reasons. First, SEM's visual inspection process, including routine site visits, is designed to identify unapproved drilling activity in the Rangely Field. Second, SEM plans to operate the CO_2 EOR flood in the Rangely Field for several more years, and will continue to be vigilant about protecting the integrity of its assets and maximizing the potential of resources (oil, gas, CO_2). In the unlikely event SEM would sell the field to a new operator, provisions would result in a change to the reporting program and would be addressed at that time.

4.9 Diffuse Leakage through the Seal

Diffuse leakage through the seal formed by the Moenkopi Formation is highly unlikely. The presence of a gas cap trapped over millions of years as discussed in Section 2.2.3 confirms that the seal has been secure for a very long time. Injection pattern monitoring program referenced in Section 2.3.1 and detailed in Section 5 assures that no breach of the seal will be created. The seal is highly impermeable where unperforated, cemented across the horizon where perforated by wells, and unexplained changes in injection pressure would trigger investigation as to the cause. Further, if CO_2 were to migrate through the Moenkopi seal, it would migrate vertically until it encountered and was trapped by any of the numerous shallower shale seals

4.10 Monitoring, Response, and Reporting Plan for CO_2 Loss

As discussed above, the potential sources of leakage include fairly routine issues, such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment (wellbores), and unique events such as induced fractures. Table 3 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, SEM's 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 CO_2. Given the uncertainty concerning the nature and characteristics of leaks that will be encountered, the most appropriate methods for quantifying the volume of leaked CO_2 will be determined at the time. In the event leakage occurs, SEM plans 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, SEM's field experience, and other factors such as the 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.

Table 3 Response Plan for CO_2 Loss

Risk	Monitoring Plan	Response Plan	Parallel Reporting (if any)
Loss of Well Control			
Tubing Leak	Monitor changes in tubing and annulus pressure; MIT for injectors	Well is shut in and Workover crews respond within days	COGCC
Casing Leak	Routine Field inspection; monitor changes in annulus pressure; MIT for injectors; extra attention to high risk wells	Well is shut in and Workover crews respond within days	COGCC
Wellhead Leak	Routine Field inspection	Well is shut in and Workover crews respond within days	COGCC
Loss of Bottom-hole pressure control	Blowout during well operations	Maintain well kill procedures	COGCC

Unplanned wells drilled through Weber Sands	Routine Field inspection to prevent unapproved drilling; compliance with COGCC permitting for planned wells.	Assure compliance with COGCC regulations	COGCC Permitting
Loss of seal in abandoned wells	Reservoir pressure in monitor wells; high pressure found in new wells	Re-enter and reseal abandoned wells	COGCC
Leaks in Surface Facilities			
Pumps, valves, etc.	Routine Field inspection; SCADA	Maintenance crews respond within days	Subpart W
Subsurface Leaks			
Leakage along faults	Reservoir pressure in monitor wells; high pressure found in new wells	Shut in injectors near faults	-
Overfill beyond spill points	Reservoir pressure in monitor wells; high; pressure found in new wells	Fluid management along lease lines	-
Leakage through induced fractures	Reservoir pressure in monitor wells; high pressure found in new wells	Comply with rules for keeping pressures below parting pressure	-
Leakage due to seismic event	Reservoir pressure in monitor wells; high pressure found in new wells	Shut in injectors near seismic event	-

Available studies of actual well leaks and natural analogs (e.g., naturally occurring CO2 geysers) suggest that the amount released from routine leaks would be small as compared to the amount of CO2 that would remain stored in the formation.

4.11 Summary

The structure and stratigraphy of the Weber Sands in the Rangely Field is ideally suited for the injection and storage of CO2. The stratigraphy within the CO2 injection zones is porous, permeable and very thick, providing ample capacity for long-term CO2 storage. The Weber Sands is overlain by several intervals of impermeable geologic zones that form effective seals or “caps” to fluids in the Weber Sands (See Figure 4). After assessing potential risk of release from the subsurface and steps that have been taken to prevent leaks, SEM has determined that the potential threat of leakage is extremely low.

In summary, based on a careful assessment of the potential risk of release of CO2 from the subsurface, SEM has determined that there are no leakage pathways at the Rangely Field that are likely to result in significant loss of CO2 to the atmosphere. Further, given the detailed knowledge of the Field and its operating protocols, SEM concludes that it would be able to both detect and quantify any CO2 leakage to the surface that could arise through either identified or unexpected leakage pathways.

5. Monitoring and Considerations for Calculating Site Specific Variables

Monitoring will also be used to determine the quantities in the mass balance equation and to make the demonstration that the CO2 plume will not migrate to the surface after the time of discontinuation.

5.1 For the Mass Balance Equation

5.1.1 General Monitoring Procedures

As part of its ongoing operations, SEM monitors and collects flow, pressure, and gas composition data from the Rangely Field in centralized data management systems. These data are monitored continually by qualified technicians who follow SEM response and reporting protocols when the systems deliver notifications that data exceed statistically acceptable boundaries.

As indicated in Figures 10 and 11, custody-transfer meters are used at the point at which custody of the CO2 from the Raven Ridge pipeline delivery system is transferred to SEM, and at the points at which custody of oil and NGLs are transferred to outside parties. Meters measure flow rate continually. Fluid composition will be determined, at a minimum, quarterly, consistent with EPA GHGRP's Subpart RR, section 98.447(a). All meter and composition data are documented, and records will be retained for at least three years.

Metering protocols used by SEM 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. This approach is consistent with EPA GHGRP's Subpart RR, section 98.444(e)(3). These meters will be maintained routinely, operated continually, and will feed data directly to the centralized data collection systems. The meters meet the industry standard for custody transfer meter accuracy and calibration frequency. These custody meters provide the most accurate way to measure mass flows.

SEM maintains in-field process control meters to monitor and manage in-field activities on a real time basis. These are identified as operations meters in Figures 10 and 11. These meters provide information used to make operational decisions but are not intended to provide the same level of accuracy as the custody-transfer meters. The level of precision and accuracy for in-field meters currently satisfies the requirements for reporting in existing UIC permits. Although these meters are accurate for operational purposes, it is important to note that there is some variance between most commercial meters (on the order of 1-5%) which is additive across meters. This variance is due to differences in factory settings and meter calibration, as well as 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 can affect in-field meter readings. Unlike in a saline formation, where there are likely to be only a few injection wells and associated meters, at CO2 EOR operations in the Rangely Field there are currently 662 active injection and 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.

5.1.2 CO2 Received

SEM measures the volume of received CO2 using commercial custody transfer meters at the off-take point from the Raven Ridge pipeline delivery system. This transfer is a commercial transaction that is documented. CO2 composition is governed by the contract and the gas is routinely sampled to determine composition. No CO2 is received in containers.

5.1.3 CO2 Injected into the Subsurface

Injected CO2 will be calculated using the flow meter volumes at the operations meter at the outlet of the CO2 Reinjection Facility and the custody transfer meter at the CO2 off-take points from the Raven Ridge pipeline delivery system

5.1.4 CO2 Produced, Entrained in Products, and Recycled

The following measurements are used for the mass balance equations in Section 7:

CO2 produced is calculated using the volumetric flow meters at the inlet to the CO2 Reinjection Facility. These flow meters, as illustrated on Figure 10, are downstream of the field collection station separators and bulk produced fluid separators at the water injection plants

CO2 is produced as entrained or dissolved CO2 in produced oil, as indicated in Figures 10 and 11. This is calculated using volumetric flow through the custody transfer meter.

Recycled CO2 is calculated using the volumetric flow meter at the outlet of the CO2 Reinjection Facility, which is an operations meter.

5.1.5 CO2 Emitted by Surface Leakage

As discussed in Section 5.1.6 and 5.1.7 below, SEM uses 40 CFR Part 98 Subpart W to estimate surface leaks from equipment at the Rangely Field. Subpart W uses a factor-driven approach to estimate equipment leakage. In addition, SEM uses an event-driven process to assess, address, track, and if applicable quantify potential CO_2 leakage to the surface.

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.

<u>Monitoring for potential Leakage from the Injection/Production Zone:</u>

SEM will monitor both injection into and production from the reservoir as a means of early identification of potential anomalies that could indicate leakage from the subsurface.

SEM develops injection plans for each well and that is distributed to operations weekly. If injection pressure or rate measurements are beyond the specified set points determined as part of each pattern injection plan, the operations engineer will notify field personnel and they 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 SEM support staff would provide additional assistance and evaluation. Such issues would lead to the development of a work order in SEM's work order management system. This record enables the company to track progress on investigating potential leaks and, if a leak has occurred, to quantify its magnitude.

Likewise, SEM develops a forecast of the rate and composition of produced fluids. Each producer well is assigned to one collection station and is isolated twice 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. If the issue cannot be resolved quickly, more detailed investigation and response would be initiated. As in the case of the injection pattern monitoring, if the investigation leads to a work order in the SEM work order management system, this record will provide the basis for tracking the outcome of the investigation and if a leak has occurred. If leakage in the flood zone were detected, SEM would use an appropriate method to quantify the involved volume of CO_2. This might include use of material balance equations based on known injected quantities and monitored pressures in the injection zone to estimate the volume of CO_2 involved.

A subsurface leak might not lead to a surface leak. In the event of a subsurface leak, SEM would determine the appropriate approach for tracking subsurface leakage to determine and quantify leakage to the surface. To quantify leakage to the surface, SEM would estimate the relevant parameters (e.g., the rate, concentration, and duration of leakage) to quantify the leak volume. Depending on specific circumstances, these determinations may rely on engineering estimates.

In the event leakage from the subsurface occurred diffusely through the seals, the leaked gas would include H_2S, which would trigger the alarm on the personal monitors worn by field personnel. Such a diffuse leak from the subsurface has not occurred in the Rangely Field. In the event such a leak was detected, field personnel from across SEM would determine how to address the problem. The team might use modeling, engineering estimates, and direct measurements to assess, address, and quantify the leakage.

Monitoring of Wellbores:
SEM monitors wells through continual, automated pressure monitoring in the injection zone (as described in Section 4.2), monitoring of the annular pressure in wellheads, and routine maintenance and inspection.

Leaks from wellbores would be detected through the follow-up investigation of pressure anomalies, visual inspection, or the use of personal H_2S monitors.

Anomalies in injection zone pressure may not indicate a leak, as discussed above. However, if an investigation leads to a work order, field personnel would inspect the equipment in question and determine the nature of the problem. If it is a simple matter, the repair would be made and the volume of leaked CO_2 would be included in the 40 CFR Part 98 Subpart W report for the Rangely Field, as well as reported in Subpart RR . If more extensive repair were needed, SEM would determine the appropriate approach for quantifying leaked CO_2 using the relevant parameters (e.g., the rate, concentration, and duration of leakage). The work order would serve as the basis for tracking the event for GHG reporting.

Anomalies in annular pressure or other issues detected during routine maintenance inspections would be treated in the same way. Field personnel would inspect the equipment in question and determine the nature of the problem. For simple matters the repair would be made at the time of inspection and the volume of leaked CO_2 would be included in the 40 CFR Part 98 Subpart W report for the Rangely Field, as well as reported in Subpart RR. If more extensive repairs were needed, a work order would be generated and SEM would determine the appropriate approach for quantifying leaked CO_2 using the relevant parameters (e.g., the rate, concentration, and duration of leakage). The work order would serve as the basis for tracking the event for GHG reporting.

Because leaking CO_2 at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, SEM also employs a two-part visual inspection process in the general area of the Rangely Field 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 also check that injectors are on the proper WAG schedule and observe the facility for visible CO_2 or fluid line leaks.

Historically, SEM has not experienced any unexpected release events in the Rangely Field. An identified need for repair or maintenance through visual inspections results in a work order being entered into SEM's equipment and maintenance work order management system. The time to repair any leak is dependent on several factors, such as the severity of the leak, available manpower, location of the leak, and availability of materials required for the repair. Critical leaks are acted upon immediately.

Finally, SEM uses the data collected by the H_2S monitors, which are worn by all field personnel at all times, as a last method to detect leakage from wellbores. The H_2S monitors detection limit is 10ppm; if an H_2S 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. As noted previously, SEM considers H_2S a proxy for potential CO_2 leaks in the field. Thus, detected H_2S leaks will be investigated to determine if potential CO_2 leakage is present, but not used to determine the leak volume. 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:
SEM will utilize the same visual inspection process and H_2S monitoring system to detect other potential leakage at the surface as it does for leakage from wellbores. SEM utilizes routine visual inspections to detect significant loss of CO_2 to the surface. Field personnel routinely visit surface facilities to conduct a visual inspection. Inspections may include review of tank level, equipment status, lube oil levels, pressures and flow rates in the facility, valve leaks, ensuring that injectors are on the proper WAG schedule, and also 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, SEM will use the results

of the personal H_2S monitors worn by field personnel 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 CO2 emitted from equipment leaks and vented emissions of CO2 from surface equipment located between the injection flow meter and the injection wellhead.

SEM evaluates and estimates the mass of CO_2 emitted (in metric tons) annually 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, as required under 40 CFR Part 98 Subpart W and 40 CFR Part 98 Subpart RR.

5.1.7 Mass of CO2 emissions from equipment leaks and vented emissions of CO2 from surface equipment located between the production flow meter and the production wellhead

SEM evaluates and estimates the mass of CO_2 emitted (in metric tons) annually 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, as required under 40 CFR Part 98 Subpart W and 40 CFR Part 98 Subpart RR.

5.2 To Demonstrate that Injected CO2 is not Expected to Migrate to the Surface

At the end of the Specified Period, SEM intends to cease injecting CO_2 for the subsidiary purpose of establishing the long-term storage of CO_2 in the Rangely Field. After the end of the Specified Period, SEM anticipates 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, SEM will be able to support its 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 (purchase, 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 Rangely Field that demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

6. Determination of Baselines

SEM intends to utilize existing automatic data systems to identify and investigate excursions from expected performance that could indicate CO_2 leakage. SEM's 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. SEM will develop the necessary system guidelines to capture the information that is relevant to identify possible CO_2 leakage. The following describes SEM's 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 addressed on the spot. 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 H_2S Monitors

H_2S 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. The person responsible for MRV documentation will receive notice of all incidents where H_2S is confirmed to be present. The Annual Subpart RR Report will provide an estimate 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

SEM develops target injection rate and pressure for each injector, based on the results of ongoing pattern modeling and within permitted limits. The injection targets are programmed into the WAG controllers. High and low set points are also programmed into the SCADA, and flags whenever statistically significant deviations from the targeted ranges are identified. The set points are designed to be conservative, because it is preferable to have too many flags rather than too few. 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

SEM develops a general forecast of 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 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 the site conditions and complexity of a large, active EOR operation, SEM will utilize the locations described below for obtaining volume data for the equations in Subpart RR §98.443 as indicated below.

The selection of the utilized locations, more specifically described in this Section 7, address the propagation of error that would result if volume data from meters at each injection 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 the approximately 284 meters within the Rangely Field. As such, SEM will use the data from custody and operations meters on the main system pipelines to determine injection volumes used in the mass balance. This satisfies the requirement in 40 CFR 98.444 (b) 1 that you must select a point or points of measurement at which the CO_2 stream is representative of the CO_2 streams being injected.

The volumetric flow meters utilized for CO_2 produced are located at the inlet to the RCF. These flow meters, as illustrated on Figure 10, are directly downstream of the field collection station separators and bulk produced fluid separators at the water injection plants. This satisfies the requirement in 40 CFR 98.444 (c)(1) for production, which states, “The point of measurement for the quantity of CO2 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 following sections describe how each element of the mass-balance equation (Equation RR-11) will be calculated.

7.1. Mass of CO2 Received

SEM will use equation RR-2 as indicated in Subpart RR §98.443 to calculate the mass of CO2 received from each delivery meter immediately upstream of the Raven Ridge pipeline delivery system on the Rangely Field. The volumetric flow at standard conditions will be multiplied by the CO2 concentration and the density of CO2 at standard conditions to determine mass.

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

where:
$CO_{2T,r}$ = Net annual mass of CO2 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 your well in quarter p (standard cubic meters).
D = Density of CO2 at standard conditions (metric tons per standard cubic meter): 0.0018682.
$C_{CO2,p,r}$ = Quarterly CO2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO2, expressed as a decimal fraction).
p = Quarter of the year.
r = Receiving flow meter.

Given SEM’s method of receiving CO2 and requirements at Subpart RR §98.444(a):

- All delivery to the Rangely Field is used within the unit so quarterly flow redelivered, $S_{r,p}$, is zero (0) and will not be included in the equation.
- Quarterly CO2 concentration will be taken from the gas measurement database SEM will sum to total Mass of CO2 Received using equation RR-3 in 98.443

$$\mathrm{CO}_2 = \sum_{r=1}^{R}\mathrm{CO}_{2\mathrm{T},r} \qquad \text{(Eq. RR-3)}$$

where:
CO_2 = Total net annual mass of CO2 received (metric tons).
$CO_{2T,r}$ = Net annual mass of CO2 received (metric tons) as calculated in Equation RR–1 or RR–2 for flow meter r.
r = Receiving flow meter.

7.2 Mass of CO2 Injected into the Subsurface

The equation for calculating the Mass of CO2 Injected into the Subsurface at the Rangely Field is equal to the sum of the Mass of CO2 Received as calculated in RR-3 of 98.443 (as described in Section 7.1) and the Mass of CO2 Recycled as calculated using measurements taken from the flow meter located at the output of the RCF. As previously explained, using data at each injection well would give an inaccurate estimate of total injection volume due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

The mass of CO2 recycled will be determined using equation RR-5 as follows:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \quad \text{(Eq. RR-5)}$$

where:
$CO_{2,u}$ = Annual CO2 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 CO2 at standard conditions (metric tons per standard cubic meter): 0.0018682.
$C_{CO2,p,u}$ = CO2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO2, expressed as a decimal fraction).
p = Quarter of the year.
u = Flow meter.

The aggregate injection data will be calculated pursuant to the procedures specified in equation RR-6 as follows:

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

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

7.3 Mass of CO2 Produced

The Mass of CO2 Produced at the Rangely Field will be calculated using the measurements from the flow meters at the inlet to RCF and for CO2 entrained in the sales oil, 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 CO2 produced from all injection wells as follows:

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * D * C_{CO_{2,p,w}} \quad \text{(Eq. RR-8)}$$

Where:
$CO_{2,w}$ = Annual CO2 mass produced (metric tons) through separator w.
$Q_{p,w}$ = Volumetric gas flow rate measurement for separator w in quarter p at standard conditions (standard cubic meters).
D = Density of CO2 at standard conditions (metric tons per standard cubic meter): 0.0018682.
$C_{CO2,p,w}$ = CO2 concentration measurement in flow for separator w in quarter p (vol. percent CO2, expressed as a decimal fraction).
p = Quarter of the year.
w = Separator.

Equation RR-9 in 98.443 will be used to aggregate the mass of CO2 produced and the mass of CO2 entrained in oil or other fluid leaving the Rangely Field as follows:

$$CO_{2P} = (1+X) * \sum_{w=1}^{W} CO_{2,w} \qquad \text{(Eq. RR-9)}$$

Where:
CO_{2P} = Total annual CO2 mass produced (metric tons) through all separators in the reporting year.
$CO_{2,w}$ = Annual CO2 mass produced (metric tons) through separator w in the reporting year.
X = Entrained CO2 in produced oil or other fluid divided by the CO2 separated through all separators in the reporting year (weight percent CO2, expressed as a decimal fraction).
w = Separator.

7.4 Mass of CO2 emitted by Surface Leakage

SEM will calculate and report the total annual Mass of CO2 emitted by Surface Leakage using an approach that relies on 40 CFR Part 98 Subpart W reports for equipment leakage, and tailored calculations for all other surface leaks. As described in Sections 4 and 5.1.5-5.1.7, SEM is prepared to address the potential for leakage in a variety of settings. Given the uncertainty concerning the nature and characteristics of leaks that will be encountered, it is not clear the method for quantifying the volume of leaked CO2 that would be most appropriate. Estimates of the amount of CO2 leaked to the surface will depend on a number of site-specific factors including measurements of flowrate, pressure, size of leak opening, and duration of the leak. Engineering estimates, and emission factors, depending on the source and nature of the leakage will also be used.

SEM's 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, SEM describes some approaches for quantification in Section 5.1.5-5.1.7. In the event leakage to the surface occurs, SEM would quantify and report leakage amounts, and retain records that describe the methods used to estimate or measure the volume leaked as reported in the Annual Subpart RR Report.

Equation RR-10 in 48.433 will be used to calculate and report the Mass of CO2 emitted by Surface Leakage:

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

where:
CO_{2E} = Total annual CO2 mass emitted by surface leakage (metric tons) in the reporting year.
$CO_{2,x}$ = Annual CO2 mass emitted (metric tons) at leakage pathway x in the reporting year.
x = Leakage pathway.

7.5 Mass of CO2 sequestered in subsurface geologic formations.

SEM will use equation RR-11 in 98.443 to calculate the Mass of CO2 Sequestered in Subsurface Geologic Formations in the Reporting Year as follows:

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \qquad \text{(Eq. RR-11)}$$

where:
CO2 = Total annual CO2 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_{2P} = Total annual CO2 mass produced (metric tons) in the reporting year.
CO_{2E} = Total annual CO2 mass emitted (metric tons) by surface leakage in the reporting year.
CO_{2FI} = Total annual CO2 mass emitted (metric tons) from equipment leaks and vented emissions of CO2 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 CO2 mass emitted (metric tons) from equipment leaks and vented emissions of CO2 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.

7.6 Cumulative mass of CO2 reported as sequestered in subsurface geologic formations

SEM will sum up the total annual volumes obtained using equation RR-11 in 98.443 to calculate the Cumulative Mass of CO2 Sequestered in Subsurface Geologic Formations.

8. MRV Plan Implementation Schedule

The activities described in this MRV Plan are in place, and reporting is planned to start upon EPA approval. 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, SEM anticipates that the MRV program will be in effect during the Specified Period, during which time SEM will operate the Rangely Field with the subsidiary purpose of establishing long-term containment of a measurable quantity of CO2 in subsurface geological formations at the Rangely Field. SEM anticipates establishing that a measurable amount of CO2 injected during the Specified Period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, SEM will prepare a demonstration supporting the long-term containment determination and submit 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, SEM has incorporated the requirements of §98.444 (a) – (d) in the discussion of mass balance equations. These include the following provisions.

CO2 Received and Injected

- The quarterly flow rate of CO2 received by pipeline is measured at the receiving custody transfer meters.
- The quarterly CO2 flow rate for recycled CO2 is measured at the flow meter located at the CO2 Reinjection facility outlet.

CO2 Produced

- The point of measurement for the quantity of CO2 produced is a flow meter at the CO2 Reinjection facility inlet. . CO2 produced as entrained or dissolved CO2 in produced oil is calculated using volumetric flow through the custody transfer meter.
- 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 CO2 concentration of the sample.
- The quarterly flow rate of the produced gas is measured at the flow meters located at the CO2 Reinjection facility inlet.

CO2 emissions from equipment leaks and vented emissions of CO2
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 date 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 CO2
As indicated in Appendix 1, CO2 concentration is measured using an appropriate standard method. Further, all measured volumes of CO2 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 SEM is unable to collect data needed for the mass balance calculations, procedures for estimating missing data in §98.445 will be used as follows:

- A quarterly flow rate of CO2 received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.
- A quarterly CO2 concentration of a CO2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO2 injected that is missing would be estimated using a representative quantity of CO2injected from the nearest previous period of time at a similar injection pressure.
- For any values associated with CO2 emissions from equipment leaks and vented emissions of CO2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.
- The quarterly quantity of CO2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO2 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 of the SEM CO2 EOR operations in the Rangely Field that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in §98.448(d).

10. Records Retention

SEM will follow the record retention requirements specified by §98.3(g). 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 CO2 received at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of produced CO2, 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

Appendix 1. Conversion Factors

SEM reports CO_2 volumes at standard conditions of temperature and pressure as defined in the State of Colorado, which follows the international standard conditions for measuring CO_2 properties – 77 ^{o}F and 14.696 psi.

To convert these volumes into metric tonnes, a density is calculated using the Span and Wagner equation of state as recommended by the EPA. Density was calculated using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST), available at http://webbook.nist.gov/chemistry/fluid/.

At EPA standard conditions of 77 ^{o}F and one atmosphere, the Span and Wagner equation of state gives a density of 0.0026500 lb-moles per cubic foot. Using a molecular weight for CO_2 of 44.0095, 2204.62 lbs/metric ton and 35.314667 ft^3/m^3, gives a CO_2 density of 5.29003 x 10^{-5} MT/ft^3 or 0.0018682 MT/m^3.

The conversion factor 5.29003 x 10^{-5} MT/Mcf has been used throughout to convert SEM volumes to metric tons.

Appendix 2. Acronyms

AGA – American Gas Association
AMA – Active Monitoring Area
AoR – Area of Review
API – American Petroleum Institute
BCF – Billion Cubic Feet
bopd – barrels of oil per day
Cf – Cubic Feet
CCR - Code of Colorado Regulations
COGCC - Colorado Oil and Gas Conservation Commission
CO2 – Carbon Dioxide
CRF – CO2 Removal Facilities
EOR – Enhanced Oil Recovery
EPA – US Environmental Protection Agency
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
H2S – Hydrogen Sulfide
IWR - Injection to Withdrawal Ratio
LACT – Lease Automatic Custody Transfer meter
Md - Millidarcy
MIT – Mechanical Integrity Test
MFF – Main Field Fault
MMA – Maximum Monitoring Area
MMB – Million barrels
Mscf – Thousand standard cubic feet
MMscf – Million standard cubic feet
MMMT – Million metric tonnes
MMT – Thousand metric tonnes
MRV – Monitoring, Reporting, and Verification
MOC – Main oil column
MT - Metric Tonne
NG—Natural Gas
NGLs – Natural Gas Liquids
NIST – National Institute of Standards and Technology
OOIP – Original Oil-In-Place
OH – Open hole
POWC - Producible oil/water contact
PPM – Parts Per Million
RCF – Rangely Field CO2 Recycling and Compression Facility
RRPC - Raven Ridge pipeline
RWSU - Rangely Weber Sand Unit
SCADA - Supervisory Control and Data Acquisition
SEM – Scout Energy Management, LLC
UIC – Underground Injection Control
VRU - Vapor Recovery Unit
WAG – Water Alternating Gas
XOM - ExxonMobil

Appendix 3. References

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Appendix 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/).

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

Dip -- Very few, if any, geologic features are perfectly horizontal. They are almost always tilted. The direction of tilt is called "dip." Dip is the angle of steepest descent measured from the horizontal plane. 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."

Formation -- A body of rock that is sufficiently distinctive and continuous that it can be mapped.

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

Pore Space -- See porosity.

Porosity -- Porosity is the fraction of a rock that is not occupied by solid grains or minerals. Almost 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."

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 gas injection and waterflooding.

Stratigraphic section -- A stratigraphic section is a sequence of layers of rocks in the order they were deposited.

Strike -- See “dip.”

Updip -- See “dip.”

Appendix 5. Well Identification Numbers

The following table presents the well name, API number, status and type for the wells in the RWSU as of April 2023. The table is subject to change over time as new wells are drilled, existing wells change status, or existing wells are repurposed. The following terms are used:

Well Status

- Producing refers to a well that is actively producing
- Injecting refers to a well that is actively injecting
- P&A refers to wells that have been closed (plugged and abandoned) per COGCC regulations
- Shut In refers to wells that have been temporarily idled or shut-in
- Monitor refers to a well that is used to monitor bottom home pressure in the reservoir

Well Type

- Water / Gas Inject refers to wells that inject water and CO2 Gas
- Water Injection Well refers to wells that inject water
- Oil well refers to wells that produce oil
- Salt Water Disposal refers to a well used to dispose of excess water

Name	API Number	Well Type	Well Status
A C MCLAUGHLIN 46	51030632300	Water Injection Well	P&A
AC MCLAUGHLIN 64X	51030771700	Oil well	Producing
ASSOCIATED A 2	51030571400	Water / Gas Inject	P&A
ASSOCIATED A1	51030571300	Oil well	Producing
ASSOCIATED A2ST	51030571401	Water / Gas Inject	Injecting
ASSOCIATED A3X	51030778600	Oil well	Producing
ASSOCIATED A4X	51030791600	Oil well	Producing
ASSOCIATED A5X	51030803400	Water / Gas Inject	Injecting
ASSOCIATED A6X	51030801100	Water / Gas Inject	Injecting
ASSOCIATED LARSON UNIT A1	51030600900	Oil well	Producing
ASSOCIATED LARSON UNIT A2X	51030881500	Oil well	Producing
ASSOCIATED LARSON UNIT B1	51030601100	Oil well	Producing
ASSOCIATED LARSON UNIT B2X	51030950200	Oil well	Producing
ASSOCIATED UNIT A1	51030602600	Oil well	Producing
ASSOCIATED UNIT A2X UN A-2X	51031053200	Oil well	Producing
ASSOCIATED UNIT A3X	51031072300	Oil well	Producing
ASSOCIATED UNIT A4X	51031072200	Water / Gas Inject	Injecting
ASSOCIATED UNIT C1	51030582700	Oil well	Producing
BEEZLEY 1X22AX	51031075400	Water / Gas Inject	Injecting
BEEZLEY 2-22	51030574200	Oil well	Producing
BEEZLEY 3X 3X22	51031054900	Oil well	Producing
BEEZLEY 4X 22	51031055300	Oil well	Producing
BEEZLEY 5X22	51031174200	Oil well	Producing
BEEZLEY 6X22	51031174300	Oil well	Producing

CARNEY 22X-35	51030724500	Oil well	P&A
CARNEY CT 10-4	51030608600	Oil well	Monitor
CARNEY CT 11-4	51030545700	Oil well	Monitor
CARNEY CT 12AX5	51030917600	Water / Gas Inject	Monitor
CARNEY CT 13-4	51030545900	Oil well	Producing
CARNEY CT 1-34	51030548200	Oil well	Producing
CARNEY CT 14-34	51030103500	Oil well	Producing
CARNEY CT 15-35	51030103700	Water / Gas Inject	Injecting
CARNEY CT 16-35	51030103300	Water / Gas Inject	Monitor
CARNEY CT 17-35	51030103200	Oil well	Producing
CARNEY CT 18-35	51030629500	Water / Gas Inject	Injecting
CARNEY CT 19-34	51030604400	Oil well	Producing
CARNEY CT 20X35	51030641300	Oil well	Producing
CARNEY CT 21X35	51030703300	Water / Gas Inject	Injecting
CARNEY CT 22X35ST	51030724501	Oil well	Producing
CARNEY CT 2-34	51030551400	Oil well	Monitor
CARNEY CT 23X35	51030726200	Water / Gas Inject	Injecting
CARNEY CT 24X35	51030728300	Water / Gas Inject	Monitor
CARNEY CT 27X34	51030746600	Water / Gas Inject	Injecting
CARNEY CT 28X	51030747400	Water / Gas Inject	Monitor
CARNEY CT 29X	51030753700	Water / Gas Inject	Injecting
CARNEY CT 30X34 30X	51030752600	Water / Gas Inject	Injecting
CARNEY CT 32X34	51030758900	Water / Gas Inject	Injecting
CARNEY CT 3-34	51030103900	Oil well	Producing
CARNEY CT 33X34	51030759200	Water / Gas Inject	Injecting
CARNEY CT 35X34	51030759300	Water / Gas Inject	Injecting
CARNEY CT 37X4	51030856300	Oil well	Producing
CARNEY CT 38X4	51030881300	Water / Gas Inject	Monitor
CARNEY CT 39X4	51030881400	Oil well	Producing
CARNEY CT 41Y34	51030914900	Oil well	Monitor
CARNEY CT 4-34	51030555900	Oil well	Producing
CARNEY CT 43Y34	51030914800	Oil well	Monitor
CARNEY CT 44Y34	51030915300	Oil well	Monitor
CARNEY CT 5-34	51030103800	Oil well	Producing
CARNEY CT 6-5	51030609100	Water / Gas Inject	Monitor
CARNEY CT 7-35	51030629300	Oil well	Producing
CARNEY CT 8-34	51030104000	Oil well	Producing
CARNEY CT 9-35	51030548600	Water / Gas Inject	Monitor
CARNEY UNIT 1	51030608700	Oil well	Producing
CARNEY UNIT 2X	51030719100	Water / Gas Inject	Injecting
COLTHARP JE 10X	51030869400	Oil well	Producing

COLTHARP JE 2	51030602300	Water / Gas Inject	Monitor
COLTHARP JE 4	51030602200	Water / Gas Inject	Monitor
COLTHARP JE 5X	51030705700	Oil well	Producing
COLTHARP JE 7X	51030727900	Oil well	Producing
COLTHARP JE 8X	51030734300	Oil well	Producing
COLTHARP WH A1	51030601900	Water / Gas Inject	Injecting
COLTHARP WH A3	51030602100	Water / Gas Inject	Monitor
COLTHARP WH A4	51030102800	Water / Gas Inject	Injecting
COLTHARP WH A5X	51030725000	Oil well	Producing
COLTHARP WH A6X	51030744700	Oil well	Producing
COLTHARP WH A8X	51030909900	Oil well	Producing
COLTHARP WH B2X	51030859400	Oil well	Monitor
COLTHARP WH B3X	51030879300	Oil well	Shut In
COLTHARP WH C1	51030107700	Water / Gas Inject	Monitor
COLTHARP WH C2X	51030919800	Oil well	Producing
CT CARNEY 25X34	51030741500	Water / Gas Inject	Injecting
EMERALD 10	51030566200	Oil well	Producing
EMERALD 11	51030567100	Oil well	Producing
EMERALD 13ST	51030563601	Water / Gas Inject	Injecting
EMERALD 14	51030556500	Water / Gas Inject	Injecting
EMERALD 16	51030625300	Oil well	Monitor
EMERALD 17	51030567700	Water / Gas Inject	Injecting
EMERALD 18AX	51030920200	Oil well	Producing
EMERALD 19	51030624000	Oil well	Producing
EMERALD 2	51030566900	Oil well	Producing
EMERALD 20	51030555800	Water / Gas Inject	Injecting
EMERALD 22	51030625400	Water / Gas Inject	Injecting
EMERALD 23	51030558900	Water / Gas Inject	Injecting
EMERALD 25	51030548100	Water / Gas Inject	Injecting
EMERALD 26	51030624200	Water / Gas Inject	Injecting
EMERALD 27	51030565300	Oil well	Producing
EMERALD 28	51030562800	Water / Gas Inject	Injecting
EMERALD 29AX	51030924500	Water / Gas Inject	Injecting
EMERALD 30AX	51030920300	Water / Gas Inject	Injecting
EMERALD 31AX	51030923600	Water / Gas Inject	Injecting
EMERALD 32	51030623800	Oil well	Producing
EMERALD 33AX	51030923900	Water / Gas Inject	Injecting
EMERALD 34	51030559500	Water / Gas Inject	Injecting
EMERALD 35	51030559400	Water / Gas Inject	Injecting
EMERALD 36	51030548800	Water / Gas Inject	Injecting
EMERALD 37	51030551200	Water / Gas Inject	Injecting

EMERALD 38	51030624900	Water / Gas Inject	Injecting
EMERALD 39	51030625100	Water / Gas Inject	Injecting
EMERALD 3ST	51030559901	Water / Gas Inject	Injecting
EMERALD 3ST 3	51030559900	Water / Gas Inject	P&A
EMERALD 4	51030550500	Oil well	Producing
EMERALD 40	51030625000	Water / Gas Inject	Injecting
EMERALD 41	51030546300	Water / Gas Inject	Monitor
EMERALD 42D	51030634000	Salt Water Disposal	Injecting
EMERALD 44AX	51030918700	Water / Gas Inject	Injecting
EMERALD 46X	51030713000	Oil well	Producing
EMERALD 47X	51030720100	Oil well	Producing
EMERALD 48X	51030725700	Oil well	Monitor
EMERALD 49AX	51031068000	Oil well	Producing
EMERALD 50X	51030733100	Oil well	Producing
EMERALD 51X	51030733300	Oil well	Producing
EMERALD 52X	51030737100	Oil well	Producing
EMERALD 53X	51030737600	Oil well	Producing
EMERALD 54X	51030763700	Oil well	Producing
EMERALD 55X	51030763800	Oil well	Producing
EMERALD 56X	51030768700	Oil well	Producing
EMERALD 57XST	51030764901	Oil well	Producing
EMERALD 58X	51030773900	Oil well	Producing
EMERALD 59X	51030774000	Oil well	Producing
EMERALD 6	51030558800	Water / Gas Inject	Injecting
EMERALD 60X	51030779800	Oil well	Producing
EMERALD 61X	51030780300	Oil well	Producing
EMERALD 62X	51030781100	Oil well	Producing
EMERALD 63ST	51030804101	Water / Gas Inject	Injecting
EMERALD 63XST	51030804100	Water / Gas Inject	P&A
EMERALD 64X	51030799200	Water / Gas Inject	Injecting
EMERALD 65X	51030794800	Oil well	Producing
EMERALD 66X	51030786800	Oil well	Producing
EMERALD 67X	51030797400	Oil well	Producing
EMERALD 68X	51030797500	Oil well	Producing
EMERALD 69X	51030810300	Water / Gas Inject	Injecting
EMERALD 70X	51030807200	Water / Gas Inject	Injecting
EMERALD 71X	51030804600	Water / Gas Inject	Injecting
EMERALD 72X	51030810400	Water / Gas Inject	Monitor
EMERALD 73X	51030810500	Oil well	Monitor
EMERALD 74X	51030816900	Oil well	Producing
EMERALD 75X	51030843700	Oil well	Producing

EMERALD 76X	51030848100	Oil well	Producing
EMERALD 77X	51030848000	Oil well	Producing
EMERALD 78X	51030849100	Oil well	Producing
EMERALD 79X	51030895500	Salt Water Disposal	Injecting
EMERALD 7A	51030928500	Water / Gas Inject	Injecting
EMERALD 8	51030559000	Water / Gas Inject	P&A
EMERALD 80X	51030876900	Oil well	Producing
EMERALD 81X	51030888300	Oil well	Producing
EMERALD 82X	51030849200	Water / Gas Inject	Injecting
EMERALD 83X	51030876500	Oil well	Producing
EMERALD 84X	51030888500	Oil well	Producing
EMERALD 85X	51030877000	Oil well	Producing
EMERALD 86X	51030877200	Oil well	Producing
EMERALD 87X	51030877300	Oil well	Monitor
EMERALD 88X	51030876600	Oil well	Producing
EMERALD 89X	51030877100	Oil well	Producing
EMERALD 8ST	51030559001	Water / Gas Inject	Injecting
EMERALD 90X	51030914600	Water / Gas Inject	Injecting
EMERALD 91Y	51030914700	Water / Gas Inject	Injecting
EMERALD 92X	51030929500	Oil well	Producing
EMERALD 93X	51031185800	Oil well	Producing
EMERALD 94X	51031185500	Oil well	Producing
EMERALD 95X	51031191400	Oil well	Producing
EMERALD 96X	51031192200	Oil well	Producing
EMERALD 97X	51031191300	Oil well	Producing
EMERALD 98X	51031191500	Water / Gas Inject	Injecting
EMERALD 9ST	51030566101	Water / Gas Inject	Injecting
EMERALD 9ST 9	51030566100	Water / Gas Inject	P&A
FAIRFIELD KITTI A 4	51031101700	Oil well	P&A
FAIRFIELD KITTI A 5P	51031101000	Oil well	P&A
FAIRFIELD KITTI A1	51030611100	Water / Gas Inject	Injecting
FAIRFIELD KITTI A4	51031101701	Oil well	Producing
FAIRFIELD KITTI A5	51031101001	Oil well	Producing
FAIRFIELD KITTI B1	51030107800	Water / Gas Inject	Injecting
FE156X	51031033600	Oil well	Producing
FEE 1	51030563400	Oil well	Producing
FEE 1 162Y	51031194500	Water / Gas Inject	Injecting
FEE 10	51030566800	Water / Gas Inject	Injecting
FEE 100X	51030786900	Oil well	Producing
FEE 101X	51030787000	Oil well	Producing
FEE 102X	51030787700	Oil well	Producing

FEE 103X	51030788500	Oil well	Monitor
FEE 104X	51030785700	Oil well	Producing
FEE 105X	51030785800	Oil well	Producing
FEE 106X	51030794600	Water / Gas Inject	Injecting
FEE 107X	51030803200	Water / Gas Inject	Injecting
FEE 108X	51030795200	Oil well	Producing
FEE 109X	51030798900	Water / Gas Inject	Injecting
FEE 11	51030559600	Oil well	Producing
FEE 110X	51030802600	Water / Gas Inject	Injecting
FEE 111X	51030802700	Water / Gas Inject	Monitor
FEE 112X	51030802800	Water / Gas Inject	Injecting
FEE 113X	51030802900	Water / Gas Inject	Injecting
FEE 114X	51030803100	Water / Gas Inject	Injecting
FEE 115X	51030803300	Water / Gas Inject	Injecting
FEE 116X	51030829900	Water / Gas Inject	Injecting
FEE 117X	51030843800	Oil well	Producing
FEE 118AX	51030928300	Oil well	Monitor
FEE 12	51030565100	Oil well	Producing
FEE 121X	51030857500	Oil well	Producing
FEE 122X	51030866300	Water / Gas Inject	Injecting
FEE 124X	51030866400	Oil well	Producing
FEE 125X	51030868100	Oil well	Monitor
FEE 126X	51030868600	Oil well	Producing
FEE 127X	51030868700	Water / Gas Inject	Injecting
FEE 128X	51030868800	Oil well	Monitor
FEE 129X	51030868900	Oil well	Producing
FEE 13	51030622600	Oil well	Producing
FEE 130X	51030870400	Oil well	Monitor
FEE 133X	51030888400	Oil well	Producing
FEE 135X	51030876000	Oil well	Monitor
FEE 136X	51030874500	Water / Gas Inject	Injecting
FEE 137X	51030876100	Water / Gas Inject	Injecting
FEE 138X	51030876300	Oil well	Producing
FEE 139X	51030876200	Oil well	Producing
FEE 14	51030568700	Oil well	Producing
FEE 140Y	51030910600	Oil well	Monitor
FEE 141X	51030913300	Water / Gas Inject	Injecting
FEE 142X	51030913100	Oil well	Producing
FEE 143X	51030913000	Oil well	Producing
FEE 144Y	51030917500	Oil well	Shut In
FEE 145Y	51030917400	Oil well	Producing

FEE 146X	51030946400	Oil well	Producing
FEE 15	51030556800	Oil well	Producing
FEE 153X	51030929700	Oil well	Producing
Fee 154X	51031036500	Oil well	Producing
Fee 155X	51031037300	Oil well	Producing
FEE 157X	51031101900	Oil well	Monitor
FEE 158 X	51031115900	Oil well	Producing
FEE 159 X	51031101100	Oil well	Producing
FEE 160X	51031186600	Oil well	Producing
FEE 163X	51031195100	Oil well	Producing
FEE 16AX	51030923500	Water / Gas Inject	Monitor
FEE 17	51030580100	Water / Gas Inject	Injecting
FEE 18	51030623600	Water / Gas Inject	Monitor
FEE 19	51030622400	Oil well	Producing
FEE 1AX	51030924400	Water / Gas Inject	Monitor
FEE 20	51030616800	Oil well	Producing
FEE 21	51030620700	Oil well	Producing
FEE 22	51030616100	Water / Gas Inject	Injecting
FEE 23	51030615600	Oil well	Producing
FEE 24	51030611200	Water / Gas Inject	Injecting
FEE 25	51030614500	Oil well	Producing
FEE 26	51030615200	Oil well	Producing
FEE 27	51030617500	Oil well	Producing
FEE 28	51030613500	Water / Gas Inject	Injecting
FEE 29	51030614400	Water / Gas Inject	Injecting
FEE 2AX	51030924700	Water / Gas Inject	Injecting
FEE 3	51030565700	Oil well	Producing
FEE 30	51030621100	Water / Gas Inject	Monitor
FEE 31	51030611800	Water / Gas Inject	Injecting
FEE 32	51030614200	Oil well	Producing
FEE 33	51030614700	Oil well	Producing
FEE 34	51030624500	Oil well	Producing
FEE 35	51030611300	Oil well	Producing
FEE 36	51030617600	Oil well	Producing
FEE 37	51030611500	Water / Gas Inject	Injecting
FEE 38	51030625500	Water / Gas Inject	Injecting
FEE 39	51030623300	Water / Gas Inject	Injecting
FEE 4	51030576900	Oil well	Monitor
FEE 40	51030622300	Water / Gas Inject	Injecting
FEE 41	51030622200	Water / Gas Inject	Monitor
FEE 42	51030568800	Water / Gas Inject	Monitor

FEE 43	51030614100	Water / Gas Inject	Injecting
FEE 44	51030624700	Water / Gas Inject	Injecting
FEE 45	51030617900	Oil well	Producing
FEE 47	51030616000	Water / Gas Inject	Injecting
FEE 48	51030625900	Water / Gas Inject	Injecting
FEE 49	51030611900	Water / Gas Inject	Injecting
FEE 5	51030574500	Oil well	Producing
FEE 51	51030614900	Water / Gas Inject	Injecting
FEE 52	51030567400	Water / Gas Inject	Injecting
FEE 53AX	51030861200	Water / Gas Inject	Injecting
FEE 55	51030615300	Water / Gas Inject	Injecting
FEE 56	51030615700	Water / Gas Inject	Injecting
FEE 58AX	51030924300	Water / Gas Inject	Injecting
FEE 59	51030616900	Water / Gas Inject	Injecting
FEE 6	51030572000	Oil well	Producing
FEE 60	51030622500	Water / Gas Inject	Injecting
FEE 61	51030620300	Oil well	Producing
FEE 62	51030614000	Oil well	Monitor
FEE 63	51030614600	Water / Gas Inject	Injecting
FEE 64	51030614800	Water / Gas Inject	Injecting
FEE 65	51030615000	Water / Gas Inject	Injecting
FEE 67A	51030929300	Water / Gas Inject	Injecting
FEE 68A	51030568300	Oil well	Producing
FEE 69	51030625600	Water / Gas Inject	Monitor
FEE 7	51030571600	Oil well	Producing
FEE 70AX	51030919100	Water / Gas Inject	Monitor
FEE 72X	51030718000	Oil well	Producing
FEE 73X	51030727400	Oil well	Producing
FEE 74X	51030730700	Oil well	Producing
FEE 75X	51030732600	Oil well	Producing
FEE 76X	51030733900	Oil well	Producing
FEE 78X	51030743400	Oil well	Producing
FEE 79X	51030742400	Water / Gas Inject	Injecting
FEE 8	51030563300	Water / Gas Inject	Injecting
FEE 80X	51030749100	Water / Gas Inject	Injecting
FEE 81X	51030751900	Oil well	Producing
FEE 82X	51030752900	Oil well	Producing
FEE 83X	51030757200	Oil well	Producing
FEE 84X	51030755400	Water / Gas Inject	Injecting
FEE 85X	51030758100	Water / Gas Inject	Injecting
FEE 86X	51030756900	Water Injection Well	P&A

FEE 86XST	51030756901	Water / Gas Inject	Injecting
FEE 87X	51030754600	Water / Gas Inject	Monitor
FEE 88X	51030755900	Water / Gas Inject	Injecting
FEE 89X	51030755500	Water / Gas Inject	Injecting
FEE 9	51030551100	Oil well	P&A
FEE 90X	51030758000	Water / Gas Inject	Injecting
FEE 91X	51030757300	Water / Gas Inject	Injecting
FEE 92X	51030755600	Water / Gas Inject	Monitor
FEE 93X	51030759100	Water / Gas Inject	Injecting
FEE 94X	51030759400	Water / Gas Inject	Injecting
FEE 95X	51030764700	Oil well	Producing
FEE 96X	51030764800	Oil well	Producing
FEE 97X	51030779100	Oil well	Producing
FEE 98X	51030782700	Water / Gas Inject	Injecting
FEE 99X	51030784000	Oil well	Producing
FEE 9ST 9	51030551101	Oil well	Producing
GRAY A A17X	51030768900	Water / Gas Inject	Injecting
GRAY A A21X	51030830200	Water / Gas Inject	Injecting
GRAY A A8AX	51030919700	Water / Gas Inject	Injecting
GRAY A10	51030573400	Water / Gas Inject	Injecting
GRAY A12	51030613700	Oil well	Producing
GRAY A13	51030577800	Water / Gas Inject	Monitor
GRAY A14	51030613900	Oil well	Producing
GRAY A15	51030576200	Oil well	Producing
GRAY A16	51030613600	Water / Gas Inject	Injecting
GRAY A18X	51030789800	Oil well	Producing
GRAY A19X	51030787300	Oil well	Producing
GRAY A20X	51030803500	Water / Gas Inject	Injecting
GRAY A22X	51030831700	Oil well	Producing
GRAY A9	51030571500	Oil well	Producing
GRAY B10	51030612300	Water / Gas Inject	Injecting
GRAY B11	51030581800	Oil well	Producing
GRAY B12	51030612900	Oil well	Producing
GRAY B13	51030612600	Oil well	Producing
GRAY B14A	51030928900	Water / Gas Inject	Injecting
GRAY B15	51030579600	Oil well	Producing
GRAY B16	51030612700	Oil well	Producing
GRAY B17	51030582500	Oil well	Monitor
GRAY B18X	51030638600	Oil well	Monitor
GRAY B19X	51036639700	Oil well	Producing
GRAY B2	51030578700	Oil well	Producing

GRAY B20X	51030101500	Water / Gas Inject	Injecting
GRAY B21X	51031035700	Oil well	Producing
GRAY B22X	51031036000	Oil well	Producing
GRAY B23X	51031033800	Oil well	Producing
GRAY B24X	51031033700	Oil well	Producing
GRAY B25X	51031057200	Oil well	Producing
GRAY B26X	51031057500	Oil well	Producing
GRAY B27X	51031057400	Oil well	Producing
GRAY B28X	51031101200	Oil well	Producing
GRAY B3	51030613200	Water / Gas Inject	Injecting
GRAY B4	51030613300	Water / Gas Inject	Injecting
GRAY B5	51030612400	Water / Gas Inject	Injecting
GRAY B6	51030613100	Water / Gas Inject	Injecting
GRAY B7	51030612800	Water / Gas Inject	Injecting
GRAY B8	51030581100	Water / Gas Inject	Injecting
GRAY B9	51030612500	Water / Gas Inject	Injecting
GUIBERSON SA 1	51030581300	Water / Gas Inject	Injecting
GUIBERSON SA 5 X	51031115600	Oil well	Producing
HAGOOD L N-A 17X	51030914200	Oil well	P&A
HAGOOD LN A10X	51030791300	Oil well	Shut In
HAGOOD LN A11X	51030794900	Water / Gas Inject	Injecting
HAGOOD LN A12X	51030793600	Oil well	Producing
HAGOOD LN A13X	51030799100	Water / Gas Inject	Injecting
HAGOOD LN A14X	51030795000	Water / Gas Inject	P&A
HAGOOD LN A14XST	51030795001	Water / Gas Inject	Injecting
HAGOOD LN A15X	51030829300	Oil well	Producing
HAGOOD LN A16X	51030830000	Water / Gas Inject	Injecting
HAGOOD LN A17XST	51030914201	Water / Gas Inject	Monitor
HAGOOD LN A2	51030574300	Oil well	Monitor
HAGOOD LN A3	51030576800	Oil well	Monitor
HAGOOD LN A5	51030573600	Water / Gas Inject	Injecting
HAGOOD LN A7	51030575700	Water / Gas Inject	Monitor
HAGOOD LN A9X	51030702200	Water / Gas Inject	Injecting
HAGOOD MC A1	51030632800	Water / Gas Inject	Injecting
HAGOOD MC A10X	51031041400	Oil well	Producing
HAGOOD MC A11X	51031041300	Oil well	Producing
HAGOOD MC A12X	51031053300	Oil well	Producing
HAGOOD MC A13X	51031053100	Oil well	Producing
HAGOOD MC A14X	51031054800	Oil well	Shut In
HAGOOD MC A15X	51031062800	Oil well	Producing
HAGOOD MC A16X	51031061200	Oil well	Producing

HAGOOD MC A17X	51031062900	Oil well	Producing
HAGOOD MC A18X	51031061300	Oil well	Producing
HAGOOD MC A19X	51031067000	Water / Gas Inject	Injecting
HAGOOD MC A2	51030102300	Oil well	Producing
HAGOOD MC A21X	51031070900	Oil well	Producing
HAGOOD MC A3	51030633000	Water / Gas Inject	Injecting
HAGOOD MC A4	51030632600	Water / Gas Inject	Injecting
HAGOOD MC A5	51030633100	Water / Gas Inject	Injecting
HAGOOD MC A6	51030102400	Oil well	Producing
HAGOOD MC A7	51030106700	Oil well	Producing
HAGOOD MC A8 A 8	51030632500	Water / Gas Inject	Injecting
HAGOOD MC A9	51030632700	Water / Gas Inject	Injecting
HAGOOD MC B1A	51031102800	Oil well	Producing
HAGOOD MC B2	51031187000	Oil well	Producing
HEFLEY CS 4X	51030856200	Oil well	Producing
HEFLEY ME 2	51030545200	Water / Gas Inject	Monitor
HEFLEY ME 5X	51030719600	Oil well	Producing
HEFLEY ME 6X	51030729300	Oil well	Producing
HEFLEY ME 7X	51030873700	Oil well	Producing
HEFLEY ME 8X	51030869600	Oil well	Producing
L N HAGOOD A- 1	51030572100	Water / Gas Inject	Injecting
L N HAGOOD A-8 IJ A8	51030569100	Water / Gas Inject	Injecting
LACY SB 1	51030573200	Oil well	Producing
LACY SB 11Y	51030914400	Salt Water Disposal	Injecting
LACY SB 12Y	51030914500	Oil well	Producing
LACY SB 13Y	51031057000	Oil well	Producing
LACY SB 2AX	51030928200	Water / Gas Inject	Injecting
LACY SB 3	51030568900	Oil well	Producing
LACY SB 4	51030575800	Water / Gas Inject	Monitor
LACY SB 6X	51030794700	Oil well	Monitor
LACY SB 7X	51030797800	Water / Gas Inject	Injecting
LACY SB 9X	51030831800	Oil well	Monitor
LARSON FA 1	51030106600	Oil well	Producing
LARSON FA 2	51030107200	Water / Gas Inject	Injecting
LARSON FA 3X	51031071000	Oil well	Monitor
LARSON FV A1	51030547600	Oil well	Producing
LARSON FV A2X	51030721600	Water / Gas Inject	Monitor
LARSON FV B11	51030630200	Water / Gas Inject	Injecting
LARSON FV B12	51030100900	Oil well	Producing
LARSON FV B14X	51030641400	Oil well	Shut In
LARSON FV B15X	51030700800	Oil well	Producing

LARSON FV B17X	51030707800	Oil well	Producing
LARSON FV B18X	51030708300	Oil well	Producing
LARSON FV B19X	51030710600	Oil well	Producing
LARSON FV B2	51030620200	Water / Gas Inject	Monitor
LARSON FV B20X	51030709900	Oil well	Producing
LARSON FV B21X	51030716500	Oil well	Producing
LARSON FV B22X	51030722700	Oil well	Producing
LARSON FV B23X	51030724200	Oil well	Producing
LARSON FV B24X	51030873800	Oil well	Producing
LARSON FV B25X	51030916500	Oil well	Producing
LARSON FV B27X	51030948800	Oil well	Producing
LARSON FV B4	51030629800	Water / Gas Inject	Injecting
LARSON FV B8	51030620100	Water / Gas Inject	Injecting
LARSON MB 10X25	51030715900	Oil well	Producing
LARSON MB 12X25	51030727000	Oil well	Producing
LARSON MB 2-26 A226	51030566300	Oil well	Producing
LARSON MB 3X26	51030711000	Oil well	Producing
LARSON MB 4X26	51030717700	Oil well	Monitor
LARSON MB 8X25	51030709300	Oil well	Producing
LARSON MB A1AX	51031075600	Water / Gas Inject	Monitor
LARSON MB A2	51030633200	Oil well	Producing
LARSON MB A3X	51031053400	Oil well	Producing
LARSON MB A4X	51031055200	Oil well	Producing
LARSON MB B1	51030576500	Water / Gas Inject	Injecting
LARSON MB B3AX	51031075500	Water / Gas Inject	Injecting
LARSON MB C1-25	51030618600	Water / Gas Inject	Monitor
LARSON MB C1AX	51031076300	Oil well	Producing
LARSON MB C2	51030569000	Water / Gas Inject	Injecting
LARSON MB C3	51030570800	Water / Gas Inject	Injecting
LARSON MB C3-25	51030618700	Water / Gas Inject	Injecting
LARSON MB C4	51031139700	Oil well	Producing
LARSON MB C5	51031142900	Oil well	Producing
LARSON MB C9X25	51030715500	Oil well	Producing
LARSON MB D1-26E	51030620000	Water / Gas Inject	Injecting
LEVISON 10	51030621700	Oil well	Producing
LEVISON 11	51030619800	Water / Gas Inject	Injecting
LEVISON 12	51030103100	Water / Gas Inject	Injecting
LEVISON 13	51030619400	Water / Gas Inject	Injecting
LEVISON 14	51030619900	Water / Gas Inject	Injecting
LEVISON 17	51030619500	Water / Gas Inject	Injecting
LEVISON 18	51030618200	Oil well	Producing

LEVISON 2	51030559300	Oil well	Producing
LEVISON 21X	51030638700	Oil well	Producing
LEVISON 22X	51030708900	Oil well	Monitor
LEVISON 23X	51030712300	Oil well	Producing
LEVISON 24X	51030711400	Oil well	Producing
LEVISON 25X	51030722200	Oil well	Producing
LEVISON 26X	51030726700	Oil well	Producing
LEVISON 27X	51030728900	Oil well	Producing
LEVISON 28X	51030731600	Oil well	Monitor
LEVISON 29X	51030732000	Water / Gas Inject	Injecting
LEVISON 30X	51030735100	Water / Gas Inject	Injecting
LEVISON 31X	51030735300	Oil well	Monitor
LEVISON 32X	51030747500	Water / Gas Inject	Injecting
LEVISON 33X	51030752100	Oil well	Producing
LEVISON 34X	51030758600	Water / Gas Inject	Injecting
LEVISON 35X	51030868300	Oil well	Producing
LEVISON 6	51030106200	Oil well	Producing
LEVISON 7	51030619700	Oil well	Monitor
LEVISON 8	51030103000	Water / Gas Inject	Injecting
LEVISON 9	51030628600	Water / Gas Inject	Injecting
LEVSION 1	51030559100	Oil well	Producing
LN - HAGOOD A6	51030569400	Oil well	Producing
LN HAGOOD A-4	51030570700	Oil well	Shut In
MAGOR 1A	51030989300	Water / Gas Inject	Injecting
MATTERN 1	51030580400	Water / Gas Inject	Injecting
MCLAUGHLIN AC 1	51030573100	Water / Gas Inject	Injecting
MCLAUGHLIN AC 10	51030578000	Oil well	Monitor
MCLAUGHLIN AC 11	51030569300	Oil well	Producing
MCLAUGHLIN AC 12	51030579800	Water / Gas Inject	Injecting
MCLAUGHLIN AC 13	51030581000	Water / Gas Inject	Injecting
MCLAUGHLIN AC 14	51030105800	Oil well	Producing
MCLAUGHLIN AC 15	51030576700	Oil well	Producing
MCLAUGHLIN AC 16	51030105400	Oil well	Producing
MCLAUGHLIN AC 17	51030631700	Water / Gas Inject	Injecting
MCLAUGHLIN AC 18	51030105300	Water / Gas Inject	Injecting
MCLAUGHLIN AC 19	51030579400	Oil well	Producing
MCLAUGHLIN AC 2	51030573300	Oil well	Producing
MCLAUGHLIN AC 20	51030578200	Water / Gas Inject	Injecting
MCLAUGHLIN AC 21	51030578100	Oil well	Producing
MCLAUGHLIN AC 22	51030105500	Water / Gas Inject	Injecting
MCLAUGHLIN AC 23	51030571800	Water / Gas Inject	Injecting

MCLAUGHLIN AC 24	51030576300	Water / Gas Inject	Injecting
MCLAUGHLIN AC 25	51030631800	Oil well	Producing
MCLAUGHLIN AC 26	51030105000	Water / Gas Inject	Injecting
MCLAUGHLIN AC 27	51036005300	Oil well	Producing
MCLAUGHLIN AC 28	51030569900	Oil well	Producing
MCLAUGHLIN AC 29	51030581900	Oil well	Producing
MCLAUGHLIN AC 30	51030105100	Water / Gas Inject	Injecting
MCLAUGHLIN AC 31	51030105200	Water / Gas Inject	Injecting
MCLAUGHLIN AC 32	51030581200	Water / Gas Inject	Injecting
MCLAUGHLIN AC 33	51030631500	Water / Gas Inject	Injecting
MCLAUGHLIN AC 34	51030104700	Water / Gas Inject	Injecting
MCLAUGHLIN AC 35	51030581700	Oil well	Producing
MCLAUGHLIN AC 36	51030104800	Oil well	Producing
MCLAUGHLIN AC 37	51030633300	Oil well	Producing
MCLAUGHLIN AC 38	51030632200	Oil well	Producing
MCLAUGHLIN AC 39A	51031049300	Oil well	Producing
MCLAUGHLIN AC 3AX	51030920700	Water / Gas Inject	Injecting
MCLAUGHLIN AC 4	51030573800	Oil well	Producing
MCLAUGHLIN AC 41AX	51030920100	Water / Gas Inject	Injecting
MCLAUGHLIN AC 42	51030579500	Water / Gas Inject	Monitor
MCLAUGHLIN AC 43	51030632400	Water / Gas Inject	Injecting
MCLAUGHLIN AC 44A	51031096100	Oil well	Producing
MCLAUGHLIN AC 44D	51030631600	Salt Water Disposal	Injecting
MCLAUGHLIN AC 45 AC	51030631900	Water / Gas Inject	Injecting
MCLAUGHLIN AC 46ST	51030632301	Water / Gas Inject	Monitor
MCLAUGHLIN AC 47X	51030107500	Water / Gas Inject	Injecting
MCLAUGHLIN AC 49X	51030641700	Oil well	Monitor
MCLAUGHLIN AC 5	51030571200	Oil well	Monitor
MCLAUGHLIN AC 50X	51030632100	Oil well	Producing
MCLAUGHLIN AC 51X	51030641800	Oil well	Producing
MCLAUGHLIN AC 52X	51030642500	Water / Gas Inject	Injecting
MCLAUGHLIN AC 53X	51030101400	Oil well	Producing
MCLAUGHLIN AC 54X	51030642600	Oil well	Producing
MCLAUGHLIN AC 55X	51030641900	Water / Gas Inject	Injecting
MCLAUGHLIN AC 56X	51030642000	Water / Gas Inject	Injecting
MCLAUGHLIN AC 57X	51030701000	Oil well	Monitor
MCLAUGHLIN AC 58X	51030701400	Oil well	Producing
MCLAUGHLIN AC 59AX	51030928800	Oil well	Producing
MCLAUGHLIN AC 6	51030579900	Oil well	Producing
MCLAUGHLIN AC 60X	51030769200	Water / Gas Inject	Injecting
MCLAUGHLIN AC 61X	51030769000	Oil well	Monitor

MCLAUGHLIN AC 62X	51030771500	Oil well	Producing
MCLAUGHLIN AC 63X	51030771600	Water / Gas Inject	Injecting
MCLAUGHLIN AC 65X	51030771800	Oil well	Producing
MCLAUGHLIN AC 66X	51030773800	Water / Gas Inject	Injecting
MCLAUGHLIN AC 67X	51030817000	Oil well	Producing
MCLAUGHLIN AC 68X	51030829200	Oil well	Producing
MCLAUGHLIN AC 69X	51030829400	Water / Gas Inject	Injecting
MCLAUGHLIN AC 7	51030580900	Water / Gas Inject	Injecting
MCLAUGHLIN AC 70X	51030830100	Water / Gas Inject	Injecting
MCLAUGHLIN AC 71X	51030829700	Oil well	Producing
MCLAUGHLIN AC 72X	51030832000	Water / Gas Inject	Injecting
MCLAUGHLIN AC 73X	51030831900	Oil well	Producing
MCLAUGHLIN AC 74X	51030832100	Water / Gas Inject	Injecting
MCLAUGHLIN AC 75X	51030829800	Oil well	Producing
MCLAUGHLIN AC 76X	51030914100	Water / Gas Inject	Injecting
MCLAUGHLIN AC 77X	51030915200	Oil well	Producing
MCLAUGHLIN AC 78X	51030915500	Oil well	Producing
MCLAUGHLIN AC 79X	51030930000	Oil well	Monitor
MCLAUGHLIN AC 8	51030573500	Oil well	Producing
MCLAUGHLIN AC 80X	51030930100	Oil well	Monitor
MCLAUGHLIN AC 81AX	51031064500	Oil well	Producing
MCLAUGHLIN AC 82X	51031054600	Oil well	Producing
MCLAUGHLIN AC 83X	51031059500	Oil well	Producing
MCLAUGHLIN AC 84Y	51031057300	Oil well	Producing
MCLAUGHLIN AC 86Y	51031058400	Oil well	Producing
MCLAUGHLIN AC 88X	51031070000	Oil well	Producing
MCLAUGHLIN AC 9	51030576600	Oil well	Monitor
MCLAUGHLIN AC 90X	51031069900	Oil well	Producing
MCLAUGHLIN AC 91X	51031072600	Water / Gas Inject	Injecting
MCLAUGHLIN AC 92X	51031070800	Oil well	Producing
MCLAUGHLIN AC 93X	51031072700	Water / Gas Inject	Injecting
MCLAUGHLIN AC 94X	51031072500	Water / Gas Inject	Injecting
MCLAUGHLIN AC 95X	51031140800	Oil well	Producing
MCLAUGHLIN AC A1	51030609200	Oil well	Monitor
MCLAUGHLIN AC A3X	51030863000	Oil well	Producing
MCLAUGHLIN AC C2	51031104100	Oil well	Monitor
MCLAUGHLIN S W 6	51030627800	Oil well	P&A
MCLAUGHLIN SHARPLES 10X28	51030749000	Oil well	Producing
MCLAUGHLIN SHARPLES 1-28	51030560300	Water / Gas Inject	Injecting
MCLAUGHLIN SHARPLES 12X33	51030759800	Oil well	Producing
MCLAUGHLIN SHARPLES 1-33	51030551300	Oil well	Producing

MCLAUGHLIN SHARPLES 13X3	51030873900	Oil well	Producing
MCLAUGHLIN SHARPLES 14Y33	51030912300	Oil well	Producing
MCLAUGHLIN SHARPLES 15X32	51030885400	Oil well	Producing
MCLAUGHLIN SHARPLES 16X32	51030913200	Water / Gas Inject	Injecting
MCLAUGHLIN SHARPLES 2-28	51030560000	Oil well	Producing
MCLAUGHLIN SHARPLES 2-32	51030627300	Water / Gas Inject	Monitor
MCLAUGHLIN SHARPLES 2-33	51030106800	Water / Gas Inject	Injecting
MCLAUGHLIN SHARPLES 3-32	51030627000	Oil well	Monitor
MCLAUGHLIN SHARPLES 3-33	51030629000	Oil well	Producing
MCLAUGHLIN SHARPLES 4-33	51030629100	Water / Gas Inject	Injecting
MCLAUGHLIN SHARPLES 5-33	51030104500	Oil well	Monitor
MCLAUGHLIN SHARPLES 6-33	51030628800	Oil well	Monitor
MCLAUGHLIN SHARPLES 7-33	51030104600	Water / Gas Inject	Monitor
MCLAUGHLIN SHARPLES 8-33	51030628900	Water / Gas Inject	Monitor
MCLAUGHLIN SHARPLES 9X33	51030746500	Oil well	Producing
MCLAUGHLIN SW 11X	51030759700	Water / Gas Inject	Injecting
MCLAUGHLIN SW 12X	51030760100	Water / Gas Inject	Injecting
MCLAUGHLIN SW 1ST	51030548300	Oil well	P&A
MCLAUGHLIN SW 1ST 1	51030548301	Water / Gas Inject	Monitor
MCLAUGHLIN SW 2	51030627700	Oil well	Producing
MCLAUGHLIN SW 3	51030104400	Water / Gas Inject	Injecting
MCLAUGHLIN SW 4	51030107600	Oil well	Producing
MCLAUGHLIN SW 5	51030627900	Oil well	Producing
MCLAUGHLIN SW 6ST	51030627801	Water / Gas Inject	Injecting
MCLAUGHLIN SW 7X	51030746100	Oil well	Producing
MCLAUGHLIN SW 8X	51030753000	Water / Gas Inject	Injecting
MCLAUGHLIN UNIT A1	51030581600	Oil well	Producing
MCLAUGHLIN UNIT B1	51030582600	Oil well	Producing
MCLAUGHLIN UNIT B2X	51031057600	Water / Gas Inject	Injecting
MELLEN 3A	51031098100	Oil well	Producing
MELLEN WP 1	51036000300	Water / Gas Inject	Injecting
MELLEN WP 2	51030105600	Water / Gas Inject	Injecting
NEAL 2AX	51030920800	Water / Gas Inject	Injecting
NEAL 4	51030565500	Water / Gas Inject	Injecting
NEAL 5A	51030565900	Oil well	Producing
NEAL 6X	51030790600	Oil well	Producing
NEAL 7X	51030804200	Water / Gas Inject	Injecting
NEAL 8X	51030804300	Water / Gas Inject	P&A
NEAL 8XST	51030804301	Water / Gas Inject	Injecting
NEAL 9Y	51030912000	Oil well	Producing
NEWTON ASSOC UNIT D2X	51030868500	Oil well	Monitor

NIKKEL 3	51030619200	Water / Gas Inject	Injecting
PURDY 1-1	51030545300	Water / Gas Inject	Monitor
PURDY 2X1	51030881000	Oil well	Producing
RAVEN A1AX	51030917800	Water / Gas Inject	Injecting
RAVEN A2	51030625700	Water / Gas Inject	Injecting
RAVEN A3	51030624400	Water / Gas Inject	Injecting
RAVEN A4	51030625800	Water / Gas Inject	Injecting
RAVEN A5X	51030718800	Oil well	Producing
RAVEN B1	51030564900	Oil well	Producing
RAVEN B2AX	51030923800	Water / Gas Inject	Monitor
RECTOR 1	51030549400	Oil well	Producing
RECTOR 11X	51030867200	Oil well	Shut In
RECTOR 12X	51030919900	Oil well	Shut In
RECTOR 3	51030106000	Water / Gas Inject	Injecting
RECTOR 8X	51030704300	Oil well	Producing
RECTOR 9X	51030714700	Oil well	Shut In
RIGBY 1	51030569700	Oil well	Producing
RIGBY 5X	51030804700	Water / Gas Inject	Injecting
RIGBY 6Y	51030910700	Oil well	Producing
RIGBY A2AX	51030920000	Water / Gas Inject	Injecting
RIGBY A3X	51030791000	Oil well	Producing
RIGBY A4X	51030791100	Oil well	Monitor
RIGBY A7Y	51030915100	Oil well	Monitor
ROOTH DF 1	51030579700	Water / Gas Inject	Injecting
ROOTH DF 5 X	51031143000	Oil well	Producing
ROOTH DF 6 X	51031125000	Oil well	Producing
S B LACY 3	51030568900	Oil well	Monitor
STOFFER CR A1	51030562700	Water / Gas Inject	Injecting
STOFFER CR A2	51030559200	Water / Gas Inject	Injecting
STOFFER CR B1	51030567300	Oil well	Producing
SW MCLAUGHLIN 10X	51030754700	Oil well	Producing
SW MCLAUGHLIN 9X	51030753500	Oil well	Producing
U P 4829	51030623100	Water / Gas Inject	P&A
UNION PACIFIC 1 150X 16	51031150200	Oil well	Producing
UNION PACIFIC 1 151X 16	51031150100	Oil well	Producing
UNION PACIFIC 1 153X 16	51031146401	Water / Gas Inject	Injecting
UNION PACIFIC 100X20	51030788600	Oil well	Producing
UNION PACIFIC 101X20	51030797300	Oil well	Monitor
UNION PACIFIC 10-21	51030568501	Oil well	Monitor
UNION PACIFIC 102X20	51030797700	Water / Gas Inject	Injecting
UNION PACIFIC 103X20	51030799000	Water / Gas Inject	Injecting

UNION PACIFIC 104X20	51030803000	Water / Gas Inject	Injecting
UNION PACIFIC 105X29	51030794500	Oil well	Producing
UNION PACIFIC 106X32	51030845000	Oil well	Producing
UNION PACIFIC 107X32	51030849800	Oil well	Producing
UNION PACIFIC 108X21	51030849500	Water / Gas Inject	Injecting
UNION PACIFIC 109X32	51030849700	Oil well	Producing
UNION PACIFIC 110X21	51030853000	Water / Gas Inject	Injecting
UNION PACIFIC 111X29	51030852200	Oil well	Producing
UNION PACIFIC 11-21	51030616200	Oil well	Producing
UNION PACIFIC 112X21	51030873500	Oil well	Monitor
UNION PACIFIC 113X22	51030860600	Oil well	Monitor
UNION PACIFIC 115X21	51030866600	Oil well	Producing
UNION PACIFIC 117X22	51030866700	Oil well	Producing
UNION PACIFIC 118X21	51030869700	Oil well	Producing
UNION PACIFIC 119X21	51030869800	Oil well	Producing
UNION PACIFIC 120X21	51030869900	Oil well	Producing
UNION PACIFIC 12-27	51030620400	Oil well	Producing
UNION PACIFIC 122X21	51030870000	Oil well	Monitor
UNION PACIFIC 126X32	51030885100	Oil well	Producing
UNION PACIFIC 127X31	51030884700	Oil well	Producing
UNION PACIFIC 128X31	51030910000	Oil well	Producing
UNION PACIFIC 129X31	51030885200	Oil well	Producing
UNION PACIFIC 130X32	51030885300	Oil well	Producing
UNION PACIFIC 131X32	51030885500	Oil well	Producing
UNION PACIFIC 1-32	51030556700	Water / Gas Inject	Injecting
UNION PACIFIC 13-28	51030622000	Water / Gas Inject	Injecting
UNION PACIFIC 132X21	51030874600	Oil well	Monitor
UNION PACIFIC 133X21	51030876400	Oil well	Producing
UNION PACIFIC 134X21	51030904100	Water / Gas Inject	Injecting
UNION PACIFIC 135Y28	51030910500	Oil well	Monitor
UNION PACIFIC 136X20	51030913800	Oil well	Producing
UNION PACIFIC 137X20	51030913900	Water / Gas Inject	Monitor
UNION PACIFIC 138Y28	51030917300	Oil well	Producing
UNION PACIFIC 139Y28	51030918500	Oil well	Monitor
UNION PACIFIC 140Y27	51030918800	Oil well	Producing
UNION PACIFIC 141Y28	51030918900	Oil well	Producing
UNION PACIFIC 14-20	51030615400	Oil well	Producing
UNION PACIFIC 142Y28	51030919000	Oil well	Monitor
UNION PACIFIC 143Y28	51030918600	Oil well	Monitor
UNION PACIFIC 15-28	51030102900	Oil well	Monitor
UNION PACIFIC 154Y29	51031172000	Oil well	Producing

UNION PACIFIC 156Y29	51031172100	Oil well	Producing
UNION PACIFIC 16-27	51030620600	Oil well	Shut In
UNION PACIFIC 17-27	51030621400	Oil well	Producing
UNION PACIFIC 18-21	51030616400	Oil well	Producing
UNION PACIFIC 19-28	51030621900	Water / Gas Inject	Injecting
UNION PACIFIC 20-29	51030622800	Water / Gas Inject	Injecting
UNION PACIFIC 21-32	51030627100	Water / Gas Inject	Monitor
UNION PACIFIC 2-20	51030569200	Oil well	Producing
UNION PACIFIC 22-32	51030627500	Oil well	Producing
UNION PACIFIC 23-32	51030626900	Oil well	Producing
UNION PACIFIC 24-27	51030621200	Water / Gas Inject	Injecting
UNION PACIFIC 25-34	51030106900	Oil well	Shut In
UNION PACIFIC 26-31	51030626100	Water / Gas Inject	Injecting
UNION PACIFIC 27-20	51030577000	Oil well	Monitor
UNION PACIFIC 28-22	51030617300	Oil well	Producing
UNION PACIFIC 29-32	51030548700	Oil well	Monitor
UNION PACIFIC 31-21	51030616600	Oil well	Monitor
UNION PACIFIC 32-27	51030620800	Oil well	Monitor
UNION PACIFIC 33-32	51030626600	Water / Gas Inject	Injecting
UNION PACIFIC 3-34	51030551000	Oil well	Producing
UNION PACIFIC 34-31	51030626300	Water / Gas Inject	Injecting
UNION PACIFIC 35-32	51030626800	Water / Gas Inject	Injecting
UNION PACIFIC 36-32	51030627200	Water / Gas Inject	Injecting
UNION PACIFIC 37AX29	51030917700	Water / Gas Inject	Injecting
UNION PACIFIC 39-17	51030612100	Water / Gas Inject	Injecting
UNION PACIFIC 41-20	51030615800	Water / Gas Inject	Shut In
UNION PACIFIC 4-29	51030563200	Water / Gas Inject	Injecting
UNION PACIFIC 42AX28	51030925700	Water / Gas Inject	Injecting
UNION PACIFIC 43-28	51030622100	Water / Gas Inject	Monitor
UNION PACIFIC 44AX20	51030923300	Water / Gas Inject	Injecting
UNION PACIFIC 45-21	51030569600	Water / Gas Inject	Injecting
UNION PACIFIC 47-21	51030615900	Water / Gas Inject	Injecting
UNION PACIFIC 48-29ST	51030623101	Water / Gas Inject	Injecting
UNION PACIFIC 49-27	51030621300	Oil well	Producing
UNION PACIFIC 50-29	51030107100	Water / Gas Inject	Injecting
UNION PACIFIC 51AX20	51030892800	Water / Gas Inject	Injecting
UNION PACIFIC 5-28	51030563900	Oil well	Producing
UNION PACIFIC 52A-29	51030928400	Water / Gas Inject	Injecting
UNION PACIFIC 53-32	51030627600	Water / Gas Inject	Monitor
UNION PACIFIC 54-21	51030616300	Water / Gas Inject	Injecting
UNION PACIFIC 55-17	51030612200	Water / Gas Inject	Injecting

UNION PACIFIC 56-21	51030616700	Water / Gas Inject	Injecting
UNION PACIFIC 58-27	51030620500	Water / Gas Inject	Injecting
UNION PACIFIC 59A-27	51031120700	Oil well	Producing
UNION PACIFIC 60-31	51030626200	Water / Gas Inject	Injecting
UNION PACIFIC 61-20	51030615500	Water / Gas Inject	Injecting
UNION PACIFIC 6-21	51030574100	Oil well	Producing
UNION PACIFIC 62AX32	51030919600	Water / Gas Inject	Injecting
UNION PACIFIC 65-5	51030608900	Water / Gas Inject	Monitor
UNION PACIFIC 67-32	51030626700	Water / Gas Inject	Injecting
UNION PACIFIC 68-32	51030628700	Water / Gas Inject	Injecting
UNION PACIFIC 69-27	51030621000	Oil well	Shut In
UNION PACIFIC 71X31	51030727600	Oil well	Producing
UNION PACIFIC 7-29	51030559700	Water / Gas Inject	Injecting
UNION PACIFIC 73X29	51030738600	Oil well	Producing
UNION PACIFIC 74X27	51030741600	Oil well	Monitor
UNION PACIFIC 75X32	51030740200	Oil well	Producing
UNION PACIFIC 76X21	51030742100	Oil well	Producing
UNION PACIFIC 77X32	51030745400	Oil well	Producing
UNION PACIFIC 78X21	51030742600	Water / Gas Inject	Injecting
UNION PACIFIC 79X32	51030744800	Oil well	Monitor
UNION PACIFIC 80X28	51030746000	Water / Gas Inject	Monitor
UNION PACIFIC 81X29	51030749900	Oil well	Producing
UNION PACIFIC 8-20	51030568600	Oil well	Producing
UNION PACIFIC 82X28	51030749400	Oil well	Producing
UNION PACIFIC 83X28	51030750000	Oil well	Producing
UNION PACIFIC 84X28	51030749500	Oil well	Producing
UNION PACIFIC 85X34	51030748100	Water / Gas Inject	Injecting
UNION PACIFIC 86X27	51030748200	Water / Gas Inject	Injecting
UNION PACIFIC 87X29	51030750900	Oil well	Producing
UNION PACIFIC 88X21	51030751400	Oil well	Producing
UNION PACIFIC 89X34	51030754800	Water / Gas Inject	Injecting
UNION PACIFIC 91X28	51030756000	Water / Gas Inject	Injecting
UNION PACIFIC 9-29	51030565600	Water / Gas Inject	Injecting
UNION PACIFIC 92X28	51030757400	Water / Gas Inject	Monitor
UNION PACIFIC 94X27	51030758800	Water / Gas Inject	Injecting
UNION PACIFIC 96X29	51030765000	Oil well	Producing
UNION PACIFIC 97X29	51030765100	Oil well	Producing
UNION PACIFIC 98X32	51030765200	Oil well	Producing
UNION PACIFIC 99X29	51030785600	Oil well	Producing
UNION PACIFIC B1-34	51030548900	Water / Gas Inject	Monitor
UNION PACIFIC B2-34	51030102700	Oil well	Monitor

UNION PACIFIC B3X34	51030744000	Oil well	Producing
UNION PACIFIC B4X34	51030753600	Water / Gas Inject	Injecting
UNION PACIFIC B5X34	51030759900	Water / Gas Inject	Injecting
UNION PACIFIC B6X34	51030760200	Water / Gas Inject	Monitor
WALBRIDGE LB 1	51030607000	Water / Gas Inject	Monitor
WALBRIDGE UNIT 1	51030607200	Water / Gas Inject	Monitor
WALBRIDGE UNIT 2X	51030920500	Oil well	Producing
WALBRIDGE UNIT 3X	51030920600	Oil well	Monitor
WEYRAUCH 2-36	51030630600	Water / Gas Inject	Injecting
WEYRAUCH 4X36	51030707200	Oil well	Producing
WEYRAUCH 5X36	51030881900	Oil well	Producing
WEYRAUCH 6X36	51030916600	Oil well	Producing
WEYRAUCH 7X36	51030916300	Oil well	Producing
A C MCLAUGHLIN 39	51030582400	P&A	P&A
A C MCLAUGHLIN 3	51030578600	P&A	P&A
MCLAUGHLIN AC 40	51030632000	P&A	P&A
A C MCLAUGHLIN 41	51030575900	P&A	P&A
A C MCLAUGHLIN 48X	51030580300	P&A	P&A
A C MCLAUGHLIN 59X	51030769100	P&A	P&A
MCLAUGHLIN AC 81X	51031053000	P&A	P&A
A.C. MCLAUGHLIN A A2	51030609300	P&A	P&A
A C MCLAUGHLIN B 1	51030611000	P&A	P&A
A C MCLAUGHLIN B 2	51030610500	P&A	P&A
A C MCLAUGHLIN 1	51030612000	P&A	P&A
A C MCLAUGHLIN 1	51030757700	P&A	P&A
ASSOCIATED 4X	51030881200	P&A	P&A
ASSOCIATED B 1	51030601200	P&A	P&A
ASSOCIATED B 2	51030601000	P&A	P&A
ASSOCIATED B 3	51030601300	P&A	P&A
BEEZLEY 1 22	51030573900	P&A	P&A
C T CARNEY 12-5	51030107000	P&A	P&A
C T CARNEY 26X35	51030745000	P&A	P&A
CARNEY CT 31X4	51030760400	P&A	P&A
CARNEY C T 34X-4	51030760000	P&A	P&A
CARNEY CT 36X34	51030759500	P&A	P&A
CARNEY CT 40X35	51030911700	P&A	P&A
CARNEY CT 42Y34	51030915400	P&A	P&A
CHASE UNIT U 1	51030600800	P&A	P&A
HILL,C.E. 1	51030601800	P&A	P&A
HEFLEY C-S 1	51030104100	P&A	P&A
C-S HEFLEY 2	51030607700	P&A	P&A

C-S HEFLEY 3	51030607800	P&A	P&A
C R STOFFER A 3	51030562600	P&A	P&A
EMERALD 12	51030566700	P&A	P&A
EMERALD 15	51030565400	P&A	P&A
EMERALD 18	51030104900	P&A	P&A
EMERALD 21	51030546400	P&A	P&A
EMERALD 24	51030563500	P&A	P&A
EMERALD 29	51030565800	P&A	P&A
EMERALD 30	51030563000	P&A	P&A
EMERALD 31	51030623700	P&A	P&A
EMERALD 33	51030623900	P&A	P&A
EMERALD OIL CO. 3M	51030724700	P&A	P&A
EMERALD 43	51030625200	P&A	P&A
EMERALD 44	51030633800	P&A	P&A
EMERALD 45	51030603000	P&A	P&A
EMERALD 49X	51030729600	P&A	P&A
EMERALD 5	51030566600	P&A	P&A
EMERALD 7	51030624100	P&A	P&A
E OLDLAND 4	51030715200	P&A	P&A
FAIRFIELD,KITTIE A 2	51030611400	P&A	P&A
FAIRFIELD,KITTIE A 3	51030611700	P&A	P&A
F V LARSON 116	51036652500	P&A	P&A
FEE 118X	51030843900	P&A	P&A
FEE 119X	51030849400	P&A	P&A
FEE 161X	51031185900	P&A	P&A
FEE 16	51030624600	P&A	P&A
FEE 2	51030558600	P&A	P&A
FEE 46	51030610700	P&A	P&A
FEE 53	51030617400	P&A	P&A
FEE 54	51030618000	P&A	P&A
FEE 57	51030622700	P&A	P&A
FEE 58	51030614300	P&A	P&A
FEE 66	51030610900	P&A	P&A
FEE 67	51030611600	P&A	P&A
FEE 70	51030626000	P&A	P&A
FEE 71	51030610800	P&A	P&A
FEE 77X	51030736000	P&A	P&A
FEDERAL ET AL 2M	51030719700	P&A	P&A
FEDERAL ET AL 5M	51030731700	P&A	P&A
LARSON FV B10	51030629900	P&A	P&A
LARSON FV B13X	51030557900	P&A	P&A

LARSON FV B16X	51030702400	P&A	P&A
LARSON FV B1	51030629600	P&A	P&A
LARSON FV 26Y	51030948500	P&A	P&A
LARSON FV B3	51030630500	P&A	P&A
LARSON FV B5	51030630100	P&A	P&A
LARSON FV B6	51030630300	P&A	P&A
LARSON F V B7	51030630001	P&A	P&A
LARSON FV B9	51030102500	P&A	P&A
F V LARSON 1	51030539800	P&A	P&A
GENTRY 2D	51030543700	P&A	P&A
GENTRY 3D	51030608500	P&A	P&A
NEWTON 4-D	51030104300	P&A	P&A
GENTRY 4D	51030543700	P&A	P&A
GENTRY 5D	51030608300	P&A	P&A
GENTRY 6X	51030744200	P&A	P&A
GRAY A 11	51030613800	P&A	P&A
GRAY A 11AX	51030927500	P&A	P&A
GRAY A 8	51030568100	P&A	P&A
GRAY B 14	51030613000	P&A	P&A
GUIBERSON,S.A. A 2	51030613400	P&A	P&A
HILDENBRANDT 1	51030608100	P&A	P&A
COLTHARP JE 1	51030602400	P&A	P&A
J E COLTHARP 3	51030602500	P&A	P&A
COLTHARP JE 6X	51030714800	P&A	P&A
COLTHARP JE 9X P 9X	51030853500	P&A	P&A
PEPPER,J.E. A 1	51030550200	P&A	P&A
J E PEPPER B 1	51030606300	P&A	P&A
LACY SB 10Y	51030914300	P&A	P&A
S B LACY 2	51030570600	P&A	P&A
F V LARSON 1	51030106500	P&A	P&A
LEVISON 15	51030618100	P&A	P&A
LEVISON 16	51030619600	P&A	P&A
LEVISON 19	51030106300	P&A	P&A
LEVISON 20	51030618300	P&A	P&A
LEVISON 3	51030621600	P&A	P&A
LEVISON 4	51030560400	P&A	P&A
LEVISON 5	51030621500	P&A	P&A
L N HAGOOD B 1	51030607300	P&A	P&A
L N HAGOOD B 2	51030607100	P&A	P&A
L N HAGOOD B 3	51030607400	P&A	P&A
WALBRIDGE LB 3	51030630800	P&A	P&A

WALBRIDGE LB 4X	51030873600	P&A	P&A
WALBRIDGE LB 5Y	51030948300	P&A	P&A
MAGOR 1	51030580800	P&A	P&A
MCLAUGHLIN 3	51030556100	P&A	P&A
MELLEN,W.P. A 3	51030105700	P&A	P&A
HEFLEY ME 1	51030607500	P&A	P&A
HEFLEY ME 3	51030545400	P&A	P&A
HEFLEY ME 4	51030543300	P&A	P&A
M B LARSON C11 X 25	51030717300	P&A	P&A
M B LARSON A 1	51030632900	P&A	P&A
MB LARSON A3	51030576400	P&A	P&A
LARSON MB 1-35	51030555700	P&A	P&A
M B LARSON C 1	51030571900	P&A	P&A
LARSON MB C2-25	51030106400	P&A	P&A
M B LARSON C425	51030618900	P&A	P&A
LARSON MB D136	51030631000	P&A	P&A
LARSON MB D226	51030102600	P&A	P&A
M B LARSON D525	51030618500	P&A	P&A
M B LARSON D625	51030619000	P&A	P&A
M B LARSON D725	51030618400	P&A	P&A
NEAL 2	51030566000	P&A	P&A
NEAL 3	51030567200	P&A	P&A
NEWTON ASSOC A1	51030107300	P&A	P&A
NEWTON ASSOC B 1	51030101800	P&A	P&A
NEWTON ASSOC C 1	51030102100	P&A	P&A
NEWTON ASSOC D 1	51030102200	P&A	P&A
NIKKEL 1	51030619300	P&A	P&A
NIKKEL 2	51030619100	P&A	P&A
OLDLAND 1	51030102000	P&A	P&A
OLDLAND 2	51030106100	P&A	P&A
OLDLAND 3	51030630400	P&A	P&A
OLDLAND E 5X	51030853600	P&A	P&A
OLDLAND E 6X	51030947600	P&A	P&A
PURDY 1 6	51030606200	P&A	P&A
PURDY 3X1	51030870300	P&A	P&A
RANGELY 2M-33-19B	51030939800	P&A	P&A
RAVEN A 1	51030562900	P&A	P&A
RAVEN B 2	51030624300	P&A	P&A
RECTOR 10X	51030760300	P&A	P&A
RECTOR 2	51030608400	P&A	P&A
RECTOR 4	51030629400	P&A	P&A

RECTOR 5	51030629200	P&A	P&A
RECTOR 6	51030608200	P&A	P&A
RECTOR 7	51030105900	P&A	P&A
RIGBY A224	51030570000	P&A	P&A
ROOTH 3	51030564700	P&A	P&A
MCLAUGHLIN SHARPLES 11X 3	51030760500	P&A	P&A
SHARPLES MCLAUGHLIN 132	51030107400	P&A	P&A
SHARPLES MCLAUGHLIN 432	51030627400	P&A	P&A
UNION PACIFIC 121X21	51030870500	P&A	P&A
U P 3016	51030578300	P&A	P&A
UNION PACIFIC 37-29	51030623200	P&A	P&A
U P 3822	51030574400	P&A	P&A
U P 4022	51030617800	P&A	P&A
U P 4228	51030621800	P&A	P&A
U P 4420	51030571000	P&A	P&A
UNION PACIFIC 46-21	51030573700	P&A	P&A
U P 5721	51030616500	P&A	P&A
U P 5927	51030620900	P&A	P&A
UNION PACIFIC 62-32	51030626500	P&A	P&A
UNION PACIFIC 63-31	51030623000	P&A	P&A
UNION PACIFIC 63-31	51030626400	P&A	P&A
UNION PACIFIC 63AX31	51030917900	P&A	P&A
U P 6422	51030617200	P&A	P&A
U P 6616	51030610600	P&A	P&A
UNION PACIFIC 72X31	51030736400	P&A	P&A
UNION PACIFIC 90X29	51030758200	P&A	P&A
UNION PACIFIC 93X27	51030756100	P&A	P&A
U P 95X 34	51030759600	P&A	P&A
COLTHARP WH A2	51030602000	P&A	P&A
COLTHARP WH A7X	51030869300	P&A	P&A
COLTHARP WH B1	51030101900	P&A	P&A
WEYRAUCH 1-36	51030630700	P&A	P&A
WEYRAUCH 336	51030630900	P&A	P&A
WHITE 1	51030543500	P&A	P&A
WHITE 2	51030545100	P&A	P&A