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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
AIR AND RADIATION

December 14, 2022

Mr. Carl Thunem
Camrick Unit
1101 Central Expressway South
Suite 150
Allen, Texas 75013

Re: Monitoring, Reporting and Verification (MRV) Plan for Camrick Unit

Dear Mr. Thunem:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Camrick Unit, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Camrick Unit on October 20, 2022, as the final MRV plan. The MRV Plan Approval Number is 1009997-1. This decision is effective December 19, 2022 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78.

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

Sincerely,

Julius Banks, Chief
Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for Camrick Unit

December 2022

Contents

Appendices

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) Subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted by CapturePoint, LLC (CapturePoint) for the carbon dioxide (CO_2) capture and enhanced oil recovery (EOR) project in the Camrick Field Area (CFA). Note that this evaluation pertains only to the Subpart RR MRV plan for the Camrick Unit facility, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations.

1 Overview of Project

CapturePoint indicates in the introduction of the MRV plan that it operates the CFA located in Beaver and Texas Counties, Oklahoma and in Ochiltree County, Texas for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) with retention of CO_2 serving a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The CFA is composed of three units, the Camrick Unit (CU), the North Perryton Unit (NPU), and the Northwest Camrick Unit (NWCU). The GHGRP facility, called Camrick Unit, has been operating the CFA since 2017. Camrick Unit acquired the CFA from Chaparral Energy LLC, which initiated the CO_2-EOR project in March 2001 for the CU and January 2007 for the NPU. No CO_2 has been injected into the NWCU as of the date of the MRV plan submission. Camrick Unit intends to continue CO_2-EOR operations until the end of the economic life of the CO_2-EOR program using various Class II injection wells as defined by Underground Injection Control (UIC) regulations and permitted under Texas Railroad Commission (TRRC) Rule 46 of the Texas Administrative Code (TAC) and the Oklahoma Corporation Commission (OCC) Title 165:10 of the Oklahoma Administrative Code (OAC). This MRV plan was developed 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 Camrick Unit.

The two units with prior operations previously reported to the GHGRP subpart UU under two separate facility identification numbers. CU CO_2 Flood reported under GHGRP identification number 544678 and the NPU CO_2 Flood reported under GHGRP identification number 544679. As stated in the MRV plan, Camrick Unit has notified the EPA that the NPU will not be reporting for 2022, and that the facilities will be merged into the Camrick Unit (544678) for subpart RR reporting.

The States of Texas and Oklahoma have primacy with respect to implementation of UIC Class II injection well permits. The MRV plan states that the relevant OCC rules are OAC Title 165:10-5-1 through 165:10-5-15, OAC 165:5-7-27, OAC 165:5-7-30, the request for an exception to UIC rules under OAC 165:5-7-29, and other governing filing forms. The TRRC has issued UIC Class II enhanced recovery permits under its Rule 46, TAC Title 16 Part 1 Chapter 3. All wells in the CFA, including both injection and production wells, are regulated by the OCC and the TRRC. According to the MRV plan, CO_2 is injected into the Upper Morrowan, a lenticular bedded sandstone trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth.

Section 2 of the MRV plan provides a description of the CFA project, including detail on estimated CO_2 volumes to be injected over the life of the project, site geology, injection operations and results of reservoir modeling.

Camrick Unit states in the MRV plan that CO_2-EOR operations have been ongoing within the CFA for over 20 years and Camrick Unit intends to continue injection for another 12 years. The MRV plan forecasts cumulative CO_2 injection and storage over the life of the project to be approximately 100 billion standard cubic feet (Bscf) or 5.3 million metric tonnes (MMMT) from initial injection to end of the project in October 2034. During the period covered by the MRV plan, September 2022 through October 2034, Camrick Unit expects to store 52.5 Bscf or 2.77 MMMT in the CFA.

The MRV plan bases the site geology on logs from both the CFA and the Farnsworth Unit, which is located 10 miles South-South-West of the CFA. According to Camrick Unit, both areas have similar pay thickness, porosity values, permeability measurements, depositional environment, tectonic processes, and overburden strata layers. The CFA is located on the northwest shelf of the Anadarko basin, see Figure 2.2-1 of the MRV plan, and is one of many oil fields in the area that produce from a sequence of alternating sandstones and mudstones deposited during the late Pennsylvanian Morrowan period. According to the MRV plan, oil production and CO_2 injection at CFA are restricted to the operationally named Morrow B sandstone; the uppermost Morrow sandstone encountered below the Atokan Thirteen Finger limestone. The plan also states that the primary caprock intervals at CFA are comprised of the upper Morrow shale and the Thirteen Finger limestone. The Morrowan and Atokan intervals were deposited approximately 315-300 million years ago. Overlying stratigraphy includes late Pennsylvanian through the middle Permian shales and limestones, with lesser amounts of dolomite, sandstone and evaporites. The MRV plan notes that the primary seal rocks of the Morrow shale and the Thirteen Finger Limestone comprise a package of approximately 180-200 feet thick in the field and are overlain by thousands of feet of Atokan and younger limestones and shales. Figure 2.2-1 in the MRV plan shows a generalized stratigraphic column of the area underlying the CFA.

The MRV plan states that the Upper Morrowan sandstones in the Anadarko Basin margins have long been recognized as fluvial deposits. At the Farnsworth Unit, and similarly at the CFA, the Morrow B is described as a relatively coarse-grained subarkosic sandstone. The upper Morrowan facies, with sequences of basal conglomerate, coarse-grained sandstone, and fine-grained sandstone appear to be typical of incised valley deposits. The Morrow B sandstones are encased above and below by shales. Contacts with shale both below and above the sandstone are sharp and irregular. The Morrow shale generally fines upwards in a series of thin beds that alternate between upper fine sands and fine to medium muds.

As stated in the MRV plan, the Thirteen Finger limestone formation has two different lithofacies: diagenetic limestone (cementstone) and pyrite and fossil bearing fine to medium mudstone and coal. The two facies are intercalated with each other but tend to cluster in layers dominated more by one or the other. The entire Thirteen Finger interval is typically 130 feet (39.6 meters) thick, comprised of mudstone, coal, and limestone. The mudstone is calcite rich, with some dolomite, and is completely diagenetic in origin and probably formed relatively soon following deposition.

The description of the project is determined to be acceptable and provides the necessary information for 40 CFR 98.448(a)(6).

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

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

Camrick Unit has defined the MMA as the boundary of the CFA plus an additional one-half mile buffer zone. Some wells have CO_2 retention on the 4,800 acres that have been under EOR injection in the CFA since project initialization, see Figure 3.1-1 of the MRV plan for a map of these wells. Camrick Unit reports that oil recovery in the CFA since August 1955 has resulted in a voidage space of 36 million standard cubic feet (MMscf) of CO_2 per acre of surface area that was later filled with water during waterflood operations. According to the MRV plan, the average decimal fraction of CO_2 injection to hydrocarbon pore volume left in the ground after accounting for CO_2 production through 2021 is 0.29. The lateral extent of CO_2 in the injection zone or the CO_2 storage radius for each well was estimated based on cumulative CO_2 injected times the decimal fraction of CO_2 remaining divided by the voidage space. The MRV plan states that the site characterization and stratigraphic trapping of the Morrow did not reveal any leakage pathways that would allow free-phase CO_2 to migrate laterally, thus, a buffer zone greater than one-half mile, the minimum required, was not necessary.

The MRV plan states that the volumetric storage capacity calculated for the 49 patterns identified for continued injection indicates an additional 90 Bscf of CO_2 can be stored. This 90 Bscf would be added to the 50 Bscf already stored to result in 140 Bscf of total storage. The MRV plan states that with the anticipated 12 MMCFD rate or purchased CO_2, this storage volume will only be 60 percent utilized. Camrick Unit states in their MRV plan that the MMA accounts for an injected volume of up to 140 Bscf and includes all areas of the CFA that could be utilized in the future for CO_2 injection.

As described in the introduction and section 2.2.1 of the MRV plan, the AMA is defined by Camrick Unit’s exclusive right to operate the CFA unitized leases. The MRV plan states that Camrick Unit focuses their current operations on the western portion of the CU and the entire NPU. It is anticipated that as the project develops, or as additional CO_2 volumes become available, additional areas within the CFA may be developed.. However, Camrick Unit indicates in the MRV plan that project development will be driven by the market price of oil, so Camrick Unit is unable to provide a specific time in the future when the eastern portion of the CFA will be developed. The MRV plan states that as CO_2 injection operations are expanded beyond the currently active CO_2-EOR portion of the CFA, all additional CO_2 injection wells will be permitted under the UIC program and will be included in the annual submittal per 40 CFR 98.446(f)(13). Camrick Unit states that all future CO_2 injection wells permitted will be within the AMA. The MRV plan states that Camrick Unit expects the free phase CO_2 plume to remain within the CFA for the entire length of the project and through year [t + 5]. Therefore, Camrick Unit is defining the AMA as the CFA plus an all-around one-half mile buffer, as required by 40 CFR 98.449. Camrick Unit states that a new MRV plan will be resubmitted if there are any material changes to the monitoring/operational parameters not outlined in this MRV plan, as directed by 40 CFR 98.448(d)(1).

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

3 Identification of Potential Surface Leakage Pathways

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

- Leakage from Surface Equipment
- Leakage through Wells
    - Abandoned Wells
    - Injection Wells
    - Production Wells
    - Inactive Wells
    - New Wells
- Leakage through Faults and Bedding Plane Partings
    - Presence of Hydrocarbons
    - Fracture Analysis
- Leakage through Lateral Fluid Movement
- Leakage through Confining/Seal system
- Leakage through Natural and Induced Seismic Activity

3.1 Leakage through Surface Equipment

The MRV plan states that the surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO_2-EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment via personnel instructed on how to detect surface leaks and other equipment failure minimizes releases. In addition, the Oil and Gas Division requirements of the OAC rules of the OCC and the TAC rules of the TRRC require operators to report and quantify leaks. Both serve to minimize leakage of GHG from surface equipment. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards.

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

3.2 Leakage through Wells

Camrick Unit has identified 68 abandoned wells, 49 injection wells (29 active) and 94 production wells (59 active) within the MMA and assessed their potential for leakage of CO_2 to the surface.

Abandoned Wells

Because the CFA was unitized in 1969 to 1972, Camrick Unit asserts that all plugging and abandonment activities of wells within the CFA have been conducted under the regulations of the OCC and the TRRC for plugging wells. Camrick Unit further states that the cement used to plug wells when exposed to CO_2 will form colloidal gels that further reduce any flow. Camrick Unit concludes that leakage of CO_2 to the surface through abandoned wells is unlikely.

Injection Wells

The MRV plan states that mechanical integrity testing (MIT) is an essential requirement of the UIC program in demonstrating that injection wells themselves do not act as conduits for leakage into underground sources of drinking water (USDW) and to the surface environment. TRRC Rule 46 requirements include special equipment requirements (e.g., tubing and packer) and modification; records maintenance; monitoring and reporting; testing; plugging; and penalties for violations of the rule. The TRRC and the OCC detail all the requirements for the Class II permits issued to Camrick Unit. These rules ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Thus, Camrick Unit concludes that leakage of CO_2 to the surface through active injection wells is unlikely.

Production Wells

The MRV plan states that some of the original field wells drilled as oil wells were reclassified, administratively, to gas wells per OAC Title 165:10-1-6 paragraph (d), because of the gas-oil ratio growth due to reservoir depletion. Hence, there is no difference in well construction. As the field is being further developed for enhanced oil recovery, these gas wells have been reclassified to oil wells per OCC regulations and will be monitored for leakage. Once EOR operations commence, the energy content of the produced gas drops and cannot be sold; therefore, Camrick Unit asserts that any inactive gas wells are reclassified to either oil producer or WAG injector. Presumably, in this case, the wells are merely reclassified, with no conversion or well workover taking place. Nonetheless, upon reclassification, these wells will be assumed to have the same potential leakage characteristics as the well category to which they are reclassified, with the corresponding monitoring activities and quantification of emissions from such wells used.

As the project develops in the CFA; additional production wells may be added and will be constructed according to the relevant rules of the OCC and the TRRC per the MRV plan. Additionally, inactive wells may become active according to the rules of the OCC and the TRRC.

Inactive Wells

The MRV plan notes that the OCC has regulations for temporally abandoned/not plugged (TA) and terminated order wells/UIC not plugged (TM) and likewise the TRRC has regulations for inactive wells. Inactive wells have a cast iron bridge plug set or long cement plugs placed above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. Camrick Unit concludes that leakage of CO_2 to the surface through inactive wells is unlikely.

New Wells

According to Camrick Unit, all new wells will be constructed according to the relevant rules for the OCC and the TRRC, which ensure protection of subsurface and surface resources, as well as the environment. All wells in Oklahoma oilfields and all wells in Texas oilfields, including both injection and production wells, are regulated by the OCC and the TRRC, respectively, which have primacy to implement the UIC Class II programs. New well construction is based on existing best practices, established during the drilling of existing wells in CFA, and follows the OCC and the TRRC rules. The MRV plan states that these practices significantly limit any potential leakage from well pathways. Additionally, Camrick Unit notes that the existing wells followed the OCC and the TRRC rules. Therefore, Camrick Unit concludes that leakage of CO_2 to the surface through new wells is unlikely.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected through abandoned, injection, production, inactive, and new wells.

3.3 Leakage through Faults and Bedding Plane Partings

According to the MRV plan, primary seals at CFA have been demonstrated to be mechanically very competent, thus the main concern of CO_2 migration at CFA is via seal bypass systems along fracture networks.

Presence of Hydrocarbons

The MRV plan states that the presence of 75 MMB of oil in the reservoir helps show the lack of significant leakage pathways present, as oil would have drained from the reservoir prior to the current day should such pathways exist.

Fracture Analysis

The MRV plan asserts that work done at the Farnsworth Unit is analogous to the CFA. Specifically, the MRV plan acknowledges that small aperture fractures were noted but not common in most of the reservoir cores examined, but most of these fractures appear to be drilling induced. The MRV plan also notes that fractures in the Thirteen Finger limestone caprock were described using an industry-standard format for fracture class type, orientation, fracture dip, type of mineral fill, fracture porosity, fracture spacing, and intensity. Natural mineral-filled fractures, which are rare, were formed during diagenesis at shallow depths, and are of late Carboniferous age. Unless significantly damaged by large changes in reservoir pressure, the MRV plan claims that they are highly unlikely to provide migration pathways.

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

3.4 Leakage through Lateral Fluid Movement

The MRV plan states that the Morrow strata in the Oklahoma and Texas Panhandle was primarily a deltaic sequence that prograded toward the southeast, resulting in deposition of mainly shales with lenticular, discontinuous coarse sandstones separated with very fine sandstone, minor conglomerates, and shale. Since CO_2 is lighter than the water remaining in the reservoir, it should migrate to the top of each lenticular structure as it is filled according to the MRV plan. The producing wells, which create low pressure points in the field, will drain the water and keep the CO_2 within each discontinuous sandstone. Therefore, Camrick Unit believes the likelihood of any extensive migration of fluid outside of the AMA is very low.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected through lateral fluid movement.

3.5 Leakage through Confining/Seal System

The MRV plan states that petrophysical analytical methods used at the CFA include retort analysis, pulse-decay permeability measurement, pressure decay permeability analysis for tight rocks, and mercury injection porosimetry, which is also known as mercury injection capillary pressure (MICP). Results of the MICP analysis show that the mudstone lithologies in the Morrow Shale and Thirteen Finger Limestone can support CO_2 column heights of approximately 1,000 to 10,000 feet. At an order of magnitude over the thickness of the Morrow reservoir, according to the MRV plan, this should prove an effective seal for CO_2 storage in the Morrow B injection horizon.

As stated in the MRV plan, failure analyses show that the Morrow B sands are weaker than overlying lithologies, so that any fracture initiation around the injection well would not be expected to propagate into the overlying sealing units. Mechanical properties of the overlying shale and limestones provide an interesting and effective combination of strength and elasticity. Limestone layers are strong but brittle, while the shale layers are weaker but sufficiently ductile to prevent extensive fracture propagation.

Thus, the MRV plan provides an acceptable characterization of the likelihood of CO_2 leakage that could be expected from the confining/seal system.

3.6 Leakage through Natural and Induced Seismic Activity

Figure 4.6-1 of the MRV plans shows the map of earthquakes with magnitudes measured at greater than 2.5 as defined by the United States Geological Survey (USGS). The small number of events near CFA after the 29 waterflood operations were initiated in 1969 implies the area is not seismically sensitive to injection. Also, no documentation exists that any of the distant earthquake events caused a disruption in injectivity or damage to any of the wellbores in CFA. Camrick Unit states that there is also no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the CFA.

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

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

40 CFR 98.448(a)(3) requires that an MRV plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring CO_2 surface leakage. Section 4 of the MRV plan details Camrick Unit's strategy for monitoring and quantifying CO_2 leakage, and section 5 of the MRV plan details strategies for establishing baselines for CO_2 leakage. Camrick Unit claims the atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values for soil measurement in the CFA area, per the characterization, monitoring and well data collected by the Southwest Regional Partnership on Carbon Sequestration (SWP) in the analogous Farnsworth Unit. Monitoring will occur during the planned 12-year injection period. Table 1 of the MRV plan, which has been reproduced below, provides a summary of the potential leakage pathway(s), their respective monitoring methods, and anticipated responses.

Known Potential Leakage Risks	Monitoring Methods and Frequency	Anticipated Response Plan
Tubing Leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days
Casing Leak	Weekly field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days
Wellhead Leak	Weekly field inspection	Workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations (weekly inspection but field personnel present daily)	Maintain well kill procedures
Unplanned wells drilled through Morrow	Weekly field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Re-enter and reseal abandoned wells
Pumps, values, etc.	Weekly field inspection	Workover crews respond within days
Leakage along faults	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near faults
Leakage laterally	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Fluid management along lease lines
Leakage through induced fractures	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near seismic event

4.1 Detection of Leakage through Surface Equipment

The MRV plan states that the combination of regulation from the OCC and the TRRC and following industry standards minimize leakage from surface equipment in the facility. If leakage should be detected through periodic inspections or a MIT, it will be quantified according to the procedures in Subpart W of the GHGRP.

Thus, the MRV plan provides an acceptable characterization of Camrick Unit's approach to detecting and quantifying potential CO_2 leakage that could be expected through surface equipment as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through Wells

The MRV plan identifies several abandoned, injection, and production wells in the MMA. These wells all have different leakage risks associated with them.

Abandoned Wells

Camrick Unit states that CO_2 leakage is unlikely through abandoned wells thanks to the cement used to plug abandoned wells. If leakage were to occur though, it would be detected through changes of pressure in WAG skids and quantified using techniques per Subpart W of the GHGRP.

Injection Wells

Since injection wells must follow TRRC and OCC requirements to be active, Camrick Unit asserts leakage is not likely through injection wells. MITs would also be used to detect the potential leakage and the leak would be quantified according to procedures in Subpart W of the GHGRP.

Inactive Wells

As stated in the MRV plan, inactive wells are not plugged, and so are subject to TRRC regulations that diminish leakage risk. A leak that occurs would be detected by field inspection and changes in pressure and quantified according to procedures in Subpart W of the GHGRP.

New Wells

The MRV discusses how new production and injection wells may be added to the CFA in the future. OCC and TRRC rules reduce the risk of leakage. These wells will be subject to the same CO_2 leakage detection and quantification methods as active injection wells.

Thus, the MRV plan provides an acceptable characterization of Camrick Unit's approach to detecting and quantifying potential CO_2 leakage through wells within the MMA as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage through Faults and Bedding Plane Partings

Since there are no faults or fracture zones cutting across the seal units according to the MRV, the risk of leakage is very low. Regardless, if a leak were to occur, it would be detected by monitoring changes in WAG skid pressure, and the volume of leakage will be reported in Subpart RR of the GHGRP.

Thus, the MRV plan provides an acceptable characterization of Camrick Unit's approach to detecting and quantifying potential CO_2 leakage through faults and bedding plane partings as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage through Lateral Fluid Movement

The likelihood of any extensive migration of fluid outside of the AMA is very low due to the shale and fine sandstone composition of the Morrow strata per the MRV plan. Leakage laterally would be detected though continuous pressure monitoring using WAG skids, with the volume of the leakage being reported in Subpart RR of the GHGRP.

Thus, the MRV plan provides an acceptable characterization of Camrick Unit's approach to detecting and quantifying potential CO_2 leakage through lateral fluid movement as required by 40 CFR 98.448(a)(3).

4.5 Detection of Leakage through Confining/Seal System

Petrophysical and caprock analysis was performed at the Farnsworth Unit, which is analogous to the CFA according to Camrick Unit. Per the analyses, it is unlikely for hydrocarbon migration pathways that charged the Morrow reservoir to be potential CO_2 migration pathways via primary pore networks today. Camrick Unit states that CO_2 migration is more likely due to leakage through other pathways. The MRV plan states that leakage would be detected with WAG skids' pressure measurements, with the volume of the leakage being reported in Subpart RR of the GHGRP.

Thus, the MRV plan provides an acceptable characterization of Camrick Unit's approach to detecting and quantifying potential CO_2 leakage through the confining/seal system as required by 40 CFR 98.448(a)(3).

4.6 Detection of Leakage through Natural and Induced Seismic Activity

A small number of seismic events have occurred near the CFA, which were attributed to waterflood operations. These events did not disrupt injection or damage any well bores in the CFA. Therefore, Camrick Unit asserts that seismic activity will likely not contribute to major CO_2 leakage in the CFA. If leakage were to occur, constant monitoring of pressure in the WAG skids would detect the leak, and its volume would be reported in Subpart RR of the GHGRP.

While the risk to leakage is small, the MRV plan discusses how detection of leaks as a result of seismic activity will occur using soil CO_2 and groundwater monitoring.

Thus, the MRV plan provides an acceptable characterization of Camrick Unit's approach to detecting and quantifying potential CO_2 leakage through the natural and induced seismic activity as required by 40 CFR 98.448(a)(3).

4.7 Strategy for Determining CO_2 Baselines for CO_2 Monitoring

Site Characterization and Monitoring

According to the MRV plan, the primary seal consists of 180 – 200 ft of Morrow shale and Thirteen Finger Limestone which in turn is overlain by over a thousand feet of younger shale and limestone. These units provide a suitable seal to prevent the migration of CO_2 out of the injection reservoir. Additionally, the MRV plan states that no significant faults or fracture zones that cut across the seal units have been identified in the CFA, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented.

Groundwater Monitoring

While Camrick Unit states that it does not usually pull water samples from the Ogallala water wells, samples are pulled when OCC injection permits are submitted in Oklahoma and there has been no indication of fluid leakage from any samples. Camrick Unit is unlikely to continue monitoring USDW wells for CO_2 or brine contamination because it contends the Morrow has been characterized as having a minimal risk of groundwater contamination from CO_2 leakage.

Soil CO_2 Monitoring

Atmospheric CO_2 values at the Farnsworth Unit have been determined by a SWP eddy tower installation, as mentioned in the MRV plan. While the tower malfunctioned and was not repaired in 2019 due to COVID, the data values from the tower when it worked were quite close to the data gathered from the NOAA Global Monitoring Laboratory station in Moody, Texas (Station: WKT). Since the CFA area is near the Farnsworth Unit, Camrick Unit states that atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values.

Visual Inspection

Camrick Unit states that operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage.

Well Surveillance

Camrick Unit says it adheres to the requirements of OAC Title 165:10-5 for the OCC and of TAC Rule 46 for the TRRC governing fluid injection into productive reservoirs. Rule 46 includes requirements for monitoring, reporting, and testing of Class II injection wells. Furthermore, the OCC and the TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well if they are deemed necessary.

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

5.1 Determining Mass of CO_2 Received

According to the MRV plan, Camrick Unit currently receives CO_2 at its CFA facility through its own pipeline from the Arkalon Ethanol plant in Liberal, Kansas. Camrick Unit also recycles CO_2 from its production wells in the CFA. Therefore, in accordance with 40 CFR §98.444(a)(2), Camrick Unit has elected to use Equation RR-2.

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

Where:

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

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into the well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

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

p = Quarter of the year.

r = Flow meter.

Camrick Unit provides an acceptable approach to calculating the mass of CO_2 received in accordance with Subpart RR requirements.

5.2 Determining Mass of CO_2 Injected

Camrick Unit lists the SEF injection wells in Appendix 1 of the MRV plan and uses Equation RR-5 to calculate the mass of CO_2 that is injected.

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

Where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

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

p = Quarter of the year.

r = Flow meter.

Camrick Unit provides an acceptable approach to calculating the mass of CO_2 injected in accordance with Subpart RR requirements.

5.3 Mass of CO_2 Produced from Oil Wells

Camrick Unit also recycles CO_2 from its production wells which are part of its operations in the CFA. Therefore, Equation RR-8 is used to calculate the mass of CO_2 produced.

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

Where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

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

p = Quarter of the year.

w = Separator.

To aggregate production data, Camrick Unit will sum the mass of all of the CO_2 separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 below:

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

Where:

CO_{2p} = Total annual CO_2 mass produced (metric tons) through all separators in the reporting year.

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction), CU is 0.00236 and NPU is 0.00454 at the last sample.

w = Separator.

Camrick Unit provides an acceptable approach to calculating the mass of CO_2 produced from oil wells in accordance with Subpart RR requirements.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

The MRV plan states that per 98.448 (d) of Subpart RR, Camrick Unit will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r)

(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations.

Camrick Unit will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below:

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

Where:

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

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

X = Leakage pathway.

Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

Camrick Unit provides an acceptable approach for calculating the mass of CO_2 emitted by surface leakage in accordance with Subpart RR requirements.

5.5 Calculation of Mass of CO_2 Sequestered

The MRV Plan states that the mass of CO_2 sequestered in subsurface geologic formations will be calculated based off Equation RR-11, because the facility will be actively producing oil or natural gas, as follows:

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \quad \text{(Equation RR-11)}$$

Where:

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

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

$CO_{2P=}$ Total annual CO_2 mass produced (metric tons) in the reporting year.

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

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

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

Camrick Unit provides an acceptable approach for calculating the mass of CO_2 sequestered in accordance with Subpart RR requirements.

6 Summary of Findings

The Subpart RR MRV plan for Camrick Unit Facility meets the requirements of 40 CFR 98.238. The regulatory provisions of 40 CFR 98.238(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the Camrick Unit MRV plan.

Subpart RR MRV Plan Requirement	Camrick Unit MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 3 of the MRV plan describes the MMA and AMA. The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The AMA has been defined as the entire CFA.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 4 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: leakage from surface equipment, leakage through existing wells within MMA, leakage through faults and bedding plane partings, leakage through lateral fluid movement, leakage through confining/seal system, and leakage through natural and induced seismic activity. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways. Camrick Unit determined that these leakage pathways are not likely at the Camrick Unit facility, and that it is unexpected that potential leakage conduits would result in significant loss of CO_2 to the atmosphere.

40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 4 of the MRV plan also describes both the strategy for how the facility would detect CO_2 leakage to the surface and how the leakage would be quantified, should leakage occur. Leaks would be detecting using methods such as field inspections, continuous monitoring of pressure in WAG skids, and mechanical integrity testing.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 5 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 6 of the MRV plan describes Camrick Unit's approach to determining the amount of CO_2 sequestered using the Subpart RR mass balance equation, including as related to calculation of total annual mass emitted from equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Appendix 1 of the MRV plan provides the well identification numbers for all injection wells. The MRV plan specifies that the wells have been issued a UIC Class II permit under TRRC Rule 46.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 7 of the MRV plan states that Camrick Unit will begin implementing baseline measurements of injection volumes and pressures will be taken September 1, 2022.

Appendix A: Final MRV Plan

Camrick Field Area (CFA)

MONITORING, REPORTING AND VERIFICATION PLAN (MRV)

CapturePoint LLC

April 2022

Contents

INTRODUCTION

CapturePoint, LLC (CapturePoint) operates the Camrick Field Area (CFA) located in Beaver and Texas Counties, Oklahoma and in Ochiltree County, Texas for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) with retention of CO_2 serving a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The CFA was discovered in 1955 and is composed of three units, the Camrick Unit (CU) that was unitized by Humble Oil Company on October 14, 1969, the North Perryton Unit (NPU) that was unitized by Humble Oil Company on March 17, 1969, and the Northwest Camrick Unit (NWCU) that was unitized by Atlantic RichField Company on September 15, 1972. The Units were formed for the purpose of waterflooding with salt water sourced from the Wolfcamp formation. The field structure is a lenticular bedding sand trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. CapturePoint has been operating the CFA since 2017. CapturePoint acquired the CFA from Chaparral Energy LLC, which initiated the CO_2-EOR project in March 2001 for the CU and January 2007 for the NPU. No CO_2 has been injected in the NWCU. CapturePoint intends to continue CO_2-EOR operations until the end of the economic life of the CO_2-EOR program using various Class II injection wells as defined by Underground Injection Control (UIC) regulations and permitted under Texas Railroad Commission (TRRC) Rule 46 of the Texas Administrative Code (TAC) and the Oklahoma Corporation Commission (OCC) Title 165:10 of the Oklahoma Administrative Code (OAC). In this document, the term “gas” means a mixture of hydrocarbon light end components and the CO_2 component that can be produced as part of the EOR process.

CapturePoint has chosen to submit this Monitoring, Reporting, and Verification (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 (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code.

This MRV Plan contains ten sections:

Section 1 contains facility information.

Section 2 contains the project description including: a detailed description of the injection operation including the duration and volume of CO_2 to be injected; a detailed description of the geology and hydrogeology of the CFA located on the northwest shelf of the Anadarko basin; and a detailed characterization of the injection reservoir modeling techniques employed.

Section 3 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449 and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 4 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. This section also describes the strategy for detecting, verifying, and quantifying any surface leakage of CO_2 as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Finally, this section also demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

Section 5 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 6 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 9 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 10 includes Appendices supporting the narrative of the MRV Plan.

1 Facility

1.1 Reporter Number

The CU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544678 and the NPU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544679. The EPA has been notified that the NPU will not be reporting for 2022, and that the facility has been merged into the Camrick Unit Facility Identification number 544678.

1.2 UIC Permit Class

For injection wells (see Appendix 2) that are the subject of this MRV plan, the OCC has rules governing UIC Class II injection wells. These OCC rules are OAC Title 165:10-5-1 through 165:10-5-15, OAC 165:5-7-27, OAC 165:5-7-30, the request for an exception to UIC rules under OAC 165:5-7-29, and other governing filing forms. Also, the TRRC has issued UIC Class II enhanced recovery permits under its Rule 46, TAC Title 16 Part 1 Chapter 3. All wells in the CFA, including both injection and production wells, are regulated by the OCC and the TRRC, which have primacy to implement the UIC Class II program.

1.3 UIC Injection Well Numbers

A list of the injection wells in the CFA is provided in Appendix 1. The details of the injection process are provided in Section 2.3.

2 Project Description

2.1 Project Characteristics

2.1.1 Estimated years of CO_2 injection

The CFA has been injecting CO_2 for the last 20+ years and it is currently projected that CapturePoint will inject CO_2 for an additional 12 years.

2.1.2 Estimated volume of CO_2 injected over lifetime of project

Historical and forecasted cumulative CO_2 retention volumes are approximately 100 billion standard cubic feet (Bscf) or 5.3 million metric tonnes (MMMT) from the start of CO_2

injection through October 2034. During the MRV plan, the period September 2022 through October 2034, 52.5 Bscf or 2.77 MMMT will be stored in the CFA. (See Figure 2.4-6)

2.2 Environmental Setting of MMA

2.2.1 Boundary of the MMA

CapturePoint has defined the boundary of the MMA as equivalent to the boundary of the CFA plus ½ mile beyond. A discussion of the methods used in delineating the MMA and the AMA are presented in Section 3.

2.2.2 Geology

The geological discussions in Sections 2.2.2 and 4.3-4.4 are based on analysis of logs from both the Farnsworth Unit, which is located 10 miles South-South-West of the CFA, and the CFA. Both areas have similar pay thickness, porosity values, permeability measurements, depositional environment, tectonic processes, and overburden strata layers. The descriptions of cores at the Farnsworth Unit included sections from overlying seals as well as the shale underlying the main reservoirs, petrographic thin section descriptions and point counts as well as a variety of special analytical techniques. These techniques included X-ray diffraction (XRD), which is the science of determining the atomic and molecular structure of rock crystals with an X-ray beam; scanning electron microscope (SEM) analysis, which uses a beam of electrons to define the surface of crystals; carbon isotope analysis to estimate the age of the CO_2 in the sample; and a variety of mechanical tests. Two dimensional (2D) and three dimensional (3D) geophysical surveys were also used as part of the Farnsworth Unit MRV Plan (2021). Details of recent geological investigations can be found in Gallagher (2014), Gragg (2016), Rasmussen et al (2019), Rose-Coss et al (2015), Trujillo (2018), Hobbs et al (2019), and Gragg et al (2018).

2.2.2.1 Tectonic Setting and Stratigraphy

The CFA is located on the northwest shelf of the Anadarko basin (Figure 2.2-1) and is one of many oil fields in the area that produce from a sequence of alternating sandstones and mudstones deposited during the late Pennsylvanian Morrowan period. Oil production and CO_2 injection at CFA is restricted to the operationally named Morrow B sandstone; the uppermost Morrow sandstone encountered below the Atokan Thirteen Finger limestone. The primary caprock intervals at CFA are comprised of the upper Morrow shale and the Thirteen Finger limestone (Figure 2.2-2). The Morrowan and Atokan intervals were deposited approximately 315-300 million years ago. Overlying stratigraphy includes late Pennsylvanian through the middle Permian shales and limestones, with lesser amounts of dolomite, sandstone and evaporites (Ball, 1991). The reservoir is approximately 60 feet thick throughout the field and lies at a depth of approximately 6,800-7,600 feet. The primary seal rocks of the Morrow shale and the Thirteen Finger Limestone comprise a package of approximately 180-200 feet thick in the field and are overlain by thousands of feet of Atokan and younger limestones and shales.

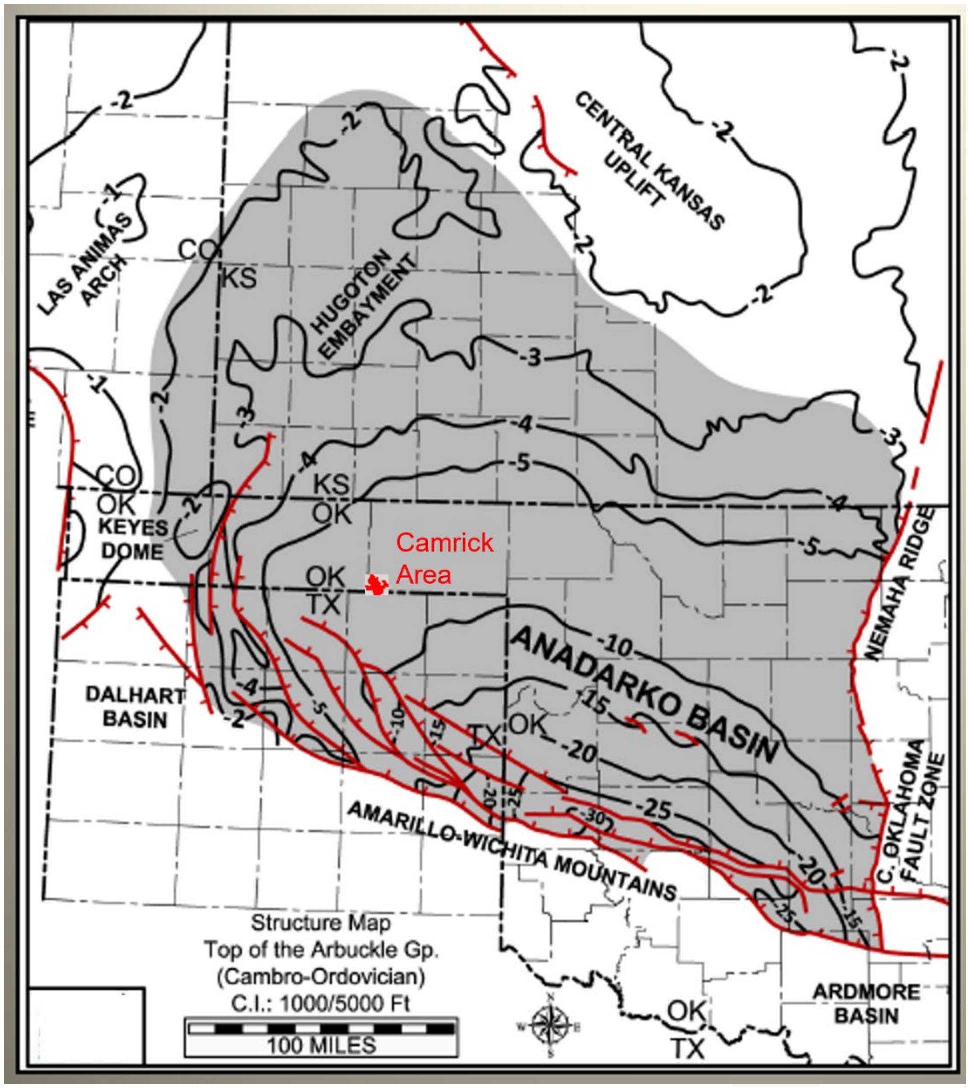

Figure 2.2-1. Location of the CFA on the Northwest Shelf of the Anadarko Basin in West Texas. Red lines are approximate locations of faults that have been documented in the region.

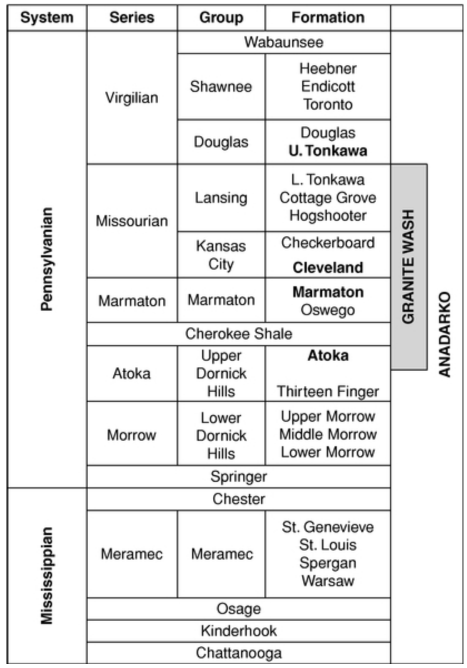

Figure 2.2-2. Stratigraphic section.

Tectonic Setting

From CFA's location on the western edge of the basin, the Anadarko Basin plunges to the southeast (Figure 2.2-3) where it reaches depths of over 40,000 feet (12,192 meters) adjacent to the Amarillo-Wichita Uplift (Perry, 1989). Maximum rates of subsidence occurred during Morrowan to Atokan times (Evans, 1979; Perry, 1989; Higley, 2014). Positive features that might have influenced deposition within the region include the Ancestral Rockies to the north, the Central Kansas uplift to the northeast, and the Wichita-Amarillo uplift to the south (Evans, 1979; Munson, 1989). Of note is the fact that during the Pennsylvanian time, the CFA was located on the basin shelf in an area that was not affected greatly by tectonic deformation. Although faults have been reported previously in the northwest Anadarko Basin, we found no direct evidence for tectonic faults within the CFA (see Section 4).

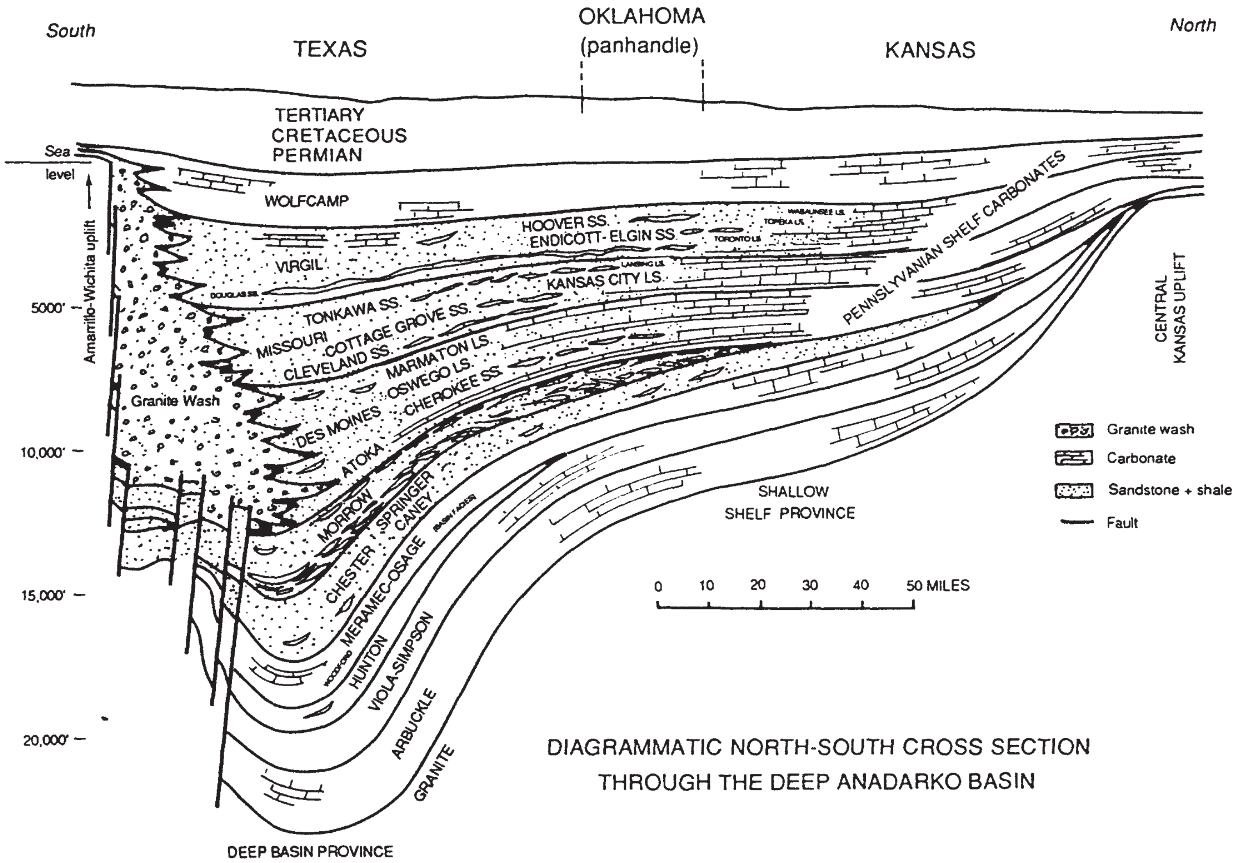

Figure 2.2-3. Diagrammatic North-South Section (Bottom) of the CFA.

Stratigraphy

Reservoir

Upper Morrowan sandstones in the Anadarko Basin margins have long been recognized as fluvial deposits (Swanson, 1979; Sonnenberg, 1985; Munson, 1989; Krystinik and Blakeney, 1990; Bowen et al., 1990; Al-Shaieb et al., 1995; Mckay and Noah, 1996; Puckette et al., 1996; Bowen and Weimer, 2003, 2004; Devries 2005; Puckette et al., 2008; Gallagher, 2014). At the Farnsworth Unit and similarly at the CFA, the Morrow B is described as a relatively coarse-grained subarkosic sandstone. The upper Morrowan facies, with sequences of basal conglomerate, coarse-grained sandstone, and fine-grained sandstone appear to be typical of incised valley deposits, as described by Wheeler et al. (1990), Krystinik and Blakeney (1990), Bowen et al. (1990), Blakeney et al. (1990), Sonnenberg et al. (1990) and Puckette et al. (2008).

Primary Seals

The Morrow B sandstones are encased above and below by shales. Contacts with shale both below and above the sandstone are sharp and irregular. The Morrow shale generally fines upwards in a series of thin beds that alternate between upper fine sands and fine to medium muds. Sand content decreases upwards through the section.

The Thirteen Finger limestone formation has two different lithofacies: diagenetic limestone (cementstone) and pyrite and fossil bearing fine to medium mudstone and coal. The two facies are intercalated with each other but tend to cluster in layers dominated more by one or the other.

The entire Thirteen Finger interval is typically 130 feet (39.6 meters) thick, comprised of mudstone, coal, and limestone. The mudstone is calcite rich, with some dolomite, and is completely diagenetic in origin and probably formed relatively soon following deposition.

2.2.2.2 Hydrogeology

Information about Morrowan and Atokan formation water flow during oil operations has not been discovered in any oil or gas company published reports or academic research studies in the Anadarko Basin. Groundwater flow rates in confined deep Anadarko layers at present are considered to be low to no flow (Nelson and Gianoutsos, 2014). Their arguments are based on (1) restricted recharge in the western basin, (2) density barriers to flow in the east, and (3) an overpressure pocket inhibiting flow in the deep basin. Jorgenson (1989) suggested flow could be west to east, driven by potential recharge to elevated units in the west and discharge at lower elevation outcrops in the east. The CFA CO_2 injection and production operations have negligible likelihood of causing water to flow to outcrops of the late Carboniferous (Pennsylvanian) time period that extend from Brownwood, Texas, to the Jacksboro/Bowie, Texas, area, which are hundreds of miles away (The Paleontology Portal).

The Carboniferous is a geologic period and system that covers 60 million years from the Devonian Period 358.9 million years ago, to the beginning of the Permian Period, 298.9 million years ago. As noted in the Section 2.2.2.1, the Morrowan and Atokan intervals of the CFA were deposited approximately 315-300 million years ago and are contained in the Carboniferous period.

2.3 Description of the Injection Process

Figure 2.3-1 depicts a simplified flow diagram of the facilities and equipment within the boundaries of the CFA. CO_2 captured from the ethanol plant fermentation process is delivered via pipeline to the field for injection. The Arkalon plant in Liberal, Kansas is the only source of CO_2 to the field. The amount delivered is dependent on the production of CO_2 produced from the fermentation process. This amount will vary but should average 12 MMCFD. Once CO_2 enters the CFA there are three main processes involved in EOR operations. These processes are shown in Figure 2.3-1 and include:

1. CO_2 distribution and injection. Purchased CO_2 is combined with recycled CO_2 from the CFA central tank battery (CTB) and sent through the main CO_2 distribution system to various water alternating gas (WAG) injectors.

2. Produced Fluids Handling. Full well stream fluids are produced to the "all well test" (AWT) site. The AWT site has two major purposes; 1) to individually test a well's performance by separating and metering oil, gas, and water, and 2) to separate all gas from liquid then send these two phases to the CTB for final separation; while only the gas from NPU is sent to the CTB the NPU oil and water remains in Texas.

3. Produced Gas Processing. All gases from the AWT sites are transferred to the CTB to separate the oil, gas, and water using a series of vessels and storage tanks.

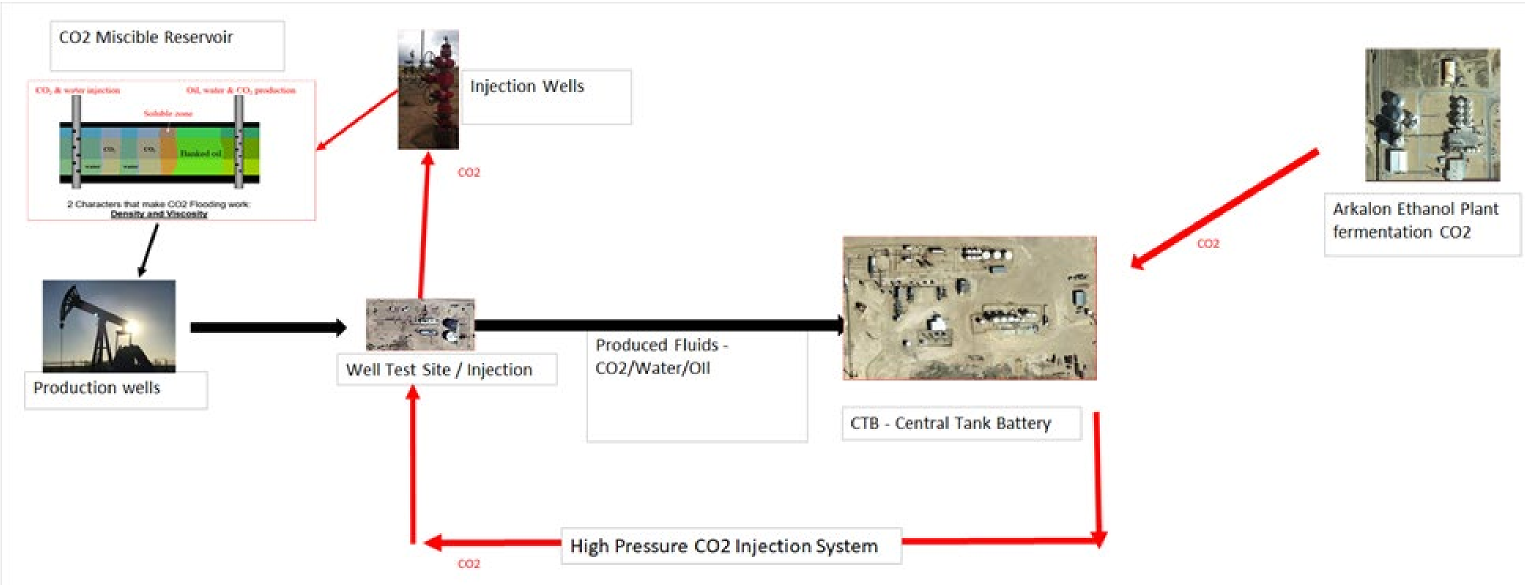

Figure 2.3–1. Simplified flow diagram of the facilities and equipment within the boundaries of the CFA.

2.3.1 CO_2 Distribution and Injection

CapturePoint purchases CO_2 from Conestoga Energy Partners, the parent company of the Arkalon Ethanol plant located in Liberal, Kansas. A custody transfer meter is located in the compression facility owned and operated by CapturePoint. The purchased CO_2 from the fermentation process is transported via a United States Department of Transportation (DOT) regulated pipeline to the CFA. A totalizer meter, for the purchased CO_2, is located in the field where instantaneous data is summed into a 24-hour flow rate which is recorded. A totalizer meter is a meter approved by the American Gas Association (AGA) Report #3 to measure the flowrate of gases. The actual measurements taken are temperature, line pressure, and differential pressure across the meter. Gas produced, which contains recycled CO_2, from the wells is compressed and metered by a similar totalizer meter as the purchase CO_2 meter and is recorded daily.

CapturePoint currently has seven active injection manifolds and approximately 29 active injection wells that the CO_2 is distributed through. When the MRV plan becomes active, the daily injection volume of the combined purchased CO_2 and recycled CO_2 will be approximately 24 MMCFD. Of this volume 12 MMCFD is purchased CO_2 and 12 MMCFD is recycled CO_2. This ratio of purchased CO_2 to recycled CO_2 is expected to change over time, with the percentage of recycled CO_2 increasing and purchased CO_2 decreasing. The current reservoir management plan projects that CO_2 purchases will remain constant at 12 MMCFD for 12 years and cease after 2034. A reservoir management plan is an integrated process using various surveillance techniques, economic evaluations, and accepted petroleum technical practices to efficiently operate enhanced oil recovery projects.

The seven injection manifolds currently in the field distribute the CO_2 to the field. These manifolds have valves to switch to water when the time is called for. Depending on the reservoir management plan, the WAG cycle will be adjusted to maximize oil recovery and minimize CO_2 utilization in each injection pattern. At each injection well pad there is a totalizer to measure the volumes injected every 24 hours. This data is collected daily by the field personnel and input into the data warehouse to be allocated for the pattern injection.

The two totalizer meters as described above will be used to determine the total volume injected used in section 7 for the mass balance equations necessary to determine annual and cumulative volumes of the stored CO_2.

2.3.2 Produced Fluids Handling

As injected CO_2 and water migrate through the reservoir; a mixture of oil, gas, and water (referred to as "produced fluids") flows to the production wells. Gathering lines bring the produced fluids from each production well to the AWT sites. CapturePoint has approximately 32 active production wells producing at any time. Each AWT has two separators. The first separator is used for testing individual wells to separate the gas, oil, and water produced from an individual well. This gas, oil, and water is subsequently measured and recorded for the well. Each producing well is production tested every 30 to 60 days after the last production test, or after the well is returned to production. Depending on the reservoir management plan, well testing can be more frequent to obtain data. The second separator is used to separate the gas from the oil/water mixture from the other wells producing into the AWT, and the gas and liquids are displaced from the vessel in separate lines. Leaving the AWT sites are two lines transporting produced fluids. One line is used for the liquid phase, a mixture of oil and water, and one line is used for the gas phase. However, the AWT in NPU does not transfer oil or gas to the CTB, it only transfers gas while reinjecting water with pumps at the NPU AWT and sells oil at the NPU AWT.

When gas and liquid lines enter the CTB, a series of vessels separate the oil, gas, and water to be accounted for and distributed for sales or reinjected. The liquid phase line has vessels to separate the oil from the water using density and residence time. The gas phase vessels collect any free liquids entrained with the gas. These free liquids are then combined back into the liquid phase line. All gas and water are reinjected, and the oil, which contains an estimated 2,360 ppm CO_2 (0.236%) for CU and 4,540 ppm CO_2 (0.454%) for NPU, is sold out of tanks. Annually, the oil from the stock tank is analyzed by a laboratory using ASTM crude oil analysis methods to determine the CO_2 content in the oil being sold.

After separation, the gas phase, which is approximately 92-95% CO_2, is mixed with reservoir volatile components, compressed, and distributed throughout the high-pressure distribution system using reciprocal compression and high-pressure horizontal pumps.

The water is transferred from the separation vessels to tanks for reinjection. After the water is conditioned, it is either reinjected at the WAG skids or disposed of into permitted disposal wells. Although CapturePoint is not required to determine or report the amount of dissolved CO_2 in the water as it is reinjected into the ground and not emitted to the atmosphere, the analyses have shown the water typically contains <690 ppm (0.069%) CO_2.

CFA production has trace amounts of hydrogen sulfide (H_2S), which is toxic. There are approximately 8-10 workers on the ground in the CFA at any given time, and all field and contractor personnel are always required to wear H_2S detectors. The primary purpose of the H_2S detectors is protecting people from the risk of being harmed. The detection limit of the H_2S detectors is quantified for readings in the range of 0-100 ppm and will sound an alarm above 10 ppm. The secondary purpose of the H_2S detectors would be to provide an indication of emissions of gas from a pipeline or surface equipment, which might go unnoticed by other observations or measurements. No gas volumes can be calculated based on the detector reading or alarm; only a H_2S leakage is detected and located. Once identified, a further response will be initiated and CO_2 volumes will be quantified as discussed in sections 4.5, 4.6, 5.4, and 8.1.5 of this MRV plan.

2.3.3 Produced Gas Handling

Produced gas separated at the CTB is stripped by a series of vessels of entrained and free water. The water content has been recorded to be < 20 pounds mass per MMCF, thus dehydration is not necessary. The gas is then sent to a centralized compression system to be compressed and placed in the high-pressure distribution system. This compression turns the CO_2 into a variable density liquid, which is then transported out via high pressure lines to the AWT sites where a manifold splits this dense CO_2 to the wells that are on CO_2 injection at that time.

2.3.4 Facilities Locations

The locations of the AWT sites are positioned in the field to access both injection distribution and production gathering. The CTB is where the final separation and injection equipment is maintained and operated. The water injection station is where the horizontal pumps are located to reinject the produced brine.

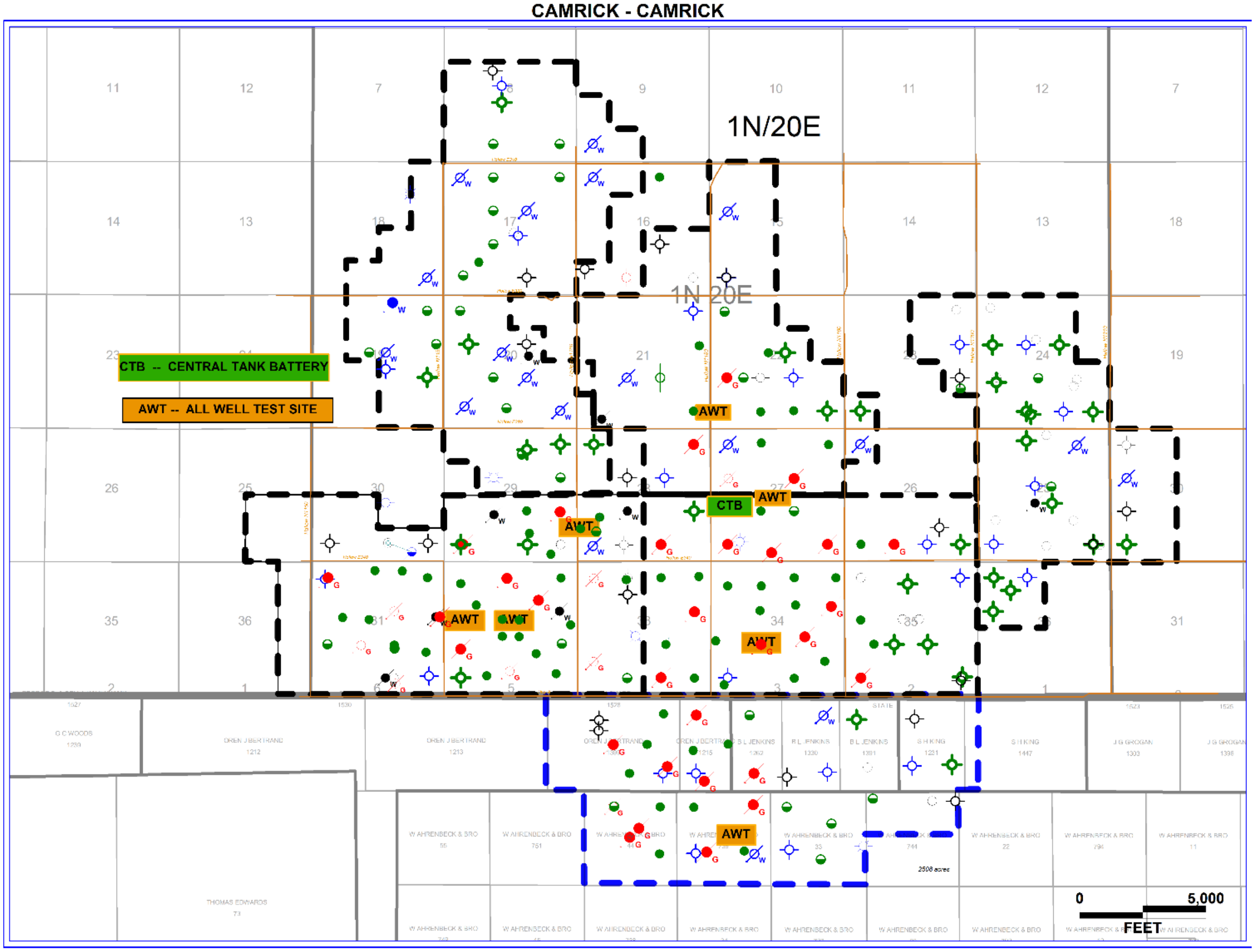

Figure 2.3-2. Location of AWT sites and CTB in the CFA

2.3.5 Water Conditioning and Injection

Produced water collected at the CTB is collected in a series of vessels and tanks in a cascade system. This allows any entrained oil to further separate to the top of the tanks because of the density difference. This oil is skimmed off and put back in the oil separation system. The clean water is then transferred to the water injection system where it is boosted in pressure and sent out to the AWT sites for distribution to all wells that are currently on water injection.

2.3.6 Well Operation and Permitting

The OCC and TRRC rules (Appendix 2) govern well location, construction, operation, maintenance, and plugging for all wells in permitted units and wells. CapturePoint follows these rules and regulations to maintain safe and efficient operations. This includes complying with all current and updated information for mechanical integrity testing, well repairs for injection wells, drilling and completion, permitting, and reporting.

Briefly, the following bulleted list is what the current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface waters.
- That wells file a completion report including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore).
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.
- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location, and setting of plugs.

2.3.7 Number, Location, and Depth of Wells

CapturePoint's CFA injection wells are listed in Appendix 1. Injection is into the Upper Morrowan, a lenticular bedded sandstone trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. The Upper Morrowan is described in section 2.2.2.1 above.

2.4 Reservoir Characterization

2.4.1 Reservoir Description

The target reservoir CFA Morrow B is a sandstone formation overlain by the Morrow shale and the Thirteen Finger limestone, which serve as excellent seals for injected CO_2 as determined by Farnsworth data (Ampomah et al., 2016a). The Morrow B sandstone reservoir is at a depth between 6,800 feet and 7,600 feet subsurface with an average dip of less than one degree (Figure 2.4-1). The productive limit of the CFA is about 80 to 90 percent of the total operated surface acreage, which is 14,652.315 acres. The maximum pay thickness is 56 feet with an average of 15 feet and does diminish to zero in spots.

The CFA is approximately eight miles by seven miles with areas that exhibit different reservoir behavior. The southwest portion of CU was most prolific oil producing area of the CFA under primary and secondary production; whereas the western portion of NPU is now responding to CO_2 better than historical operations would have indicated.

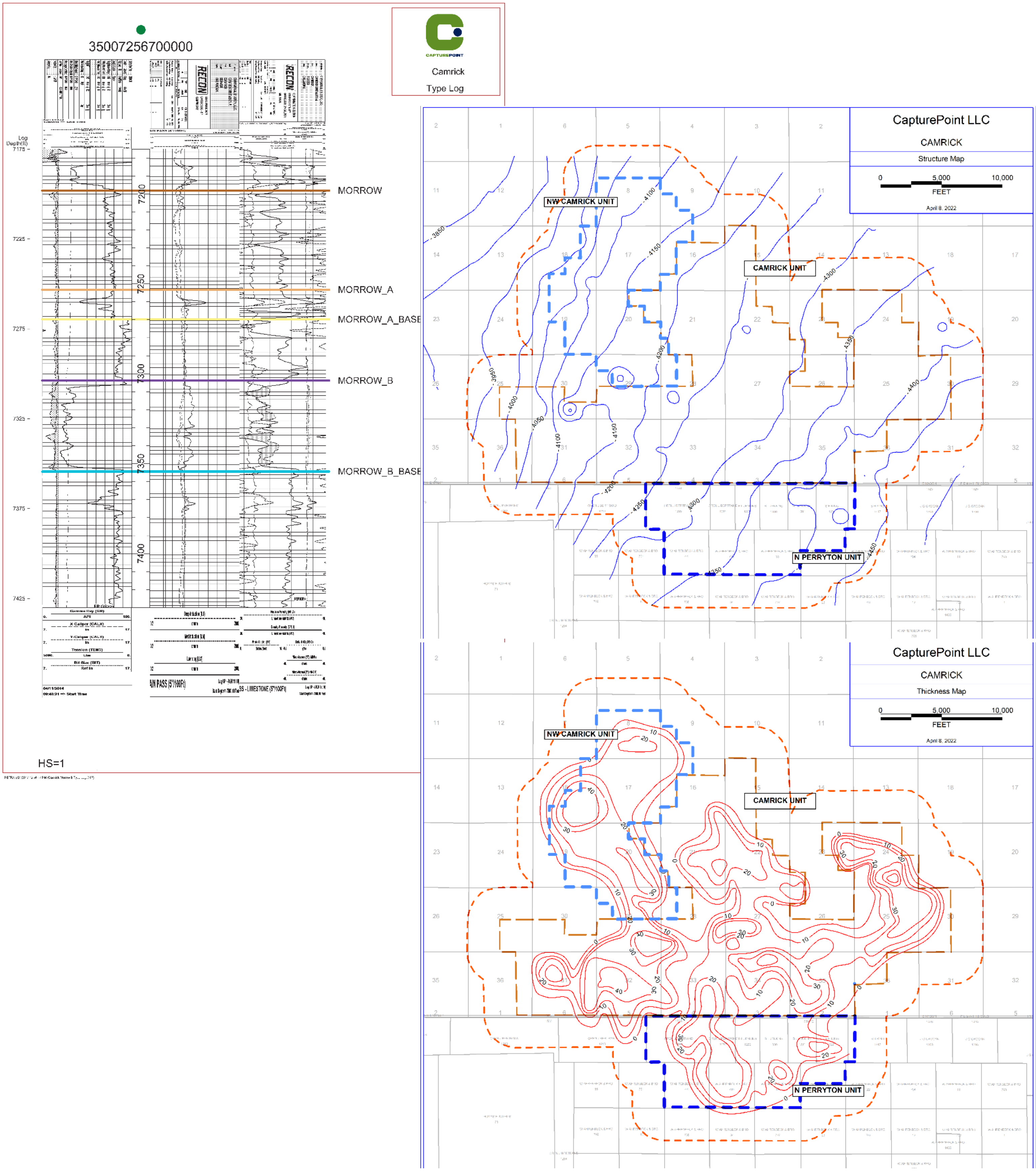

Figure 2.4-1. (Left) Type log of CFA caprock and reservoir, (Upper Right) Surface contour of Morrow top, (Lower Right) Thickness map of Morrow sands.

2.4.2 Reservoir Fluid Modeling

The compositional fluid model was constructed for the CapturePoint operated Farnsworth Unit. From laboratory compositional analysis an equation of state was tuned (Gunda et al., 2015). The minimum miscibility pressure (MMP) experiment was then simulated using a one-dimensional model. The simulated Farnworth Unit MMP of 4,009 psia compared to an MMP value of 4,200 psia derived from laboratory experiments provided by the operator represents a less than 5% error (Gunda et al., 2015).

The reservoir temperature in the CFA is 152 degrees Fahrenheit or 16 degrees lower than the temperature at Farnsworth Unit of 168 degrees. Using parameters of the Alston empirical correlation (1985), the MMP would be 170 psia lower at the CFA or 3,510 psia compared to 3,680 psia at the Farnsworth Unit (Figure 2.4-2).

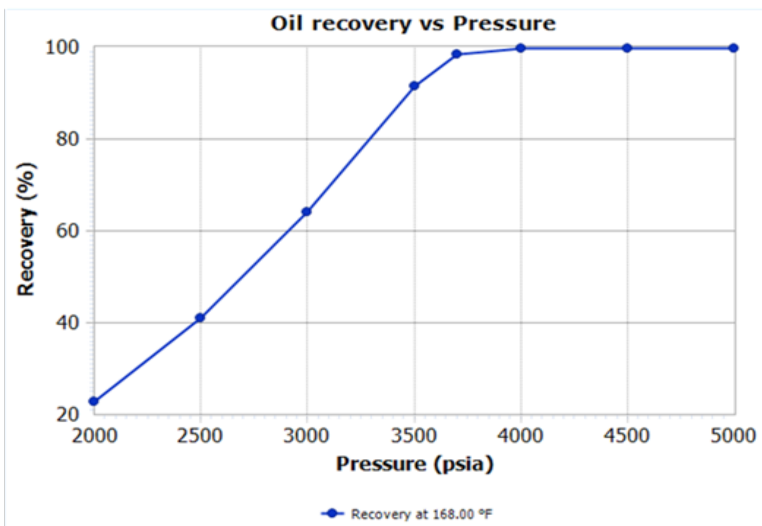

Figure 2.4-2. Oil recovery plot for 1D slim tube test for Farnsworth Unit.

2.4.3 CO_2 Analogy Field Study

Based on similar geologic, petrophysical, engineering, and operational parameters between the Farnsworth Unit and the CFA, the oil recovery performance of both fields is expected to be similar. Due to the stratigraphic nature of the Morrow channel sands, the potential movement of CO_2 is severely limited. The CFA area has contained the free phase CO_2 plume in a very confined area since March 2001 as exhibited by oil, water, and CO_2 recovery performance. Also, during CFA drilling and production operations, no reports exist which would indicate any plume has moved outside of the MMA. The Farnsworth Unit MRV and the CFA data justifies the conclusion that CO_2 will continue to be contained inside the MMA at the end of the CO_2 injection year t + 5, per §98.449 definitions.

2.4.4 CO_2 – EOR Performance Projections

For years, the oil industry has used dimensionless equations to predict the amount of oil that can be recovered using CO_2 for flooding oil reservoirs (Lee et al, 2018, Stell 2010). The

amount of oil recovered from projects is plotted as a decimal fraction of the original-oil-in-place versus the decimal fraction of the hydrocarbon pore volume (HPV) of CO_2 injected into the oil reservoir as measured in reservoir barrels (RB).

The CFA has been injecting CO_2 since March 2001. The dimensionless curves were matched to historical performance through early 2020 (Figure 2.4-3). The supply of CO_2 was curtailed from March 2020 until present, due to oil price uncertainty, and will resume after the Arkalon Plant upgrade that will be finished in the 4th quarter of 2022.

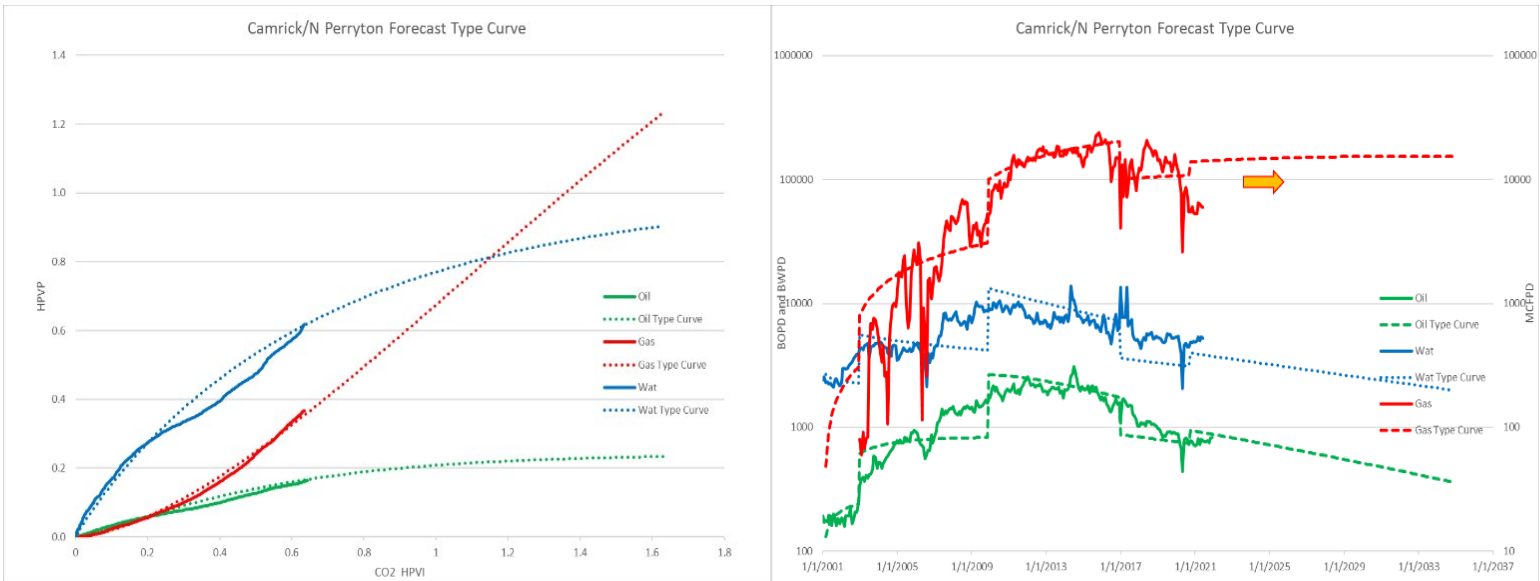

Figure 2.4-3. Dimensionless curves for CO_2 injection (left) with rate time curves (right).

The dimensionless water oil ratio and the gas oil ratio trends (Figure 2.4-4) for the CFA flooded acreage are very similar to what was forecasted by simulation in the Farnsworth Field as expected because of the porosity, permeability, and sand similarities.

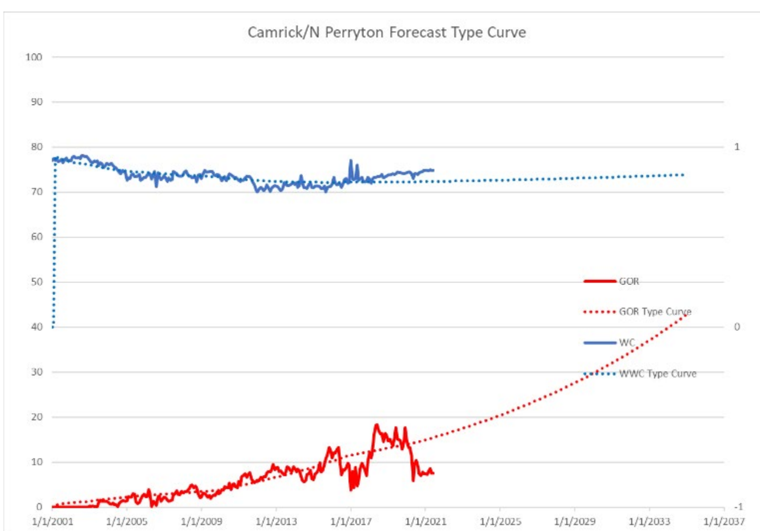

Figure 2.4-4. Dimensionless water cut and GOR vs. observed EOR data.

The CO_2 storage volumes for Arkalon fermentation CO_2 were also forecasted (Figure 2.4-5) using the same dimensionless technique. This technique indicates that the flooded acreage still has significant additional storage potential. The maximum CO_2 storage is limited to the amount of space available by the removal of the produced hydrocarbon. The projection indicates that there is pore space available to store approximately 0.4 to 0.5 decimal fraction of HPV amounting to 30 to 40 MMB.

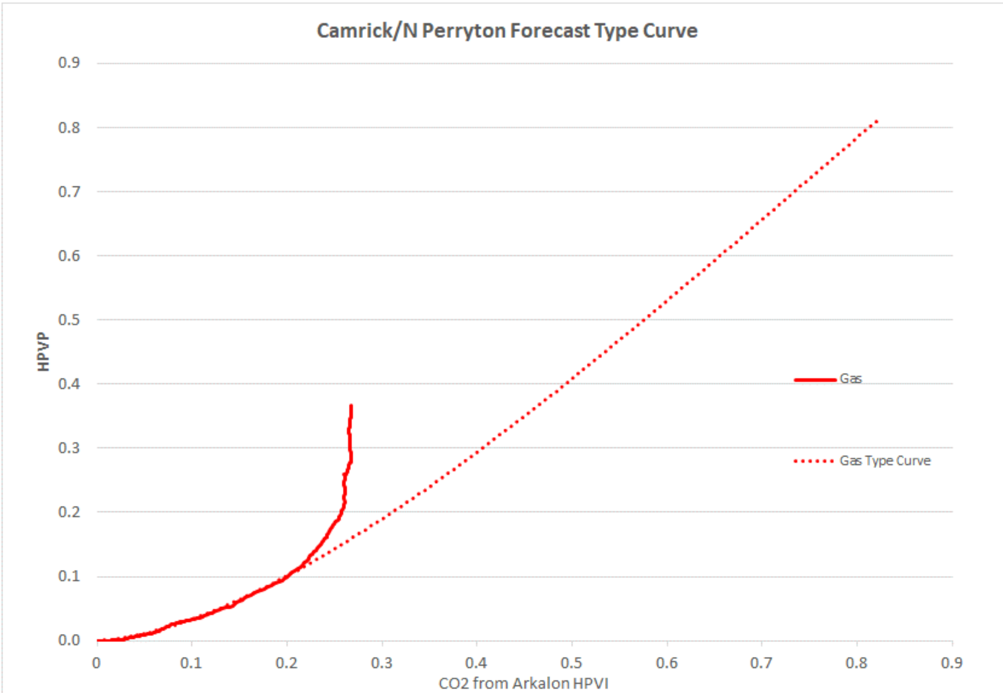

Figure 2.4-5. Dimensionless CO_2 Purchase (Fermentation) Curves

The barrels of reservoir volume were converted to standard cubic feet of gas and is displayed in the CFA Purchase CO_2, or Fermentation CO_2, vs Time chart (Figure 2.4-6).

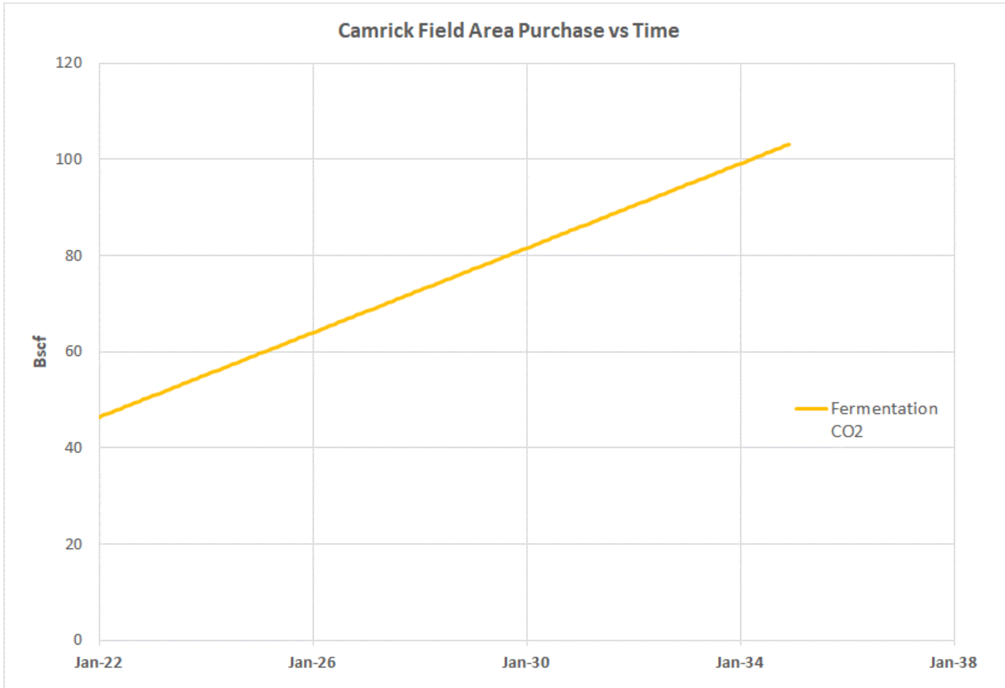

Figure 2.4-6. CO_2 Purchase (Fermentation) Volume.

3 Delineation of Monitoring Area

3.1 MMA

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The purchase volumes that are displayed in Figure 2.4-6 were mapped and are displayed in Section 3.1.1 indicating that CO_2 storage pore space is available, barring unforeseen future operational issues. Therefore, CapturePoint is defining the MMA as the boundary of the CFA plus an additional one-half mile buffer zone. This will allow for operational expansion throughout the CFA for the next 12 years, the anticipated life of the project.

3.1.1 Determination of Storage Volumes

Figure 3.1-1 displays wells that have CO_2 retention on the developed 4,800 acres that have been under CO_2 EOR injection in the CFA since project initialization (14,652.315 acres are in the CFA). The volume of the oil recovered since August 1955, resulted in a voidage space of 36 MMscf of CO_2 per acre of surface area that was later filled with water during waterflood operations. The average decimal fraction of CO_2 injection to hydrocarbon pore volume left in the ground after accounting for CO_2 production through 2021 is 0.29. The lateral extent of CO_2 in the injection zone or the CO_2 storage radius for each well was estimated based on cumulative CO_2 injected times the decimal fraction of CO_2 remaining divided by the voidage space. The largest CO_2 storage areas are around wells that injected the largest volume CO_2.

Figure 3.1-2 displays the potential area of the reservoir that can be filled with CO_2 with the existing injection wells. This assumed that only 78 percent of the average injection pattern area or 80 acres per pattern can be filled. The volumetric storage capacity calculated for the 49 patterns identified for continued injection indicates an additional 90 Bscf of CO_2 can be stored and with 50 Bscf already stored results in 140 Bscf of total storage. With the anticipated 12 MMCFD rate of purchased CO_2, this storage volume will only be 60 percent utilized. As delineated in this MRV plan, the MMA account for an injected volume of up to 140 Bscf and includes all areas of the CFA that could be utilized in the future for CO_2 injection. The MMA will contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. If there are any material changes to the monitoring/operational parameters not outlined in this MRV plan, the plan will be resubmitted in accordance with 40 CFR 98.448(d)(1).

Areas that do not have CO_2 storage posted on Figure 3.1-2 will be evaluated if existing CO_2 injection operations experience any rate restriction or develop any operational issues in the future. If necessary, replacement wells or additional injection locations in inactive areas of the CFA will be drilled or activated. This will be accomplished by utilizing existing plugged and abandoned wells or redrilling old locations as described in Section 3.2.

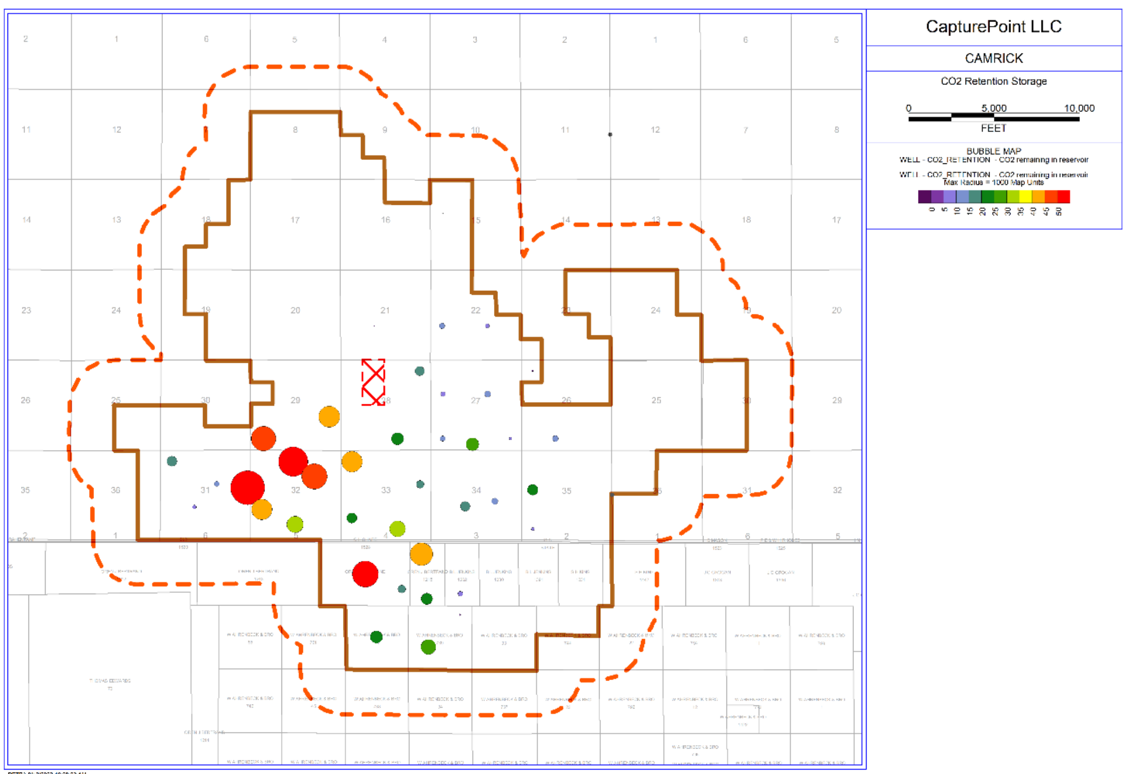

Figure 3.1-1. Estimated CO_2 storage as of 2021 in CFA.
The AMA is the land area inside the solid line polygon except for the red hashed rectangle.
The MMA extends to dotted red line and includes the red hashed rectangle.

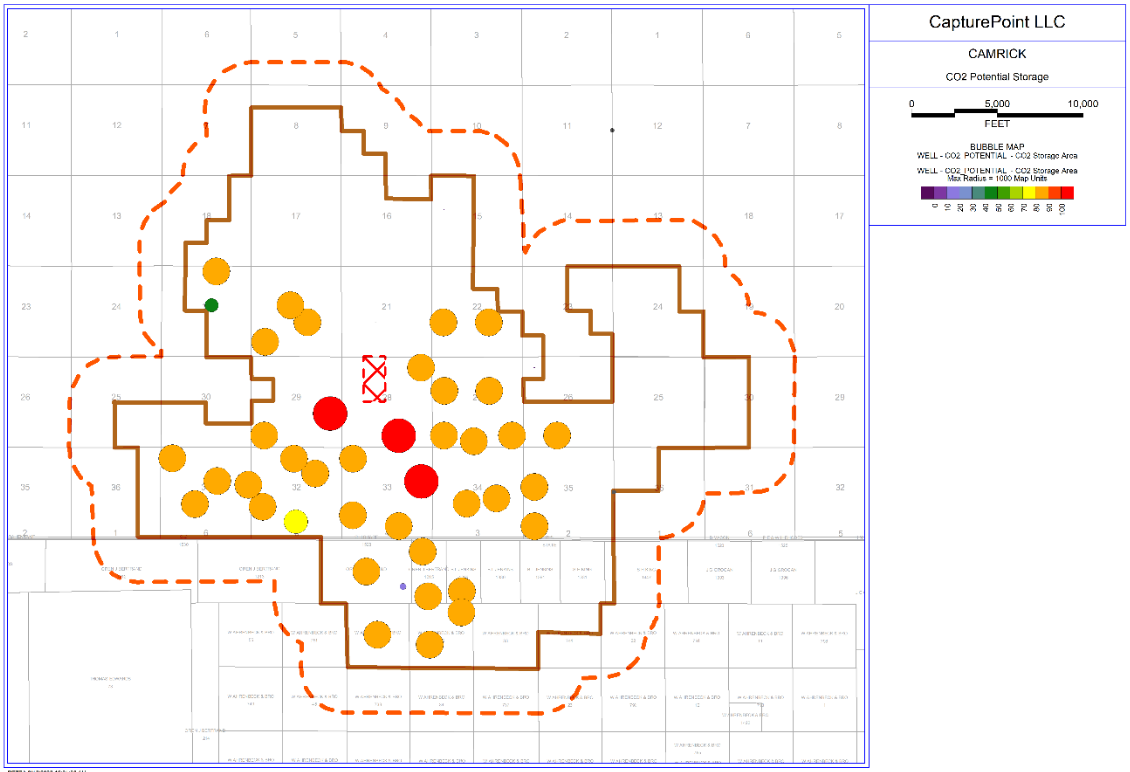

Figure 3.1-2. Potential Total CO_2 Storage in the CFA.
The AMA is the land area inside the solid line polygon except for the red hashed rectangle.
The MMA extends to dotted red line and includes the red hashed rectangle.

3.1.2 Determination of Buffer Zone

CapturePoint intends to implement a buffer zone of one-half mile around the CFA, the minimum required by Subpart RR, because the site characterization and stratigraphic trapping of the Morrow did not reveal any leakage pathways that would allow free-phase CO_2 to migrate laterally thereby warranting a buffer zone greater than one-half mile.

3.2 AMA

The Active Monitoring Area (AMA) is defined by CapturePoint's exclusive right to operate the CFA unitized leases, as described in the INTRODUCTION and Section 2.2.1. Currently, CapturePoint's operations are focused on the western portion of the CU and the entire NPU. However, it is anticipated as time passes, or additional CO_2 volumes become available additional areas within the CFA may be developed. Additional development is driven by the market price of oil coupled with the availability of sufficient CO_2 volumes and thus the timing of additional development is uncertain at this time. As CO_2 injection operations are expanded beyond the currently active CO_2 EOR portion of the CFA, all additional CO_2 injection wells will be permitted under the UIC program and will be included in the annual submittal per 40 CFR 98.446(f)(13). All future CO_2 injection wells permitted will be within the AMA. Based on our projections, CapturePoint expects the free phase CO_2 plume to remain within the CFA for the entire length of the project and through year [t + 5]. Therefore, CapturePoint is defining the AMA as the CFA plus an all-around one-half mile buffer, consistent with the definitions in 40 CFR 98.449. If there are any material changes to the monitoring/operational parameters not outlined in this MRV plan, the plan will be resubmitted in accordance with 40 CFR 98.448(d)(1).

Therefore, for the purposes of this MRV plan, CapturePoint is continuously monitoring the entire CFA, which is the AMA.

4 Identification and Evaluation of Leakage Pathways

Since its discovery in 1955, the unitization of the different units from 1969 to 1972, and the commencement of CO_2 EOR in 2001; the CFA is an analogous field to the Farnsworth Unit, which has undergone extensive investigation and documentation as indicated in Section 2. From this body of work, CapturePoint has identified the following potential pathways of CO_2 leakage to the surface. This section will also address detection, verification, and quantification of leakage from each pathway.

4.1 Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO_2 EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment via personnel instructed on how to detect surface leaks and other equipment failure minimizes releases. In addition, the Oil and Gas Division requirements of the OAC rules of the OCC and the TAC rules of the TRRC to report and quantify leaks, both serve to minimize leakage of GHG from surface equipment. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. As described in Section 6.4 below, should leakage from surface equipment occur it will be quantified according to the procedures in Subpart W of the GHGRP.

4.2 Leakage from Wells

CapturePoint has identified 68 abandoned wells, 49 injection wells (29 active) and 94 production wells (59 active) within the MMA and assessed their potential for leakage of CO_2 to the surface as listed in Appendix 1.

4.2.1 Abandoned Wells

Figure 4.2-1 shows all wells plugged and abandoned in the CFA. Because the CFA was unitized in 1969 to 1972, all plugging and abandonment activities of wells within the CFA have been conducted under the regulations of the OCC and the TRRC for plugging wells. The cement used to plug wells when exposed to CO_2 will form colloidal gels that further reduce any flow. CapturePoint concludes that leakage of CO_2 to the surface through abandoned wells is unlikely. However, strategies for leak detection are in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

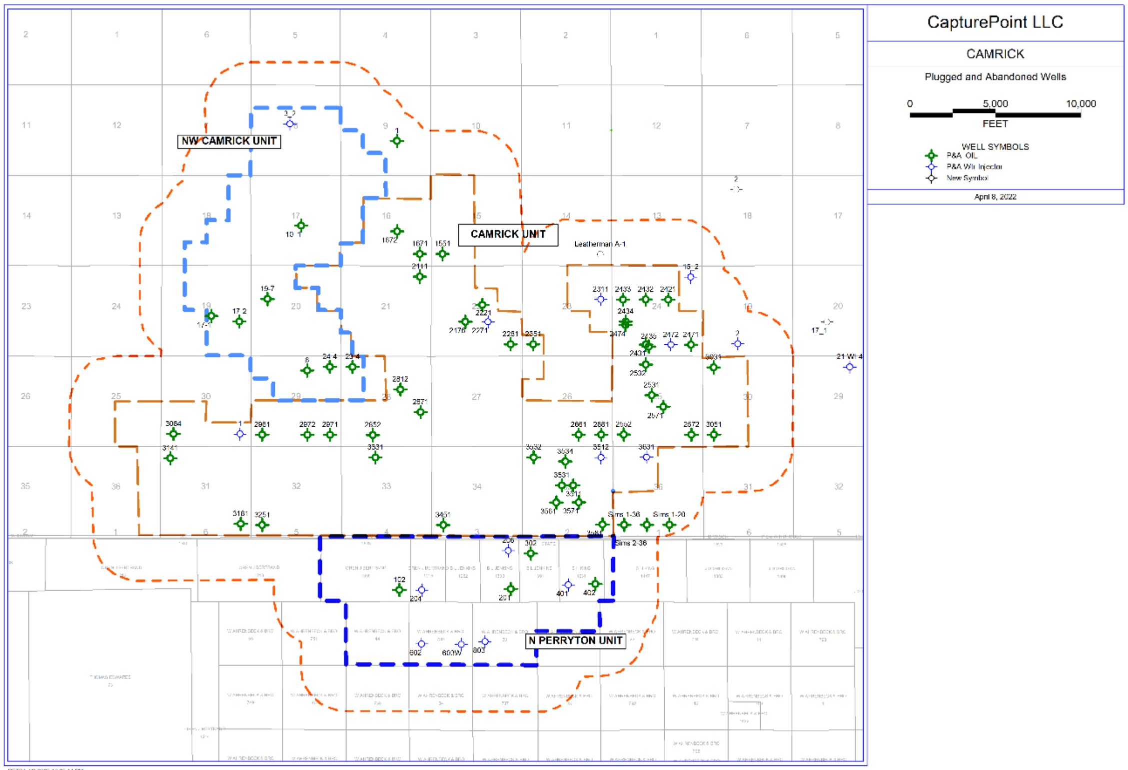

Figure 4.2-1. Plugged and Abandoned Wells in the CFA.

4.2.2 Injection Wells

Mechanical integrity testing (MIT) is an essential requirement of the UIC program in demonstrating that injection wells themselves do not act as conduits for leakage into underground sources of drinking water (USDW) and to the surface environment. TRRC Rule 46 requirements include special equipment requirements (e.g., tubing and packer) and modification; records maintenance; monitoring and reporting; testing; plugging; and penalties for violations of the rule. Permit revocation may result as a consequence of noncompliance. (See Section 2.3.6) The TRRC and the OCC detail all the requirements for the Class II permits issued to CapturePoint. These rules ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Figure 4.2-2 shows the active injection wells in the CFA. CapturePoint concludes that leakage of CO_2 to the surface through active injection wells is unlikely.

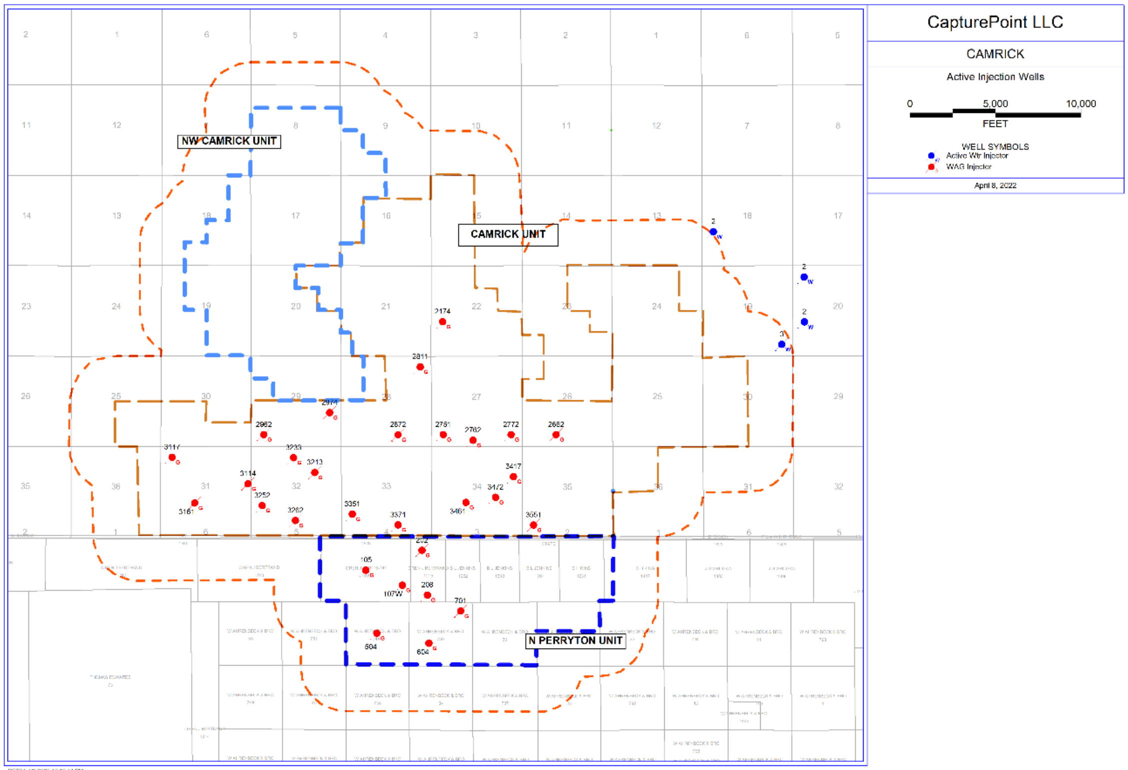

Figure 4.2-2. Active Injection Wells in the CFA.

4.2.3 Production Wells

Some of the original field wells drilled as oil wells were reclassified, administratively, to gas wells per OAC Title 165:10-1-6 paragraph (d), because of the gas-oil ratio growth due to reservoir depletion. Hence, there is no difference in well construction. (See Section 2.3.6) As the field is being further developed for enhanced oil recovery, these gas wells have been reclassified to oil wells per OCC regulations and will be monitored for leakage. (See Section 4.7) Figure 4.2-3 shows the active oil production wells in the CFA. Once EOR operations commence, the energy content of the produced gas drops and cannot be sold; therefore, any inactive gas wells are either reclassified to oil producers, or activated to WAG injectors, as described earlier. (See Section 4.2.2) However, as the project develops in the CFA additional production wells may be added and will be constructed according to the relevant rules of the OCC and the TRRC. Additionally, inactive wells may become active according to the rules of the OCC and the TRRC.

During production, oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure where the bottom hole wellbore pressure is less than the reservoir pressure. These lower pressure fluids, which also contains CO_2, are contained by the casing, tubing, wellhead, and flowline all the way to the CTB. CapturePoint concludes that leakage of CO_2 to the surface through production wells is unlikely.

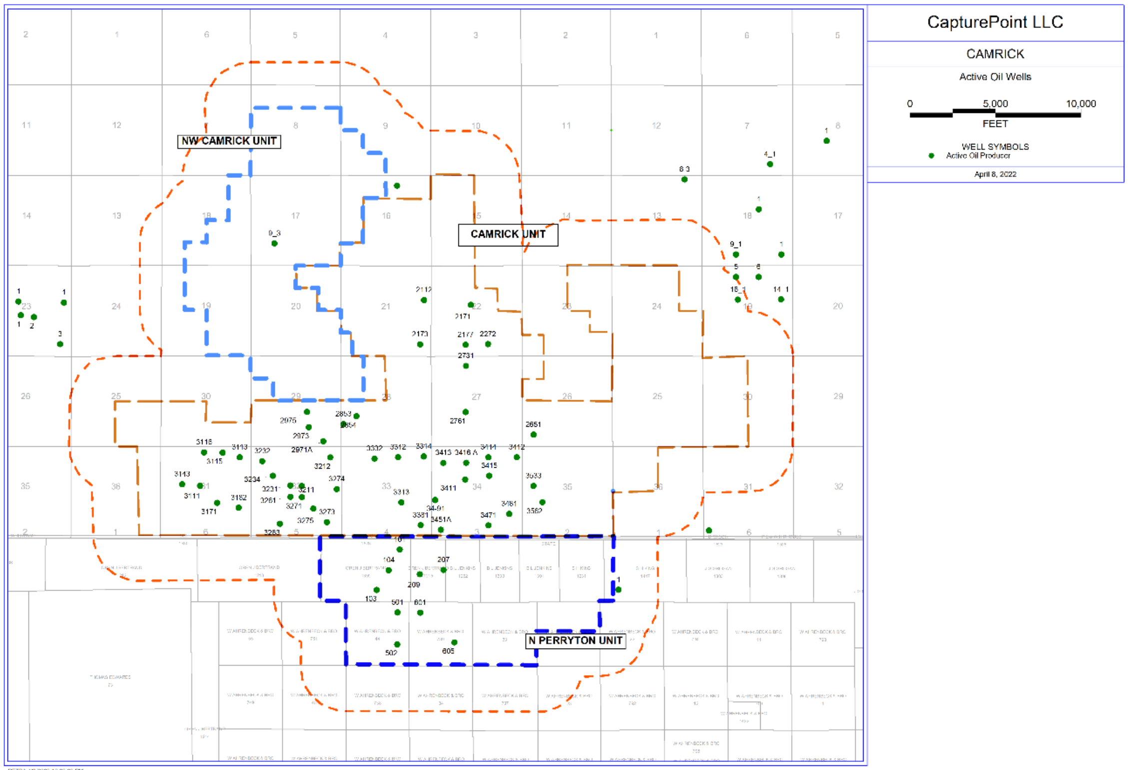

Figure 4.2-3. Active Oil Production Wells in the CFA.

4.2.4 Inactive Wells

Figure 4.2-4 shows all of the inactive wells in the CFA. The OCC has regulations for temporally abandoned/not plugged (TA) and terminated order wells/UIC not plugged (TM) and likewise the TRRC has regulations for inactive wells.

Inactive wells have a cast iron bridge plug set or long cement plugs placed above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. CapturePoint concludes that leakage of CO_2 to the surface through inactive wells is unlikely.

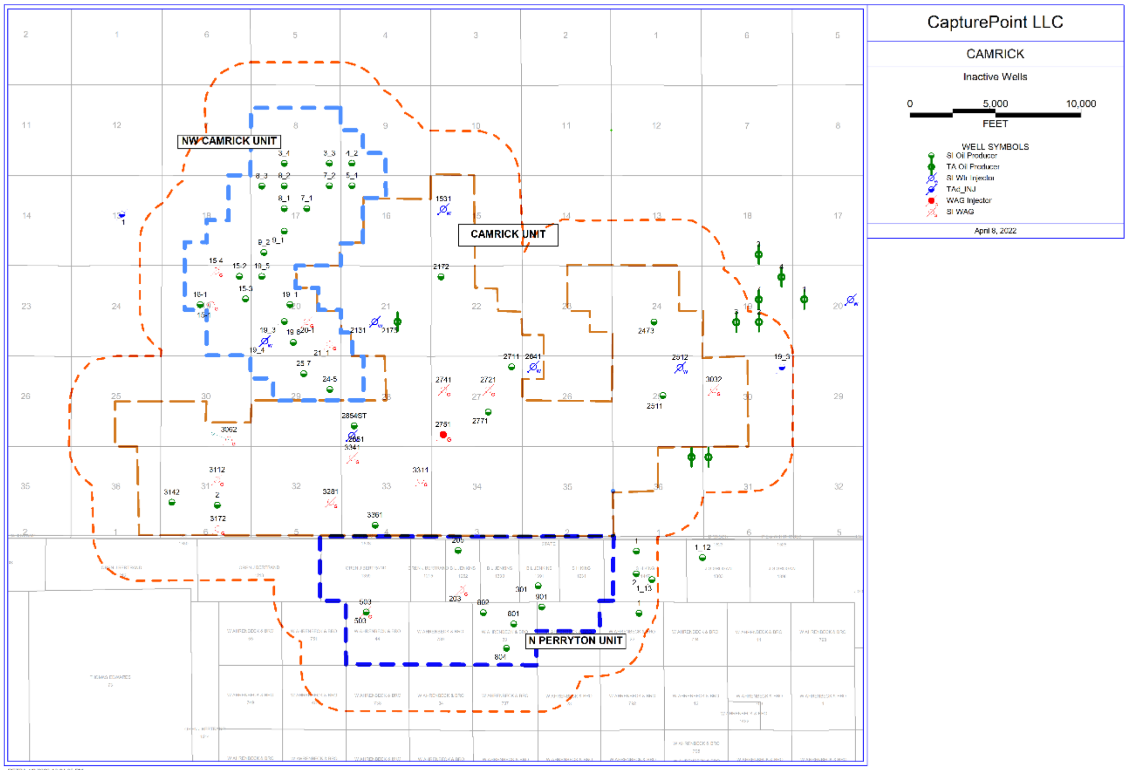

Figure 4.2-4. Inactive wells in the CFA

4.2.5 New Wells

As the project develops, new production wells and injection wells may be added to the CFA. All new wells will be constructed according to the relevant rules for the OCC and the TRRC which ensure protection of subsurface and surface resources, and the environment.

All wells in Oklahoma oilfields and all wells in Texas oilfields, including both injection and production wells, are regulated by the OCC and the TRRC, respectively, which has primacy to implement the UIC Class II programs.

Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Briefly current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface water.
- That wells file a completion report including basic electric logs.
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.

- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.

New well construction is based on existing best practices, established during the drilling of existing wells in CFA and follows the OCC and the TRRC rules, which significantly limits any potential leakage from well pathways. Additionally, the existing wells followed the OCC and the TRRC rules.

In public databases, the area of CFA plus one mile past the unit boundary contains over 100 wells that were drilled deeper than the Morrow formation and none of these wells were productive in reservoirs deeper than the Morrow. Therefore, it is very unlikely that anyone will ever drill through the AMA reservoir in the future. In the event a well is drilled within the AMA, the operator would be required to follow all the OCC and the TRRC rules and procedures in the drilling the well and the potential for leakage would be similar to any well that CapturePoint drills within the AMA. In addition, CapturePoint's visual inspection process during routine field operation will identify any unapproved drilling activity in the CFA.

4.3 Leakage from Faults and Bedding Plane Partings

Primary seals at CFA have been demonstrated to be mechanically very competent (see Section 2.2.2), thus the main concern of CO_2 migration at CFA is via seal bypass systems along fracture networks. The following lines of analysis have been used to assess this risk in the area.

4.3.1 Prescence of Hydrocarbons

The first and foremost argument against present day up-fault transmissibility is the 75 MMB of oil that was found trapped in the reservoir. If significant escape pathways existed, oil would have drained from the reservoir prior to the current day.

4.3.2 Fracture analysis

At the CFA, the work done at the Farnsworth Unit is analogous, where small aperture fractures were noted but not common in most of the reservoir cores examined but most of these fractures appear to be drilling induced. Fractures in the Thirteen Finger limestone caprock were described using an industry-standard format for fracture class type, orientation, fracture dip, type of mineral fill, fracture porosity, fracture spacing, and intensity. Again, drilling induced fractures are most common. Natural mineral-filled fractures are quite rare, were formed during diagenesis at shallow depths, and are of late Carboniferous age. Unless significantly damaged by large changes in reservoir pressure, they are highly unlikely to provide migration pathways.

In the unlikely event CO_2 leakage occurs as a result of leakage through the faults and fractures, it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.4 Lateral Fluid Movement

The Morrow strata in the Oklahoma and Texas Panhandle was primarily a deltaic sequence that prograded toward the southeast, resulting in deposition of mainly shales with lenticular, discontinuous coarse sandstones separated with very fine sandstone, minor conglomerates, and shale. The likelihood of any extensive migration of fluid outside of the AMA is very low.

Since CO_2 is lighter than the water remaining in the reservoir, it will migrate to the top of each lenticular structure as it is filled. The producing wells, which create low pressure points in the field, will drain the water and keep the CO_2 within each discontinuous sandstone.

4.5 Leakage through Confining/Seal system

At the CFA, the work done at the Farnsworth Unit will apply, where a variety of analytical methods were used for caprock (confining system) analysis, and the results should be the same for the CFA. Petrologic examination included standard thin section petrography and backscattered electron microscopy. Petrophysical analytical methods include retort analysis, pulse-decay permeability measurement, pressure decay permeability analysis for tight rocks, and mercury injection porosimetry, which is also known as mercury injection capillary pressure (MICP). Geomechanical analysis involved a standard series of mechanical tests: Brazil tension, unconfined compression, triaxial compression, and multi-stress compression.

Results of the MICP analysis show that the mudstone lithologies in the Morrow Shale and Thirteen Finger Limestone can support CO_2 column heights of ~1,000 to 10,000 feet. At an order of magnitude over the thickness of the Morrow reservoir, this should prove an effective seal for CO_2 storage in the Morrow B injection horizon.

Failure analyses show that the Morrow B sands are weaker than overlying lithologies, so that any fracture initiation around the injection well would not be expected to propagate into the overlying sealing units. Mechanical properties of the overlying shale and limestones provide an interesting and effective combination of strength and elasticity. Limestone layers are strong but brittle, while the shale layers are weaker but sufficiently ductile to prevent extensive fracture propagation.

It is unlikely for hydrocarbon migration pathways that charged the Morrow reservoir to be potential CO_2 migration pathways via primary pore networks today. Any potential CO_2 migration would be most likely due to leakage from wellbores or bypass through fault and fracture networks, discussed in Sections 4.2 and 4.3.

In the unlikely event CO_2 leakage occurs as a result of leakage through the confining seal it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.6 Natural and Induced Seismic Activity

Figure 4.6-1 shows the map of earthquakes with magnitudes measured at greater than 2.5 as defined by the United States Geological Survey (USGS). While past earthquake data cannot predict future earthquakes, the small number of events near CFA after the waterflood operations were initiated in 1969 implies the area is not seismically sensitive to injection. Also, no documentation exists that any of the distant earthquake events caused a disruption in injectivity or damage to any of the wellbores in CFA.

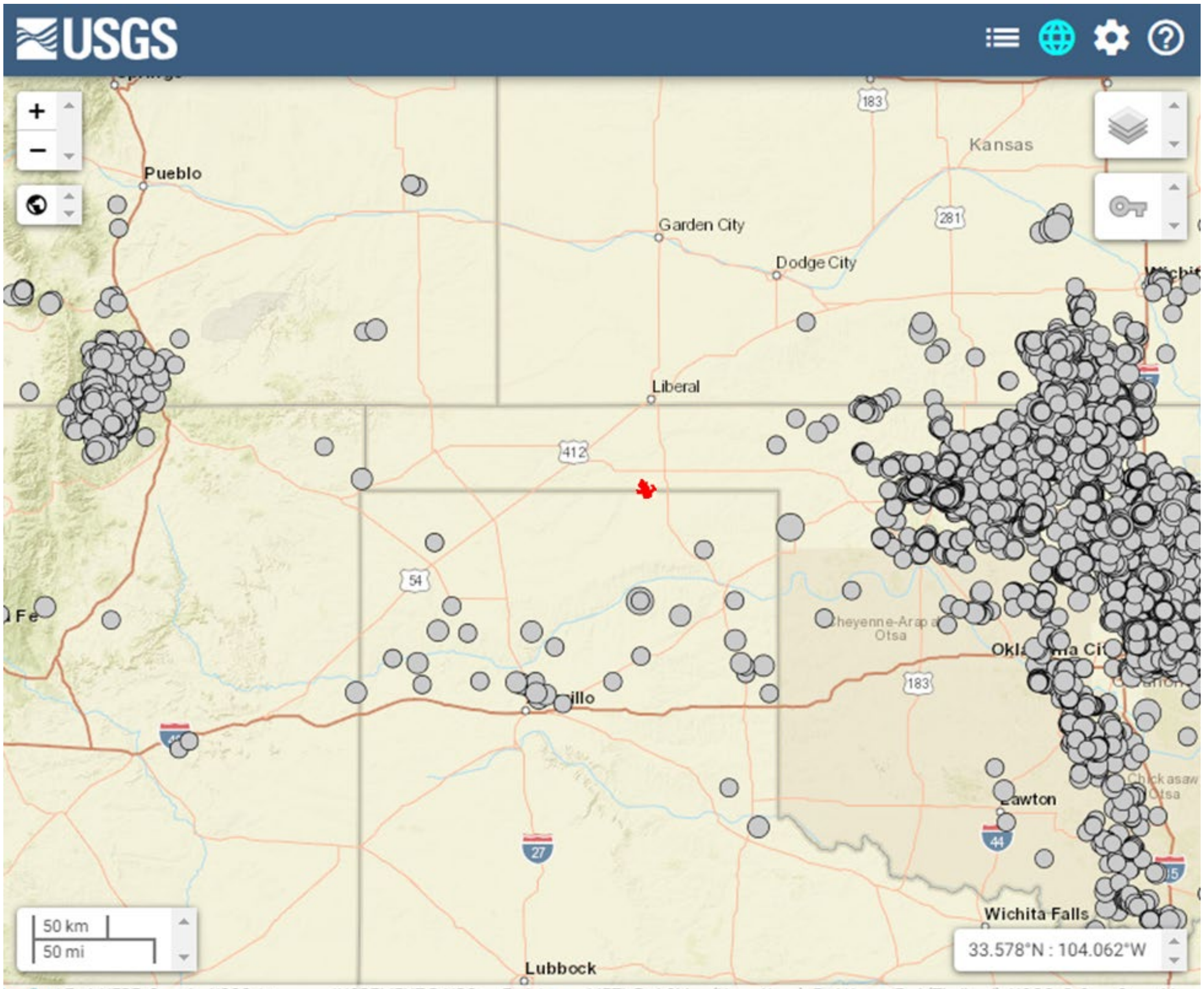

Figure 4.6-1. USGS earthquakes (+2.5 magnitude) for last 40 years with CFA highlighted red.

There is no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the CFA.

In the unlikely event that induced seismicity resulted in a pathway for material amounts of CO_2 to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would lead to further investigation.

4.7 Strategy for Detection and Response to 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 (well bores), and unique events such as induced fractures. Table 1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, CapturePoint's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO_2 losses discussed in the table are identified by type. Once the type is reported to a response manager the correct resources and personnel can be mobilized to develop the optimal response procedure. The procedure will address and mitigate further CO_2 leakage.

Table 1 Response Plan for CO_2 Loss

Known Potential Leakage Risks	Monitoring Methods and Frequency	Anticipated Response Plan
Tubing Leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days
Casing Leak	Weekly field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days
Wellhead Leak	Weekly field inspection	Workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations (weekly inspection but field personnel present daily)	Maintain well kill procedures
Unplanned wells drilled through Morrow	Weekly field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Re-enter and reseal abandoned wells
Pumps, values, etc.	Weekly field inspection	Workover crews respond within days
Leakage along faults	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near faults
Leakage laterally	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Fluid management along lease lines
Leakage through induced fractures	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near seismic event

4.8 Strategy for Quantifying CO_2 loss

Major CO_2 losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. CapturePoint will use Subpart W techniques to estimate leakages only on equipment and ensure those results are consistently represented in the Subpart RR report. Any event-driven leakage quantification reported in Subpart RR for surface leaks will use other techniques.

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 CO_2 that would be most appropriate. In the event leakage occurs, CapturePoint will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission.

Any volume of CO_2 detected leaking to the 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, CapturePoint's field experience, and other factors such as the frequency of inspection. As indicated in Section 6.4, leaks will be documented, and the records of leakage events will be retained in the electronic environmental documentation and reporting system, which consists of reports stored on servers, with information uploaded into third party software.

Available studies of actual well leaks and natural analogs (e.g., naturally occurring CO_2 geysers) suggest that the amount released from routine leaks would be small as compared to the amount of CO_2 that would remain stored in the formation.

5 Strategy for Determining CO_2 Baselines for CO_2 Monitoring

Atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values for soil measurement in the CFA area, per the characterization, monitoring and well data collected by the Southwest Regional Partnership on Carbon Sequestration (SWP) in the analogous Farnsworth Unit.

5.1 Site Characterization and Monitoring

As described in Sections 2.2.2 and 2.4, the Morrow B sandstone is isolated both above and below by shale units of the Morrow. The primary seal consists of 180 – 200 ft of Morrow shale and Thirteen Finger Limestone which in turn is overlain by over a thousand feet of younger shale and limestone. These units provide a suitable seal to prevent the migration of CO_2 out of the injection reservoir. Additionally, no significant faults or fracture zones that cut across the seal units have been identified in the CFA, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented.

5.2 Groundwater monitoring

CapturePoint does not routinely pull water samples from the Ogallala water wells. However, samples are pulled when OCC injection permits are submitted in Oklahoma. No indication of fluid leakage has been identified from any of these in the CFA area. CapturePoint is unlikely to continue monitoring USDW wells for CO_2 or brine contamination, as characterization of the Morrow (see section 5.1) has suggested minimal risk of groundwater contamination from CO_2 leakage from this depth.

5.3 Soil CO_2 monitoring

Atmospheric CO_2 values at the Farnsworth Unit have been determined by a SWP eddy tower installation. In winter 2019, the eddy system malfunctioned and has not been repaired due to COVID travel restrictions. However, the atmospheric CO_2 concentration data from the eddy tower were in very good agreement with values obtained from the NOAA Global Monitoring Laboratory station in Moody, Texas (Station: WKT). Since the CFA area is in close proximity to the Farnsworth Unit, atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values.

5.4 Visual Inspection

CapturePoint operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage.

5.5 Well Surveillance

CapturePoint adheres to the requirements of OAC Title 165:10-5 for the OCC and of TAC Rule 46 for the TRRC governing fluid injection into productive reservoirs. Rule 46 includes requirements for monitoring, reporting, and testing of Class II injection wells. Furthermore, the OCC and the TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well if they are deemed necessary.

CapturePoint also adheres to the requirements of OAC Title 165:10-7 for the OCC and TAC Rule 20 for the TRRC governing the notification of fires, breaks, leaks, or escapes. Rule 20 requires that all operators report leaks to the OCC or the TRRC including measured or estimated quantities of product leaked.

6 Site specific considerations for determining the Mass of CO_2 Sequestered

Of the twelve RR equations in 98.443 of Subpart RR, the following are relevant to CapturePoint's operations.

6.1 Determining Mass of CO_2 received

CapturePoint currently receives CO_2 at its CFA facility through its own pipeline from the Arkalon Ethanol plant in Liberal, Kansas. CapturePoint also recycles CO_2 from its production wells in the CFA.

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

where:

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

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into the well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

6.2 Determining Mass of CO_2 Injected

CapturePoint injects CO_2 into the injection wells listed in Appendix 1.

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

where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

6.3 Determining Mass of CO_2 produced from Oil Wells

CapturePoint also recycles CO_2 from its production wells which are part of its operations in the CFA. Therefore, the following equation is relevant to its operations.

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

Where:

$CO_{2,w}$ = Annual CO_2 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 CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,w}}$ = CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator.

To aggregate production data, CapturePoint will sum the mass of all of the CO_2 separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 below:

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

Where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) through all separators in the reporting year.

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction), CU is 0.00236 and NPU is 0.00454 at the last sample.

w = Separator.

6.4 Determining Mass of CO_2 emitted by Surface Leakage

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations.

CapturePoint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below:

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

where:

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

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

x = Leakage pathway.

6.5 Determining Mass of CO_2 sequestered

The following Equation RR-11 pertains to facilities that are actively producing oil or natural gas.

$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP}$ (Equation RR-11)

Where:

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

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

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

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

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

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

7 Estimated Schedule for Implementation of MRV plan

CapturePoint expects to begin implementing the approved MRV plan when the new CO_2 capture facility is operational, September 1, 2022.

8 GHG monitoring and Quality Assurance Program

CapturePoint will meet the monitoring and QA/QC requirements of 98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 98.444 (d).

8.1 GHG monitoring

As required by 40 CFR 98.3(g)(5)(i), CapturePoint's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

8.1.1 General

Measurement of CO_2 *Concentration* – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GSA) standards.

Measurement of CO_2 *Volume* – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. CapturePoint will adhere to the American Gas Association (AGA) Report #3 – (ORIFICE METERING OF NATURAL GAS AND OTHER RELATED HYDROCARBON FLUIDS)

8.1.2 CO_2 Received

Daily fermentation CO_2 purchased is received via the pipeline from the Arkalon ethanol plant in Liberal, Kansas, and is measured using a volumetric totalizer, which uses accepted flow calculations for CO_2 according to the AGA Report #3.

8.1.3 CO_2 Injected

Daily CO_2 injection is recorded by combining the totals for the recycle compressor meter and the received CO_2 meter from Arkalon based on what's delivered on a 24-hour basis. This data is taken from the meter daily and stored in CapturePoint's data warehouse for records and reservoir management.

8.1.4 CO_2 Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO_2. The produced gas is sampled at least quarterly for the CO_2 content.

8.1.5 CO_2 Emissions from equipment leaks and vented emissions of CO_2

As required by 98.444 (d), CapturePoint will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead and between the flow meter used to measure production quantity and the production wellhead.

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6 Measurement Devices

As required by 40 CFR 98.444(e), CapturePoint will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration.
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meters are National Institute of Standards and Technology (NIST) traceable.

8.2 QA/QC procedures

CapturePoint will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

8.3 Estimating missing data

CapturePoint will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

A quarterly flow rate of CO_2 received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.

A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.

A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

8.4 Revisions of the MRV plan

CapturePoint will revise the MRV Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

9 Records Retention

CapturePoint will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, CapturePoint will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.
(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
   (i) The GHG emissions calculations and methods used.
   (ii) Analytical results for the development of site-specific emissions factors, if applicable.
   (iii) The results of all required analyses.
   (iv) Any facility operating data or process information used for the GHG emission calculations.
(3) The annual GHG reports.
(4) Missing data computations. For each missing data event, CapturePoint will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
(5) A copy of the most recent revision of this MRV Plan.
(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(9) Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(10) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(11) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
(12) 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.
(13) 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.
(14) Any other records as specified for retention in this EPA-approved MRV plan.

10 Appendices

Appendix 1 – CFA Wells

Table A1.1 – Production Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2112	35007353570000	Oil Prod	Active	CO_2	1	0
CU 2171	35007354120000	Oil Prod	Active	CO_2	1	0
CU 2173	35007354140000	Oil Prod	Active	CO_2	1	0
CU 2177	35007222340000	Oil Prod	Active	CO_2	1	0
CU 2272	35007224530000	Oil Prod	Active	CO_2	1	0
CU 2651	35007362650000	Oil Prod	Active	CO_2	1	0
CU 2731	35007359750000	Oil Prod	Active	CO_2	1	0
CU 2761	35007350590000	Oil Prod	Active	CO_2	1	0
CU 2853	35007250840000	Oil Prod	Active	CO_2	1	0
CU 2854	35007250850000	Oil Prod	Active	CO_2	1	0
CU 2971A	35007256700000	Oil Prod	Active	CO_2	1	0
CU 2973	35007213750000	Oil Prod	Active	CO_2	1	0
CU 2975	35007223730000	Oil Prod	Active	CO_2	1	0
CU 3111	35007350600000	Oil Prod	Active	CO_2	1	0
CU 3113	35007359460000	Oil Prod	Active	CO_2	1	0
CU 3115	35007251710000	Oil Prod	Active	CO_2	1	0
CU 3116	35007252570000	Oil Prod	Active	CO_2	1	0
CU 3143	35007250860000	Oil Prod	Active	CO_2	1	0
CU 3171	35007359600000	Oil Prod	Active	CO_2	1	0
CU 3182	35007249250000	Oil Prod	Active	CO_2	1	0
CU 3211	35007352150000	Oil Prod	Active	CO_2	1	0
CU 3212	35007352690000	Oil Prod	Active	CO_2	1	0
CU 3231	35007001820000	Oil Prod	Active	CO_2	1	0
CU 3232	35007352720000	Oil Prod	Active	CO_2	1	0
CU 3234	35007212010000	Oil Prod	Active	CO_2	1	0
CU 3261	35007352170000	Oil Prod	Active	CO_2	1	0
CU 3263	35007251640000	Oil Prod	Active	CO_2	1	0
CU 3271	35007352160000	Oil Prod	Active	CO_2	1	0
CU 3273	35007252580000	Oil Prod	Active	CO_2	1	0
CU 3274	35007253140000	Oil Prod	Active	CO_2	1	0
CU 3275	35007254040000	Oil Prod	Active	CO_2	1	0
CU 3312	35007360800000	Oil Prod	Active	CO_2	1	0
CU 3313	35007254370000	Oil Prod	Active	CO_2	1	0
CU 3314	35007254030000	Oil Prod	Active	CO_2	1	0
CU 3332	35007254020000	Oil Prod	Active	CO_2	1	0
CU 3381	35007360780000	Oil Prod	Active	CO_2	1	0
CU 3411	35007351700000	Oil Prod	Active	CO_2	1	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3412	35007351720000	Oil Prod	Active	CO_2	1	0
CU 3413	35007351730000	Oil Prod	Active	CO_2	1	0
CU 3414	35007005220000	Oil Prod	Active	CO_2	1	0
CU 3415	35007211170000	Oil Prod	Active	CO_2	1	0
CU 3416A	35007252590000	Oil Prod	Active	CO_2	1	0
CU 3451A	35007256710000	Oil Prod	Active	CO_2	1	0
CU 3471	35007351750000	Oil Prod	Active	CO_2	1	0
CU 3481	35007351710001	Oil Prod	Active	CO_2	1	0
CU 3491	35007254330000	Oil Prod	Active	CO_2	1	0
CU 3533	35007206880000	Oil Prod	Active	CO_2	1	0
CU 3562	35007255050000	Oil Prod	Active	CO_2	1	0
NPU 101	42357010440000	Oil Prod	Active	CO_2	1	0
NPU 103	42357010060000	Oil Prod	Active	CO_2	1	0
NPU 104	42357000050000	Oil Prod	Active	CO_2	1	0
NPU 207	42357302000000	Oil Prod	Active	CO_2	1	0
NPU 209	42357333830000	Oil Prod	Active	CO_2	1	0
NPU 501	42357009140000	Oil Prod	Active	CO_2	1	0
NPU 502	42357024100000	Oil Prod	Active	CO_2	1	0
NPU 601	42357008420000	Oil Prod	Active	CO_2	1	0
NPU 605	42357333840000	Oil Prod	Active	CO_2	1	0
NWCU 3-1	35007360850000	Gas Prod	Active	CO_2	1	0
NWCU 9-3	35007249430000	Oil Prod	Active	CO_2	1	0
CU 2172	35007354130000	Oil Prod	Inactive	CO_2	0	0
CU 2175	35007354160000	Oil Prod	Inactive	CO_2	0	0
CU 2473	35007211990000	Oil Prod	Inactive	CO_2	0	0
CU 2511	35007350790000	Oil Prod	Inactive	CO_2	0	0
CU 2711	35007359260000	Oil Prod	Inactive	CO_2	0	0
CU 2771	35007359850000	Oil Prod	Inactive	CO_2	0	0
CU 3142	35007222350000	Oil Prod	Inactive	CO_2	0	0
CU 3361	35007352670000	Oil Prod	Inactive	CO_2	0	0
NPU 205	42357008070000	Oil Prod	Inactive	CO_2	0	0
NPU 301	42357022080000	Oil Prod	Inactive	CO_2	0	0
NPU 801	42357004630000	Oil Prod	Inactive	CO_2	0	0
NPU 802	42357004620000	Oil Prod	Inactive	CO_2	0	0
NPU 804	42357201730000	Oil Prod	Inactive	CO_2	0	0
NPU 901	42357000660000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-2	35007350870000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-3	35007210790000	Oil Prod	Inactive	CO_2	0	0
NWCU 16-1	35007350720000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-1	35007360900000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-3	35007360920000	Oil Prod	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
NWCU 19-4	35007360930000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-5	35007360940000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-6	35007211250000	Oil Prod	Inactive	CO_2	0	0
NWCU 24-5	35007222710000	Oil Prod	Inactive	CO_2	0	0
NWCU 25-7	35007228000000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-3	35007360870000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-4	35007360880000	Oil Prod	Inactive	CO_2	0	0
NWCU 4-2	35007360740000	Oil Prod	Inactive	CO_2	0	0
NWCU 5-1	35007361050000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-1	35007360980000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-2	35007360990000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-1	35007360810000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-2	35007360820000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-3	35007208260000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-1	35007360950000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-2	35007360960000	Oil Prod	Inactive	CO_2	0	0
CU 1551	35007350740000	Oil Prod	P&A	CO_2	0	0
CU 1671	35007352180000	Oil Prod	P&A	CO_2	0	0
CU 2111	35007353560000	Oil Prod	P&A	CO_2	0	0
CU 2176	35007358870000	Oil Prod	P&A	CO_2	0	0
CU 2221	35007000490000	Oil Prod	P&A	CO_2	0	0
CU 2281	35007359220000	Oil Prod	P&A	CO_2	0	0
CU 2421	35007359350000	Oil Prod	P&A	CO_2	0	0
CU 2431	35007350330000	Oil Prod	P&A	CO_2	0	0
CU 2432	35007350340000	Oil Prod	P&A	CO_2	0	0
CU 2433	35007350350000	Oil Prod	P&A	CO_2	0	0
CU 2434	35007350360000	Oil Prod	P&A	CO_2	0	0
CU 2435	35007218800000	Oil Prod	P&A	CO_2	0	0
CU 2471	35007359080000	Oil Prod	P&A	CO_2	0	0
CU 2531	35007361090000	Oil Prod	P&A	CO_2	0	0
CU 2532	35007361100000	Oil Prod	P&A	CO_2	0	0
CU 2552	35007359760000	Oil Prod	P&A	CO_2	0	0
CU 2571	35007350730000	Oil Prod	P&A	CO_2	0	0
CU 2572	35007359320000	Oil Prod	P&A	CO_2	0	0
CU 2661	35007361990000	Oil Prod	P&A	CO_2	0	0
CU 2681	35007350320000	Oil Prod	P&A	CO_2	0	0
CU 2852	35007301360000	Oil Prod	P&A	CO_2	0	0
CU 2961	35007358760000	Oil Prod	P&A	CO_2	0	0
CU 2971	35007358750000	Oil Prod	P&A	CO_2	0	0
CU 2972	35007358780000	Oil Prod	P&A	CO_2	0	0
CU 3031	35007359560000	Oil Prod	P&A	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3051	35007300380000	Oil Prod	P&A	CO_2	0	0
CU 3064	35007254270000	Oil Prod	P&A	CO_2	0	0
CU 3141	35007359610000	Oil Prod	P&A	CO_2	0	0
CU 3181	35007359470000	Oil Prod	P&A	CO_2	0	0
CU 3251	35007352710000	Oil Prod	P&A	CO_2	0	0
CU 3331	35007200750000	Oil Prod	P&A	CO_2	0	0
CU 3451	35007351690000	Oil Prod	P&A	CO_2	0	0
CU 3511	35007359730000	Oil Prod	P&A	CO_2	0	0
CU 3531	35007350850000	Oil Prod	P&A	CO_2	0	0
CU 3532	35007359950000	Oil Prod	P&A	CO_2	0	0
CU 3534	35007211180000	Oil Prod	P&A	CO_2	0	0
CU 3561	35007359830000	Oil Prod	P&A	CO_2	0	0
CU 3571	35007359980000	Oil Prod	P&A	CO_2	0	0
CU 3581	35007359970000	Oil Prod	P&A	CO_2	0	0
CU 3631	35007301000000	Oil Prod	P&A	CO_2	0	0
CU 1672	35007352190000	Oil Prod	P&A	CO_2	0	0
CU 2351	35007350370000	Oil Prod	P&A	CO_2	0	0
CU 2474	35007228200000	Oil Prod	P&A	CO_2	0	0
CU 2812	35007352340000	Oil Prod	P&A	CO_2	0	0
CU 2871	35007359060000	Oil Prod	P&A	CO_2	0	0
NPU 102	42357021420000	Oil Prod	P&A	CO_2	0	0
NPU 201	42357001280000	Oil Prod	P&A	CO_2	0	0
NPU 302	42357022290000	Oil Prod	P&A	CO_2	0	0
NPU 402	42357022300000	Oil Prod	P&A	CO_2	0	0
NWCU 17-2	35007359620000	Oil Prod	P&A	CO_2	0	0
NWCU 10-1	35007361010000	Oil Prod	P&A	CO_2	0	0
NWCU 17-1	35007350710000	Oil Prod	P&A	CO_2	0	0
NWCU 19-7	35007224520000	Oil Prod	P&A	CO_2	0	0
NWCU 24-4	35007358770000	Oil Prod	P&A	CO_2	0	0
NWCU 25-6	35007358790000	Oil Prod	P&A	CO_2	0	0

Table A1.2 – Water Alternating Gas (WAG) Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 2662 (INJ)	35007362010000	WAG Inj	Active	CO_2	0	1
CU 2751 (INJ)	35007359440002	WAG Inj	Active	CO_2	0	1
CU 2762 (INJ)	35007213660000	WAG Inj	Active	CO_2	0	1
CU 2772 (INJ)	35007359860001	WAG Inj	Active	CO_2	0	1
CU 2811 (INJ)	35007352200000	WAG Inj	Active	CO_2	0	1
CU 2872 (INJ)	35007359070000	WAG Inj	Active	CO_2	0	1
CU 2962 (INJ)	35007212000000	WAG Inj	Active	CO_2	0	1
CU 2974 (INJ)	35007220770000	WAG Inj	Active	CO_2	0	1
CU 3114 (INJ)	35007206540000	WAG Inj	Active	CO_2	0	1
CU 3117 (INJ)	35007254000000	WAG Inj	Active	CO_2	0	1
CU 3161 (INJ)	35007359590002	WAG Inj	Active	CO_2	0	1
CU 3213 (INJ)	35007224570000	WAG Inj	Active	CO_2	0	1
CU 3233 (INJ)	35007206890000	WAG Inj	Active	CO_2	0	1
CU 3252 (INJ)	35007211020000	WAG Inj	Active	CO_2	0	1
CU 3262 (INJ)	35007206870000	WAG Inj	Active	CO_2	0	1
CU 3351 (INJ)	35007352680000	WAG Inj	Active	CO_2	0	1
CU 3371 (INJ)	35007360770000	WAG Inj	Active	CO_2	0	1
CU 3417 (INJ)	35007255060000	WAG Inj	Active	CO_2	0	1
CU 3461 (INJ)	35007351680000	WAG Inj	Active	CO_2	0	1
CU 3472 (INJ)	35007206940000	WAG Inj	Active	CO_2	0	1
CU 3551 (INJ)	35007359840000	WAG Inj	Active	CO_2	0	1
NPU 105 (INJ)	42357000030000	WAG Inj	Active	CO_2	0	1
NPU 107W (INJ)	42357333770000	WAG Inj	Active	CO_2	0	1
NPU 202WI (INJ)	42357021500000	WAG Inj	Active	CO_2	0	1
NPU 208 (INJ)	42357327410000	WAG Inj	Active	CO_2	0	1
NPU 701 (INJ)	42357008410000	WAG Inj	Active	CO_2	0	1
NPU 504 (INJ)	42357329480000	WAG Inj	Active	CO_2	0	1
NPU 604W (INJ)	42357330870000	WAG Inj	Active	CO_2	0	1
CU 1531 (INJ)	35007359990000	WAG Inj	Inactive	CO_2	0	0
CU 2131 (INJ)	35007362700000	WAG Inj	Inactive	CO_2	0	0
CU 2512 (INJ)	35007350780000	WAG Inj	Inactive	CO_2	0	0
CU 2641 (INJ)	35007359250001	WAG Inj	Inactive	CO_2	0	0
CU 2721 (INJ)	35007359870001	WAG Inj	Inactive	CO_2	0	0
CU 2741 (INJ)	35007359430000	WAG Inj	Inactive	CO_2	0	0
CU 2851 (INJ)	35007355420001	WAG Inj	Inactive	CO_2	0	0
CU 3032 (INJ)	35007359580000	WAG Inj	Inactive	CO_2	0	0
CU 3062 (INJ)	35007253090000	WAG Inj	Inactive	CO_2	0	0
CU 3112 (INJ)	35007359450001	WAG Inj	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 3172 (INJ)	35007251690000	WAG Inj	Inactive	CO_2	0	0
CU 3281 (INJ)	35007352700003	WAG Inj	Inactive	CO_2	0	0
CU 3311 (INJ)	35007360790000	WAG Inj	Inactive	CO_2	0	0
CU 3341 (INJ)	35007353530000	WAG Inj	Inactive	CO_2	0	0
NPU 203W (INJ)	42357008270000	WAG Inj	Inactive	CO_2	0	0
NPU 503 (INJ)	42357009150001	WAG Inj	Inactive	CO_2	0	0
NWCU 15-1 (INJ)	35007350860000	WAG Inj	Inactive	CO_2	0	0
NWCU 15-4 (INJ)	35007224510000	WAG Inj	Inactive	CO_2	0	0
NWCU 20-1 (INJ)	35007360760000	WAG Inj	Inactive	CO_2	0	0
NWCU 21-1 (INJ)	35007361020000	WAG Inj	Inactive	CO_2	0	0
CU 2271 (INJ)	35007359230000	WAG Inj	P&A	CO_2	0	0
CU 2311 (INJ)	35007362000000	WAG Inj	P&A	CO_2	0	0
CU 2472 (INJ)	35007359090000	WAG Inj	P&A	CO_2	0	0
CU 3061 (INJ)	35007359820000	WAG Inj	P&A	CO_2	0	0
CU 3512 (INJ)	35007359740000	WAG Inj	P&A	CO_2	0	0
NPU 204W (INJ)	42357022520000	WAG Inj	P&A	CO_2	0	0
NPU 206W (INJ)	42357022510000	WAG Inj	P&A	CO_2	0	0
NPU 401W (INJ)	42357004520000	WAG Inj	P&A	CO_2	0	0
NPU 602W (INJ)	42357020230000	WAG Inj	P&A	CO_2	0	0
NPU 603W (INJ)	42357201720001	WAG Inj	P&A	CO_2	0	0
NPU 803W (INJ)	42357201710000	WAG Inj	P&A	CO_2	0	0
NWCU 14-1 (INJ)	35007350530000	WAG Inj	P&A	CO_2	0	0
NWCU 3-2 (INJ)	35007360860000	WAG Inj	P&A	CO_2	0	0

Table A1.3 – Water Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU WSW 1	35007355430001	Wtr Inj	Active	CO_2	0	1
NPU W 1W	42357300050002	Wtr Inj	Inactive	CO_2	0	0
CU 2551	35007350750000	Wtr Inj	P&A	CO_2	0	0

Appendix 2 – Referenced Regulations

U.S. Code > Title 26, INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1, NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits >

Section 45Q ..... Credit for carbon oxide sequestration

OCC > Title 165: CORPORATION COMMISSION > UNDERGROUND INJECTION CONTROL

Section

165:10-5-1 .... Classification of underground injection wells
165:10-5-2 .... Approval of injection wells or disposal wells
165:10-5-3 .... Authorization for existing enhanced recovery injection wells and existing disposal wells
165:10-5-4 .... Application for approval of enhanced recovery projects
165:10-5-5 .... Application for approval of injection and disposal operations
165:10-5-6 .... Testing and monitoring requirements for injection wells and disposal wells
165:10-5-7 .... Monitoring and reporting requirements for wells covered by 165:10-5-1
165:10-5-8 .... Liquid hydrocarbon storage wells
165:10-5-9 .... Duration of underground injection well orders or permits
165:10-5-10 ..... Transfer of authority to inject
165:10-5-11 ..... Notarized reports
165:10-5-12 ..... Application for administrative approval for the subsurface injection of onsite reserve pit fluids
165:10-5-13 ..... Application for permit for one time injection of reserve pit fluids
165:10-5-14 ..... Exempt aquifers
165:10-5-15 ..... Application for permit for simultaneous injection well

165:5-7-27 .... Application for approval of injection and disposal wells
165:5-7-29 .... Request for exception to certain underground injection well requirements
165:5-7-30 .... Amending existing orders or permits authorizing injection for injection, disposal, or LPG storage wells

TAC > Title 16 - Economic Regulation> Part 1 TRRC > Chapter 3 – Oil and Gas Division >

Rules

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Appendix 4 – Abbreviations and Acronyms

2D – 2 dimensional
3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
ANSI – American National Standards Institute
API – American Petroleum Institute
AWT – All Well Test
ASTM - American Society for Testing and Materials
Bscf – billion standard cubic feet
B/D – barrels per day
bopd – barrels of oil per day
C4 – butane
C5 – pentane
C7 – heptane
C7+ - standard heptane plus
CCE – constant composition expansion
CCUS – carbon capture utilization and storage
CFA – Camrick Field Area
CFR – Code of Federal Regulations
cf – cubic feet
CH4 – methane
CO_2 – carbon dioxide
EOR – Enhanced Oil Recovery
EOS – Equation of State
EPA – US Environmental Protection Agency
ESD – Emergency Shutdown Device
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
H_2S – hydrogen sulfide
lb – pound
mD – millidarcy(ies)
MICP – mercury injection capillary pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MMB – million barrels
MMP – minimum miscible pressure
MMscf – million standard cubic feet
MMstb – million stock tank barrels
MRV – Monitoring, Reporting, and Verification
MMMT – Million metric tonnes
MT – Metric tonne

NIST – National Institute of Standards and Technology
NAESB – North American Energy Standards Board
OAC – Oklahoma Administrative Code
OCC – Oklahoma Corporation Commission
OOIP – Original Oil-In-Place
OWC – oil water contact
PPM – Parts Per Million
psia – pounds per square inch absolute
PVT – pressure, volume, temperature
QA/QC – quality assurance/quality control
RMS – root mean square
SEM – scanning electron microscope
SWP - Southwest Regional Partnership on Carbon Sequestration
TAC – Texas Administrative Code
TA – Temporally Abandoned/not plugged
TD – total depth
TM – Terminated order wells/UIC not plugged
TRRC – Texas Railroad Commission
TSD – Technical Support Document
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water
WAG – Water Alternating Gas (Gas is recycled CO_2 and purchase CO_2)
XRD – x-ray diffraction

Appendix 5 – Conversion Factors

CapturePoint reports CO_2 at standard conditions of temperature and pressure as defined in the State of Texas in the Texas Administrative Code for the Oil and Gas Division, Rule 3.79 as follows:

> Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit.

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at:

https://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At State of Texas standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.002641684 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2{,}204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2} = 0.002641684$$

$$MW_{CO2} = 44.0095$$

$$Density_{CO2} = 5.2734\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.2734\ x\ 10^{-2}\frac{MT}{Mcf}$$

The conversion factor 5.2734 x 10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Appendix B: Submissions and Responses to Requests for Additional Information

Camrick Field Area (CFA)

MONITORING, REPORTING AND VERIFICATION PLAN (MRV)

CapturePoint LLC

April 2022

Contents

INTRODUCTION

CapturePoint, LLC (CapturePoint) operates the Camrick Field Area (CFA) located in Beaver and Texas Counties, Oklahoma and in Ochiltree County, Texas for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) with retention of CO_2 serving a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The CFA was discovered in 1955 and is composed of three units, the Camrick Unit (CU) that was unitized by Humble Oil Company on October 14, 1969, the North Perryton Unit (NPU) that was unitized by Humble Oil Company on March 17, 1969, and the Northwest Camrick Unit (NWCU) that was unitized by Atlantic RichField Company on September 15, 1972. The Units were formed for the purpose of waterflooding with salt water sourced from the Wolfcamp formation. The field structure is a lenticular bedding sand trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. CapturePoint has been operating the CFA since 2017. CapturePoint acquired the CFA from Chaparral Energy LLC, which initiated the CO_2-EOR project in March 2001 for the CU and January 2007 for the NPU. No CO_2 has been injected in the NWCU. CapturePoint intends to continue CO_2-EOR operations until the end of the economic life of the CO_2-EOR program using various Class II injection wells as defined by Underground Injection Control (UIC) regulations and permitted under Texas Railroad Commission (TRRC) Rule 46 of the Texas Administrative Code (TAC) and the Oklahoma Corporation Commission (OCC) Title 165:10 of the Oklahoma Administrative Code (OAC). In this document, the term "gas" means a mixture of hydrocarbon light end components and the CO_2 component that can be produced as part of the EOR process.

CapturePoint has chosen to submit this Monitoring, Reporting, and Verification (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 (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code.

This MRV Plan contains ten sections:

Section 1 contains facility information.

Section 2 contains the project description including: a detailed description of the injection operation including the duration and volume of CO_2 to be injected; a detailed description of the geology and hydrogeology of the CFA located on the northwest shelf of the Anadarko basin; and a detailed characterization of the injection reservoir modeling techniques employed.

Section 3 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449 and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 4 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. This section also describes the strategy for detecting, verifying, and quantifying any surface leakage of CO_2 as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Finally, this section also demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

Section 5 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 6 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 9 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 10 includes Appendices supporting the narrative of the MRV Plan.

1 Facility

1.1 Reporter Number

The CU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544678 and the NPU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544679. The EPA has been notified that the NPU will not be reporting for 2022, and that the facility has been merged into the Camrick Unit Facility Identification number 544678.

1.2 UIC Permit Class

For injection wells (see Appendix 2) that are the subject of this MRV plan, the OCC has rules governing UIC Class II injection wells. These OCC rules are OAC Title 165:10-5-1 through 165:10-5-15, OAC 165:5-7-27, OAC 165:5-7-30, the request for an exception to UIC rules under OAC 165:5-7-29, and other governing filing forms. Also, the TRRC has issued UIC Class II enhanced recovery permits under its Rule 46, TAC Title 16 Part 1 Chapter 3. All wells in the CFA, including both injection and production wells, are regulated by the OCC and the TRRC, which have primacy to implement the UIC Class II program.

1.3 UIC Injection Well Numbers

A list of the injection wells in the CFA is provided in Appendix 1. The details of the injection process are provided in Section 2.3.

2 Project Description

2.1 Project Characteristics

2.1.1 Estimated years of CO_2 injection

The CFA has been injecting CO_2 for the last 20+ years and it is currently projected that CapturePoint will inject CO_2 for an additional 12 years.

2.1.2 Estimated volume of CO_2 injected over lifetime of project

Historical and forecasted cumulative CO_2 retention volumes are approximately 100 billion standard cubic feet (Bscf) or 5.3 million metric tonnes (MMMT) from the start of CO_2

injection through October 2034. During the MRV plan, the period September 2022 through October 2034, 52.5 Bscf or 2.77 MMMT will be stored in the CFA. (See Figure 2.4-6)

2.2 Environmental Setting of MMA

2.2.1 Boundary of the MMA

CapturePoint has defined the boundary of the MMA as equivalent to the boundary of the CFA plus ½ mile beyond. A discussion of the methods used in delineating the MMA and the AMA are presented in Section 3.

2.2.2 Geology

The geological discussions in Sections 2.2.2 and 4.3-4.4 are based on analysis of logs from both the Farnsworth Unit, which is located 10 miles South-South-West of the CFA, and the CFA. Both areas have similar pay thickness, porosity values, permeability measurements, depositional environment, tectonic processes, and overburden strata layers. The descriptions of cores at the Farnsworth Unit included sections from overlying seals as well as the shale underlying the main reservoirs, petrographic thin section descriptions and point counts as well as a variety of special analytical techniques. These techniques included X-ray diffraction (XRD), which is the science of determining the atomic and molecular structure of rock crystals with an X-ray beam; scanning electron microscope (SEM) analysis, which uses a beam of electrons to define the surface of crystals; carbon isotope analysis to estimate the age of the CO_2 in the sample; and a variety of mechanical tests. Two dimensional (2D) and three dimensional (3D) geophysical surveys were also used as part of the Farnsworth Unit MRV Plan (2021). Details of recent geological investigations can be found in Gallagher (2014), Gragg (2016), Rasmussen et al (2019), Rose-Coss et al (2015), Trujillo (2018), Hobbs et al (2019), and Gragg et al (2018).

2.2.2.1 Tectonic Setting and Stratigraphy

The CFA is located on the northwest shelf of the Anadarko basin (Figure 2.2-1) and is one of many oil fields in the area that produce from a sequence of alternating sandstones and mudstones deposited during the late Pennsylvanian Morrowan period. Oil production and CO_2 injection at CFA is restricted to the operationally named Morrow B sandstone; the uppermost Morrow sandstone encountered below the Atokan Thirteen Finger limestone. The primary caprock intervals at CFA are comprised of the upper Morrow shale and the Thirteen Finger limestone (Figure 2.2-2). The Morrowan and Atokan intervals were deposited approximately 315-300 million years ago. Overlying stratigraphy includes late Pennsylvanian through the middle Permian shales and limestones, with lesser amounts of dolomite, sandstone and evaporites (Ball, 1991). The reservoir is approximately 60 feet thick throughout the field and lies at a depth of approximately 6,800-7,600 feet. The primary seal rocks of the Morrow shale and the Thirteen Finger Limestone comprise a package of approximately 180-200 feet thick in the field and are overlain by thousands of feet of Atokan and younger limestones and shales.

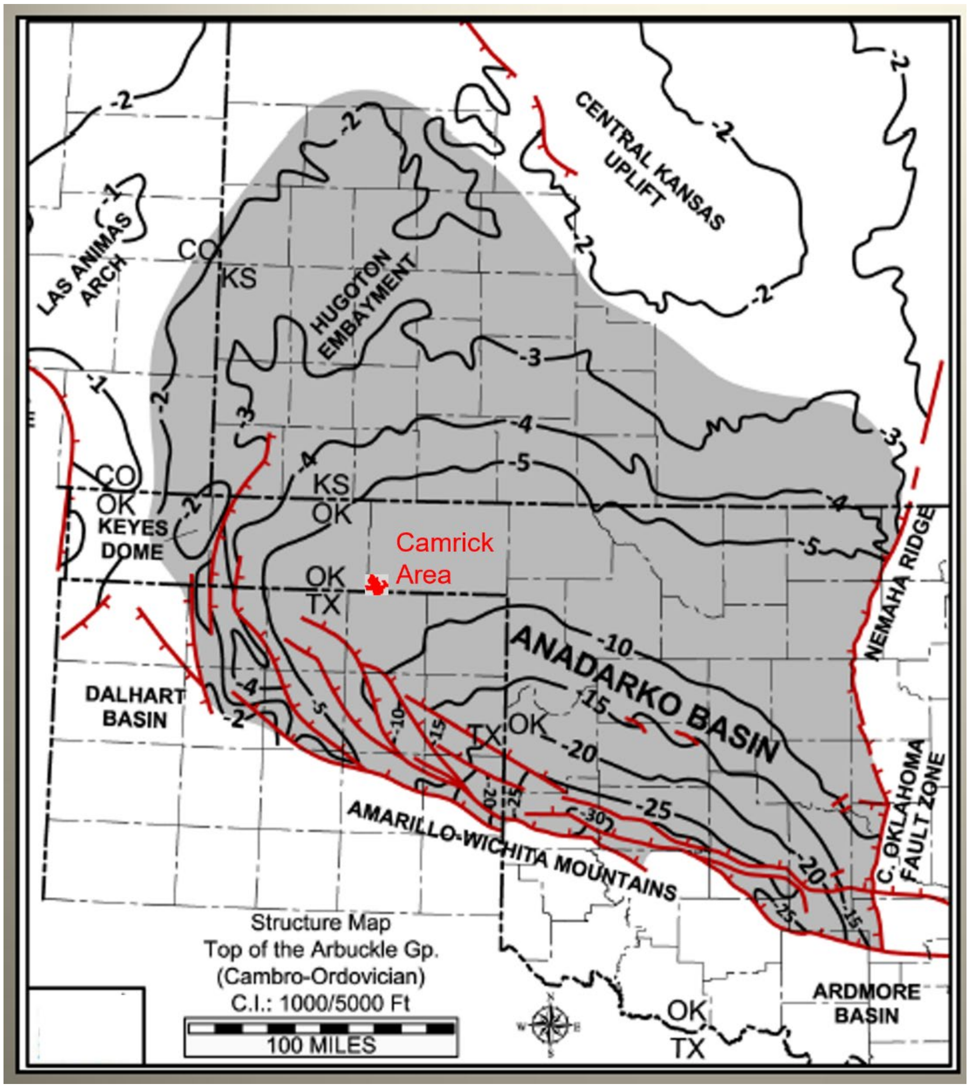

Figure 2.2-1. Location of the CFA on the Northwest Shelf of the Anadarko Basin in West Texas. Red lines are approximate locations of faults that have been documented in the region.

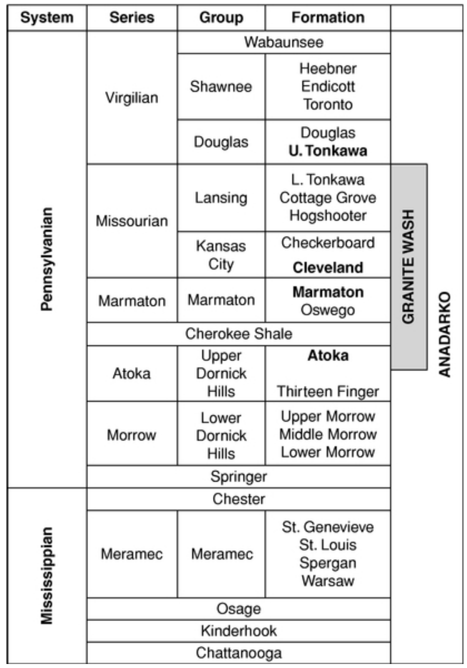

Figure 2.2-2. Stratigraphic section.

Tectonic Setting

From CFA's location on the western edge of the basin, the Anadarko Basin plunges to the southeast (Figure 2.2-3) where it reaches depths of over 40,000 feet (12,192 meters) adjacent to the Amarillo-Wichita Uplift (Perry, 1989). Maximum rates of subsidence occurred during Morrowan to Atokan times (Evans, 1979; Perry, 1989; Higley, 2014). Positive features that might have influenced deposition within the region include the Ancestral Rockies to the north, the Central Kansas uplift to the northeast, and the Wichita-Amarillo uplift to the south (Evans, 1979; Munson, 1989). Of note is the fact that during the Pennsylvanian time, the CFA was located on the basin shelf in an area that was not affected greatly by tectonic deformation. Although faults have been reported previously in the northwest Anadarko Basin, we found no direct evidence for tectonic faults within the CFA (see Section 4).

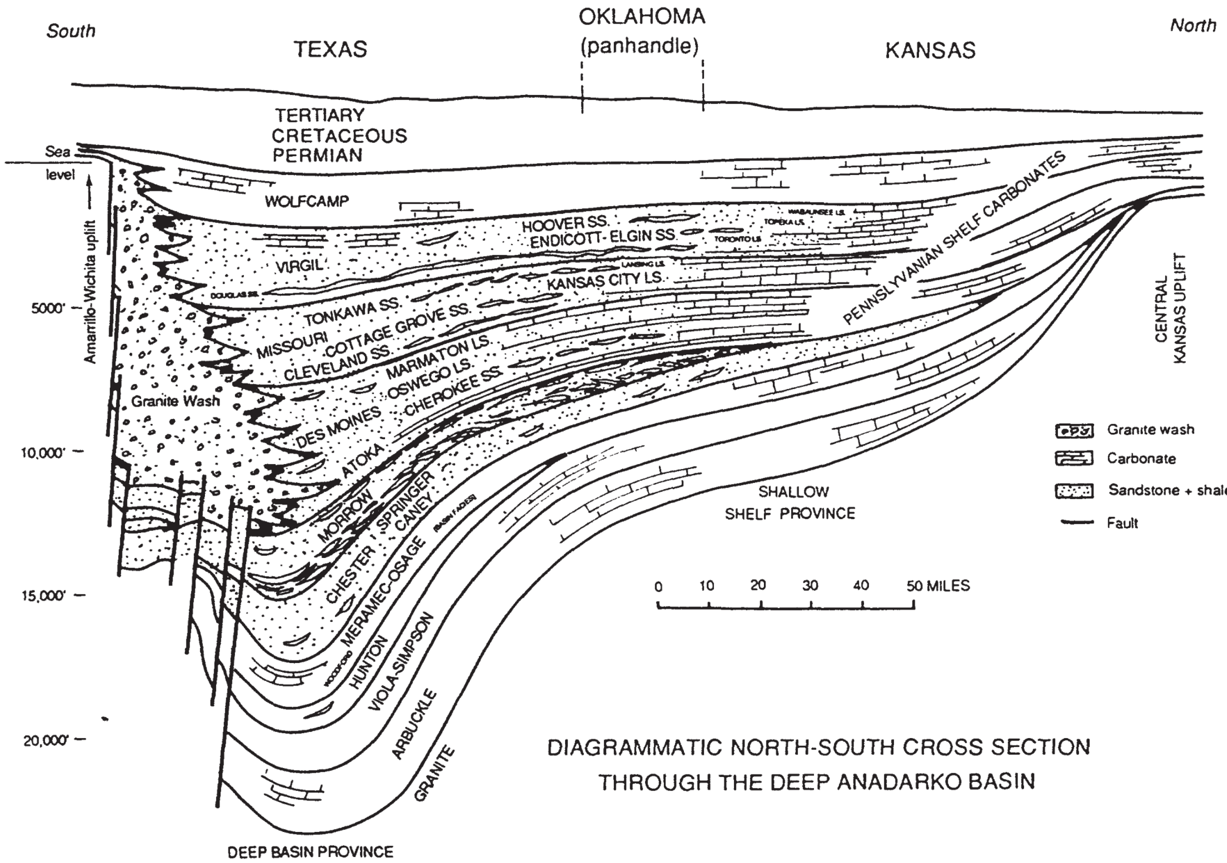

Figure 2.2-3. Diagrammatic North-South Section (Bottom) of the CFA.

Stratigraphy

Reservoir

Upper Morrowan sandstones in the Anadarko Basin margins have long been recognized as fluvial deposits (Swanson, 1979; Sonnenberg, 1985; Munson, 1989; Krystinik and Blakeney, 1990; Bowen et al., 1990; Al-Shaieb et al., 1995; Mckay and Noah, 1996; Puckette et al., 1996; Bowen and Weimer, 2003, 2004; Devries 2005; Puckette et al., 2008; Gallagher, 2014). At the Farnsworth Unit and similarly at the CFA, the Morrow B is described as a relatively coarse-grained subarkosic sandstone. The upper Morrowan facies, with sequences of basal conglomerate, coarse-grained sandstone, and fine-grained sandstone appear to be typical of incised valley deposits, as described by Wheeler et al. (1990), Krystinik and Blakeney (1990), Bowen et al. (1990), Blakeney et al. (1990), Sonnenberg et al. (1990) and Puckette et al. (2008).

Primary Seals

The Morrow B sandstones are encased above and below by shales. Contacts with shale both below and above the sandstone are sharp and irregular. The Morrow shale generally fines upwards in a series of thin beds that alternate between upper fine sands and fine to medium muds. Sand content decreases upwards through the section.

The Thirteen Finger limestone formation has two different lithofacies: diagenetic limestone (cementstone) and pyrite and fossil bearing fine to medium mudstone and coal. The two facies are intercalated with each other but tend to cluster in layers dominated more by one or the other.

The entire Thirteen Finger interval is typically 130 feet (39.6 meters) thick, comprised of mudstone, coal, and limestone. The mudstone is calcite rich, with some dolomite, and is completely diagenetic in origin and probably formed relatively soon following deposition.

2.2.2.2 Hydrogeology

Information about Morrowan and Atokan formation water flow during oil operations has not been discovered in any oil or gas company published reports or academic research studies in the Anadarko Basin. Groundwater flow rates in confined deep Anadarko layers at present are considered to be low to no flow (Nelson and Gianoutsos, 2014). Their arguments are based on (1) restricted recharge in the western basin, (2) density barriers to flow in the east, and (3) an overpressure pocket inhibiting flow in the deep basin. Jorgenson (1989) suggested flow could be west to east, driven by potential recharge to elevated units in the west and discharge at lower elevation outcrops in the east. The CFA CO_2 injection and production operations have negligible likelihood of causing water to flow to outcrops of the late Carboniferous (Pennsylvanian) time period that extend from Brownwood, Texas, to the Jacksboro/Bowie, Texas, area, which are hundreds of miles away (The Paleontology Portal).

The Carboniferous is a geologic period and system that covers 60 million years from the Devonian Period 358.9 million years ago, to the beginning of the Permian Period, 298.9 million years ago. As noted in the Section 2.2.2.1, the Morrowan and Atokan intervals of the CFA were deposited approximately 315-300 million years ago and are contained in the Carboniferous period.

2.3 Description of the Injection Process

Figure 2.3-1 depicts a simplified flow diagram of the facilities and equipment within the boundaries of the CFA. CO_2 captured from the ethanol plant fermentation process is delivered via pipeline to the field for injection. The Arkalon plant in Liberal, Kansas is the only source of CO_2 to the field. The amount delivered is dependent on the production of CO_2 produced from the fermentation process. This amount will vary but should average 12 MMCFD. Once CO_2 enters the CFA there are three main processes involved in EOR operations. These processes are shown in Figure 2.3-1 and include:

1. CO_2 distribution and injection. Purchased CO_2 is combined with recycled CO_2 from the CFA central tank battery (CTB) and sent through the main CO_2 distribution system to various water alternating gas (WAG) injectors.

2. Produced Fluids Handling. Full well stream fluids are produced to the “all well test” (AWT) site. The AWT site has two major purposes; 1) to individually test a well’s performance by separating and metering oil, gas, and water, and 2) to separate all gas from liquid then send these two phases to the CTB for final separation; while only the gas from NPU is sent to the CTB the NPU oil and water remains in Texas.

3. Produced Gas Processing. All gases from the AWT sites are transferred to the CTB to separate the oil, gas, and water using a series of vessels and storage tanks.

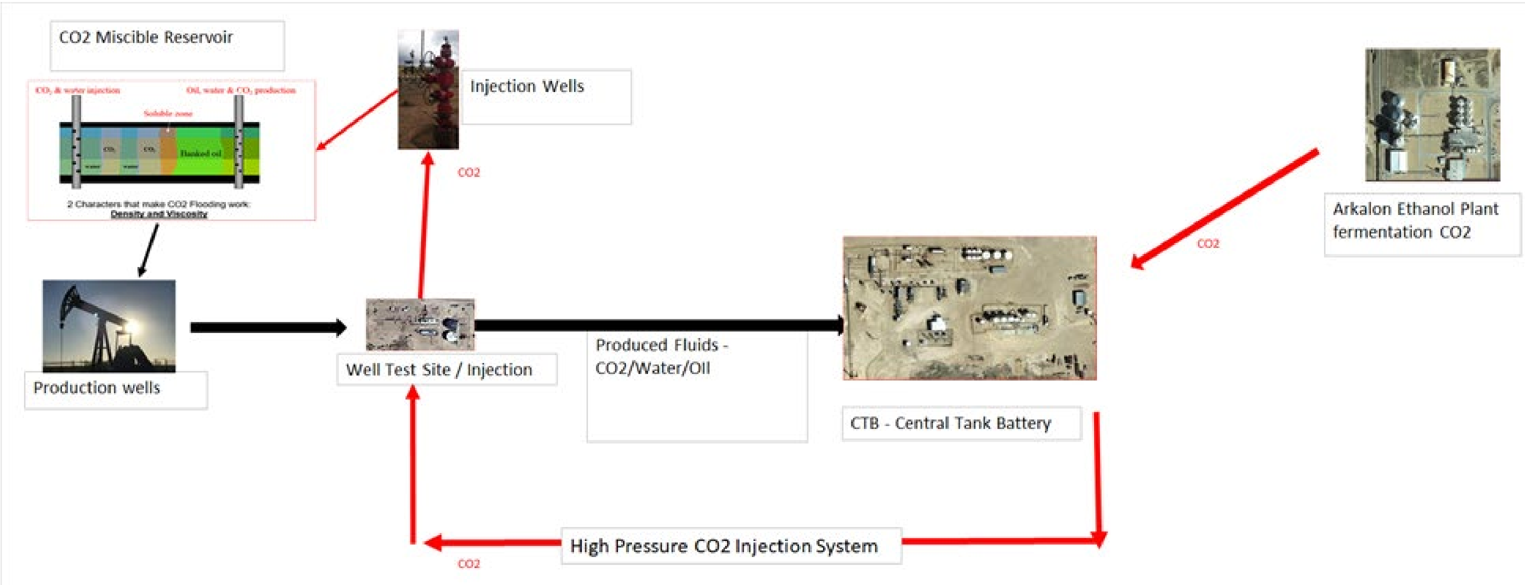

Figure 2.3–1. Simplified flow diagram of the facilities and equipment within the boundaries of the CFA.

2.3.1 CO_2 Distribution and Injection

CapturePoint purchases CO_2 from Conestoga Energy Partners, the parent company of the Arkalon Ethanol plant located in Liberal, Kansas. A custody transfer meter is located in the compression facility owned and operated by CapturePoint. The purchased CO_2 from the fermentation process is transported via a United States Department of Transportation (DOT) regulated pipeline to the CFA. A totalizer meter, for the purchased CO_2, is located in the field where instantaneous data is summed into a 24-hour flow rate which is recorded. A totalizer meter is a meter approved by the American Gas Association (AGA) Report #3 to measure the flowrate of gases. The actual measurements taken are temperature, line pressure, and differential pressure across the meter. Gas produced, which contains recycled CO_2, from the wells is compressed and metered by a similar totalizer meter as the purchase CO_2 meter and is recorded daily.

CapturePoint currently has seven active injection manifolds and approximately 29 active injection wells that the CO_2 is distributed through. When the MRV plan becomes active, the daily injection volume of the combined purchased CO_2 and recycled CO_2 will be approximately 24 MMCFD. Of this volume 12 MMCFD is purchased CO_2 and 12 MMCFD is recycled CO_2. This ratio of purchased CO_2 to recycled CO_2 is expected to change over time, with the percentage of recycled CO_2 increasing and purchased CO_2 decreasing. The current reservoir management plan projects that CO_2 purchases will remain constant at 12 MMCFD for 12 years and cease after 2034. A reservoir management plan is an integrated process using various surveillance techniques, economic evaluations, and accepted petroleum technical practices to efficiently operate enhanced oil recovery projects.

The seven injection manifolds currently in the field distribute the CO_2 to the field. These manifolds have valves to switch to water when the time is called for. Depending on the reservoir management plan, the WAG cycle will be adjusted to maximize oil recovery and minimize CO_2 utilization in each injection pattern. At each injection well pad there is a totalizer to measure the volumes injected every 24 hours. This data is collected daily by the field personnel and input into the data warehouse to be allocated for the pattern injection.

The two totalizer meters as described above will be used to determine the total volume injected used in section 7 for the mass balance equations necessary to determine annual and cumulative volumes of the stored CO_2.

2.3.2 Produced Fluids Handling

As injected CO_2 and water migrate through the reservoir; a mixture of oil, gas, and water (referred to as “produced fluids”) flows to the production wells. Gathering lines bring the produced fluids from each production well to the AWT sites. CapturePoint has approximately 32 active production wells producing at any time. Each AWT has two separators. The first separator is used for testing individual wells to separate the gas, oil, and water produced from an individual well. This gas, oil, and water is subsequently measured and recorded for the well. Each producing well is production tested every 30 to 60 days after the last production test, or after the well is returned to production. Depending on the reservoir management plan, well testing can be more frequent to obtain data. The second separator is used to separate the gas from the oil/water mixture from the other wells producing into the AWT, and the gas and liquids are displaced from the vessel in separate lines. Leaving the AWT sites are two lines transporting produced fluids. One line is used for the liquid phase, a mixture of oil and water, and one line is used for the gas phase. However, the AWT in NPU does not transfer oil or gas to the CTB, it only transfers gas while reinjecting water with pumps at the NPU AWT and sells oil at the NPU AWT.

When gas and liquid lines enter the CTB, a series of vessels separate the oil, gas, and water to be accounted for and distributed for sales or reinjected. The liquid phase line has vessels to separate the oil from the water using density and residence time. The gas phase vessels collect any free liquids entrained with the gas. These free liquids are then combined back into the liquid phase line. All gas and water are reinjected, and the oil, which contains an estimated 2,360 ppm CO_2 (0.236%) for CU and 4,540 ppm CO_2 (0.454%) for NPU, is sold out of tanks. Annually, the oil from the stock tank is analyzed by a laboratory using ASTM crude oil analysis methods to determine the CO_2 content in the oil being sold.

After separation, the gas phase, which is approximately 92-95% CO_2, is mixed with reservoir volatile components, compressed, and distributed throughout the high-pressure distribution system using reciprocal compression and high-pressure horizontal pumps.

The water is transferred from the separation vessels to tanks for reinjection. After the water is conditioned, it is either reinjected at the WAG skids or disposed of into permitted disposal wells. Although CapturePoint is not required to determine or report the amount of dissolved CO_2 in the water as it is reinjected into the ground and not emitted to the atmosphere, the analyses have shown the water typically contains <690 ppm (0.069%) CO_2.

CFA production has trace amounts of hydrogen sulfide (H_2S), which is toxic. There are approximately 8-10 workers on the ground in the CFA at any given time, and all field and contractor personnel are always required to wear H_2S detectors. The primary purpose of the H_2S detectors is protecting people from the risk of being harmed. The detection limit of the H_2S detectors is quantified for readings in the range of 0-100 ppm and will sound an alarm above 10 ppm. The secondary purpose of the H_2S detectors would be to provide an indication of emissions of gas from a pipeline or surface equipment, which might go unnoticed by other observations or measurements. No gas volumes can be calculated based on the detector reading or alarm; only a H_2S leakage is detected and located. Once identified, a further response will be initiated and CO_2 volumes will be quantified as discussed in sections 4.5, 4.6, 5.4, and 8.1.5 of this MRV plan.

2.3.3 Produced Gas Handling

Produced gas separated at the CTB is stripped by a series of vessels of entrained and free water. The water content has been recorded to be < 20 pounds mass per MMCF, thus dehydration is not necessary. The gas is then sent to a centralized compression system to be compressed and placed in the high-pressure distribution system. This compression turns the CO_2 into a variable density liquid, which is then transported out via high pressure lines to the AWT sites where a manifold splits this dense CO_2 to the wells that are on CO_2 injection at that time.

2.3.4 Facilities Locations

The locations of the AWT sites are positioned in the field to access both injection distribution and production gathering. The CTB is where the final separation and injection equipment is maintained and operated. The water injection station is where the horizontal pumps are located to reinject the produced brine.

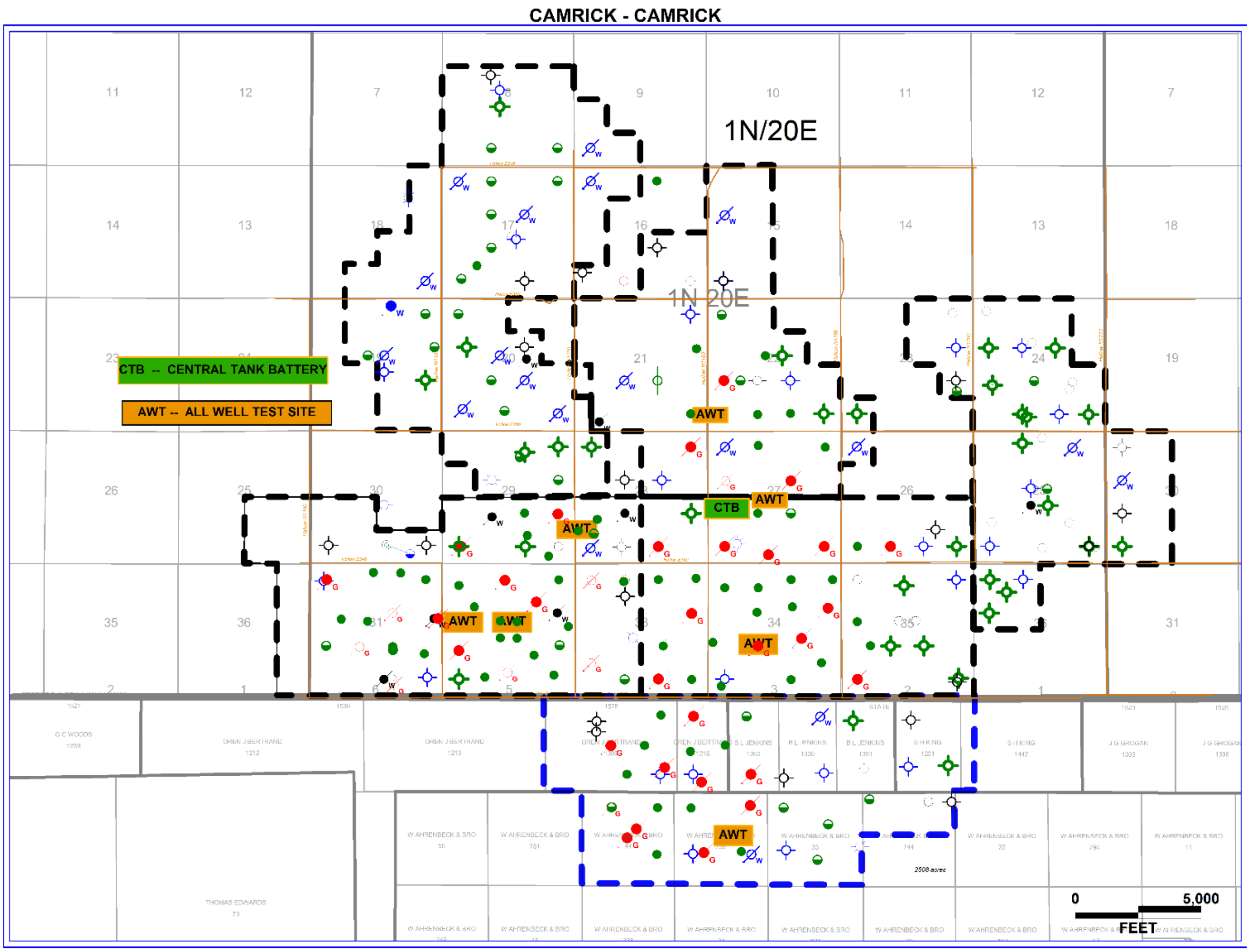

Figure 2.3-2. Location of AWT sites and CTB in the CFA

2.3.5 Water Conditioning and Injection

Produced water collected at the CTB is collected in a series of vessels and tanks in a cascade system. This allows any entrained oil to further separate to the top of the tanks because of the density difference. This oil is skimmed off and put back in the oil separation system. The clean water is then transferred to the water injection system where it is boosted in pressure and sent out to the AWT sites for distribution to all wells that are currently on water injection.

2.3.6 Well Operation and Permitting

The OCC and TRRC rules (Appendix 2) govern well location, construction, operation, maintenance, and plugging for all wells in permitted units and wells. CapturePoint follows these rules and regulations to maintain safe and efficient operations. This includes complying with all current and updated information for mechanical integrity testing, well repairs for injection wells, drilling and completion, permitting, and reporting.

Briefly, the following bulleted list is what the current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface waters.
- That wells file a completion report including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore).
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.
- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location, and setting of plugs.

2.3.7 Number, Location, and Depth of Wells

CapturePoint's CFA injection wells are listed in Appendix 1. Injection is into the Upper Morrowan, a lenticular bedded sandstone trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. The Upper Morrowan is described in section 2.2.2.1 above.

2.4 Reservoir Characterization

2.4.1 Reservoir Description

The target reservoir CFA Morrow B is a sandstone formation overlain by the Morrow shale and the Thirteen Finger limestone, which serve as excellent seals for injected CO_2 as determined by Farnsworth data (Ampomah et al., 2016a). The Morrow B sandstone reservoir is at a depth between 6,800 feet and 7,600 feet subsurface with an average dip of less than one degree (Figure 2.4-1). The productive limit of the CFA is about 80 to 90 percent of the total operated surface acreage, which is 14,652.315 acres. The maximum pay thickness is 56 feet with an average of 15 feet and does diminish to zero in spots.

The CFA is approximately eight miles by seven miles with areas that exhibit different reservoir behavior. The southwest portion of CU was most prolific oil producing area of the CFA under primary and secondary production; whereas the western portion of NPU is now responding to CO_2 better than historical operations would have indicated.

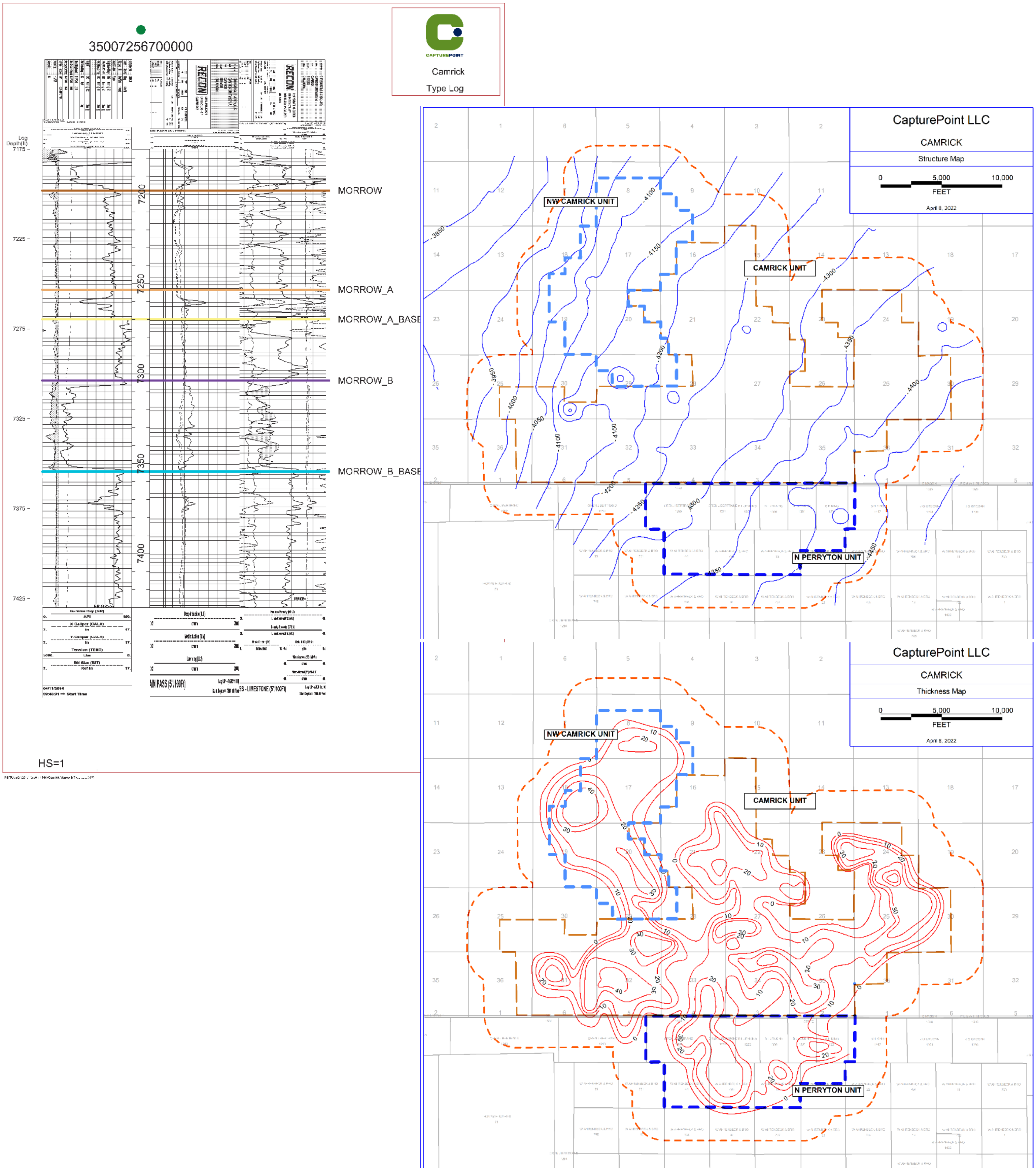

Figure 2.4-1. (Left) Type log of CFA caprock and reservoir, (Upper Right) Surface contour of Morrow top, (Lower Right) Thickness map of Morrow sands.

2.4.2 Reservoir Fluid Modeling

The compositional fluid model was constructed for the CapturePoint operated Farnsworth Unit. From laboratory compositional analysis an equation of state was tuned (Gunda et al., 2015). The minimum miscibility pressure (MMP) experiment was then simulated using a one-dimensional model. The simulated Farnworth Unit MMP of 4,009 psia compared to an MMP value of 4,200 psia derived from laboratory experiments provided by the operator represents a less than 5% error (Gunda et al., 2015).

The reservoir temperature in the CFA is 152 degrees Fahrenheit or 16 degrees lower than the temperature at Farnsworth Unit of 168 degrees. Using parameters of the Alston empirical correlation (1985), the MMP would be 170 psia lower at the CFA or 3,510 psia compared to 3,680 psia at the Farnsworth Unit (Figure 2.4-2).

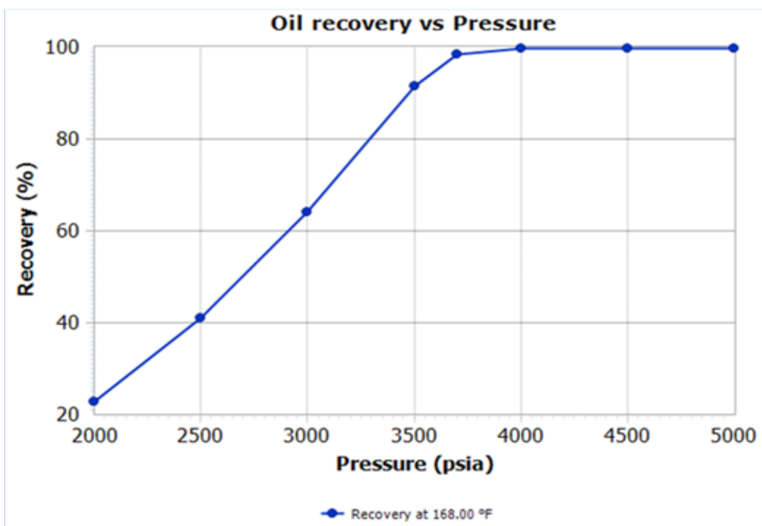

Figure 2.4-2. Oil recovery plot for 1D slim tube test for Farnsworth Unit.

2.4.3 CO_2 Analogy Field Study

Based on similar geologic, petrophysical, engineering, and operational parameters between the Farnsworth Unit and the CFA, the oil recovery performance of both fields is expected to be similar. Due to the stratigraphic nature of the Morrow channel sands, the potential movement of CO_2 is severely limited. The CFA area has contained the free phase CO_2 plume in a very confined area since March 2001 as exhibited by oil, water, and CO_2 recovery performance. Also, during CFA drilling and production operations, no reports exist which would indicate any plume has moved outside of the MMA. The Farnsworth Unit MRV and the CFA data justifies the conclusion that CO_2 will continue to be contained inside the MMA at the end of the CO_2 injection year t + 5, per §98.449 definitions.

2.4.4 CO_2 – EOR Performance Projections

For years, the oil industry has used dimensionless equations to predict the amount of oil that can be recovered using CO_2 for flooding oil reservoirs (Lee et al, 2018, Stell 2010). The

amount of oil recovered from projects is plotted as a decimal fraction of the original-oil-in-place versus the decimal fraction of the hydrocarbon pore volume (HPV) of CO_2 injected into the oil reservoir as measured in reservoir barrels (RB).

The CFA has been injecting CO_2 since March 2001. The dimensionless curves were matched to historical performance through early 2020 (Figure 2.4-3). The supply of CO_2 was curtailed from March 2020 until present, due to oil price uncertainty, and will resume after the Arkalon Plant upgrade that will be finished in the 4th quarter of 2022.

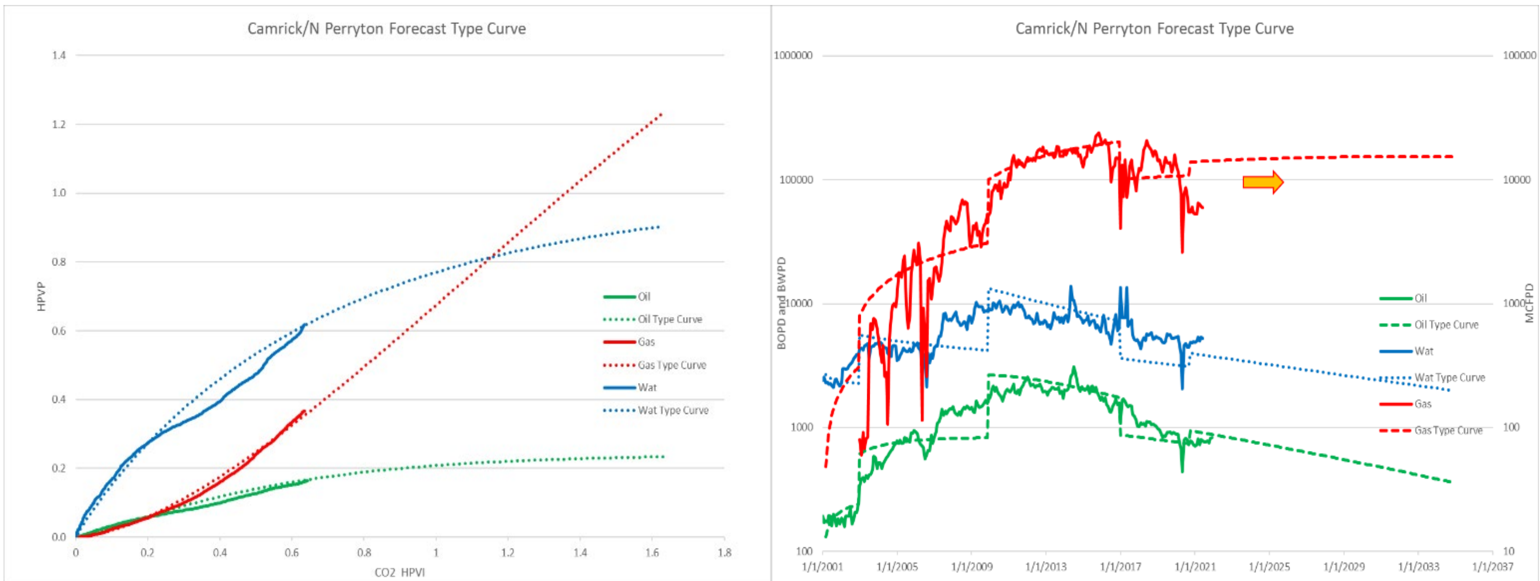

Figure 2.4-3. Dimensionless curves for CO_2 injection (left) with rate time curves (right).

The dimensionless water oil ratio and the gas oil ratio trends (Figure 2.4-4) for the CFA flooded acreage are very similar to what was forecasted by simulation in the Farnsworth Field as expected because of the porosity, permeability, and sand similarities.

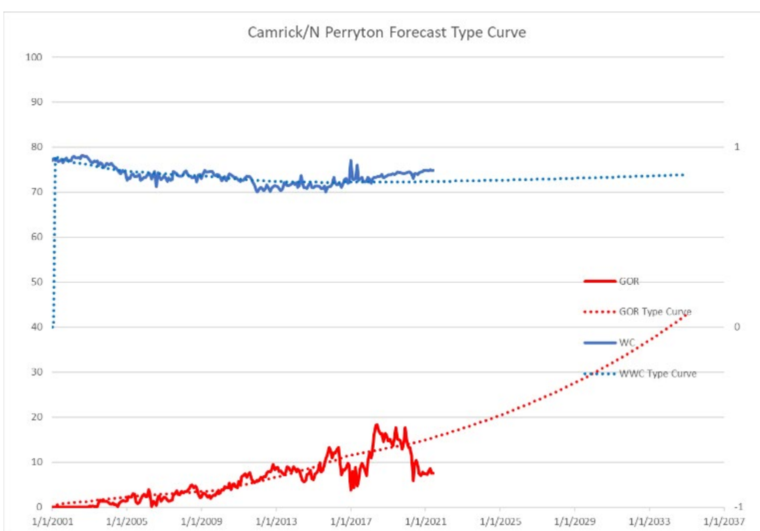

Figure 2.4-4. Dimensionless water cut and GOR vs. observed EOR data.

The CO_2 storage volumes for Arkalon fermentation CO_2 were also forecasted (Figure 2.4-5) using the same dimensionless technique. This technique indicates that the flooded acreage still has significant additional storage potential. The maximum CO_2 storage is limited to the amount of space available by the removal of the produced hydrocarbon. The projection indicates that there is pore space available to store approximately 0.4 to 0.5 decimal fraction of HPV amounting to 30 to 40 MMB.

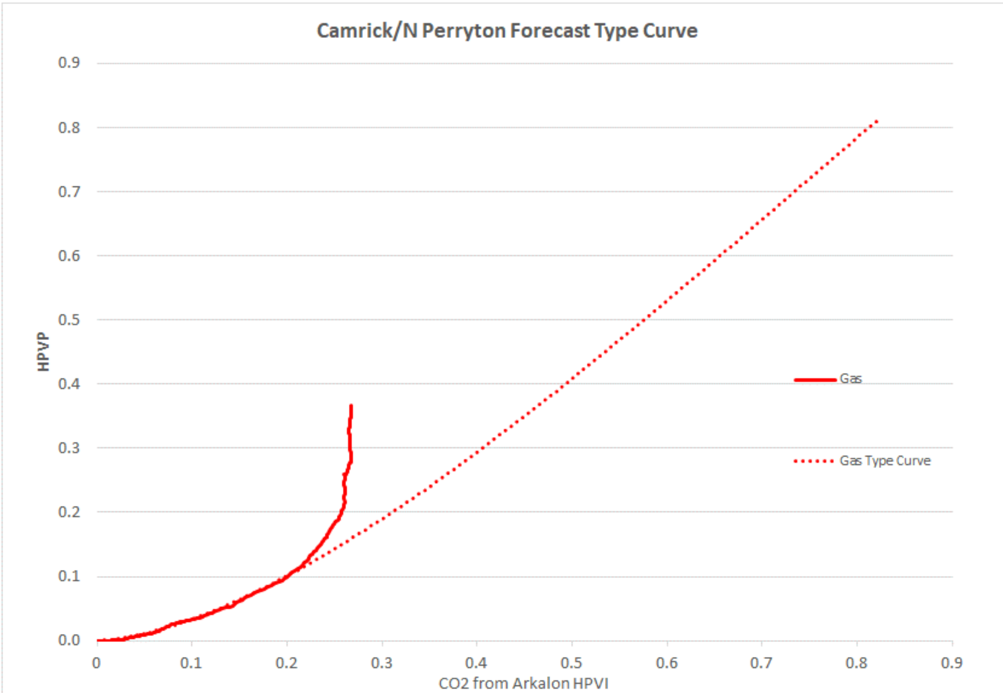

Figure 2.4-5. Dimensionless CO_2 Purchase (Fermentation) Curves

The barrels of reservoir volume were converted to standard cubic feet of gas and is displayed in the CFA Purchase CO_2, or Fermentation CO_2, vs Time chart (Figure 2.4-6).

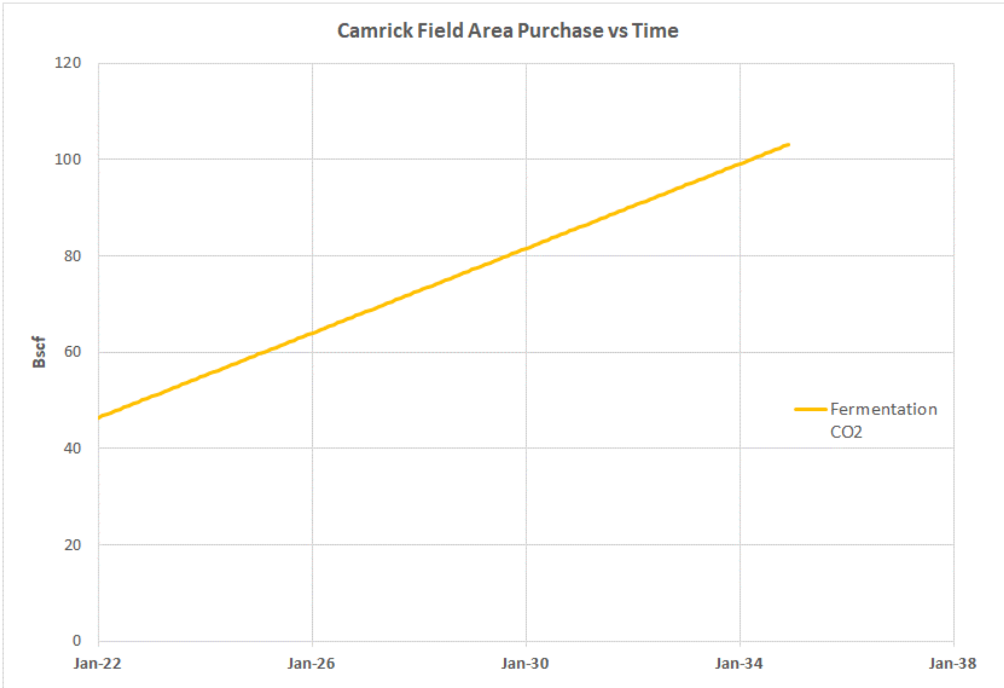

Figure 2.4-6. CO_2 Purchase (Fermentation) Volume.

3 Delineation of Monitoring Area

3.1 MMA

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The purchase volumes that are displayed in Figure 2.4-6 were mapped and are displayed in Section 3.1.1 indicating that CO_2 storage pore space is available, barring unforeseen future operational issues. Therefore, CapturePoint is defining the MMA as the boundary of the CFA plus an additional one-half mile buffer zone. This will allow for operational expansion throughout the CFA for the next 12 years, the anticipated life of the project.

3.1.1 Determination of Storage Volumes

Figure 3.1-1 displays wells that have CO_2 retention on the developed 4,800 acres that have been under CO_2 EOR injection in the CFA since project initialization (14,652.315 acres are in the CFA). The volume of the oil recovered since August 1955, resulted in a voidage space of 36 MMscf of CO_2 per acre of surface area that was later filled with water during waterflood operations. The average decimal fraction of CO_2 injection to hydrocarbon pore volume left in the ground after accounting for CO_2 production through 2021 is 0.29. The lateral extent of CO_2 in the injection zone or the CO_2 storage radius for each well was estimated based on cumulative CO_2 injected times the decimal fraction of CO_2 remaining divided by the voidage space. The largest CO_2 storage areas are around wells that injected the largest volume CO_2.

Figure 3.1-2 displays the potential area of the reservoir that can be filled with CO_2 with the existing injection wells. This assumed that only 78 percent of the average injection pattern area or 80 acres per pattern can be filled. The volumetric storage capacity calculated for the 49 patterns identified for continued injection indicates an additional 90 Bscf of CO_2 can be stored and with 50 Bscf already stored results in 140 Bscf of total storage. With the anticipated 12 MMCFD rate of purchased CO_2, this storage volume will only be 60 percent utilized. As delineated in this MRV plan, the MMA account for an injected volume of up to 140 Bscf and includes all areas of the CFA that could be utilized in the future for CO_2 injection. The MMA will contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. If there are any material changes to the monitoring/operational parameters not outlined in this MRV plan, the plan will be resubmitted in accordance with 40 CFR 98.448(d)(1).

Areas that do not have CO_2 storage posted on Figure 3.1-2 will be evaluated if existing CO_2 injection operations experience any rate restriction or develop any operational issues in the future. If necessary, replacement wells or additional injection locations in inactive areas of the CFA will be drilled or activated. This will be accomplished by utilizing existing plugged and abandoned wells or redrilling old locations as described in Section 3.2.

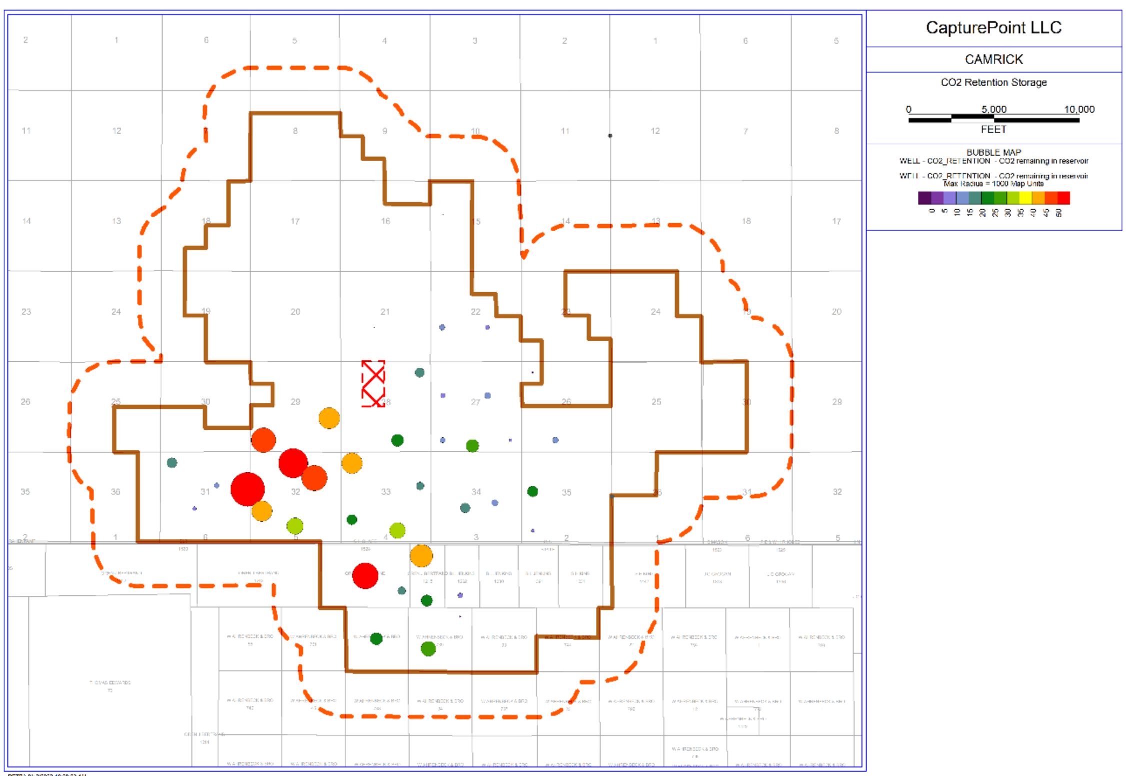

Figure 3.1-1. Estimated CO_2 storage as of 2021 in CFA.
The AMA is the land area inside the solid line polygon except for the red hashed rectangle.
The MMA extends to dotted red line and includes the red hashed rectangle.

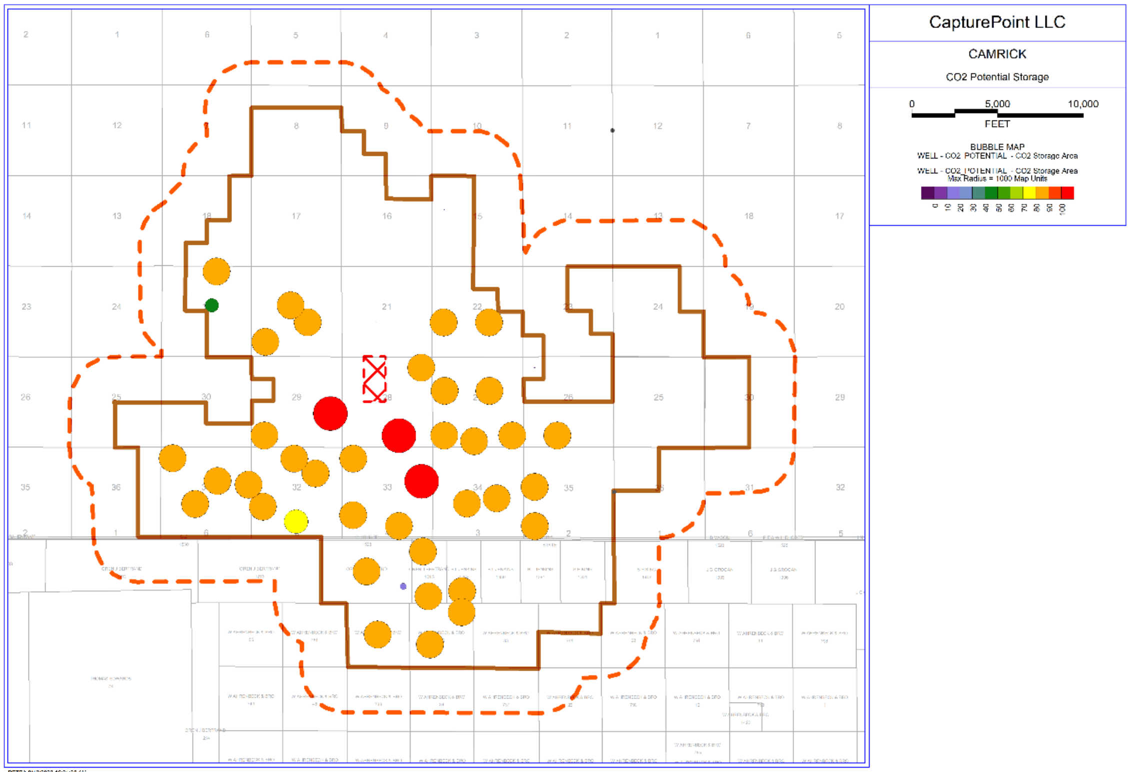

Figure 3.1-2. Potential Total CO_2 Storage in the CFA.
The AMA is the land area inside the solid line polygon except for the red hashed rectangle.
The MMA extends to dotted red line and includes the red hashed rectangle.

3.1.2 Determination of Buffer Zone

CapturePoint intends to implement a buffer zone of one-half mile around the CFA, the minimum required by Subpart RR, because the site characterization and stratigraphic trapping of the Morrow did not reveal any leakage pathways that would allow free-phase CO_2 to migrate laterally thereby warranting a buffer zone greater than one-half mile.

3.2 AMA

The Active Monitoring Area (AMA) is defined by CapturePoint's exclusive right to operate the CFA unitized leases, as described in the INTRODUCTION and Section 2.2.1. Currently, CapturePoint's operations are focused on the western portion of the CU and the entire NPU. However, it is anticipated as time passes, or additional CO_2 volumes become available additional areas within the CFA may be developed. Additional development is driven by the market price of oil coupled with the availability of sufficient CO_2 volumes and thus the timing of additional development is uncertain at this time. As CO_2 injection operations are expanded beyond the currently active CO_2 EOR portion of the CFA, all additional CO_2 injection wells will be permitted under the UIC program and will be included in the annual submittal per 40 CFR 98.446(f)(13). All future CO_2 injection wells permitted will be within the AMA. Based on our projections, CapturePoint expects the free phase CO_2 plume to remain within the CFA for the entire length of the project and through year [t + 5]. Therefore, CapturePoint is defining the AMA as the CFA plus an all-around one-half mile buffer, consistent with the definitions in 40 CFR 98.449. If there are any material changes to the monitoring/operational parameters not outlined in this MRV plan, the plan will be resubmitted in accordance with 40 CFR 98.448(d)(1).

Therefore, for the purposes of this MRV plan, CapturePoint is continuously monitoring the entire CFA, which is the AMA.

4 Identification and Evaluation of Leakage Pathways

Since its discovery in 1955, the unitization of the different units from 1969 to 1972, and the commencement of CO_2 EOR in 2001; the CFA is an analogous field to the Farnsworth Unit, which has undergone extensive investigation and documentation as indicated in Section 2. From this body of work, CapturePoint has identified the following potential pathways of CO_2 leakage to the surface. This section will also address detection, verification, and quantification of leakage from each pathway.

4.1 Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO_2 EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment via personnel instructed on how to detect surface leaks and other equipment failure minimizes releases. In addition, the Oil and Gas Division requirements of the OAC rules of the OCC and the TAC rules of the TRRC to report and quantify leaks, both serve to minimize leakage of GHG from surface equipment. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. As described in Section 6.4 below, should leakage from surface equipment occur it will be quantified according to the procedures in Subpart W of the GHGRP.

4.2 Leakage from Wells

CapturePoint has identified 68 abandoned wells, 49 injection wells (29 active) and 94 production wells (59 active) within the MMA and assessed their potential for leakage of CO_2 to the surface as listed in Appendix 1.

4.2.1 Abandoned Wells

Figure 4.2-1 shows all wells plugged and abandoned in the CFA. Because the CFA was unitized in 1969 to 1972, all plugging and abandonment activities of wells within the CFA have been conducted under the regulations of the OCC and the TRRC for plugging wells. The cement used to plug wells when exposed to CO_2 will form colloidal gels that further reduce any flow. CapturePoint concludes that leakage of CO_2 to the surface through abandoned wells is unlikely. However, strategies for leak detection are in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

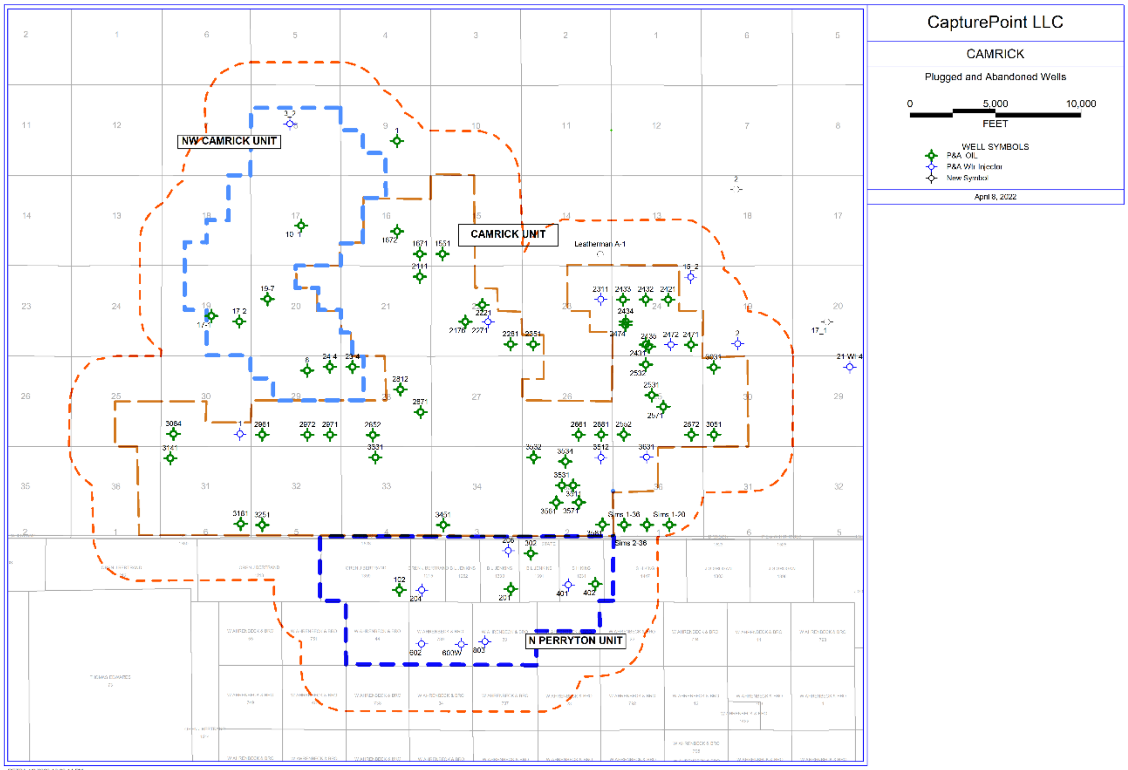

Figure 4.2-1. Plugged and Abandoned Wells in the CFA.

4.2.2 Injection Wells

Mechanical integrity testing (MIT) is an essential requirement of the UIC program in demonstrating that injection wells themselves do not act as conduits for leakage into underground sources of drinking water (USDW) and to the surface environment. TRRC Rule 46 requirements include special equipment requirements (e.g., tubing and packer) and modification; records maintenance; monitoring and reporting; testing; plugging; and penalties for violations of the rule. Permit revocation may result as a consequence of noncompliance. (See Section 2.3.6) The TRRC and the OCC detail all the requirements for the Class II permits issued to CapturePoint. These rules ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Figure 4.2-2 shows the active injection wells in the CFA. CapturePoint concludes that leakage of CO_2 to the surface through active injection wells is unlikely.

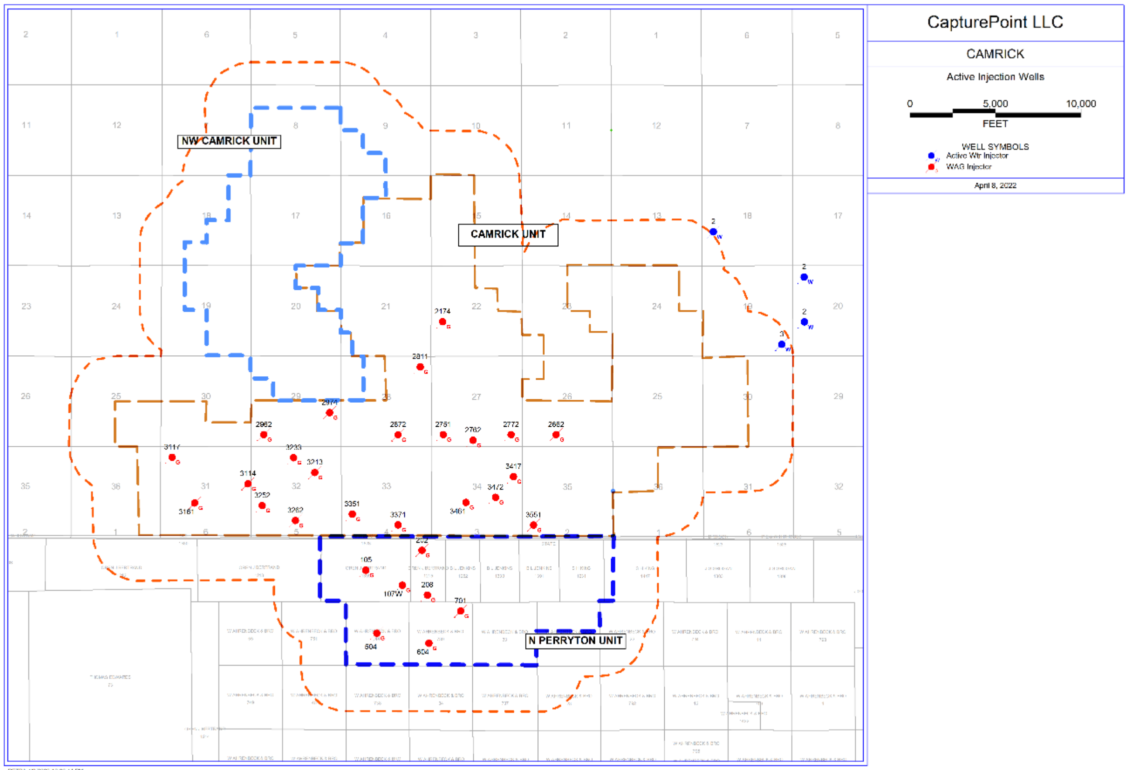

Figure 4.2-2. Active Injection Wells in the CFA.

4.2.3 Production Wells

Some of the original field wells drilled as oil wells were reclassified, administratively, to gas wells per OAC Title 165:10-1-6 paragraph (d), because of the gas-oil ratio growth due to reservoir depletion. Hence, there is no difference in well construction. (See Section 2.3.6) As the field is being further developed for enhanced oil recovery, these gas wells have been reclassified to oil wells per OCC regulations and will be monitored for leakage. (See Section 4.7) Figure 4.2-3 shows the active oil production wells in the CFA. Once EOR operations commence, the energy content of the produced gas drops and cannot be sold; therefore, any inactive gas wells are either reclassified to oil producers, or activated to WAG injectors, as described earlier. (See Section 4.2.2) However, as the project develops in the CFA additional production wells may be added and will be constructed according to the relevant rules of the OCC and the TRRC. Additionally, inactive wells may become active according to the rules of the OCC and the TRRC.

During production, oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure where the bottom hole wellbore pressure is less than the reservoir pressure. These lower pressure fluids, which also contains CO_2, are contained by the casing, tubing, wellhead, and flowline all the way to the CTB. CapturePoint concludes that leakage of CO_2 to the surface through production wells is unlikely.

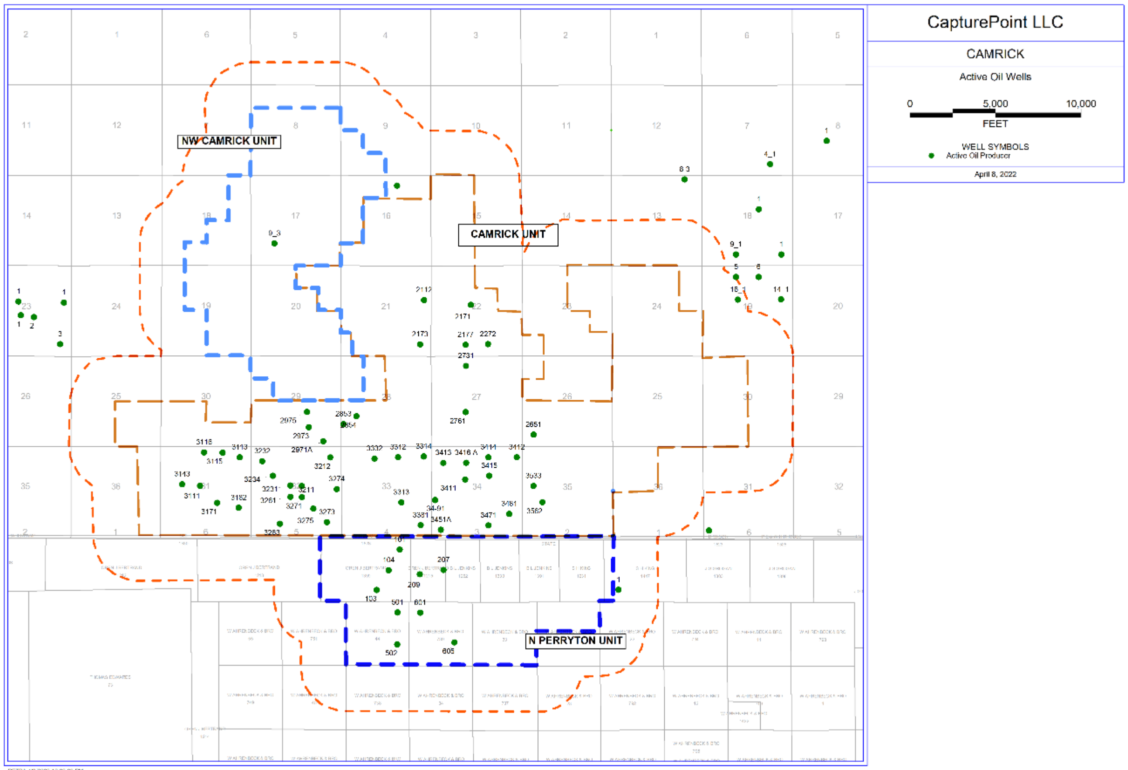

Figure 4.2-3. Active Oil Production Wells in the CFA.

4.2.4 Inactive Wells

Figure 4.2-4 shows all of the inactive wells in the CFA. The OCC has regulations for temporally abandoned/not plugged (TA) and terminated order wells/UIC not plugged (TM) and likewise the TRRC has regulations for inactive wells.

Inactive wells have a cast iron bridge plug set or long cement plugs placed above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. CapturePoint concludes that leakage of CO_2 to the surface through inactive wells is unlikely.

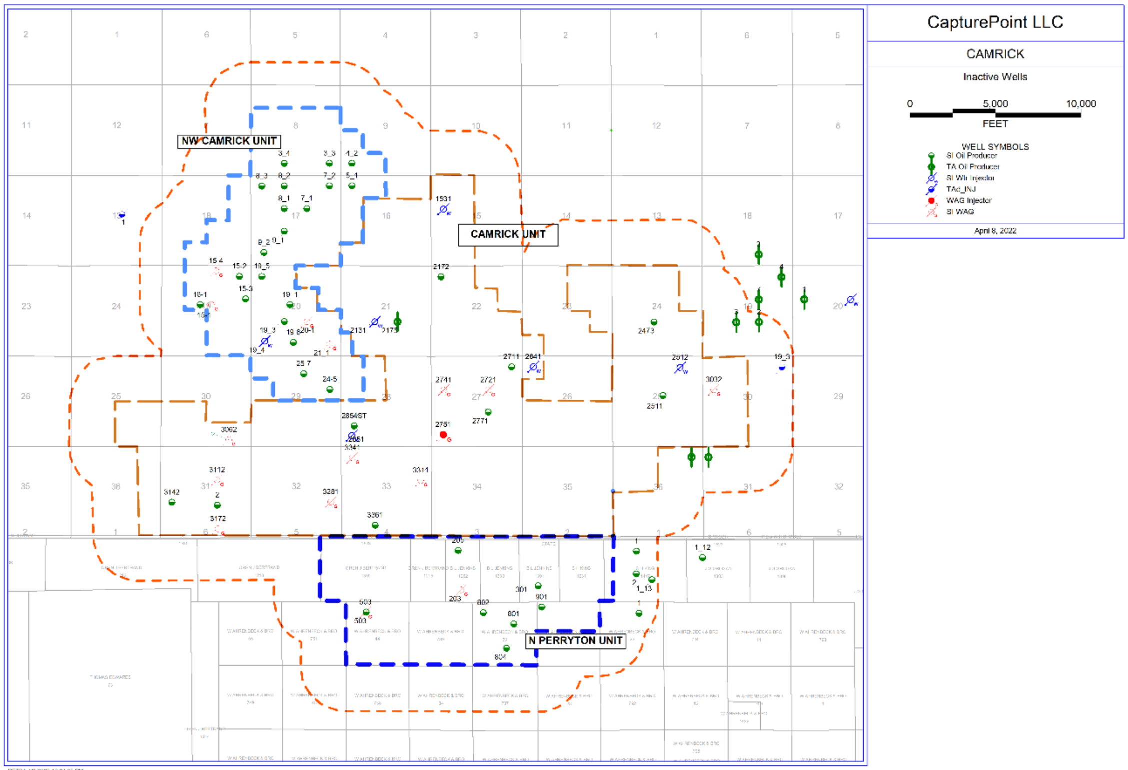

Figure 4.2-4. Inactive wells in the CFA

4.2.5 New Wells

As the project develops, new production wells and injection wells may be added to the CFA. All new wells will be constructed according to the relevant rules for the OCC and the TRRC which ensure protection of subsurface and surface resources, and the environment.

All wells in Oklahoma oilfields and all wells in Texas oilfields, including both injection and production wells, are regulated by the OCC and the TRRC, respectively, which has primacy to implement the UIC Class II programs.

Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Briefly current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface water.
- That wells file a completion report including basic electric logs.
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.

- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.

New well construction is based on existing best practices, established during the drilling of existing wells in CFA and follows the OCC and the TRRC rules, which significantly limits any potential leakage from well pathways. Additionally, the existing wells followed the OCC and the TRRC rules.

In public databases, the area of CFA plus one mile past the unit boundary contains over 100 wells that were drilled deeper than the Morrow formation and none of these wells were productive in reservoirs deeper than the Morrow. Therefore, it is very unlikely that anyone will ever drill through the AMA reservoir in the future. In the event a well is drilled within the AMA, the operator would be required to follow all the OCC and the TRRC rules and procedures in the drilling the well and the potential for leakage would be similar to any well that CapturePoint drills within the AMA. In addition, CapturePoint's visual inspection process during routine field operation will identify any unapproved drilling activity in the CFA.

4.3 Leakage from Faults and Bedding Plane Partings

Primary seals at CFA have been demonstrated to be mechanically very competent (see Section 2.2.2), thus the main concern of CO_2 migration at CFA is via seal bypass systems along fracture networks. The following lines of analysis have been used to assess this risk in the area.

4.3.1 Prescence of Hydrocarbons

The first and foremost argument against present day up-fault transmissibility is the 75 MMB of oil that was found trapped in the reservoir. If significant escape pathways existed, oil would have drained from the reservoir prior to the current day.

4.3.2 Fracture analysis

At the CFA, the work done at the Farnsworth Unit is analogous, where small aperture fractures were noted but not common in most of the reservoir cores examined but most of these fractures appear to be drilling induced. Fractures in the Thirteen Finger limestone caprock were described using an industry-standard format for fracture class type, orientation, fracture dip, type of mineral fill, fracture porosity, fracture spacing, and intensity. Again, drilling induced fractures are most common. Natural mineral-filled fractures are quite rare, were formed during diagenesis at shallow depths, and are of late Carboniferous age. Unless significantly damaged by large changes in reservoir pressure, they are highly unlikely to provide migration pathways.

In the unlikely event CO_2 leakage occurs as a result of leakage through the faults and fractures, it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.4 Lateral Fluid Movement

The Morrow strata in the Oklahoma and Texas Panhandle was primarily a deltaic sequence that prograded toward the southeast, resulting in deposition of mainly shales with lenticular, discontinuous coarse sandstones separated with very fine sandstone, minor conglomerates, and shale. The likelihood of any extensive migration of fluid outside of the AMA is very low.

Since CO_2 is lighter than the water remaining in the reservoir, it will migrate to the top of each lenticular structure as it is filled. The producing wells, which create low pressure points in the field, will drain the water and keep the CO_2 within each discontinuous sandstone.

4.5 Leakage through Confining/Seal system

At the CFA, the work done at the Farnsworth Unit will apply, where a variety of analytical methods were used for caprock (confining system) analysis, and the results should be the same for the CFA. Petrologic examination included standard thin section petrography and backscattered electron microscopy. Petrophysical analytical methods include retort analysis, pulse-decay permeability measurement, pressure decay permeability analysis for tight rocks, and mercury injection porosimetry, which is also known as mercury injection capillary pressure (MICP). Geomechanical analysis involved a standard series of mechanical tests: Brazil tension, unconfined compression, triaxial compression, and multi-stress compression.

Results of the MICP analysis show that the mudstone lithologies in the Morrow Shale and Thirteen Finger Limestone can support CO_2 column heights of ~1,000 to 10,000 feet. At an order of magnitude over the thickness of the Morrow reservoir, this should prove an effective seal for CO_2 storage in the Morrow B injection horizon.

Failure analyses show that the Morrow B sands are weaker than overlying lithologies, so that any fracture initiation around the injection well would not be expected to propagate into the overlying sealing units. Mechanical properties of the overlying shale and limestones provide an interesting and effective combination of strength and elasticity. Limestone layers are strong but brittle, while the shale layers are weaker but sufficiently ductile to prevent extensive fracture propagation.

It is unlikely for hydrocarbon migration pathways that charged the Morrow reservoir to be potential CO_2 migration pathways via primary pore networks today. Any potential CO_2 migration would be most likely due to leakage from wellbores or bypass through fault and fracture networks, discussed in Sections 4.2 and 4.3.

In the unlikely event CO_2 leakage occurs as a result of leakage through the confining seal it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.6 Natural and Induced Seismic Activity

Figure 4.6-1 shows the map of earthquakes with magnitudes measured at greater than 2.5 as defined by the United States Geological Survey (USGS). While past earthquake data cannot predict future earthquakes, the small number of events near CFA after the waterflood operations were initiated in 1969 implies the area is not seismically sensitive to injection. Also, no documentation exists that any of the distant earthquake events caused a disruption in injectivity or damage to any of the wellbores in CFA.

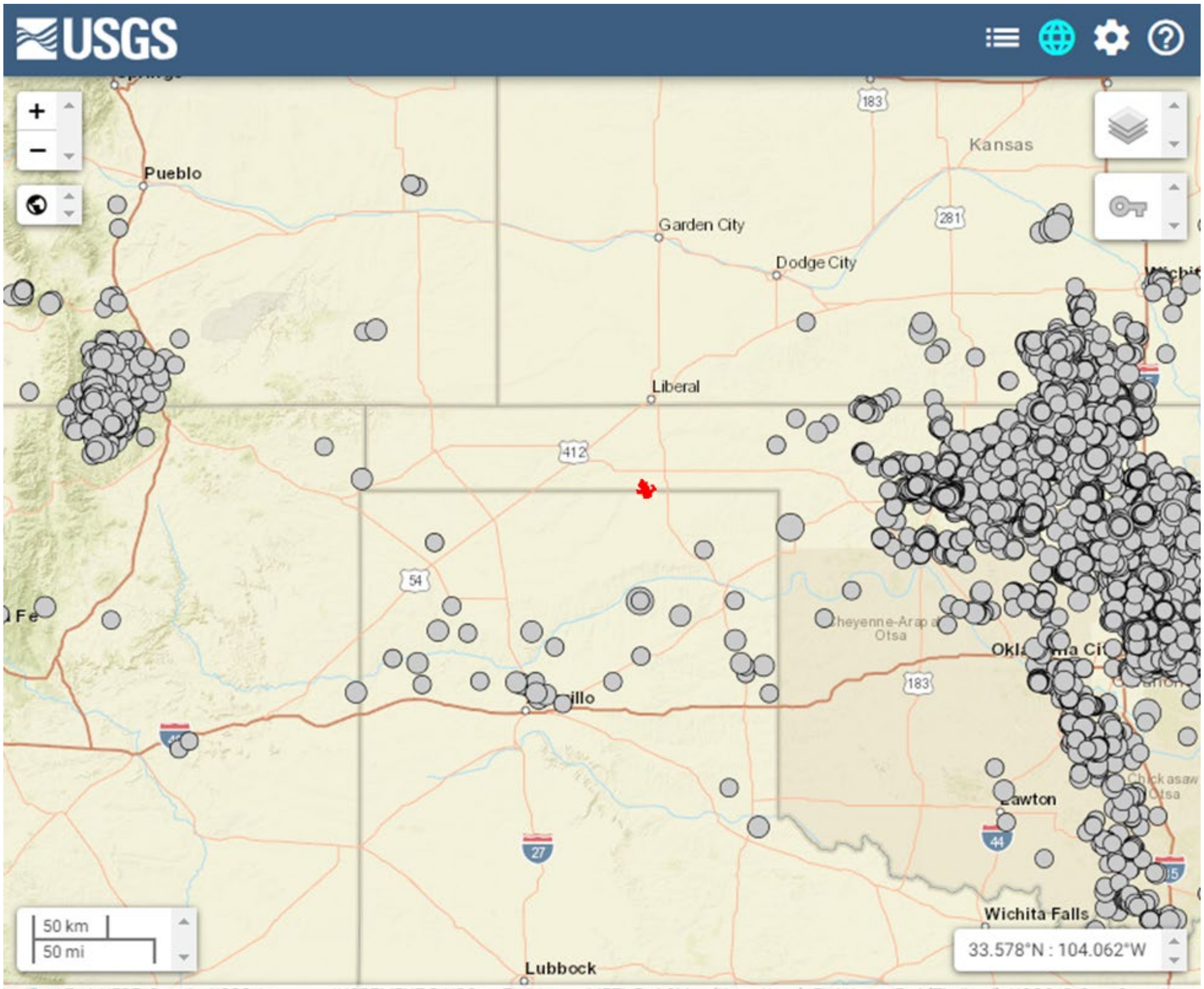

Figure 4.6-1. USGS earthquakes (+2.5 magnitude) for last 40 years with CFA highlighted red.

There is no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the CFA.

In the unlikely event that induced seismicity resulted in a pathway for material amounts of CO_2 to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would lead to further investigation.

4.7 Strategy for Detection and Response to 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 (well bores), and unique events such as induced fractures. Table 1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, CapturePoint's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO_2 losses discussed in the table are identified by type. Once the type is reported to a response manager the correct resources and personnel can be mobilized to develop the optimal response procedure. The procedure will address and mitigate further CO_2 leakage.

Table 1 Response Plan for CO_2 Loss

Known Potential Leakage Risks	Monitoring Methods and Frequency	Anticipated Response Plan
Tubing Leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days
Casing Leak	Weekly field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days
Wellhead Leak	Weekly field inspection	Workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations (weekly inspection but field personnel present daily)	Maintain well kill procedures
Unplanned wells drilled through Morrow	Weekly field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Re-enter and reseal abandoned wells
Pumps, values, etc.	Weekly field inspection	Workover crews respond within days
Leakage along faults	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near faults
Leakage laterally	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Fluid management along lease lines
Leakage through induced fractures	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near seismic event

4.8 Strategy for Quantifying CO_2 loss

Major CO_2 losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. CapturePoint will use Subpart W techniques to estimate leakages only on equipment and ensure those results are consistently represented in the Subpart RR report. Any event-driven leakage quantification reported in Subpart RR for surface leaks will use other techniques.

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 CO_2 that would be most appropriate. In the event leakage occurs, CapturePoint will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission.

Any volume of CO_2 detected leaking to the 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, CapturePoint's field experience, and other factors such as the frequency of inspection. As indicated in Section 6.4, leaks will be documented, and the records of leakage events will be retained in the electronic environmental documentation and reporting system, which consists of reports stored on servers, with information uploaded into third party software.

Available studies of actual well leaks and natural analogs (e.g., naturally occurring CO_2 geysers) suggest that the amount released from routine leaks would be small as compared to the amount of CO_2 that would remain stored in the formation.

5 Strategy for Determining CO_2 Baselines for CO_2 Monitoring

Atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values for soil measurement in the CFA area, per the characterization, monitoring and well data collected by the Southwest Regional Partnership on Carbon Sequestration (SWP) in the analogous Farnsworth Unit.

5.1 Site Characterization and Monitoring

As described in Sections 2.2.2 and 2.4, the Morrow B sandstone is isolated both above and below by shale units of the Morrow. The primary seal consists of 180 – 200 ft of Morrow shale and Thirteen Finger Limestone which in turn is overlain by over a thousand feet of younger shale and limestone. These units provide a suitable seal to prevent the migration of CO_2 out of the injection reservoir. Additionally, no significant faults or fracture zones that cut across the seal units have been identified in the CFA, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented.

5.2 Groundwater monitoring

CapturePoint does not routinely pull water samples from the Ogallala water wells. However, samples are pulled when OCC injection permits are submitted in Oklahoma. No indication of fluid leakage has been identified from any of these in the CFA area. CapturePoint is unlikely to continue monitoring USDW wells for CO_2 or brine contamination, as characterization of the Morrow (see section 5.1) has suggested minimal risk of groundwater contamination from CO_2 leakage from this depth.

5.3 Soil CO_2 monitoring

Atmospheric CO_2 values at the Farnsworth Unit have been determined by a SWP eddy tower installation. In winter 2019, the eddy system malfunctioned and has not been repaired due to COVID travel restrictions. However, the atmospheric CO_2 concentration data from the eddy tower were in very good agreement with values obtained from the NOAA Global Monitoring Laboratory station in Moody, Texas (Station: WKT). Since the CFA area is in close proximity to the Farnsworth Unit, atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values.

5.4 Visual Inspection

CapturePoint operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage.

5.5 Well Surveillance

CapturePoint adheres to the requirements of OAC Title 165:10-5 for the OCC and of TAC Rule 46 for the TRRC governing fluid injection into productive reservoirs. Rule 46 includes requirements for monitoring, reporting, and testing of Class II injection wells. Furthermore, the OCC and the TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well if they are deemed necessary.

CapturePoint also adheres to the requirements of OAC Title 165:10-7 for the OCC and TAC Rule 20 for the TRRC governing the notification of fires, breaks, leaks, or escapes. Rule 20 requires that all operators report leaks to the OCC or the TRRC including measured or estimated quantities of product leaked.

6 Site specific considerations for determining the Mass of CO_2 Sequestered

Of the twelve RR equations in 98.443 of Subpart RR, the following are relevant to CapturePoint's operations.

6.1 Determining Mass of CO_2 received

CapturePoint currently receives CO_2 at its CFA facility through its own pipeline from the Arkalon Ethanol plant in Liberal, Kansas. CapturePoint also recycles CO_2 from its production wells in the CFA.

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

where:

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

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into the well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

6.2 Determining Mass of CO_2 Injected

CapturePoint injects CO_2 into the injection wells listed in Appendix 1.

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

where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

6.3 Determining Mass of CO_2 produced from Oil Wells

CapturePoint also recycles CO_2 from its production wells which are part of its operations in the CFA. Therefore, the following equation is relevant to its operations.

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

Where:

$CO_{2,w}$ = Annual CO_2 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 CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,w}}$ = CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator.

To aggregate production data, CapturePoint will sum the mass of all of the CO_2 separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 below:

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

Where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) through all separators in the reporting year.

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction), CU is 0.00236 and NPU is 0.00454 at the last sample.

w = Separator.

6.4 Determining Mass of CO_2 emitted by Surface Leakage

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations.

CapturePoint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below:

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

where:

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

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

x = Leakage pathway.

6.5 Determining Mass of CO_2 sequestered

The following Equation RR-11 pertains to facilities that are actively producing oil or natural gas.

$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP}$ (Equation RR-11)

Where:

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

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

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

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

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

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

7 Estimated Schedule for Implementation of MRV plan

CapturePoint expects to begin implementing the approved MRV plan when the new CO_2 capture facility is operational, September 1, 2022.

8 GHG monitoring and Quality Assurance Program

CapturePoint will meet the monitoring and QA/QC requirements of 98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 98.444 (d).

8.1 GHG monitoring

As required by 40 CFR 98.3(g)(5)(i), CapturePoint's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

8.1.1 General

Measurement of CO_2 *Concentration* – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GSA) standards.

Measurement of CO_2 *Volume* – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. CapturePoint will adhere to the American Gas Association (AGA) Report #3 – (ORIFICE METERING OF NATURAL GAS AND OTHER RELATED HYDROCARBON FLUIDS)

8.1.2 CO_2 Received

Daily fermentation CO_2 purchased is received via the pipeline from the Arkalon ethanol plant in Liberal, Kansas, and is measured using a volumetric totalizer, which uses accepted flow calculations for CO_2 according to the AGA Report #3.

8.1.3 CO_2 Injected

Daily CO_2 injection is recorded by combining the totals for the recycle compressor meter and the received CO_2 meter from Arkalon based on what's delivered on a 24-hour basis. This data is taken from the meter daily and stored in CapturePoint's data warehouse for records and reservoir management.

8.1.4 CO_2 Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO_2. The produced gas is sampled at least quarterly for the CO_2 content.

8.1.5 CO_2 Emissions from equipment leaks and vented emissions of CO_2

As required by 98.444 (d), CapturePoint will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead and between the flow meter used to measure production quantity and the production wellhead.

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6 Measurement Devices

As required by 40 CFR 98.444(e), CapturePoint will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration.
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meters are National Institute of Standards and Technology (NIST) traceable.

8.2 QA/QC procedures

CapturePoint will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

8.3 Estimating missing data

CapturePoint will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

A quarterly flow rate of CO_2 received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.

A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.

A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

8.4 Revisions of the MRV plan

CapturePoint will revise the MRV Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

9 Records Retention

CapturePoint will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, CapturePoint will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.
(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
    (i) The GHG emissions calculations and methods used.
    (ii) Analytical results for the development of site-specific emissions factors, if applicable.
    (iii) The results of all required analyses.
    (iv) Any facility operating data or process information used for the GHG emission calculations.
(3) The annual GHG reports.
(4) Missing data computations. For each missing data event, CapturePoint will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
(5) A copy of the most recent revision of this MRV Plan.
(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(9) Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(10) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(11) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
(12) 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.
(13) 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.
(14) Any other records as specified for retention in this EPA-approved MRV plan.

10 Appendices

Appendix 1 – CFA Wells

Table A1.1 – Production Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2112	35007353570000	Oil Prod	Active	CO_2	1	0
CU 2171	35007354120000	Oil Prod	Active	CO_2	1	0
CU 2173	35007354140000	Oil Prod	Active	CO_2	1	0
CU 2177	35007222340000	Oil Prod	Active	CO_2	1	0
CU 2272	35007224530000	Oil Prod	Active	CO_2	1	0
CU 2651	35007362650000	Oil Prod	Active	CO_2	1	0
CU 2731	35007359750000	Oil Prod	Active	CO_2	1	0
CU 2761	35007350590000	Oil Prod	Active	CO_2	1	0
CU 2853	35007250840000	Oil Prod	Active	CO_2	1	0
CU 2854	35007250850000	Oil Prod	Active	CO_2	1	0
CU 2971A	35007256700000	Oil Prod	Active	CO_2	1	0
CU 2973	35007213750000	Oil Prod	Active	CO_2	1	0
CU 2975	35007223730000	Oil Prod	Active	CO_2	1	0
CU 3111	35007350600000	Oil Prod	Active	CO_2	1	0
CU 3113	35007359460000	Oil Prod	Active	CO_2	1	0
CU 3115	35007251710000	Oil Prod	Active	CO_2	1	0
CU 3116	35007252570000	Oil Prod	Active	CO_2	1	0
CU 3143	35007250860000	Oil Prod	Active	CO_2	1	0
CU 3171	35007359600000	Oil Prod	Active	CO_2	1	0
CU 3182	35007249250000	Oil Prod	Active	CO_2	1	0
CU 3211	35007352150000	Oil Prod	Active	CO_2	1	0
CU 3212	35007352690000	Oil Prod	Active	CO_2	1	0
CU 3231	35007001820000	Oil Prod	Active	CO_2	1	0
CU 3232	35007352720000	Oil Prod	Active	CO_2	1	0
CU 3234	35007212010000	Oil Prod	Active	CO_2	1	0
CU 3261	35007352170000	Oil Prod	Active	CO_2	1	0
CU 3263	35007251640000	Oil Prod	Active	CO_2	1	0
CU 3271	35007352160000	Oil Prod	Active	CO_2	1	0
CU 3273	35007252580000	Oil Prod	Active	CO_2	1	0
CU 3274	35007253140000	Oil Prod	Active	CO_2	1	0
CU 3275	35007254040000	Oil Prod	Active	CO_2	1	0
CU 3312	35007360800000	Oil Prod	Active	CO_2	1	0
CU 3313	35007254370000	Oil Prod	Active	CO_2	1	0
CU 3314	35007254030000	Oil Prod	Active	CO_2	1	0
CU 3332	35007254020000	Oil Prod	Active	CO_2	1	0
CU 3381	35007360780000	Oil Prod	Active	CO_2	1	0
CU 3411	35007351700000	Oil Prod	Active	CO_2	1	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3412	35007351720000	Oil Prod	Active	CO_2	1	0
CU 3413	35007351730000	Oil Prod	Active	CO_2	1	0
CU 3414	35007005220000	Oil Prod	Active	CO_2	1	0
CU 3415	35007211170000	Oil Prod	Active	CO_2	1	0
CU 3416A	35007252590000	Oil Prod	Active	CO_2	1	0
CU 3451A	35007256710000	Oil Prod	Active	CO_2	1	0
CU 3471	35007351750000	Oil Prod	Active	CO_2	1	0
CU 3481	35007351710001	Oil Prod	Active	CO_2	1	0
CU 3491	35007254330000	Oil Prod	Active	CO_2	1	0
CU 3533	35007206880000	Oil Prod	Active	CO_2	1	0
CU 3562	35007255050000	Oil Prod	Active	CO_2	1	0
NPU 101	42357010440000	Oil Prod	Active	CO_2	1	0
NPU 103	42357010060000	Oil Prod	Active	CO_2	1	0
NPU 104	42357000050000	Oil Prod	Active	CO_2	1	0
NPU 207	42357302000000	Oil Prod	Active	CO_2	1	0
NPU 209	42357333830000	Oil Prod	Active	CO_2	1	0
NPU 501	42357009140000	Oil Prod	Active	CO_2	1	0
NPU 502	42357024100000	Oil Prod	Active	CO_2	1	0
NPU 601	42357008420000	Oil Prod	Active	CO_2	1	0
NPU 605	42357333840000	Oil Prod	Active	CO_2	1	0
NWCU 3-1	35007360850000	Gas Prod	Active	CO_2	1	0
NWCU 9-3	35007249430000	Oil Prod	Active	CO_2	1	0
CU 2172	35007354130000	Oil Prod	Inactive	CO_2	0	0
CU 2175	35007354160000	Oil Prod	Inactive	CO_2	0	0
CU 2473	35007211990000	Oil Prod	Inactive	CO_2	0	0
CU 2511	35007350790000	Oil Prod	Inactive	CO_2	0	0
CU 2711	35007359260000	Oil Prod	Inactive	CO_2	0	0
CU 2771	35007359850000	Oil Prod	Inactive	CO_2	0	0
CU 3142	35007222350000	Oil Prod	Inactive	CO_2	0	0
CU 3361	35007352670000	Oil Prod	Inactive	CO_2	0	0
NPU 205	42357008070000	Oil Prod	Inactive	CO_2	0	0
NPU 301	42357022080000	Oil Prod	Inactive	CO_2	0	0
NPU 801	42357004630000	Oil Prod	Inactive	CO_2	0	0
NPU 802	42357004620000	Oil Prod	Inactive	CO_2	0	0
NPU 804	42357201730000	Oil Prod	Inactive	CO_2	0	0
NPU 901	42357000660000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-2	35007350870000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-3	35007210790000	Oil Prod	Inactive	CO_2	0	0
NWCU 16-1	35007350720000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-1	35007360900000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-3	35007360920000	Oil Prod	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
NWCU 19-4	35007360930000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-5	35007360940000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-6	35007211250000	Oil Prod	Inactive	CO_2	0	0
NWCU 24-5	35007222710000	Oil Prod	Inactive	CO_2	0	0
NWCU 25-7	35007228000000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-3	35007360870000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-4	35007360880000	Oil Prod	Inactive	CO_2	0	0
NWCU 4-2	35007360740000	Oil Prod	Inactive	CO_2	0	0
NWCU 5-1	35007361050000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-1	35007360980000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-2	35007360990000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-1	35007360810000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-2	35007360820000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-3	35007208260000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-1	35007360950000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-2	35007360960000	Oil Prod	Inactive	CO_2	0	0
CU 1551	35007350740000	Oil Prod	P&A	CO_2	0	0
CU 1671	35007352180000	Oil Prod	P&A	CO_2	0	0
CU 2111	35007353560000	Oil Prod	P&A	CO_2	0	0
CU 2176	35007358870000	Oil Prod	P&A	CO_2	0	0
CU 2221	35007000490000	Oil Prod	P&A	CO_2	0	0
CU 2281	35007359220000	Oil Prod	P&A	CO_2	0	0
CU 2421	35007359350000	Oil Prod	P&A	CO_2	0	0
CU 2431	35007350330000	Oil Prod	P&A	CO_2	0	0
CU 2432	35007350340000	Oil Prod	P&A	CO_2	0	0
CU 2433	35007350350000	Oil Prod	P&A	CO_2	0	0
CU 2434	35007350360000	Oil Prod	P&A	CO_2	0	0
CU 2435	35007218800000	Oil Prod	P&A	CO_2	0	0
CU 2471	35007359080000	Oil Prod	P&A	CO_2	0	0
CU 2531	35007361090000	Oil Prod	P&A	CO_2	0	0
CU 2532	35007361100000	Oil Prod	P&A	CO_2	0	0
CU 2552	35007359760000	Oil Prod	P&A	CO_2	0	0
CU 2571	35007350730000	Oil Prod	P&A	CO_2	0	0
CU 2572	35007359320000	Oil Prod	P&A	CO_2	0	0
CU 2661	35007361990000	Oil Prod	P&A	CO_2	0	0
CU 2681	35007350320000	Oil Prod	P&A	CO_2	0	0
CU 2852	35007301360000	Oil Prod	P&A	CO_2	0	0
CU 2961	35007358760000	Oil Prod	P&A	CO_2	0	0
CU 2971	35007358750000	Oil Prod	P&A	CO_2	0	0
CU 2972	35007358780000	Oil Prod	P&A	CO_2	0	0
CU 3031	35007359560000	Oil Prod	P&A	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3051	35007300380000	Oil Prod	P&A	CO_2	0	0
CU 3064	35007254270000	Oil Prod	P&A	CO_2	0	0
CU 3141	35007359610000	Oil Prod	P&A	CO_2	0	0
CU 3181	35007359470000	Oil Prod	P&A	CO_2	0	0
CU 3251	35007352710000	Oil Prod	P&A	CO_2	0	0
CU 3331	35007200750000	Oil Prod	P&A	CO_2	0	0
CU 3451	35007351690000	Oil Prod	P&A	CO_2	0	0
CU 3511	35007359730000	Oil Prod	P&A	CO_2	0	0
CU 3531	35007350850000	Oil Prod	P&A	CO_2	0	0
CU 3532	35007359950000	Oil Prod	P&A	CO_2	0	0
CU 3534	35007211180000	Oil Prod	P&A	CO_2	0	0
CU 3561	35007359830000	Oil Prod	P&A	CO_2	0	0
CU 3571	35007359980000	Oil Prod	P&A	CO_2	0	0
CU 3581	35007359970000	Oil Prod	P&A	CO_2	0	0
CU 3631	35007301000000	Oil Prod	P&A	CO_2	0	0
CU 1672	35007352190000	Oil Prod	P&A	CO_2	0	0
CU 2351	35007350370000	Oil Prod	P&A	CO_2	0	0
CU 2474	35007228200000	Oil Prod	P&A	CO_2	0	0
CU 2812	35007352340000	Oil Prod	P&A	CO_2	0	0
CU 2871	35007359060000	Oil Prod	P&A	CO_2	0	0
NPU 102	42357021420000	Oil Prod	P&A	CO_2	0	0
NPU 201	42357001280000	Oil Prod	P&A	CO_2	0	0
NPU 302	42357022290000	Oil Prod	P&A	CO_2	0	0
NPU 402	42357022300000	Oil Prod	P&A	CO_2	0	0
NWCU 17-2	35007359620000	Oil Prod	P&A	CO_2	0	0
NWCU 10-1	35007361010000	Oil Prod	P&A	CO_2	0	0
NWCU 17-1	35007350710000	Oil Prod	P&A	CO_2	0	0
NWCU 19-7	35007224520000	Oil Prod	P&A	CO_2	0	0
NWCU 24-4	35007358770000	Oil Prod	P&A	CO_2	0	0
NWCU 25-6	35007358790000	Oil Prod	P&A	CO_2	0	0

Table A1.2 – Water Alternating Gas (WAG) Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 2662 (INJ)	35007362010000	WAG Inj	Active	CO_2	0	1
CU 2751 (INJ)	35007359440002	WAG Inj	Active	CO_2	0	1
CU 2762 (INJ)	35007213660000	WAG Inj	Active	CO_2	0	1
CU 2772 (INJ)	35007359860001	WAG Inj	Active	CO_2	0	1
CU 2811 (INJ)	35007352200000	WAG Inj	Active	CO_2	0	1
CU 2872 (INJ)	35007359070000	WAG Inj	Active	CO_2	0	1
CU 2962 (INJ)	35007212000000	WAG Inj	Active	CO_2	0	1
CU 2974 (INJ)	35007220770000	WAG Inj	Active	CO_2	0	1
CU 3114 (INJ)	35007206540000	WAG Inj	Active	CO_2	0	1
CU 3117 (INJ)	35007254000000	WAG Inj	Active	CO_2	0	1
CU 3161 (INJ)	35007359590002	WAG Inj	Active	CO_2	0	1
CU 3213 (INJ)	35007224570000	WAG Inj	Active	CO_2	0	1
CU 3233 (INJ)	35007206890000	WAG Inj	Active	CO_2	0	1
CU 3252 (INJ)	35007211020000	WAG Inj	Active	CO_2	0	1
CU 3262 (INJ)	35007206870000	WAG Inj	Active	CO_2	0	1
CU 3351 (INJ)	35007352680000	WAG Inj	Active	CO_2	0	1
CU 3371 (INJ)	35007360770000	WAG Inj	Active	CO_2	0	1
CU 3417 (INJ)	35007255060000	WAG Inj	Active	CO_2	0	1
CU 3461 (INJ)	35007351680000	WAG Inj	Active	CO_2	0	1
CU 3472 (INJ)	35007206940000	WAG Inj	Active	CO_2	0	1
CU 3551 (INJ)	35007359840000	WAG Inj	Active	CO_2	0	1
NPU 105 (INJ)	42357000030000	WAG Inj	Active	CO_2	0	1
NPU 107W (INJ)	42357333770000	WAG Inj	Active	CO_2	0	1
NPU 202WI (INJ)	42357021500000	WAG Inj	Active	CO_2	0	1
NPU 208 (INJ)	42357327410000	WAG Inj	Active	CO_2	0	1
NPU 701 (INJ)	42357008410000	WAG Inj	Active	CO_2	0	1
NPU 504 (INJ)	42357329480000	WAG Inj	Active	CO_2	0	1
NPU 604W (INJ)	42357330870000	WAG Inj	Active	CO_2	0	1
CU 1531 (INJ)	35007359990000	WAG Inj	Inactive	CO_2	0	0
CU 2131 (INJ)	35007362700000	WAG Inj	Inactive	CO_2	0	0
CU 2512 (INJ)	35007350780000	WAG Inj	Inactive	CO_2	0	0
CU 2641 (INJ)	35007359250001	WAG Inj	Inactive	CO_2	0	0
CU 2721 (INJ)	35007359870001	WAG Inj	Inactive	CO_2	0	0
CU 2741 (INJ)	35007359430000	WAG Inj	Inactive	CO_2	0	0
CU 2851 (INJ)	35007355420001	WAG Inj	Inactive	CO_2	0	0
CU 3032 (INJ)	35007359580000	WAG Inj	Inactive	CO_2	0	0
CU 3062 (INJ)	35007253090000	WAG Inj	Inactive	CO_2	0	0
CU 3112 (INJ)	35007359450001	WAG Inj	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 3172 (INJ)	35007251690000	WAG Inj	Inactive	CO_2	0	0
CU 3281 (INJ)	35007352700003	WAG Inj	Inactive	CO_2	0	0
CU 3311 (INJ)	35007360790000	WAG Inj	Inactive	CO_2	0	0
CU 3341 (INJ)	35007353530000	WAG Inj	Inactive	CO_2	0	0
NPU 203W (INJ)	42357008270000	WAG Inj	Inactive	CO_2	0	0
NPU 503 (INJ)	42357009150001	WAG Inj	Inactive	CO_2	0	0
NWCU 15-1 (INJ)	35007350860000	WAG Inj	Inactive	CO_2	0	0
NWCU 15-4 (INJ)	35007224510000	WAG Inj	Inactive	CO_2	0	0
NWCU 20-1 (INJ)	35007360760000	WAG Inj	Inactive	CO_2	0	0
NWCU 21-1 (INJ)	35007361020000	WAG Inj	Inactive	CO_2	0	0
CU 2271 (INJ)	35007359230000	WAG Inj	P&A	CO_2	0	0
CU 2311 (INJ)	35007362000000	WAG Inj	P&A	CO_2	0	0
CU 2472 (INJ)	35007359090000	WAG Inj	P&A	CO_2	0	0
CU 3061 (INJ)	35007359820000	WAG Inj	P&A	CO_2	0	0
CU 3512 (INJ)	35007359740000	WAG Inj	P&A	CO_2	0	0
NPU 204W (INJ)	42357022520000	WAG Inj	P&A	CO_2	0	0
NPU 206W (INJ)	42357022510000	WAG Inj	P&A	CO_2	0	0
NPU 401W (INJ)	42357004520000	WAG Inj	P&A	CO_2	0	0
NPU 602W (INJ)	42357020230000	WAG Inj	P&A	CO_2	0	0
NPU 603W (INJ)	42357201720001	WAG Inj	P&A	CO_2	0	0
NPU 803W (INJ)	42357201710000	WAG Inj	P&A	CO_2	0	0
NWCU 14-1 (INJ)	35007350530000	WAG Inj	P&A	CO_2	0	0
NWCU 3-2 (INJ)	35007360860000	WAG Inj	P&A	CO_2	0	0

Table A1.3 – Water Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU WSW 1	35007355430001	Wtr Inj	Active	CO_2	0	1
NPU W 1W	42357300050002	Wtr Inj	Inactive	CO_2	0	0
CU 2551	35007350750000	Wtr Inj	P&A	CO_2	0	0

Appendix 2 – Referenced Regulations

U.S. Code > Title 26, INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1, NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits >

Section 45Q ..... Credit for carbon oxide sequestration

OCC > Title 165: CORPORATION COMMISSION > UNDERGROUND INJECTION CONTROL

Section

165:10-5-1 .... Classification of underground injection wells
165:10-5-2 .... Approval of injection wells or disposal wells
165:10-5-3 .... Authorization for existing enhanced recovery injection wells and existing disposal wells
165:10-5-4 .... Application for approval of enhanced recovery projects
165:10-5-5 .... Application for approval of injection and disposal operations
165:10-5-6 .... Testing and monitoring requirements for injection wells and disposal wells
165:10-5-7 .... Monitoring and reporting requirements for wells covered by 165:10-5-1
165:10-5-8 .... Liquid hydrocarbon storage wells
165:10-5-9 .... Duration of underground injection well orders or permits
165:10-5-10 ..... Transfer of authority to inject
165:10-5-11 ..... Notarized reports
165:10-5-12 ..... Application for administrative approval for the subsurface injection of onsite reserve pit fluids
165:10-5-13 ..... Application for permit for one time injection of reserve pit fluids
165:10-5-14 ..... Exempt aquifers
165:10-5-15 ..... Application for permit for simultaneous injection well

165:5-7-27 .... Application for approval of injection and disposal wells
165:5-7-29 .... Request for exception to certain underground injection well requirements
165:5-7-30 .... Amending existing orders or permits authorizing injection for injection, disposal, or LPG storage wells

TAC > Title 16 - Economic Regulation> Part 1 TRRC > Chapter 3 – Oil and Gas Division >

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Appendix 4 – Abbreviations and Acronyms

2D – 2 dimensional
3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
ANSI – American National Standards Institute
API – American Petroleum Institute
AWT – All Well Test
ASTM - American Society for Testing and Materials
Bscf – billion standard cubic feet
B/D – barrels per day
bopd – barrels of oil per day
C4 – butane
C5 – pentane
C7 – heptane
C7+ - standard heptane plus
CCE – constant composition expansion
CCUS – carbon capture utilization and storage
CFA – Camrick Field Area
CFR – Code of Federal Regulations
cf – cubic feet
CH4 – methane
CO_2 – carbon dioxide
EOR – Enhanced Oil Recovery
EOS – Equation of State
EPA – US Environmental Protection Agency
ESD – Emergency Shutdown Device
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
H_2S – hydrogen sulfide
lb – pound
mD – millidarcy(ies)
MICP – mercury injection capillary pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MMB – million barrels
MMP – minimum miscible pressure
MMscf – million standard cubic feet
MMstb – million stock tank barrels
MRV – Monitoring, Reporting, and Verification
MMMT – Million metric tonnes
MT – Metric tonne

NIST – National Institute of Standards and Technology
NAESB – North American Energy Standards Board
OAC – Oklahoma Administrative Code
OCC – Oklahoma Corporation Commission
OOIP – Original Oil-In-Place
OWC – oil water contact
PPM – Parts Per Million
psia – pounds per square inch absolute
PVT – pressure, volume, temperature
QA/QC – quality assurance/quality control
RMS – root mean square
SEM – scanning electron microscope
SWP - Southwest Regional Partnership on Carbon Sequestration
TAC – Texas Administrative Code
TA – Temporally Abandoned/not plugged
TD – total depth
TM – Terminated order wells/UIC not plugged
TRRC – Texas Railroad Commission
TSD – Technical Support Document
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water
WAG – Water Alternating Gas (Gas is recycled CO_2 and purchase CO_2)
XRD – x-ray diffraction

Appendix 5 – Conversion Factors

CapturePoint reports CO_2 at standard conditions of temperature and pressure as defined in the State of Texas in the Texas Administrative Code for the Oil and Gas Division, Rule 3.79 as follows:

> Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit.

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at:

https://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At State of Texas standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.002641684 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2{,}204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2} = 0.002641684$$

$$MW_{CO2} = 44.0095$$

$$Density_{CO2} = 5.2734\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.2734\ x\ 10^{-2}\frac{MT}{Mcf}$$

The conversion factor 5.2734 x 10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Request for Additional Information: Camrick Unit
October 18, 2022

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	3.1	19-20	Per 40 CFR 98.449, "Maximum monitoring area (MMA) means the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." In the Request for Additional Information (RFAI) sent on September 1, 2022, EPA requested that the MRV plan clarify specific details regarding the expansion into other portions of the CFA which is mentioned in Section 3. Although your resubmitted MRV plan includes additional details on the projected injection volumes, please clarify whether the current delineated MMA accounts for the area expansions and any increased injection volumes. You may consider adding a clarifying statement, such as: "…***As delineated in this MRV plan, the MMA accounts for an injected volume of up to ____ Bscf and includes all areas of the CFA that could be utilized in the future for CO_2 injection. The MMA will contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. If there are any material changes to the monitoring/operational parameters not outlined in this MRV plan, the plan will be resubmitted in accordance with 40 CFR 98.448(d)(1).***" If the above is accurate for your facility, then please add a similar statement to the MRV plan to ensure it is clear what is accounted for in the current MMA. Otherwise, please clarify what is and is not accounted for in the current MMA.	Added the following "As delineated in this MRV plan, the MMA account for an injected volume of up to 140 Bscf and includes all areas of the CFA that could be utilized in the future for CO2 injection. The MMA will contain the free phase CO2 plume until the CO2 plume has stabilized plus an all-around buffer zone of at least one-half mile. If there are any material changes to the monitoring/operational parameters not outlined in this MRV plan, the plan will be resubmitted in accordance with 40 CFR 98.448(d)(1)."

2.	3.2	21	Per 40 CFR 98.449, "Active monitoring area" (AMA) is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile. (2) The area projected to contain the free phase CO_2 plume at the end of year t + 5. In the Request for Additional Information (RFAI) sent on September 1, 2022, EPA requested that you ensure that the discussion in section 3.2 clearly identifies the AMA boundaries and describes whether the AMA for the CFA presented in the MRV plan conforms to the definition of the AMA in 40 CFR 98.449. Although you added details on CO_2 injection at CFA, we are requesting a more direct statement regarding whether the AMA delineation meets the definition provided in in 40 CFR 98.449. Please note that the subpart RR definition of AMA is based on expected plume boundaries, not well locations or lease boundaries. You may consider adding a clarifying statement, such: "***…Based on our projections, CapturePoint expects the free phase CO2 plume to remain within the CFA for the entire length of the project and through year [t+5]. Therefore, CapturePoint is defining the AMA as the CFA plus an all-around one-half mile buffer, consistent with the definitions in 40 CFR 98.449. If there are any material changes to the monitoring/operational parameters not outlined in this MRV plan, the plan will be resubmitted in accordance with 40 CFR 98.448(d)(1).***" If the above is accurate for your facility, then please add a similar statement to the MRV plan to ensure it is clear whether the delineated AMA is consistent with Subpart RR definitions. Otherwise, please clarify and/or revise the AMA as necessary.	Added the following "Based on our projections, CapturePoint expects the free phase CO2 plume to remain within the CFA for the entire length of the project and through year [t + 5]. Therefore, CapturePoint is defining the AMA as the CFA plus an all-around one-half mile buffer, consistent with the definitions in 40 CFR 98.449. If there are any material changes to the monitoring/operational parameters not outlined in this MRV plan, the plan will be resubmitted in accordance with 40 CFR 98.448(d)(1)."

Camrick Field Area (CFA)

MONITORING, REPORTING AND VERIFICATION PLAN (MRV)

CapturePoint LLC

April 2022

Contents

INTRODUCTION

CapturePoint, LLC (CapturePoint) operates the Camrick Field Area (CFA) located in Beaver and Texas Counties, Oklahoma and in Ochiltree County, Texas for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) with retention of CO_2 serving a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The CFA was discovered in 1955 and is composed of three units, the Camrick Unit (CU) that was unitized by Humble Oil Company on October 14, 1969, the North Perryton Unit (NPU) that was unitized by Humble Oil Company on March 17, 1969, and the Northwest Camrick Unit (NWCU) that was unitized by Atlantic RichField Company on September 15, 1972. The Units were formed for the purpose of waterflooding with salt water sourced from the Wolfcamp formation. The field structure is a lenticular bedding sand trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. CapturePoint has been operating the CFA since 2017. CapturePoint acquired the CFA from Chaparral Energy LLC, which initiated the CO_2-EOR project in March 2001 for the CU and January 2007 for the NPU. No CO_2 has been injected in the NWCU. CapturePoint intends to continue CO_2-EOR operations until the end of the economic life of the CO_2-EOR program using various Class II injection wells as defined by Underground Injection Control (UIC) regulations and permitted under Texas Railroad Commission (TRRC) Rule 46 of the Texas Administrative Code (TAC) and the Oklahoma Corporation Commission (OCC) Title 165:10 of the Oklahoma Administrative Code (OAC). In this document, the term “gas” means a mixture of hydrocarbon light end components and the CO_2 component that can be produced as part of the EOR process.

CapturePoint has chosen to submit this Monitoring, Reporting, and Verification (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 (GHGRP) for the purpose of qualifying for the tax credit in section 45Q of the federal Internal Revenue Code.

This MRV Plan contains ten sections:

Section 1 contains facility information.

Section 2 contains the project description including: a detailed description of the injection operation including the duration and volume of CO_2 to be injected; a detailed description of the geology and hydrogeology of the CFA located on the northwest shelf of the Anadarko basin; and a detailed characterization of the injection reservoir modeling techniques employed.

Section 3 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449 and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 4 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. This section also describes the strategy for detecting, verifying, and quantifying any surface leakage of CO_2 as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Finally, this section also demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

Section 5 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 6 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 9 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 10 includes Appendices supporting the narrative of the MRV Plan.

1 Facility

1.1 Reporter Number

The CU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544678 and the NPU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544679. The EPA has been notified that the NPU will not be reporting for 2022, and that the facility has been merged into the Camrick Unit Facility Identification number 544678.

1.2 UIC Permit Class

For injection wells (see Appendix 2) that are the subject of this MRV plan, the OCC has rules governing UIC Class II injection wells. These OCC rules are OAC Title 165:10-5-1 through 165:10-5-15, OAC 165:5-7-27, OAC 165:5-7-30, the request for an exception to UIC rules under OAC 165:5-7-29, and other governing filing forms. Also, the TRRC has issued UIC Class II enhanced recovery permits under its Rule 46, TAC Title 16 Part 1 Chapter 3. All wells in the CFA, including both injection and production wells, are regulated by the OCC and the TRRC, which have primacy to implement the UIC Class II program.

1.3 UIC Injection Well Numbers

A list of the injection wells in the CFA is provided in Appendix 1. The details of the injection process are provided in Section 2.3.

2 Project Description

2.1 Project Characteristics

2.1.1 Estimated years of CO_2 injection

The CFA has been injecting CO_2 for the last 20+ years and it is currently projected that CapturePoint will inject CO_2 for an additional 12 years.

2.1.2 Estimated volume of CO_2 injected over lifetime of project

Historical and forecasted cumulative CO_2 retention volumes are approximately 100 billion standard cubic feet (Bscf) or 5.3 million metric tonnes (MMMT) from the start of CO_2

injection through October 2034. During the MRV plan, the period September 2022 through October 2034, 52.5 Bscf or 2.77 MMMT will be stored in the CFA. (See Figure 2.4-6)

2.2 Environmental Setting of MMA

2.2.1 Boundary of the MMA

CapturePoint has defined the boundary of the MMA as equivalent to the boundary of the CFA plus ½ mile beyond. A discussion of the methods used in delineating the MMA and the AMA are presented in Section 3.

2.2.2 Geology

The geological discussions in Sections 2.2.2 and 4.3-4.4 are based on analysis of logs from both the Farnsworth Unit, which is located 10 miles South-South-West of the CFA, and the CFA. Both areas have similar pay thickness, porosity values, permeability measurements, depositional environment, tectonic processes, and overburden strata layers. The descriptions of cores at the Farnsworth Unit included sections from overlying seals as well as the shale underlying the main reservoirs, petrographic thin section descriptions and point counts as well as a variety of special analytical techniques. These techniques included X-ray diffraction (XRD), which is the science of determining the atomic and molecular structure of rock crystals with an X-ray beam; scanning electron microscope (SEM) analysis, which uses a beam of electrons to define the surface of crystals; carbon isotope analysis to estimate the age of the CO_2 in the sample; and a variety of mechanical tests. Two dimensional (2D) and three dimensional (3D) geophysical surveys were also used as part of the Farnsworth Unit MRV Plan (2021). Details of recent geological investigations can be found in Gallagher (2014), Gragg (2016), Rasmussen et al (2019), Rose-Coss et al (2015), Trujillo (2018), Hobbs et al (2019), and Gragg et al (2018).

2.2.2.1 Tectonic Setting and Stratigraphy

The CFA is located on the northwest shelf of the Anadarko basin (Figure 2.2-1) and is one of many oil fields in the area that produce from a sequence of alternating sandstones and mudstones deposited during the late Pennsylvanian Morrowan period. Oil production and CO_2 injection at CFA is restricted to the operationally named Morrow B sandstone; the uppermost Morrow sandstone encountered below the Atokan Thirteen Finger limestone. The primary caprock intervals at CFA are comprised of the upper Morrow shale and the Thirteen Finger limestone (Figure 2.2-2). The Morrowan and Atokan intervals were deposited approximately 315-300 million years ago. Overlying stratigraphy includes late Pennsylvanian through the middle Permian shales and limestones, with lesser amounts of dolomite, sandstone and evaporites (Ball, 1991). The reservoir is approximately 60 feet thick throughout the field and lies at a depth of approximately 6,800-7,600 feet. The primary seal rocks of the Morrow shale and the Thirteen Finger Limestone comprise a package of approximately 180-200 feet thick in the field and are overlain by thousands of feet of Atokan and younger limestones and shales.

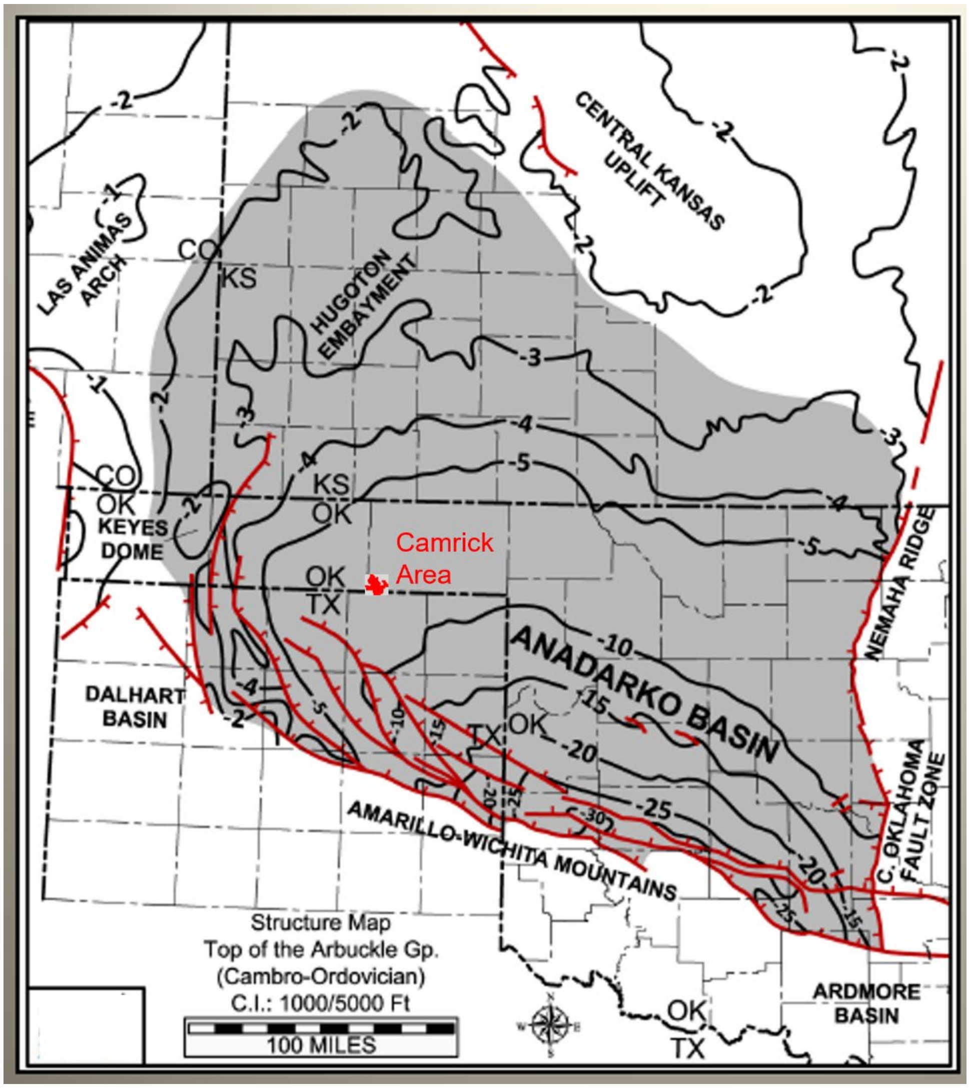

Figure 2.2-1. Location of the CFA on the Northwest Shelf of the Anadarko Basin in West Texas. Red lines are approximate locations of faults that have been documented in the region.

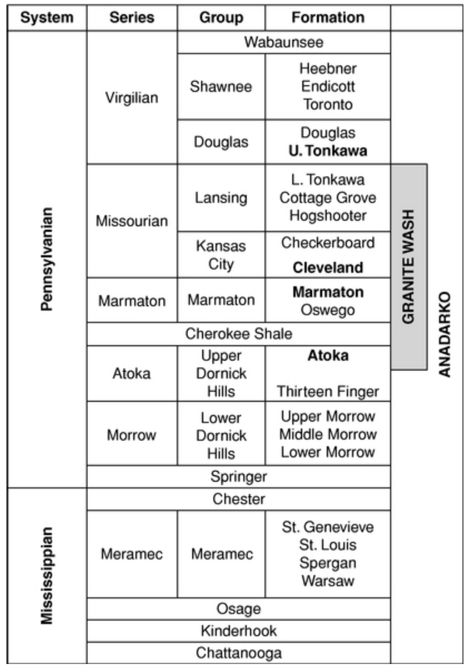

Figure 2.2-2. Stratigraphic section.

Tectonic Setting

From CFA's location on the western edge of the basin, the Anadarko Basin plunges to the southeast (Figure 2.2-3) where it reaches depths of over 40,000 feet (12,192 meters) adjacent to the Amarillo-Wichita Uplift (Perry, 1989). Maximum rates of subsidence occurred during Morrowan to Atokan times (Evans, 1979; Perry, 1989; Higley, 2014). Positive features that might have influenced deposition within the region include the Ancestral Rockies to the north, the Central Kansas uplift to the northeast, and the Wichita-Amarillo uplift to the south (Evans, 1979; Munson, 1989). Of note is the fact that during the Pennsylvanian time, the CFA was located on the basin shelf in an area that was not affected greatly by tectonic deformation. Although faults have been reported previously in the northwest Anadarko Basin, we found no direct evidence for tectonic faults within the CFA (see Section 4).

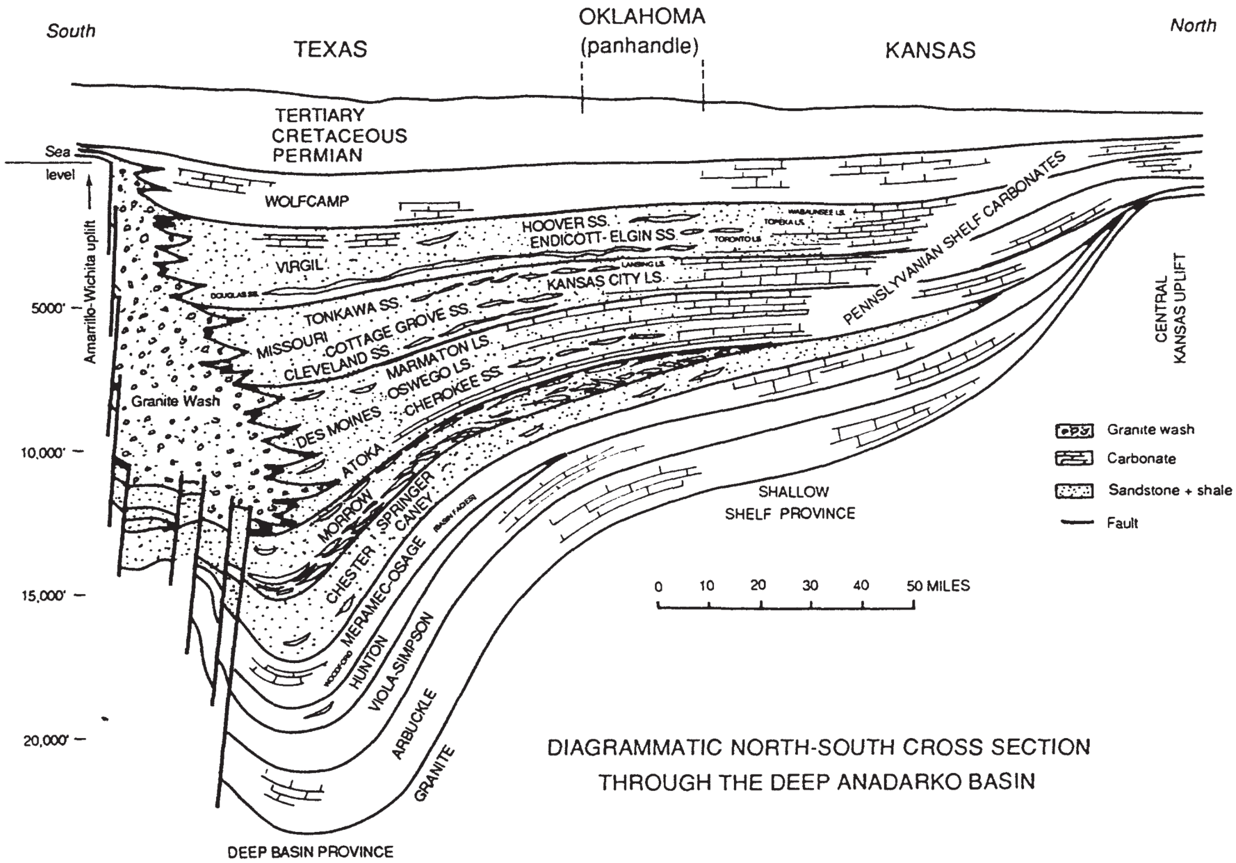

Figure 2.2-3. Diagrammatic North-South Section (Bottom) of the CFA.

Stratigraphy

Reservoir

Upper Morrowan sandstones in the Anadarko Basin margins have long been recognized as fluvial deposits (Swanson, 1979; Sonnenberg, 1985; Munson, 1989; Krystinik and Blakeney, 1990; Bowen et al., 1990; Al-Shaieb et al., 1995; Mckay and Noah, 1996; Puckette et al., 1996; Bowen and Weimer, 2003, 2004; Devries 2005; Puckette et al., 2008; Gallagher, 2014). At the Farnsworth Unit and similarly at the CFA, the Morrow B is described as a relatively coarse-grained subarkosic sandstone. The upper Morrowan facies, with sequences of basal conglomerate, coarse-grained sandstone, and fine-grained sandstone appear to be typical of incised valley deposits, as described by Wheeler et al. (1990), Krystinik and Blakeney (1990), Bowen et al. (1990), Blakeney et al. (1990), Sonnenberg et al. (1990) and Puckette et al. (2008).

Primary Seals

The Morrow B sandstones are encased above and below by shales. Contacts with shale both below and above the sandstone are sharp and irregular. The Morrow shale generally fines upwards in a series of thin beds that alternate between upper fine sands and fine to medium muds. Sand content decreases upwards through the section.

The Thirteen Finger limestone formation has two different lithofacies: diagenetic limestone (cementstone) and pyrite and fossil bearing fine to medium mudstone and coal. The two facies are intercalated with each other but tend to cluster in layers dominated more by one or the other.

The entire Thirteen Finger interval is typically 130 feet (39.6 meters) thick, comprised of mudstone, coal, and limestone. The mudstone is calcite rich, with some dolomite, and is completely diagenetic in origin and probably formed relatively soon following deposition.

2.2.2.2 Hydrogeology

Information about Morrowan and Atokan formation water flow during oil operations has not been discovered in any oil or gas company published reports or academic research studies in the Anadarko Basin. Groundwater flow rates in confined deep Anadarko layers at present are considered to be low to no flow (Nelson and Gianoutsos, 2014). Their arguments are based on (1) restricted recharge in the western basin, (2) density barriers to flow in the east, and (3) an overpressure pocket inhibiting flow in the deep basin. Jorgenson (1989) suggested flow could be west to east, driven by potential recharge to elevated units in the west and discharge at lower elevation outcrops in the east. The CFA CO_2 injection and production operations have negligible likelihood of causing water to flow to outcrops of the late Carboniferous (Pennsylvanian) time period that extend from Brownwood, Texas, to the Jacksboro/Bowie, Texas, area, which are hundreds of miles away (The Paleontology Portal).

The Carboniferous is a geologic period and system that covers 60 million years from the Devonian Period 358.9 million years ago, to the beginning of the Permian Period, 298.9 million years ago. As noted in the Section 2.2.2.1, the Morrowan and Atokan intervals of the CFA were deposited approximately 315-300 million years ago and are contained in the Carboniferous period.

2.3 Description of the Injection Process

Figure 2.3-1 depicts a simplified flow diagram of the facilities and equipment within the boundaries of the CFA. CO_2 captured from the ethanol plant fermentation process is delivered via pipeline to the field for injection. The Arkalon plant in Liberal, Kansas is the only source of CO_2 to the field. The amount delivered is dependent on the production of CO_2 produced from the fermentation process. This amount will vary but should average 12 MMCFD. Once CO_2 enters the CFA there are three main processes involved in EOR operations. These processes are shown in Figure 2.3-1 and include:

1. CO_2 distribution and injection. Purchased CO_2 is combined with recycled CO_2 from the CFA central tank battery (CTB) and sent through the main CO_2 distribution system to various water alternating gas (WAG) injectors.

2. Produced Fluids Handling. Full well stream fluids are produced to the “all well test” (AWT) site. The AWT site has two major purposes; 1) to individually test a well’s performance by separating and metering oil, gas, and water, and 2) to separate all gas from liquid then send these two phases to the CTB for final separation; while only the gas from NPU is sent to the CTB the NPU oil and water remains in Texas.

3. Produced Gas Processing. All gases from the AWT sites are transferred to the CTB to separate the oil, gas, and water using a series of vessels and storage tanks.

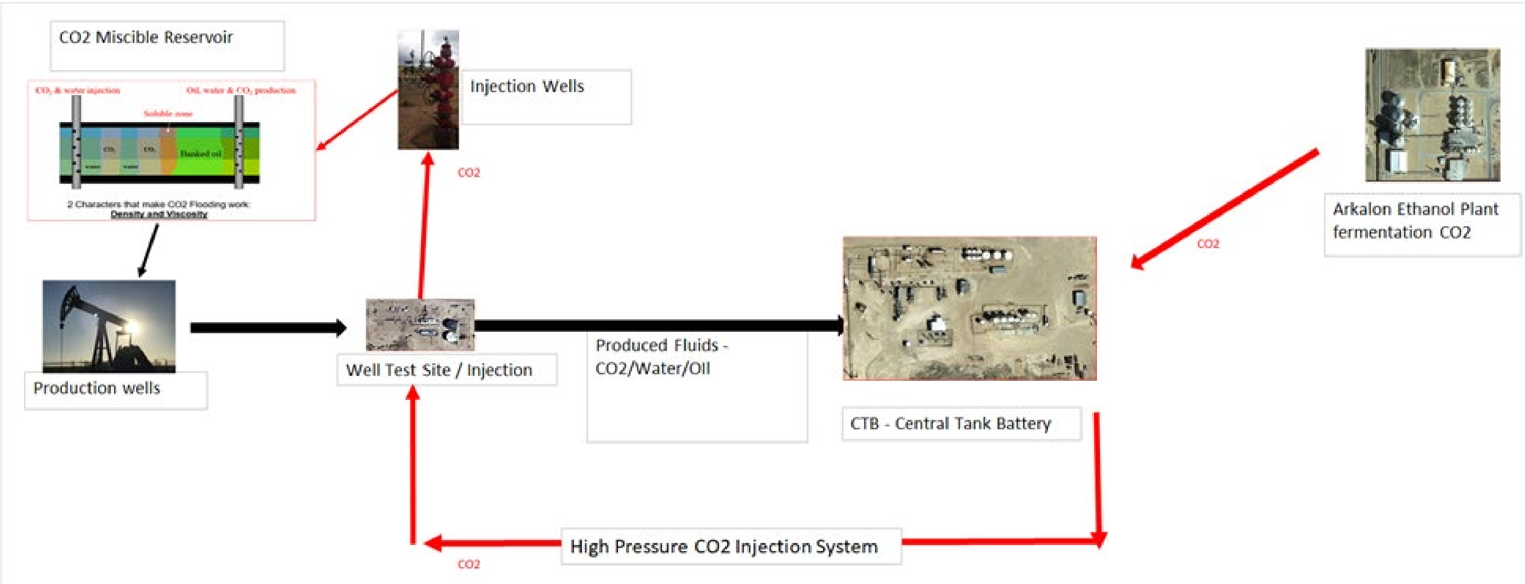

Figure 2.3–1. Simplified flow diagram of the facilities and equipment within the boundaries of the CFA.

2.3.1 CO_2 Distribution and Injection

CapturePoint purchases CO_2 from Conestoga Energy Partners, the parent company of the Arkalon Ethanol plant located in Liberal, Kansas. A custody transfer meter is located in the compression facility owned and operated by CapturePoint. The purchased CO_2 from the fermentation process is transported via a United States Department of Transportation (DOT) regulated pipeline to the CFA. A totalizer meter, for the purchased CO_2, is located in the field where instantaneous data is summed into a 24-hour flow rate which is recorded. A totalizer meter is a meter approved by the American Gas Association (AGA) Report #3 to measure the flowrate of gases. The actual measurements taken are temperature, line pressure, and differential pressure across the meter. Gas produced, which contains recycled CO_2, from the wells is compressed and metered by a similar totalizer meter as the purchase CO_2 meter and is recorded daily.

CapturePoint currently has seven active injection manifolds and approximately 29 active injection wells that the CO_2 is distributed through. When the MRV plan becomes active, the daily injection volume of the combined purchased CO_2 and recycled CO_2 will be approximately 24 MMCFD. Of this volume 12 MMCFD is purchased CO_2 and 12 MMCFD is recycled CO_2. This ratio of purchased CO_2 to recycled CO_2 is expected to change over time, with the percentage of recycled CO_2 increasing and purchased CO_2 decreasing. The current reservoir management plan projects that CO_2 purchases will remain constant at 12 MMCFD for 12 years and cease after 2034. A reservoir management plan is an integrated process using various surveillance techniques, economic evaluations, and accepted petroleum technical practices to efficiently operate enhanced oil recovery projects.

The seven injection manifolds currently in the field distribute the CO_2 to the field. These manifolds have valves to switch to water when the time is called for. Depending on the reservoir management plan, the WAG cycle will be adjusted to maximize oil recovery and minimize CO_2 utilization in each injection pattern. At each injection well pad there is a totalizer to measure the volumes injected every 24 hours. This data is collected daily by the field personnel and input into the data warehouse to be allocated for the pattern injection.

The two totalizer meters as described above will be used to determine the total volume injected used in section 7 for the mass balance equations necessary to determine annual and cumulative volumes of the stored CO_2.

2.3.2 Produced Fluids Handling

As injected CO_2 and water migrate through the reservoir; a mixture of oil, gas, and water (referred to as "produced fluids") flows to the production wells. Gathering lines bring the produced fluids from each production well to the AWT sites. CapturePoint has approximately 32 active production wells producing at any time. Each AWT has two separators. The first separator is used for testing individual wells to separate the gas, oil, and water produced from an individual well. This gas, oil, and water is subsequently measured and recorded for the well. Each producing well is production tested every 30 to 60 days after the last production test, or after the well is returned to production. Depending on the reservoir management plan, well testing can be more frequent to obtain data. The second separator is used to separate the gas from the oil/water mixture from the other wells producing into the AWT, and the gas and liquids are displaced from the vessel in separate lines. Leaving the AWT sites are two lines transporting produced fluids. One line is used for the liquid phase, a mixture of oil and water, and one line is used for the gas phase. However, the AWT in NPU does not transfer oil or gas to the CTB, it only transfers gas while reinjecting water with pumps at the NPU AWT and sells oil at the NPU AWT.

When gas and liquid lines enter the CTB, a series of vessels separate the oil, gas, and water to be accounted for and distributed for sales or reinjected. The liquid phase line has vessels to separate the oil from the water using density and residence time. The gas phase vessels collect any free liquids entrained with the gas. These free liquids are then combined back into the liquid phase line. All gas and water are reinjected, and the oil, which contains an estimated 2,360 ppm CO_2 (0.236%) for CU and 4,540 ppm CO_2 (0.454%) for NPU, is sold out of tanks. Annually, the oil from the stock tank is analyzed by a laboratory using ASTM crude oil analysis methods to determine the CO_2 content in the oil being sold.

After separation, the gas phase, which is approximately 92-95% CO_2, is mixed with reservoir volatile components, compressed, and distributed throughout the high-pressure distribution system using reciprocal compression and high-pressure horizontal pumps.

The water is transferred from the separation vessels to tanks for reinjection. After the water is conditioned, it is either reinjected at the WAG skids or disposed of into permitted disposal wells. Although CapturePoint is not required to determine or report the amount of dissolved CO_2 in the water as it is reinjected into the ground and not emitted to the atmosphere, the analyses have shown the water typically contains <690 ppm (0.069%) CO_2.

CFA production has trace amounts of hydrogen sulfide (H_2S), which is toxic. There are approximately 8-10 workers on the ground in the CFA at any given time, and all field and contractor personnel are always required to wear H_2S detectors. The primary purpose of the H_2S detectors is protecting people from the risk of being harmed. The detection limit of the H_2S detectors is quantified for readings in the range of 0-100 ppm and will sound an alarm above 10 ppm. The secondary purpose of the H_2S detectors would be to provide an indication of emissions of gas from a pipeline or surface equipment, that might go unnoticed by other observations or measurements. No gas volumes can be calculated based on the detector reading or alarm; only a H_2S leakage is detected and located. Once identified, a further response will be initiated and CO_2 volumes will be quantified as discussed in sections 4.5, 4.6, 5.4, and 8.1.5 of this MRV plan.

2.3.3 Produced Gas Handling

Produced gas separated at the CTB is stripped by a series of vessels of entrained and free water. The water content has been recorded to be < 20 pounds mass per MMCF, thus dehydration is not necessary. The gas is then sent to a centralized compression system to be compressed and placed in the high-pressure distribution system. This compression turns the CO_2 into a variable density liquid, which is then transported out via high pressure lines to the AWT sites where a manifold splits this dense CO_2 to the wells that are on CO_2 injection at that time.

2.3.4 Facilities Locations

The locations of the AWT sites are positioned in the field to access both injection distribution and production gathering. The CTB is where the final separation and injection equipment is maintained and operated. The water injection station is where the horizontal pumps are located to reinject the produced brine.

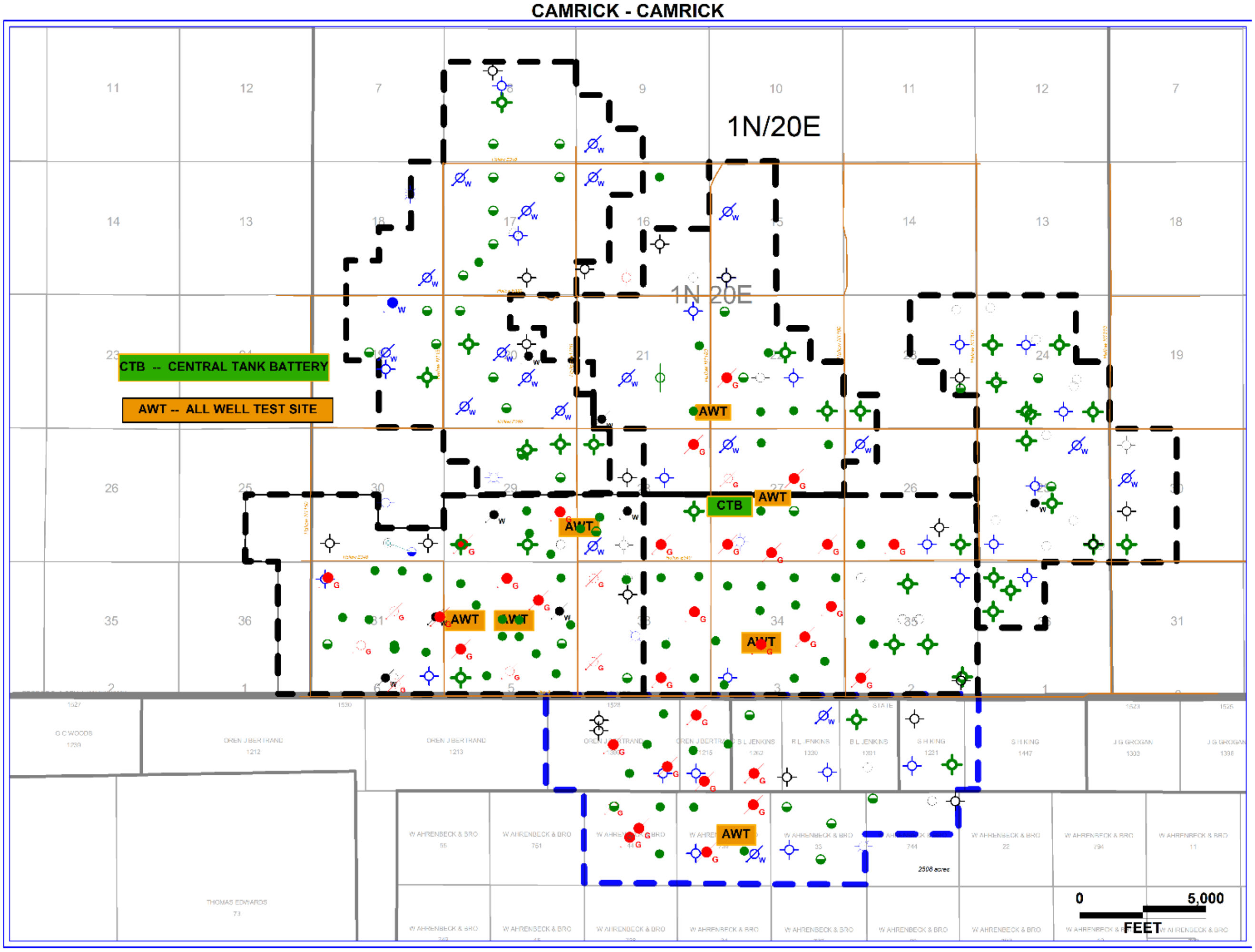

Figure 2.3-2. Location of AWT sites and CTB in the CFA

2.3.5 Water Conditioning and Injection

Produced water collected at the CTB is collected in a series of vessels and tanks in a cascade system. This allows any entrained oil to further separate to the top of the tanks because of the density difference. This oil is skimmed off and put back in the oil separation system. The clean water is then transferred to the water injection system where it is boosted in pressure and sent out to the AWT sites for distribution to all wells that are currently on water injection.

2.3.6 Well Operation and Permitting

The OCC and TRRC rules (Appendix 2) govern well location, construction, operation, maintenance, and plugging for all wells in permitted units and wells. CapturePoint follows these rules and regulations to maintain safe and efficient operations. This includes complying with all current and updated information for mechanical integrity testing, well repairs for injection wells, drilling and completion, permitting, and reporting.

Briefly, the following bulleted list is what the current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface waters.
- That wells file a completion report including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore).
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.
- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location, and setting of plugs.

2.3.7 Number, Location, and Depth of Wells

CapturePoint's CFA injection wells are listed in Appendix 1. Injection is into the Upper Morrowan, a lenticular bedded sandstone trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. The Upper Morrowan is described in section 2.2.2.1 above.

2.4 Reservoir Characterization

2.4.1 Reservoir Description

The target reservoir CFA Morrow B is a sandstone formation overlain by the Morrow shale and the Thirteen Finger limestone, which serve as excellent seals for injected CO_2 as determined by Farnsworth data (Ampomah et al., 2016a). The Morrow B sandstone reservoir is at a depth between 6,800 feet and 7,600 feet subsurface with an average dip of less than one degree (Figure 2.4-1). The productive limit of the CFA is about 80 to 90 percent of the total operated surface acreage, which is 14,652.315 acres. The maximum pay thickness is 56 feet with an average of 15 feet and does diminish to zero in spots.

The CFA is approximately eight miles by seven miles with areas that exhibit different reservoir behavior. The southwest portion of CU was most prolific oil producing area of the CFA under primary and secondary production; whereas the western portion of NPU is now responding to CO_2 better than historical operations would have indicated.

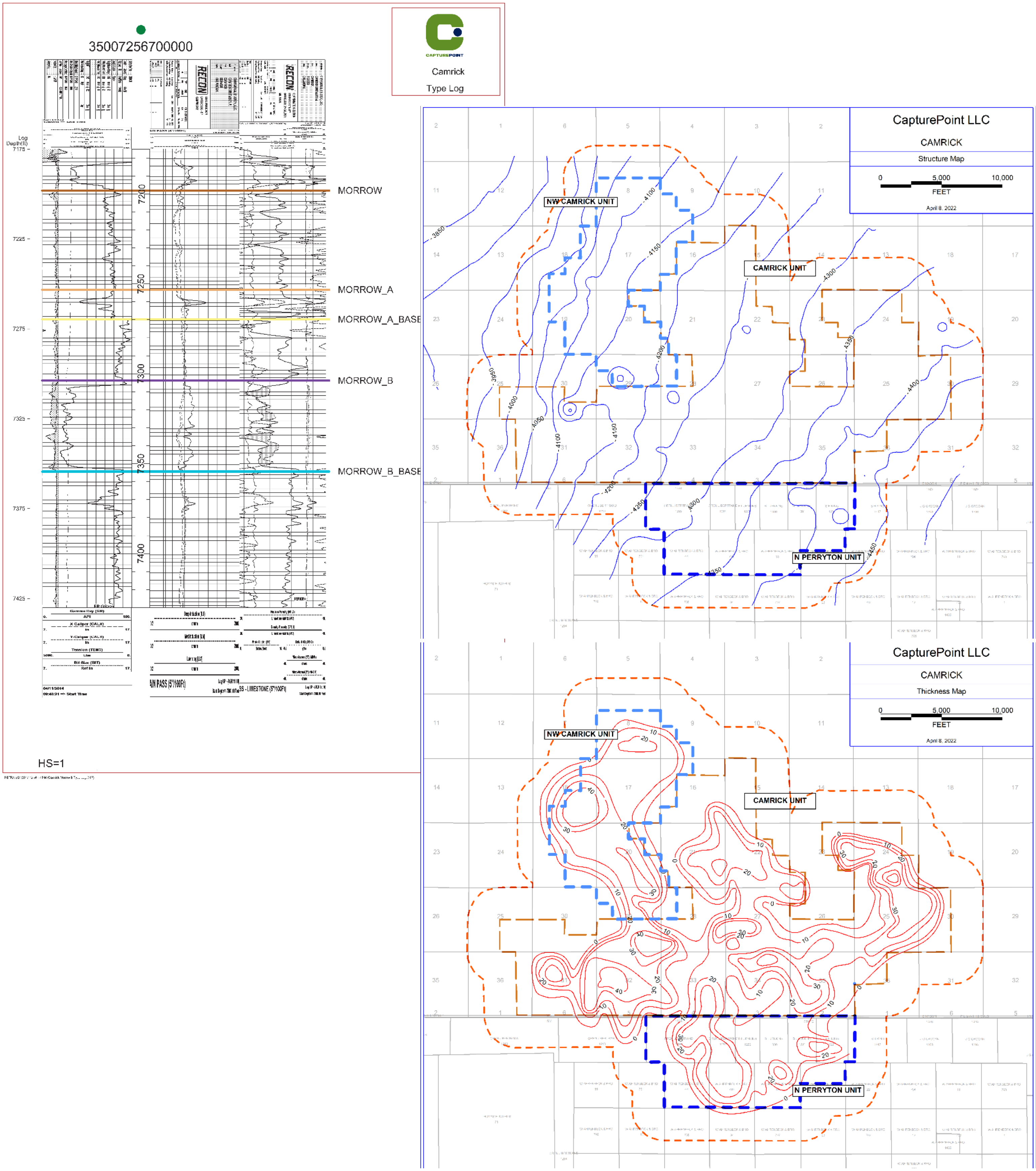

Figure 2.4-1. (Left) Type log of CFA caprock and reservoir, (Upper Right) Surface contour of Morrow top, (Lower Right) Thickness map of Morrow sands.

2.4.2 Reservoir Fluid Modeling

The compositional fluid model was constructed for the CapturePoint operated Farnsworth Unit. From laboratory compositional analysis an equation of state was tuned (Gunda et al., 2015). The minimum miscibility pressure (MMP) experiment was then simulated using a one-dimensional model. The simulated Farnworth Unit MMP of 4,009 psia compared to an MMP value of 4,200 psia derived from laboratory experiments provided by the operator represents a less than 5% error (Gunda et al., 2015).

The reservoir temperature in the CFA is 152 degrees Fahrenheit or 16 degrees lower than the temperature at Farnsworth Unit of 168 degrees. Using parameters of the Alston empirical correlation (1985), the MMP would be 170 psia lower at the CFA or 3,510 psia compared to 3,680 psia at the Farnsworth Unit (Figure 2.4-2).

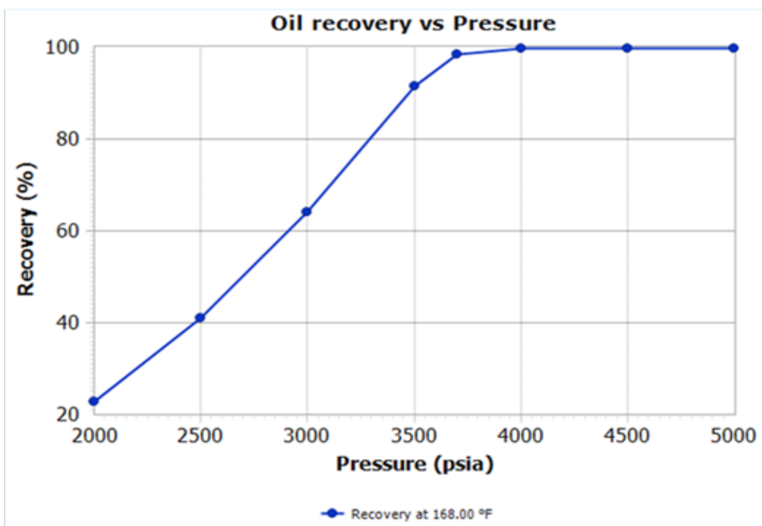

Figure 2.4-2. Oil recovery plot for 1D slim tube test for Farnsworth Unit.

2.4.3 CO_2 Analogy Field Study

Based on similar geologic, petrophysical, engineering, and operational parameters between the Farnsworth Unit and the CFA, the oil recovery performance of both fields is expected to be similar. Due to the stratigraphic nature of the Morrow channel sands, the potential movement of CO_2 is severely limited. The CFA area has contained the free phase CO_2 plume in a very confined area since March 2001 as exhibited by oil, water, and CO_2 recovery performance. Also, during CFA drilling and production operations, no reports exist which would indicate any plume has moved outside of the MMA. The Farnsworth Unit MRV and the CFA data justifies the conclusion that CO_2 will continue to be contained inside the MMA at the end of the CO_2 injection year t + 5, per §98.449 definitions.

2.4.4 CO_2 – EOR Performance Projections

For years, the oil industry has used dimensionless equations to predict the amount of oil that can be recovered using CO_2 for flooding oil reservoirs (Lee et al, 2018, Stell 2010). The

amount of oil recovered from projects is plotted as a decimal fraction of the original-oil-in-place versus the decimal fraction of the hydrocarbon pore volume (HPV) of CO_2 injected into the oil reservoir as measured in reservoir barrels (RB).

The CFA has been injecting CO_2 since March 2001. The dimensionless curves were matched to historical performance through early 2020 (Figure 2.4-3). The supply of CO_2 was curtailed from March 2020 until present, due to oil price uncertainty, and will resume after the Arkalon Plant upgrade that will be finished in the 4th quarter of 2022.

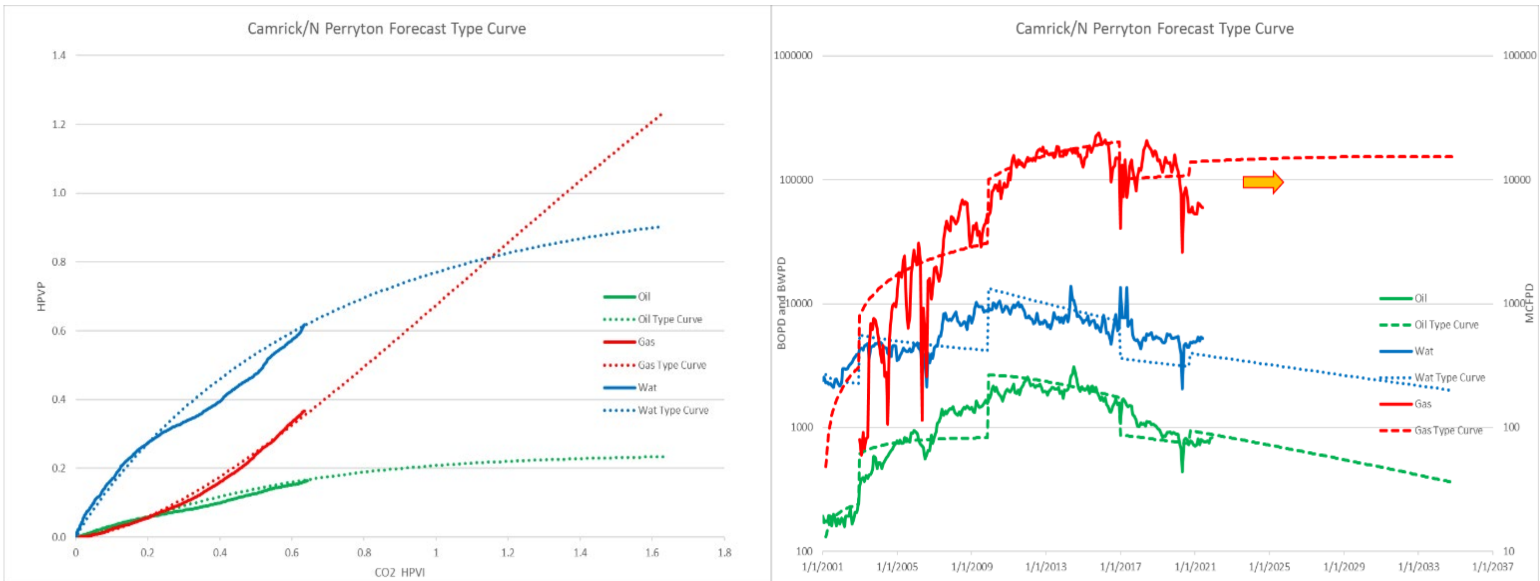

Figure 2.4-3. Dimensionless curves for CO_2 injection (left) with rate time curves (right).

The dimensionless water oil ratio and the gas oil ratio trends (Figure 2.4-4) for the CFA flooded acreage are very similar to what was forecasted by simulation in the Farnsworth Field as expected because of the porosity, permeability, and sand similarities.

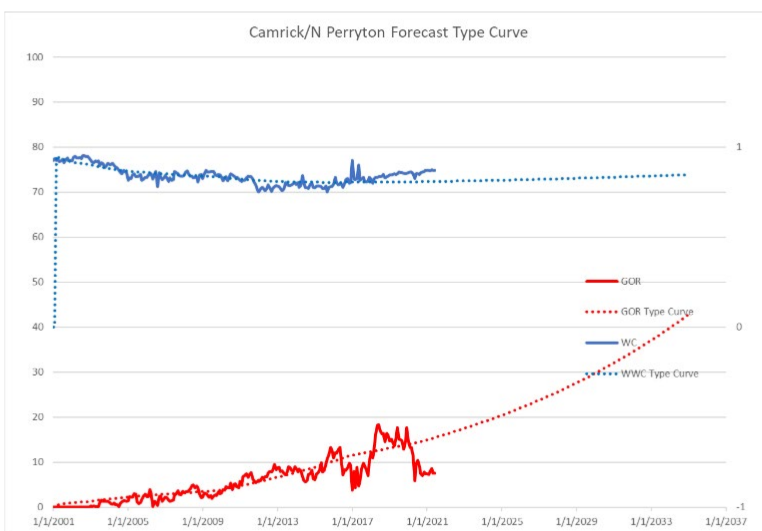

Figure 2.4-4. Dimensionless water cut and GOR vs. observed EOR data.

The CO_2 storage volumes for Arkalon fermentation CO_2 were also forecasted (Figure 2.4-5) using the same dimensionless technique. This technique indicates that the flooded acreage still has significant additional storage potential. The maximum CO_2 storage is limited to the amount of space available by the removal of the produced hydrocarbon. The projection indicates that there is pore space available to store approximately 0.4 to 0.5 decimal fraction of HPV amounting to 30 to 40 MMB.

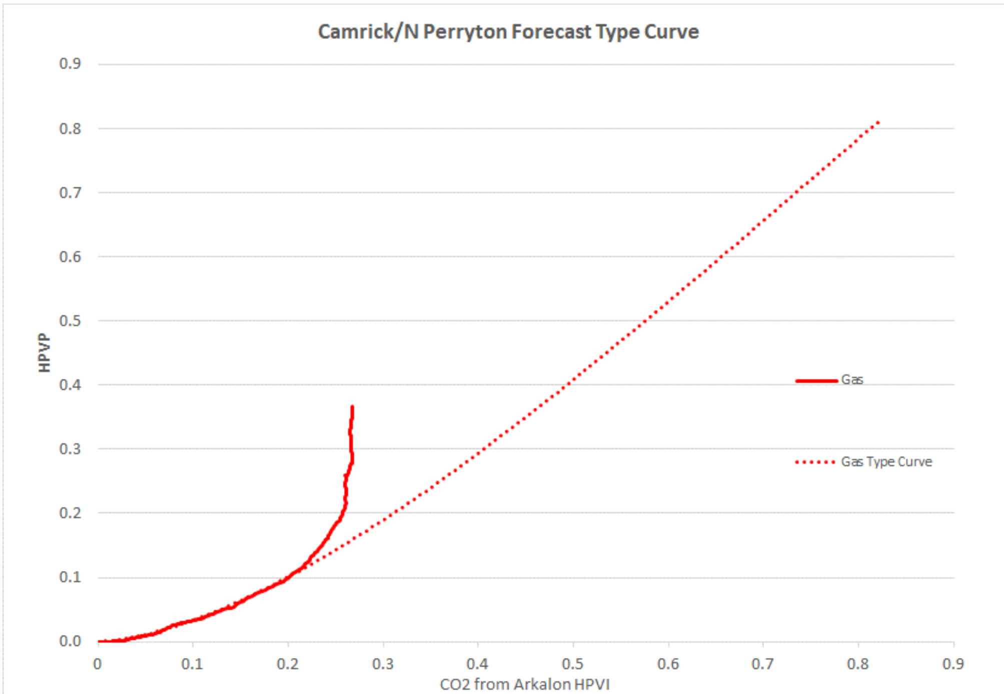

Figure 2.4-5. Dimensionless CO_2 Purchase (Fermentation) Curves

The barrels of reservoir volume were converted to standard cubic feet of gas and is displayed in the CFA Purchase CO_2, or Fermentation CO_2, vs Time chart (Figure 2.4-6).

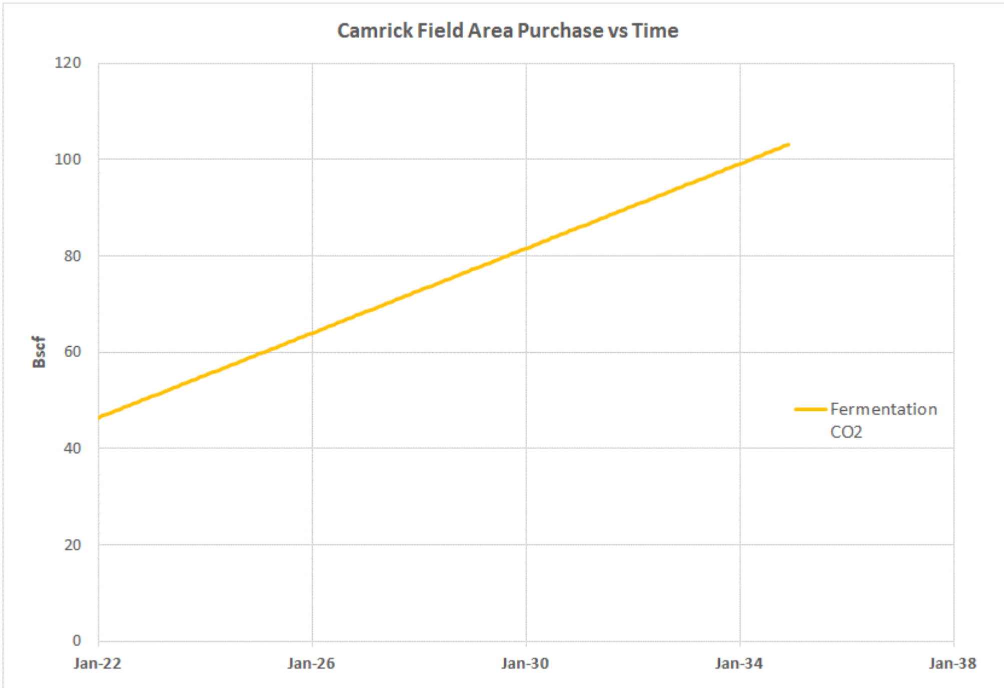

Figure 2.4-6. CO_2 Purchase (Fermentation) Volume.

3 Delineation of Monitoring Area

3.1 MMA

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The purchase volumes that are displayed in Figure 2.4-6 were mapped and are displayed in Section 3.1.1 indicating that CO_2 storage pore space is available, barring unforeseen future operational issues. Therefore, CapturePoint is defining the MMA as the boundary of the CFA plus an additional one-half mile buffer zone. This will allow for operational expansion throughout the CFA for the next 12 years, the anticipated life of the project.

3.1.1 Determination of Storage Volumes

Figure 3.1-1 displays wells that have CO_2 retention on the developed 4,800 acres that have been under CO_2 EOR injection in the CFA since project initialization (14,652.315 acres are in the CFA). The volume of the oil recovered since August 1955, resulted in a voidage space of 36 MMscf of CO_2 per acre of surface area that was later filled with water during waterflood operations. The average decimal fraction of CO_2 injection to hydrocarbon pore volume left in the ground after accounting for CO_2 production through 2021 is 0.29. The lateral extent of CO_2 in the injection zone or the CO_2 storage radius for each well was estimated based on cumulative CO_2 injected times the decimal fraction of CO_2 remaining divided by the voidage space. The largest CO_2 storage areas are around wells that injected the largest volume CO_2.

Figure 3.1-2 displays the potential area of the reservoir that can be filled with CO_2 with the existing injection wells. This assumed that only 78 percent of the average injection pattern area or 80 acres per pattern can be filled. The volumetric storage capacity calculated for the 49 patterns identified for continued injection indicates an additional 90 Bscf of CO_2 can be stored and with 50 Bscf already stored results in 140 Bscf of total storage. With the anticipated 12 MMCFD rate of purchased CO_2, this storage volume will only be 60 percent utilized.

Areas that do not have CO_2 storage posted on Figure 3.1-2 will be evaluated if existing CO_2 injection operations experience any rate restriction or develop any operational issues in the future. If necessary, replacement wells or additional injection locations in inactive areas of the CFA will be drilled or activated. This will be accomplished by utilizing existing plugged and abandoned wells or redrilling old locations as described in Section 3.2.

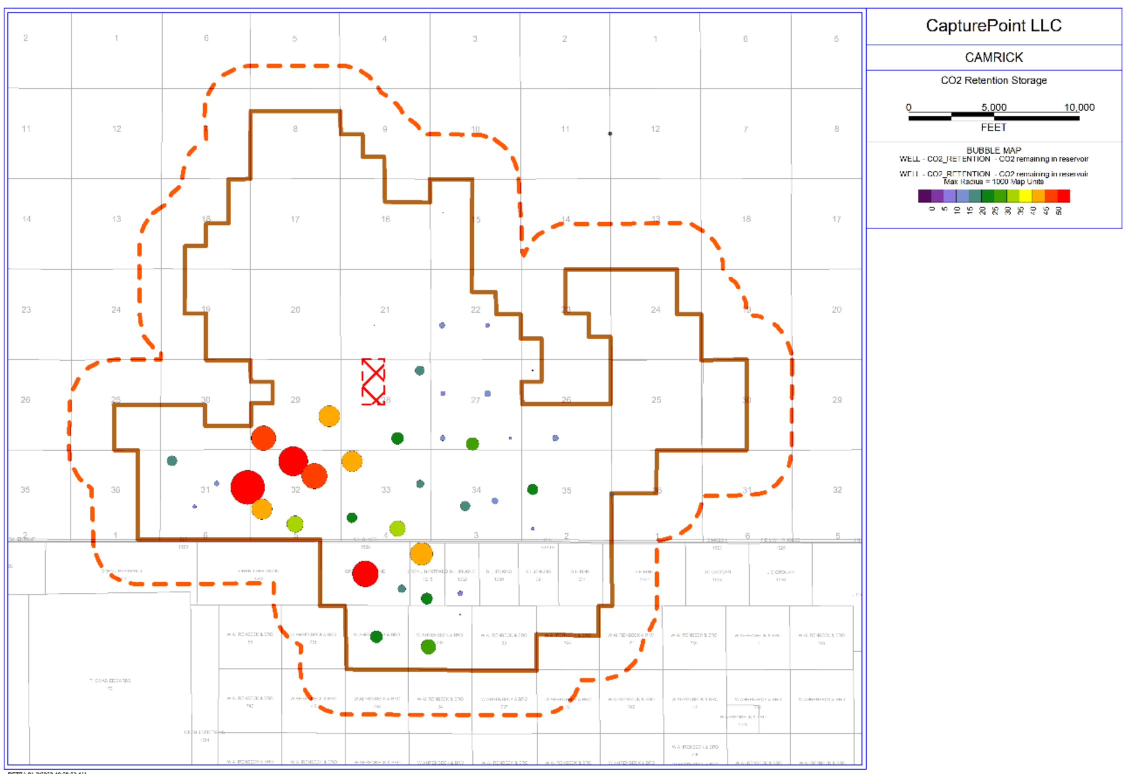

Figure 3.1-1. Estimated CO_2 storage as of 2021 in CFA.
The AMA is the land area inside the solid line polygon except for the red hashed rectangle.
The MMA extends to dotted red line and includes the red hashed rectangle.

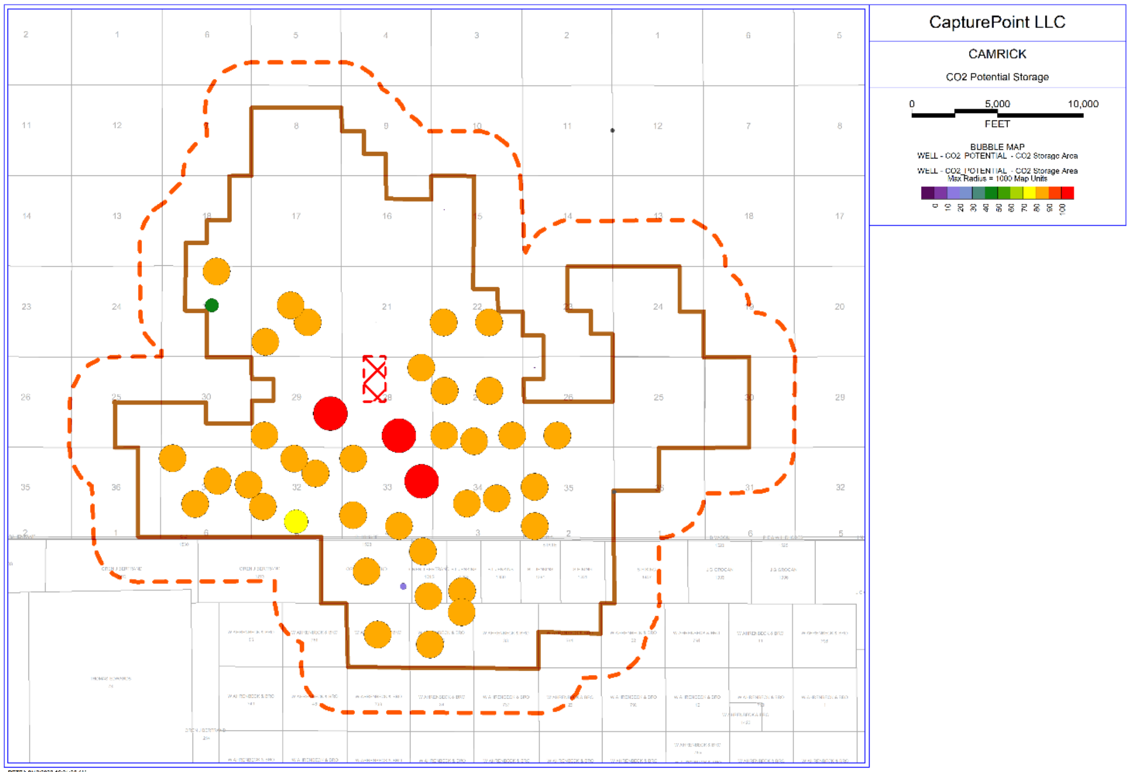

Figure 3.1-2. Potential Total CO_2 Storage in the CFA.
The AMA is the land area inside the solid line polygon except for the red hashed rectangle.
The MMA extends to dotted red line and includes the red hashed rectangle.

3.1.2 Determination of Buffer Zone

CapturePoint intends to implement a buffer zone of one-half mile around the CFA, the minimum required by Subpart RR, because the site characterization and stratigraphic trapping of the Morrow did not reveal any leakage pathways that would allow free-phase CO_2 to migrate laterally thereby warranting a buffer zone greater than one-half mile.

3.2 AMA

The Active Monitoring Area (AMA) is defined by CapturePoint's exclusive right to operate the CFA unitized leases, as described in the INTRODUCTION and Section 2.2.1. Currently, CapturePoint's operations are focused on the western portion of the CU and the entire NPU. However, it is anticipated as time passes, or additional CO_2 volumes become available additional areas within the CFA may be developed. Additional development is driven by the market price of oil coupled with the availability of sufficient CO_2 volumes and thus the timing of additional development is uncertain at this time. As CO_2 injection operations are expanded beyond the currently active CO_2 EOR portion of the CFA, all additional CO_2 injection wells will be permitted under the UIC program and will be included in the annual submittal per 40 CFR 98.446(f)(13). All future CO_2 injection wells permitted will be within the AMA.

Therefore, for the purposes of this MRV plan, CapturePoint is continuously monitoring the entire CFA, which is the AMA.

4 Identification and Evaluation of Leakage Pathways

Since its discovery in 1955, the unitization of the different units from 1969 to 1972, and the commencement of CO_2 EOR in 2001; the CFA is an analogous field to the Farnsworth Unit, which has undergone extensive investigation and documentation as indicated in Section 2. From this body of work, CapturePoint has identified the following potential pathways of CO_2 leakage to the surface. This section will also address detection, verification, and quantification of leakage from each pathway.

4.1 Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO_2 EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment via personnel instructed on how to detect surface leaks and other equipment failure minimizes releases. In addition, the Oil and Gas Division requirements of the OAC rules of the OCC and the TAC rules of the TRRC to report and quantify leaks, both serve to minimize leakage of GHG from surface equipment. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. As described in Section 6.4 below, should leakage from surface equipment occur it will be quantified according to the procedures in Subpart W of the GHGRP.

4.2 Leakage from Wells

CapturePoint has identified 68 abandoned wells, 49 injection wells (29 active) and 94 production wells (59 active) within the MMA and assessed their potential for leakage of CO_2 to the surface as listed in Appendix 1.

4.2.1 Abandoned Wells

Figure 4.2-1 shows all wells plugged and abandoned in the CFA. Because the CFA was unitized in 1969 to 1972, all plugging and abandonment activities of wells within the CFA have been conducted under the regulations of the OCC and the TRRC for plugging wells. The cement used to plug wells when exposed to CO_2 will form colloidal gels that further reduce any flow. CapturePoint concludes that leakage of CO_2 to the surface through abandoned wells is unlikely. However, strategies for leak detection are in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

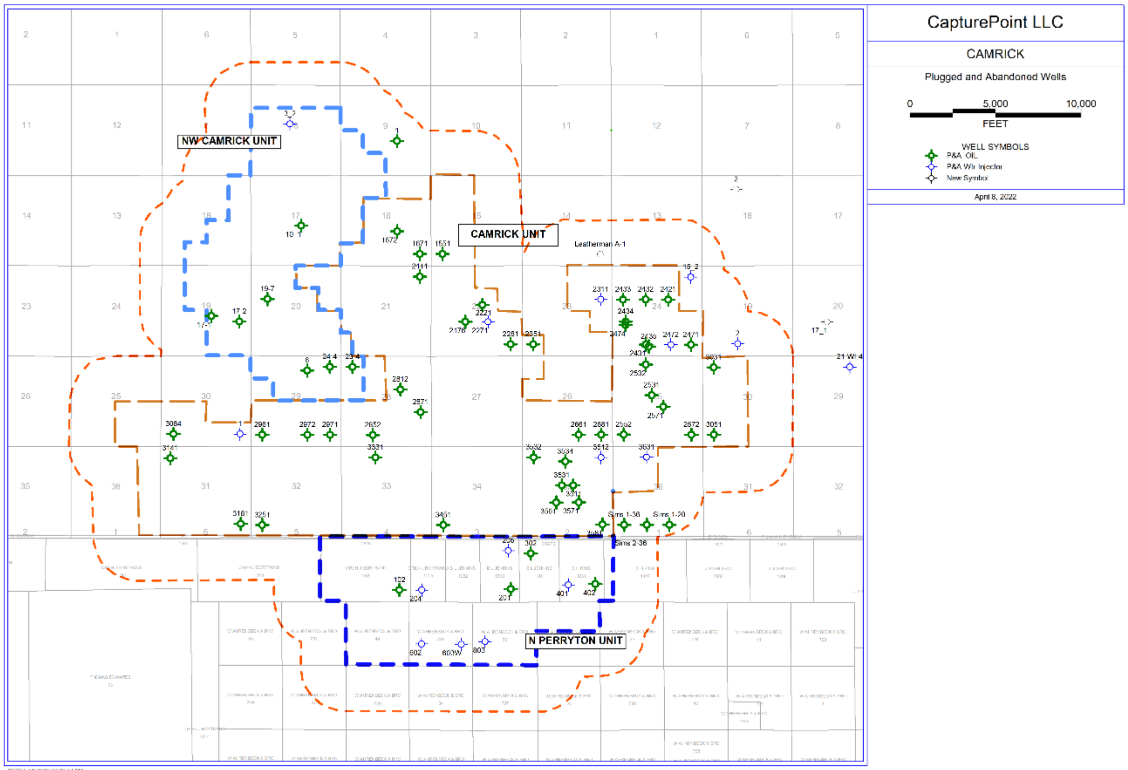

Figure 4.2-1. Plugged and Abandoned Wells in the CFA.

4.2.2 Injection Wells

Mechanical integrity testing (MIT) is an essential requirement of the UIC program in demonstrating that injection wells themselves do not act as conduits for leakage into underground sources of drinking water (USDW) and to the surface environment. TRRC Rule 46 requirements include special equipment requirements (e.g., tubing and packer) and modification; records maintenance; monitoring and reporting; testing; plugging; and penalties for violations of the rule. Permit revocation may result as a consequence of noncompliance. (See Section 2.3.6) The TRRC and the OCC detail all the requirements for the Class II permits issued to CapturePoint. These rules ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Figure 4.2-2 shows the active injection wells in the CFA. CapturePoint concludes that leakage of CO_2 to the surface through active injection wells is unlikely.

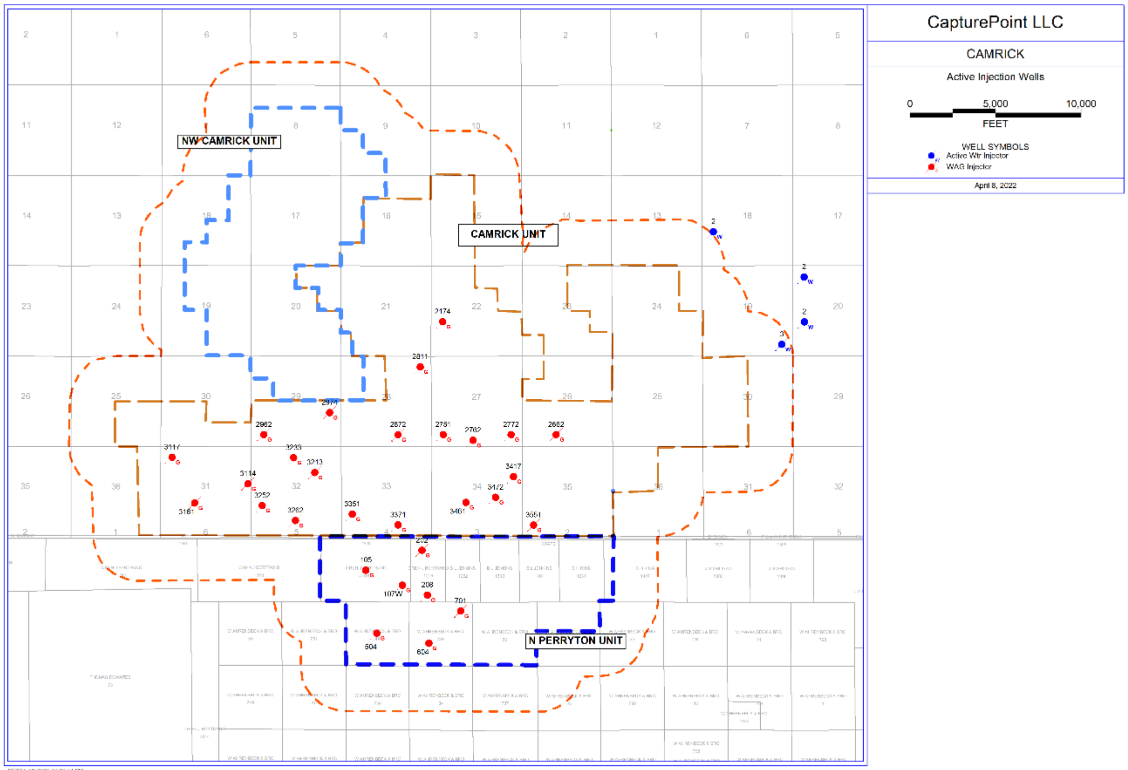

Figure 4.2-2. Active Injection Wells in the CFA.

4.2.3 Production Wells

Some of the original field wells drilled as oil wells were reclassified, administratively, to gas wells per OAC Title 165:10-1-6 paragraph (d), because of the gas-oil ratio growth due to reservoir depletion. Hence, there is no difference in well construction. (See Section 2.3.6) As the field is being further developed for enhanced oil recovery, these gas wells have been reclassified to oil wells per OCC regulations and will be monitored for leakage. (See Section 4.7) Figure 4.2-3 shows the active oil production wells in the CFA. Once EOR operations commence, the energy content of the produced gas drops and cannot be sold; therefore, any inactive gas wells are either reclassified to oil producers, or activated to WAG injectors, as described earlier. (See Section 4.2.2) However, as the project develops in the CFA additional production wells may be added and will be constructed according to the relevant rules of the OCC and the TRRC. Additionally, inactive wells may become active according to the rules of the OCC and the TRRC.

During production, oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure where the bottom hole wellbore pressure is less than the reservoir pressure. These lower pressure fluids, which also contains CO_2, are contained by the casing, tubing, wellhead, and flowline all the way to the CTB. CapturePoint concludes that leakage of CO_2 to the surface through production wells is unlikely.

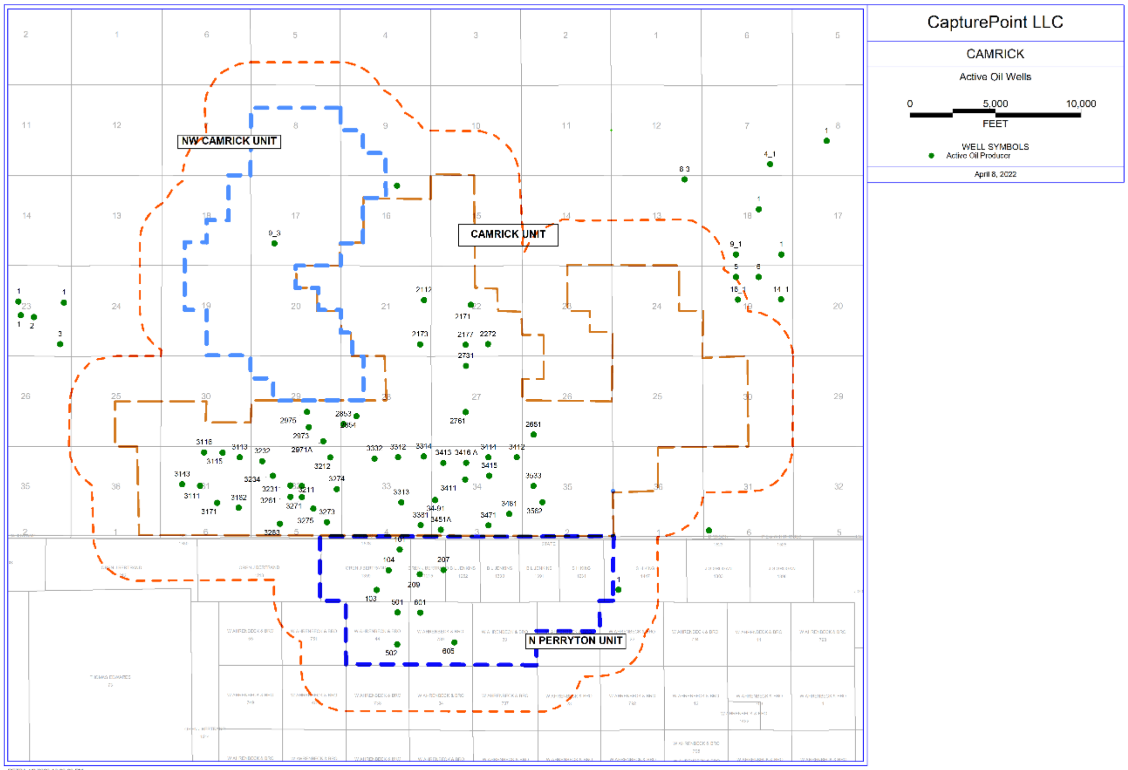

Figure 4.2-3. Active Oil Production Wells in the CFA.

4.2.4 Inactive Wells

Figure 4.2-4 shows all of the inactive wells in the CFA. The OCC has regulations for temporally abandoned/not plugged (TA) and terminated order wells/UIC not plugged (TM) and likewise the TRRC has regulations for inactive wells.

Inactive wells have a cast iron bridge plug set or long cement plugs placed above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. CapturePoint concludes that leakage of CO_2 to the surface through inactive wells is unlikely.

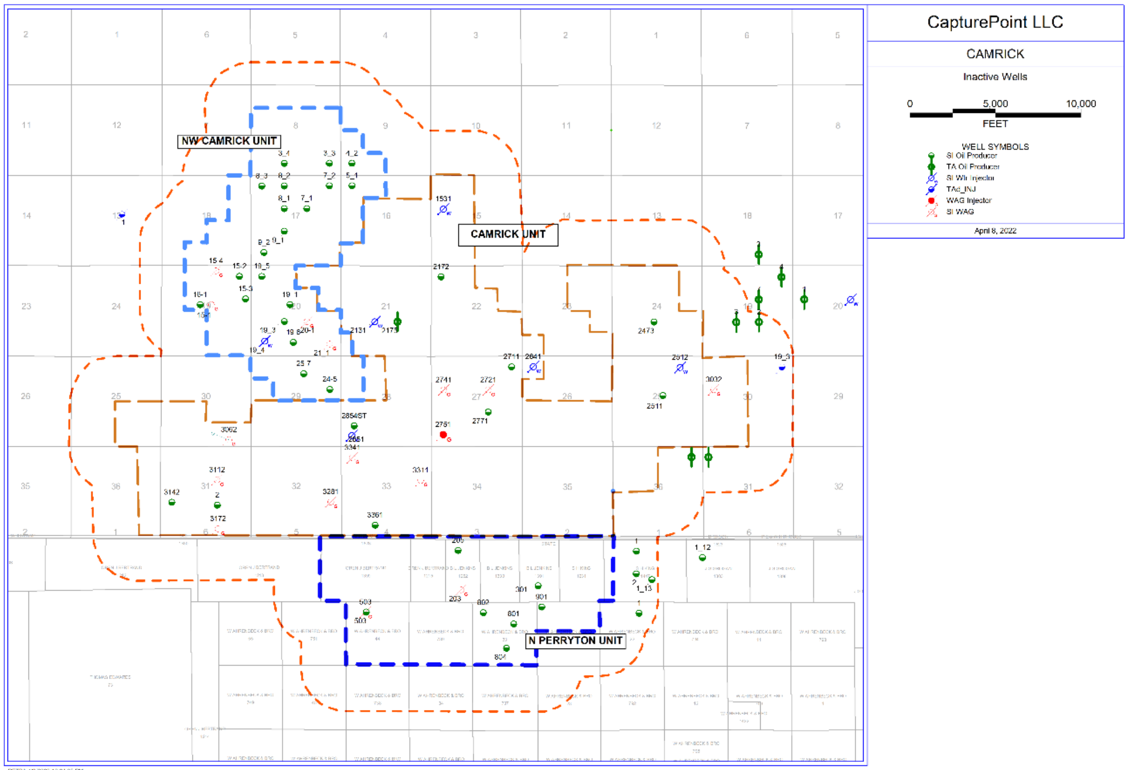

Figure 4.2-4. Inactive wells in the CFA

4.2.5 New Wells

As the project develops, new production wells and injection wells may be added to the CFA. All new wells will be constructed according to the relevant rules for the OCC and the TRRC which ensure protection of subsurface and surface resources, and the environment.

All wells in Oklahoma oilfields and all wells in Texas oilfields, including both injection and production wells, are regulated by the OCC and the TRRC, respectively, which has primacy to implement the UIC Class II programs.

Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Briefly current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface water.
- That wells file a completion report including basic electric logs.
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.

- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.

New well construction is based on existing best practices, established during the drilling of existing wells in CFA and follows the OCC and the TRRC rules, which significantly limits any potential leakage from well pathways. Additionally, the existing wells followed the OCC and the TRRC rules.

In public databases, the area of CFA plus one mile past the unit boundary contains over 100 wells that were drilled deeper than the Morrow formation and none of these wells were productive in reservoirs deeper than the Morrow. Therefore, it is very unlikely that anyone will ever drill through the AMA reservoir in the future. In the event a well is drilled within the AMA, the operator would be required to follow all the OCC and the TRRC rules and procedures in the drilling the well and the potential for leakage would be similar to any well that CapturePoint drills within the AMA. In addition, CapturePoint's visual inspection process during routine field operation will identify any unapproved drilling activity in the CFA.

4.3 Leakage from Faults and Bedding Plane Partings

Primary seals at CFA have been demonstrated to be mechanically very competent (see Section 2.2.2), thus the main concern of CO_2 migration at CFA is via seal bypass systems along fracture networks. The following lines of analysis have been used to assess this risk in the area.

4.3.1 Prescence of Hydrocarbons

The first and foremost argument against present day up-fault transmissibility is the 75 MMB of oil that was found trapped in the reservoir. If significant escape pathways existed, oil would have drained from the reservoir prior to the current day.

4.3.2 Fracture analysis

At the CFA, the work done at the Farnsworth Unit is analagous, where small aperture fractures were noted but not common in most of the reservoir cores examined but most of these fractures appear to be drilling induced. Fractures in the Thirteen Finger limestone caprock were described using an industry-standard format for fracture class type, orientation, fracture dip, type of mineral fill, fracture porosity, fracture spacing, and intensity. Again, drilling induced fractures are most common. Natural mineral-filled fractures are quite rare, were formed during diagenesis at shallow depths, and are of late Carboniferous age. Unless significantly damaged by large changes in reservoir pressure, they are highly unlikely to provide migration pathways.

In the unlikely event CO_2 leakage occurs as a result of leakage through the faults and fractures, it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.4 Lateral Fluid Movement

The Morrow strata in the Oklahoma and Texas Panhandle was primarily a deltaic sequence that prograded toward the southeast, resulting in deposition of mainly shales with lenticular, discontinuous coarse sandstones separated with very fine sandstone, minor conglomerates, and shale. The likelihood of any extensive migration of fluid outside of the AMA is very low.

Since CO_2 is lighter than the water remaining in the reservoir, it will migrate to the top of each lenticular structure as it is filled. The producing wells, which create low pressure points in the field, will drain the water and keep the CO_2 within each discontinuous sandstone.

4.5 Leakage through Confining/Seal system

At the CFA, the work done at the Farnsworth Unit will apply, where a variety of analytical methods were used for caprock (confining system) analysis, and the results should be the same for the CFA. Petrologic examination included standard thin section petrography and backscattered electron microscopy. Petrophysical analytical methods include retort analysis, pulse-decay permeability measurement, pressure decay permeability analysis for tight rocks, and mercury injection porosimetry, which is also known as mercury injection capillary pressure (MICP). Geomechanical analysis involved a standard series of mechanical tests: Brazil tension, unconfined compression, triaxial compression, and multi-stress compression.

Results of the MICP analysis show that the mudstone lithologies in the Morrow Shale and Thirteen Finger Limestone can support CO_2 column heights of ~1,000 to 10,000 feet. At an order of magnitude over the thickness of the Morrow reservoir, this should prove an effective seal for CO_2 storage in the Morrow B injection horizon.

Failure analyses show that the Morrow B sands are weaker than overlying lithologies, so that any fracture initiation around the injection well would not be expected to propagate into the overlying sealing units. Mechanical properties of the overlying shale and limestones provide an interesting and effective combination of strength and elasticity. Limestone layers are strong but brittle, while the shale layers are weaker but sufficiently ductile to prevent extensive fracture propagation.

It is unlikely for hydrocarbon migration pathways that charged the Morrow reservoir to be potential CO_2 migration pathways via primary pore networks today. Any potential CO_2 migration would be most likely due to leakage from wellbores or bypass through fault and fracture networks, discussed in Sections 4.2 and 4.3.

In the unlikely event CO_2 leakage occurs as a result of leakage through the confining seal it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.6 Natural and Induced Seismic Activity

Figure 4.6-1 shows the map of earthquakes with magnitudes measured at greater than 2.5 as defined by the United States Geological Survey (USGS). While past earthquake data cannot predict future earthquakes, the small number of events near CFA after the

waterflood operations were initiated in 1969 implies the area is not seismically sensitive to injection. Also, no documentation exists that any of the distant earthquake events caused a disruption in injectivity or damage to any of the wellbores in CFA.

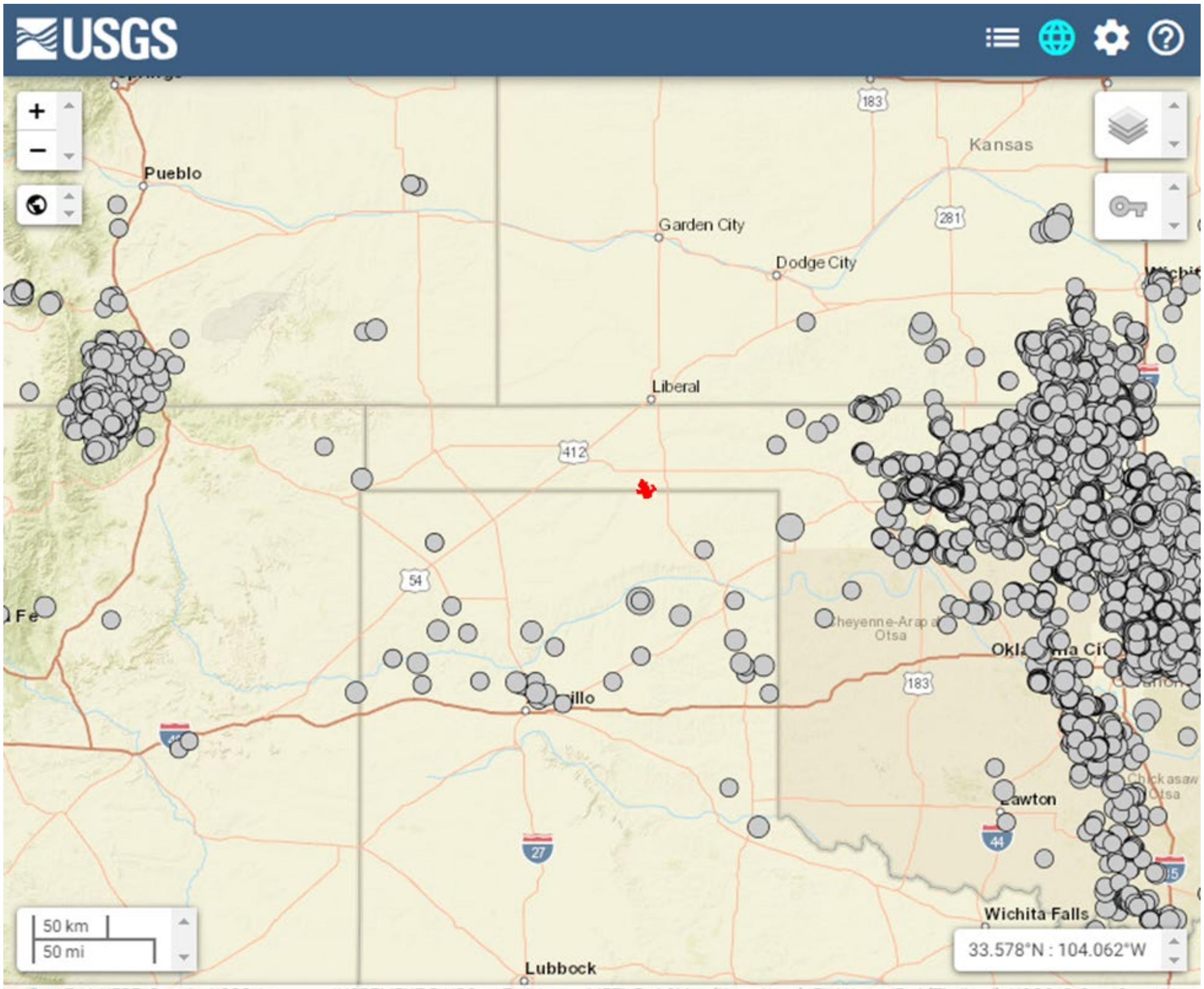

Figure 4.6-1. USGS earthquakes (+2.5 magnitude) for last 40 years with CFA highlighted red.

There is no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the CFA.

In the unlikely event that induced seismicity resulted in a pathway for material amounts of CO_2 to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would lead to further investigation.

4.7 Strategy for Detection and Response to 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 (well bores), and unique events such as induced fractures. Table 1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks,

CapturePoint's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO_2 losses discussed in the table are identified by type. Once the type is reported to a response manager the correct resources and personnel can be mobilized to develop the optimal response procedure. The procedure will address and mitigate further CO_2 leakage.

Table 1 Response Plan for CO_2 Loss

Known Potential Leakage Risks	Monitoring Methods and Frequency	Anticipated Response Plan
Tubing Leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days
Casing Leak	Weekly field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days
Wellhead Leak	Weekly field inspection	Workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations (weekly inspection but field personnel present daily)	Maintain well kill procedures
Unplanned wells drilled through Morrow	Weekly field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Re-enter and reseal abandoned wells
Pumps, values, etc.	Weekly field inspection	Workover crews respond within days
Leakage along faults	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near faults
Leakage laterally	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Fluid management along lease lines
Leakage through induced fractures	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near seismic event

4.8 Strategy for Quantifying CO_2 loss

Major CO_2 losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. CapturePoint will use Subpart W techniques to estimate leakages only on equipment and ensure those results are consistently represented in the Subpart RR report. Any event-driven leakage quantification reported in Subpart RR for surface leaks will use other techniques.

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 CO_2 that would be most appropriate. In the event leakage occurs, CapturePoint will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission.

Any volume of CO_2 detected leaking to the 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, CapturePoint's field experience, and other factors such as the frequency of inspection. As indicated in Section 6.4, leaks will be documented, and the records of leakage events will be retained in the electronic environmental documentation and reporting system, which consists of reports stored on servers, with information uploaded into third party software.

Available studies of actual well leaks and natural analogs (e.g., naturally occurring CO_2 geysers) suggest that the amount released from routine leaks would be small as compared to the amount of CO_2 that would remain stored in the formation.

5 Strategy for Determining CO_2 Baselines for CO_2 Monitoring

Atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values for soil measurement in the CFA area, per the characterization, monitoring and well data collected by the Southwest Regional Partnership on Carbon Sequestration (SWP) in the analogous Farnsworth Unit.

5.1 Site Characterization and Monitoring

As described in Sections 2.2.2 and 2.4, the Morrow B sandstone is isolated both above and below by shale units of the Morrow. The primary seal consists of 180 – 200 ft of Morrow shale and Thirteen Finger Limestone which in turn is overlain by over a thousand feet of younger shale and limestone. These units provide a suitable seal to prevent the migration of CO_2 out of the injection reservoir. Additionally, no significant faults or fracture zones that cut across the seal units have been identified in the CFA, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented.

5.2 Groundwater monitoring

CapturePoint does not routinely pull water samples from the Ogallala water wells. However, samples are pulled when OCC injection permits are submitted in Oklahoma. No indication of fluid leakage has been identified from any of these in the CFA area. CapturePoint is unlikely to continue monitoring USDW wells for CO_2 or brine contamination, as characterization of the Morrow (see section 5.1) has suggested minimal risk of groundwater contamination from CO_2 leakage from this depth.

5.3 Soil CO_2 monitoring

Atmospheric CO_2 values at the Farnsworth Unit have been determined by a SWP eddy tower installation. In winter 2019, the eddy system malfunctioned and has not been repaired due to COVID travel restrictions. However, the atmospheric CO_2 concentration data from the eddy tower were in very good agreement with values obtained from the NOAA Global Monitoring Laboratory station in Moody, Texas (Station: WKT). Since the CFA area is in close proximity to the Farnsworth Unit, atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values.

5.4 Visual Inspection

CapturePoint operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage.

5.5 Well Surveillance

CapturePoint adheres to the requirements of OAC Title 165:10-5 for the OCC and of TAC Rule 46 for the TRRC governing fluid injection into productive reservoirs. Rule 46 includes requirements for monitoring, reporting, and testing of Class II injection wells. Furthermore, the OCC and the TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well if they are deemed necessary.

CapturePoint also adheres to the requirements of OAC Title 165:10-7 for the OCC and TAC Rule 20 for the TRRC governing the notification of fires, breaks, leaks, or escapes. Rule 20 requires that all operators report leaks to the OCC or the TRRC including measured or estimated quantities of product leaked.

6 Site specific considerations for determining the Mass of CO_2 Sequestered

Of the twelve RR equations in 98.443 of Subpart RR, the following are relevant to CapturePoint's operations.

6.1 Determining Mass of CO_2 received

CapturePoint currently receives CO_2 at its CFA facility through its own pipeline from the Arkalon Ethanol plant in Liberal, Kansas. CapturePoint also recycles CO_2 from its production wells in the CFA.

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

where:

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

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into the well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

6.2 Determining Mass of CO_2 Injected

CapturePoint injects CO_2 into the injection wells listed in Appendix 1.

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

where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

6.3 Determining Mass of CO_2 produced from Oil Wells

CapturePoint also recycles CO_2 from its production wells which are part of its operations in the CFA. Therefore, the following equation is relevant to its operations.

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

Where:

$CO_{2,w}$ = Annual CO_2 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 CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,w}}$ = CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator.

To aggregate production data, CapturePoint will sum the mass of all of the CO_2 separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 below:

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

Where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) through all separators in the reporting year.

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction), CU is 0.00236 and NPU is 0.00454 at the last sample.

w = Separator.

6.4 Determining Mass of CO_2 emitted by Surface Leakage

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations.

CapturePoint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below:

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

where:

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

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

x = Leakage pathway.

6.5 Determining Mass of CO_2 sequestered

The following Equation RR-11 pertains to facilities that are actively producing oil or natural gas.

$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP}$ (Equation RR-11)

Where:

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

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

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

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

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

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

7 Estimated Schedule for Implementation of MRV plan

CapturePoint expects to begin implementing the approved MRV plan when the new CO_2 capture facility is operational, September 1, 2022.

8 GHG monitoring and Quality Assurance Program

CapturePoint will meet the monitoring and QA/QC requirements of 98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 98.444 (d).

8.1 GHG monitoring

As required by 40 CFR 98.3(g)(5)(i), CapturePoint's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

8.1.1 General

Measurement of CO_2 *Concentration* – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GSA) standards.

Measurement of CO_2 *Volume* – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. CapturePoint will adhere to the American Gas Association (AGA) Report #3 – (ORIFICE METERING OF NATURAL GAS AND OTHER RELATED HYDROCARBON FLUIDS)

8.1.2 CO_2 Received

Daily fermentation CO_2 purchased is received via the pipeline from the Arkalon ethanol plant in Liberal, Kansas, and is measured using a volumetric totalizer, which uses accepted flow calculations for CO_2 according to the AGA Report #3.

8.1.3 CO_2 Injected

Daily CO_2 injection is recorded by combining the totals for the recycle compressor meter and the received CO_2 meter from Arkalon based on what's delivered on a 24-hour basis. This data is taken from the meter daily and stored in CapturePoint's data warehouse for records and reservoir management.

8.1.4 CO_2 Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO_2. The produced gas is sampled at least quarterly for the CO_2 content.

8.1.5 CO_2 Emissions from equipment leaks and vented emissions of CO_2

As required by 98.444 (d), CapturePoint will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead and between the flow meter used to measure production quantity and the production wellhead.

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6 Measurement Devices

As required by 40 CFR 98.444(e), CapturePoint will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration.
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meters are National Institute of Standards and Technology (NIST) traceable.

8.2 QA/QC procedures

CapturePoint will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

8.3 Estimating missing data

CapturePoint will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

A quarterly flow rate of CO_2 received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.

A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.

A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

8.4 Revisions of the MRV plan

CapturePoint will revise the MRV Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

9 Records Retention

CapturePoint will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, CapturePoint will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.
(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
    (i) The GHG emissions calculations and methods used.
    (ii) Analytical results for the development of site-specific emissions factors, if applicable.
    (iii) The results of all required analyses.
    (iv) Any facility operating data or process information used for the GHG emission calculations.
(3) The annual GHG reports.
(4) Missing data computations. For each missing data event, CapturePoint will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
(5) A copy of the most recent revision of this MRV Plan.
(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(9) Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(10) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(11) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
(12) 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.
(13) 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.
(14) Any other records as specified for retention in this EPA-approved MRV plan.

10 Appendices

Appendix 1 – CFA Wells

Table A1.1 – Production Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2112	35007353570000	Oil Prod	Active	CO_2	1	0
CU 2171	35007354120000	Oil Prod	Active	CO_2	1	0
CU 2173	35007354140000	Oil Prod	Active	CO_2	1	0
CU 2177	35007222340000	Oil Prod	Active	CO_2	1	0
CU 2272	35007224530000	Oil Prod	Active	CO_2	1	0
CU 2651	35007362650000	Oil Prod	Active	CO_2	1	0
CU 2731	35007359750000	Oil Prod	Active	CO_2	1	0
CU 2761	35007350590000	Oil Prod	Active	CO_2	1	0
CU 2853	35007250840000	Oil Prod	Active	CO_2	1	0
CU 2854	35007250850000	Oil Prod	Active	CO_2	1	0
CU 2971A	35007256700000	Oil Prod	Active	CO_2	1	0
CU 2973	35007213750000	Oil Prod	Active	CO_2	1	0
CU 2975	35007223730000	Oil Prod	Active	CO_2	1	0
CU 3111	35007350600000	Oil Prod	Active	CO_2	1	0
CU 3113	35007359460000	Oil Prod	Active	CO_2	1	0
CU 3115	35007251710000	Oil Prod	Active	CO_2	1	0
CU 3116	35007252570000	Oil Prod	Active	CO_2	1	0
CU 3143	35007250860000	Oil Prod	Active	CO_2	1	0
CU 3171	35007359600000	Oil Prod	Active	CO_2	1	0
CU 3182	35007249250000	Oil Prod	Active	CO_2	1	0
CU 3211	35007352150000	Oil Prod	Active	CO_2	1	0
CU 3212	35007352690000	Oil Prod	Active	CO_2	1	0
CU 3231	35007001820000	Oil Prod	Active	CO_2	1	0
CU 3232	35007352720000	Oil Prod	Active	CO_2	1	0
CU 3234	35007212010000	Oil Prod	Active	CO_2	1	0
CU 3261	35007352170000	Oil Prod	Active	CO_2	1	0
CU 3263	35007251640000	Oil Prod	Active	CO_2	1	0
CU 3271	35007352160000	Oil Prod	Active	CO_2	1	0
CU 3273	35007252580000	Oil Prod	Active	CO_2	1	0
CU 3274	35007253140000	Oil Prod	Active	CO_2	1	0
CU 3275	35007254040000	Oil Prod	Active	CO_2	1	0
CU 3312	35007360800000	Oil Prod	Active	CO_2	1	0
CU 3313	35007254370000	Oil Prod	Active	CO_2	1	0
CU 3314	35007254030000	Oil Prod	Active	CO_2	1	0
CU 3332	35007254020000	Oil Prod	Active	CO_2	1	0
CU 3381	35007360780000	Oil Prod	Active	CO_2	1	0
CU 3411	35007351700000	Oil Prod	Active	CO_2	1	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3412	35007351720000	Oil Prod	Active	CO_2	1	0
CU 3413	35007351730000	Oil Prod	Active	CO_2	1	0
CU 3414	35007005220000	Oil Prod	Active	CO_2	1	0
CU 3415	35007211170000	Oil Prod	Active	CO_2	1	0
CU 3416A	35007252590000	Oil Prod	Active	CO_2	1	0
CU 3451A	35007256710000	Oil Prod	Active	CO_2	1	0
CU 3471	35007351750000	Oil Prod	Active	CO_2	1	0
CU 3481	35007351710001	Oil Prod	Active	CO_2	1	0
CU 3491	35007254330000	Oil Prod	Active	CO_2	1	0
CU 3533	35007206880000	Oil Prod	Active	CO_2	1	0
CU 3562	35007255050000	Oil Prod	Active	CO_2	1	0
NPU 101	42357010440000	Oil Prod	Active	CO_2	1	0
NPU 103	42357010060000	Oil Prod	Active	CO_2	1	0
NPU 104	42357000050000	Oil Prod	Active	CO_2	1	0
NPU 207	42357302000000	Oil Prod	Active	CO_2	1	0
NPU 209	42357333830000	Oil Prod	Active	CO_2	1	0
NPU 501	42357009140000	Oil Prod	Active	CO_2	1	0
NPU 502	42357024100000	Oil Prod	Active	CO_2	1	0
NPU 601	42357008420000	Oil Prod	Active	CO_2	1	0
NPU 605	42357333840000	Oil Prod	Active	CO_2	1	0
NWCU 3-1	35007360850000	Gas Prod	Active	CO_2	1	0
NWCU 9-3	35007249430000	Oil Prod	Active	CO_2	1	0
CU 2172	35007354130000	Oil Prod	Inactive	CO_2	0	0
CU 2175	35007354160000	Oil Prod	Inactive	CO_2	0	0
CU 2473	35007211990000	Oil Prod	Inactive	CO_2	0	0
CU 2511	35007350790000	Oil Prod	Inactive	CO_2	0	0
CU 2711	35007359260000	Oil Prod	Inactive	CO_2	0	0
CU 2771	35007359850000	Oil Prod	Inactive	CO_2	0	0
CU 3142	35007222350000	Oil Prod	Inactive	CO_2	0	0
CU 3361	35007352670000	Oil Prod	Inactive	CO_2	0	0
NPU 205	42357008070000	Oil Prod	Inactive	CO_2	0	0
NPU 301	42357022080000	Oil Prod	Inactive	CO_2	0	0
NPU 801	42357004630000	Oil Prod	Inactive	CO_2	0	0
NPU 802	42357004620000	Oil Prod	Inactive	CO_2	0	0
NPU 804	42357201730000	Oil Prod	Inactive	CO_2	0	0
NPU 901	42357000660000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-2	35007350870000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-3	35007210790000	Oil Prod	Inactive	CO_2	0	0
NWCU 16-1	35007350720000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-1	35007360900000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-3	35007360920000	Oil Prod	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
NWCU 19-4	35007360930000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-5	35007360940000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-6	35007211250000	Oil Prod	Inactive	CO_2	0	0
NWCU 24-5	35007222710000	Oil Prod	Inactive	CO_2	0	0
NWCU 25-7	35007228000000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-3	35007360870000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-4	35007360880000	Oil Prod	Inactive	CO_2	0	0
NWCU 4-2	35007360740000	Oil Prod	Inactive	CO_2	0	0
NWCU 5-1	35007361050000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-1	35007360980000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-2	35007360990000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-1	35007360810000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-2	35007360820000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-3	35007208260000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-1	35007360950000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-2	35007360960000	Oil Prod	Inactive	CO_2	0	0
CU 1551	35007350740000	Oil Prod	P&A	CO_2	0	0
CU 1671	35007352180000	Oil Prod	P&A	CO_2	0	0
CU 2111	35007353560000	Oil Prod	P&A	CO_2	0	0
CU 2176	35007358870000	Oil Prod	P&A	CO_2	0	0
CU 2221	35007000490000	Oil Prod	P&A	CO_2	0	0
CU 2281	35007359220000	Oil Prod	P&A	CO_2	0	0
CU 2421	35007359350000	Oil Prod	P&A	CO_2	0	0
CU 2431	35007350330000	Oil Prod	P&A	CO_2	0	0
CU 2432	35007350340000	Oil Prod	P&A	CO_2	0	0
CU 2433	35007350350000	Oil Prod	P&A	CO_2	0	0
CU 2434	35007350360000	Oil Prod	P&A	CO_2	0	0
CU 2435	35007218800000	Oil Prod	P&A	CO_2	0	0
CU 2471	35007359080000	Oil Prod	P&A	CO_2	0	0
CU 2531	35007361090000	Oil Prod	P&A	CO_2	0	0
CU 2532	35007361100000	Oil Prod	P&A	CO_2	0	0
CU 2552	35007359760000	Oil Prod	P&A	CO_2	0	0
CU 2571	35007350730000	Oil Prod	P&A	CO_2	0	0
CU 2572	35007359320000	Oil Prod	P&A	CO_2	0	0
CU 2661	35007361990000	Oil Prod	P&A	CO_2	0	0
CU 2681	35007350320000	Oil Prod	P&A	CO_2	0	0
CU 2852	35007301360000	Oil Prod	P&A	CO_2	0	0
CU 2961	35007358760000	Oil Prod	P&A	CO_2	0	0
CU 2971	35007358750000	Oil Prod	P&A	CO_2	0	0
CU 2972	35007358780000	Oil Prod	P&A	CO_2	0	0
CU 3031	35007359560000	Oil Prod	P&A	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3051	35007300380000	Oil Prod	P&A	CO_2	0	0
CU 3064	35007254270000	Oil Prod	P&A	CO_2	0	0
CU 3141	35007359610000	Oil Prod	P&A	CO_2	0	0
CU 3181	35007359470000	Oil Prod	P&A	CO_2	0	0
CU 3251	35007352710000	Oil Prod	P&A	CO_2	0	0
CU 3331	35007200750000	Oil Prod	P&A	CO_2	0	0
CU 3451	35007351690000	Oil Prod	P&A	CO_2	0	0
CU 3511	35007359730000	Oil Prod	P&A	CO_2	0	0
CU 3531	35007350850000	Oil Prod	P&A	CO_2	0	0
CU 3532	35007359950000	Oil Prod	P&A	CO_2	0	0
CU 3534	35007211180000	Oil Prod	P&A	CO_2	0	0
CU 3561	35007359830000	Oil Prod	P&A	CO_2	0	0
CU 3571	35007359980000	Oil Prod	P&A	CO_2	0	0
CU 3581	35007359970000	Oil Prod	P&A	CO_2	0	0
CU 3631	35007301000000	Oil Prod	P&A	CO_2	0	0
CU 1672	35007352190000	Oil Prod	P&A	CO_2	0	0
CU 2351	35007350370000	Oil Prod	P&A	CO_2	0	0
CU 2474	35007228200000	Oil Prod	P&A	CO_2	0	0
CU 2812	35007352340000	Oil Prod	P&A	CO_2	0	0
CU 2871	35007359060000	Oil Prod	P&A	CO_2	0	0
NPU 102	42357021420000	Oil Prod	P&A	CO_2	0	0
NPU 201	42357001280000	Oil Prod	P&A	CO_2	0	0
NPU 302	42357022290000	Oil Prod	P&A	CO_2	0	0
NPU 402	42357022300000	Oil Prod	P&A	CO_2	0	0
NWCU 17-2	35007359620000	Oil Prod	P&A	CO_2	0	0
NWCU 10-1	35007361010000	Oil Prod	P&A	CO_2	0	0
NWCU 17-1	35007350710000	Oil Prod	P&A	CO_2	0	0
NWCU 19-7	35007224520000	Oil Prod	P&A	CO_2	0	0
NWCU 24-4	35007358770000	Oil Prod	P&A	CO_2	0	0
NWCU 25-6	35007358790000	Oil Prod	P&A	CO_2	0	0

Table A1.2 – Water Alternating Gas (WAG) Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 2662 (INJ)	35007362010000	WAG Inj	Active	CO_2	0	1
CU 2751 (INJ)	35007359440002	WAG Inj	Active	CO_2	0	1
CU 2762 (INJ)	35007213660000	WAG Inj	Active	CO_2	0	1
CU 2772 (INJ)	35007359860001	WAG Inj	Active	CO_2	0	1
CU 2811 (INJ)	35007352200000	WAG Inj	Active	CO_2	0	1
CU 2872 (INJ)	35007359070000	WAG Inj	Active	CO_2	0	1
CU 2962 (INJ)	35007212000000	WAG Inj	Active	CO_2	0	1
CU 2974 (INJ)	35007220770000	WAG Inj	Active	CO_2	0	1
CU 3114 (INJ)	35007206540000	WAG Inj	Active	CO_2	0	1
CU 3117 (INJ)	35007254000000	WAG Inj	Active	CO_2	0	1
CU 3161 (INJ)	35007359590002	WAG Inj	Active	CO_2	0	1
CU 3213 (INJ)	35007224570000	WAG Inj	Active	CO_2	0	1
CU 3233 (INJ)	35007206890000	WAG Inj	Active	CO_2	0	1
CU 3252 (INJ)	35007211020000	WAG Inj	Active	CO_2	0	1
CU 3262 (INJ)	35007206870000	WAG Inj	Active	CO_2	0	1
CU 3351 (INJ)	35007352680000	WAG Inj	Active	CO_2	0	1
CU 3371 (INJ)	35007360770000	WAG Inj	Active	CO_2	0	1
CU 3417 (INJ)	35007255060000	WAG Inj	Active	CO_2	0	1
CU 3461 (INJ)	35007351680000	WAG Inj	Active	CO_2	0	1
CU 3472 (INJ)	35007206940000	WAG Inj	Active	CO_2	0	1
CU 3551 (INJ)	35007359840000	WAG Inj	Active	CO_2	0	1
NPU 105 (INJ)	42357000030000	WAG Inj	Active	CO_2	0	1
NPU 107W (INJ)	42357333770000	WAG Inj	Active	CO_2	0	1
NPU 202WI (INJ)	42357021500000	WAG Inj	Active	CO_2	0	1
NPU 208 (INJ)	42357327410000	WAG Inj	Active	CO_2	0	1
NPU 701 (INJ)	42357008410000	WAG Inj	Active	CO_2	0	1
NPU 504 (INJ)	42357329480000	WAG Inj	Active	CO_2	0	1
NPU 604W (INJ)	42357330870000	WAG Inj	Active	CO_2	0	1
CU 1531 (INJ)	35007359990000	WAG Inj	Inactive	CO_2	0	0
CU 2131 (INJ)	35007362700000	WAG Inj	Inactive	CO_2	0	0
CU 2512 (INJ)	35007350780000	WAG Inj	Inactive	CO_2	0	0
CU 2641 (INJ)	35007359250001	WAG Inj	Inactive	CO_2	0	0
CU 2721 (INJ)	35007359870001	WAG Inj	Inactive	CO_2	0	0
CU 2741 (INJ)	35007359430000	WAG Inj	Inactive	CO_2	0	0
CU 2851 (INJ)	35007355420001	WAG Inj	Inactive	CO_2	0	0
CU 3032 (INJ)	35007359580000	WAG Inj	Inactive	CO_2	0	0
CU 3062 (INJ)	35007253090000	WAG Inj	Inactive	CO_2	0	0
CU 3112 (INJ)	35007359450001	WAG Inj	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 3172 (INJ)	35007251690000	WAG Inj	Inactive	CO_2	0	0
CU 3281 (INJ)	35007352700003	WAG Inj	Inactive	CO_2	0	0
CU 3311 (INJ)	35007360790000	WAG Inj	Inactive	CO_2	0	0
CU 3341 (INJ)	35007353530000	WAG Inj	Inactive	CO_2	0	0
NPU 203W (INJ)	42357008270000	WAG Inj	Inactive	CO_2	0	0
NPU 503 (INJ)	42357009150001	WAG Inj	Inactive	CO_2	0	0
NWCU 15-1 (INJ)	35007350860000	WAG Inj	Inactive	CO_2	0	0
NWCU 15-4 (INJ)	35007224510000	WAG Inj	Inactive	CO_2	0	0
NWCU 20-1 (INJ)	35007360760000	WAG Inj	Inactive	CO_2	0	0
NWCU 21-1 (INJ)	35007361020000	WAG Inj	Inactive	CO_2	0	0
CU 2271 (INJ)	35007359230000	WAG Inj	P&A	CO_2	0	0
CU 2311 (INJ)	35007362000000	WAG Inj	P&A	CO_2	0	0
CU 2472 (INJ)	35007359090000	WAG Inj	P&A	CO_2	0	0
CU 3061 (INJ)	35007359820000	WAG Inj	P&A	CO_2	0	0
CU 3512 (INJ)	35007359740000	WAG Inj	P&A	CO_2	0	0
NPU 204W (INJ)	42357022520000	WAG Inj	P&A	CO_2	0	0
NPU 206W (INJ)	42357022510000	WAG Inj	P&A	CO_2	0	0
NPU 401W (INJ)	42357004520000	WAG Inj	P&A	CO_2	0	0
NPU 602W (INJ)	42357020230000	WAG Inj	P&A	CO_2	0	0
NPU 603W (INJ)	42357201720001	WAG Inj	P&A	CO_2	0	0
NPU 803W (INJ)	42357201710000	WAG Inj	P&A	CO_2	0	0
NWCU 14-1 (INJ)	35007350530000	WAG Inj	P&A	CO_2	0	0
NWCU 3-2 (INJ)	35007360860000	WAG Inj	P&A	CO_2	0	0

Table A1.3 – Water Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU WSW 1	35007355430001	Wtr Inj	Active	CO_2	0	1
NPU W 1W	42357300050002	Wtr Inj	Inactive	CO_2	0	0
CU 2551	35007350750000	Wtr Inj	P&A	CO_2	0	0

Appendix 2 – Referenced Regulations

U.S. Code > Title 26, INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1, NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits >

Section 45Q ..... Credit for carbon oxide sequestration

OCC > Title 165: CORPORATION COMMISSION > UNDERGROUND INJECTION CONTROL

Section

165:10-5-1 .... Classification of underground injection wells
165:10-5-2 .... Approval of injection wells or disposal wells
165:10-5-3 .... Authorization for existing enhanced recovery injection wells and existing disposal wells
165:10-5-4 .... Application for approval of enhanced recovery projects
165:10-5-5 .... Application for approval of injection and disposal operations
165:10-5-6 .... Testing and monitoring requirements for injection wells and disposal wells
165:10-5-7 .... Monitoring and reporting requirements for wells covered by 165:10-5-1
165:10-5-8 .... Liquid hydrocarbon storage wells
165:10-5-9 .... Duration of underground injection well orders or permits
165:10-5-10 ..... Transfer of authority to inject
165:10-5-11 ..... Notarized reports
165:10-5-12 ..... Application for administrative approval for the subsurface injection of onsite reserve pit fluids
165:10-5-13 ..... Application for permit for one time injection of reserve pit fluids
165:10-5-14 ..... Exempt aquifers
165:10-5-15 ..... Application for permit for simultaneous injection well

165:5-7-27 .... Application for approval of injection and disposal wells
165:5-7-29 .... Request for exception to certain underground injection well requirements
165:5-7-30 .... Amending existing orders or permits authorizing injection for injection, disposal, or LPG storage wells

TAC > Title 16 - Economic Regulation> Part 1 TRRC > Chapter 3 – Oil and Gas Division >

Rules

Appendix 3 – References

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Appendix 4 – Abbreviations and Acronyms

2D – 2 dimensional
3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
ANSI – American National Standards Institute
API – American Petroleum Institute
AWT – All Well Test
ASTM - American Society for Testing and Materials
Bscf – billion standard cubic feet
B/D – barrels per day
bopd – barrels of oil per day
C4 – butane
C5 – pentane
C7 – heptane
C7+ - standard heptane plus
CCE – constant composition expansion
CCUS – carbon capture utilization and storage
CFA – Camrick Field Area
CFR – Code of Federal Regulations
cf – cubic feet
CH4 – methane
CO_2 – carbon dioxide
EOR – Enhanced Oil Recovery
EOS – Equation of State
EPA – US Environmental Protection Agency
ESD – Emergency Shutdown Device
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
H_2S – hydrogen sulfide
lb – pound
mD – millidarcy(ies)
MICP – mercury injection capillary pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MMB – million barrels
MMP – minimum miscible pressure
MMscf – million standard cubic feet
MMstb – million stock tank barrels
MRV – Monitoring, Reporting, and Verification
MMMT – Million metric tonnes
MT – Metric tonne

NIST – National Institute of Standards and Technology
NAESB – North American Energy Standards Board
OAC – Oklahoma Administrative Code
OCC – Oklahoma Corporation Commission
OOIP – Original Oil-In-Place
OWC – oil water contact
PPM – Parts Per Million
psia – pounds per square inch absolute
PVT – pressure, volume, temperature
QA/QC – quality assurance/quality control
RMS – root mean square
SEM – scanning electron microscope
SWP - Southwest Regional Partnership on Carbon Sequestration
TAC – Texas Administrative Code
TA – Temporally Abandoned/not plugged
TD – total depth
TM – Terminated order wells/UIC not plugged
TRRC – Texas Railroad Commission
TSD – Technical Support Document
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water
WAG – Water Alternating Gas (Gas is recycled CO_2 and purchase CO_2)
XRD – x-ray diffraction

Appendix 5 – Conversion Factors

CapturePoint reports CO_2 at standard conditions of temperature and pressure as defined in the State of Texas in the Texas Administrative Code for the Oil and Gas Division, Rule 3.79 as follows:

> Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit.

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at:

https://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At State of Texas standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.002641684 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2{,}204.62\ lbs}$$

Where:

$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$

$Density_{CO2}\ =\ 0.002641684$

$MW_{CO2}\ =\ 44.0095$

$$Density_{CO2} = 5.2734\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.2734\ x\ 10^{-2}\frac{MT}{Mcf}$$

The conversion factor 5.2734×10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Request for Additional Information: Camrick Unit
September 1, 2022

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	3.1	19	Per 40 CFR 98.449, "Maximum monitoring area (MMA) means the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile." In the Request for Additional Information (RFAI) sent on August 11, 2022, EPA requested that the MRV plan more clearly identify the boundaries of the MMA and explain how the delineation of the MMA in the MRV plan meets the definition in 40 CFR 98.449. While the proposed MMA may account for the free phase CO_2 plume of the current project, we seek clarification regarding possible future expansion of the project. Section 3.1 of the MRV plan states that CO_2 storage pore space is available, and Figure 3.1-2 shows pore space within the western portion of the Camrick Unit and the NPU. However, in reference to Figure 3.1-2, Section 3.1.1 of the MRV plan states, "This assumed that only 78 percent of the average injection pattern area or 80 acres could be filled. There are 49 injectors identified for further injection that have room for an additional 90 Bscf of CO_2 storage volume or 140 Bscf total storage." Neither the discussion nor the figure provides specific details regarding the expansion into other portions of the CFA which is mentioned in Section 3.2. In addition, it is not clear whether the current MMA includes storage of the additional 90 Bscf to be created by the 49 injectors. If the intent is to include CO_2 stored through the 49 injection wells, this should be clarified in the description of the MMA to confirm that the existing facility boundary will contain all stabilized CO_2 plumes from current and future injection wells and the boundary of the MMA will meet the half-mile buffer requirement. In the MRV plan, please expand upon any future injection plans in the CFA and explain whether the MMA accommodates them. If applicable, the diagrams in Section 3 should show the extent of the modeled plumes and the discussion in Section 3.1 should be consistent with Section 2.1.2 of the Project Description which presents the estimated volume of CO_2 to be injected. Lastly, please note that per 40 CFR 98.448(d)(1), changes in the volume of CO_2 injected can warrant a revision to your MRV plan. We recommend ensuring that this MRV plan accounts for the different injection scenarios you may encounter.	Section 3.1.2 describes plume containment as "the site characterization and stratigraphic trapping of the Morrow did not reveal any leakage pathways that would allow free-phase CO_2 to migrate laterally thereby warranting a buffer zone greater than one-half mile." Changed and added "The volumetric storage capacity calculated for the 49 patterns identified for continued injection indicates an additional 90 Bscf of CO_2 can be stored and with 50 Bscf already stored results in 140 Bscf of total storage. With the anticipated 12 MMCFD rate of purchased CO2, this storage volume will only be 60 percent utilized." Added "Areas that do not have CO_2 storage posted on Figure 3.1-2 will be evaluated if existing CO_2 injection operations experience any rate restriction or develop any operational issues in the future. If necessary, replacement wells or additional injection locations in inactive areas of the CFA will be drilled or activated. This will be accomplished by utilizing existing plugged and abandoned wells or redrilling old locations as described in Section 3.2."

2.	3.2	21	Per 40 CFR 98.449, "Active monitoring area" (AMA) is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile. (2) The area projected to contain the free phase CO_2 plume at the end of year t + 5. Section 3.2 is the only section that addresses the AMA and states, "Currently, CapturePoint's operations are focused on the western portion of the CU (Camrick Unit) and all of the NPU (North Perryton Unit). However, it is anticipated as the project develops, additional activity will occur in the NWCU (Northwest Camrick Unit) of the CFA (Camrick Field Area). However, project development is driven by the market price of oil so CapturePoint is unable to provide a specific time in the future when the eastern portion of the CFA will be developed. Therefore, for the purposes of this MRV plan, CapturePoint is continuously monitoring the entire CFA, which is the AMA." Although Section 3.2 states that the CFA is the AMA, there is no explanation or rationale for this decision. Please ensure that the discussion in section 3.2 clearly identifies the AMA boundaries, describes how the AMA for the CFA presented in the MRV plan conforms to the definition of the AMA in 40 CFR 98.449, and describes how the delineation of the AMA in the MRV plan meets the requirements in 40 CFR 98.448(a)(1).	Reworded, "The Active Monitoring Area (AMA) is defined by CapturePoint's exclusive right to operate the CFA unitized leases, as described in the INTRODUCTION and Section 2.2.1. Currently, CapturePoint's operations are focused on the western portion of the CU and the entire NPU. However, it is anticipated as time passes, or additional CO_2 volumes become available additional areas within the CFA may be developed. Additional development is driven by the market price of oil coupled with the availability of sufficient CO_2 volumes and thus the timing of additional development is uncertain at this time. As CO_2 injection operations are expanded beyond the currently active CO_2 EOR portion of the CFA, all additional CO_2 injection wells will be permitted under the UIC program and will be included in the annual submittal per 40 CFR 98.446(f)(13). All future CO_2 injection wells permitted will be within the AMA."

Additionally, corrected some grammar.

Camrick Field Area (CFA)

MONITORING, REPORTING AND VERIFICATION PLAN (MRV)

CapturePoint LLC

April 2022

Contents

INTRODUCTION

CapturePoint, LLC (CapturePoint) operates the Camrick Field Area (CFA) located in Beaver and Texas Counties, Oklahoma and in Ochiltree County, Texas for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) with retention of CO_2 serving a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The CFA was discovered in 1955 and is composed of three units, the Camrick Unit (CU) that was unitized by Humble Oil Company on October 14, 1969, the North Perryton Unit (NPU) that was unitized by Humble Oil Company on March 17, 1969, and the Northwest Camrick Unit (NWCU) that was unitized by Atlantic RichField Company on September 15, 1972. The Units were formed for the purpose of waterflooding with salt water sourced from the Wolfcamp formation. The field structure is a lenticular bedding sand trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. CapturePoint has been operating the CFA since 2017. CapturePoint acquired the CFA from Chaparral Energy LLC, which initiated the CO_2-EOR project in March 2001 for the CU and January 2007 for the NPU. No CO_2 has been injected in the NWCU. CapturePoint intends to continue CO_2-EOR operations until the end of the economic life of the CO_2-EOR program using various Class II injection wells as defined by Underground Injection Control (UIC) regulations and permitted under Texas Railroad Commission (TRRC) Rule 46 of the Texas Administrative Code (TAC) and the Oklahoma Corporation Commission (OCC) Title 165:10 of the Oklahoma Administrative Code (OAC). In this document, the term “gas” means a mixture of hydrocarbon light end components and the CO_2 component that can be produced as part of the EOR process.

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

This MRV Plan contains ten sections:

Section 1 contains facility information.

Section 2 contains the project description including: a detailed description of the injection operation including the duration and volume of CO_2 to be injected; a detailed description of the geology and hydrogeology of the CFA located on the northwest shelf of the Anadarko basin; and a detailed characterization of the injection reservoir modeling techniques employed.

Section 3 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449 and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 4 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. This section also describes the strategy for detecting, verifying, and quantifying any surface leakage of CO_2 as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Finally, this section also demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

Section 5 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 6 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 9 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 10 includes Appendices supporting the narrative of the MRV Plan.

1 Facility

1.1 Reporter Number

The CU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544678 and the NPU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544679. The EPA has been notified that the NPU will not be reporting for 2022, and that the facility has been merged into the Camrick Unit Facility Identification number 544678.

1.2 UIC Permit Class

For injection wells (see Appendix 2) that are the subject of this MRV plan, the OCC has rules governing UIC Class II injection wells. These OCC rules are OAC Title 165:10-5-1 through 165:10-5-15, OAC 165:5-7-27, OAC 165:5-7-30, the request for an exception to UIC rules under OAC 165:5-7-29, and other governing filing forms. Also, the TRRC has issued UIC Class II enhanced recovery permits under its Rule 46, TAC Title 16 Part 1 Chapter 3. All wells in the CFA, including both injection and production wells, are regulated by the OCC and the TRRC, which have primacy to implement the UIC Class II program.

1.3 UIC Injection Well Numbers

A list of the injection wells in the CFA is provided in Appendix 1. The details of the injection process are provided in Section 2.3.

2 Project Description

2.1 Project Characteristics

2.1.1 Estimated years of CO_2 injection

The CFA has been injecting CO_2 for the last 20+ years and it is currently projected that CapturePoint will inject CO_2 for an additional 12 years.

2.1.2 Estimated volume of CO_2 injected over lifetime of project

Historical and forecasted cumulative CO_2 retention volumes are approximately 100 billion standard cubic feet (Bscf) or 5.3 million metric tonnes (MMMT) from the start of CO_2

injection through October 2034. During the MRV plan, the period September 2022 through October 2034, 52.5 Bscf or 2.77 MMMT will be stored in the CFA. (See Figure 2.4-6)

2.2 Environmental Setting of MMA

2.2.1 Boundary of the MMA

CapturePoint has defined the boundary of the MMA as equivalent to the boundary of the CFA plus ½ mile beyond. A discussion of the methods used in delineating the MMA and the AMA are presented in Section 3.

2.2.2 Geology

The geological discussions in Sections 2.2.2 and 4.3-4.4 are based on analysis of logs from both the Farnsworth Unit, which is located 10 miles South-South-West of the CFA, and the CFA. Both areas have similar pay thickness, porosity values, permeability measurements, depositional environment, tectonic processes, and overburden strata layers. The descriptions of cores at the Farnsworth Unit included sections from overlying seals as well as the shale underlying the main reservoirs, petrographic thin section descriptions and point counts as well as a variety of special analytical techniques. These techniques included X-ray diffraction (XRD), which is the science of determining the atomic and molecular structure of rock crystals with an X-ray beam; scanning electron microscope (SEM) analysis, which uses a beam of electrons to define the surface of crystals; carbon isotope analysis to estimate the age of the CO_2 in the sample; and a variety of mechanical tests. Two dimensional (2D) and three dimensional (3D) geophysical surveys were also used as part of the Farnsworth Unit MRV Plan (2021). Details of recent geological investigations can be found in Gallagher (2014), Gragg (2016), Rasmussen et al (2019), Rose-Coss et al (2015), Trujillo (2018), Hobbs et al (2019), and Gragg et al (2018).

2.2.2.1 Tectonic Setting and Stratigraphy

The CFA is located on the northwest shelf of the Anadarko basin (Figure 2.2-1) and is one of many oil fields in the area that produce from a sequence of alternating sandstones and mudstones deposited during the late Pennsylvanian Morrowan period. Oil production and CO_2 injection at CFA is restricted to the operationally named Morrow B sandstone; the uppermost Morrow sandstone encountered below the Atokan Thirteen Finger limestone. The primary caprock intervals at CFA are comprised of the upper Morrow shale and the Thirteen Finger limestone (Figure 2.2-2). The Morrowan and Atokan intervals were deposited approximately 315-300 million years ago. Overlying stratigraphy includes late Pennsylvanian through the middle Permian shales and limestones, with lesser amounts of dolomite, sandstone and evaporites (Ball, 1991). The reservoir is approximately 60 feet thick throughout the field and lies at a depth of approximately 6,800-7,600 feet. The primary seal rocks of the Morrow shale and the Thirteen Finger Limestone comprise a package of approximately 180-200 feet thick in the field and are overlain by thousands of feet of Atokan and younger limestones and shales.

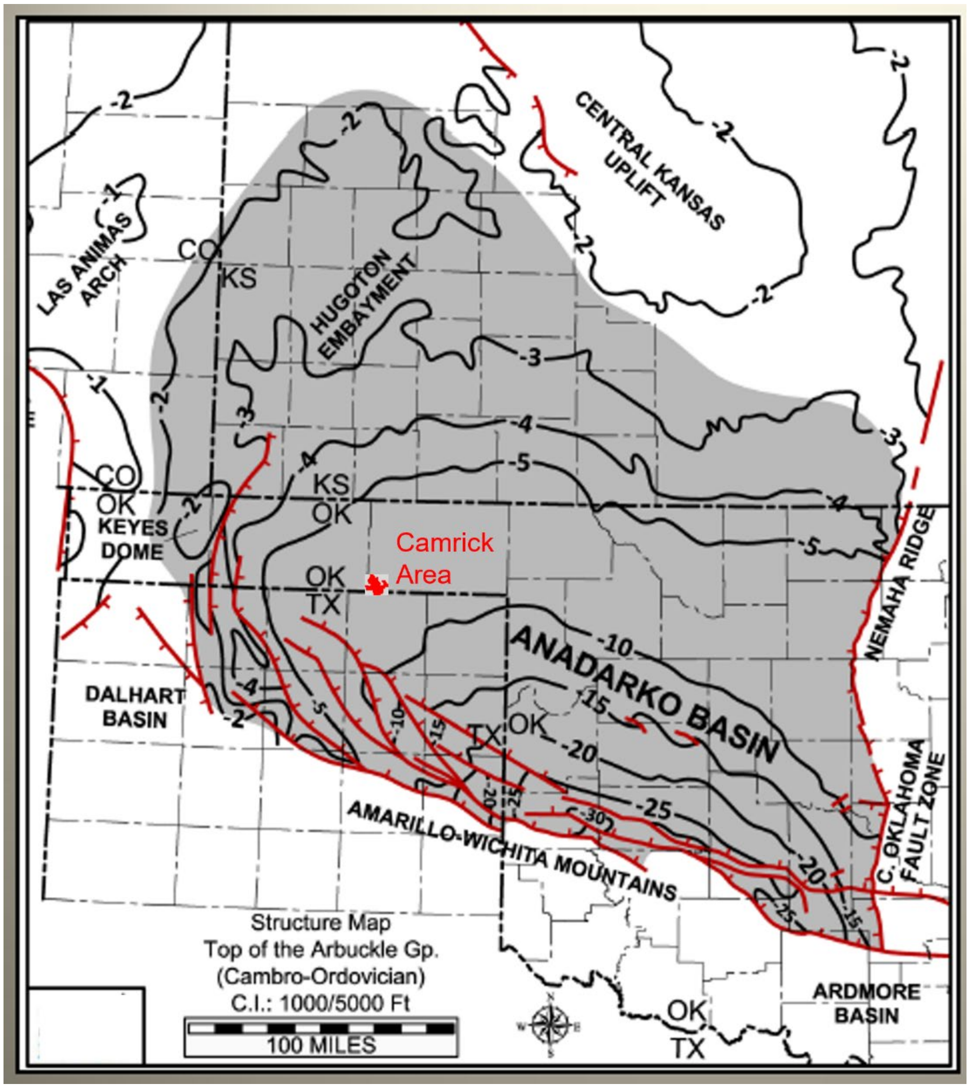

Figure 2.2-1. Location of the CFA on the Northwest Shelf of the Anadarko Basin in West Texas. Red lines are approximate locations of faults that have been documented in the region.

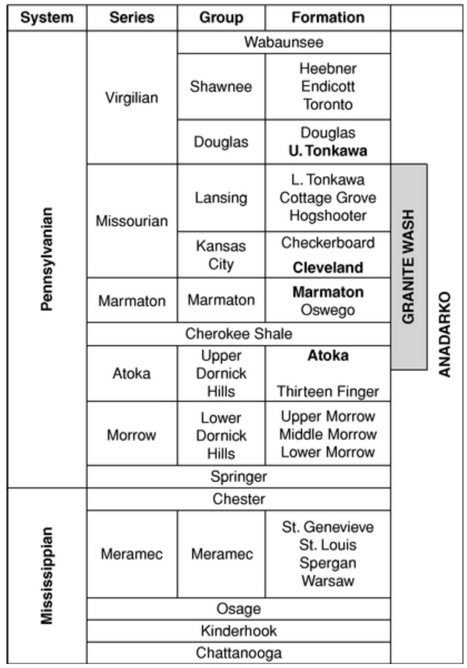

Figure 2.2-2. Stratigraphic section.

Tectonic Setting

From CFA's location on the western edge of the basin, the Anadarko Basin plunges to the southeast (Figure 2.2-3) where it reaches depths of over 40,000 feet (12,192 meters) adjacent to the Amarillo-Wichita Uplift (Perry, 1989). Maximum rates of subsidence occurred during Morrowan to Atokan times (Evans, 1979; Perry, 1989; Higley, 2014). Positive features that might have influenced deposition within the region include the Ancestral Rockies to the north, the Central Kansas uplift to the northeast, and the Wichita-Amarillo uplift to the south (Evans, 1979; Munson, 1989). Of note is the fact that during the Pennsylvanian time, the CFA was located on the basin shelf in an area that was not affected greatly by tectonic deformation. Although faults have been reported previously in the northwest Anadarko Basin, we found no direct evidence for tectonic faults within the CFA (see Section 4).

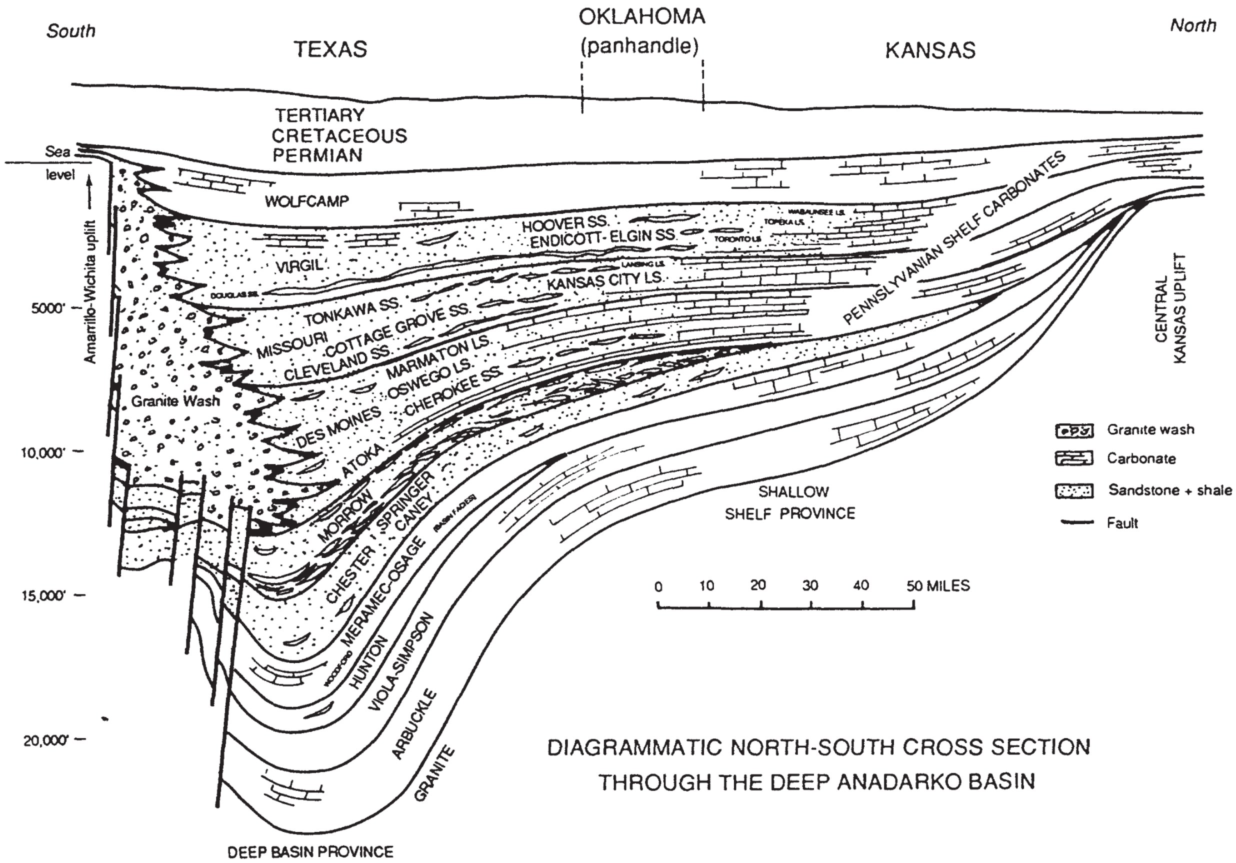

Figure 2.2-3. Diagrammatic North-South Section (Bottom) of the CFA.

Stratigraphy

Reservoir

Upper Morrowan sandstones in the Anadarko Basin margins have long been recognized as fluvial deposits (Swanson, 1979; Sonnenberg, 1985; Munson, 1989; Krystinik and Blakeney, 1990; Bowen et al., 1990; Al-Shaieb et al., 1995; Mckay and Noah, 1996; Puckette et al., 1996; Bowen and Weimer, 2003, 2004; Devries 2005; Puckette et al., 2008; Gallagher, 2014). At the Farnsworth Unit and similarly at the CFA, the Morrow B is described as a relatively coarse-grained subarkosic sandstone. The upper Morrowan facies, with sequences of basal conglomerate, coarse-grained sandstone, and fine-grained sandstone appear to be typical of incised valley deposits, as described by Wheeler et al. (1990), Krystinik and Blakeney (1990), Bowen et al. (1990), Blakeney et al. (1990), Sonnenberg et al. (1990) and Puckette et al. (2008).

Primary Seals

The Morrow B sandstones are encased above and below by shales. Contacts with shale both below and above the sandstone are sharp and irregular. The Morrow shale generally fines upwards in a series of thin beds that alternate between upper fine sands and fine to medium muds. Sand content decreases upwards through the section.

The Thirteen Finger limestone formation has two different lithofacies: diagenetic limestone (cementstone) and pyrite and fossil bearing fine to medium mudstone and coal. The two facies are intercalated with each other but tend to cluster in layers dominated more by one or the other.

The entire Thirteen Finger interval is typically 130 feet (39.6 meters) thick, comprised of mudstone, coal, and limestone. The mudstone is calcite rich, with some dolomite, and is completely diagenetic in origin and probably formed relatively soon following deposition.

2.2.2.2 Hydrogeology

Information about Morrowan and Atokan formation water flow during oil operations has not been discovered in any oil or gas company published reports or academic research studies in the Anadarko Basin. Groundwater flow rates in confined deep Anadarko layers at present are considered to be low to no flow (Nelson and Gianoutsos, 2014). Their arguments are based on (1) restricted recharge in the western basin, (2) density barriers to flow in the east, and (3) an overpressure pocket inhibiting flow in the deep basin. Jorgenson (1989) suggested flow could be west to east, driven by potential recharge to elevated units in the west and discharge at lower elevation outcrops in the east. The CFA CO_2 injection and production operations have negligible likelihood of causing water to flow to outcrops of the late Carboniferous (Pennsylvanian) time period that extend from Brownwood, Texas, to the Jacksboro/Bowie, Texas, area, which are hundreds of miles away (The Paleontology Portal).

The Carboniferous is a geologic period and system that covers 60 million years from the Devonian Period 358.9 million years ago, to the beginning of the Permian Period, 298.9 million years ago. As noted in the Section 2.2.2.1, the Morrowan and Atokan intervals of the CFA were deposited approximately 315-300 million years ago and are contained in the Carboniferous period.

2.3 Description of the Injection Process

Figure 2.3-1 depicts a simplified flow diagram of the facilities and equipment within the boundaries of the CFA. CO_2 captured from the ethanol plant fermentation process is delivered via pipeline to the field for injection. The Arkalon plant in Liberal, Kansas is the only source of CO_2 to the field. The amount delivered is dependent on the production of CO_2 produced from the fermentation process. This amount will vary but should average 12 MMCFD. Once CO_2 enters the CFA there are three main processes involved in EOR operations. These processes are shown in Figure 2.3-1 and include:

1. CO_2 distribution and injection. Purchased CO_2 is combined with recycled CO_2 from the CFA central tank battery (CTB) and sent through the main CO_2 distribution system to various water alternating gas (WAG) injectors.

2. Produced Fluids Handling. Full well stream fluids are produced to the “all well test” (AWT) site. The AWT site has two major purposes; 1) to individually test a well’s performance by separating and metering oil, gas, and water, and 2) to separate all gas from liquid then send these two phases to the CTB for final separation; while only the gas from NPU is sent to the CTB the NPU oil and water remains in Texas.

3. Produced Gas Processing. All gases from the AWT sites are transferred to the CTB to separate the oil, gas, and water using a series of vessels and storage tanks.

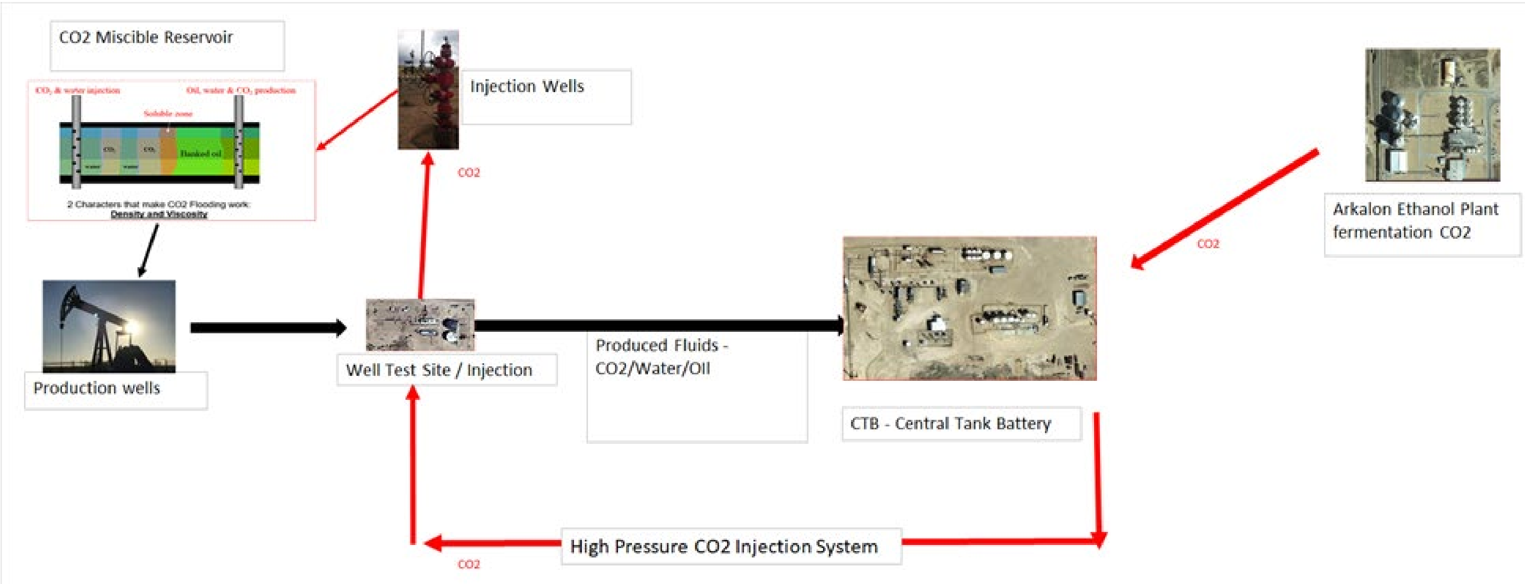

Figure 2.3–1. Simplified flow diagram of the facilities and equipment within the boundaries of the CFA.

2.3.1 CO_2 Distribution and Injection

CapturePoint purchases CO_2 from Conestoga Energy Partners, the parent company of the Arkalon Ethanol plant located in Liberal, Kansas. A custody transfer meter is located in the compression facility owned and operated by CapturePoint. The purchased CO_2 from the fermentation process is transported via a United States Department of Transportation (DOT) regulated pipeline to the CFA. A totalizer meter, for the purchased CO_2, is located in the field where instantaneous data is summed into a 24-hour flow rate which is recorded. A totalizer meter is a meter approved by the American Gas Association (AGA) Report #3 to measure the flowrate of gases. The actual measurements taken are temperature, line pressure, and differential pressure across the meter. Gas produced, which contains recycled CO_2, from the wells is compressed and metered by a similar totalizer meter as the purchase CO_2 meter and is recorded daily.

CapturePoint currently has seven active injection manifolds and approximately 29 active injection wells that the CO_2 is distributed through. When the MRV plan becomes active, the daily injection volume of the combined purchased CO_2 and recycled CO_2 will be approximately 24 MMCFD. Of this volume 12 MMCFD is purchased CO_2 and 12 MMCFD is recycled CO_2. This ratio of purchased CO_2 to recycled CO_2 is expected to change over time, with the percentage of recycled CO_2 increasing and purchased CO_2 decreasing. The current reservoir management plan projects that CO_2 purchases will remain constant at 12 MMCFD for 12 years and cease after 2034. A reservoir management plan is an integrated process using various surveillance techniques, economic evaluations, and accepted petroleum technical practices to efficiently operate enhanced oil recovery projects.

The seven injection manifolds currently in the field distribute the CO_2 to the field. These manifolds have valves to switch to water when the time is called for. Depending on the reservoir management plan, the WAG cycle will be adjusted to maximize oil recovery and minimize CO_2 utilization in each injection pattern. At each injection well pad there is a totalizer to measure the volumes injected every 24 hours. This data is collected daily by the field personnel and input into the data warehouse to be allocated for the pattern injection.

The two totalizer meters as described above will be used to determine the total volume injected used in section 7 for the mass balance equations necessary to determine annual and cumulative volumes of the stored CO_2.

2.3.2 Produced Fluids Handling

As injected CO_2 and water migrate through the reservoir; a mixture of oil, gas, and water (referred to as "produced fluids") flows to the production wells. Gathering lines bring the produced fluids from each production well to the AWT sites. CapturePoint has approximately 32 active production wells producing at any time. Each AWT has two separators. The first separator is used for testing individual wells to separate the gas, oil, and water produced from an individual well. This gas, oil, and water is subsequently measured and recorded for the well. Each producing well is production tested every 30 to 60 days after the last production test, or after the well is returned to production. Depending on the reservoir management plan, well testing can be more frequent to obtain data. The second separator is used to separate the gas from the oil/water mixture from the other wells producing into the AWT, and the gas and liquids are displaced from the vessel in separate lines. Leaving the AWT sites are two lines transporting produced fluids. One line is used for the liquid phase, a mixture of oil and water, and one line is used for the gas phase. However, the AWT in NPU does not transfer oil or gas to the CTB, it only transfers gas while reinjecting water with pumps at the NPU AWT and sells oil at the NPU AWT.

When gas and liquid lines enter the CTB, a series of vessels separate the oil, gas, and water to be accounted for and distributed for sales or reinjected. The liquid phase line has vessels to separate the oil from the water using density and residence time. The gas phase vessels collect any free liquids entrained with the gas. These free liquids are then combined back into the liquid phase line. All gas and water are reinjected, and the oil, which contains an estimated 2,360 ppm CO_2 (0.236%) for CU and 4,540 ppm CO_2 (0.454%) for NPU, is sold out of tanks. Annually, the oil from the stock tank is analyzed by a laboratory using ASTM crude oil analysis methods to determine the CO_2 content in the oil being sold.

After separation, the gas phase, which is approximately 92-95% CO_2, is mixed with reservoir volatile components, compressed, and distributed throughout the high-pressure distribution system using reciprocal compression and high-pressure horizontal pumps.

The water is transferred from the separation vessels to tanks for reinjection. After the water is conditioned, it is either reinjected at the WAG skids or disposed of into permitted disposal wells. Although CapturePoint is not required to determine or report the amount of dissolved CO_2 in the water as it is reinjected into the ground and not emitted to the atmosphere, the analyses have shown the water typically contains <690 ppm (0.069%) CO_2.

CFA production has trace amounts of hydrogen sulfide (H_2S), which is toxic. There are approximately 8-10 workers on the ground in the CFA at any given time, and all field and contractor personnel are always required to wear H_2S detectors. The primary purpose of the H_2S detectors is protecting people from the risk of being harmed. The detection limit of the H_2S detectors is quantified for readings in the range of 0-100 ppm and will sound an alarm above 10 ppm. The secondary purpose of the H_2S detectors would be to provide an indication of emissions of gas from a pipeline or surface equipment, that might go unnoticed by other observations or measurements. No gas volumes can be calculated based on the detector reading or alarm; only a H_2S leakage is detected and located. Once identified, a further response will be initiated and CO_2 volumes will be quantified as discussed in sections 4.5, 4.6, 5.4, and 8.1.5 of this MRV plan.

2.3.3 Produced Gas Handling

Produced gas separated at the CTB is stripped by a series of vessels of entrained and free water. The water content has been recorded to be < 20 pounds mass per MMCF, thus dehydration is not necessary. The gas is then sent to a centralized compression system to be compressed and placed in the high-pressure distribution system. This compression turns the CO_2 into a variable density liquid, which is then transported out via high pressure lines to the AWT sites where a manifold splits this dense CO_2 to the wells that are on CO_2 injection at that time.

2.3.4 Facilities Locations

The locations of the AWT sites are positioned in the field to access both injection distribution and production gathering. The CTB is where the final separation and injection equipment is maintained and operated. The water injection station is where the horizontal pumps are located to reinject the produced brine.

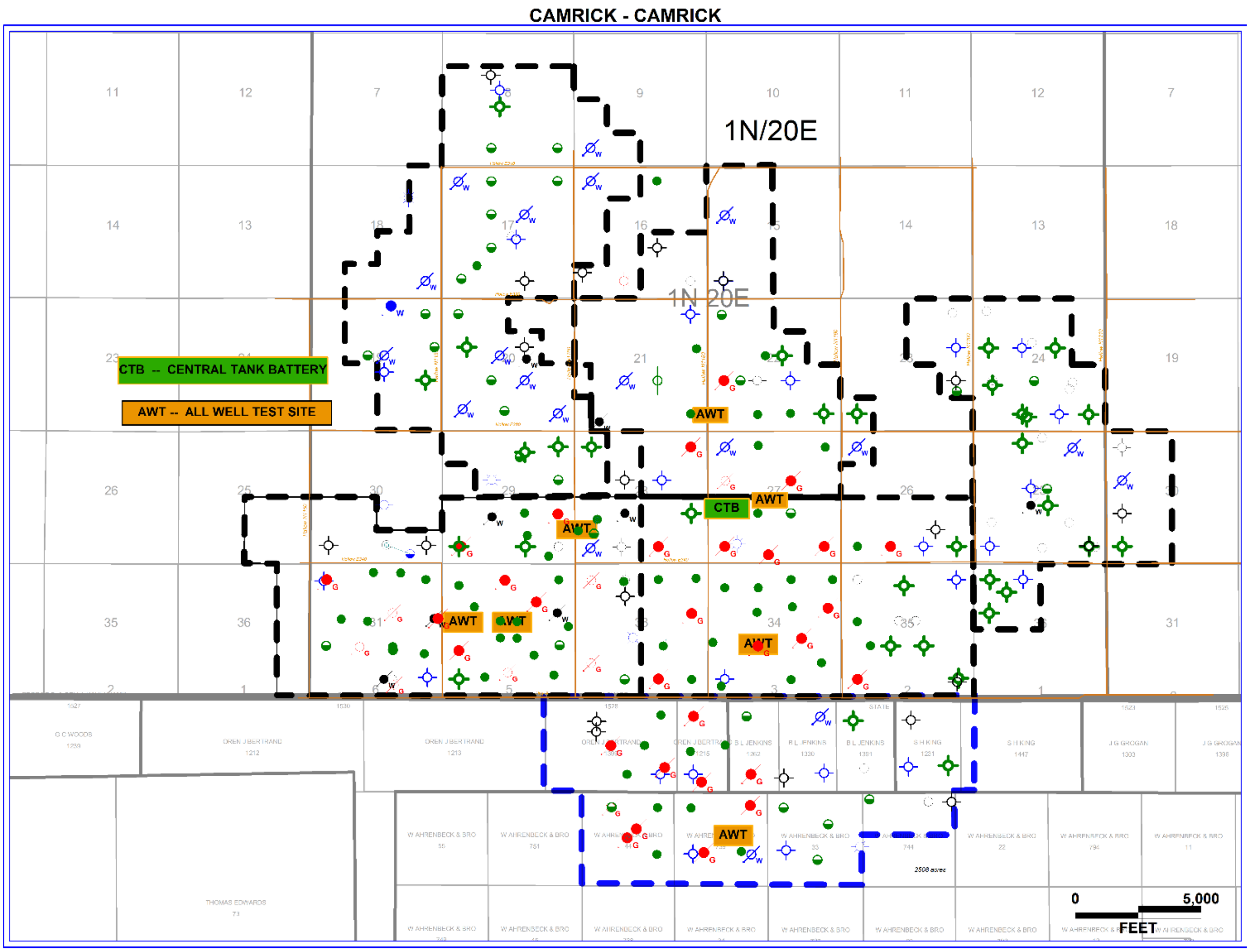

Figure 2.3-2. Location of AWT sites and CTB in the CFA

2.3.5 Water Conditioning and Injection

Produced water collected at the CTB is collected in a series of vessels and tanks in a cascade system. This allows any entrained oil to further separate to the top of the tanks because of the density difference. This oil is skimmed off and put back in the oil separation system. The clean water is then transferred to the water injection system where it is boosted in pressure and sent out to the AWT sites for distribution to all wells that are currently on water injection.

2.3.6 Well Operation and Permitting

The OCC and TRRC rules (Appendix 2) govern well location, construction, operation, maintenance, and plugging for all wells in permitted units and wells. CapturePoint follows these rules and regulations to maintain safe and efficient operations. This includes complying with all current and updated information for mechanical integrity testing, well repairs for injection wells, drilling and completion, permitting, and reporting.

Briefly, the following bulleted list is what the current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface waters.
- That wells file a completion report including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore).
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.
- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location, and setting of plugs.

2.3.7 Number, Location, and Depth of Wells

CapturePoint's CFA injection wells are listed in Appendix 1. Injection is into the Upper Morrowan, a lenticular bedded sandstone trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. The Upper Morrowan is described in section 2.2.2.1 above.

2.4 Reservoir Characterization

2.4.1 Reservoir Description

The target reservoir CFA Morrow B is a sandstone formation overlain by the Morrow shale and the Thirteen Finger limestone, which serve as excellent seals for injected CO_2 as determined by Farnsworth data (Ampomah et al., 2016a). The Morrow B sandstone reservoir is at a depth between 6,800 feet and 7,600 feet subsurface with an average dip of less than one degree (Figure 2.4-1). The productive limit of the CFA is about 80 to 90 percent of the total operated surface acreage, which is 14,652.315 acres. The maximum pay thickness is 56 feet with an average of 15 feet and does diminish to zero in spots.

The CFA is approximately eight miles by seven miles with areas that exhibit different reservoir behavior. The southwest portion of CU was most prolific oil producing area of the CFA under primary and secondary production; whereas the western portion of NPU is now responding to CO_2 better than historical operations would have indicated.

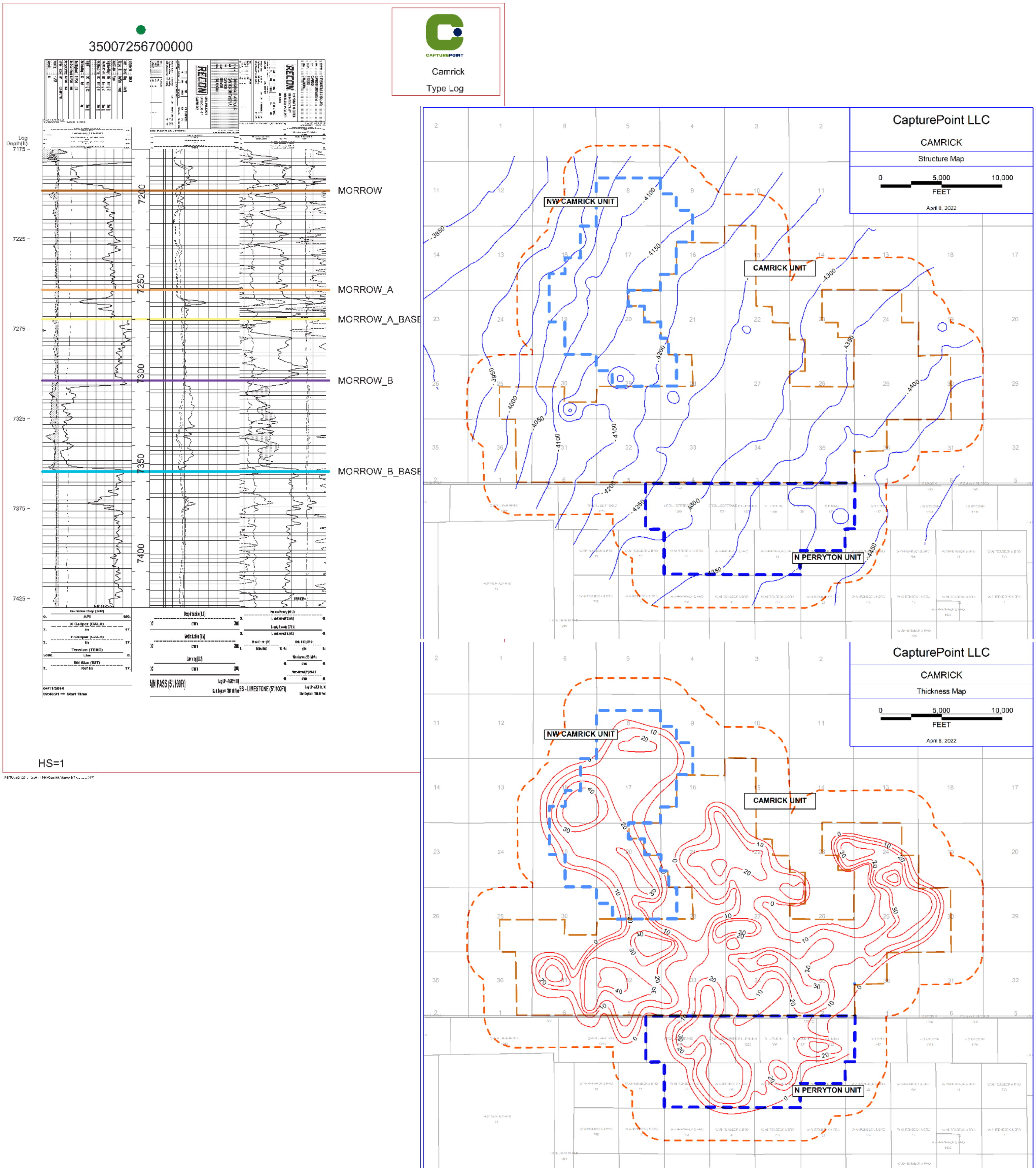

Figure 2.4-1. (Left) Type log of CFA caprock and reservoir, (Upper Right) Surface contour of Morrow top, (Lower Right) Thickness map of Morrow sands.

2.4.2 Reservoir Fluid Modeling

The compositional fluid model was constructed for the CapturePoint operated Farnsworth Unit. From laboratory compositional analysis an equation of state was tuned (Gunda et al., 2015). The minimum miscibility pressure (MMP) experiment was then simulated using a one-dimensional model. The simulated Farnworth Unit MMP of 4,009 psia compared to an MMP value of 4,200 psia derived from laboratory experiments provided by the operator represents a less than 5% error (Gunda et al., 2015).

The reservoir temperature in the CFA is 152 degrees Fahrenheit or 16 degrees lower than the temperature at Farnsworth Unit of 168 degrees. Using parameters of the Alston empirical correlation (1985), the MMP would be 170 psia lower at the CFA or 3,510 psia compared to 3,680 psia at the Farnsworth Unit (Figure 2.4-2).

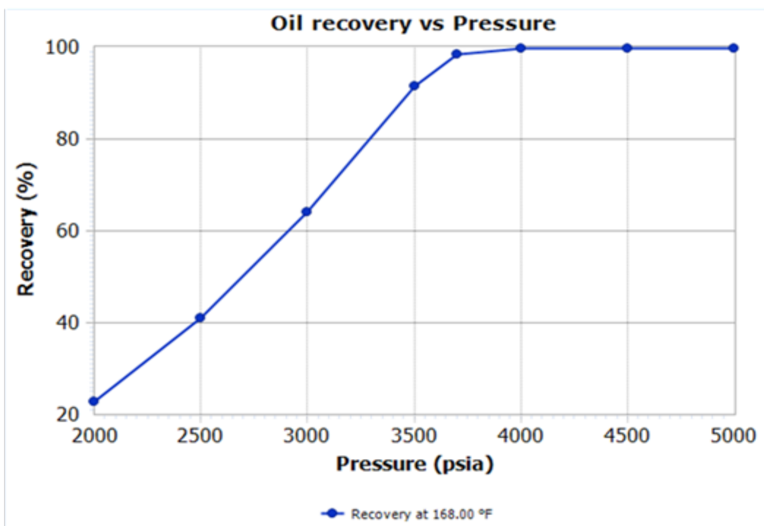

Figure 2.4-2. Oil recovery plot for 1D slim tube test for Farnsworth Unit.

2.4.3 CO_2 Analogy Field Study

Based on similar geologic, petrophysical, engineering, and operational parameters between the Farnsworth Unit and the CFA, the oil recovery performance of both fields is expected to be similar. Due to the stratigraphic nature of the Morrow channel sands, the potential movement of CO_2 is severely limited. The CFA area has contained the free phase CO_2 plume in a very confined area since March 2001 as exhibited by oil, water, and CO_2 recovery performance. Also, during CFA drilling and production operations, no reports exist which would indicate any plume has moved outside of the MMA. The Farnsworth Unit MRV and the CFA data justifies the conclusion that CO_2 will continue to be contained inside the MMA at the end of the CO_2 injection year t + 5, per §98.449 definitions.

2.4.4 CO_2 – EOR Performance Projections

For years, the oil industry has used dimensionless equations to predict the amount of oil that can be recovered using CO_2 for flooding oil reservoirs (Lee et al, 2018, Stell 2010). The

amount of oil recovered from projects is plotted as a decimal fraction of the original-oil-in-place versus the decimal fraction of the hydrocarbon pore volume (HPV) of CO_2 injected into the oil reservoir as measured in reservoir barrels (RB).

The CFA has been injecting CO_2 since March 2001. The dimensionless curves were matched to historical performance through early 2020 (Figure 2.4-3). The supply of CO_2 was curtailed from March 2020 until present, due to oil price uncertainty, and will resume after the Arkalon Plant upgrade that will be finished in the 4th quarter of 2022.

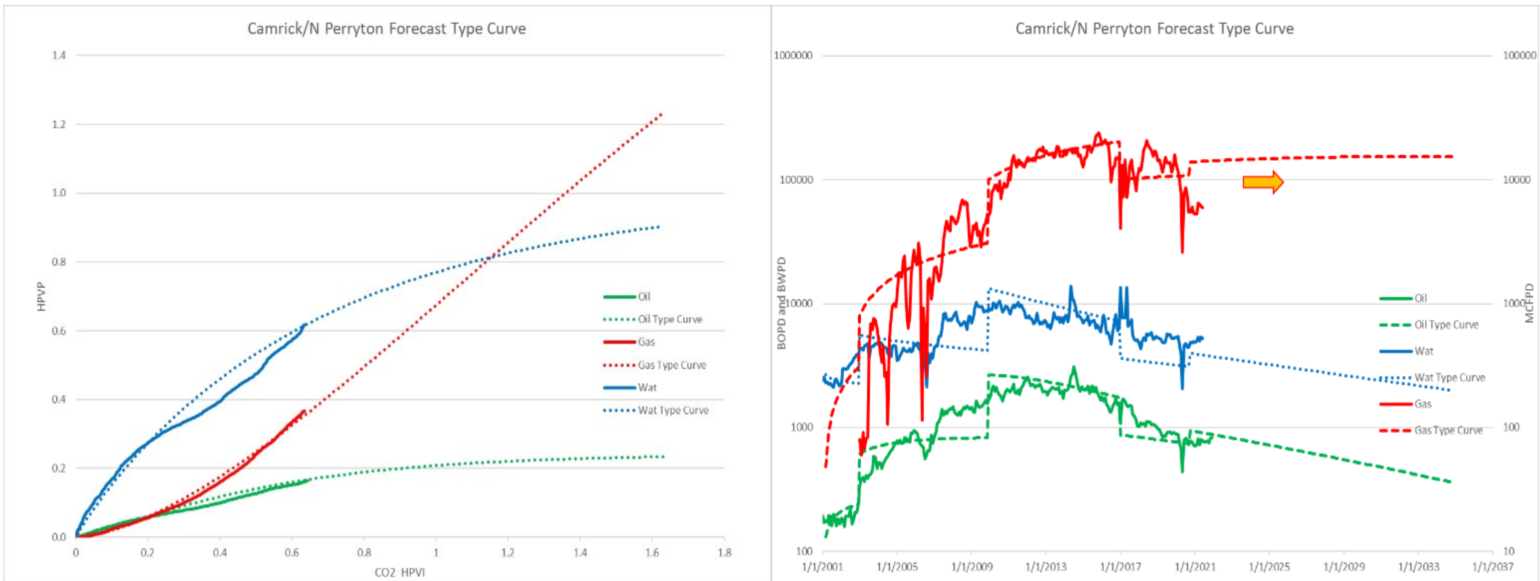

Figure 2.4-3. Dimensionless curves for CO_2 injection (left) with rate time curves (right).

The dimensionless water oil ratio and the gas oil ratio trends (Figure 2.4-4) for the CFA flooded acreage are very similar to what was forecasted by simulation in the Farnsworth Field as expected because of the porosity, permeability, and sand similarities.

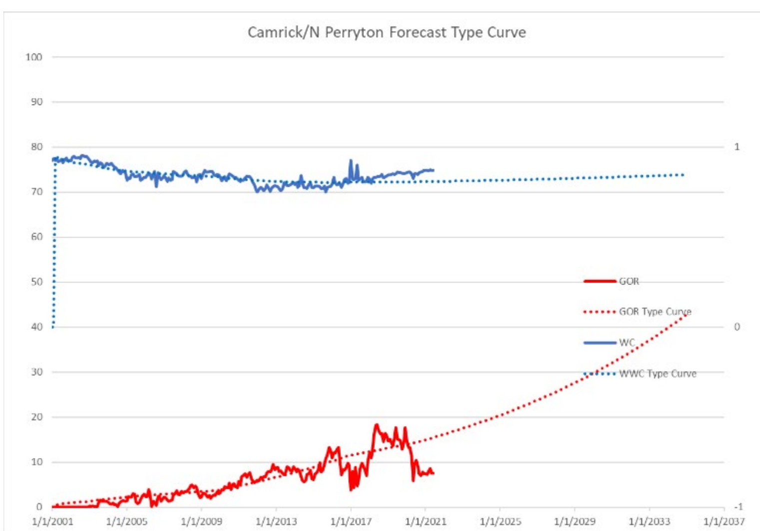

Figure 2.4-4. Dimensionless water cut and GOR vs. observed EOR data.

The CO_2 storage volumes for Arkalon fermentation CO_2 were also forecasted (Figure 2.4-5) using the same dimensionless technique. This technique indicates that the flooded acreage still has significant additional storage potential. The maximum CO_2 storage is limited to the amount of space available by the removal of the produced hydrocarbon. The projection indicates that there is pore space available to store approximately 0.4 to 0.5 decimal fraction of HPV amounting to 30 to 40 MMB.

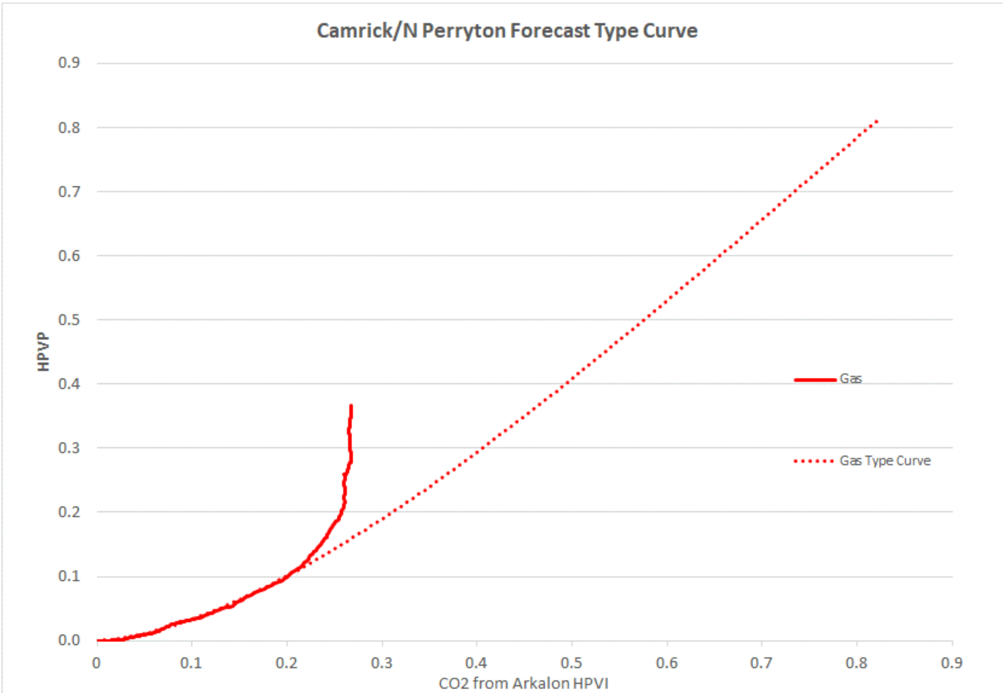

Figure 2.4-5. Dimensionless CO_2 Fermentation Curves

The barrels of reservoir volume were converted to standard cubic feet of gas and is displayed in the CFA Purchase CO_2, or Fermentation CO_2, vs Time chart (Figure 2.4-6).

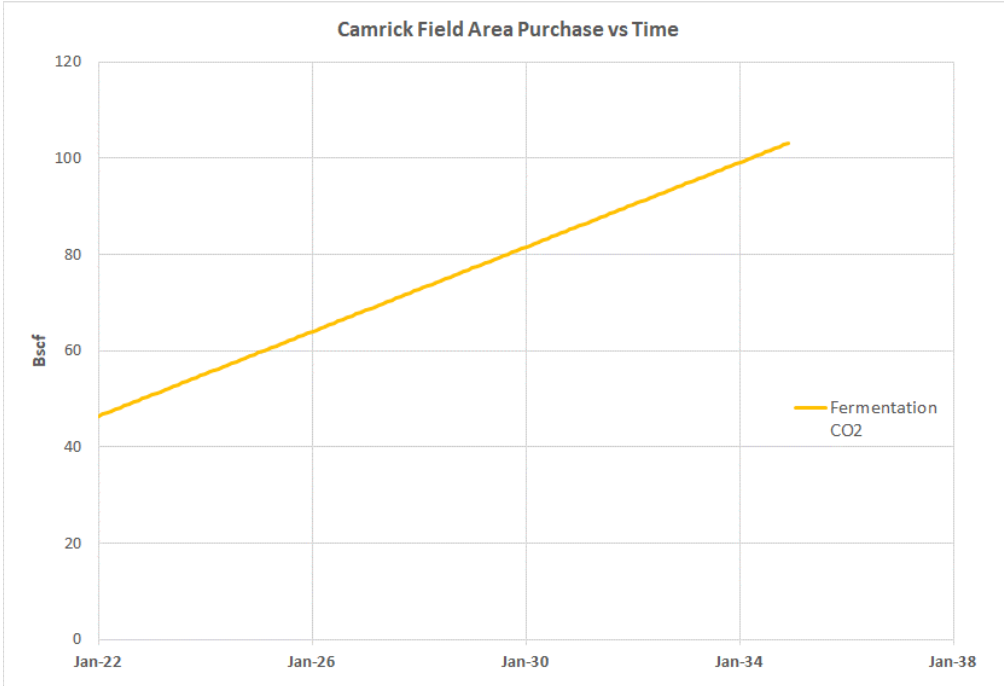

Figure 2.4-6. CO_2 Fermentation Volume.

3 Delineation of Monitoring Area

3.1 MMA

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The purchase volumes that are displayed in Figure 2.4-6 were mapped and are displayed in Section 3.1.1 indicates that CO_2 storage pore space is available, barring unforeseen future operational issues. Therefore, CapturePoint is defining the MMA as the boundary of the CFA plus an additional one-half mile buffer zone. This will allow for operational expansion throughout the CFA for the next 12 years, the anticipated life of the project.

3.1.1 Determination of Storage Volumes

Figure 3.1-1 displays wells that have CO_2 retention on the 4,800 acres that have been under EOR injection in the CFA since project initialization. The volume of the oil recovered since August 1955, resulted in a voidage space of 36 MMscf of CO_2 per acre of surface area that was later filled with water during waterflood. The average decimal fraction of CO_2 injection to hydrocarbon pore volume left in the ground after accounting for CO_2 production through 2021 is 0.29. The lateral extent of CO_2 in the injection zone or the CO_2 storage radius for each well was estimated based on cumulative CO_2 injected times the decimal fraction of CO_2 remaining divided by the voidage space. The largest CO_2 storage areas are around wells that injected CO_2 for the most years.

Figure 3.1-2 displays the potential area of the reservoir that can be filled with CO_2 with the existing injection wells. This assumed that only 78 percent of the average injection pattern area or 80 acres could be filled. There are 49 injectors identified for further injection that have room for an additional 90 Bscf of CO_2 storage volume or 140 Bscf total storage.

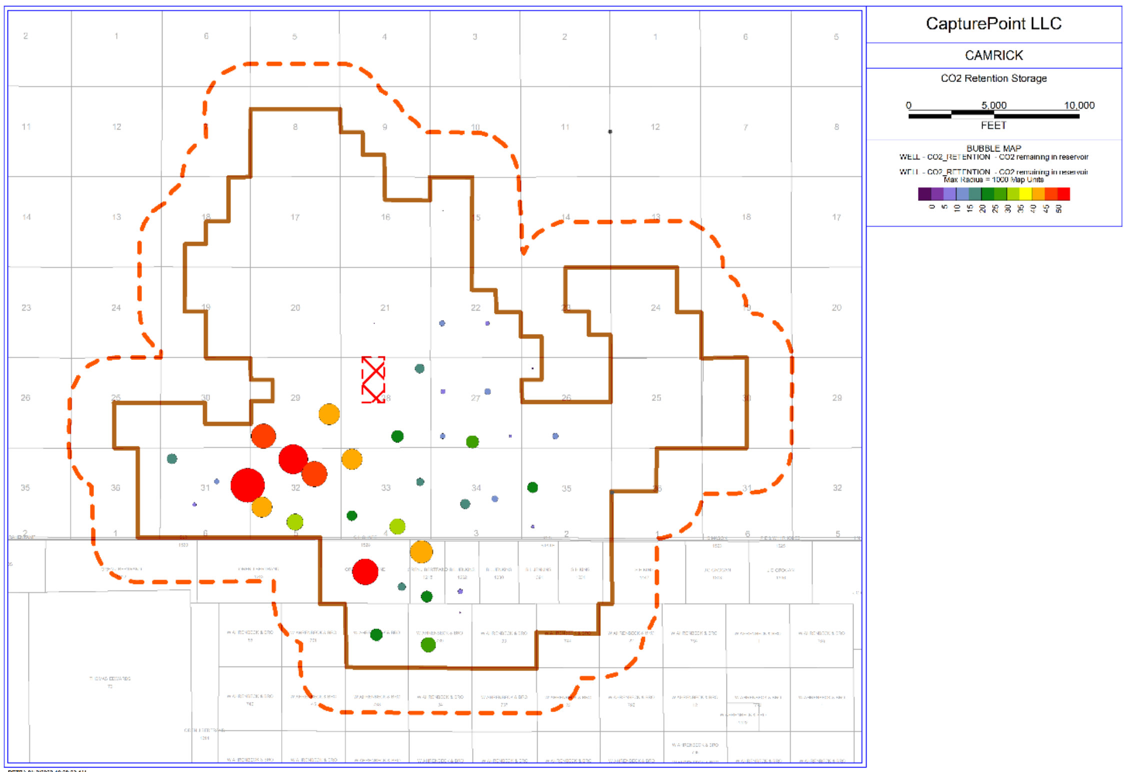

Figure 3.1-1. Estimated CO_2 storage as of 2021 in CFA.
The AMA is the land area inside the solid line polygon except for the red hashed rectangle.
The MMA extends to dotted red line and includes the red hashed rectangle.

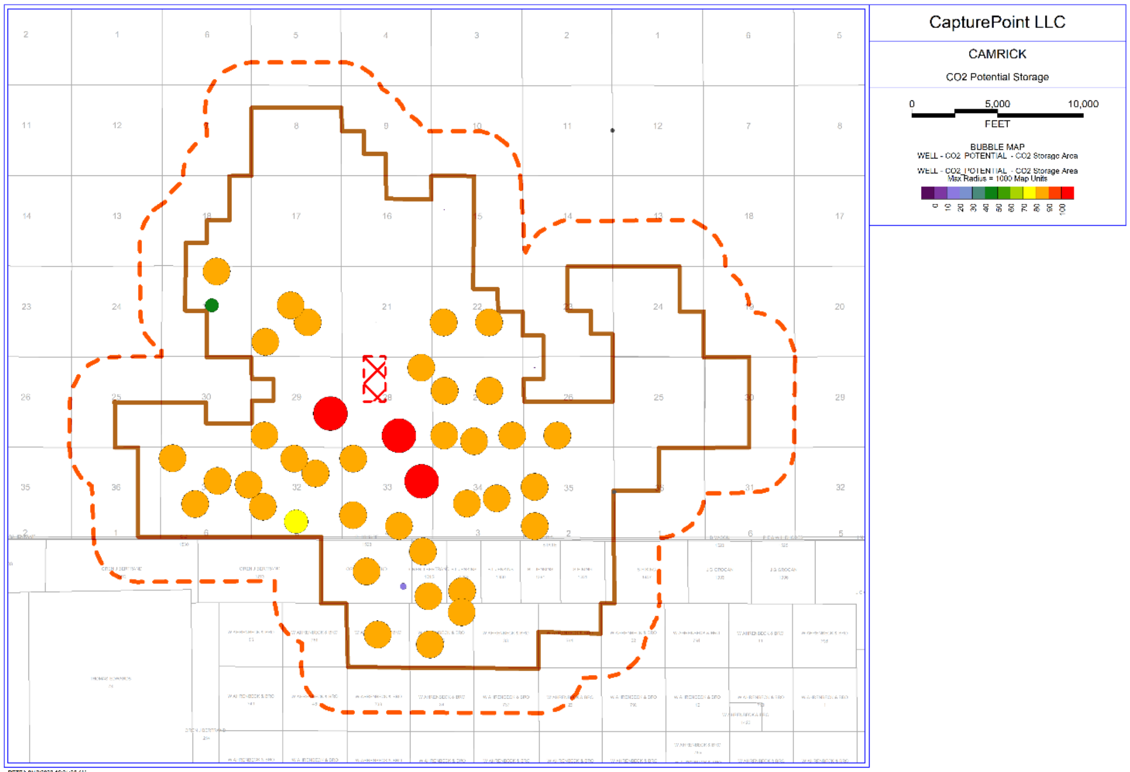

Figure 3.1-2. Potential Total CO_2 Storage in the CFA.
The AMA is the land area inside the solid line polygon except for the red hashed rectangle.
The MMA extends to dotted red line and includes the red hashed rectangle.

3.1.2 Determination of Buffer Zone

CapturePoint intends to implement a buffer zone of one-half mile around the CFA, the minimum required by Subpart RR, because the site characterization of the Morrow did not reveal any leakage pathways that would allow free-phase CO_2 to migrate laterally thereby warranting a buffer zone greater than one-half mile.

3.2 AMA

Currently, CapturePoint's operations are focused on the western portion of the CU and all of the NPU. However, it is anticipated as the project develops, additional activity will occur in the NWCU of the CFA. However, project development is driven by the market price of oil so CapturePoint is unable to provide a specific time in the future when the eastern portion of the CFA will be developed. Therefore, for the purposes of this MRV plan, CapturePoint is continuously monitoring the entire CFA, which is the AMA.

4 Identification and Evaluation of Leakage Pathways

Since its discovery in 1955, the unitization of the different units from 1969 to 1972, and the commencement of CO_2 EOR in 2001; the CFA is an analogous field to the Farnsworth Unit, which has undergone extensive investigation and documentation as indicated in Section 2. From this body of work, CapturePoint has identified the following potential pathways of CO_2 leakage to the surface. This section will also address detection, verification, and quantification of leakage from each pathway.

4.1 Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO_2 EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment via personnel instructed on how to detect surface leaks and other equipment failure minimizes releases. In addition, the Oil and Gas Division requirements of the OAC rules of the OCC and the TAC rules of the TRRC to report and quantify leaks, both serve to minimize leakage of GHG from surface equipment. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. As described in Section 6.4 below, should leakage from surface equipment occur it will be quantified according to the procedures in Subpart W of the GHGRP.

4.2 Leakage from Wells

CapturePoint has identified 68 abandoned wells, 49 injection wells (29 active) and 94 production wells (59 active) within the MMA and assessed their potential for leakage of CO_2 to the surface as listed in Appendix 1.

4.2.1 Abandoned Wells

Figure 4.2-1 shows all wells plugged and abandoned in the CFA. Because the CFA was unitized in 1969 to 1972, all plugging and abandonment activities of wells within the CFA have been conducted under the regulations of the OCC and the TRRC for plugging wells. The cement used to plug wells when exposed to CO_2 will form colloidal gels that further reduce any flow. CapturePoint concludes that leakage of CO_2 to the surface through abandoned wells is unlikely. However, strategies for leak detection are in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

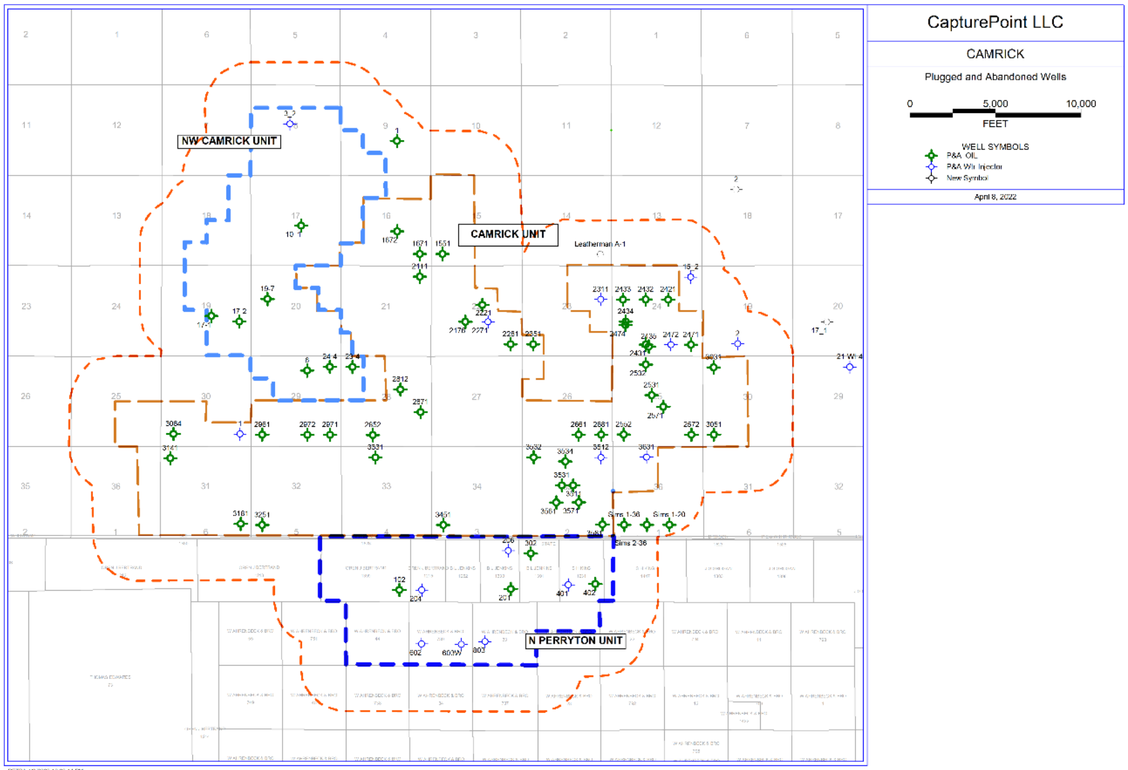

Figure 4.2-1. Plugged and Abandoned Wells in the CFA.

4.2.2 Injection Wells

Mechanical integrity testing (MIT) is an essential requirement of the UIC program in demonstrating that injection wells themselves do not act as conduits for leakage into underground sources of drinking water (USDW) and to the surface environment. TRRC Rule 46 requirements include special equipment requirements (e.g., tubing and packer) and modification; records maintenance; monitoring and reporting; testing; plugging; and penalties for violations of the rule. Permit revocation may result as a consequence of noncompliance. (See Section 2.3.6) The TRRC and the OCC detail all the requirements for the Class II permits issued to CapturePoint. These rules ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Figure 4.2-2 shows the active injection wells in the CFA. CapturePoint concludes that leakage of CO_2 to the surface through active injection wells is unlikely.

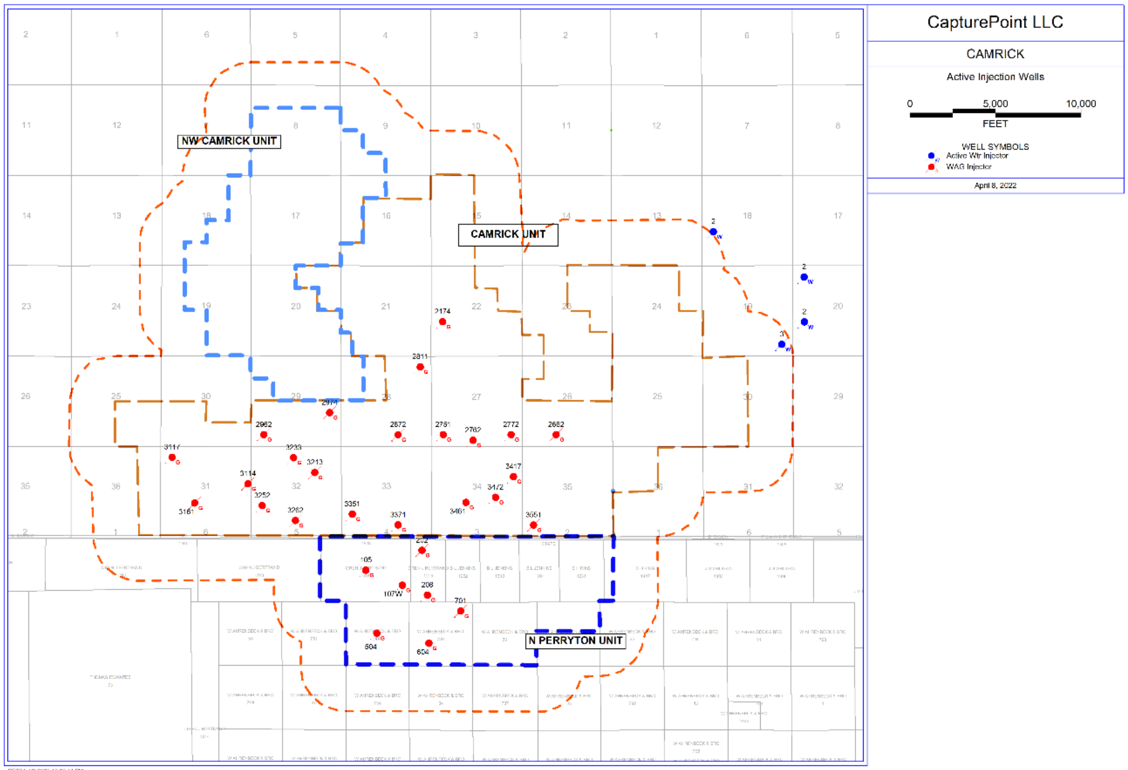

Figure 4.2-2. Active Injection Wells in the CFA.

4.2.3 Production Wells

Some of the original field wells drilled as oil wells were reclassified, administratively, to gas wells per OAC Title 165:10-1-6 paragraph (d), because of the gas-oil ratio growth due to reservoir depletion. Hence, there is no difference in well construction. (See Section 2.3.6) As the field is being further developed for enhanced oil recovery, these gas wells have been reclassified to oil wells per OCC regulations and will be monitored for leakage. (See Section 4.7) Figure 4.2-3 shows the active oil production wells in the CFA. Once EOR operations commence, the energy content of the produced gas drops and cannot be sold; therefore, any inactive gas wells are either reclassified to oil producers, or activated to WAG injectors, as described earlier. (See Section 4.2.2) However, as the project develops in the CFA additional production wells may be added and will be constructed according to the relevant rules of the OCC and the TRRC. Additionally, inactive wells may become active according to the rules of the OCC and the TRRC.

During production, oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure where the bottom hole wellbore pressure is less than the reservoir pressure. These lower pressure fluids, which also contains CO_2, are contained by the casing, tubing, wellhead, and flowline all the way to the CTB. CapturePoint concludes that leakage of CO_2 to the surface through production wells is unlikely.

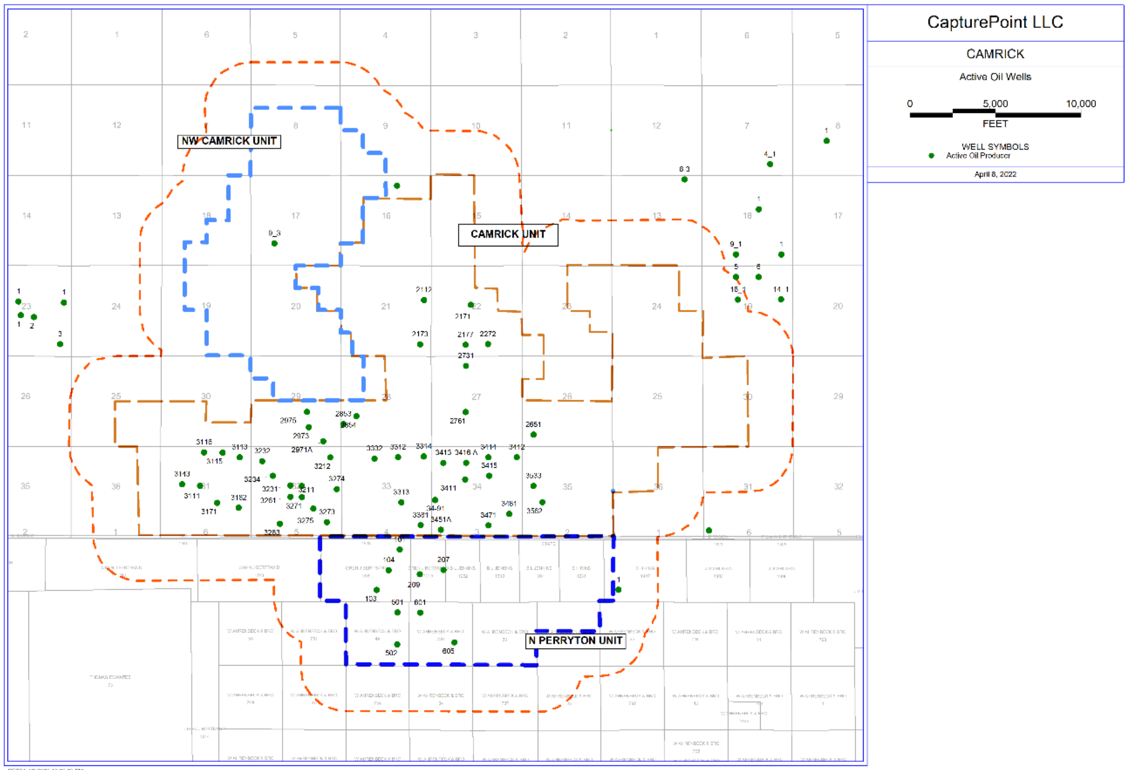

Figure 4.2-3. Active Oil Production Wells in the CFA.

4.2.4 Inactive Wells

Figure 4.2-4 shows all of the inactive wells in the CFA. The OCC has regulations for temporally abandoned/not plugged (TA) and terminated order wells/UIC not plugged (TM) and likewise the TRRC has regulations for inactive wells.

Inactive wells have a cast iron bridge plug set or long cement plugs placed above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. CapturePoint concludes that leakage of CO_2 to the surface through inactive wells is unlikely.

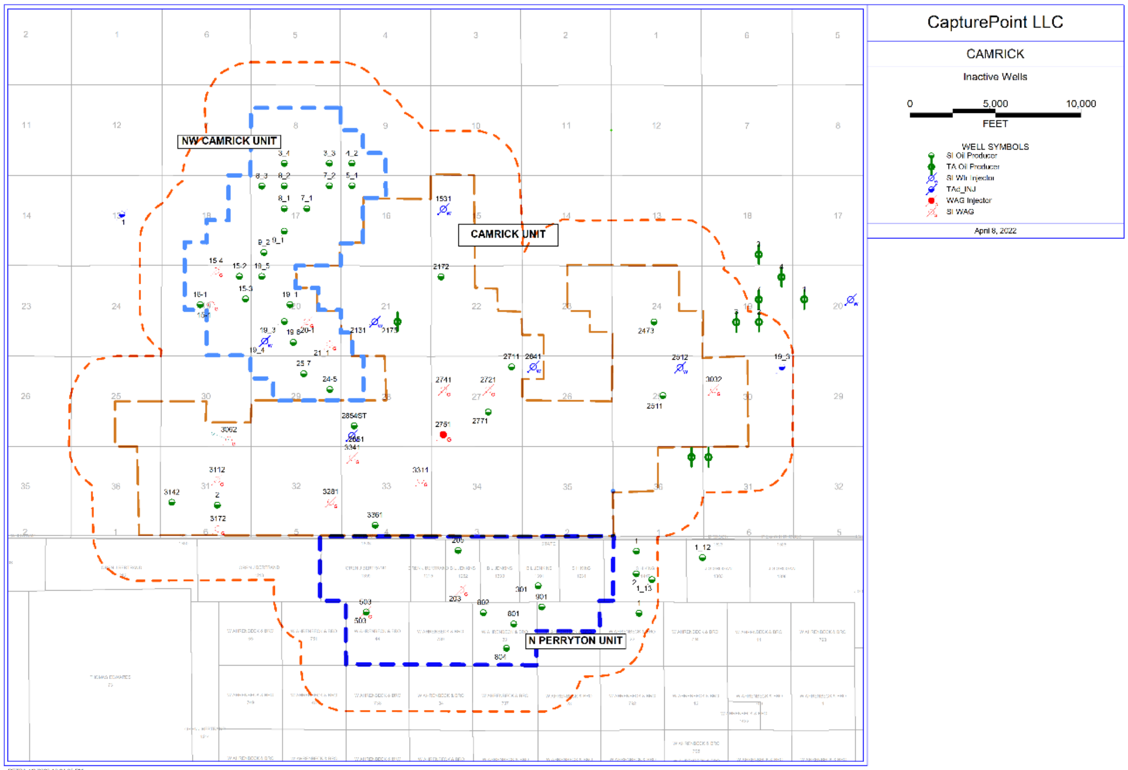

Figure 4.2-4. Inactive wells in the CFA

4.2.5 New Wells

As the project develops, new production wells and injection wells may be added to the CFA. All new wells will be constructed according to the relevant rules for the OCC and the TRRC which ensure protection of subsurface and surface resources, and the environment.

All wells in Oklahoma oilfields and all wells in Texas oilfields, including both injection and production wells, are regulated by the OCC and the TRRC, respectively, which has primacy to implement the UIC Class II programs.

Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Briefly current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface water.
- That wells file a completion report including basic electric logs.
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.

- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.

New well construction is based on existing best practices, established during the drilling of existing wells in CFA and follows the OCC and the TRRC rules, which significantly limits any potential leakage from well pathways. Additionally, the existing wells followed the OCC and the TRRC rules.

In public databases, the area of CFA plus one mile past the unit boundary contains over 100 wells that were drilled deeper than the Morrow formation and none of these wells were productive in reservoirs deeper than the Morrow. Therefore, it is very unlikely that anyone will ever drill through the AMA reservoir in the future. In the event a well is drilled within the AMA, the operator would be required to follow all the OCC and the TRRC rules and procedures in the drilling the well and the potential for leakage would be similar to any well that CapturePoint drills within the AMA. In addition, CapturePoint's visual inspection process during routine field operation will identify any unapproved drilling activity in the CFA.

4.3 Leakage from Faults and Bedding Plane Partings

Primary seals at CFA have been demonstrated to be mechanically very competent (see Section 2.2.2), thus the main concern of CO_2 migration at CFA is via seal bypass systems along fracture networks. The following lines of analysis have been used to assess this risk in the area.

4.3.1 Prescence of Hydrocarbons

The first and foremost argument against present day up-fault transmissibility is the 75 MMB of oil that was found trapped in the reservoir. If significant escape pathways existed, oil would have drained from the reservoir prior to the current day.

4.3.2 Fracture analysis

At the CFA, the work done at the Farnsworth Unit is analagous, where small aperture fractures were noted but not common in most of the reservoir cores examined but most of these fractures appear to be drilling induced. Fractures in the Thirteen Finger limestone caprock were described using an industry-standard format for fracture class type, orientation, fracture dip, type of mineral fill, fracture porosity, fracture spacing, and intensity. Again, drilling induced fractures are most common. Natural mineral-filled fractures are quite rare, were formed during diagenesis at shallow depths, and are of late Carboniferous age. Unless significantly damaged by large changes in reservoir pressure, they are highly unlikely to provide migration pathways.

In the unlikely event CO_2 leakage occurs as a result of leakage through the faults and fractures, it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.4 Lateral Fluid Movement

The Morrow strata in the Oklahoma and Texas Panhandle was primarily a deltaic sequence that prograded toward the southeast, resulting in deposition of mainly shales with lenticular, discontinuous coarse sandstones separated with very fine sandstone, minor conglomerates, and shale. The likelihood of any extensive migration of fluid outside of the AMA is very low.

Since CO_2 is lighter than the water remaining in the reservoir, it will migrate to the top of each lenticular structure as it is filled. The producing wells, which create low pressure points in the field, will drain the water and keep the CO_2 within each discontinuous sandstone.

4.5 Leakage through Confining/Seal system

At the CFA, the work done at the Farnsworth Unit will apply, where a variety of analytical methods were used for caprock (confining system) analysis, and the results should be the same for the CFA. Petrologic examination included standard thin section petrography and backscattered electron microscopy. Petrophysical analytical methods include retort analysis, pulse-decay permeability measurement, pressure decay permeability analysis for tight rocks, and mercury injection porosimetry, which is also known as mercury injection capillary pressure (MICP). Geomechanical analysis involved a standard series of mechanical tests: Brazil tension, unconfined compression, triaxial compression, and multi-stress compression.

Results of the MICP analysis show that the mudstone lithologies in the Morrow Shale and Thirteen Finger Limestone can support CO_2 column heights of ~1,000 to 10,000 feet. At an order of magnitude over the thickness of the Morrow reservoir, this should prove an effective seal for CO_2 storage in the Morrow B injection horizon.

Failure analyses show that the Morrow B sands are weaker than overlying lithologies, so that any fracture initiation around the injection well would not be expected to propagate into the overlying sealing units. Mechanical properties of the overlying shale and limestones provide an interesting and effective combination of strength and elasticity. Limestone layers are strong but brittle, while the shale layers are weaker but sufficiently ductile to prevent extensive fracture propagation.

It is unlikely for hydrocarbon migration pathways that charged the Morrow reservoir to be potential CO_2 migration pathways via primary pore networks today. Any potential CO_2 migration would be most likely due to leakage from wellbores or bypass through fault and fracture networks, discussed in Sections 4.2 and 4.3.

In the unlikely event CO_2 leakage occurs as a result of leakage through the confining seal it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.6 Natural and Induced Seismic Activity

Figure 4.6-1 shows the map of earthquakes with magnitudes measured at greater than 2.5 as defined by the United States Geological Survey (USGS). While past earthquake data cannot predict future earthquakes, the small number of events near CFA after the

waterflood operations were initiated in 1969 implies the area is not seismically sensitive to injection. Also, no documentation exists that any of the distant earthquake events caused a disruption in injectivity or damage to any of the wellbores in CFA.

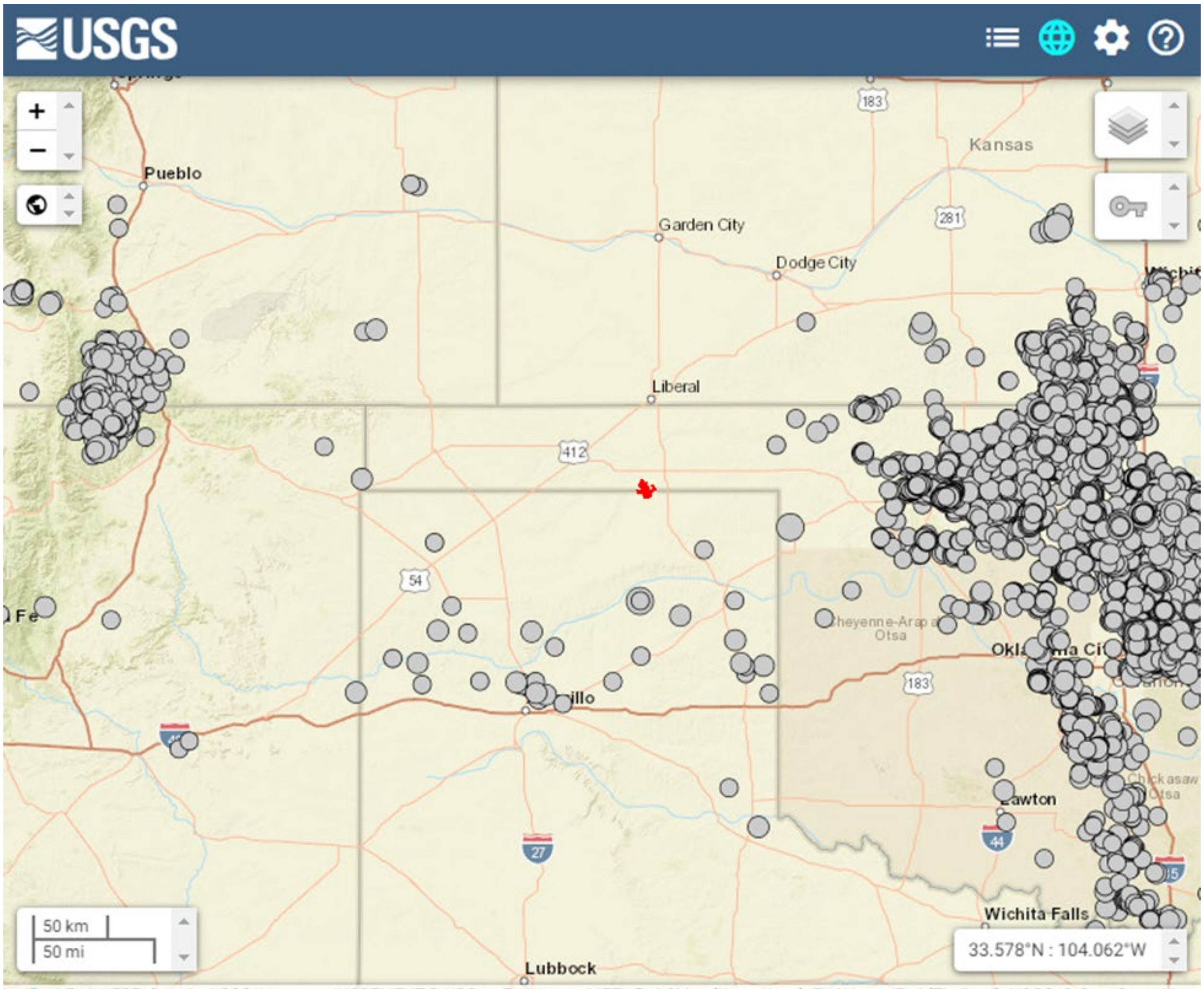

Figure 4.6-1. USGS earthquakes (+2.5 magnitude) for last 40 years with CFA highlighted red.

There is no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the CFA.

In the unlikely event that induced seismicity resulted in a pathway for material amounts of CO_2 to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would lead to further investigation.

4.7 Strategy for Detection and Response to 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 (well bores), and unique events such as induced fractures. Table 1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks,

CapturePoint's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO_2 losses discussed in the table are identified by type. Once the type is reported to a response manager the correct resources and personnel can be mobilized to develop the optimal response procedure. The procedure will address and mitigate further CO_2 leakage.

Table 1 Response Plan for CO_2 Loss

Known Potential Leakage Risks	Monitoring Methods and Frequency	Anticipated Response Plan
Tubing Leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days
Casing Leak	Weekly field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days
Wellhead Leak	Weekly field inspection	Workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations (weekly inspection but field personnel present daily)	Maintain well kill procedures
Unplanned wells drilled through Morrow	Weekly field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Re-enter and reseal abandoned wells
Pumps, values, etc.	Weekly field inspection	Workover crews respond within days
Leakage along faults	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near faults
Leakage laterally	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Fluid management along lease lines
Leakage through induced fractures	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near seismic event

4.8 Strategy for Quantifying CO_2 loss

Major CO_2 losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. CapturePoint will use Subpart W techniques to estimate leakages only on equipment and ensure those results are consistently represented in the Subpart RR report. Any event-driven leakage quantification reported in Subpart RR for surface leaks will use other techniques.

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 CO_2 that would be most appropriate. In the event leakage occurs, CapturePoint will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission.

Any volume of CO_2 detected leaking to the 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, CapturePoint's field experience, and other factors such as the frequency of inspection. As indicated in Section 6.4, leaks will be documented, and the records of leakage events will be retained in the electronic environmental documentation and reporting system, which consists of reports stored on servers, with information uploaded into third party software.

Available studies of actual well leaks and natural analogs (e.g., naturally occurring CO_2 geysers) suggest that the amount released from routine leaks would be small as compared to the amount of CO_2 that would remain stored in the formation.

5 Strategy for Determining CO_2 Baselines for CO_2 Monitoring

Atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values for soil measurement in the CFA area, per the characterization, monitoring and well data collected by the Southwest Regional Partnership on Carbon Sequestration (SWP) in the analogous Farnsworth Unit.

5.1 Site Characterization and Monitoring

As described in Sections 2.2.2 and 2.4, the Morrow B sandstone is isolated both above and below by shale units of the Morrow. The primary seal consists of 180 – 200 ft of Morrow shale and Thirteen Finger Limestone which in turn is overlain by over a thousand feet of younger shale and limestone. These units provide a suitable seal to prevent the migration of CO_2 out of the injection reservoir. Additionally, no significant faults or fracture zones that cut across the seal units have been identified in the CFA, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented.

5.2 Groundwater monitoring

CapturePoint does not routinely pull water samples from the Ogallala water wells. However, samples are pulled when OCC injection permits are submitted in Oklahoma. No indication of fluid leakage has been identified from any of these in the CFA area. CapturePoint is unlikely to continue monitoring USDW wells for CO_2 or brine contamination, as characterization of the Morrow (see section 5.1) has suggested minimal risk of groundwater contamination from CO_2 leakage from this depth.

5.3 Soil CO_2 monitoring

Atmospheric CO_2 values at the Farnsworth Unit have been determined by a SWP eddy tower installation. In winter 2019, the eddy system malfunctioned and has not been repaired due to COVID travel restrictions. However, the atmospheric CO_2 concentration data from the eddy tower were in very good agreement with values obtained from the NOAA Global Monitoring Laboratory station in Moody, Texas (Station: WKT). Since the CFA area is in close proximity to the Farnsworth Unit, atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values.

5.4 Visual Inspection

CapturePoint operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage.

5.5 Well Surveillance

CapturePoint adheres to the requirements of OAC Title 165:10-5 for the OCC and of TAC Rule 46 for the TRRC governing fluid injection into productive reservoirs. Rule 46 includes requirements for monitoring, reporting, and testing of Class II injection wells. Furthermore, the OCC and the TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well if they are deemed necessary.

CapturePoint also adheres to the requirements of OAC Title 165:10-7 for the OCC and TAC Rule 20 for the TRRC governing the notification of fires, breaks, leaks, or escapes. Rule 20 requires that all operators report leaks to the OCC or the TRRC including measured or estimated quantities of product leaked.

6 Site specific considerations for determining the Mass of CO_2 Sequestered

Of the twelve RR equations in 98.443 of Subpart RR, the following are relevant to CapturePoint's operations.

6.1 Determining Mass of CO_2 received

CapturePoint currently receives CO_2 at its CFA facility through its own pipeline from the Arkalon Ethanol plant in Liberal, Kansas. CapturePoint also recycles CO_2 from its production wells in the CFA.

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

where:

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

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into the well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

6.2 Determining Mass of CO_2 Injected

CapturePoint injects CO_2 into the injection wells listed in Appendix 1.

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

where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

6.3 Determining Mass of CO_2 produced from Oil Wells

CapturePoint also recycles CO_2 from its production wells which are part of its operations in the CFA. Therefore, the following equation is relevant to its operations.

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

Where:

$CO_{2,w}$ = Annual CO_2 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 CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,w}}$ = CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator.

To aggregate production data, CapturePoint will sum the mass of all of the CO_2 separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 below:

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

Where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) through all separators in the reporting year.

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction), CU is 0.00236 and NPU is 0.00454 at the last sample.

w = Separator.

6.4 Determining Mass of CO_2 emitted by Surface Leakage

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations.

CapturePoint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below:

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

where:

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

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

x = Leakage pathway.

6.5 Determining Mass of CO_2 sequestered

The following Equation RR-11 pertains to facilities that are actively producing oil or natural gas.

$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP}$ (Equation RR-11)

Where:

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

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

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

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

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

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

7 Estimated Schedule for Implementation of MRV plan

CapturePoint expects to begin implementing the approved MRV plan when the new CO_2 capture facility is operational, September 1, 2022.

8 GHG monitoring and Quality Assurance Program

CapturePoint will meet the monitoring and QA/QC requirements of 98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 98.444 (d).

8.1 GHG monitoring

As required by 40 CFR 98.3(g)(5)(i), CapturePoint's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

8.1.1 General

Measurement of CO_2 *Concentration* – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GSA) standards.

Measurement of CO_2 *Volume* – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. CapturePoint will adhere to the American Gas Association (AGA) Report #3 – (ORIFICE METERING OF NATURAL GAS AND OTHER RELATED HYDROCARBON FLUIDS)

8.1.2 CO_2 Received

Daily fermentation CO_2 purchased is received via the pipeline from the Arkalon ethanol plant in Liberal, Kansas, and is measured using a volumetric totalizer, which uses accepted flow calculations for CO_2 according to the AGA Report #3.

8.1.3 CO_2 Injected

Daily CO_2 injection is recorded by combining the totals for the recycle compressor meter and the received CO_2 meter from Arkalon based on what's delivered on a 24-hour basis. This data is taken from the meter daily and stored in CapturePoint's data warehouse for records and reservoir management.

8.1.4 CO_2 Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO_2. The produced gas is sampled at least quarterly for the CO_2 content.

8.1.5 CO_2 Emissions from equipment leaks and vented emissions of CO_2

As required by 98.444 (d), CapturePoint will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead and between the flow meter used to measure production quantity and the production wellhead.

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6 Measurement Devices

As required by 40 CFR 98.444(e), CapturePoint will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration.
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meters are National Institute of Standards and Technology (NIST) traceable.

8.2 QA/QC procedures

CapturePoint will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

8.3 Estimating missing data

CapturePoint will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

A quarterly flow rate of CO_2 received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.

A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.

A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

8.4 Revisions of the MRV plan

CapturePoint will revise the MRV Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

9 Records Retention

CapturePoint will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, CapturePoint will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.
(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
    (i) The GHG emissions calculations and methods used.
    (ii) Analytical results for the development of site-specific emissions factors, if applicable.
    (iii) The results of all required analyses.
    (iv) Any facility operating data or process information used for the GHG emission calculations.
(3) The annual GHG reports.
(4) Missing data computations. For each missing data event, CapturePoint will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
(5) A copy of the most recent revision of this MRV Plan.
(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(9) Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(10) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(11) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
(12) 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.
(13) 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.
(14) Any other records as specified for retention in this EPA-approved MRV plan.

10 Appendices

Appendix 1 – CFA Wells

Table A1.1 – Production Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2112	35007353570000	Oil Prod	Active	CO_2	1	0
CU 2171	35007354120000	Oil Prod	Active	CO_2	1	0
CU 2173	35007354140000	Oil Prod	Active	CO_2	1	0
CU 2177	35007222340000	Oil Prod	Active	CO_2	1	0
CU 2272	35007224530000	Oil Prod	Active	CO_2	1	0
CU 2651	35007362650000	Oil Prod	Active	CO_2	1	0
CU 2731	35007359750000	Oil Prod	Active	CO_2	1	0
CU 2761	35007350590000	Oil Prod	Active	CO_2	1	0
CU 2853	35007250840000	Oil Prod	Active	CO_2	1	0
CU 2854	35007250850000	Oil Prod	Active	CO_2	1	0
CU 2971A	35007256700000	Oil Prod	Active	CO_2	1	0
CU 2973	35007213750000	Oil Prod	Active	CO_2	1	0
CU 2975	35007223730000	Oil Prod	Active	CO_2	1	0
CU 3111	35007350600000	Oil Prod	Active	CO_2	1	0
CU 3113	35007359460000	Oil Prod	Active	CO_2	1	0
CU 3115	35007251710000	Oil Prod	Active	CO_2	1	0
CU 3116	35007252570000	Oil Prod	Active	CO_2	1	0
CU 3143	35007250860000	Oil Prod	Active	CO_2	1	0
CU 3171	35007359600000	Oil Prod	Active	CO_2	1	0
CU 3182	35007249250000	Oil Prod	Active	CO_2	1	0
CU 3211	35007352150000	Oil Prod	Active	CO_2	1	0
CU 3212	35007352690000	Oil Prod	Active	CO_2	1	0
CU 3231	35007001820000	Oil Prod	Active	CO_2	1	0
CU 3232	35007352720000	Oil Prod	Active	CO_2	1	0
CU 3234	35007212010000	Oil Prod	Active	CO_2	1	0
CU 3261	35007352170000	Oil Prod	Active	CO_2	1	0
CU 3263	35007251640000	Oil Prod	Active	CO_2	1	0
CU 3271	35007352160000	Oil Prod	Active	CO_2	1	0
CU 3273	35007252580000	Oil Prod	Active	CO_2	1	0
CU 3274	35007253140000	Oil Prod	Active	CO_2	1	0
CU 3275	35007254040000	Oil Prod	Active	CO_2	1	0
CU 3312	35007360800000	Oil Prod	Active	CO_2	1	0
CU 3313	35007254370000	Oil Prod	Active	CO_2	1	0
CU 3314	35007254030000	Oil Prod	Active	CO_2	1	0
CU 3332	35007254020000	Oil Prod	Active	CO_2	1	0
CU 3381	35007360780000	Oil Prod	Active	CO_2	1	0
CU 3411	35007351700000	Oil Prod	Active	CO_2	1	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3412	35007351720000	Oil Prod	Active	CO_2	1	0
CU 3413	35007351730000	Oil Prod	Active	CO_2	1	0
CU 3414	35007005220000	Oil Prod	Active	CO_2	1	0
CU 3415	35007211170000	Oil Prod	Active	CO_2	1	0
CU 3416A	35007252590000	Oil Prod	Active	CO_2	1	0
CU 3451A	35007256710000	Oil Prod	Active	CO_2	1	0
CU 3471	35007351750000	Oil Prod	Active	CO_2	1	0
CU 3481	35007351710001	Oil Prod	Active	CO_2	1	0
CU 3491	35007254330000	Oil Prod	Active	CO_2	1	0
CU 3533	35007206880000	Oil Prod	Active	CO_2	1	0
CU 3562	35007255050000	Oil Prod	Active	CO_2	1	0
NPU 101	42357010440000	Oil Prod	Active	CO_2	1	0
NPU 103	42357010060000	Oil Prod	Active	CO_2	1	0
NPU 104	42357000050000	Oil Prod	Active	CO_2	1	0
NPU 207	42357302000000	Oil Prod	Active	CO_2	1	0
NPU 209	42357333830000	Oil Prod	Active	CO_2	1	0
NPU 501	42357009140000	Oil Prod	Active	CO_2	1	0
NPU 502	42357024100000	Oil Prod	Active	CO_2	1	0
NPU 601	42357008420000	Oil Prod	Active	CO_2	1	0
NPU 605	42357333840000	Oil Prod	Active	CO_2	1	0
NWCU 3-1	35007360850000	Gas Prod	Active	CO_2	1	0
NWCU 9-3	35007249430000	Oil Prod	Active	CO_2	1	0
CU 2172	35007354130000	Oil Prod	Inactive	CO_2	0	0
CU 2175	35007354160000	Oil Prod	Inactive	CO_2	0	0
CU 2473	35007211990000	Oil Prod	Inactive	CO_2	0	0
CU 2511	35007350790000	Oil Prod	Inactive	CO_2	0	0
CU 2711	35007359260000	Oil Prod	Inactive	CO_2	0	0
CU 2771	35007359850000	Oil Prod	Inactive	CO_2	0	0
CU 3142	35007222350000	Oil Prod	Inactive	CO_2	0	0
CU 3361	35007352670000	Oil Prod	Inactive	CO_2	0	0
NPU 205	42357008070000	Oil Prod	Inactive	CO_2	0	0
NPU 301	42357022080000	Oil Prod	Inactive	CO_2	0	0
NPU 801	42357004630000	Oil Prod	Inactive	CO_2	0	0
NPU 802	42357004620000	Oil Prod	Inactive	CO_2	0	0
NPU 804	42357201730000	Oil Prod	Inactive	CO_2	0	0
NPU 901	42357000660000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-2	35007350870000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-3	35007210790000	Oil Prod	Inactive	CO_2	0	0
NWCU 16-1	35007350720000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-1	35007360900000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-3	35007360920000	Oil Prod	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
NWCU 19-4	35007360930000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-5	35007360940000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-6	35007211250000	Oil Prod	Inactive	CO_2	0	0
NWCU 24-5	35007222710000	Oil Prod	Inactive	CO_2	0	0
NWCU 25-7	35007228000000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-3	35007360870000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-4	35007360880000	Oil Prod	Inactive	CO_2	0	0
NWCU 4-2	35007360740000	Oil Prod	Inactive	CO_2	0	0
NWCU 5-1	35007361050000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-1	35007360980000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-2	35007360990000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-1	35007360810000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-2	35007360820000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-3	35007208260000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-1	35007360950000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-2	35007360960000	Oil Prod	Inactive	CO_2	0	0
CU 1551	35007350740000	Oil Prod	P&A	CO_2	0	0
CU 1671	35007352180000	Oil Prod	P&A	CO_2	0	0
CU 2111	35007353560000	Oil Prod	P&A	CO_2	0	0
CU 2176	35007358870000	Oil Prod	P&A	CO_2	0	0
CU 2221	35007000490000	Oil Prod	P&A	CO_2	0	0
CU 2281	35007359220000	Oil Prod	P&A	CO_2	0	0
CU 2421	35007359350000	Oil Prod	P&A	CO_2	0	0
CU 2431	35007350330000	Oil Prod	P&A	CO_2	0	0
CU 2432	35007350340000	Oil Prod	P&A	CO_2	0	0
CU 2433	35007350350000	Oil Prod	P&A	CO_2	0	0
CU 2434	35007350360000	Oil Prod	P&A	CO_2	0	0
CU 2435	35007218800000	Oil Prod	P&A	CO_2	0	0
CU 2471	35007359080000	Oil Prod	P&A	CO_2	0	0
CU 2531	35007361090000	Oil Prod	P&A	CO_2	0	0
CU 2532	35007361100000	Oil Prod	P&A	CO_2	0	0
CU 2552	35007359760000	Oil Prod	P&A	CO_2	0	0
CU 2571	35007350730000	Oil Prod	P&A	CO_2	0	0
CU 2572	35007359320000	Oil Prod	P&A	CO_2	0	0
CU 2661	35007361990000	Oil Prod	P&A	CO_2	0	0
CU 2681	35007350320000	Oil Prod	P&A	CO_2	0	0
CU 2852	35007301360000	Oil Prod	P&A	CO_2	0	0
CU 2961	35007358760000	Oil Prod	P&A	CO_2	0	0
CU 2971	35007358750000	Oil Prod	P&A	CO_2	0	0
CU 2972	35007358780000	Oil Prod	P&A	CO_2	0	0
CU 3031	35007359560000	Oil Prod	P&A	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3051	35007300380000	Oil Prod	P&A	CO_2	0	0
CU 3064	35007254270000	Oil Prod	P&A	CO_2	0	0
CU 3141	35007359610000	Oil Prod	P&A	CO_2	0	0
CU 3181	35007359470000	Oil Prod	P&A	CO_2	0	0
CU 3251	35007352710000	Oil Prod	P&A	CO_2	0	0
CU 3331	35007200750000	Oil Prod	P&A	CO_2	0	0
CU 3451	35007351690000	Oil Prod	P&A	CO_2	0	0
CU 3511	35007359730000	Oil Prod	P&A	CO_2	0	0
CU 3531	35007350850000	Oil Prod	P&A	CO_2	0	0
CU 3532	35007359950000	Oil Prod	P&A	CO_2	0	0
CU 3534	35007211180000	Oil Prod	P&A	CO_2	0	0
CU 3561	35007359830000	Oil Prod	P&A	CO_2	0	0
CU 3571	35007359980000	Oil Prod	P&A	CO_2	0	0
CU 3581	35007359970000	Oil Prod	P&A	CO_2	0	0
CU 3631	35007301000000	Oil Prod	P&A	CO_2	0	0
CU 1672	35007352190000	Oil Prod	P&A	CO_2	0	0
CU 2351	35007350370000	Oil Prod	P&A	CO_2	0	0
CU 2474	35007228200000	Oil Prod	P&A	CO_2	0	0
CU 2812	35007352340000	Oil Prod	P&A	CO_2	0	0
CU 2871	35007359060000	Oil Prod	P&A	CO_2	0	0
NPU 102	42357021420000	Oil Prod	P&A	CO_2	0	0
NPU 201	42357001280000	Oil Prod	P&A	CO_2	0	0
NPU 302	42357022290000	Oil Prod	P&A	CO_2	0	0
NPU 402	42357022300000	Oil Prod	P&A	CO_2	0	0
NWCU 17-2	35007359620000	Oil Prod	P&A	CO_2	0	0
NWCU 10-1	35007361010000	Oil Prod	P&A	CO_2	0	0
NWCU 17-1	35007350710000	Oil Prod	P&A	CO_2	0	0
NWCU 19-7	35007224520000	Oil Prod	P&A	CO_2	0	0
NWCU 24-4	35007358770000	Oil Prod	P&A	CO_2	0	0
NWCU 25-6	35007358790000	Oil Prod	P&A	CO_2	0	0

Table A1.2 – Water Alternating Gas (WAG) Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 2662 (INJ)	35007362010000	WAG Inj	Active	CO_2	0	1
CU 2751 (INJ)	35007359440002	WAG Inj	Active	CO_2	0	1
CU 2762 (INJ)	35007213660000	WAG Inj	Active	CO_2	0	1
CU 2772 (INJ)	35007359860001	WAG Inj	Active	CO_2	0	1
CU 2811 (INJ)	35007352200000	WAG Inj	Active	CO_2	0	1
CU 2872 (INJ)	35007359070000	WAG Inj	Active	CO_2	0	1
CU 2962 (INJ)	35007212000000	WAG Inj	Active	CO_2	0	1
CU 2974 (INJ)	35007220770000	WAG Inj	Active	CO_2	0	1
CU 3114 (INJ)	35007206540000	WAG Inj	Active	CO_2	0	1
CU 3117 (INJ)	35007254000000	WAG Inj	Active	CO_2	0	1
CU 3161 (INJ)	35007359590002	WAG Inj	Active	CO_2	0	1
CU 3213 (INJ)	35007224570000	WAG Inj	Active	CO_2	0	1
CU 3233 (INJ)	35007206890000	WAG Inj	Active	CO_2	0	1
CU 3252 (INJ)	35007211020000	WAG Inj	Active	CO_2	0	1
CU 3262 (INJ)	35007206870000	WAG Inj	Active	CO_2	0	1
CU 3351 (INJ)	35007352680000	WAG Inj	Active	CO_2	0	1
CU 3371 (INJ)	35007360770000	WAG Inj	Active	CO_2	0	1
CU 3417 (INJ)	35007255060000	WAG Inj	Active	CO_2	0	1
CU 3461 (INJ)	35007351680000	WAG Inj	Active	CO_2	0	1
CU 3472 (INJ)	35007206940000	WAG Inj	Active	CO_2	0	1
CU 3551 (INJ)	35007359840000	WAG Inj	Active	CO_2	0	1
NPU 105 (INJ)	42357000030000	WAG Inj	Active	CO_2	0	1
NPU 107W (INJ)	42357333770000	WAG Inj	Active	CO_2	0	1
NPU 202WI (INJ)	42357021500000	WAG Inj	Active	CO_2	0	1
NPU 208 (INJ)	42357327410000	WAG Inj	Active	CO_2	0	1
NPU 701 (INJ)	42357008410000	WAG Inj	Active	CO_2	0	1
NPU 504 (INJ)	42357329480000	WAG Inj	Active	CO_2	0	1
NPU 604W (INJ)	42357330870000	WAG Inj	Active	CO_2	0	1
CU 1531 (INJ)	35007359990000	WAG Inj	Inactive	CO_2	0	0
CU 2131 (INJ)	35007362700000	WAG Inj	Inactive	CO_2	0	0
CU 2512 (INJ)	35007350780000	WAG Inj	Inactive	CO_2	0	0
CU 2641 (INJ)	35007359250001	WAG Inj	Inactive	CO_2	0	0
CU 2721 (INJ)	35007359870001	WAG Inj	Inactive	CO_2	0	0
CU 2741 (INJ)	35007359430000	WAG Inj	Inactive	CO_2	0	0
CU 2851 (INJ)	35007355420001	WAG Inj	Inactive	CO_2	0	0
CU 3032 (INJ)	35007359580000	WAG Inj	Inactive	CO_2	0	0
CU 3062 (INJ)	35007253090000	WAG Inj	Inactive	CO_2	0	0
CU 3112 (INJ)	35007359450001	WAG Inj	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 3172 (INJ)	35007251690000	WAG Inj	Inactive	CO_2	0	0
CU 3281 (INJ)	35007352700003	WAG Inj	Inactive	CO_2	0	0
CU 3311 (INJ)	35007360790000	WAG Inj	Inactive	CO_2	0	0
CU 3341 (INJ)	35007353530000	WAG Inj	Inactive	CO_2	0	0
NPU 203W (INJ)	42357008270000	WAG Inj	Inactive	CO_2	0	0
NPU 503 (INJ)	42357009150001	WAG Inj	Inactive	CO_2	0	0
NWCU 15-1 (INJ)	35007350860000	WAG Inj	Inactive	CO_2	0	0
NWCU 15-4 (INJ)	35007224510000	WAG Inj	Inactive	CO_2	0	0
NWCU 20-1 (INJ)	35007360760000	WAG Inj	Inactive	CO_2	0	0
NWCU 21-1 (INJ)	35007361020000	WAG Inj	Inactive	CO_2	0	0
CU 2271 (INJ)	35007359230000	WAG Inj	P&A	CO_2	0	0
CU 2311 (INJ)	35007362000000	WAG Inj	P&A	CO_2	0	0
CU 2472 (INJ)	35007359090000	WAG Inj	P&A	CO_2	0	0
CU 3061 (INJ)	35007359820000	WAG Inj	P&A	CO_2	0	0
CU 3512 (INJ)	35007359740000	WAG Inj	P&A	CO_2	0	0
NPU 204W (INJ)	42357022520000	WAG Inj	P&A	CO_2	0	0
NPU 206W (INJ)	42357022510000	WAG Inj	P&A	CO_2	0	0
NPU 401W (INJ)	42357004520000	WAG Inj	P&A	CO_2	0	0
NPU 602W (INJ)	42357020230000	WAG Inj	P&A	CO_2	0	0
NPU 603W (INJ)	42357201720001	WAG Inj	P&A	CO_2	0	0
NPU 803W (INJ)	42357201710000	WAG Inj	P&A	CO_2	0	0
NWCU 14-1 (INJ)	35007350530000	WAG Inj	P&A	CO_2	0	0
NWCU 3-2 (INJ)	35007360860000	WAG Inj	P&A	CO_2	0	0

Table A1.3 – Water Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU WSW 1	35007355430001	Wtr Inj	Active	CO_2	0	1
NPU W 1W	42357300050002	Wtr Inj	Inactive	CO_2	0	0
CU 2551	35007350750000	Wtr Inj	P&A	CO_2	0	0

Appendix 2 – Referenced Regulations

U.S. Code > Title 26, INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1, NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits >

Section 45Q ..... Credit for carbon oxide sequestration

OCC > Title 165: CORPORATION COMMISSION > UNDERGROUND INJECTION CONTROL

Section

165:10-5-1 .... Classification of underground injection wells
165:10-5-2 .... Approval of injection wells or disposal wells
165:10-5-3 .... Authorization for existing enhanced recovery injection wells and existing disposal wells
165:10-5-4 .... Application for approval of enhanced recovery projects
165:10-5-5 .... Application for approval of injection and disposal operations
165:10-5-6 .... Testing and monitoring requirements for injection wells and disposal wells
165:10-5-7 .... Monitoring and reporting requirements for wells covered by 165:10-5-1
165:10-5-8 .... Liquid hydrocarbon storage wells
165:10-5-9 .... Duration of underground injection well orders or permits
165:10-5-10 ..... Transfer of authority to inject
165:10-5-11 ..... Notarized reports
165:10-5-12 ..... Application for administrative approval for the subsurface injection of onsite reserve pit fluids
165:10-5-13 ..... Application for permit for one time injection of reserve pit fluids
165:10-5-14 ..... Exempt aquifers
165:10-5-15 ..... Application for permit for simultaneous injection well

165:5-7-27 .... Application for approval of injection and disposal wells
165:5-7-29 .... Request for exception to certain underground injection well requirements
165:5-7-30 .... Amending existing orders or permits authorizing injection for injection, disposal, or LPG storage wells

TAC > Title 16 - Economic Regulation> Part 1 TRRC > Chapter 3 – Oil and Gas Division >

Rules

§3.37 .... Statewide Spacing Rule
§3.38 .... Well Densities
§3.39 .... Proration and Drilling Units: Contiguity of Acreage and Exception Thereto
§3.40 .... Assignment of Acreage to Pooled Development and Proration Units
§3.41 .... Application for New Oil or Gas Field Designation and/or Allowable
§3.42 .... Oil Discovery Allowable
§3.43 .... Application for Temporary Field Rules
§3.45 .... Oil Allowables
§3.46 .... Fluid Injection into Productive Reservoirs
§3.47 .... Allowable Transfers for Saltwater Injection Wells
§3.48 .... Capacity Oil Allowables for Secondary or Tertiary Recovery Projects
§3.49 .... Gas-Oil Ratio
§3.50 .... Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive
§3.51 .... Oil Potential Test Forms Required
§3.52 .... Oil Well Allowable Production
§3.53 .... Annual Well Tests and Well Status Reports Required
§3.54 .... Gas Reports Required
§3.55 .... Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering
§3.56 .... Scrubber Oil and Skim Hydrocarbons
§3.57 .... Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials
§3.58 .... Certificate of Compliance and Transportation Authority; Operator Reports
§3.59 .... Oil and Gas Transporter's Reports
§3.60 .... Refinery Reports
§3.61 .... Refinery and Gasoline Plants
§3.62 .... Cycling Plant Control and Reports
§3.63 .... Carbon Black Plant Permits Required
§3.70 .... Pipeline Permits Required
§3.71 .... Pipeline Tariffs
§3.72 .... Obtaining Pipeline Connections
§3.73 .... Pipeline Connection; Cancellation of Certificate of Compliance; Severance
§3.76 .... Commission Approval of Plats for Mineral Development
§3.78 .... Fees and Financial Security Requirements
§3.79 .... Definitions
§3.80 .... Commission Oil and Gas Forms, Applications, and Filing Requirements
§3.81 .... Brine Mining Injection Wells
§3.83 .... Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells
§3.84 .... Gas Shortage Emergency Response
§3.85 .... Manifest to Accompany Each Transport of Liquid Hydrocarbons by Vehicle
§3.86 .... Horizontal Drainhole Wells
§3.91 .... Cleanup of Soil Contaminated by a Crude Oil Spill
§3.93 .... Water Quality Certification Definitions

Appendix 3 – References

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Appendix 4 – Abbreviations and Acronyms

2D – 2 dimensional
3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
ANSI – American National Standards Institute
API – American Petroleum Institute
AWT – All Well Test
ASTM - American Society for Testing and Materials
Bscf – billion standard cubic feet
B/D – barrels per day
bopd – barrels of oil per day
C4 – butane
C5 – pentane
C7 – heptane
C7+ - standard heptane plus
CCE – constant composition expansion
CCUS – carbon capture utilization and storage
CFA – Camrick Field Area
cf – cubic feet
CH4 – methane
CO_2 – carbon dioxide
EOR – Enhanced Oil Recovery
EOS – Equation of State
EPA – US Environmental Protection Agency
ESD – Emergency Shutdown Device
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
H_2S – hydrogen sulfide
lb – pound
mD – millidarcy(ies)
MICP – mercury injection capillary pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MMB – million barrels
MMP – minimum miscible pressure
MMscf – million standard cubic feet
MMstb – million stock tank barrels
MRV – Monitoring, Reporting, and Verification
MMMT – Million metric tonnes
MT – Metric tonne
NIST – National Institute of Standards and Technology

NAESB – North American Energy Standards Board
OAC – Oklahoma Administrative Code
OCC – Oklahoma Corporation Commission
OOIP – Original Oil-In-Place
OWC – oil water contact
PPM – Parts Per Million
psia – pounds per square inch absolute
PVT – pressure, volume, temperature
QA/QC – quality assurance/quality control
RMS – root mean square
SEM – scanning electron microscope
SWP - Southwest Regional Partnership on Carbon Sequestration
TAC – Texas Administrative Code
TA – Temporally Abandoned/not plugged
TD – total depth
TM – Terminated order wells/UIC not plugged
TRRC – Texas Railroad Commission
TSD – Technical Support Document
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water
WAG – Water Alternating Gas (Gas is recycled CO_2 and purchase CO_2)
XRD – x-ray diffraction

Appendix 5 – Conversion Factors

CapturePoint reports CO_2 at standard conditions of temperature and pressure as defined in the State of Texas in the Texas Administrative Code for the Oil and Gas Division, Rule 3.79 as follows:

> Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit.

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at:

https://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At State of Texas standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.002641684 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2{,}204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2}\ =\ 0.002641684$$

$$MW_{CO2}\ =\ 44.0095$$

$$Density_{CO2} = 5.2734\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.2734\ x\ 10^{-2}\frac{MT}{Mcf}$$

The conversion factor 5.2734×10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Request for Additional Information: Camrick Unit
August 11, 2022

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	3.1	21	Figure 3.1-1 and Figure 3.1-2 are difficult to follow due to a lack of clear labels/legends. For example, it is not clear what the outermost dotted line represents. We recommend adjusting these legends and/or figures to clearly delineate the Maximum Monitoring Area (MMA) and the Active Monitoring Area (AMA).	Adjusted the figures and legends to clearly delineate the Active Monitoring Area (AMA) and the Maximum Monitoring Area (MMA).

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
2.	3	21	Per 40 CFR 98.449, “Active monitoring area” is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile. (2) The area projected to contain the free phase CO2 plume at the end of year t + 5.From the discussion in this section, it is not clear how the delineation of the AMA and the MMA comply with the definitions for the AMA and MMA in 40 CFR 98.449 or the requirements to delineate the AMA and MMA in 40 CFR 98.448(a)(1). Per 40 CFR 98.449, “Maximum monitoring area” means the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO2 plume until the CO2 plume has stabilized plus an all-around buffer zone of at least one-half mile. Please ensure that the discussion in sections 3.1 and 3.2 clearly identifies the AMA and MMA boundaries. Furthermore, please explain in the MRV plan whether the AMA and MMA conform to the definitions above.	These items were addressed in Section 2.1, Section 2.4, Section3 .1 and in the correction described in the answer to EPA Question 1 (previous page).

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	3	21	"Currently, CapturePoint's operations are focused on the **western portion** of the CFA. However, it is anticipated as the project develops, additional activity will occur in the **NWCU** of the CFA; therefore, requiring active monitoring in that area. However, project development is driven by the market price of oil so CapturePoint is unable to provide a specific time in the future when the **eastern portion** of the CFA will be actively monitored. Therefore, for the purposes of this MRV plan, CapturePoint has chosen to include the entire CFA in the AMA." It is unclear whether CapturePoint intends to monitor the eastern portion of the CFA or include it in the AMA. Similarly, it is also unclear if CapturePoint anticipates that the western portion or the eastern portion of the CFA will encounter additional activity. Please update the MRV plan to clarify this section. Furthermore, please note that 40 CFR 98.448(d) contains requirements for resubmitting an MRV plan if there are material changes, such as a change to the Active Monitoring Area.	Reworded. "Currently, CapturePoint's operations are focused on the western portion of the CU and all of the NPU. However, it is anticipated as the project develops, additional activity will occur in the NWCU of the CFA. However, project development is driven by the market price of oil so CapturePoint is unable to provide a specific time in the future when the eastern portion of the CFA will be developed. Therefore, for the purposes of this MRV plan, CapturePoint is continuously monitoring the entire CFA, which is the AMA."

Camrick Field Area (CFA)

MONITORING, REPORTING AND VERIFICATION PLAN (MRV)

CapturePoint LLC

CAPTUREPOINT

April 2022

Contents

INTRODUCTION

CapturePoint, LLC (CapturePoint) operates the Camrick Field Area (CFA) located in Beaver and Texas Counties, Oklahoma and in Ochiltree County, Texas for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) with retention of CO_2 serving a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The CFA was discovered in 1955 and is composed of three units, the Camrick Unit (CU) that was unitized by Humble Oil Company on October 14, 1969, the North Perryton Unit (NPU) that was unitized by Humble Oil Company on March 17, 1969, and the Northwest Camrick Unit (NWCU) that was unitized by Atlantic RichField Company on September 15, 1972. The Units were formed for the purpose of waterflooding with salt water sourced from the Wolfcamp formation. The field structure is a lenticular bedding sand trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. CapturePoint has been operating the CFA since 2017. CapturePoint acquired the CFA from Chaparral Energy LLC, which initiated the CO_2-EOR project in March 2001 for the CU and January 2007 for the NPU. No CO_2 has been injected in the NWCU. CapturePoint intends to continue CO_2-EOR operations until the end of the economic life of the CO_2-EOR program using various Class II injection wells as defined by Underground Injection Control (UIC) regulations and permitted under Texas Railroad Commission (TRRC) Rule 46 of the Texas Administrative Code (TAC) and the Oklahoma Corporation Commission (OCC) Title 165:10 of the Oklahoma Administrative Code (OAC). In this document, the term “gas” means a mixture of hydrocarbon light end components and the CO_2 component that can be produced as part of the EOR process.

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

This MRV Plan contains ten sections:

Section 1 contains facility information.

Section 2 contains the project description including: a detailed description of the injection operation including the duration and volume of CO_2 to be injected; a detailed description of the geology and hydrogeology of the CFA located on the northwest shelf of the Anadarko basin; and a detailed characterization of the injection reservoir modeling techniques employed.

Section 3 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449 and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 4 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. This section also describes the strategy for detecting, verifying, and quantifying any surface leakage of CO_2 as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Finally, this section also demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

Section 5 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 6 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 9 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 10 includes Appendices supporting the narrative of the MRV Plan.

1 Facility

1.1 Reporter Number

The CU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544678 and the NPU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544679. The EPA has been notified that the NPU will not be reporting for 2022, and that the facility has been merged into the Camrick Unit Facility Identification number 544678.

1.2 UIC Permit Class

For injection wells (see Appendix 2) that are the subject of this MRV plan, the OCC has rules governing UIC Class II injection wells. These OCC rules are OAC Title 165:10-5-1 through 165:10-5-15, OAC 165:5-7-27, OAC 165:5-7-30, the request for an exception to UIC rules under OAC 165:5-7-29, and other governing filing forms. Also, the TRRC has issued UIC Class II enhanced recovery permits under its Rule 46, TAC Title 16 Part 1 Chapter 3. All wells in the CFA, including both injection and production wells, are regulated by the OCC and the TRRC, which have primacy to implement the UIC Class II program.

1.3 UIC Injection Well Numbers

A list of the injection wells in the CFA is provided in Appendix 1. The details of the injection process are provided in Section 2.3.

2 Project Description

2.1 Project Characteristics

2.1.1 Estimated years of CO_2 injection

The CFA has been injecting CO_2 for the last 20+ years and it is currently projected that CapturePoint will inject CO_2 for an additional 12 years.

2.1.2 Estimated volume of CO_2 injected over lifetime of project

Historical and forecasted cumulative CO_2 retention volumes are approximately 100 billion standard cubic feet (Bscf) or 5.3 million metric tonnes (MMMT) from the start of CO_2

injection through October 2034. During the MRV plan, the period September 2022 through October 2034, 52.5 Bscf or 2.77 MMMT will be stored in the CFA. (See Figure 2.4-6)

2.2 Environmental Setting of MMA

2.2.1 Boundary of the MMA

CapturePoint has defined the boundary of the MMA as equivalent to the boundary of the CFA plus ½ mile beyond. A discussion of the methods used in delineating the MMA and the AMA are presented in Section 3.

2.2.2 Geology

The geological discussions in Sections 2.2.2 and 4.3-4.4 are based on analysis of logs from both the Farnsworth Unit, which is located 10 miles South-South-West of the CFA, and the CFA. Both areas have similar pay thickness, porosity values, permeability measurements, depositional environment, tectonic processes, and overburden strata layers. The descriptions of cores at the Farnsworth Unit included sections from overlying seals as well as the shale underlying the main reservoirs, petrographic thin section descriptions and point counts as well as a variety of special analytical techniques. These techniques included X-ray diffraction (XRD), which is the science of determining the atomic and molecular structure of rock crystals with an X-ray beam; scanning electron microscope (SEM) analysis, which uses a beam of electrons to define the surface of crystals; carbon isotope analysis to estimate the age of the CO_2 in the sample; and a variety of mechanical tests. Two dimensional (2D) and three dimensional (3D) geophysical surveys were also used as part of the Farnsworth Unit MRV Plan (2021). Details of recent geological investigations can be found in Gallagher (2014), Gragg (2016), Rasmussen et al (2019), Rose-Coss et al (2015), Trujillo (2018), Hobbs et al (2019), and Gragg et al (2018).

2.2.2.1 Tectonic Setting and Stratigraphy

The CFA is located on the northwest shelf of the Anadarko basin (Figure 2.2-1) and is one of many oil fields in the area that produce from a sequence of alternating sandstones and mudstones deposited during the late Pennsylvanian Morrowan period. Oil production and CO_2 injection at CFA is restricted to the operationally named Morrow B sandstone; the uppermost Morrow sandstone encountered below the Atokan Thirteen Finger limestone. The primary caprock intervals at CFA are comprised of the upper Morrow shale and the Thirteen Finger limestone (Figure 2.2-2). The Morrowan and Atokan intervals were deposited approximately 315-300 million years ago. Overlying stratigraphy includes late Pennsylvanian through the middle Permian shales and limestones, with lesser amounts of dolomite, sandstone and evaporites (Ball, 1991). The reservoir is approximately 60 feet thick throughout the field and lies at a depth of approximately 6,800-7,600 feet. The primary seal rocks of the Morrow shale and the Thirteen Finger Limestone comprise a package of approximately 180-200 feet thick in the field and are overlain by thousands of feet of Atokan and younger limestones and shales.

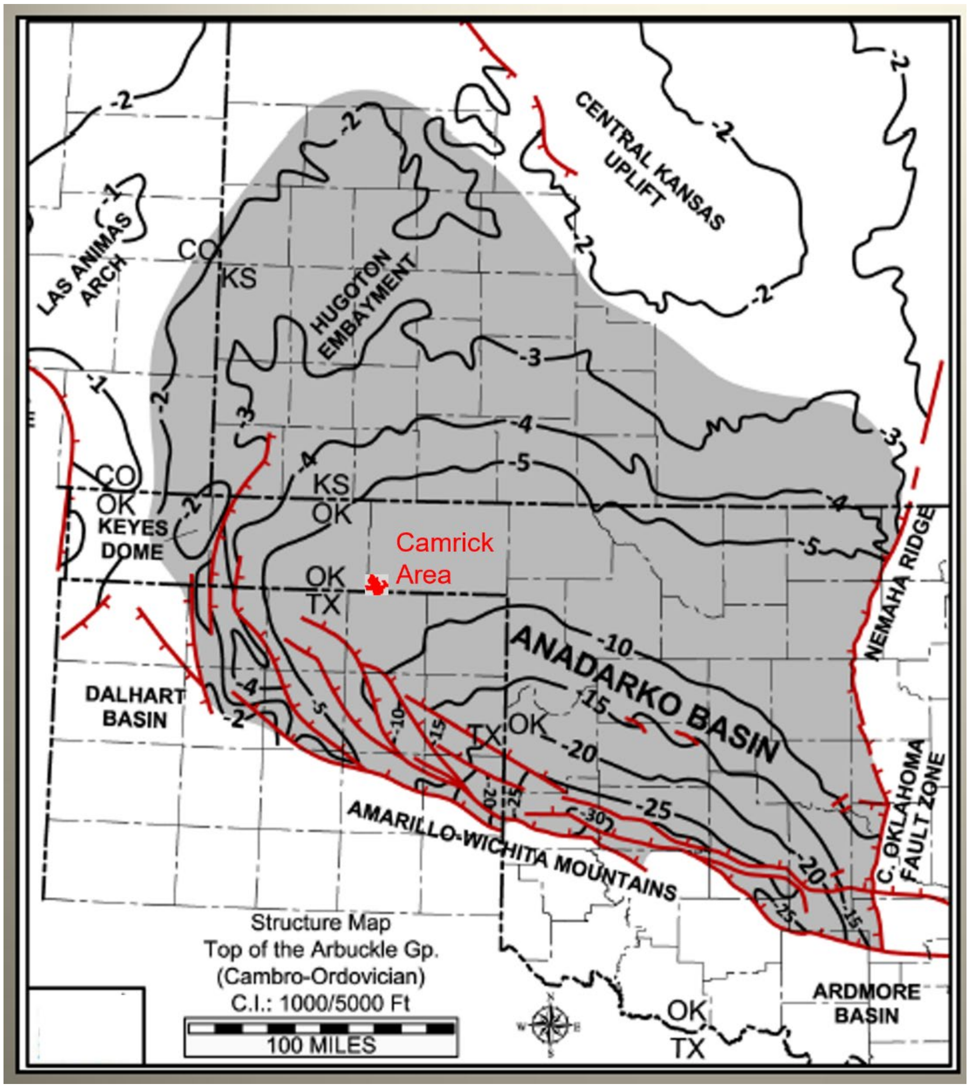

Figure 2.2-1. Location of the CFA on the Northwest Shelf of the Anadarko Basin in West Texas. Red lines are approximate locations of faults that have been documented in the region.

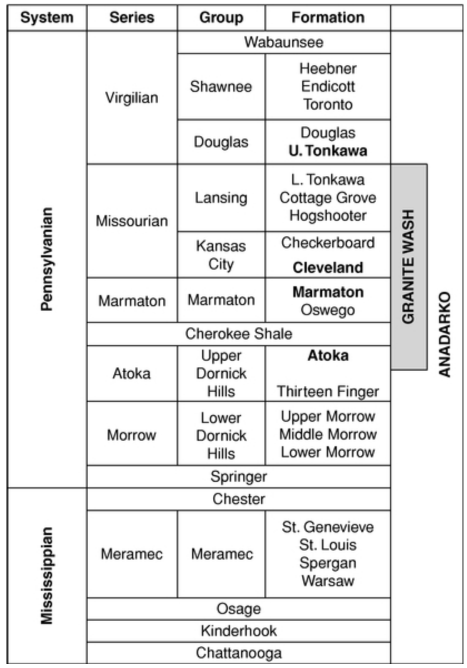

Figure 2.2-2. Stratigraphic section.

Tectonic Setting

From CFA's location on the western edge of the basin, the Anadarko Basin plunges to the southeast (Figure 2.2-3) where it reaches depths of over 40,000 feet (12,192 meters) adjacent to the Amarillo-Wichita Uplift (Perry, 1989). Maximum rates of subsidence occurred during Morrowan to Atokan times (Evans, 1979; Perry, 1989; Higley, 2014). Positive features that might have influenced deposition within the region include the Ancestral Rockies to the north, the Central Kansas uplift to the northeast, and the Wichita-Amarillo uplift to the south (Evans, 1979; Munson, 1989). Of note is the fact that during the Pennsylvanian time, the CFA was located on the basin shelf in an area that was not affected greatly by tectonic deformation. Although faults have been reported previously in the northwest Anadarko Basin, we found no direct evidence for tectonic faults within the CFA (see Section 4).

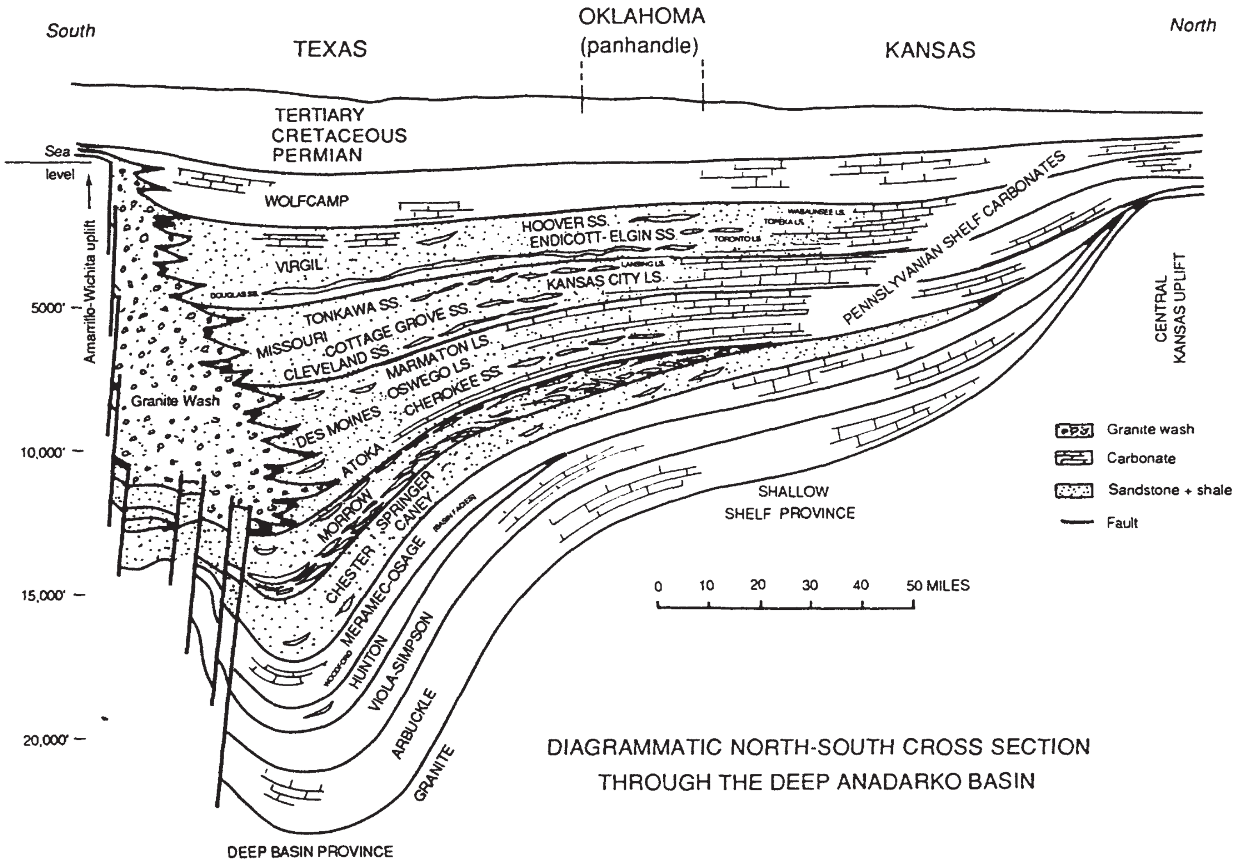

Figure 2.2-3. Diagrammatic North-South Section (Bottom) of the CFA.

Stratigraphy

Reservoir

Upper Morrowan sandstones in the Anadarko Basin margins have long been recognized as fluvial deposits (Swanson, 1979; Sonnenberg, 1985; Munson, 1989; Krystinik and Blakeney, 1990; Bowen et al., 1990; Al-Shaieb et al., 1995; Mckay and Noah, 1996; Puckette et al., 1996; Bowen and Weimer, 2003, 2004; Devries 2005; Puckette et al., 2008; Gallagher, 2014). At the Farnsworth Unit and similarly at the CFA, the Morrow B is described as a relatively coarse-grained subarkosic sandstone. The upper Morrowan facies, with sequences of basal conglomerate, coarse-grained sandstone, and fine-grained sandstone appear to be typical of incised valley deposits, as described by Wheeler et al. (1990), Krystinik and Blakeney (1990), Bowen et al. (1990), Blakeney et al. (1990), Sonnenberg et al. (1990) and Puckette et al. (2008).

Primary Seals

The Morrow B sandstones are encased above and below by shales. Contacts with shale both below and above the sandstone are sharp and irregular. The Morrow shale generally fines upwards in a series of thin beds that alternate between upper fine sands and fine to medium muds. Sand content decreases upwards through the section.

The Thirteen Finger limestone formation has two different lithofacies: diagenetic limestone (cementstone) and pyrite and fossil bearing fine to medium mudstone and coal. The two facies are intercalated with each other but tend to cluster in layers dominated more by one or the other.

The entire Thirteen Finger interval is typically 130 feet (39.6 meters) thick, comprised of mudstone, coal, and limestone. The mudstone is calcite rich, with some dolomite, and is completely diagenetic in origin and probably formed relatively soon following deposition.

2.2.2.2 Hydrogeology

Information about Morrowan and Atokan formation water flow during oil operations has not been discovered in any oil or gas company published reports or academic research studies in the Anadarko Basin. Groundwater flow rates in confined deep Anadarko layers at present are considered to be low to no flow (Nelson and Gianoutsos, 2014). Their arguments are based on (1) restricted recharge in the western basin, (2) density barriers to flow in the east, and (3) an overpressure pocket inhibiting flow in the deep basin. Jorgenson (1989) suggested flow could be west to east, driven by potential recharge to elevated units in the west and discharge at lower elevation outcrops in the east. The CFA CO_2 injection and production operations have negligible likelihood of causing water to flow to outcrops of the late Carboniferous (Pennsylvanian) time period that extend from Brownwood, Texas, to the Jacksboro/Bowie, Texas, area, which are hundreds of miles away (The Paleontology Portal).

The Carboniferous is a geologic period and system that covers 60 million years from the Devonian Period 358.9 million years ago, to the beginning of the Permian Period, 298.9 million years ago. As noted in the Section 2.2.2.1, the Morrowan and Atokan intervals of the CFA were deposited approximately 315-300 million years ago and are contained in the Carboniferous period.

2.3 Description of the Injection Process

Figure 2.3-1 depicts a simplified flow diagram of the facilities and equipment within the boundaries of the CFA. CO_2 captured from the ethanol plant fermentation process is delivered via pipeline to the field for injection. The Arkalon plant in Liberal, Kansas is the only source of CO_2 to the field. The amount delivered is dependent on the production of CO_2 produced from the fermentation process. This amount will vary but should average 12 MMCFD. Once CO_2 enters the CFA there are three main processes involved in EOR operations. These processes are shown in Figure 2.3-1 and include:

1. CO_2 distribution and injection. Purchased CO_2 is combined with recycled CO_2 from the CFA central tank battery (CTB) and sent through the main CO_2 distribution system to various water alternating gas (WAG) injectors.
2. Produced Fluids Handling. Full well stream fluids are produced to the “all well test” (AWT) site. The AWT site has two major purposes; 1) to individually test a well’s performance by separating and metering oil, gas, and water, and 2) to separate all gas from liquid then send these two phases to the CTB for final separation; while only the gas from NPU is sent to the CTB the NPU oil and water remains in Texas.

3. Produced Gas Processing. All gases from the AWT sites are transferred to the CTB to separate the oil, gas, and water using a series of vessels and storage tanks.

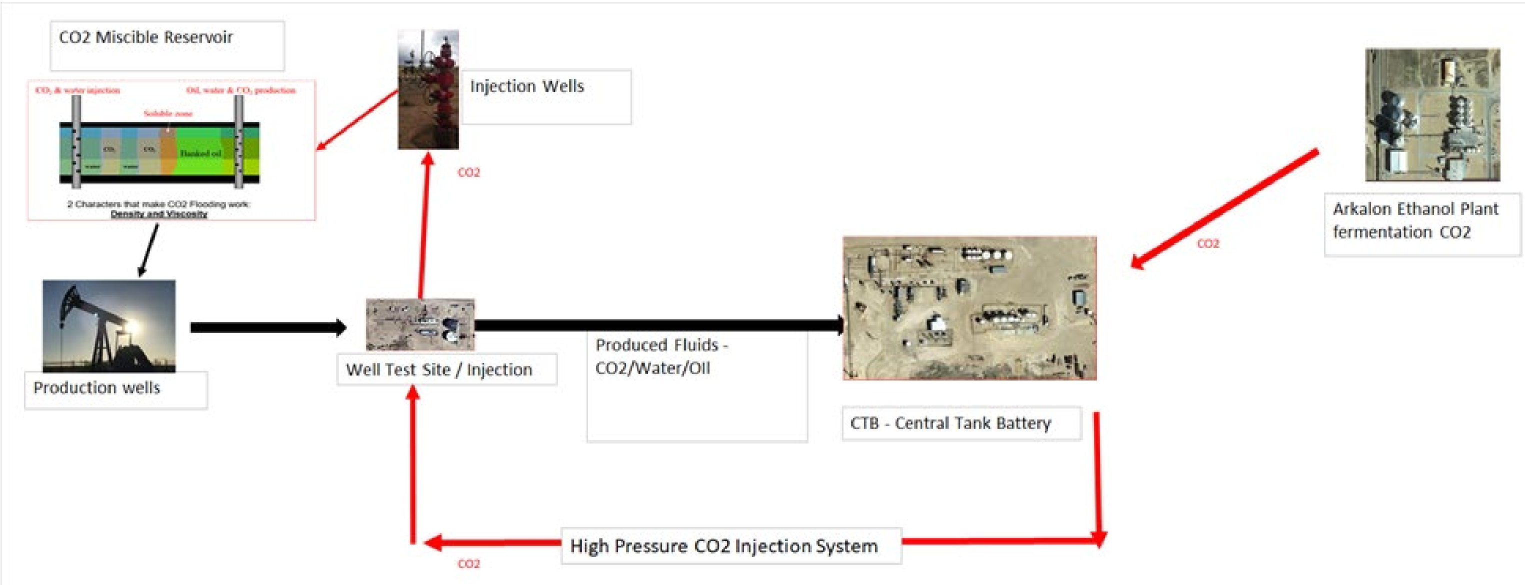

Figure 2.3–1. Simplified flow diagram of the facilities and equipment within the boundaries of the CFA.

2.3.1 CO_2 Distribution and Injection

CapturePoint purchases CO_2 from Conestoga Energy Partners, the parent company of the Arkalon Ethanol plant located in Liberal, Kansas. A custody transfer meter is located in the compression facility owned and operated by CapturePoint. The purchased CO_2 from the fermentation process is transported via a United States Department of Transportation (DOT) regulated pipeline to the CFA. A totalizer meter, for the purchased CO_2, is located in the field where instantaneous data is summed into a 24-hour flow rate which is recorded. A totalizer meter is a meter approved by the American Gas Association (AGA) Report #3 to measure the flowrate of gases. The actual measurements taken are temperature, line pressure, and differential pressure across the meter. Gas produced, which contains recycled CO_2, from the wells is compressed and metered by a similar totalizer meter as the purchase CO_2 meter and is recorded daily.

CapturePoint currently has seven active injection manifolds and approximately 29 active injection wells that the CO_2 is distributed through. When the MRV plan becomes active, the daily injection volume of the combined purchased CO_2 and recycled CO_2 will be approximately 24 MMCFD. Of this volume 12 MMCFD is purchased CO_2 and 12 MMCFD is recycled CO_2. This ratio of purchased CO_2 to recycled CO_2 is expected to change over time, with the percentage of recycled CO_2 increasing and purchased CO_2 decreasing. The current reservoir management plan projects that CO_2 purchases will remain constant at 12 MMCFD for 12 years and cease after 2034. A reservoir management plan is an integrated process using various surveillance techniques, economic evaluations, and accepted petroleum technical practices to efficiently operate enhanced oil recovery projects.

The seven injection manifolds currently in the field distribute the CO_2 to the field. These manifolds have valves to switch to water when the time is called for. Depending on the reservoir management plan, the WAG cycle will be adjusted to maximize oil recovery and minimize CO_2 utilization in each injection pattern. At each injection well pad there is a totalizer to measure the volumes injected every 24 hours. This data is collected daily by the field personnel and input into the data warehouse to be allocated for the pattern injection.

The two totalizer meters as described above will be used to determine the total volume injected used in section 7 for the mass balance equations necessary to determine annual and cumulative volumes of the stored CO_2.

2.3.2 Produced Fluids Handling

As injected CO_2 and water migrate through the reservoir; a mixture of oil, gas, and water (referred to as "produced fluids") flows to the production wells. Gathering lines bring the produced fluids from each production well to the AWT sites. CapturePoint has approximately 32 active production wells producing at any time. Each AWT has two separators. The first separator is used for testing individual wells to separate the gas, oil, and water produced from an individual well. This gas, oil, and water is subsequently measured and recorded for the well. Each producing well is production tested every 30 to 60 days after the last production test, or after the well is returned to production. Depending on the reservoir management plan, well testing can be more frequent to obtain data. The second separator is used to separate the gas from the oil/water mixture from the other wells producing into the AWT, and the gas and liquids are displaced from the vessel in separate lines. Leaving the AWT sites are two lines transporting produced fluids. One line is used for the liquid phase, a mixture of oil and water, and one line is used for the gas phase. However, the AWT in NPU does not transfer oil or gas to the CTB, it only transfers gas while reinjecting water with pumps at the NPU AWT and sells oil at the NPU AWT.

When gas and liquid lines enter the CTB, a series of vessels separate the oil, gas, and water to be accounted for and distributed for sales or reinjected. The liquid phase line has vessels to separate the oil from the water using density and residence time. The gas phase vessels collect any free liquids entrained with the gas. These free liquids are then combined back into the liquid phase line. All gas and water are reinjected, and the oil, which contains an estimated 2,360 ppm CO_2 (0.236%) for CU and 4,540 ppm CO_2 (0.454%) for NPU, is sold out of tanks. Annually, the oil from the stock tank is analyzed by a laboratory using ASTM crude oil analysis methods to determine the CO_2 content in the oil being sold.

After separation, the gas phase, which is approximately 92-95% CO_2, is mixed with reservoir volatile components, compressed, and distributed throughout the high-pressure distribution system using reciprocal compression and high-pressure horizontal pumps.

The water is transferred from the separation vessels to tanks for reinjection. After the water is conditioned, it is either reinjected at the WAG skids or disposed of into permitted disposal wells. Although CapturePoint is not required to determine or report the amount of dissolved CO_2 in the water as it is reinjected into the ground and not emitted to the atmosphere, the analyses have shown the water typically contains <690 ppm (0.069%) CO_2.

CFA production has trace amounts of hydrogen sulfide (H_2S), which is toxic. There are approximately 8-10 workers on the ground in the CFA at any given time, and all field and contractor personnel are always required to wear H_2S detectors. The primary purpose of the H_2S detectors is protecting people from the risk of being harmed. The detection limit of the H_2S detectors is quantified for readings in the range of 0-100 ppm and will sound an alarm above 10 ppm. The secondary purpose of the H_2S detectors would be to provide an indication of emissions of gas from a pipeline or surface equipment, that might go unnoticed by other observations or measurements. No gas volumes can be calculated based on the detector reading or alarm; only a H_2S leakage is detected and located. Once identified, a further response will be initiated and CO_2 volumes will be quantified as discussed in sections 4.5, 4.6, 5.4, and 8.1.5 of this MRV plan.

2.3.3 Produced Gas Handling

Produced gas separated at the CTB is stripped by a series of vessels of entrained and free water. The water content has been recorded to be < 20 pounds mass per MMCF, thus dehydration is not necessary. The gas is then sent to a centralized compression system to be compressed and placed in the high-pressure distribution system. This compression turns the CO_2 into a variable density liquid, which is then transported out via high pressure lines to the AWT sites where a manifold splits this dense CO_2 to the wells that are on CO_2 injection at that time.

2.3.4 Facilities Locations

The locations of the AWT sites are positioned in the field to access both injection distribution and production gathering. The CTB is where the final separation and injection equipment is maintained and operated. The water injection station is where the horizontal pumps are located to reinject the produced brine.

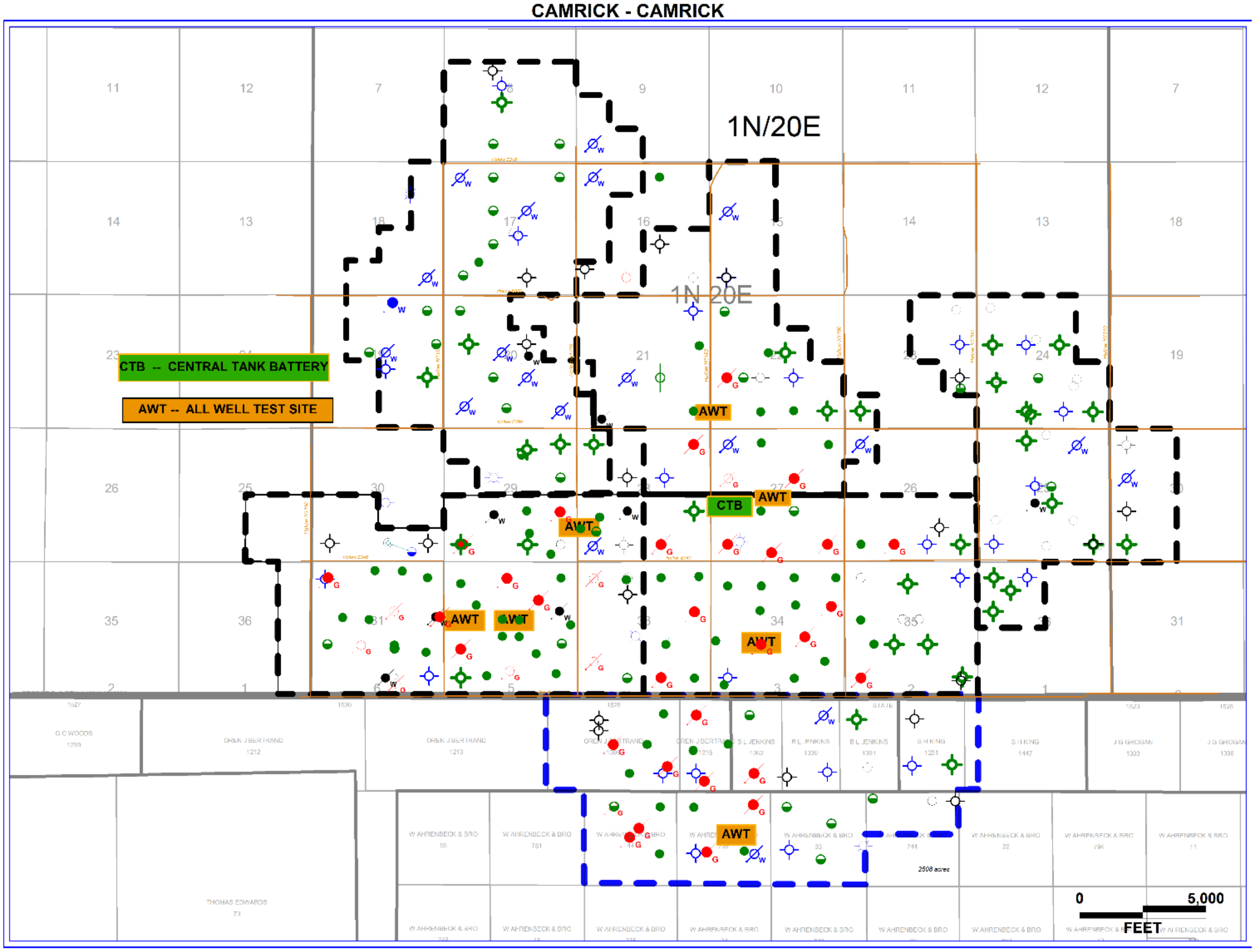

Figure 2.3-2. Location of AWT sites and CTB in the CFA

2.3.5 Water Conditioning and Injection

Produced water collected at the CTB is collected in a series of vessels and tanks in a cascade system. This allows any entrained oil to further separate to the top of the tanks because of the density difference. This oil is skimmed off and put back in the oil separation system. The clean water is then transferred to the water injection system where it is boosted in pressure and sent out to the AWT sites for distribution to all wells that are currently on water injection.

2.3.6 Well Operation and Permitting

The OCC and TRRC rules (Appendix 2) govern well location, construction, operation, maintenance, and plugging for all wells in permitted units and wells. CapturePoint follows these rules and regulations to maintain safe and efficient operations. This includes complying with all current and updated information for mechanical integrity testing, well repairs for injection wells, drilling and completion, permitting, and reporting.

Briefly, the following bulleted list is what the current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface waters.
- That wells file a completion report including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore).
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.
- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location, and setting of plugs.

2.3.7 Number, Location, and Depth of Wells

CapturePoint's CFA injection wells are listed in Appendix 1. Injection is into the Upper Morrowan, a lenticular bedded sandstone trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. The Upper Morrowan is described in section 2.2.2.1 above.

2.4 Reservoir Characterization

2.4.1 Reservoir Description

The target reservoir CFA Morrow B is a sandstone formation overlain by the Morrow shale and the Thirteen Finger limestone, which serve as excellent seals for injected CO_2 as determined by Farnsworth data (Ampomah et al., 2016a). The Morrow B sandstone reservoir is at a depth between 6,800 feet and 7,600 feet subsurface with an average dip of less than one degree (Figure 2.4-1). The productive limit of the CFA is about 80 to 90 percent of the total operated surface acreage, which is 14,652.315 acres. The maximum pay thickness is 56 feet with an average of 15 feet and does diminish to zero in spots.

The CFA is approximately eight miles by seven miles with areas that exhibit different reservoir behavior. The southwest portion of CU was most prolific oil producing area of the CFA under primary and secondary production; whereas the western portion of NPU is now responding to CO_2 better than historical operations would have indicated.

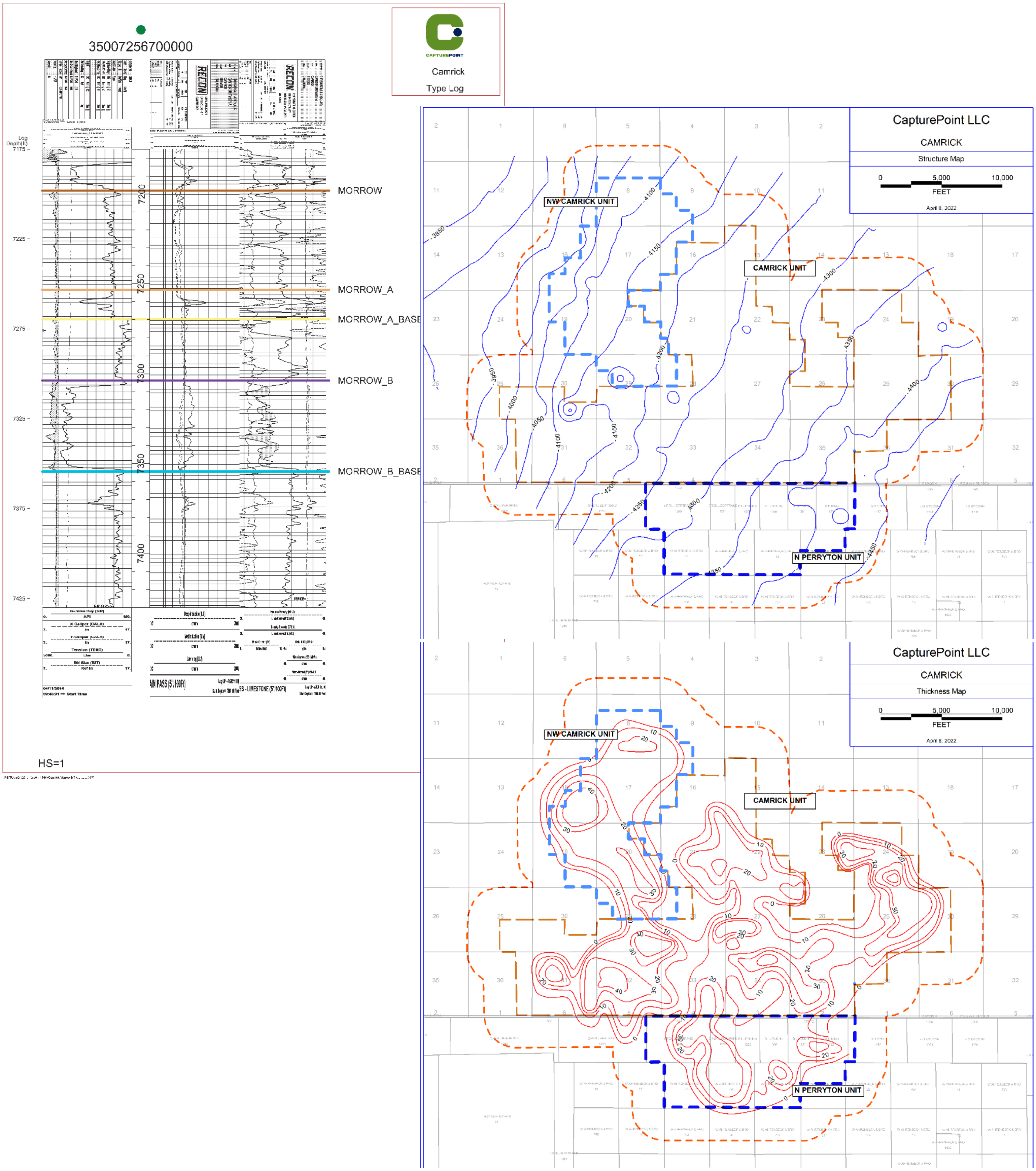

Figure 2.4-1. (Left) Type log of CFA caprock and reservoir, (Upper Right) Surface contour of Morrow top, (Lower Right) Thickness map of Morrow sands.

2.4.2 Reservoir Fluid Modeling

The compositional fluid model was constructed for the CapturePoint operated Farnsworth Unit. From laboratory compositional analysis an equation of state was tuned (Gunda et al., 2015). The minimum miscibility pressure (MMP) experiment was then simulated using a one-dimensional model. The simulated Farnworth Unit MMP of 4,009 psia compared to an MMP value of 4,200 psia derived from laboratory experiments provided by the operator represents a less than 5% error (Gunda et al., 2015).

The reservoir temperature in the CFA is 152 degrees Fahrenheit or 16 degrees lower than the temperature at Farnsworth Unit of 168 degrees. Using parameters of the Alston empirical correlation (1985), the MMP would be 170 psia lower at the CFA or 3,510 psia compared to 3,680 psia at the Farnsworth Unit (Figure 2.4-2).

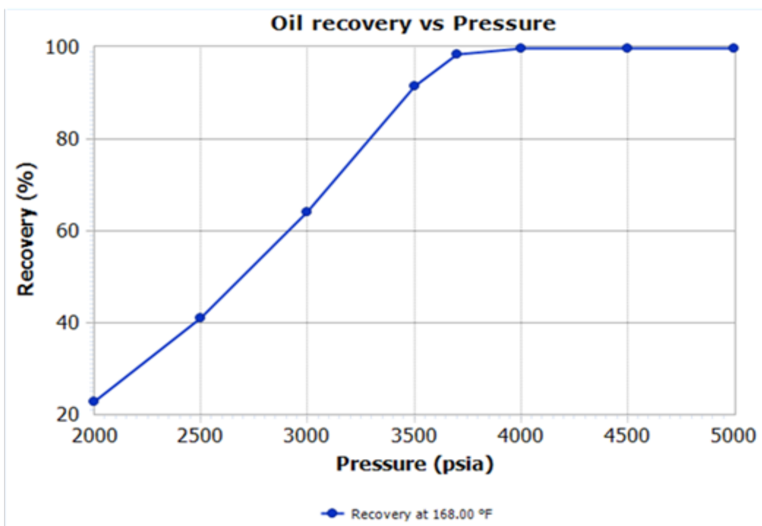

Figure 2.4-2. Oil recovery plot for 1D slim tube test for Farnsworth Unit.

2.4.3 CO_2 Analogy Field Study

Based on similar geologic, petrophysical, engineering, and operational parameters between the Farnsworth Unit and the CFA, the oil recovery performance of both fields is expected to be similar. Due to the stratigraphic nature of the Morrow channel sands, the potential movement of CO_2 is severely limited. The CFA area has contained the free phase CO_2 plume in a very confined area since March 2001 as exhibited by oil, water, and CO_2 recovery performance. Also, during CFA drilling and production operations, no reports exist which would indicate any plume has moved outside of the MMA. The Farnsworth Unit MRV and the CFA data justifies the conclusion that CO_2 will continue to be contained inside the MMA at the end of the CO_2 injection year t + 5, per §98.449 definitions.

2.4.4 CO_2 – EOR Performance Projections

For years, the oil industry has used dimensionless equations to predict the amount of oil that can be recovered using CO_2 for flooding oil reservoirs (Lee et al, 2018, Stell 2010). The

amount of oil recovered from projects is plotted as a decimal fraction of the original-oil-in-place versus the decimal fraction of the hydrocarbon pore volume (HPV) of CO_2 injected into the oil reservoir as measured in reservoir barrels (RB).

The CFA has been injecting CO_2 since March 2001. The dimensionless curves were matched to historical performance through early 2020 (Figure 2.4-3). The supply of CO_2 was curtailed from March 2020 until present, due to oil price uncertainty, and will resume after the Arkalon Plant upgrade that will be finished in the 4th quarter of 2022.

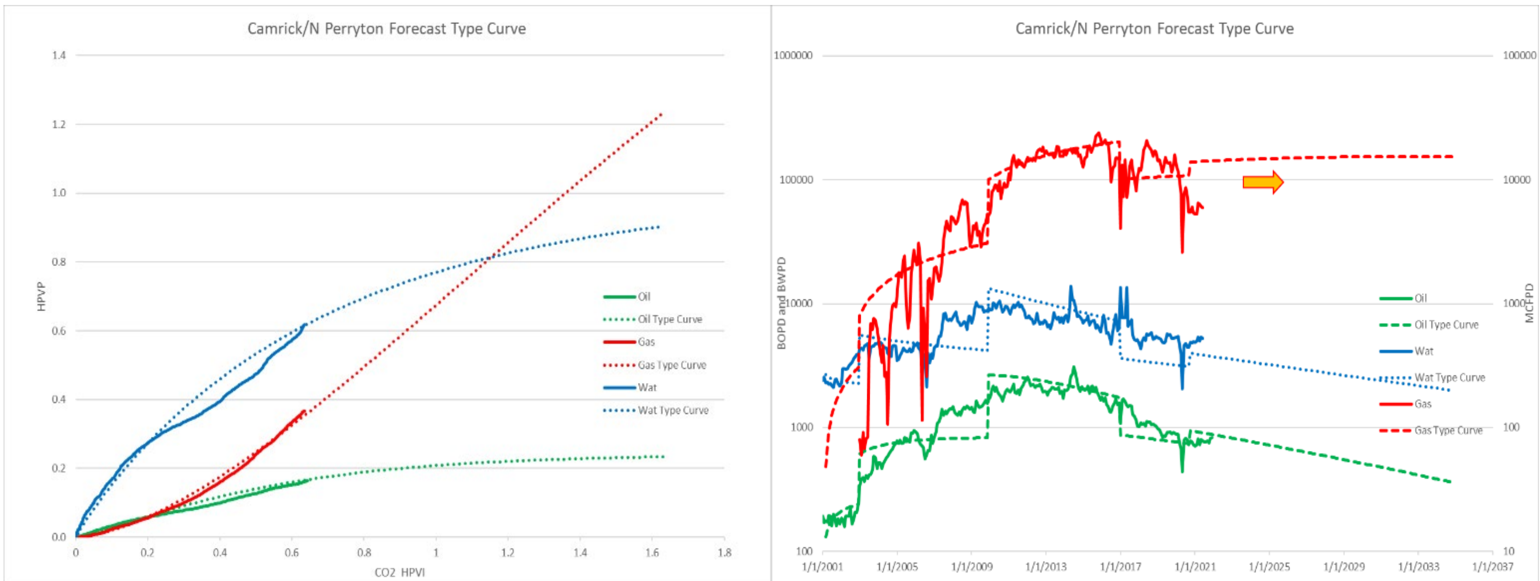

Figure 2.4-3. Dimensionless curves for CO_2 injection (left) with rate time curves (right).

The dimensionless water oil ratio and the gas oil ratio trends (Figure 2.4-4) for the CFA flooded acreage are very similar to what was forecasted by simulation in the Farnsworth Field as expected because of the porosity, permeability, and sand similarities.

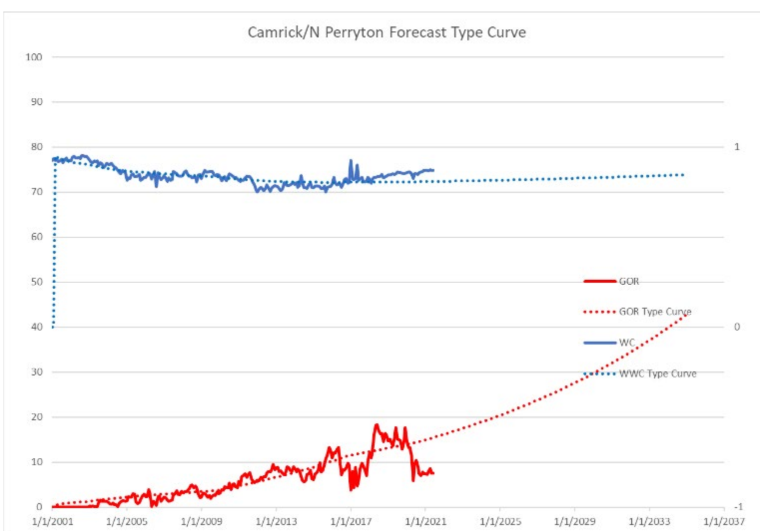

Figure 2.4-4. Dimensionless water cut and GOR vs. observed EOR data.

The CO_2 storage volumes for Arkalon fermentation CO_2 were also forecasted (Figure 2.4-5) using the same dimensionless technique. This technique indicates that the flooded acreage still has significant additional storage potential. The maximum CO_2 storage is limited to the amount of space available by the removal of the produced hydrocarbon. The projection indicates that there is pore space available to store approximately 0.4 to 0.5 decimal fraction of HPV amounting to 30 to 40 MMB.

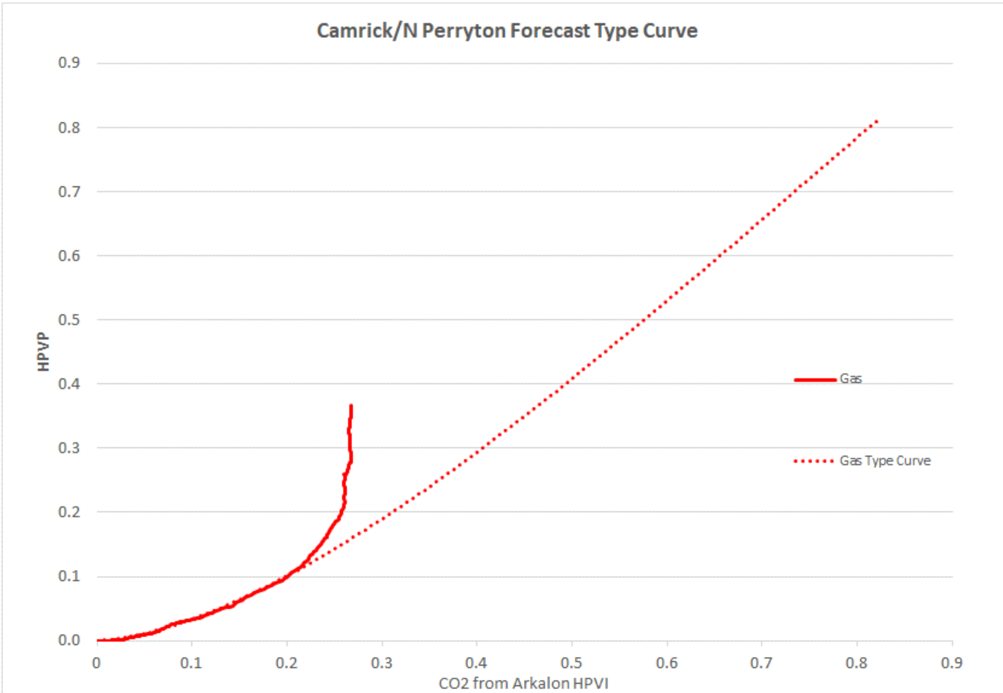

Figure 2.4-5. Dimensionless CO_2 Fermentation Curves

The barrels of reservoir volume were converted to standard cubic feet of gas and is displayed in the CFA Purchase CO_2, or Fermentation CO_2, vs Time chart (Figure 2.4-6).

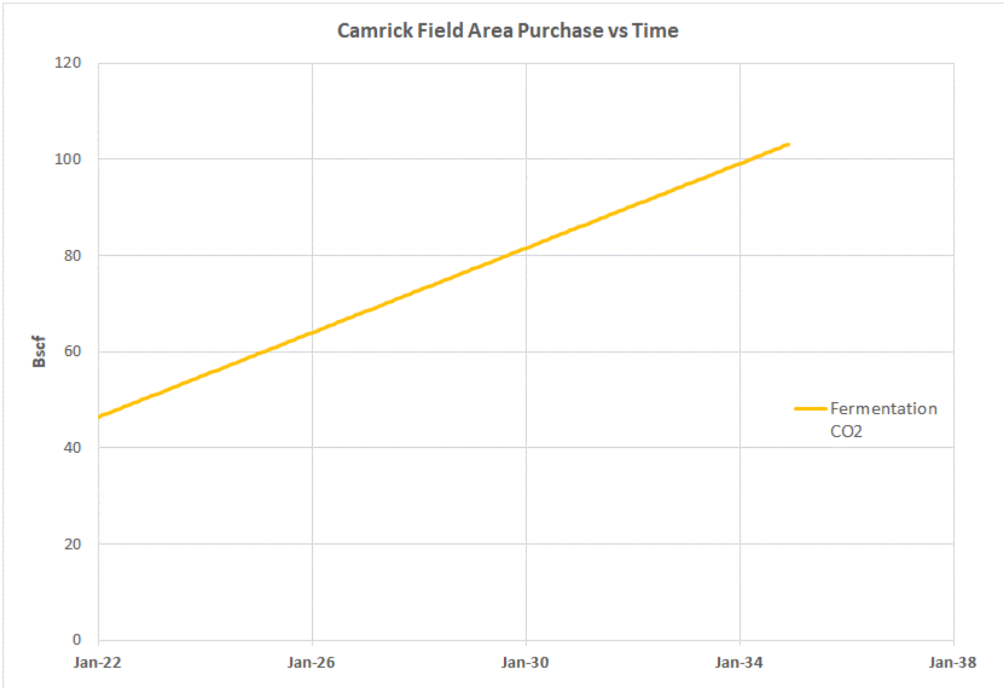

Figure 2.4-6. CO_2 Fermentation Volume.

3 Delineation of Monitoring Area

3.1 MMA

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The purchase volumes that are displayed in Figure 2.4-6 were mapped and are displayed in Section 3.1.1 indicates that CO_2 storage pore space is available, barring unforeseen future operational issues. Therefore, CapturePoint is defining the MMA as the boundary of the CFA plus an additional one-half mile buffer zone. This will allow for operational expansion throughout the CFA for the next 12 years, the anticipated life of the project.

3.1.1 Determination of Storage Volumes

Figure 3.1-1 displays wells that have CO_2 retention on the 4,800 acres that have been under EOR injection in the CFA since project initialization. The volume of the oil recovered since August 1955, resulted in a voidage space of 36 MMscf of CO_2 per acre of surface area that was later filled with water during waterflood. The average decimal fraction of CO_2 injection to hydrocarbon pore volume left in the ground after accounting for CO_2 production through 2021 is 0.29. The lateral extent of CO_2 in the injection zone or the CO_2 storage radius for each well was estimated based on cumulative CO_2 injected times the decimal fraction of CO_2 remaining divided by the voidage space. The largest CO_2 storage areas are around wells that injected CO_2 for the most years.

Figure 3.1-2 displays the potential area of the reservoir that can be filled with CO_2 with the existing injection wells. This assumed that only 78 percent of the average injection pattern area or 80 acres could be filled. There are 49 injectors identified for further injection that have room for an additional 90 Bscf of CO_2 storage volume or 140 Bscf total storage.

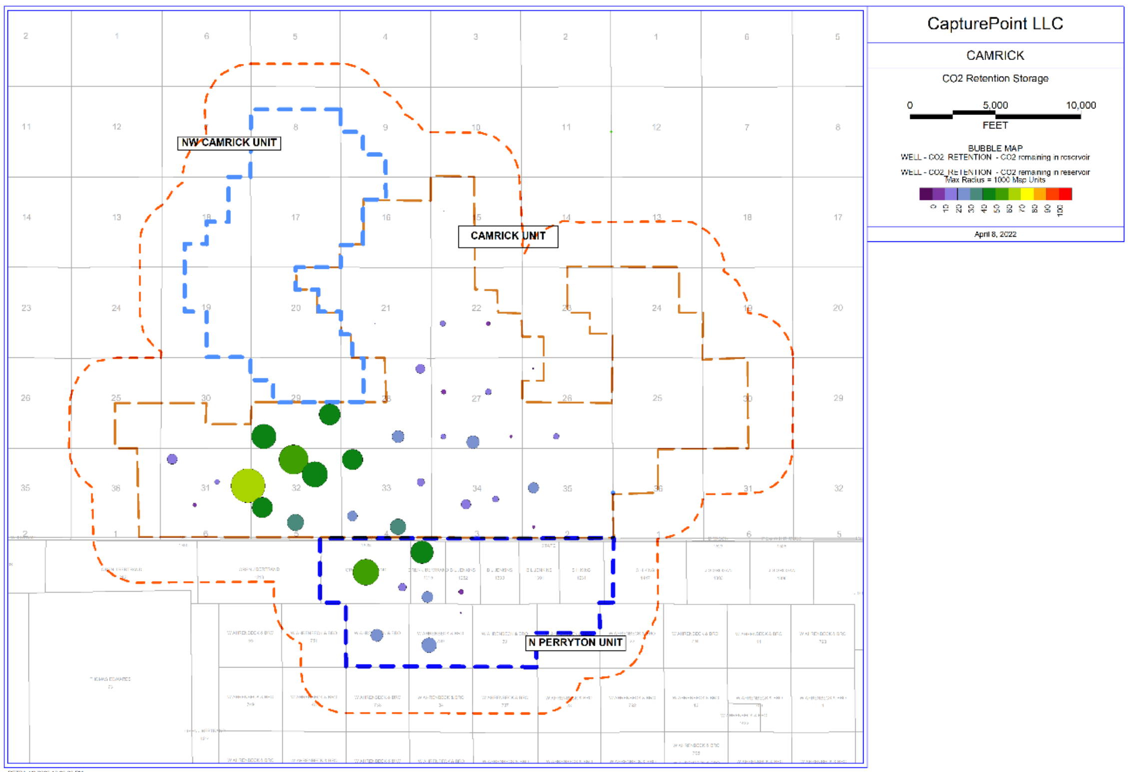

Figure 3.1-1. Estimated CO_2 storage as of 2021 in CFA.

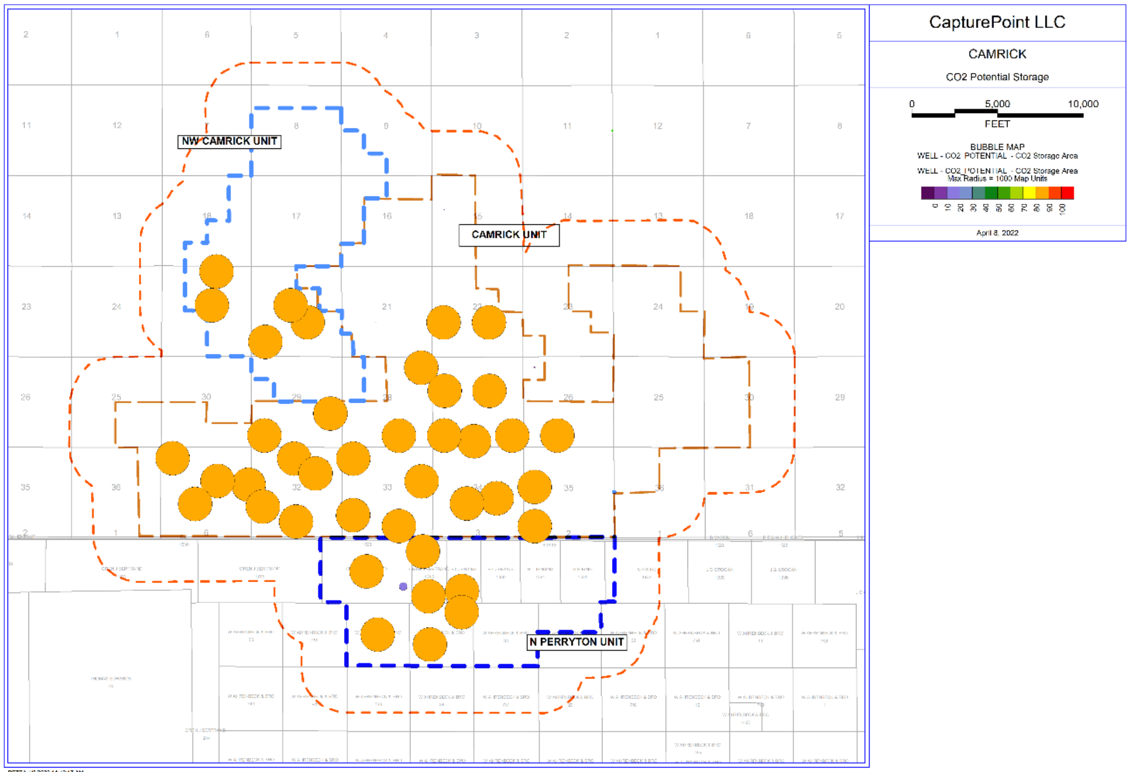

Figure 3.1-2. Potential Total CO_2 Storage in the CFA.

3.1.2 Determination of Buffer Zone

CapturePoint intends to implement a buffer zone of one-half mile around the CFA, the minimum required by Subpart RR, because the site characterization of the Morrow did not reveal any leakage pathways that would allow free-phase CO_2 to migrate laterally thereby warranting a buffer zone greater than one-half mile.

3.2 AMA

Currently, CapturePoint's operations are focused on the western portion of the CFA. However, it is anticipated as the project develops, additional activity will occur in the NWCU of the CFA; therefore, requiring active monitoring in that area. However, project development is driven by the market price of oil so CapturePoint is unable to provide a specific time in the future when the eastern portion of the CFA will be actively monitored. Therefore, for the purposes of this MRV plan, CapturePoint has chosen to include the entire CFA in the AMA.

4 Identification and Evaluation of Leakage Pathways

Since its discovery in 1955, the unitization of the different units from 1969 to 1972, and the commencement of CO_2 EOR in 2001; the CFA is an analogous field to the Farnsworth Unit, which has undergone extensive investigation and documentation as indicated in Section 2. From this body of work, CapturePoint has identified the following potential pathways of CO_2 leakage to the surface. This section will also address detection, verification, and quantification of leakage from each pathway.

4.1 Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO_2 EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment via personnel instructed on how to detect surface leaks and other equipment failure minimizes releases. In addition, the Oil and Gas Division requirements of the OAC rules of the OCC and the TAC rules of the TRRC to report and quantify leaks, both serve to minimize leakage of GHG from surface equipment. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. As described in Section 6.4 below, should leakage from surface equipment occur it will be quantified according to the procedures in Subpart W of the GHGRP.

4.2 Leakage from Wells

CapturePoint has identified 68 abandoned wells, 49 injection wells (29 active) and 94 production wells (59 active) within the MMA and assessed their potential for leakage of CO_2 to the surface as listed in Appendix 1.

4.2.1 Abandoned Wells

Figure 4.2-1 shows all wells plugged and abandoned in the CFA. Because the CFA was unitized in 1969 to 1972, all plugging and abandonment activities of wells within the CFA have been conducted under the regulations of the OCC and the TRRC for plugging wells. The cement used to plug wells when exposed to CO_2 will form colloidal gels that further reduce any flow. CapturePoint concludes that leakage of CO_2 to the surface through abandoned wells is unlikely. However, strategies for leak detection are in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

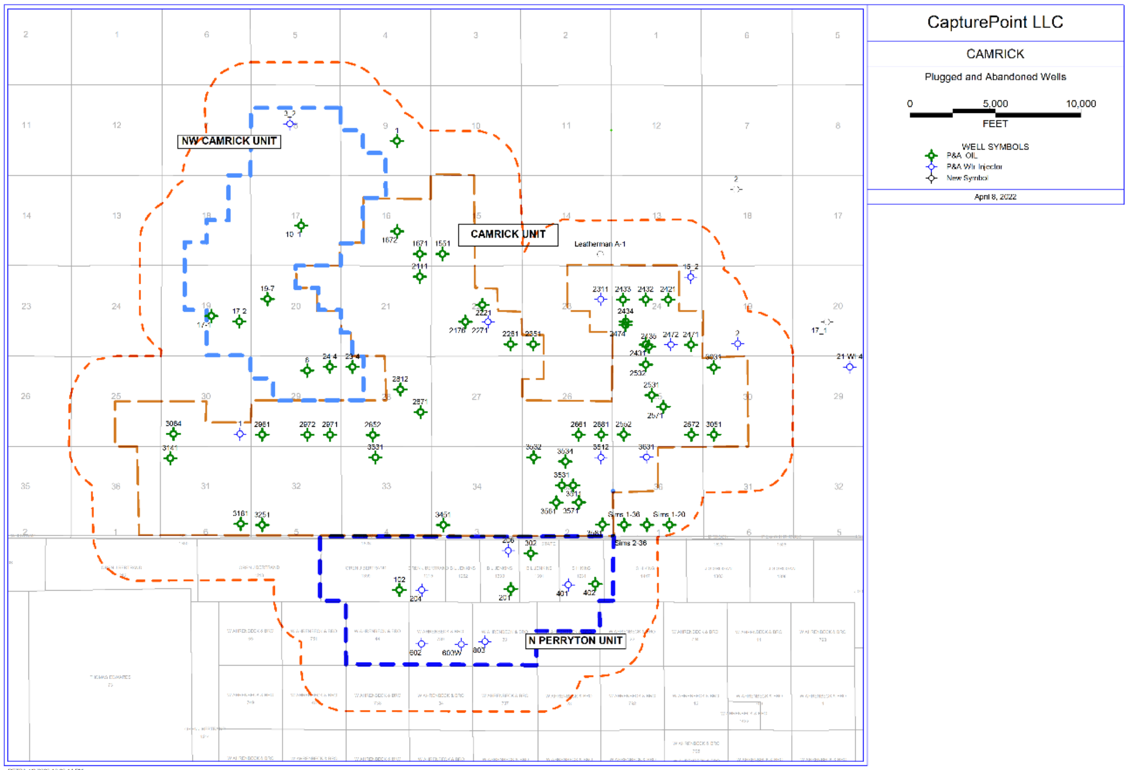

Figure 4.2-1. Plugged and Abandoned Wells in the CFA.

4.2.2 Injection Wells

Mechanical integrity testing (MIT) is an essential requirement of the UIC program in demonstrating that injection wells themselves do not act as conduits for leakage into underground sources of drinking water (USDW) and to the surface environment. TRRC Rule 46 requirements include special equipment requirements (e.g., tubing and packer) and modification; records maintenance; monitoring and reporting; testing; plugging; and penalties for violations of the rule. Permit revocation may result as a consequence of noncompliance. (See Section 2.3.6) The TRRC and the OCC detail all the requirements for the Class II permits issued to CapturePoint. These rules ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Figure 4.2-2 shows the active injection wells in the CFA. CapturePoint concludes that leakage of CO_2 to the surface through active injection wells is unlikely.

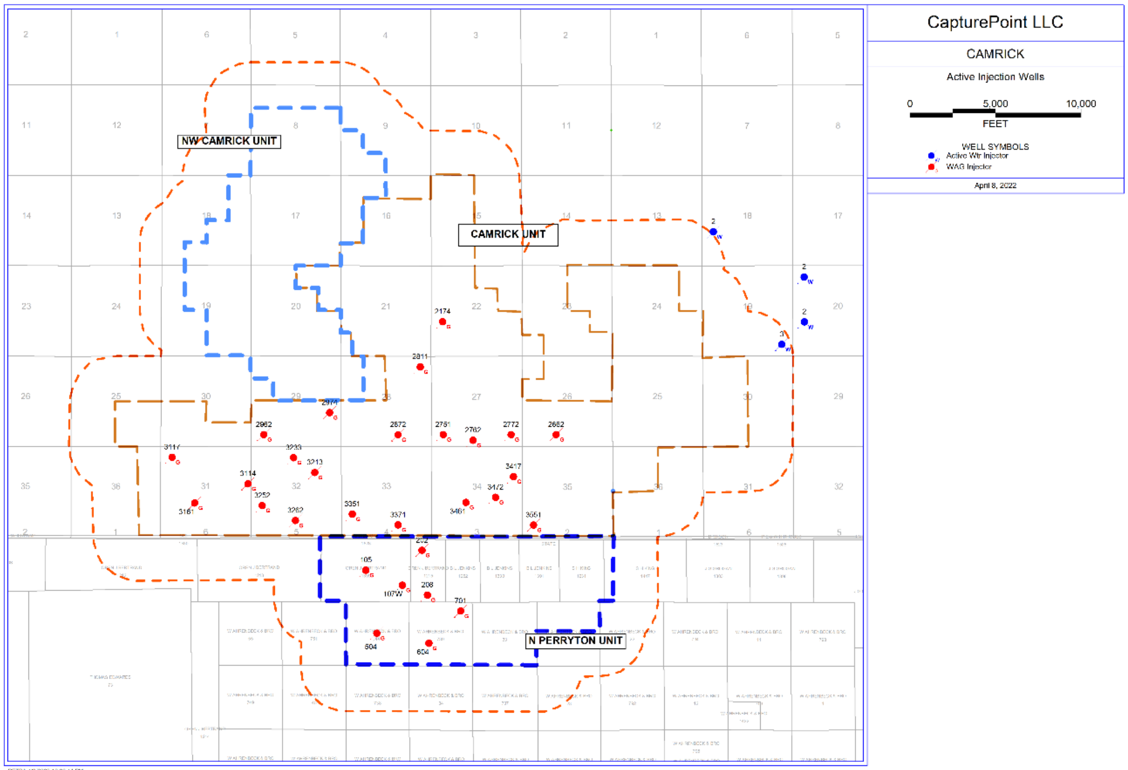

Figure 4.2-2. Active Injection Wells in the CFA.

4.2.3 Production Wells

Some of the original field wells drilled as oil wells were reclassified, administratively, to gas wells per OAC Title 165:10-1-6 paragraph (d), because of the gas-oil ratio growth due to reservoir depletion. Hence, there is no difference in well construction. (See Section 2.3.6) As the field is being further developed for enhanced oil recovery, these gas wells have been reclassified to oil wells per OCC regulations and will be monitored for leakage. (See Section 4.7) Figure 4.2-3 shows the active oil production wells in the CFA. Once EOR operations commence, the energy content of the produced gas drops and cannot be sold; therefore, any inactive gas wells are either reclassified to oil producers, or activated to WAG injectors, as described earlier. (See Section 4.2.2) However, as the project develops in the CFA additional production wells may be added and will be constructed according to the relevant rules of the OCC and the TRRC. Additionally, inactive wells may become active according to the rules of the OCC and the TRRC.

During production, oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure where the bottom hole wellbore pressure is less than the reservoir pressure. These lower pressure fluids, which also contains CO_2, are contained by the casing, tubing, wellhead, and flowline all the way to the CTB. CapturePoint concludes that leakage of CO_2 to the surface through production wells is unlikely.

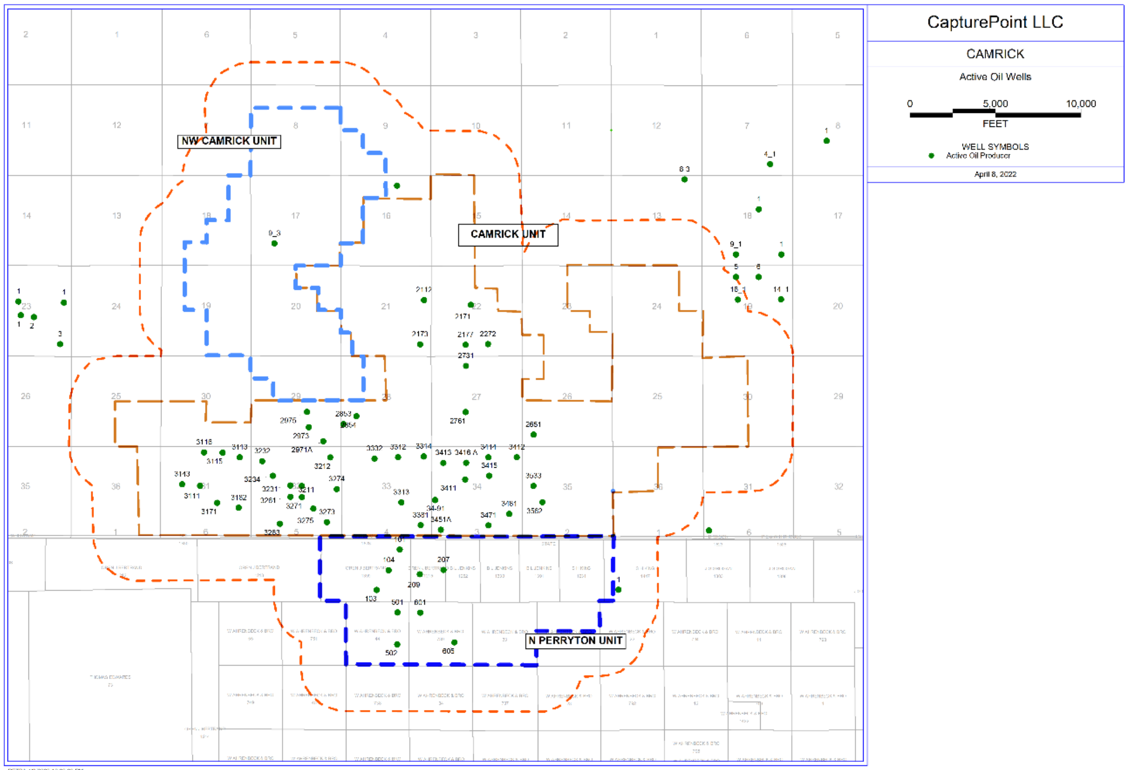

Figure 4.2-3. Active Oil Production Wells in the CFA.

4.2.4 Inactive Wells

Figure 4.2-4 shows all of the inactive wells in the CFA. The OCC has regulations for temporally abandoned/not plugged (TA) and terminated order wells/UIC not plugged (TM) and likewise the TRRC has regulations for inactive wells.

Inactive wells have a cast iron bridge plug set or long cement plugs placed above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. CapturePoint concludes that leakage of CO_2 to the surface through inactive wells is unlikely.

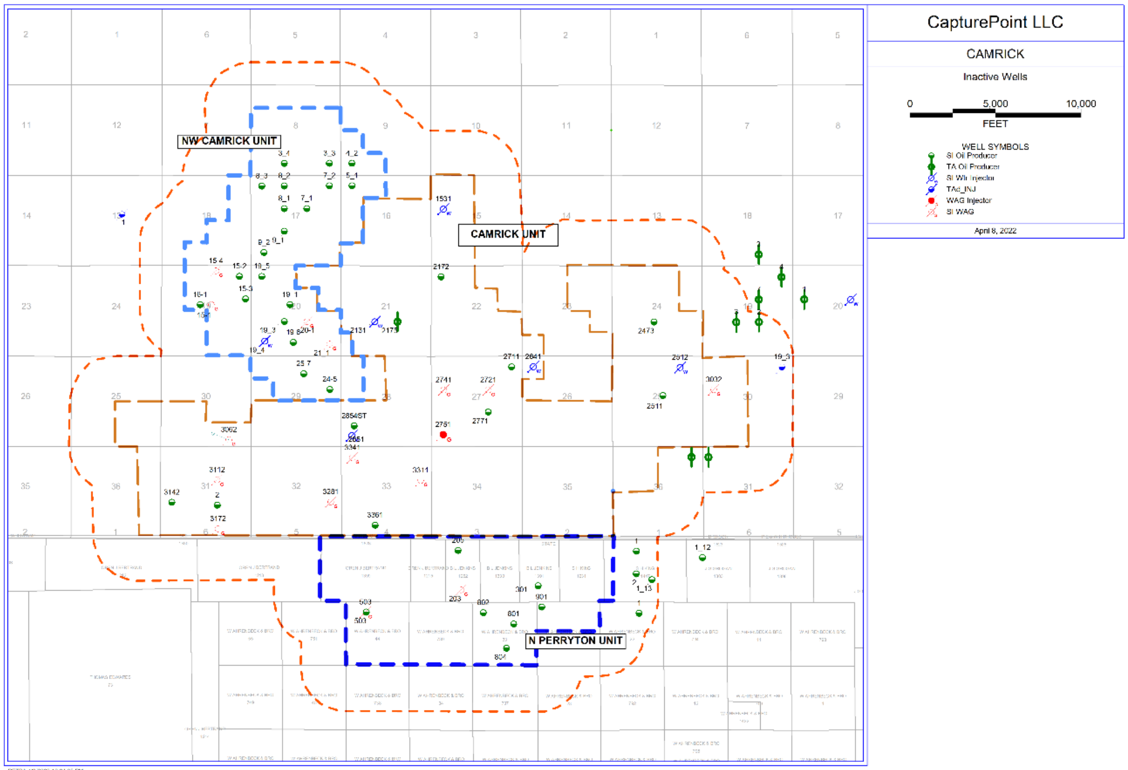

Figure 4.2-4. Inactive wells in the CFA

4.2.5 New Wells

As the project develops, new production wells and injection wells may be added to the CFA. All new wells will be constructed according to the relevant rules for the OCC and the TRRC which ensure protection of subsurface and surface resources, and the environment.

All wells in Oklahoma oilfields and all wells in Texas oilfields, including both injection and production wells, are regulated by the OCC and the TRRC, respectively, which has primacy to implement the UIC Class II programs.

Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Briefly current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface water.
- That wells file a completion report including basic electric logs.
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.

- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.

New well construction is based on existing best practices, established during the drilling of existing wells in CFA and follows the OCC and the TRRC rules, which significantly limits any potential leakage from well pathways. Additionally, the existing wells followed the OCC and the TRRC rules.

In public databases, the area of CFA plus one mile past the unit boundary contains over 100 wells that were drilled deeper than the Morrow formation and none of these wells were productive in reservoirs deeper than the Morrow. Therefore, it is very unlikely that anyone will ever drill through the AMA reservoir in the future. In the event a well is drilled within the AMA, the operator would be required to follow all the OCC and the TRRC rules and procedures in the drilling the well and the potential for leakage would be similar to any well that CapturePoint drills within the AMA. In addition, CapturePoint's visual inspection process during routine field operation will identify any unapproved drilling activity in the CFA.

4.3 Leakage from Faults and Bedding Plane Partings

Primary seals at CFA have been demonstrated to be mechanically very competent (see Section 2.2.2), thus the main concern of CO_2 migration at CFA is via seal bypass systems along fracture networks. The following lines of analysis have been used to assess this risk in the area.

4.3.1 Prescence of Hydrocarbons

The first and foremost argument against present day up-fault transmissibility is the 75 MMB of oil that was found trapped in the reservoir. If significant escape pathways existed, oil would have drained from the reservoir prior to the current day.

4.3.2 Fracture analysis

At the CFA, the work done at the Farnsworth Unit is analagous, where small aperture fractures were noted but not common in most of the reservoir cores examined but most of these fractures appear to be drilling induced. Fractures in the Thirteen Finger limestone caprock were described using an industry-standard format for fracture class type, orientation, fracture dip, type of mineral fill, fracture porosity, fracture spacing, and intensity. Again, drilling induced fractures are most common. Natural mineral-filled fractures are quite rare, were formed during diagenesis at shallow depths, and are of late Carboniferous age. Unless significantly damaged by large changes in reservoir pressure, they are highly unlikely to provide migration pathways.

In the unlikely event CO_2 leakage occurs as a result of leakage through the faults and fractures, it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.4 Lateral Fluid Movement

The Morrow strata in the Oklahoma and Texas Panhandle was primarily a deltaic sequence that prograded toward the southeast, resulting in deposition of mainly shales with lenticular, discontinuous coarse sandstones separated with very fine sandstone, minor conglomerates, and shale. The likelihood of any extensive migration of fluid outside of the AMA is very low.

Since CO_2 is lighter than the water remaining in the reservoir, it will migrate to the top of each lenticular structure as it is filled. The producing wells, which create low pressure points in the field, will drain the water and keep the CO_2 within each discontinuous sandstone.

4.5 Leakage through Confining/Seal system

At the CFA, the work done at the Farnsworth Unit will apply, where a variety of analytical methods were used for caprock (confining system) analysis, and the results should be the same for the CFA. Petrologic examination included standard thin section petrography and backscattered electron microscopy. Petrophysical analytical methods include retort analysis, pulse-decay permeability measurement, pressure decay permeability analysis for tight rocks, and mercury injection porosimetry, which is also known as mercury injection capillary pressure (MICP). Geomechanical analysis involved a standard series of mechanical tests: Brazil tension, unconfined compression, triaxial compression, and multi-stress compression.

Results of the MICP analysis show that the mudstone lithologies in the Morrow Shale and Thirteen Finger Limestone can support CO_2 column heights of ~1,000 to 10,000 feet. At an order of magnitude over the thickness of the Morrow reservoir, this should prove an effective seal for CO_2 storage in the Morrow B injection horizon.

Failure analyses show that the Morrow B sands are weaker than overlying lithologies, so that any fracture initiation around the injection well would not be expected to propagate into the overlying sealing units. Mechanical properties of the overlying shale and limestones provide an interesting and effective combination of strength and elasticity. Limestone layers are strong but brittle, while the shale layers are weaker but sufficiently ductile to prevent extensive fracture propagation.

It is unlikely for hydrocarbon migration pathways that charged the Morrow reservoir to be potential CO_2 migration pathways via primary pore networks today. Any potential CO_2 migration would be most likely due to leakage from wellbores or bypass through fault and fracture networks, discussed in Sections 4.2 and 4.3.

In the unlikely event CO_2 leakage occurs as a result of leakage through the confining seal it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.6 Natural and Induced Seismic Activity

Figure 4.6-1 shows the map of earthquakes with magnitudes measured at greater than 2.5 as defined by the United States Geological Survey (USGS). While past earthquake data cannot predict future earthquakes, the small number of events near CFA after the

waterflood operations were initiated in 1969 implies the area is not seismically sensitive to injection. Also, no documentation exists that any of the distant earthquake events caused a disruption in injectivity or damage to any of the wellbores in CFA.

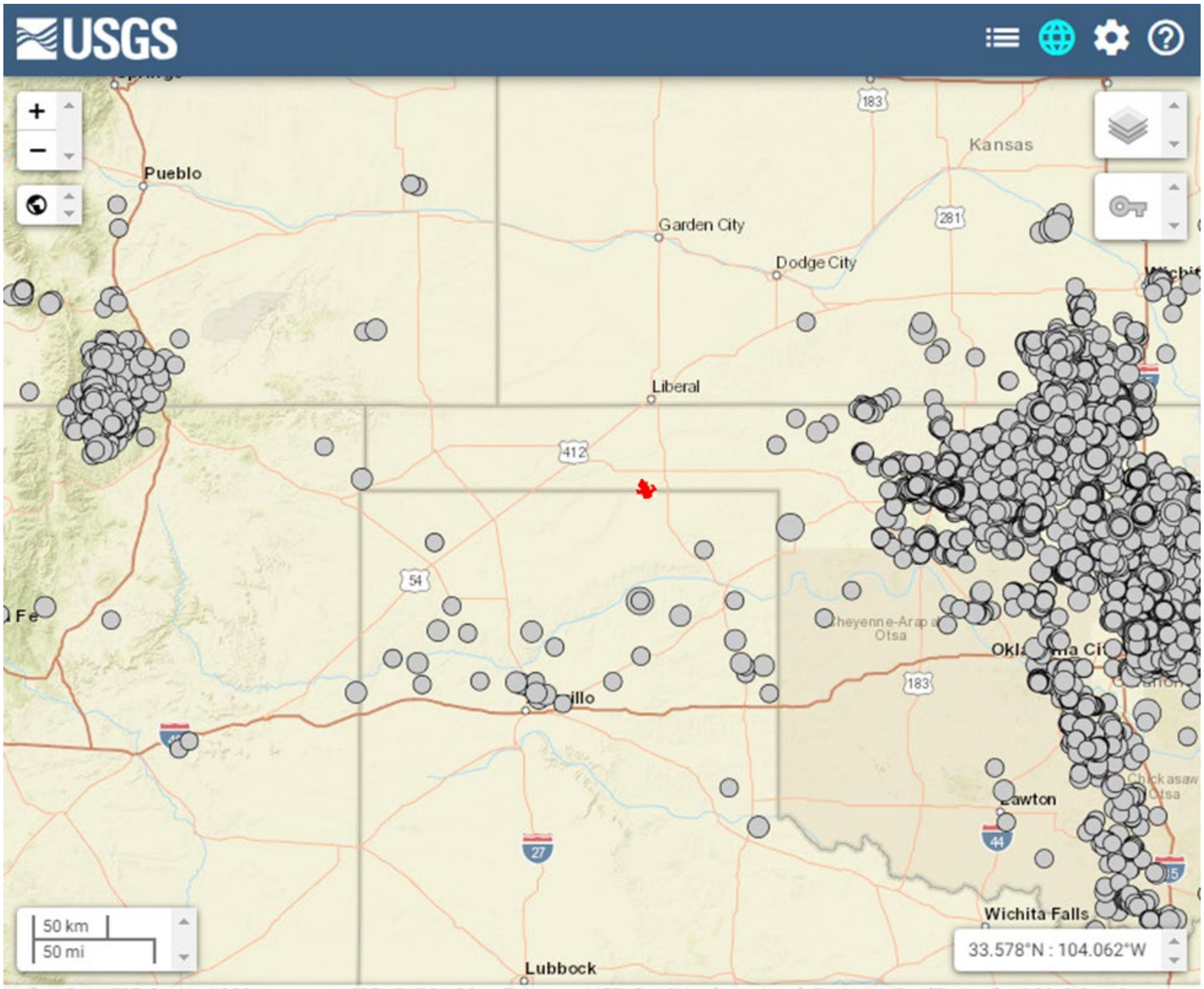

Figure 4.6-1. USGS earthquakes (+2.5 magnitude) for last 40 years with CFA highlighted red.

There is no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the CFA.

In the unlikely event that induced seismicity resulted in a pathway for material amounts of CO_2 to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would lead to further investigation.

4.7 Strategy for Detection and Response to 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 (well bores), and unique events such as induced fractures. Table 1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks,

CapturePoint's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO_2 losses discussed in the table are identified by type. Once the type is reported to a response manager the correct resources and personnel can be mobilized to develop the optimal response procedure. The procedure will address and mitigate further CO_2 leakage.

Table 1 Response Plan for CO_2 Loss

Known Potential Leakage Risks	Monitoring Methods and Frequency	Anticipated Response Plan
Tubing Leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days
Casing Leak	Weekly field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days
Wellhead Leak	Weekly field inspection	Workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations (weekly inspection but field personnel present daily)	Maintain well kill procedures
Unplanned wells drilled through Morrow	Weekly field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Re-enter and reseal abandoned wells
Pumps, values, etc.	Weekly field inspection	Workover crews respond within days
Leakage along faults	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near faults
Leakage laterally	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Fluid management along lease lines
Leakage through induced fractures	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near seismic event

4.8 Strategy for Quantifying CO_2 loss

Major CO_2 losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. CapturePoint will use Subpart W techniques to estimate leakages only on equipment and ensure those results are consistently represented in the Subpart RR report. Any event-driven leakage quantification reported in Subpart RR for surface leaks will use other techniques.

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 CO_2 that would be most appropriate. In the event leakage occurs, CapturePoint will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission.

Any volume of CO_2 detected leaking to the 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, CapturePoint's field experience, and other factors such as the frequency of inspection. As indicated in Section 6.4, leaks will be documented, and the records of leakage events will be retained in the electronic environmental documentation and reporting system, which consists of reports stored on servers, with information uploaded into third party software.

Available studies of actual well leaks and natural analogs (e.g., naturally occurring CO_2 geysers) suggest that the amount released from routine leaks would be small as compared to the amount of CO_2 that would remain stored in the formation.

5 Strategy for Determining CO_2 Baselines for CO_2 Monitoring

Atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values for soil measurement in the CFA area, per the characterization, monitoring and well data collected by the Southwest Regional Partnership on Carbon Sequestration (SWP) in the analogous Farnsworth Unit.

5.1 Site Characterization and Monitoring

As described in Sections 2.2.2 and 2.4, the Morrow B sandstone is isolated both above and below by shale units of the Morrow. The primary seal consists of 180 – 200 ft of Morrow shale and Thirteen Finger Limestone which in turn is overlain by over a thousand feet of younger shale and limestone. These units provide a suitable seal to prevent the migration of CO_2 out of the injection reservoir. Additionally, no significant faults or fracture zones that cut across the seal units have been identified in the CFA, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented.

5.2 Groundwater monitoring

CapturePoint does not routinely pull water samples from the Ogallala water wells. However, samples are pulled when OCC injection permits are submitted in Oklahoma. No indication of fluid leakage has been identified from any of these in the CFA area. CapturePoint is unlikely to continue monitoring USDW wells for CO_2 or brine contamination, as characterization of the Morrow (see section 5.1) has suggested minimal risk of groundwater contamination from CO_2 leakage from this depth.

5.3 Soil CO_2 monitoring

Atmospheric CO_2 values at the Farnsworth Unit have been determined by a SWP eddy tower installation. In winter 2019, the eddy system malfunctioned and has not been repaired due to COVID travel restrictions. However, the atmospheric CO_2 concentration data from the eddy tower were in very good agreement with values obtained from the NOAA Global Monitoring Laboratory station in Moody, Texas (Station: WKT). Since the CFA area is in close proximity to the Farnsworth Unit, atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values.

5.4 Visual Inspection

CapturePoint operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage.

5.5 Well Surveillance

CapturePoint adheres to the requirements of OAC Title 165:10-5 for the OCC and of TAC Rule 46 for the TRRC governing fluid injection into productive reservoirs. Rule 46 includes requirements for monitoring, reporting, and testing of Class II injection wells. Furthermore, the OCC and the TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well if they are deemed necessary.

CapturePoint also adheres to the requirements of OAC Title 165:10-7 for the OCC and TAC Rule 20 for the TRRC governing the notification of fires, breaks, leaks, or escapes. Rule 20 requires that all operators report leaks to the OCC or the TRRC including measured or estimated quantities of product leaked.

6 Site specific considerations for determining the Mass of CO_2 Sequestered

Of the twelve RR equations in 98.443 of Subpart RR, the following are relevant to CapturePoint's operations.

6.1 Determining Mass of CO_2 received

CapturePoint currently receives CO_2 at its CFA facility through its own pipeline from the Arkalon Ethanol plant in Liberal, Kansas. CapturePoint also recycles CO_2 from its production wells in the CFA.

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

where:

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

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into the well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

6.2 Determining Mass of CO_2 Injected

CapturePoint injects CO_2 into the injection wells listed in Appendix 1.

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

where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

6.3 Determining Mass of CO_2 produced from Oil Wells

CapturePoint also recycles CO_2 from its production wells which are part of its operations in the CFA. Therefore, the following equation is relevant to its operations.

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

Where:

$CO_{2,w}$ = Annual CO_2 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 CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,w}}$ = CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator.

To aggregate production data, CapturePoint will sum the mass of all of the CO_2 separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 below:

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

Where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) through all separators in the reporting year.

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction), CU is 0.00236 and NPU is 0.00454 at the last sample.

w = Separator.

6.4 Determining Mass of CO_2 emitted by Surface Leakage

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations.

CapturePoint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below:

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

where:

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

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

x = Leakage pathway.

6.5 Determining Mass of CO_2 sequestered

The following Equation RR-11 pertains to facilities that are actively producing oil or natural gas.

$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP}$ (Equation RR-11)

Where:

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

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

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

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

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

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

7 Estimated Schedule for Implementation of MRV plan

CapturePoint expects to begin implementing the approved MRV plan when the new CO_2 capture facility is operational, September 1, 2022.

8 GHG monitoring and Quality Assurance Program

CapturePoint will meet the monitoring and QA/QC requirements of 98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 98.444 (d).

8.1 GHG monitoring

As required by 40 CFR 98.3(g)(5)(i), CapturePoint's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

8.1.1 General

Measurement of CO_2 *Concentration* – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GSA) standards.

Measurement of CO_2 *Volume* – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. CapturePoint will adhere to the American Gas Association (AGA) Report #3 – (ORIFICE METERING OF NATURAL GAS AND OTHER RELATED HYDROCARBON FLUIDS)

8.1.2 CO_2 Received

Daily fermentation CO_2 purchased is received via the pipeline from the Arkalon ethanol plant in Liberal, Kansas, and is measured using a volumetric totalizer, which uses accepted flow calculations for CO_2 according to the AGA Report #3.

8.1.3 CO_2 Injected

Daily CO_2 injection is recorded by combining the totals for the recycle compressor meter and the received CO_2 meter from Arkalon based on what's delivered on a 24-hour basis. This data is taken from the meter daily and stored in CapturePoint's data warehouse for records and reservoir management.

8.1.4 CO_2 Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO_2. The produced gas is sampled at least quarterly for the CO_2 content.

8.1.5 CO_2 Emissions from equipment leaks and vented emissions of CO_2

As required by 98.444 (d), CapturePoint will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead and between the flow meter used to measure production quantity and the production wellhead.

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6 Measurement Devices

As required by 40 CFR 98.444(e), CapturePoint will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration.
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meters are National Institute of Standards and Technology (NIST) traceable.

8.2 QA/QC procedures

CapturePoint will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

8.3 Estimating missing data

CapturePoint will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

A quarterly flow rate of CO_2 received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.

A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.

A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

8.4 Revisions of the MRV plan

CapturePoint will revise the MRV Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

9 Records Retention

CapturePoint will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, CapturePoint will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.
(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
    (i) The GHG emissions calculations and methods used.
    (ii) Analytical results for the development of site-specific emissions factors, if applicable.
    (iii) The results of all required analyses.
    (iv) Any facility operating data or process information used for the GHG emission calculations.
(3) The annual GHG reports.
(4) Missing data computations. For each missing data event, CapturePoint will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
(5) A copy of the most recent revision of this MRV Plan.
(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(9) Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(10) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(11) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
(12) 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.
(13) 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.
(14) Any other records as specified for retention in this EPA-approved MRV plan.

10 Appendices

Appendix 1 – CFA Wells

Table A1.1 – Production Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2112	35007353570000	Oil Prod	Active	CO_2	1	0
CU 2171	35007354120000	Oil Prod	Active	CO_2	1	0
CU 2173	35007354140000	Oil Prod	Active	CO_2	1	0
CU 2177	35007222340000	Oil Prod	Active	CO_2	1	0
CU 2272	35007224530000	Oil Prod	Active	CO_2	1	0
CU 2651	35007362650000	Oil Prod	Active	CO_2	1	0
CU 2731	35007359750000	Oil Prod	Active	CO_2	1	0
CU 2761	35007350590000	Oil Prod	Active	CO_2	1	0
CU 2853	35007250840000	Oil Prod	Active	CO_2	1	0
CU 2854	35007250850000	Oil Prod	Active	CO_2	1	0
CU 2971A	35007256700000	Oil Prod	Active	CO_2	1	0
CU 2973	35007213750000	Oil Prod	Active	CO_2	1	0
CU 2975	35007223730000	Oil Prod	Active	CO_2	1	0
CU 3111	35007350600000	Oil Prod	Active	CO_2	1	0
CU 3113	35007359460000	Oil Prod	Active	CO_2	1	0
CU 3115	35007251710000	Oil Prod	Active	CO_2	1	0
CU 3116	35007252570000	Oil Prod	Active	CO_2	1	0
CU 3143	35007250860000	Oil Prod	Active	CO_2	1	0
CU 3171	35007359600000	Oil Prod	Active	CO_2	1	0
CU 3182	35007249250000	Oil Prod	Active	CO_2	1	0
CU 3211	35007352150000	Oil Prod	Active	CO_2	1	0
CU 3212	35007352690000	Oil Prod	Active	CO_2	1	0
CU 3231	35007001820000	Oil Prod	Active	CO_2	1	0
CU 3232	35007352720000	Oil Prod	Active	CO_2	1	0
CU 3234	35007212010000	Oil Prod	Active	CO_2	1	0
CU 3261	35007352170000	Oil Prod	Active	CO_2	1	0
CU 3263	35007251640000	Oil Prod	Active	CO_2	1	0
CU 3271	35007352160000	Oil Prod	Active	CO_2	1	0
CU 3273	35007252580000	Oil Prod	Active	CO_2	1	0
CU 3274	35007253140000	Oil Prod	Active	CO_2	1	0
CU 3275	35007254040000	Oil Prod	Active	CO_2	1	0
CU 3312	35007360800000	Oil Prod	Active	CO_2	1	0
CU 3313	35007254370000	Oil Prod	Active	CO_2	1	0
CU 3314	35007254030000	Oil Prod	Active	CO_2	1	0
CU 3332	35007254020000	Oil Prod	Active	CO_2	1	0
CU 3381	35007360780000	Oil Prod	Active	CO_2	1	0
CU 3411	35007351700000	Oil Prod	Active	CO_2	1	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3412	35007351720000	Oil Prod	Active	CO_2	1	0
CU 3413	35007351730000	Oil Prod	Active	CO_2	1	0
CU 3414	35007005220000	Oil Prod	Active	CO_2	1	0
CU 3415	35007211170000	Oil Prod	Active	CO_2	1	0
CU 3416A	35007252590000	Oil Prod	Active	CO_2	1	0
CU 3451A	35007256710000	Oil Prod	Active	CO_2	1	0
CU 3471	35007351750000	Oil Prod	Active	CO_2	1	0
CU 3481	35007351710001	Oil Prod	Active	CO_2	1	0
CU 3491	35007254330000	Oil Prod	Active	CO_2	1	0
CU 3533	35007206880000	Oil Prod	Active	CO_2	1	0
CU 3562	35007255050000	Oil Prod	Active	CO_2	1	0
NPU 101	42357010440000	Oil Prod	Active	CO_2	1	0
NPU 103	42357010060000	Oil Prod	Active	CO_2	1	0
NPU 104	42357000050000	Oil Prod	Active	CO_2	1	0
NPU 207	42357302000000	Oil Prod	Active	CO_2	1	0
NPU 209	42357333830000	Oil Prod	Active	CO_2	1	0
NPU 501	42357009140000	Oil Prod	Active	CO_2	1	0
NPU 502	42357024100000	Oil Prod	Active	CO_2	1	0
NPU 601	42357008420000	Oil Prod	Active	CO_2	1	0
NPU 605	42357333840000	Oil Prod	Active	CO_2	1	0
NWCU 3-1	35007360850000	Gas Prod	Active	CO_2	1	0
NWCU 9-3	35007249430000	Oil Prod	Active	CO_2	1	0
CU 2172	35007354130000	Oil Prod	Inactive	CO_2	0	0
CU 2175	35007354160000	Oil Prod	Inactive	CO_2	0	0
CU 2473	35007211990000	Oil Prod	Inactive	CO_2	0	0
CU 2511	35007350790000	Oil Prod	Inactive	CO_2	0	0
CU 2711	35007359260000	Oil Prod	Inactive	CO_2	0	0
CU 2771	35007359850000	Oil Prod	Inactive	CO_2	0	0
CU 3142	35007222350000	Oil Prod	Inactive	CO_2	0	0
CU 3361	35007352670000	Oil Prod	Inactive	CO_2	0	0
NPU 205	42357008070000	Oil Prod	Inactive	CO_2	0	0
NPU 301	42357022080000	Oil Prod	Inactive	CO_2	0	0
NPU 801	42357004630000	Oil Prod	Inactive	CO_2	0	0
NPU 802	42357004620000	Oil Prod	Inactive	CO_2	0	0
NPU 804	42357201730000	Oil Prod	Inactive	CO_2	0	0
NPU 901	42357000660000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-2	35007350870000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-3	35007210790000	Oil Prod	Inactive	CO_2	0	0
NWCU 16-1	35007350720000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-1	35007360900000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-3	35007360920000	Oil Prod	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
NWCU 19-4	35007360930000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-5	35007360940000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-6	35007211250000	Oil Prod	Inactive	CO_2	0	0
NWCU 24-5	35007222710000	Oil Prod	Inactive	CO_2	0	0
NWCU 25-7	35007228000000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-3	35007360870000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-4	35007360880000	Oil Prod	Inactive	CO_2	0	0
NWCU 4-2	35007360740000	Oil Prod	Inactive	CO_2	0	0
NWCU 5-1	35007361050000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-1	35007360980000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-2	35007360990000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-1	35007360810000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-2	35007360820000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-3	35007208260000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-1	35007360950000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-2	35007360960000	Oil Prod	Inactive	CO_2	0	0
CU 1551	35007350740000	Oil Prod	P&A	CO_2	0	0
CU 1671	35007352180000	Oil Prod	P&A	CO_2	0	0
CU 2111	35007353560000	Oil Prod	P&A	CO_2	0	0
CU 2176	35007358870000	Oil Prod	P&A	CO_2	0	0
CU 2221	35007000490000	Oil Prod	P&A	CO_2	0	0
CU 2281	35007359220000	Oil Prod	P&A	CO_2	0	0
CU 2421	35007359350000	Oil Prod	P&A	CO_2	0	0
CU 2431	35007350330000	Oil Prod	P&A	CO_2	0	0
CU 2432	35007350340000	Oil Prod	P&A	CO_2	0	0
CU 2433	35007350350000	Oil Prod	P&A	CO_2	0	0
CU 2434	35007350360000	Oil Prod	P&A	CO_2	0	0
CU 2435	35007218800000	Oil Prod	P&A	CO_2	0	0
CU 2471	35007359080000	Oil Prod	P&A	CO_2	0	0
CU 2531	35007361090000	Oil Prod	P&A	CO_2	0	0
CU 2532	35007361100000	Oil Prod	P&A	CO_2	0	0
CU 2552	35007359760000	Oil Prod	P&A	CO_2	0	0
CU 2571	35007350730000	Oil Prod	P&A	CO_2	0	0
CU 2572	35007359320000	Oil Prod	P&A	CO_2	0	0
CU 2661	35007361990000	Oil Prod	P&A	CO_2	0	0
CU 2681	35007350320000	Oil Prod	P&A	CO_2	0	0
CU 2852	35007301360000	Oil Prod	P&A	CO_2	0	0
CU 2961	35007358760000	Oil Prod	P&A	CO_2	0	0
CU 2971	35007358750000	Oil Prod	P&A	CO_2	0	0
CU 2972	35007358780000	Oil Prod	P&A	CO_2	0	0
CU 3031	35007359560000	Oil Prod	P&A	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3051	35007300380000	Oil Prod	P&A	CO_2	0	0
CU 3064	35007254270000	Oil Prod	P&A	CO_2	0	0
CU 3141	35007359610000	Oil Prod	P&A	CO_2	0	0
CU 3181	35007359470000	Oil Prod	P&A	CO_2	0	0
CU 3251	35007352710000	Oil Prod	P&A	CO_2	0	0
CU 3331	35007200750000	Oil Prod	P&A	CO_2	0	0
CU 3451	35007351690000	Oil Prod	P&A	CO_2	0	0
CU 3511	35007359730000	Oil Prod	P&A	CO_2	0	0
CU 3531	35007350850000	Oil Prod	P&A	CO_2	0	0
CU 3532	35007359950000	Oil Prod	P&A	CO_2	0	0
CU 3534	35007211180000	Oil Prod	P&A	CO_2	0	0
CU 3561	35007359830000	Oil Prod	P&A	CO_2	0	0
CU 3571	35007359980000	Oil Prod	P&A	CO_2	0	0
CU 3581	35007359970000	Oil Prod	P&A	CO_2	0	0
CU 3631	35007301000000	Oil Prod	P&A	CO_2	0	0
CU 1672	35007352190000	Oil Prod	P&A	CO_2	0	0
CU 2351	35007350370000	Oil Prod	P&A	CO_2	0	0
CU 2474	35007228200000	Oil Prod	P&A	CO_2	0	0
CU 2812	35007352340000	Oil Prod	P&A	CO_2	0	0
CU 2871	35007359060000	Oil Prod	P&A	CO_2	0	0
NPU 102	42357021420000	Oil Prod	P&A	CO_2	0	0
NPU 201	42357001280000	Oil Prod	P&A	CO_2	0	0
NPU 302	42357022290000	Oil Prod	P&A	CO_2	0	0
NPU 402	42357022300000	Oil Prod	P&A	CO_2	0	0
NWCU 17-2	35007359620000	Oil Prod	P&A	CO_2	0	0
NWCU 10-1	35007361010000	Oil Prod	P&A	CO_2	0	0
NWCU 17-1	35007350710000	Oil Prod	P&A	CO_2	0	0
NWCU 19-7	35007224520000	Oil Prod	P&A	CO_2	0	0
NWCU 24-4	35007358770000	Oil Prod	P&A	CO_2	0	0
NWCU 25-6	35007358790000	Oil Prod	P&A	CO_2	0	0

Table A1.2 – Water Alternating Gas (WAG) Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 2662 (INJ)	35007362010000	WAG Inj	Active	CO_2	0	1
CU 2751 (INJ)	35007359440002	WAG Inj	Active	CO_2	0	1
CU 2762 (INJ)	35007213660000	WAG Inj	Active	CO_2	0	1
CU 2772 (INJ)	35007359860001	WAG Inj	Active	CO_2	0	1
CU 2811 (INJ)	35007352200000	WAG Inj	Active	CO_2	0	1
CU 2872 (INJ)	35007359070000	WAG Inj	Active	CO_2	0	1
CU 2962 (INJ)	35007212000000	WAG Inj	Active	CO_2	0	1
CU 2974 (INJ)	35007220770000	WAG Inj	Active	CO_2	0	1
CU 3114 (INJ)	35007206540000	WAG Inj	Active	CO_2	0	1
CU 3117 (INJ)	35007254000000	WAG Inj	Active	CO_2	0	1
CU 3161 (INJ)	35007359590002	WAG Inj	Active	CO_2	0	1
CU 3213 (INJ)	35007224570000	WAG Inj	Active	CO_2	0	1
CU 3233 (INJ)	35007206890000	WAG Inj	Active	CO_2	0	1
CU 3252 (INJ)	35007211020000	WAG Inj	Active	CO_2	0	1
CU 3262 (INJ)	35007206870000	WAG Inj	Active	CO_2	0	1
CU 3351 (INJ)	35007352680000	WAG Inj	Active	CO_2	0	1
CU 3371 (INJ)	35007360770000	WAG Inj	Active	CO_2	0	1
CU 3417 (INJ)	35007255060000	WAG Inj	Active	CO_2	0	1
CU 3461 (INJ)	35007351680000	WAG Inj	Active	CO_2	0	1
CU 3472 (INJ)	35007206940000	WAG Inj	Active	CO_2	0	1
CU 3551 (INJ)	35007359840000	WAG Inj	Active	CO_2	0	1
NPU 105 (INJ)	42357000030000	WAG Inj	Active	CO_2	0	1
NPU 107W (INJ)	42357333770000	WAG Inj	Active	CO_2	0	1
NPU 202WI (INJ)	42357021500000	WAG Inj	Active	CO_2	0	1
NPU 208 (INJ)	42357327410000	WAG Inj	Active	CO_2	0	1
NPU 701 (INJ)	42357008410000	WAG Inj	Active	CO_2	0	1
NPU 504 (INJ)	42357329480000	WAG Inj	Active	CO_2	0	1
NPU 604W (INJ)	42357330870000	WAG Inj	Active	CO_2	0	1
CU 1531 (INJ)	35007359990000	WAG Inj	Inactive	CO_2	0	0
CU 2131 (INJ)	35007362700000	WAG Inj	Inactive	CO_2	0	0
CU 2512 (INJ)	35007350780000	WAG Inj	Inactive	CO_2	0	0
CU 2641 (INJ)	35007359250001	WAG Inj	Inactive	CO_2	0	0
CU 2721 (INJ)	35007359870001	WAG Inj	Inactive	CO_2	0	0
CU 2741 (INJ)	35007359430000	WAG Inj	Inactive	CO_2	0	0
CU 2851 (INJ)	35007355420001	WAG Inj	Inactive	CO_2	0	0
CU 3032 (INJ)	35007359580000	WAG Inj	Inactive	CO_2	0	0
CU 3062 (INJ)	35007253090000	WAG Inj	Inactive	CO_2	0	0
CU 3112 (INJ)	35007359450001	WAG Inj	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 3172 (INJ)	35007251690000	WAG Inj	Inactive	CO_2	0	0
CU 3281 (INJ)	35007352700003	WAG Inj	Inactive	CO_2	0	0
CU 3311 (INJ)	35007360790000	WAG Inj	Inactive	CO_2	0	0
CU 3341 (INJ)	35007353530000	WAG Inj	Inactive	CO_2	0	0
NPU 203W (INJ)	42357008270000	WAG Inj	Inactive	CO_2	0	0
NPU 503 (INJ)	42357009150001	WAG Inj	Inactive	CO_2	0	0
NWCU 15-1 (INJ)	35007350860000	WAG Inj	Inactive	CO_2	0	0
NWCU 15-4 (INJ)	35007224510000	WAG Inj	Inactive	CO_2	0	0
NWCU 20-1 (INJ)	35007360760000	WAG Inj	Inactive	CO_2	0	0
NWCU 21-1 (INJ)	35007361020000	WAG Inj	Inactive	CO_2	0	0
CU 2271 (INJ)	35007359230000	WAG Inj	P&A	CO_2	0	0
CU 2311 (INJ)	35007362000000	WAG Inj	P&A	CO_2	0	0
CU 2472 (INJ)	35007359090000	WAG Inj	P&A	CO_2	0	0
CU 3061 (INJ)	35007359820000	WAG Inj	P&A	CO_2	0	0
CU 3512 (INJ)	35007359740000	WAG Inj	P&A	CO_2	0	0
NPU 204W (INJ)	42357022520000	WAG Inj	P&A	CO_2	0	0
NPU 206W (INJ)	42357022510000	WAG Inj	P&A	CO_2	0	0
NPU 401W (INJ)	42357004520000	WAG Inj	P&A	CO_2	0	0
NPU 602W (INJ)	42357020230000	WAG Inj	P&A	CO_2	0	0
NPU 603W (INJ)	42357201720001	WAG Inj	P&A	CO_2	0	0
NPU 803W (INJ)	42357201710000	WAG Inj	P&A	CO_2	0	0
NWCU 14-1 (INJ)	35007350530000	WAG Inj	P&A	CO_2	0	0
NWCU 3-2 (INJ)	35007360860000	WAG Inj	P&A	CO_2	0	0

Table A1.3 – Water Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU WSW 1	35007355430001	Wtr Inj	Active	CO_2	0	1
NPU W 1W	42357300050002	Wtr Inj	Inactive	CO_2	0	0
CU 2551	35007350750000	Wtr Inj	P&A	CO_2	0	0

Appendix 2 – Referenced Regulations

U.S. Code > Title 26, INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1, NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits >

Section 45Q ..... Credit for carbon oxide sequestration

OCC > Title 165: CORPORATION COMMISSION > UNDERGROUND INJECTION CONTROL

Section

165:10-5-1 .... Classification of underground injection wells
165:10-5-2 .... Approval of injection wells or disposal wells
165:10-5-3 .... Authorization for existing enhanced recovery injection wells and existing disposal wells
165:10-5-4 .... Application for approval of enhanced recovery projects
165:10-5-5 .... Application for approval of injection and disposal operations
165:10-5-6 .... Testing and monitoring requirements for injection wells and disposal wells
165:10-5-7 .... Monitoring and reporting requirements for wells covered by 165:10-5-1
165:10-5-8 .... Liquid hydrocarbon storage wells
165:10-5-9 .... Duration of underground injection well orders or permits
165:10-5-10 ..... Transfer of authority to inject
165:10-5-11 ..... Notarized reports
165:10-5-12 ..... Application for administrative approval for the subsurface injection of onsite reserve pit fluids
165:10-5-13 ..... Application for permit for one time injection of reserve pit fluids
165:10-5-14 ..... Exempt aquifers
165:10-5-15 ..... Application for permit for simultaneous injection well

165:5-7-27 .... Application for approval of injection and disposal wells
165:5-7-29 .... Request for exception to certain underground injection well requirements
165:5-7-30 .... Amending existing orders or permits authorizing injection for injection, disposal, or LPG storage wells

TAC > Title 16 - Economic Regulation> Part 1 TRRC > Chapter 3 – Oil and Gas Division >

Rules

Appendix 3 – References

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Appendix 4 – Abbreviations and Acronyms

2D – 2 dimensional
3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
ANSI – American National Standards Institute
API – American Petroleum Institute
AWT – All Well Test
ASTM - American Society for Testing and Materials
Bscf – billion standard cubic feet
B/D – barrels per day
bopd – barrels of oil per day
C4 – butane
C5 – pentane
C7 – heptane
C7+ - standard heptane plus
CCE – constant composition expansion
CCUS – carbon capture utilization and storage
CFA – Camrick Field Area
cf – cubic feet
CH4 – methane
CO_2 – carbon dioxide
EOR – Enhanced Oil Recovery
EOS – Equation of State
EPA – US Environmental Protection Agency
ESD – Emergency Shutdown Device
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
H_2S – hydrogen sulfide
lb – pound
mD – millidarcy(ies)
MICP – mercury injection capillary pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MMB – million barrels
MMP – minimum miscible pressure
MMscf – million standard cubic feet
MMstb – million stock tank barrels
MRV – Monitoring, Reporting, and Verification
MMMT – Million metric tonnes
MT – Metric tonne
NIST – National Institute of Standards and Technology

NAESB – North American Energy Standards Board
OAC – Oklahoma Administrative Code
OCC – Oklahoma Corporation Commission
OOIP – Original Oil-In-Place
OWC – oil water contact
PPM – Parts Per Million
psia – pounds per square inch absolute
PVT – pressure, volume, temperature
QA/QC – quality assurance/quality control
RMS – root mean square
SEM – scanning electron microscope
SWP - Southwest Regional Partnership on Carbon Sequestration
TAC – Texas Administrative Code
TA – Temporally Abandoned/not plugged
TD – total depth
TM – Terminated order wells/UIC not plugged
TRRC – Texas Railroad Commission
TSD – Technical Support Document
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water
WAG – Water Alternating Gas (Gas is recycled CO_2 and purchase CO_2)
XRD – x-ray diffraction

Appendix 5 – Conversion Factors

CapturePoint reports CO_2 at standard conditions of temperature and pressure as defined in the State of Texas in the Texas Administrative Code for the Oil and Gas Division, Rule 3.79 as follows:

> Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit.

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at:

https://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At State of Texas standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.002641684 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2{,}204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2} = 0.002641684$$

$$MW_{CO2} = 44.0095$$

$$Density_{CO2} = 5.2734\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.2734\ x\ 10^{-2}\frac{MT}{Mcf}$$

The conversion factor 5.2734×10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Request for Additional Information: Camrick Unit
July 13, 2022

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	4.2.3	24	**Original EPA Question** "Once EOR operations commence, the energy content of the produced gas drops and cannot be sold; therefore, no gas wells are identified." Can you please clarify whether there are gas wells in the CFA and if they are identified in any section of the MRV plan? Even if the gas is not marketable, any gas wells could be source of potential leakage/emissions. Please update the MRV Plan as necessary. **Camrick Unit Response:** Changed "no gas wells are identified" to "any inactive gas wells are reclassified to either oil producer or WAG injector". **New EPA Question:** In the MRV plan, please clarify what actions will be taken to convert inactive gas wells to become an oil producer or WAG injector. Would this be a reclassification in name, or would well conversion or workover take place? Would the wells be assumed to have the same potential leakage characteristics, monitoring activities, and quantification of leakage as others already identified in the MRV plan? Please describe how these wells may differ from others in the plan and what actions will be taken to monitor and quantify potential leakage.	Added… "Some of the original field wells drilled as oil wells were reclassified, administratively, to gas wells per OAC Title 165:10-1-6 paragraph (d), because of the gas-oil ratio growth due to reservoir depletion. Hence, there is no difference in well construction as described in Section 2.3.6. As the field is being further developed for enhanced oil recovery, these gas wells have been reclassified to oil wells per OCC regulations and will be monitored for leakage as described in Section 4.7." Changed… "are reclassified to either oil producer or WAG injector." …to… "are either reclassified to oil producers, or activated to WAG injectors, as described earlier. (See Section 4.2.2)" Please see Attached Appendix for supplemental information

Appendix:

In MRV Section 2.3.6, Well Operation and Permitting, in Oklahoma, requires adhering to OCC regulations for such operations of oil and gas wells. The resulting wells will have the same potential leakage characteristics, monitoring activities, and quantification of leakage as any well already identified. The MRV Section 4.7, Strategy for Detection and Response to CO2 Loss, will apply directly to these well reclassifications.

The three OCC regulations for Form 1002A referenced in the answer above are listed as follows.

"OAC Title 165:10-1-6. Duties and authority of the Conservation Division"
(d) The Director of the Conservation Division may administratively reclassify a well according to the gas-oil ratio as specified in 165:10-13-2 if the retesting of a well pursuant to this Section indicates a change in the original gas-oil ratio.

"OAC Title 165:10-13-2. Classification of wells for allowable purposes"
(a) For purposes of this Subchapter the terms gas, oil, and gas-oil ratio are defined in 165:10-1-2.
(b) Any well having a gas-oil ratio of 15,000 to one or more shall be classified as a gas well for allowable purposes.

"OAC Title 165:10-15-7. Procedure for obtaining discovery allowable"
(c) If a gas well in a discovery oil pool is reclassified as an oil well for allowable purposes, the operator must file the appropriate form, information and material specified in (a) of this Section within 30 days of reclassifying the well to obtain a discovery allowable. The allowable shall be effective the date the well was reclassified as an oil well as indicated on Form 1002A.

Camrick Field Area (CFA)

MONITORING, REPORTING AND VERIFICATION PLAN (MRV)

CapturePoint LLC

April 2022

Contents

INTRODUCTION

CapturePoint, LLC (CapturePoint) operates the Camrick Field Area (CFA) located in Beaver and Texas Counties, Oklahoma and in Ochiltree County, Texas for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) with retention of CO_2 serving a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The CFA was discovered in 1955 and is composed of three units, the Camrick Unit (CU) that was unitized by Humble Oil Company on October 14, 1969, the North Perryton Unit (NPU) that was unitized by Humble Oil Company on March 17, 1969, and the Northwest Camrick Unit (NWCU) that was unitized by Atlantic RichField Company on September 15, 1972. The Units were formed for the purpose of waterflooding with salt water sourced from the Wolfcamp formation. The field structure is a lenticular bedding sand trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. CapturePoint has been operating the CFA since 2017. CapturePoint acquired the CFA from Chaparral Energy LLC, which initiated the CO_2-EOR project in March 2001 for the CU and January 2007 for the NPU. No CO_2 has been injected in the NWCU. CapturePoint intends to continue CO_2-EOR operations until the end of the economic life of the CO_2-EOR program using various Class II injection wells as defined by Underground Injection Control (UIC) regulations and permitted under Texas Railroad Commission (TRRC) Rule 46 of the Texas Administrative Code (TAC) and the Oklahoma Corporation Commission (OCC) Title 165:10 of the Oklahoma Administrative Code (OAC). In this document, the term “gas” means a mixture of hydrocarbon light end components and the CO_2 component that can be produced as part of the EOR process.

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

This MRV Plan contains ten sections:

Section 1 contains facility information.

Section 2 contains the project description including: a detailed description of the injection operation including the duration and volume of CO_2 to be injected; a detailed description of the geology and hydrogeology of the CFA located on the northwest shelf of the Anadarko basin; and a detailed characterization of the injection reservoir modeling techniques employed.

Section 3 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449 and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 4 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. This section also describes the strategy for detecting, verifying, and quantifying any surface leakage of CO_2 as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Finally, this section also demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

Section 5 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 6 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 9 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 10 includes Appendices supporting the narrative of the MRV Plan.

1 Facility

1.1 Reporter Number

The CU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544678 and the NPU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544679. The EPA has been notified that the NPU will not be reporting for 2022, and that the facility has been merged into the Camrick Unit Facility Identification number 544678.

1.2 UIC Permit Class

For injection wells (see Appendix 2) that are the subject of this MRV plan, the OCC has rules governing UIC Class II injection wells. These OCC rules are OAC Title 165:10-5-1 through 165:10-5-15, OAC 165:5-7-27, OAC 165:5-7-30, the request for an exception to UIC rules under OAC 165:5-7-29, and other governing filing forms. Also, the TRRC has issued UIC Class II enhanced recovery permits under its Rule 46, TAC Title 16 Part 1 Chapter 3. All wells in the CFA, including both injection and production wells, are regulated by the OCC and the TRRC, which have primacy to implement the UIC Class II program.

1.3 UIC Injection Well Numbers

A list of the injection wells in the CFA is provided in Appendix 1. The details of the injection process are provided in Section 2.3.

2 Project Description

2.1 Project Characteristics

2.1.1 Estimated years of CO_2 injection

The CFA has been injecting CO_2 for the last 20+ years and it is currently projected that CapturePoint will inject CO_2 for an additional 12 years.

2.1.2 Estimated volume of CO_2 injected over lifetime of project

Historical and forecasted cumulative CO_2 retention volumes are approximately 100 billion standard cubic feet (Bscf) or 5.3 million metric tonnes (MMMT) from the start of CO_2

injection through October 2034. During the MRV plan, the period September 2022 through October 2034, 52.5 Bscf or 2.77 MMMT will be stored in the CFA. (See Figure 2.4-6)

2.2 Environmental Setting of MMA

2.2.1 Boundary of the MMA

CapturePoint has defined the boundary of the MMA as equivalent to the boundary of the CFA plus ½ mile beyond. A discussion of the methods used in delineating the MMA and the AMA are presented in Section 3.

2.2.2 Geology

The geological discussions in Sections 2.2.2 and 4.3-4.4 are based on analysis of logs from both the Farnsworth Unit, which is located 10 miles South-South-West of the CFA, and the CFA. Both areas have similar pay thickness, porosity values, permeability measurements, depositional environment, tectonic processes, and overburden strata layers. The descriptions of cores at the Farnsworth Unit included sections from overlying seals as well as the shale underlying the main reservoirs, petrographic thin section descriptions and point counts as well as a variety of special analytical techniques. These techniques included X-ray diffraction (XRD), which is the science of determining the atomic and molecular structure of rock crystals with an X-ray beam; scanning electron microscope (SEM) analysis, which uses a beam of electrons to define the surface of crystals; carbon isotope analysis to estimate the age of the CO_2 in the sample; and a variety of mechanical tests. Two dimensional (2D) and three dimensional (3D) geophysical surveys were also used as part of the Farnsworth Unit MRV Plan (2021). Details of recent geological investigations can be found in Gallagher (2014), Gragg (2016), Rasmussen et al (2019), Rose-Coss et al (2015), Trujillo (2018), Hobbs et al (2019), and Gragg et al (2018).

2.2.2.1 Tectonic Setting and Stratigraphy

The CFA is located on the northwest shelf of the Anadarko basin (Figure 2.2-1) and is one of many oil fields in the area that produce from a sequence of alternating sandstones and mudstones deposited during the late Pennsylvanian Morrowan period. Oil production and CO_2 injection at CFA is restricted to the operationally named Morrow B sandstone; the uppermost Morrow sandstone encountered below the Atokan Thirteen Finger limestone. The primary caprock intervals at CFA are comprised of the upper Morrow shale and the Thirteen Finger limestone (Figure 2.2-2). The Morrowan and Atokan intervals were deposited approximately 315-300 million years ago. Overlying stratigraphy includes late Pennsylvanian through the middle Permian shales and limestones, with lesser amounts of dolomite, sandstone and evaporites (Ball, 1991). The reservoir is approximately 60 feet thick throughout the field and lies at a depth of approximately 6,800-7,600 feet. The primary seal rocks of the Morrow shale and the Thirteen Finger Limestone comprise a package of approximately 180-200 feet thick in the field and are overlain by thousands of feet of Atokan and younger limestones and shales.

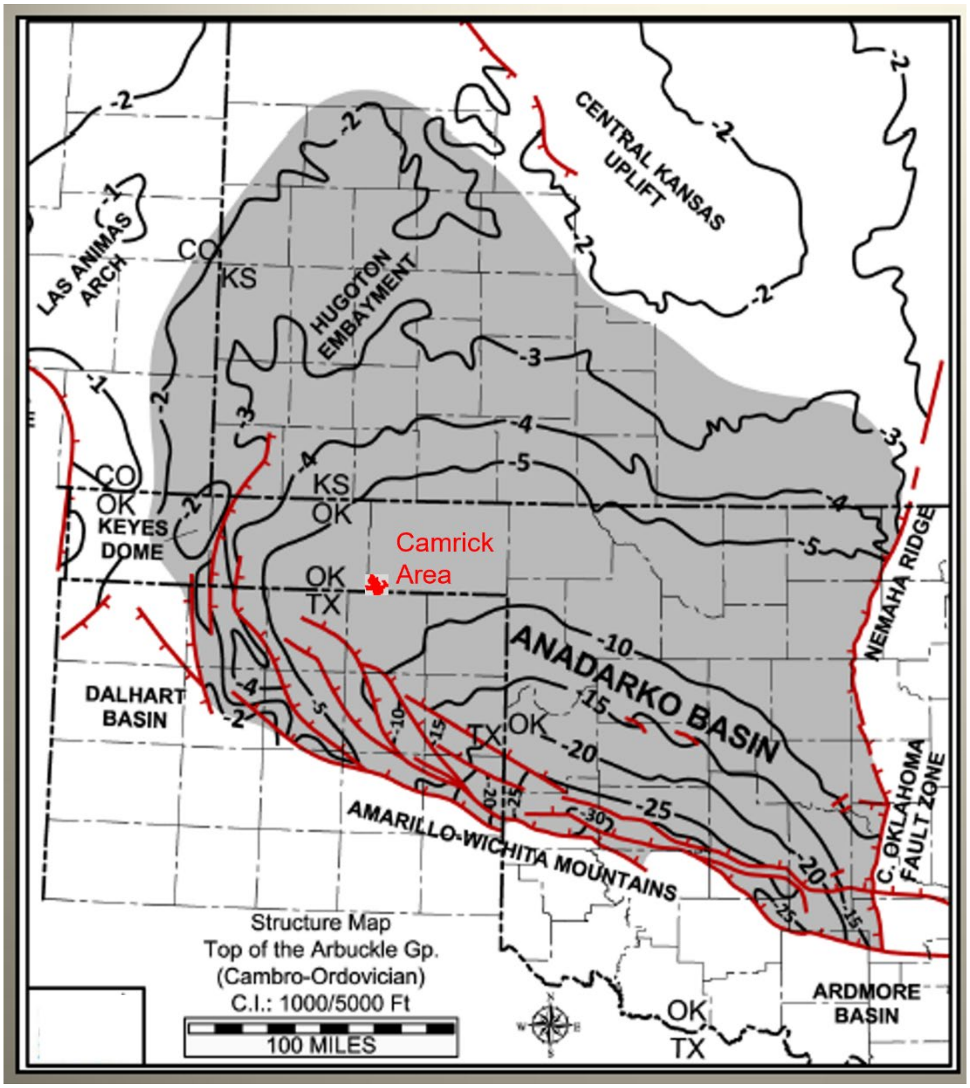

Figure 2.2-1. Location of the CFA on the Northwest Shelf of the Anadarko Basin in West Texas. Red lines are approximate locations of faults that have been documented in the region.

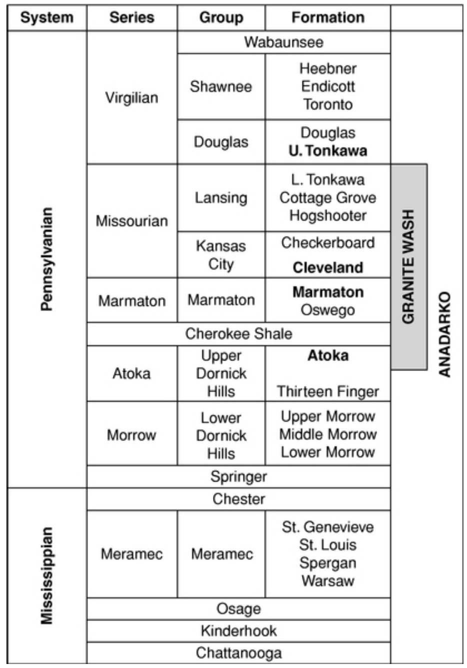

Figure 2.2-2. Stratigraphic section.

Tectonic Setting

From CFA's location on the western edge of the basin, the Anadarko Basin plunges to the southeast (Figure 2.2-3) where it reaches depths of over 40,000 feet (12,192 meters) adjacent to the Amarillo-Wichita Uplift (Perry, 1989). Maximum rates of subsidence occurred during Morrowan to Atokan times (Evans, 1979; Perry, 1989; Higley, 2014). Positive features that might have influenced deposition within the region include the Ancestral Rockies to the north, the Central Kansas uplift to the northeast, and the Wichita-Amarillo uplift to the south (Evans, 1979; Munson, 1989). Of note is the fact that during the Pennsylvanian time, the CFA was located on the basin shelf in an area that was not affected greatly by tectonic deformation. Although faults have been reported previously in the northwest Anadarko Basin, we found no direct evidence for tectonic faults within the CFA (see Section 4).

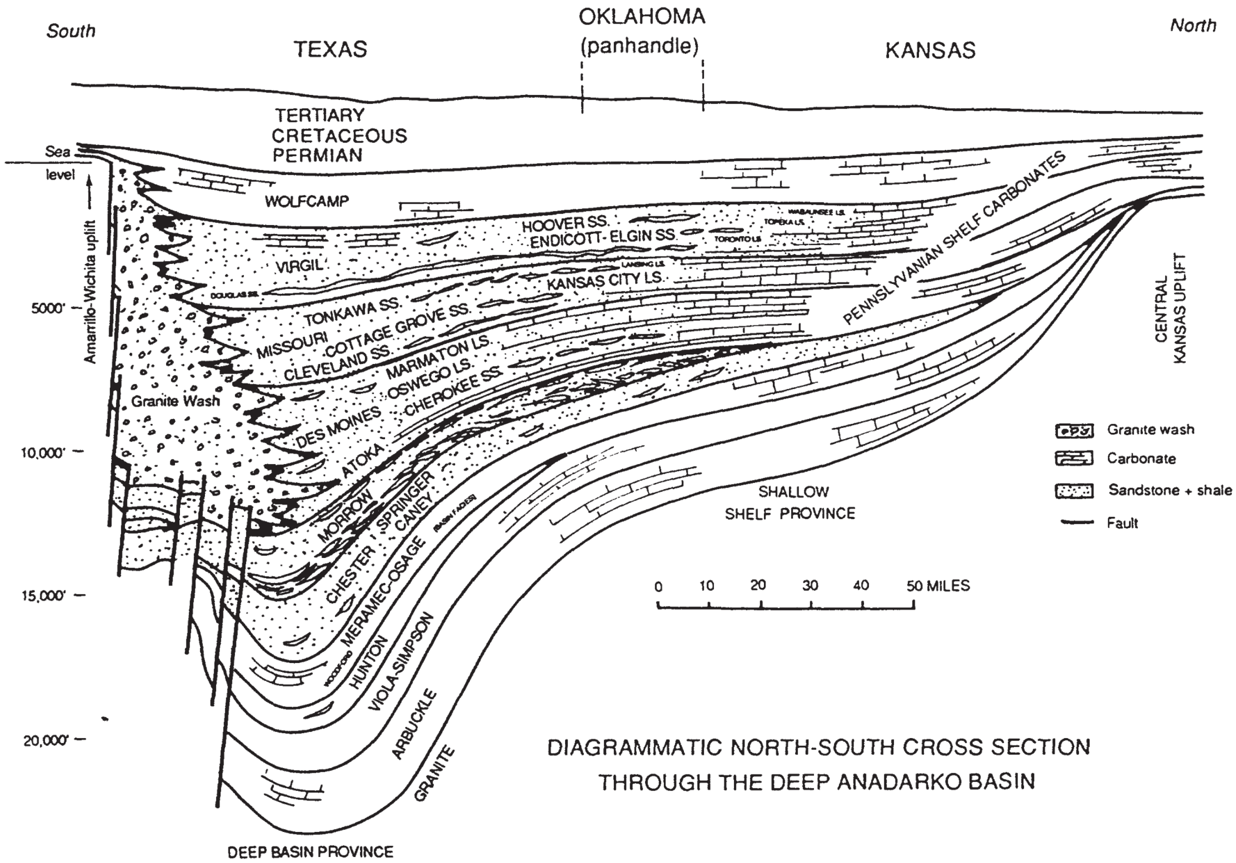

Figure 2.2-3. Diagrammatic North-South Section (Bottom) of the CFA.

Stratigraphy

Reservoir

Upper Morrowan sandstones in the Anadarko Basin margins have long been recognized as fluvial deposits (Swanson, 1979; Sonnenberg, 1985; Munson, 1989; Krystinik and Blakeney, 1990; Bowen et al., 1990; Al-Shaieb et al., 1995; Mckay and Noah, 1996; Puckette et al., 1996; Bowen and Weimer, 2003, 2004; Devries 2005; Puckette et al., 2008; Gallagher, 2014). At the Farnsworth Unit and similarly at the CFA, the Morrow B is described as a relatively coarse-grained subarkosic sandstone. The upper Morrowan facies, with sequences of basal conglomerate, coarse-grained sandstone, and fine-grained sandstone appear to be typical of incised valley deposits, as described by Wheeler et al. (1990), Krystinik and Blakeney (1990), Bowen et al. (1990), Blakeney et al. (1990), Sonnenberg et al. (1990) and Puckette et al. (2008).

Primary Seals

The Morrow B sandstones are encased above and below by shales. Contacts with shale both below and above the sandstone are sharp and irregular. The Morrow shale generally fines upwards in a series of thin beds that alternate between upper fine sands and fine to medium muds. Sand content decreases upwards through the section.

The Thirteen Finger limestone formation has two different lithofacies: diagenetic limestone (cementstone) and pyrite and fossil bearing fine to medium mudstone and coal. The two facies are intercalated with each other but tend to cluster in layers dominated more by one or the other.

The entire Thirteen Finger interval is typically 130 feet (39.6 meters) thick, comprised of mudstone, coal, and limestone. The mudstone is calcite rich, with some dolomite, and is completely diagenetic in origin and probably formed relatively soon following deposition.

2.2.2.2 Hydrogeology

Information about Morrowan and Atokan formation water flow during oil operations has not been discovered in any oil or gas company published reports or academic research studies in the Anadarko Basin. Groundwater flow rates in confined deep Anadarko layers at present are considered to be low to no flow (Nelson and Gianoutsos, 2014). Their arguments are based on (1) restricted recharge in the western basin, (2) density barriers to flow in the east, and (3) an overpressure pocket inhibiting flow in the deep basin. Jorgenson (1989) suggested flow could be west to east, driven by potential recharge to elevated units in the west and discharge at lower elevation outcrops in the east. The CFA CO_2 injection and production operations have negligible likelihood of causing water to flow to outcrops of the late Carboniferous (Pennsylvanian) time period that extend from Brownwood, Texas, to the Jacksboro/Bowie, Texas, area, which are hundreds of miles away (The Paleontology Portal).

The Carboniferous is a geologic period and system that covers 60 million years from the Devonian Period 358.9 million years ago, to the beginning of the Permian Period, 298.9 million years ago. As noted in the Section 2.2.2.1, the Morrowan and Atokan intervals of the CFA were deposited approximately 315-300 million years ago and are contained in the Carboniferous period.

2.3 Description of the Injection Process

Figure 2.3-1 depicts a simplified flow diagram of the facilities and equipment within the boundaries of the CFA. CO_2 captured from the ethanol plant fermentation process is delivered via pipeline to the field for injection. The Arkalon plant in Liberal, Kansas is the only source of CO_2 to the field. The amount delivered is dependent on the production of CO_2 produced from the fermentation process. This amount will vary but should average 12 MMCFD. Once CO_2 enters the CFA there are three main processes involved in EOR operations. These processes are shown in Figure 2.3-1 and include:

1. CO_2 distribution and injection. Purchased CO_2 is combined with recycled CO_2 from the CFA central tank battery (CTB) and sent through the main CO_2 distribution system to various water alternating gas (WAG) injectors.
2. Produced Fluids Handling. Full well stream fluids are produced to the “all well test” (AWT) site. The AWT site has two major purposes; 1) to individually test a well’s performance by separating and metering oil, gas, and water, and 2) to separate all gas from liquid then send these two phases to the CTB for final separation; while only the gas from NPU is sent to the CTB the NPU oil and water remains in Texas.

3. Produced Gas Processing. All gases from the AWT sites are transferred to the CTB to separate the oil, gas, and water using a series of vessels and storage tanks.

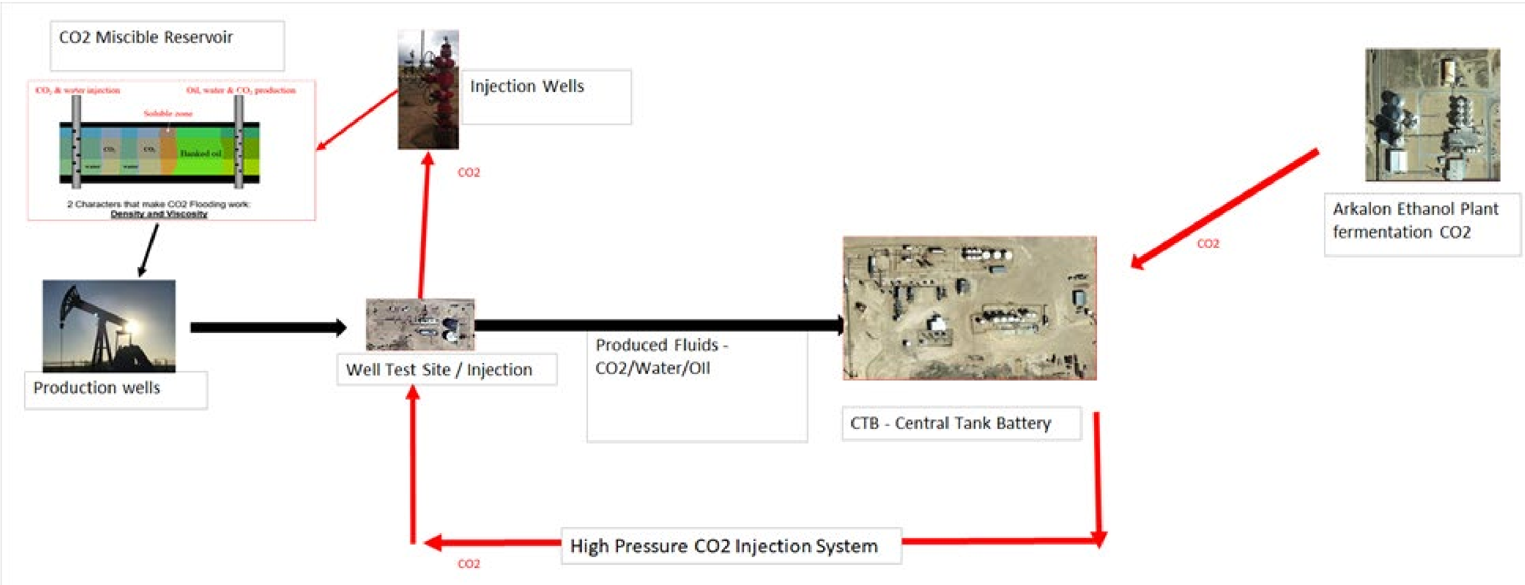

Figure 2.3–1. Simplified flow diagram of the facilities and equipment within the boundaries of the CFA.

2.3.1 CO_2 Distribution and Injection

CapturePoint purchases CO_2 from Conestoga Energy Partners, the parent company of the Arkalon Ethanol plant located in Liberal, Kansas. A custody transfer meter is located in the compression facility owned and operated by CapturePoint. The purchased CO_2 from the fermentation process is transported via a United States Department of Transportation (DOT) regulated pipeline to the CFA. A totalizer meter, for the purchased CO_2, is located in the field where instantaneous data is summed into a 24-hour flow rate which is recorded. A totalizer meter is a meter approved by the American Gas Association (AGA) Report #3 to measure the flowrate of gases. The actual measurements taken are temperature, line pressure, and differential pressure across the meter. Gas produced, which contains recycled CO_2, from the wells is compressed and metered by a similar totalizer meter as the purchase CO_2 meter and is recorded daily.

CapturePoint currently has seven active injection manifolds and approximately 29 active injection wells that the CO_2 is distributed through. When the MRV plan becomes active, the daily injection volume of the combined purchased CO_2 and recycled CO_2 will be approximately 24 MMCFD. Of this volume 12 MMCFD is purchased CO_2 and 12 MMCFD is recycled CO_2. This ratio of purchased CO_2 to recycled CO_2 is expected to change over time, with the percentage of recycled CO_2 increasing and purchased CO_2 decreasing. The current reservoir management plan projects that CO_2 purchases will remain constant at 12 MMCFD for 12 years and cease after 2034. A reservoir management plan is an integrated process using various surveillance techniques, economic evaluations, and accepted petroleum technical practices to efficiently operate enhanced oil recovery projects.

The seven injection manifolds currently in the field distribute the CO_2 to the field. These manifolds have valves to switch to water when the time is called for. Depending on the reservoir management plan, the WAG cycle will be adjusted to maximize oil recovery and minimize CO_2 utilization in each injection pattern. At each injection well pad there is a totalizer to measure the volumes injected every 24 hours. This data is collected daily by the field personnel and input into the data warehouse to be allocated for the pattern injection.

The two totalizer meters as described above will be used to determine the total volume injected used in section 7 for the mass balance equations necessary to determine annual and cumulative volumes of the stored CO_2.

2.3.2 Produced Fluids Handling

As injected CO_2 and water migrate through the reservoir; a mixture of oil, gas, and water (referred to as “produced fluids”) flows to the production wells. Gathering lines bring the produced fluids from each production well to the AWT sites. CapturePoint has approximately 32 active production wells producing at any time. Each AWT has two separators. The first separator is used for testing individual wells to separate the gas, oil, and water produced from an individual well. This gas, oil, and water is subsequently measured and recorded for the well. Each producing well is production tested every 30 to 60 days after the last production test, or after the well is returned to production. Depending on the reservoir management plan, well testing can be more frequent to obtain data. The second separator is used to separate the gas from the oil/water mixture from the other wells producing into the AWT, and the gas and liquids are displaced from the vessel in separate lines. Leaving the AWT sites are two lines transporting produced fluids. One line is used for the liquid phase, a mixture of oil and water, and one line is used for the gas phase. However, the AWT in NPU does not transfer oil or gas to the CTB, it only transfers gas while reinjecting water with pumps at the NPU AWT and sells oil at the NPU AWT.

When gas and liquid lines enter the CTB, a series of vessels separate the oil, gas, and water to be accounted for and distributed for sales or reinjected. The liquid phase line has vessels to separate the oil from the water using density and residence time. The gas phase vessels collect any free liquids entrained with the gas. These free liquids are then combined back into the liquid phase line. All gas and water are reinjected, and the oil, which contains an estimated 2,360 ppm CO_2 (0.236%) for CU and 4,540 ppm CO_2 (0.454%) for NPU, is sold out of tanks. Annually, the oil from the stock tank is analyzed by a laboratory using ASTM crude oil analysis methods to determine the CO_2 content in the oil being sold.

After separation, the gas phase, which is approximately 92-95% CO_2, is mixed with reservoir volatile components, compressed, and distributed throughout the high-pressure distribution system using reciprocal compression and high-pressure horizontal pumps.

The water is transferred from the separation vessels to tanks for reinjection. After the water is conditioned, it is either reinjected at the WAG skids or disposed of into permitted disposal wells. Although CapturePoint is not required to determine or report the amount of dissolved CO_2 in the water as it is reinjected into the ground and not emitted to the atmosphere, the analyses have shown the water typically contains <690 ppm (0.069%) CO_2.

CFA production has trace amounts of hydrogen sulfide (H_2S), which is toxic. There are approximately 8-10 workers on the ground in the CFA at any given time, and all field and contractor personnel are always required to wear H_2S detectors. The primary purpose of the H_2S detectors is protecting people from the risk of being harmed. The detection limit of the H_2S detectors is quantified for readings in the range of 0-100 ppm and will sound an alarm above 10 ppm. The secondary purpose of the H_2S detectors would be to provide an indication of emissions of gas from a pipeline or surface equipment, that might go unnoticed by other observations or measurements. No gas volumes can be calculated based on the detector reading or alarm; only a H_2S leakage is detected and located. Once identified, a further response will be initiated and CO_2 volumes will be quantified as discussed in sections 4.5, 4.6, 5.4, and 8.1.5 of this MRV plan.

2.3.3 Produced Gas Handling

Produced gas separated at the CTB is stripped by a series of vessels of entrained and free water. The water content has been recorded to be < 20 pounds mass per MMCF, thus dehydration is not necessary. The gas is then sent to a centralized compression system to be compressed and placed in the high-pressure distribution system. This compression turns the CO_2 into a variable density liquid, which is then transported out via high pressure lines to the AWT sites where a manifold splits this dense CO_2 to the wells that are on CO_2 injection at that time.

2.3.4 Facilities Locations

The locations of the AWT sites are positioned in the field to access both injection distribution and production gathering. The CTB is where the final separation and injection equipment is maintained and operated. The water injection station is where the horizontal pumps are located to reinject the produced brine.

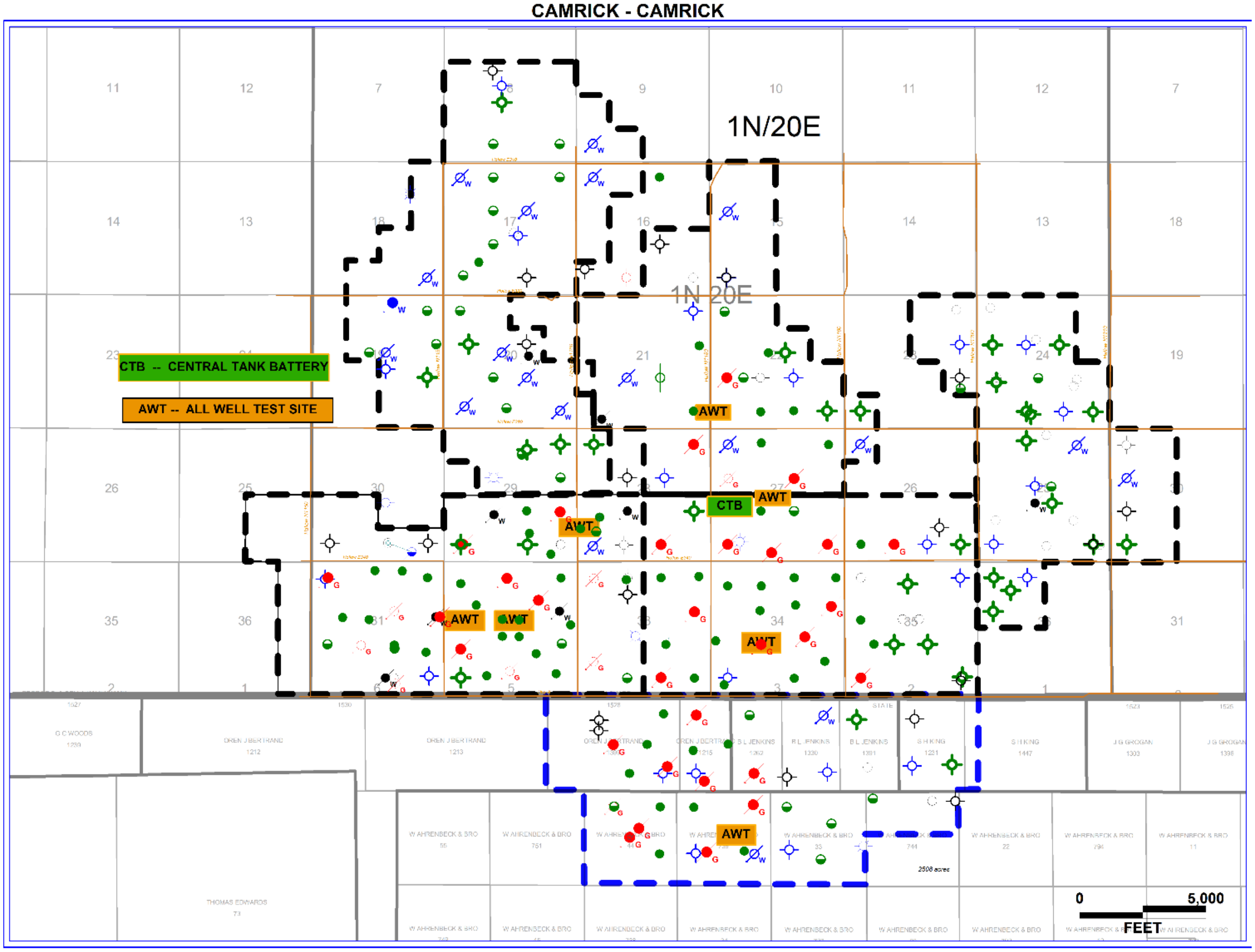

Figure 2.3-2. Location of AWT sites and CTB in the CFA

2.3.5 Water Conditioning and Injection

Produced water collected at the CTB is collected in a series of vessels and tanks in a cascade system. This allows any entrained oil to further separate to the top of the tanks because of the density difference. This oil is skimmed off and put back in the oil separation system. The clean water is then transferred to the water injection system where it is boosted in pressure and sent out to the AWT sites for distribution to all wells that are currently on water injection.

2.3.6 Well Operation and Permitting

The OCC and TRRC rules (Appendix 2) govern well location, construction, operation, maintenance, and plugging for all wells in permitted units and wells. CapturePoint follows these rules and regulations to maintain safe and efficient operations. This includes complying with all current and updated information for mechanical integrity testing, well repairs for injection wells, drilling and completion, permitting, and reporting.

Briefly, the following bulleted list is what the current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface waters.
- That wells file a completion report including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore).
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.
- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location, and setting of plugs.

2.3.7 Number, Location, and Depth of Wells

CapturePoint's CFA injection wells are listed in Appendix 1. Injection is into the Upper Morrowan, a lenticular bedded sandstone trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. The Upper Morrowan is described in section 2.2.2.1 above.

2.4 Reservoir Characterization

2.4.1 Reservoir Description

The target reservoir CFA Morrow B is a sandstone formation overlain by the Morrow shale and the Thirteen Finger limestone, which serve as excellent seals for injected CO_2 as determined by Farnsworth data (Ampomah et al., 2016a). The Morrow B sandstone reservoir is at a depth between 6,800 feet and 7,600 feet subsurface with an average dip of less than one degree (Figure 2.4-1). The productive limit of the CFA is about 80 to 90 percent of the total operated surface acreage, which is 14,652.315 acres. The maximum pay thickness is 56 feet with an average of 15 feet and does diminish to zero in spots.

The CFA is approximately eight miles by seven miles with areas that exhibit different reservoir behavior. The southwest portion of CU was most prolific oil producing area of the CFA under primary and secondary production; whereas the western portion of NPU is now responding to CO_2 better than historical operations would have indicated.

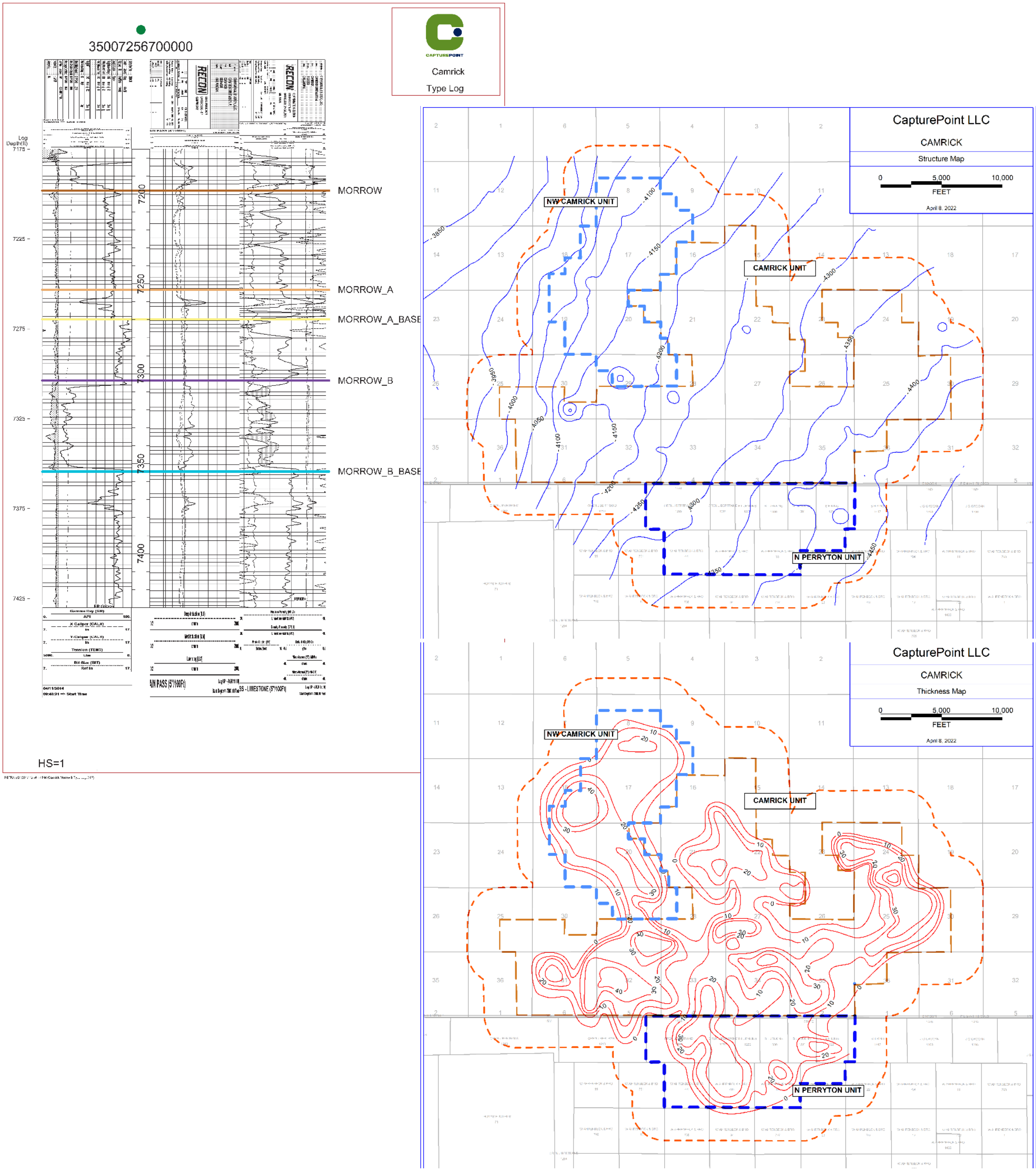

Figure 2.4-1. (Left) Type log of CFA caprock and reservoir, (Upper Right) Surface contour of Morrow top, (Lower Right) Thickness map of Morrow sands.

2.4.2 Reservoir Fluid Modeling

The compositional fluid model was constructed for the CapturePoint operated Farnsworth Unit. From laboratory compositional analysis an equation of state was tuned (Gunda et al., 2015). The minimum miscibility pressure (MMP) experiment was then simulated using a one-dimensional model. The simulated Farnworth Unit MMP of 4,009 psia compared to an MMP value of 4,200 psia derived from laboratory experiments provided by the operator represents a less than 5% error (Gunda et al., 2015).

The reservoir temperature in the CFA is 152 degrees Fahrenheit or 16 degrees lower than the temperature at Farnsworth Unit of 168 degrees. Using parameters of the Alston empirical correlation (1985), the MMP would be 170 psia lower at the CFA or 3,510 psia compared to 3,680 psia at the Farnsworth Unit (Figure 2.4-2).

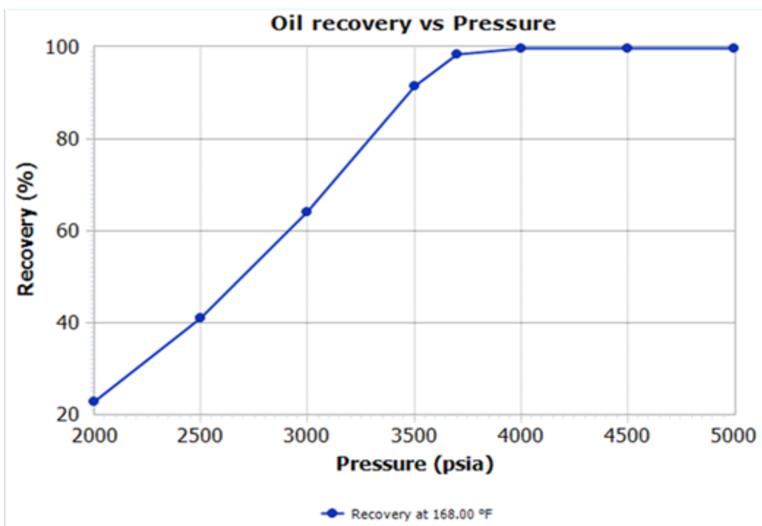

Figure 2.4-2. Oil recovery plot for 1D slim tube test for Farnsworth Unit.

2.4.3 CO_2 Analogy Field Study

Based on similar geologic, petrophysical, engineering, and operational parameters between the Farnsworth Unit and the CFA, the oil recovery performance of both fields is expected to be similar. Due to the stratigraphic nature of the Morrow channel sands, the potential movement of CO_2 is severely limited. The CFA area has contained the free phase CO_2 plume in a very confined area since March 2001 as exhibited by oil, water, and CO_2 recovery performance. Also, during CFA drilling and production operations, no reports exist which would indicate any plume has moved outside of the MMA. The Farnsworth Unit MRV and the CFA data justifies the conclusion that CO_2 will continue to be contained inside the MMA at the end of the CO_2 injection year t + 5, per §98.449 definitions.

2.4.4 CO_2 – EOR Performance Projections

For years, the oil industry has used dimensionless equations to predict the amount of oil that can be recovered using CO_2 for flooding oil reservoirs (Lee et al, 2018, Stell 2010). The

amount of oil recovered from projects is plotted as a decimal fraction of the original-oil-in-place versus the decimal fraction of the hydrocarbon pore volume (HPV) of CO_2 injected into the oil reservoir as measured in reservoir barrels (RB).

The CFA has been injecting CO_2 since March 2001. The dimensionless curves were matched to historical performance through early 2020 (Figure 2.4-3). The supply of CO_2 was curtailed from March 2020 until present, due to oil price uncertainty, and will resume after the Arkalon Plant upgrade that will be finished in the 4th quarter of 2022.

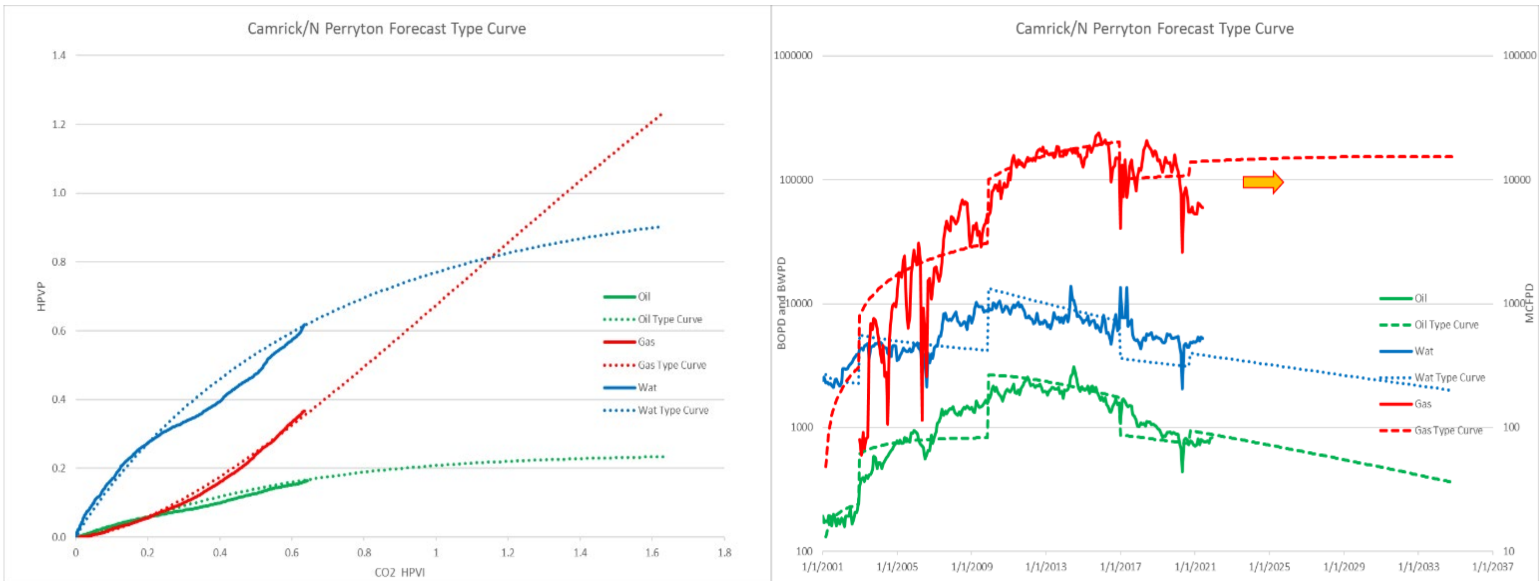

Figure 2.4-3. Dimensionless curves for CO_2 injection (left) with rate time curves (right).

The dimensionless water oil ratio and the gas oil ratio trends (Figure 2.4-4) for the CFA flooded acreage are very similar to what was forecasted by simulation in the Farnsworth Field as expected because of the porosity, permeability, and sand similarities.

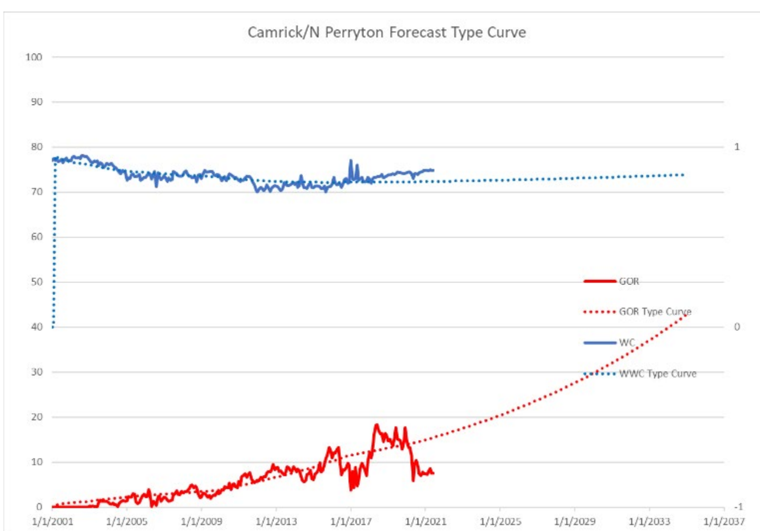

Figure 2.4-4. Dimensionless water cut and GOR vs. observed EOR data.

The CO_2 storage volumes for Arkalon fermentation CO_2 were also forecasted (Figure 2.4-5) using the same dimensionless technique. This technique indicates that the flooded acreage still has significant additional storage potential. The maximum CO_2 storage is limited to the amount of space available by the removal of the produced hydrocarbon. The projection indicates that there is pore space available to store approximately 0.4 to 0.5 decimal fraction of HPV amounting to 30 to 40 MMB.

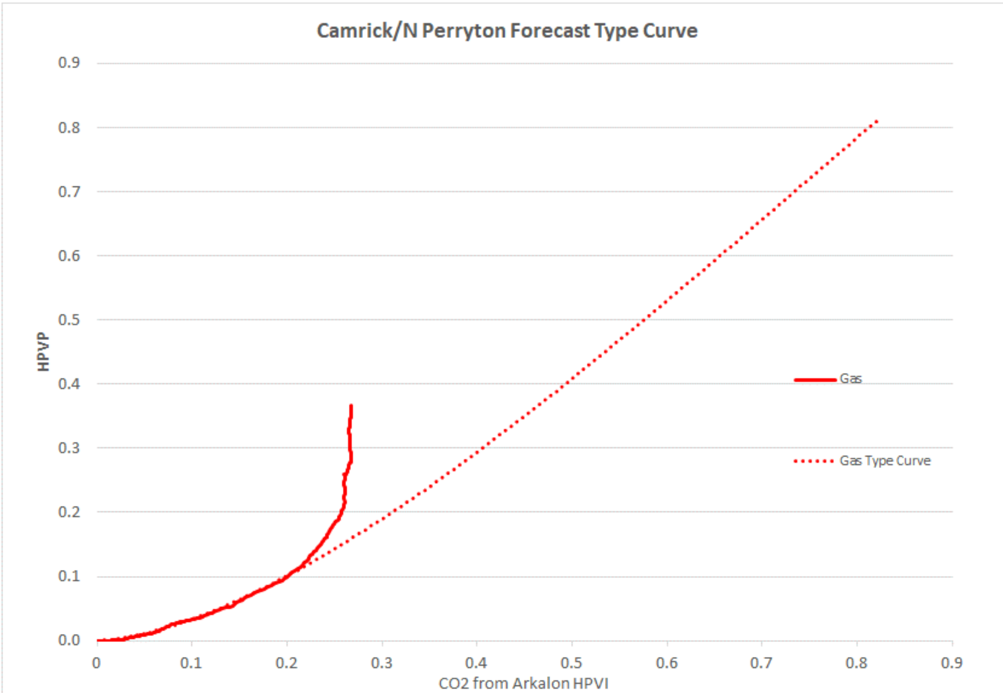

Figure 2.4-5. Dimensionless CO_2 Fermentation Curves

The barrels of reservoir volume were converted to standard cubic feet of gas and is displayed in the CFA Purchase CO_2, or Fermentation CO_2, vs Time chart (Figure 2.4-6).

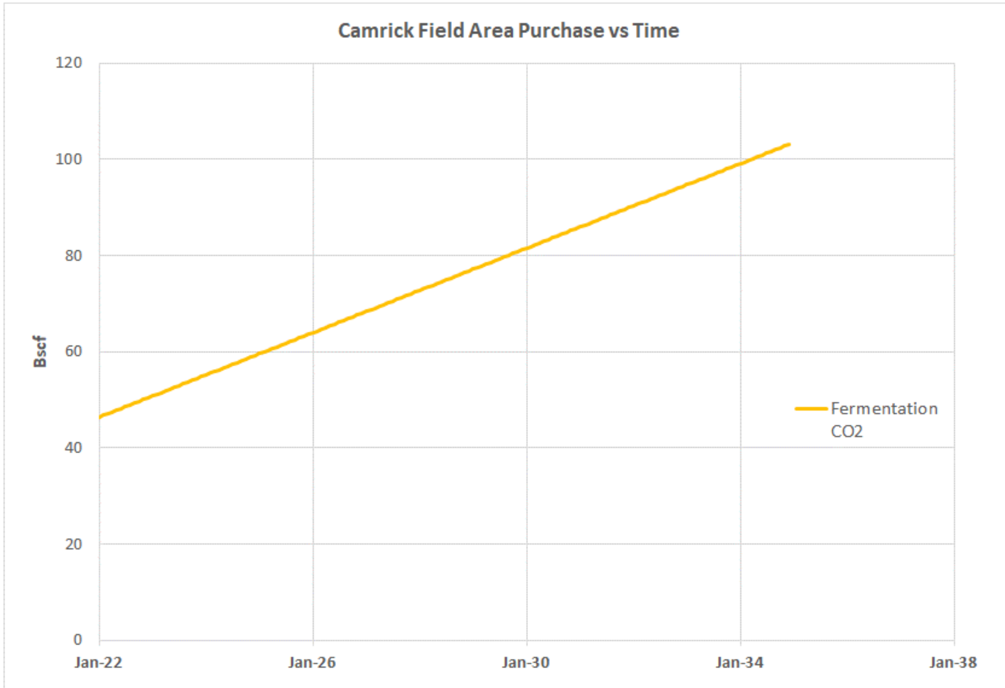

Figure 2.4-6. CO_2 Fermentation Volume.

3 Delineation of Monitoring Area

3.1 MMA

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The purchase volumes that are displayed in Figure 2.4-6 were mapped and are displayed in Section 3.1.1 indicates that CO_2 storage pore space is available, barring unforeseen future operational issues. Therefore, CapturePoint is defining the MMA as the boundary of the CFA plus an additional one-half mile buffer zone. This will allow for operational expansion throughout the CFA for the next 12 years, the anticipated life of the project.

3.1.1 Determination of Storage Volumes

Figure 3.1-1 displays wells that have CO_2 retention on the 4,800 acres that have been under EOR injection in the CFA since project initialization. The volume of the oil recovered since August 1955, resulted in a voidage space of 36 MMscf of CO_2 per acre of surface area that was later filled with water during waterflood. The average decimal fraction of CO_2 injection to hydrocarbon pore volume left in the ground after accounting for CO_2 production through 2021 is 0.29. The lateral extent of CO_2 in the injection zone or the CO_2 storage radius for each well was estimated based on cumulative CO_2 injected times the decimal fraction of CO_2 remaining divided by the voidage space. The largest CO_2 storage areas are around wells that injected CO_2 for the most years.

Figure 3.1-2 displays the potential area of the reservoir that can be filled with CO_2 with the existing injection wells. This assumed that only 78 percent of the average injection pattern area or 80 acres could be filled. There are 49 injectors identified for further injection that have room for an additional 90 Bscf of CO_2 storage volume or 140 Bscf total storage.

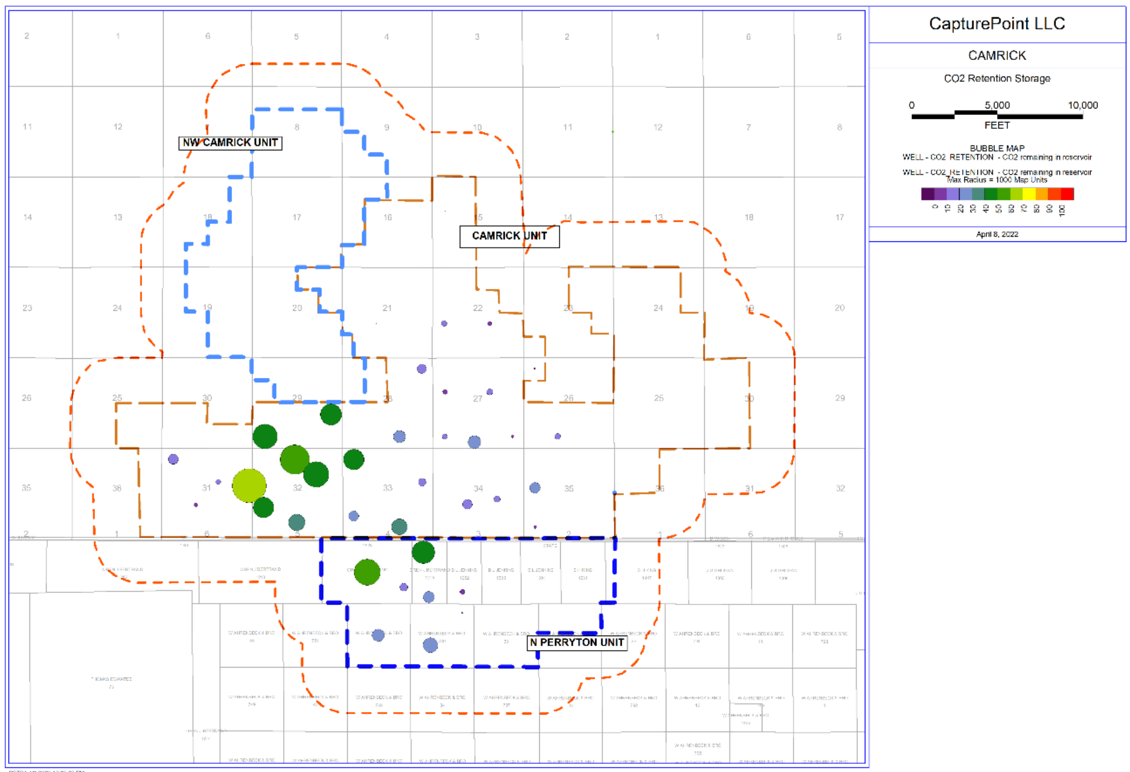

Figure 3.1-1. Estimated CO_2 storage as of 2021 in CFA.

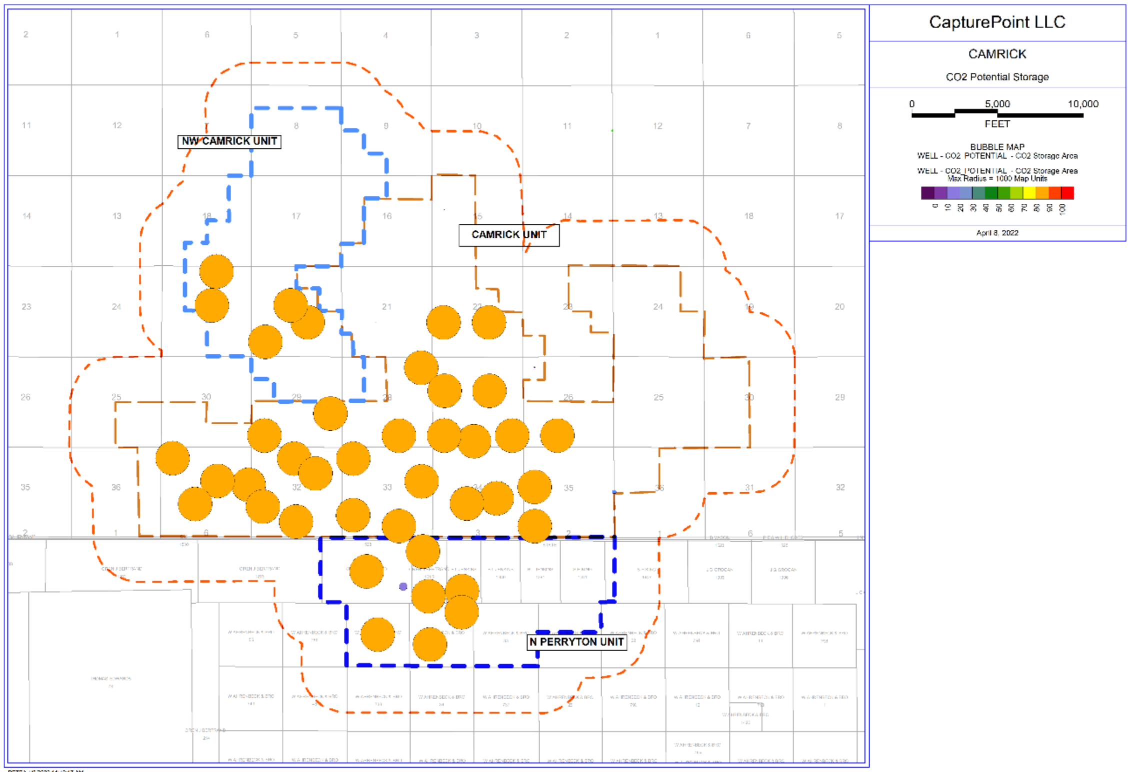

Figure 3.1-2. Potential Total CO_2 Storage in the CFA.

3.1.2 Determination of Buffer Zone

CapturePoint intends to implement a buffer zone of one-half mile around the CFA, the minimum required by Subpart RR, because the site characterization of the Morrow did not reveal any leakage pathways that would allow free-phase CO_2 to migrate laterally thereby warranting a buffer zone greater than one-half mile.

3.2 AMA

Currently, CapturePoint's operations are focused on the western portion of the CFA. However, it is anticipated as the project develops, additional activity will occur in the NWCU of the CFA; therefore, requiring active monitoring in that area. However, project development is driven by the market price of oil so CapturePoint is unable to provide a specific time in the future when the eastern portion of the CFA will be actively monitored. Therefore, for the purposes of this MRV plan, CapturePoint has chosen to include the entire CFA in the AMA.

4 Identification and Evaluation of Leakage Pathways

Since its discovery in 1955, the unitization of the different units from 1969 to 1972, and the commencement of CO_2 EOR in 2001; the CFA is an analogous field to the Farnsworth Unit, which has undergone extensive investigation and documentation as indicated in Section 2. From this body of work, CapturePoint has identified the following potential pathways of CO_2 leakage to the surface. This section will also address detection, verification, and quantification of leakage from each pathway.

4.1 Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO_2 EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment via personnel instructed on how to detect surface leaks and other equipment failure minimizes releases. In addition, the Oil and Gas Division requirements of the OAC rules of the OCC and the TAC rules of the TRRC to report and quantify leaks, both serve to minimize leakage of GHG from surface equipment. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. As described in Section 6.4 below, should leakage from surface equipment occur it will be quantified according to the procedures in Subpart W of the GHGRP.

4.2 Leakage from Wells

CapturePoint has identified 68 abandoned wells, 49 injection wells (29 active) and 94 production wells (59 active) within the MMA and assessed their potential for leakage of CO_2 to the surface as listed in Appendix 1.

4.2.1 Abandoned Wells

Figure 4.2-1 shows all wells plugged and abandoned in the CFA. Because the CFA was unitized in 1969 to 1972, all plugging and abandonment activities of wells within the CFA have been conducted under the regulations of the OCC and the TRRC for plugging wells. The cement used to plug wells when exposed to CO_2 will form colloidal gels that further reduce any flow. CapturePoint concludes that leakage of CO_2 to the surface through abandoned wells is unlikely. However, strategies for leak detection are in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

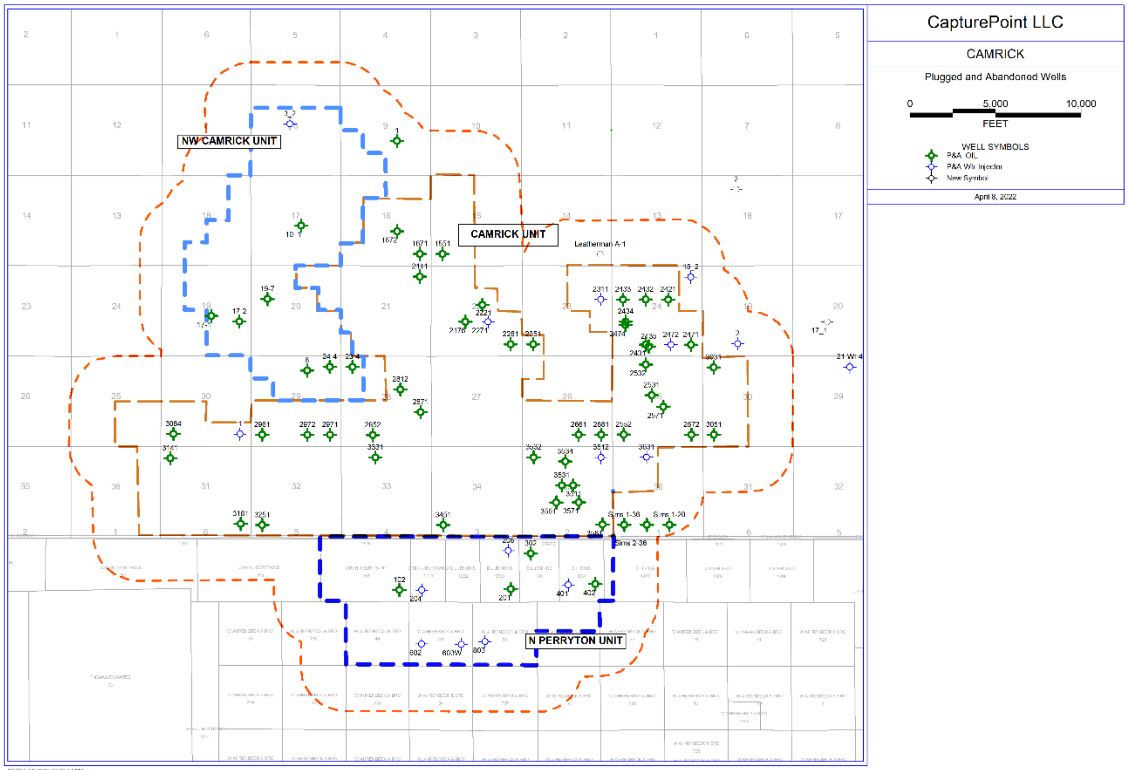

Figure 4.2-1. Plugged and Abandoned Wells in the CFA.

4.2.2 Injection Wells

Mechanical integrity testing (MIT) is an essential requirement of the UIC program in demonstrating that injection wells themselves do not act as conduits for leakage into underground sources of drinking water (USDW) and to the surface environment. TRRC Rule 46 requirements include special equipment requirements (e.g., tubing and packer) and modification; records maintenance; monitoring and reporting; testing; plugging; and penalties for violations of the rule. Permit revocation may result as a consequence of noncompliance. (See Section 2.3.6) The TRRC and the OCC detail all the requirements for the Class II permits issued to CapturePoint. These rules ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Figure 4.2-2 shows the active injection wells in the CFA. CapturePoint concludes that leakage of CO_2 to the surface through active injection wells is unlikely.

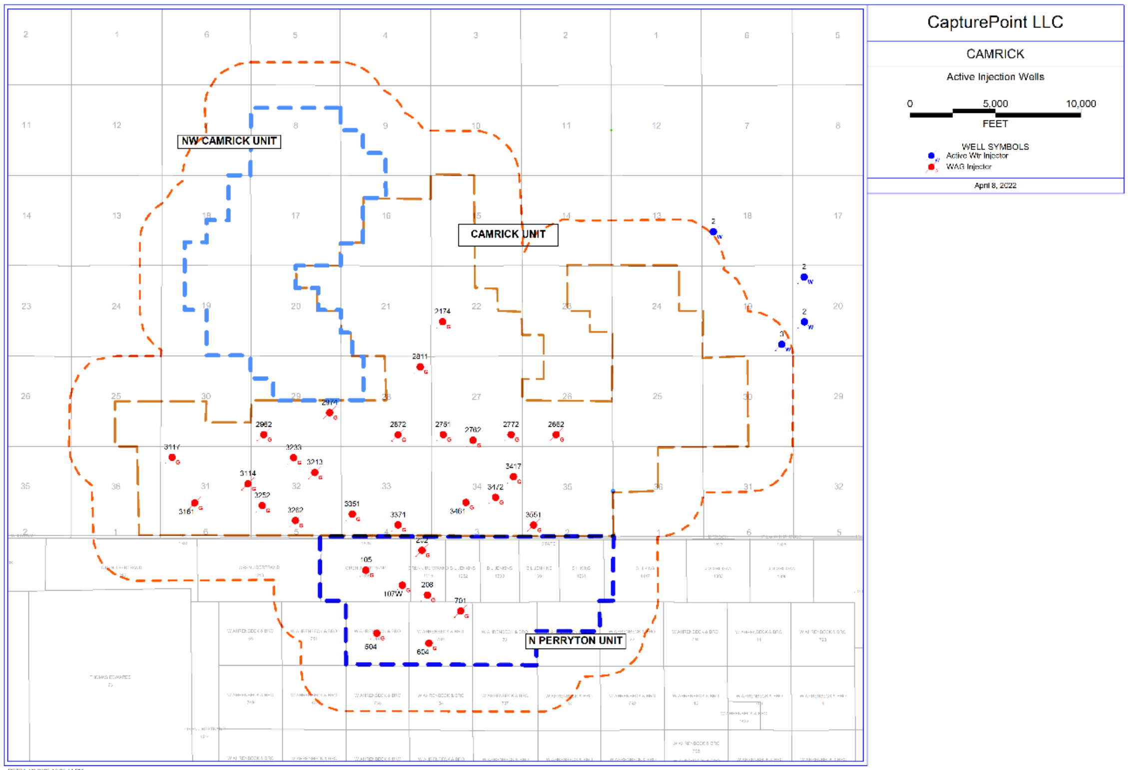

Figure 4.2-2. Active Injection Wells in the CFA.

4.2.3 Production Wells

Figure 4.2-3 shows the active oil production wells in the CFA. Once EOR operations commence, the energy content of the produced gas drops and cannot be sold; therefore, any inactive gas wells are reclassified to either oil producer or WAG injector. However, as the project develops in the CFA additional production wells may be added and will be constructed according to the relevant rules of the OCC and the TRRC. Additionally, inactive wells may become active according to the rules of the OCC and the TRRC.

During production, oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure where the bottom hole wellbore pressure is less than the reservoir pressure. These lower pressure fluids, which also contains CO_2, are contained by the casing, tubing, wellhead, and flowline all the way to the CTB. CapturePoint concludes that leakage of CO_2 to the surface through production wells is unlikely.

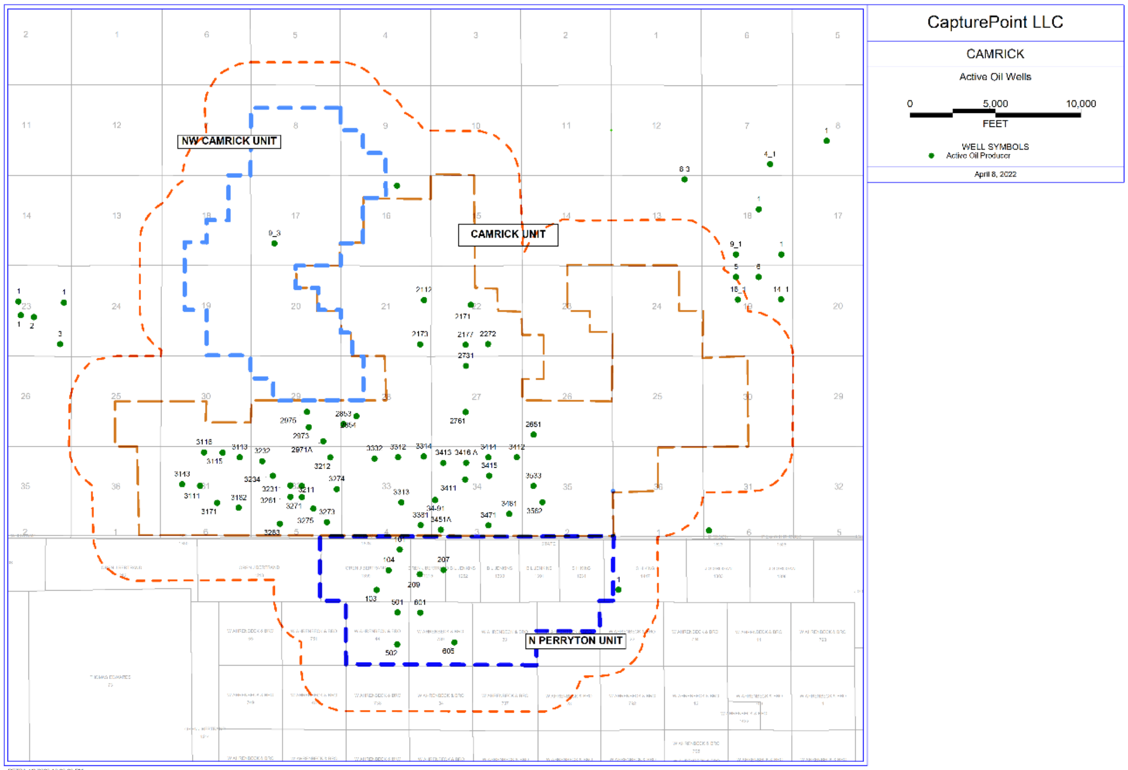

Figure 4.2-3. Active Oil Production Wells in the CFA.

4.2.4 Inactive Wells

Figure 4.2-4 shows all of the inactive wells in the CFA. The OCC has regulations for temporally abandoned/not plugged (TA) and terminated order wells/UIC not plugged (TM) and likewise the TRRC has regulations for inactive wells.

Inactive wells have a cast iron bridge plug set or long cement plugs placed above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. CapturePoint concludes that leakage of CO_2 to the surface through inactive wells is unlikely.

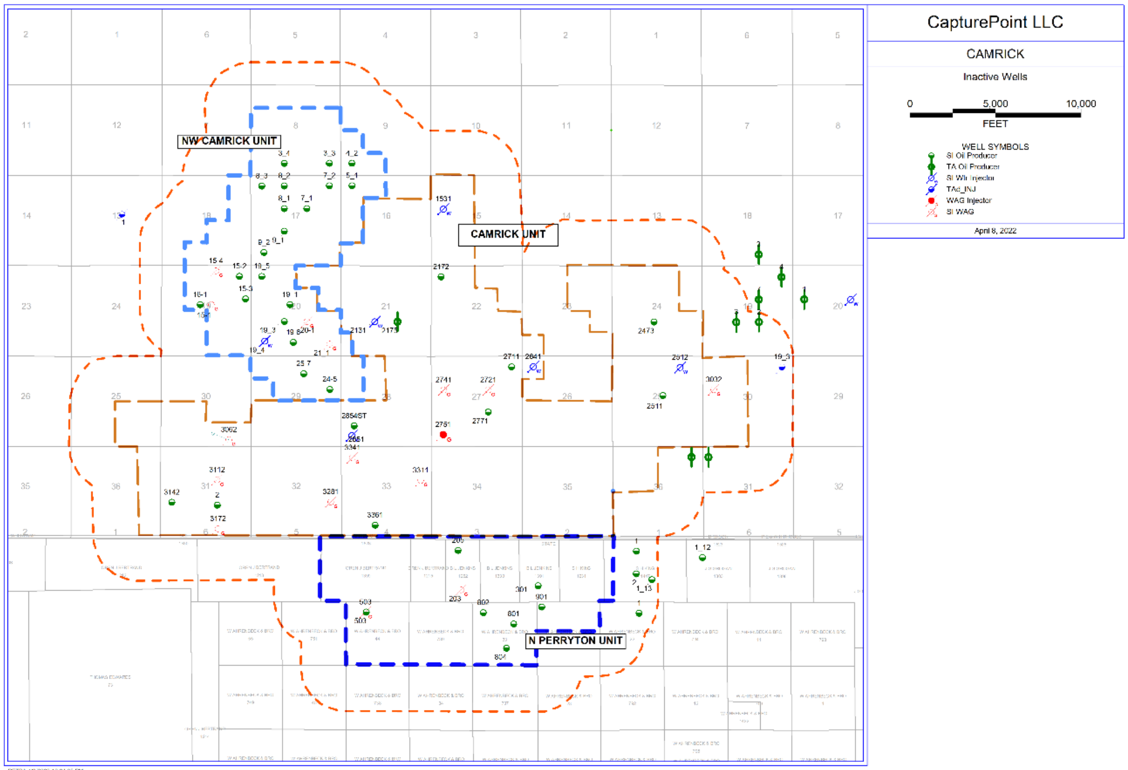

Figure 4.2-4. Inactive wells in the CFA

4.2.5 New Wells

As the project develops, new production wells and injection wells may be added to the CFA. All new wells will be constructed according to the relevant rules for the OCC and the TRRC which ensure protection of subsurface and surface resources, and the environment.

All wells in Oklahoma oilfields and all wells in Texas oilfields, including both injection and production wells, are regulated by the OCC and the TRRC, respectively, which has primacy to implement the UIC Class II programs.

Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Briefly current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface water.
- That wells file a completion report including basic electric logs.
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.

- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.

New well construction is based on existing best practices, established during the drilling of existing wells in CFA and follows the OCC and the TRRC rules, which significantly limits any potential leakage from well pathways. Additionally, the existing wells followed the OCC and the TRRC rules.

In public databases, the area of CFA plus one mile past the unit boundary contains over 100 wells that were drilled deeper than the Morrow formation and none of these wells were productive in reservoirs deeper than the Morrow. Therefore, it is very unlikely that anyone will ever drill through the AMA reservoir in the future. In the event a well is drilled within the AMA, the operator would be required to follow all the OCC and the TRRC rules and procedures in the drilling the well and the potential for leakage would be similar to any well that CapturePoint drills within the AMA. In addition, CapturePoint's visual inspection process during routine field operation will identify any unapproved drilling activity in the CFA.

4.3 Leakage from Faults and Bedding Plane Partings

Primary seals at CFA have been demonstrated to be mechanically very competent (see Section 2.2.2), thus the main concern of CO_2 migration at CFA is via seal bypass systems along fracture networks. The following lines of analysis have been used to assess this risk in the area.

4.3.1 Prescence of Hydrocarbons

The first and foremost argument against present day up-fault transmissibility is the 75 MMB of oil that was found trapped in the reservoir. If significant escape pathways existed, oil would have drained from the reservoir prior to the current day.

4.3.2 Fracture analysis

At the CFA, the work done at the Farnsworth Unit is analagous, where small aperture fractures were noted but not common in most of the reservoir cores examined but most of these fractures appear to be drilling induced. Fractures in the Thirteen Finger limestone caprock were described using an industry-standard format for fracture class type, orientation, fracture dip, type of mineral fill, fracture porosity, fracture spacing, and intensity. Again, drilling induced fractures are most common. Natural mineral-filled fractures are quite rare, were formed during diagenesis at shallow depths, and are of late Carboniferous age. Unless significantly damaged by large changes in reservoir pressure, they are highly unlikely to provide migration pathways.

In the unlikely event CO_2 leakage occurs as a result of leakage through the faults and fractures, it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.4 Lateral Fluid Movement

The Morrow strata in the Oklahoma and Texas Panhandle was primarily a deltaic sequence that prograded toward the southeast, resulting in deposition of mainly shales with lenticular, discontinuous coarse sandstones separated with very fine sandstone, minor conglomerates, and shale. The likelihood of any extensive migration of fluid outside of the AMA is very low.

Since CO_2 is lighter than the water remaining in the reservoir, it will migrate to the top of each lenticular structure as it is filled. The producing wells, which create low pressure points in the field, will drain the water and keep the CO_2 within each discontinuous sandstone.

4.5 Leakage through Confining/Seal system

At the CFA, the work done at the Farnsworth Unit will apply, where a variety of analytical methods were used for caprock (confining system) analysis, and the results should be the same for the CFA. Petrologic examination included standard thin section petrography and backscattered electron microscopy. Petrophysical analytical methods include retort analysis, pulse-decay permeability measurement, pressure decay permeability analysis for tight rocks, and mercury injection porosimetry, which is also known as mercury injection capillary pressure (MICP). Geomechanical analysis involved a standard series of mechanical tests: Brazil tension, unconfined compression, triaxial compression, and multi-stress compression.

Results of the MICP analysis show that the mudstone lithologies in the Morrow Shale and Thirteen Finger Limestone can support CO_2 column heights of ~1,000 to 10,000 feet. At an order of magnitude over the thickness of the Morrow reservoir, this should prove an effective seal for CO_2 storage in the Morrow B injection horizon.

Failure analyses show that the Morrow B sands are weaker than overlying lithologies, so that any fracture initiation around the injection well would not be expected to propagate into the overlying sealing units. Mechanical properties of the overlying shale and limestones provide an interesting and effective combination of strength and elasticity. Limestone layers are strong but brittle, while the shale layers are weaker but sufficiently ductile to prevent extensive fracture propagation.

It is unlikely for hydrocarbon migration pathways that charged the Morrow reservoir to be potential CO_2 migration pathways via primary pore networks today. Any potential CO_2 migration would be most likely due to leakage from wellbores or bypass through fault and fracture networks, discussed in Sections 4.2 and 4.3.

In the unlikely event CO_2 leakage occurs as a result of leakage through the confining seal it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.6 Natural and Induced Seismic Activity

Figure 4.6-1 shows the map of earthquakes with magnitudes measured at greater than 2.5 as defined by the United States Geological Survey (USGS). While past earthquake data cannot predict future earthquakes, the small number of events near CFA after the

waterflood operations were initiated in 1969 implies the area is not seismically sensitive to injection. Also, no documentation exists that any of the distant earthquake events caused a disruption in injectivity or damage to any of the wellbores in CFA.

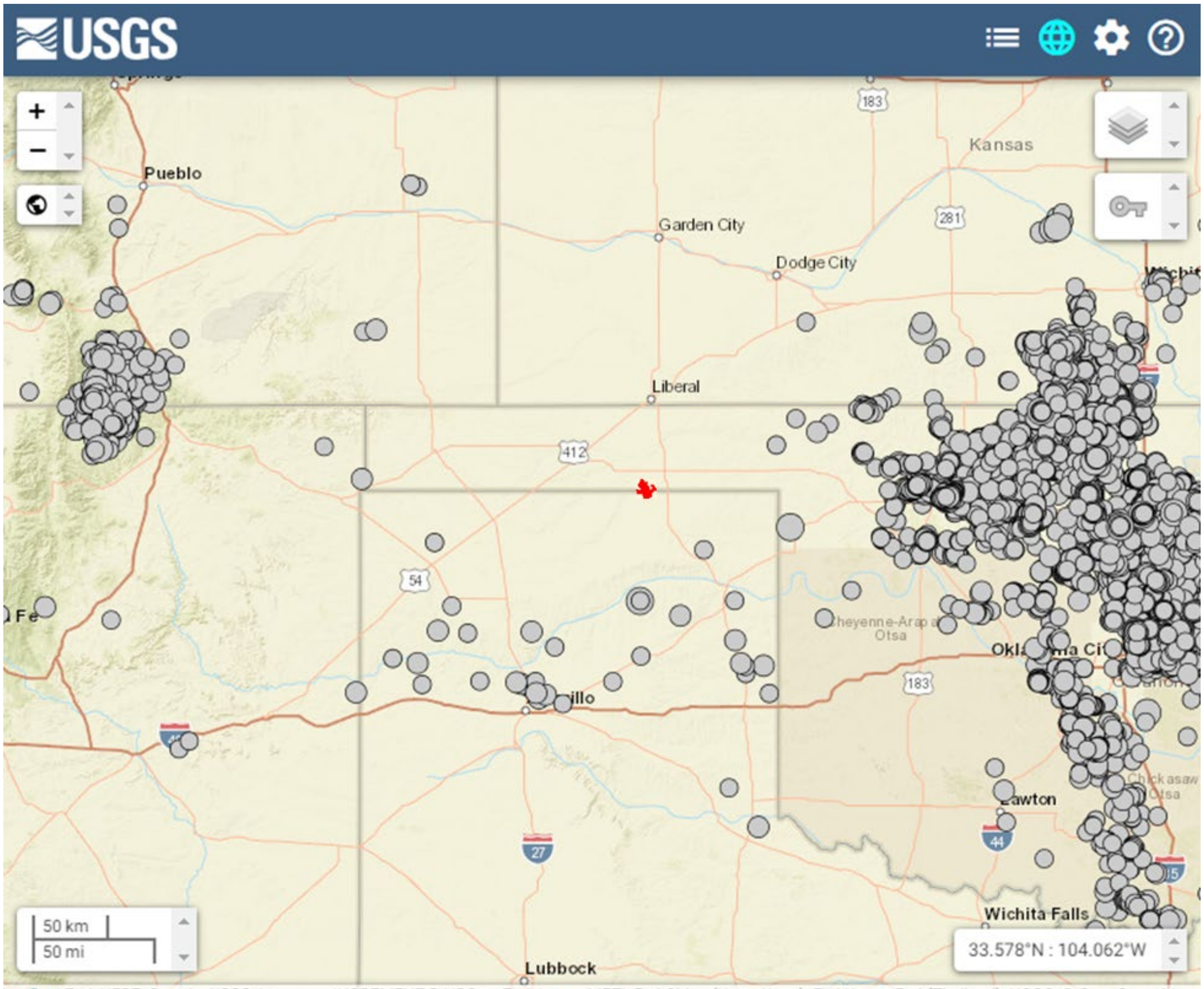

Figure 4.6-1. USGS earthquakes (+2.5 magnitude) for last 40 years with CFA highlighted red.

There is no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the CFA.

In the unlikely event that induced seismicity resulted in a pathway for material amounts of CO_2 to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would lead to further investigation.

4.7 Strategy for Detection and Response to 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 (well bores), and unique events such as induced fractures. Table 1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks,

CapturePoint's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO_2 losses discussed in the table are identified by type. Once the type is reported to a response manager the correct resources and personnel can be mobilized to develop the optimal response procedure. The procedure will address and mitigate further CO_2 leakage.

Table 1 Response Plan for CO_2 Loss

Known Potential Leakage Risks	Monitoring Methods and Frequency	Anticipated Response Plan
Tubing Leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days
Casing Leak	Weekly field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days
Wellhead Leak	Weekly field inspection	Workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations (weekly inspection but field personnel present daily)	Maintain well kill procedures
Unplanned wells drilled through Morrow	Weekly field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Re-enter and reseal abandoned wells
Pumps, values, etc.	Weekly field inspection	Workover crews respond within days
Leakage along faults	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near faults
Leakage laterally	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Fluid management along lease lines
Leakage through induced fractures	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near seismic event

4.8 Strategy for Quantifying CO_2 loss

Major CO_2 losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. CapturePoint will use Subpart W techniques to estimate leakages only on equipment and ensure those results are consistently represented in the Subpart RR report. Any event-driven leakage quantification reported in Subpart RR for surface leaks will use other techniques.

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 CO_2 that would be most appropriate. In the event leakage occurs, CapturePoint will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission.

Any volume of CO_2 detected leaking to the 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, CapturePoint's field experience, and other factors such as the frequency of inspection. As indicated in Section 6.4, leaks will be documented, and the records of leakage events will be retained in the electronic environmental documentation and reporting system, which consists of reports stored on servers, with information uploaded into third party software.

Available studies of actual well leaks and natural analogs (e.g., naturally occurring CO_2 geysers) suggest that the amount released from routine leaks would be small as compared to the amount of CO_2 that would remain stored in the formation.

5 Strategy for Determining CO_2 Baselines for CO_2 Monitoring

Atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values for soil measurement in the CFA area, per the characterization, monitoring and well data collected by the Southwest Regional Partnership on Carbon Sequestration (SWP) in the analogous Farnsworth Unit.

5.1 Site Characterization and Monitoring

As described in Sections 2.2.2 and 2.4, the Morrow B sandstone is isolated both above and below by shale units of the Morrow. The primary seal consists of 180 – 200 ft of Morrow shale and Thirteen Finger Limestone which in turn is overlain by over a thousand feet of younger shale and limestone. These units provide a suitable seal to prevent the migration of CO_2 out of the injection reservoir. Additionally, no significant faults or fracture zones that cut across the seal units have been identified in the CFA, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented.

5.2 Groundwater monitoring

CapturePoint does not routinely pull water samples from the Ogallala water wells. However, samples are pulled when OCC injection permits are submitted in Oklahoma. No indication of fluid leakage has been identified from any of these in the CFA area. CapturePoint is unlikely to continue monitoring USDW wells for CO_2 or brine contamination, as characterization of the Morrow (see section 5.1) has suggested minimal risk of groundwater contamination from CO_2 leakage from this depth.

5.3 Soil CO_2 monitoring

Atmospheric CO_2 values at the Farnsworth Unit have been determined by a SWP eddy tower installation. In winter 2019, the eddy system malfunctioned and has not been repaired due to COVID travel restrictions. However, the atmospheric CO_2 concentration data from the eddy tower were in very good agreement with values obtained from the NOAA Global Monitoring Laboratory station in Moody, Texas (Station: WKT). Since the CFA area is in close proximity to the Farnsworth Unit, atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values.

5.4 Visual Inspection

CapturePoint operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage.

5.5 Well Surveillance

CapturePoint adheres to the requirements of OAC Title 165:10-5 for the OCC and of TAC Rule 46 for the TRRC governing fluid injection into productive reservoirs. Rule 46 includes requirements for monitoring, reporting, and testing of Class II injection wells. Furthermore, the OCC and the TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well if they are deemed necessary.

CapturePoint also adheres to the requirements of OAC Title 165:10-7 for the OCC and TAC Rule 20 for the TRRC governing the notification of fires, breaks, leaks, or escapes. Rule 20 requires that all operators report leaks to the OCC or the TRRC including measured or estimated quantities of product leaked.

6 Site specific considerations for determining the Mass of CO_2 Sequestered

Of the twelve RR equations in 98.443 of Subpart RR, the following are relevant to CapturePoint's operations.

6.1 Determining Mass of CO_2 received

CapturePoint currently receives CO_2 at its CFA facility through its own pipeline from the Arkalon Ethanol plant in Liberal, Kansas. CapturePoint also recycles CO_2 from its production wells in the CFA.

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

where:

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

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into the well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

6.2 Determining Mass of CO_2 Injected

CapturePoint injects CO_2 into the injection wells listed in Appendix 1.

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

where:

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

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

6.3 Determining Mass of CO_2 produced from Oil Wells

CapturePoint also recycles CO_2 from its production wells which are part of its operations in the CFA. Therefore, the following equation is relevant to its operations.

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

Where:

$CO_{2,w}$ = Annual CO_2 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 CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,w}}$ = CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator.

To aggregate production data, CapturePoint will sum the mass of all of the CO_2 separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 below:

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

Where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) through all separators in the reporting year.

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction), CU is 0.00236 and NPU is 0.00454 at the last sample.

w = Separator.

6.4 Determining Mass of CO_2 emitted by Surface Leakage

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations.

CapturePoint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below:

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

where:

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

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

x = Leakage pathway.

6.5 Determining Mass of CO_2 sequestered

The following Equation RR-11 pertains to facilities that are actively producing oil or natural gas.

$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP}$ (Equation RR-11)

Where:

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

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

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

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

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

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

7 Estimated Schedule for Implementation of MRV plan

CapturePoint expects to begin implementing the approved MRV plan when the new CO_2 capture facility is operational, September 1, 2022.

8 GHG monitoring and Quality Assurance Program

CapturePoint will meet the monitoring and QA/QC requirements of 98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 98.444 (d).

8.1 GHG monitoring

As required by 40 CFR 98.3(g)(5)(i), CapturePoint's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

8.1.1 General

Measurement of CO_2 *Concentration* – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GSA) standards.

Measurement of CO_2 *Volume* – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. CapturePoint will adhere to the American Gas Association (AGA) Report #3 – (ORIFICE METERING OF NATURAL GAS AND OTHER RELATED HYDROCARBON FLUIDS)

8.1.2 CO_2 Received

Daily fermentation CO_2 purchased is received via the pipeline from the Arkalon ethanol plant in Liberal, Kansas, and is measured using a volumetric totalizer, which uses accepted flow calculations for CO_2 according to the AGA Report #3.

8.1.3 CO_2 Injected

Daily CO_2 injection is recorded by combining the totals for the recycle compressor meter and the received CO_2 meter from Arkalon based on what's delivered on a 24-hour basis. This data is taken from the meter daily and stored in CapturePoint's data warehouse for records and reservoir management.

8.1.4 CO_2 Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO_2. The produced gas is sampled at least quarterly for the CO_2 content.

8.1.5 CO_2 Emissions from equipment leaks and vented emissions of CO_2

As required by 98.444 (d), CapturePoint will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead and between the flow meter used to measure production quantity and the production wellhead.

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6 Measurement Devices

As required by 40 CFR 98.444(e), CapturePoint will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration.
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meters are National Institute of Standards and Technology (NIST) traceable.

8.2 QA/QC procedures

CapturePoint will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

8.3 Estimating missing data

CapturePoint will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

A quarterly flow rate of CO_2 received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.

A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.

A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

8.4 Revisions of the MRV plan

CapturePoint will revise the MRV Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

9 Records Retention

CapturePoint will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, CapturePoint will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.
(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
    (i) The GHG emissions calculations and methods used.
    (ii) Analytical results for the development of site-specific emissions factors, if applicable.
    (iii) The results of all required analyses.
    (iv) Any facility operating data or process information used for the GHG emission calculations.
(3) The annual GHG reports.
(4) Missing data computations. For each missing data event, CapturePoint will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
(5) A copy of the most recent revision of this MRV Plan.
(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(9) Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(10) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(11) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
(12) 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.
(13) 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.
(14) Any other records as specified for retention in this EPA-approved MRV plan.

10 Appendices

Appendix 1 – CFA Wells

Table A1.1 – Production Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2112	35007353570000	Oil Prod	Active	CO_2	1	0
CU 2171	35007354120000	Oil Prod	Active	CO_2	1	0
CU 2173	35007354140000	Oil Prod	Active	CO_2	1	0
CU 2177	35007222340000	Oil Prod	Active	CO_2	1	0
CU 2272	35007224530000	Oil Prod	Active	CO_2	1	0
CU 2651	35007362650000	Oil Prod	Active	CO_2	1	0
CU 2731	35007359750000	Oil Prod	Active	CO_2	1	0
CU 2761	35007350590000	Oil Prod	Active	CO_2	1	0
CU 2853	35007250840000	Oil Prod	Active	CO_2	1	0
CU 2854	35007250850000	Oil Prod	Active	CO_2	1	0
CU 2971A	35007256700000	Oil Prod	Active	CO_2	1	0
CU 2973	35007213750000	Oil Prod	Active	CO_2	1	0
CU 2975	35007223730000	Oil Prod	Active	CO_2	1	0
CU 3111	35007350600000	Oil Prod	Active	CO_2	1	0
CU 3113	35007359460000	Oil Prod	Active	CO_2	1	0
CU 3115	35007251710000	Oil Prod	Active	CO_2	1	0
CU 3116	35007252570000	Oil Prod	Active	CO_2	1	0
CU 3143	35007250860000	Oil Prod	Active	CO_2	1	0
CU 3171	35007359600000	Oil Prod	Active	CO_2	1	0
CU 3182	35007249250000	Oil Prod	Active	CO_2	1	0
CU 3211	35007352150000	Oil Prod	Active	CO_2	1	0
CU 3212	35007352690000	Oil Prod	Active	CO_2	1	0
CU 3231	35007001820000	Oil Prod	Active	CO_2	1	0
CU 3232	35007352720000	Oil Prod	Active	CO_2	1	0
CU 3234	35007212010000	Oil Prod	Active	CO_2	1	0
CU 3261	35007352170000	Oil Prod	Active	CO_2	1	0
CU 3263	35007251640000	Oil Prod	Active	CO_2	1	0
CU 3271	35007352160000	Oil Prod	Active	CO_2	1	0
CU 3273	35007252580000	Oil Prod	Active	CO_2	1	0
CU 3274	35007253140000	Oil Prod	Active	CO_2	1	0
CU 3275	35007254040000	Oil Prod	Active	CO_2	1	0
CU 3312	35007360800000	Oil Prod	Active	CO_2	1	0
CU 3313	35007254370000	Oil Prod	Active	CO_2	1	0
CU 3314	35007254030000	Oil Prod	Active	CO_2	1	0
CU 3332	35007254020000	Oil Prod	Active	CO_2	1	0
CU 3381	35007360780000	Oil Prod	Active	CO_2	1	0
CU 3411	35007351700000	Oil Prod	Active	CO_2	1	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3412	35007351720000	Oil Prod	Active	CO_2	1	0
CU 3413	35007351730000	Oil Prod	Active	CO_2	1	0
CU 3414	35007005220000	Oil Prod	Active	CO_2	1	0
CU 3415	35007211170000	Oil Prod	Active	CO_2	1	0
CU 3416A	35007252590000	Oil Prod	Active	CO_2	1	0
CU 3451A	35007256710000	Oil Prod	Active	CO_2	1	0
CU 3471	35007351750000	Oil Prod	Active	CO_2	1	0
CU 3481	35007351710001	Oil Prod	Active	CO_2	1	0
CU 3491	35007254330000	Oil Prod	Active	CO_2	1	0
CU 3533	35007206880000	Oil Prod	Active	CO_2	1	0
CU 3562	35007255050000	Oil Prod	Active	CO_2	1	0
NPU 101	42357010440000	Oil Prod	Active	CO_2	1	0
NPU 103	42357010060000	Oil Prod	Active	CO_2	1	0
NPU 104	42357000050000	Oil Prod	Active	CO_2	1	0
NPU 207	42357302000000	Oil Prod	Active	CO_2	1	0
NPU 209	42357333830000	Oil Prod	Active	CO_2	1	0
NPU 501	42357009140000	Oil Prod	Active	CO_2	1	0
NPU 502	42357024100000	Oil Prod	Active	CO_2	1	0
NPU 601	42357008420000	Oil Prod	Active	CO_2	1	0
NPU 605	42357333840000	Oil Prod	Active	CO_2	1	0
NWCU 3-1	35007360850000	Gas Prod	Active	CO_2	1	0
NWCU 9-3	35007249430000	Oil Prod	Active	CO_2	1	0
CU 2172	35007354130000	Oil Prod	Inactive	CO_2	0	0
CU 2175	35007354160000	Oil Prod	Inactive	CO_2	0	0
CU 2473	35007211990000	Oil Prod	Inactive	CO_2	0	0
CU 2511	35007350790000	Oil Prod	Inactive	CO_2	0	0
CU 2711	35007359260000	Oil Prod	Inactive	CO_2	0	0
CU 2771	35007359850000	Oil Prod	Inactive	CO_2	0	0
CU 3142	35007222350000	Oil Prod	Inactive	CO_2	0	0
CU 3361	35007352670000	Oil Prod	Inactive	CO_2	0	0
NPU 205	42357008070000	Oil Prod	Inactive	CO_2	0	0
NPU 301	42357022080000	Oil Prod	Inactive	CO_2	0	0
NPU 801	42357004630000	Oil Prod	Inactive	CO_2	0	0
NPU 802	42357004620000	Oil Prod	Inactive	CO_2	0	0
NPU 804	42357201730000	Oil Prod	Inactive	CO_2	0	0
NPU 901	42357000660000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-2	35007350870000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-3	35007210790000	Oil Prod	Inactive	CO_2	0	0
NWCU 16-1	35007350720000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-1	35007360900000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-3	35007360920000	Oil Prod	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
NWCU 19-4	35007360930000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-5	35007360940000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-6	35007211250000	Oil Prod	Inactive	CO_2	0	0
NWCU 24-5	35007222710000	Oil Prod	Inactive	CO_2	0	0
NWCU 25-7	35007228000000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-3	35007360870000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-4	35007360880000	Oil Prod	Inactive	CO_2	0	0
NWCU 4-2	35007360740000	Oil Prod	Inactive	CO_2	0	0
NWCU 5-1	35007361050000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-1	35007360980000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-2	35007360990000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-1	35007360810000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-2	35007360820000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-3	35007208260000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-1	35007360950000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-2	35007360960000	Oil Prod	Inactive	CO_2	0	0
CU 1551	35007350740000	Oil Prod	P&A	CO_2	0	0
CU 1671	35007352180000	Oil Prod	P&A	CO_2	0	0
CU 2111	35007353560000	Oil Prod	P&A	CO_2	0	0
CU 2176	35007358870000	Oil Prod	P&A	CO_2	0	0
CU 2221	35007000490000	Oil Prod	P&A	CO_2	0	0
CU 2281	35007359220000	Oil Prod	P&A	CO_2	0	0
CU 2421	35007359350000	Oil Prod	P&A	CO_2	0	0
CU 2431	35007350330000	Oil Prod	P&A	CO_2	0	0
CU 2432	35007350340000	Oil Prod	P&A	CO_2	0	0
CU 2433	35007350350000	Oil Prod	P&A	CO_2	0	0
CU 2434	35007350360000	Oil Prod	P&A	CO_2	0	0
CU 2435	35007218800000	Oil Prod	P&A	CO_2	0	0
CU 2471	35007359080000	Oil Prod	P&A	CO_2	0	0
CU 2531	35007361090000	Oil Prod	P&A	CO_2	0	0
CU 2532	35007361100000	Oil Prod	P&A	CO_2	0	0
CU 2552	35007359760000	Oil Prod	P&A	CO_2	0	0
CU 2571	35007350730000	Oil Prod	P&A	CO_2	0	0
CU 2572	35007359320000	Oil Prod	P&A	CO_2	0	0
CU 2661	35007361990000	Oil Prod	P&A	CO_2	0	0
CU 2681	35007350320000	Oil Prod	P&A	CO_2	0	0
CU 2852	35007301360000	Oil Prod	P&A	CO_2	0	0
CU 2961	35007358760000	Oil Prod	P&A	CO_2	0	0
CU 2971	35007358750000	Oil Prod	P&A	CO_2	0	0
CU 2972	35007358780000	Oil Prod	P&A	CO_2	0	0
CU 3031	35007359560000	Oil Prod	P&A	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3051	35007300380000	Oil Prod	P&A	CO_2	0	0
CU 3064	35007254270000	Oil Prod	P&A	CO_2	0	0
CU 3141	35007359610000	Oil Prod	P&A	CO_2	0	0
CU 3181	35007359470000	Oil Prod	P&A	CO_2	0	0
CU 3251	35007352710000	Oil Prod	P&A	CO_2	0	0
CU 3331	35007200750000	Oil Prod	P&A	CO_2	0	0
CU 3451	35007351690000	Oil Prod	P&A	CO_2	0	0
CU 3511	35007359730000	Oil Prod	P&A	CO_2	0	0
CU 3531	35007350850000	Oil Prod	P&A	CO_2	0	0
CU 3532	35007359950000	Oil Prod	P&A	CO_2	0	0
CU 3534	35007211180000	Oil Prod	P&A	CO_2	0	0
CU 3561	35007359830000	Oil Prod	P&A	CO_2	0	0
CU 3571	35007359980000	Oil Prod	P&A	CO_2	0	0
CU 3581	35007359970000	Oil Prod	P&A	CO_2	0	0
CU 3631	35007301000000	Oil Prod	P&A	CO_2	0	0
CU 1672	35007352190000	Oil Prod	P&A	CO_2	0	0
CU 2351	35007350370000	Oil Prod	P&A	CO_2	0	0
CU 2474	35007228200000	Oil Prod	P&A	CO_2	0	0
CU 2812	35007352340000	Oil Prod	P&A	CO_2	0	0
CU 2871	35007359060000	Oil Prod	P&A	CO_2	0	0
NPU 102	42357021420000	Oil Prod	P&A	CO_2	0	0
NPU 201	42357001280000	Oil Prod	P&A	CO_2	0	0
NPU 302	42357022290000	Oil Prod	P&A	CO_2	0	0
NPU 402	42357022300000	Oil Prod	P&A	CO_2	0	0
NWCU 17-2	35007359620000	Oil Prod	P&A	CO_2	0	0
NWCU 10-1	35007361010000	Oil Prod	P&A	CO_2	0	0
NWCU 17-1	35007350710000	Oil Prod	P&A	CO_2	0	0
NWCU 19-7	35007224520000	Oil Prod	P&A	CO_2	0	0
NWCU 24-4	35007358770000	Oil Prod	P&A	CO_2	0	0
NWCU 25-6	35007358790000	Oil Prod	P&A	CO_2	0	0

Table A1.2 – Water Alternating Gas (WAG) Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 2662 (INJ)	35007362010000	WAG Inj	Active	CO_2	0	1
CU 2751 (INJ)	35007359440002	WAG Inj	Active	CO_2	0	1
CU 2762 (INJ)	35007213660000	WAG Inj	Active	CO_2	0	1
CU 2772 (INJ)	35007359860001	WAG Inj	Active	CO_2	0	1
CU 2811 (INJ)	35007352200000	WAG Inj	Active	CO_2	0	1
CU 2872 (INJ)	35007359070000	WAG Inj	Active	CO_2	0	1
CU 2962 (INJ)	35007212000000	WAG Inj	Active	CO_2	0	1
CU 2974 (INJ)	35007220770000	WAG Inj	Active	CO_2	0	1
CU 3114 (INJ)	35007206540000	WAG Inj	Active	CO_2	0	1
CU 3117 (INJ)	35007254000000	WAG Inj	Active	CO_2	0	1
CU 3161 (INJ)	35007359590002	WAG Inj	Active	CO_2	0	1
CU 3213 (INJ)	35007224570000	WAG Inj	Active	CO_2	0	1
CU 3233 (INJ)	35007206890000	WAG Inj	Active	CO_2	0	1
CU 3252 (INJ)	35007211020000	WAG Inj	Active	CO_2	0	1
CU 3262 (INJ)	35007206870000	WAG Inj	Active	CO_2	0	1
CU 3351 (INJ)	35007352680000	WAG Inj	Active	CO_2	0	1
CU 3371 (INJ)	35007360770000	WAG Inj	Active	CO_2	0	1
CU 3417 (INJ)	35007255060000	WAG Inj	Active	CO_2	0	1
CU 3461 (INJ)	35007351680000	WAG Inj	Active	CO_2	0	1
CU 3472 (INJ)	35007206940000	WAG Inj	Active	CO_2	0	1
CU 3551 (INJ)	35007359840000	WAG Inj	Active	CO_2	0	1
NPU 105 (INJ)	42357000030000	WAG Inj	Active	CO_2	0	1
NPU 107W (INJ)	42357333770000	WAG Inj	Active	CO_2	0	1
NPU 202WI (INJ)	42357021500000	WAG Inj	Active	CO_2	0	1
NPU 208 (INJ)	42357327410000	WAG Inj	Active	CO_2	0	1
NPU 701 (INJ)	42357008410000	WAG Inj	Active	CO_2	0	1
NPU 504 (INJ)	42357329480000	WAG Inj	Active	CO_2	0	1
NPU 604W (INJ)	42357330870000	WAG Inj	Active	CO_2	0	1
CU 1531 (INJ)	35007359990000	WAG Inj	Inactive	CO_2	0	0
CU 2131 (INJ)	35007362700000	WAG Inj	Inactive	CO_2	0	0
CU 2512 (INJ)	35007350780000	WAG Inj	Inactive	CO_2	0	0
CU 2641 (INJ)	35007359250001	WAG Inj	Inactive	CO_2	0	0
CU 2721 (INJ)	35007359870001	WAG Inj	Inactive	CO_2	0	0
CU 2741 (INJ)	35007359430000	WAG Inj	Inactive	CO_2	0	0
CU 2851 (INJ)	35007355420001	WAG Inj	Inactive	CO_2	0	0
CU 3032 (INJ)	35007359580000	WAG Inj	Inactive	CO_2	0	0
CU 3062 (INJ)	35007253090000	WAG Inj	Inactive	CO_2	0	0
CU 3112 (INJ)	35007359450001	WAG Inj	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 3172 (INJ)	35007251690000	WAG Inj	Inactive	CO_2	0	0
CU 3281 (INJ)	35007352700003	WAG Inj	Inactive	CO_2	0	0
CU 3311 (INJ)	35007360790000	WAG Inj	Inactive	CO_2	0	0
CU 3341 (INJ)	35007353530000	WAG Inj	Inactive	CO_2	0	0
NPU 203W (INJ)	42357008270000	WAG Inj	Inactive	CO_2	0	0
NPU 503 (INJ)	42357009150001	WAG Inj	Inactive	CO_2	0	0
NWCU 15-1 (INJ)	35007350860000	WAG Inj	Inactive	CO_2	0	0
NWCU 15-4 (INJ)	35007224510000	WAG Inj	Inactive	CO_2	0	0
NWCU 20-1 (INJ)	35007360760000	WAG Inj	Inactive	CO_2	0	0
NWCU 21-1 (INJ)	35007361020000	WAG Inj	Inactive	CO_2	0	0
CU 2271 (INJ)	35007359230000	WAG Inj	P&A	CO_2	0	0
CU 2311 (INJ)	35007362000000	WAG Inj	P&A	CO_2	0	0
CU 2472 (INJ)	35007359090000	WAG Inj	P&A	CO_2	0	0
CU 3061 (INJ)	35007359820000	WAG Inj	P&A	CO_2	0	0
CU 3512 (INJ)	35007359740000	WAG Inj	P&A	CO_2	0	0
NPU 204W (INJ)	42357022520000	WAG Inj	P&A	CO_2	0	0
NPU 206W (INJ)	42357022510000	WAG Inj	P&A	CO_2	0	0
NPU 401W (INJ)	42357004520000	WAG Inj	P&A	CO_2	0	0
NPU 602W (INJ)	42357020230000	WAG Inj	P&A	CO_2	0	0
NPU 603W (INJ)	42357201720001	WAG Inj	P&A	CO_2	0	0
NPU 803W (INJ)	42357201710000	WAG Inj	P&A	CO_2	0	0
NWCU 14-1 (INJ)	35007350530000	WAG Inj	P&A	CO_2	0	0
NWCU 3-2 (INJ)	35007360860000	WAG Inj	P&A	CO_2	0	0

Table A1.3 – Water Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU WSW 1	35007355430001	Wtr Inj	Active	CO_2	0	1
NPU W 1W	42357300050002	Wtr Inj	Inactive	CO_2	0	0
CU 2551	35007350750000	Wtr Inj	P&A	CO_2	0	0

Appendix 2 – Referenced Regulations

U.S. Code > Title 26, INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1, NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits >

Section 45Q ..... Credit for carbon oxide sequestration

OCC > Title 165: CORPORATION COMMISSION > UNDERGROUND INJECTION CONTROL

Section

165:10-5-1 .... Classification of underground injection wells
165:10-5-2 .... Approval of injection wells or disposal wells
165:10-5-3 .... Authorization for existing enhanced recovery injection wells and existing disposal wells
165:10-5-4 .... Application for approval of enhanced recovery projects
165:10-5-5 .... Application for approval of injection and disposal operations
165:10-5-6 .... Testing and monitoring requirements for injection wells and disposal wells
165:10-5-7 .... Monitoring and reporting requirements for wells covered by 165:10-5-1
165:10-5-8 .... Liquid hydrocarbon storage wells
165:10-5-9 .... Duration of underground injection well orders or permits
165:10-5-10 ..... Transfer of authority to inject
165:10-5-11 ..... Notarized reports
165:10-5-12 ..... Application for administrative approval for the subsurface injection of onsite reserve pit fluids
165:10-5-13 ..... Application for permit for one time injection of reserve pit fluids
165:10-5-14 ..... Exempt aquifers
165:10-5-15 ..... Application for permit for simultaneous injection well

165:5-7-27 .... Application for approval of injection and disposal wells
165:5-7-29 .... Request for exception to certain underground injection well requirements
165:5-7-30 .... Amending existing orders or permits authorizing injection for injection, disposal, or LPG storage wells

TAC > Title 16 - Economic Regulation> Part 1 TRRC > Chapter 3 – Oil and Gas Division >

Rules

Appendix 3 – References

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Appendix 4 – Abbreviations and Acronyms

2D – 2 dimensional
3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
ANSI – American National Standards Institute
API – American Petroleum Institute
AWT – All Well Test
ASTM - American Society for Testing and Materials
Bscf – billion standard cubic feet
B/D – barrels per day
bopd – barrels of oil per day
C4 – butane
C5 – pentane
C7 – heptane
C7+ - standard heptane plus
CCE – constant composition expansion
CCUS – carbon capture utilization and storage
CFA – Camrick Field Area
cf – cubic feet
CH4 – methane
CO_2 – carbon dioxide
EOR – Enhanced Oil Recovery
EOS – Equation of State
EPA – US Environmental Protection Agency
ESD – Emergency Shutdown Device
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
H_2S – hydrogen sulfide
lb – pound
mD – millidarcy(ies)
MICP – mercury injection capillary pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MMB – million barrels
MMP – minimum miscible pressure
MMscf – million standard cubic feet
MMstb – million stock tank barrels
MRV – Monitoring, Reporting, and Verification
MMMT – Million metric tonnes
MT – Metric tonne
NIST – National Institute of Standards and Technology

NAESB – North American Energy Standards Board
OAC – Oklahoma Administrative Code
OCC – Oklahoma Corporation Commission
OOIP – Original Oil-In-Place
OWC – oil water contact
PPM – Parts Per Million
psia – pounds per square inch absolute
PVT – pressure, volume, temperature
QA/QC – quality assurance/quality control
RMS – root mean square
SEM – scanning electron microscope
SWP - Southwest Regional Partnership on Carbon Sequestration
TAC – Texas Administrative Code
TA – Temporally Abandoned/not plugged
TD – total depth
TM – Terminated order wells/UIC not plugged
TRRC – Texas Railroad Commission
TSD – Technical Support Document
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water
WAG – Water Alternating Gas (Gas is recycled CO_2 and purchase CO_2)
XRD – x-ray diffraction

Appendix 5 – Conversion Factors

CapturePoint reports CO_2 at standard conditions of temperature and pressure as defined in the State of Texas in the Texas Administrative Code for the Oil and Gas Division, Rule 3.79 as follows:

> Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit.

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at:

https://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At State of Texas standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.002641684 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2{,}204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2} = 0.002641684$$

$$MW_{CO2} = 44.0095$$

$$Density_{CO2} = 5.2734\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.2734\ x\ 10^{-2}\frac{MT}{Mcf}$$

The conversion factor 5.2734 x 10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Request for Additional Information: Camrick Unit
May 26, 2022

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	While the resolution and overall quality of the figures have increased markedly in this version of the draft MRV plan, there are now issues with the naming and referencing of figures throughout the MRV plan. Specifically, there is an inconsistency in using dashes vs. dots as separators in the figure names, such as "Figure 2.2-1" vs. "Figure 2.2.3" Additionally, the MRV plan goes from "Figure 2.4-1" to "Figure 2.4-4" while still referencing a now non-existent "Figure 2.4.3" in section 2.4.2 of the draft MRV plan. Please review figure numbering and references to figures in the text and correct these errors.	Corrected figure numbering and references.
2.	2.1.2	4	"Historical and forecasted cumulative CO2 retention volumes are approximately 100 billion standard cubic feet (Bscf) or 5.3 million metric tonnes (MMMT) from the start of CO2 injection through October 2034. **During the MRV plan, the period September 2022 through October 2034,** 52.5 Bscf or 2.77 MMMT will be stored in the CFA. (See Figure 2.4.8)" The beginning date of the time period differs from that stated in Section 7 which declares November 1, 2022 as the beginning date. Please clarify and update the MRV plan as necessary.	Corrected Section 7 to September 1, 2022

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	2.3.2	11	"Although CapturePoint is not required to determine or report the amount of dissolved CO2 in the water as it is reinjected into the ground and not emitted to the atmosphere. The analyses have shown the water typically contains <690 ppm (0.069%) CO2." The edit to the above phrase has introduced a new sentence fragment. Replacing the period with a comma would fix this error.	Corrected sentence fragment by replacing period with a comma.
4.	4.2.3	24	"Once EOR operations commence, the energy content of the produced gas drops and cannot be sold; therefore, no gas wells are identified." Can you please clarify whether there are gas wells in the CFA and if they are identified in any section of the MRV plan? Even if the gas is not marketable, any gas wells could be source of potential leakage/emissions. Please update the MRV Plan as necessary.	Changed "no gas wells are identified" to "any inactive gas wells are reclassified to either oil producer or WAG injector".
5.	4.2.4	25	"Inactive wells have a cast iron bridge plug set or long cement plugs placed above the existing perforations to **isolate reservoir** from the surface." It appears there is typo in the above phrase with "the" missing before reservoir. Please correct it.	Added "the" before "reservoir".
6.	4.8	31	"As indicated in Section 6.4, leaks will be documented, and the records of leakage events will be retained in the electronic environmental documentation and reporting system." Is the electronic documentation and reporting system an internal system for documenting and reporting leaks? Please clarify and provide a brief description.	Added the descriptive phrase ", which consists of reports stored on servers, with information uploaded into third party software."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
7.	Email From: Melinda Miller	N/A	"determine whether one or more facilities is represented by the Camrick Field"	The production reservoir is the same for both units, is continuous and the facilities and boundaries are contiguous, however they extend across the Texas and Oklahoma border. The EPA has been notified through eGGRT that the North Perryton Unit will not be reporting for 2022, and that the facility has been merged into the Camrick Unit Facility ID. Appropriate edits were made to reflect this in the MRV Plan for Camrick Unit prior to resubmittal.

Camrick Field Area (CFA)

MONITORING, REPORTING AND VERIFICATION PLAN (MRV)

CapturePoint LLC

April 2022

Contents

INTRODUCTION

CapturePoint, LLC (CapturePoint) operates the Camrick Field Area (CFA) located in Beaver and Texas Counties, Oklahoma and in Ochiltree County, Texas for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) with retention of CO_2 serving a subsidiary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The CFA was discovered in 1955 and is composed of three units, the Camrick Unit (CU) that was unitized by Humble Oil Company on October 14, 1969, the North Perryton Unit (NPU) that was unitized by Humble Oil Company on March 17, 1969, and the Northwest Camrick Unit (NWCU) that was unitized by Atlantic RichField Company on September 15, 1972. The Units were formed for the purpose of waterflooding with salt water sourced from the Wolfcamp formation. The field structure is a lenticular bedding sand trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. CapturePoint has been operating the CFA since 2017. CapturePoint acquired the CFA from Chaparral Energy LLC, which initiated the CO_2-EOR project in March 2001 for the CU and January 2007 for the NPU. No CO_2 has been injected in the NWCU. CapturePoint intends to continue CO_2-EOR operations until the end of the economic life of the CO_2-EOR program using various Class II injection wells as defined by Underground Injection Control (UIC) regulations and permitted under Texas Railroad Commission (TRRC) Rule 46 of the Texas Administrative Code (TAC) and the Oklahoma Corporation Commission (OCC) Title 165:10 of the Oklahoma Administrative Code (OAC). In this document, the term "gas" means a mixture of hydrocarbon light end components and the CO_2 component that can be produced as part of the EOR process.

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

This MRV Plan contains ten sections:

Section 1 contains facility information.

Section 2 contains the project description including: a detailed description of the injection operation including the duration and volume of CO_2 to be injected; a detailed description of the geology and hydrogeology of the CFA located on the northwest shelf of the Anadarko basin; and a detailed characterization of the injection reservoir modeling techniques employed.

Section 3 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449 and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 4 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. This section also describes the strategy for detecting, verifying, and quantifying any surface leakage of CO_2 as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Finally, this section also demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

Section 5 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 6 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 9 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 10 includes Appendices supporting the narrative of the MRV Plan.

1 Facility

1.1 Reporter Number

The CU CO_2 Flood reports under Greenhouse Gas Reporting Program Identification number 544678 and the NPU CO_2 Flood reports under Greenhouse Gas Reporting Program Identification number 544679.

1.2 UIC Permit Class

For injection wells (see Appendix 2) that are the subject of this MRV plan, the OCC has rules governing UIC Class II injection wells. These OCC rules are OAC Title 165:10-5-1 through 165:10-5-15, OAC 165:5-7-27, OAC 165:5-7-30, the request for an exception to UIC rules under OAC 165:5-7-29, and other governing filing forms. Also, the TRRC has issued UIC Class II enhanced recovery permits under its Rule 46, TAC Title 16 Part 1 Chapter 3. All wells in the CFA, including both injection and production wells, are regulated by the OCC and the TRRC, which have primacy to implement the UIC Class II program.

1.3 UIC Injection Well Numbers

A list of the injection wells in the CFA is provided in Appendix 1. The details of the injection process are provided in Section 2.3.

2 Project Description

2.1 Project Characteristics

2.1.1 Estimated years of CO_2 injection

The CFA has been injecting CO_2 for the last 20+ years and it is currently projected that CapturePoint will inject CO_2 for an additional 12 years.

2.1.2 Estimated volume of CO_2 injected over lifetime of project

Historical and forecasted cumulative CO_2 retention volumes are approximately 100 billion standard cubic feet (Bscf) or 5.3 million metric tonnes (MMMT) from the start of CO_2 injection through October 2034. During the MRV plan, the period September 2022 through October 2034, 52.5 Bscf or 2.77 MMMT will be stored in the CFA. (See Figure 2.4.8)

2.2 Environmental Setting of MMA

2.2.1 Boundary of the MMA

CapturePoint has defined the boundary of the MMA as equivalent to the boundary of the CFA plus ½ mile beyond. A discussion of the methods used in delineating the MMA and the AMA are presented in Section 3.

2.2.2 Geology

The geological discussions in Sections 2.2.2 and 4.3-4.4 are based on analysis of logs from both the Farnsworth Unit, which is located 10 miles South-South-West of the CFA, and the CFA. Both areas have similar pay thickness, porosity values, permeability measurements, depositional environment, tectonic processes, and overburden strata layers. The descriptions of cores at the Farnsworth Unit included sections from overlying seals as well as the shale underlying the main reservoirs, petrographic thin section descriptions and point counts as well as a variety of special analytical techniques. These techniques included X-ray diffraction (XRD), which is the science of determining the atomic and molecular structure of rock crystals with an X-ray beam; scanning electron microscope (SEM) analysis, which uses a beam of electrons to define the surface of crystals; carbon isotope analysis to estimate the age of the CO_2 in the sample; and a variety of mechanical tests. Two dimensional (2D) and three dimensional (3D) geophysical surveys were also used as part of the Farnsworth Unit MRV Plan (2021). Details of recent geological investigations can be found in Gallagher (2014), Gragg (2016), Rasmussen et al (2019), Rose-Coss et al (2015), Trujillo (2018), Hobbs et al (2019), and Gragg et al (2018).

2.2.2.1 Tectonic Setting and Stratigraphy

The CFA is located on the northwest shelf of the Anadarko basin (Figure 2.2-1) and is one of many oil fields in the area that produce from a sequence of alternating sandstones and mudstones deposited during the late Pennsylvanian Morrowan period. Oil production and CO_2 injection at CFA is restricted to the operationally named Morrow B sandstone; the uppermost Morrow sandstone encountered below the Atokan Thirteen Finger limestone. The primary caprock intervals at CFA are comprised of the upper Morrow shale and the Thirteen Finger limestone (Figure 2.2-2). The Morrowan and Atokan intervals were deposited approximately 315-300 million years ago. Overlying stratigraphy includes late Pennsylvanian through the middle Permian shales and limestones, with lesser amounts of dolomite, sandstone and evaporites (Ball, 1991). The reservoir is approximately 60 feet thick throughout the field and lies at a depth of approximately 6,800-7,600 feet. The primary seal rocks of the Morrow shale and the Thirteen Finger Limestone comprise a package of approximately 180-200 feet thick in the field and are overlain by thousands of feet of Atokan and younger limestones and shales.

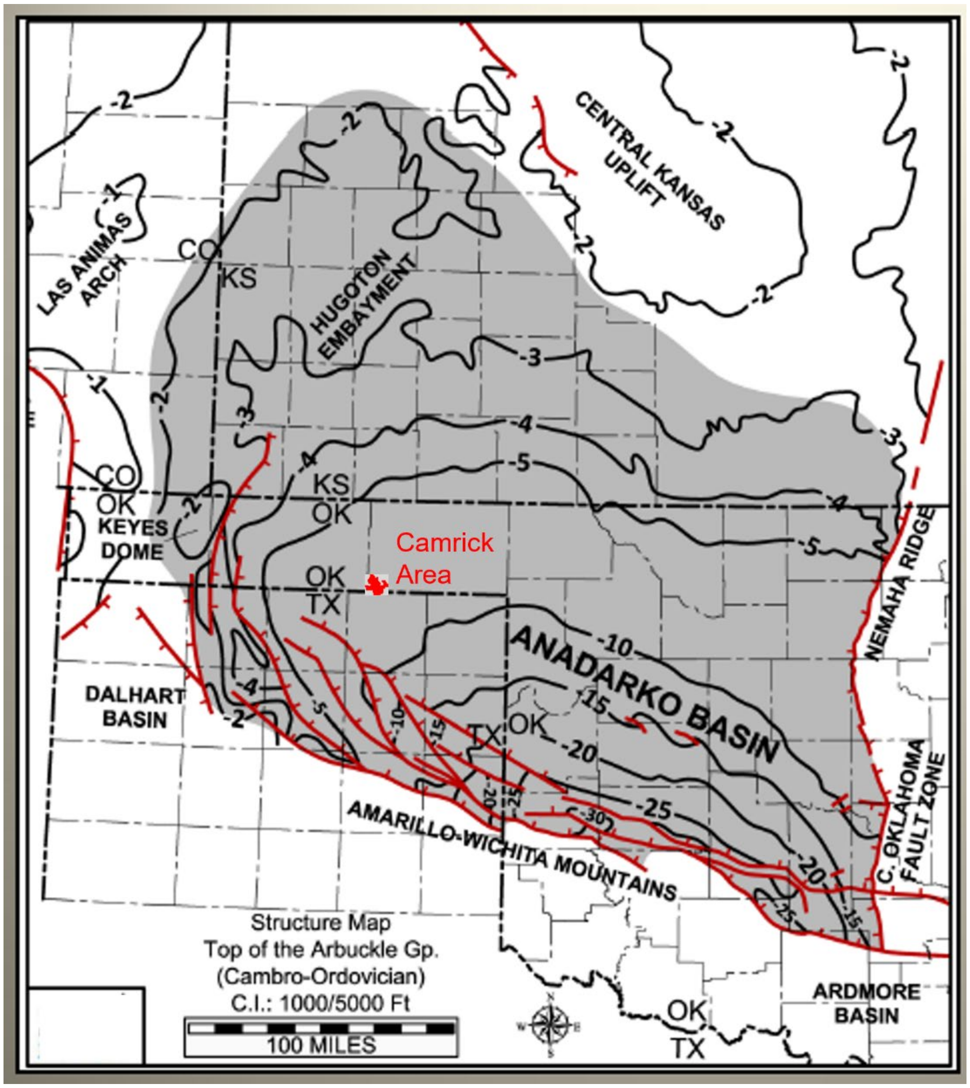


Figure 2.2-1. Location of the CFA on the Northwest Shelf of the Anadarko Basin in West Texas. Red lines are approximate locations of faults that have been documented in the region.

System	Series	Group	Formation		
Pennsylvanian	Virgilian	Wabaunsee			ANADARKO
		Shawnee	Heebner Endicott Toronto		
		Douglas	Douglas **U. Tonkawa**		
	Missourian	Lansing	L. Tonkawa Cottage Grove Hogshooter	GRANITE WASH	
		Kansas City	Checkerboard **Cleveland**		
	Marmaton	Marmaton	**Marmaton** Oswego		
	Cherokee Shale				
	Atoka	Upper Dornick Hills	**Atoka** Thirteen Finger		
	Morrow	Lower Dornick Hills	Upper Morrow Middle Morrow Lower Morrow		
	Springer				
Mississippian	Chester				
	Meramec	Meramec	St. Genevieve St. Louis Spergan Warsaw		
	Osage				
	Kinderhook				
	Chattanooga				

Figure 2.2-2. Stratigraphic section.

Tectonic Setting

From CFA's location on the western edge of the basin, the Anadarko Basin plunges to the southeast (Figure 2.2-3) where it reaches depths of over 40,000 feet (12,192 meters) adjacent to the Amarillo-Wichita Uplift (Perry, 1989). Maximum rates of subsidence occurred during Morrowan to Atokan times (Evans, 1979; Perry, 1989; Higley, 2014). Positive features that might have influenced deposition within the region include the Ancestral Rockies to the north, the Central Kansas uplift to the northeast, and the Wichita-Amarillo uplift to the south (Evans, 1979; Munson, 1989). Of note is the fact that during the Pennsylvanian time, the CFA was located on the basin shelf in an area that was not affected greatly by tectonic deformation. Although faults have been reported previously in the northwest Anadarko Basin, we found no direct evidence for tectonic faults within the CFA (see Section 4).

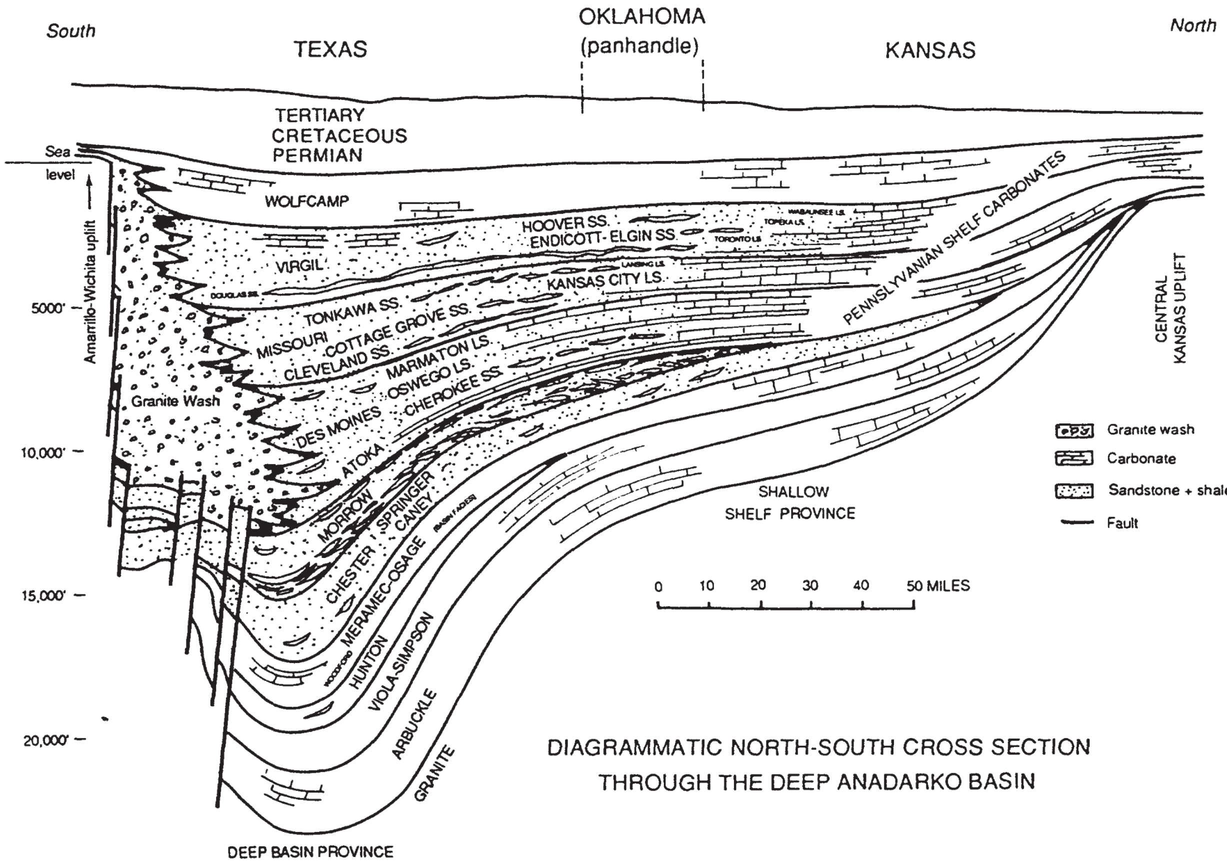


Figure 2.2.3. Diagrammatic North-South Section (Bottom) of the CFA.

Stratigraphy

Reservoir

Upper Morrowan sandstones in the Anadarko Basin margins have long been recognized as fluvial deposits (Swanson, 1979; Sonnenberg, 1985; Munson, 1989; Krystinik and Blakeney, 1990; Bowen et al., 1990; Al-Shaieb et al., 1995; Mckay and Noah, 1996; Puckette et al., 1996; Bowen and Weimer, 2003, 2004; Devries 2005; Puckette et al., 2008; Gallagher, 2014). At the Farnsworth Unit and similarly at the CFA, the Morrow B is described as a relatively coarse-grained subarkosic sandstone. The upper Morrowan facies, with sequences of basal conglomerate, coarse-grained sandstone, and fine-grained sandstone appear to be typical of incised valley deposits, as described by Wheeler et al. (1990), Krystinik and Blakeney (1990), Bowen et al. (1990), Blakeney et al. (1990), Sonnenberg et al. (1990) and Puckette et al. (2008).

Primary Seals

The Morrow B sandstones are encased above and below by shales. Contacts with shale both below and above the sandstone are sharp and irregular. The Morrow shale generally fines upwards in a series of thin beds that alternate between upper fine sands and fine to medium muds. Sand content decreases upwards through the section.

The Thirteen Finger limestone formation has two different lithofacies: diagenetic limestone (cementstone) and pyrite and fossil bearing fine to medium mudstone and coal. The two facies are intercalated with each other but tend to cluster in layers dominated more by one or the other.

The entire Thirteen Finger interval is typically 130 feet (39.6 meters) thick, comprised of mudstone, coal, and limestone. The mudstone is calcite rich, with some dolomite, and is completely diagenetic in origin and probably formed relatively soon following deposition.

2.2.2.2 Hydrogeology

Information about Morrowan and Atokan formation water flow during oil operations has not been discovered in any oil or gas company published reports or academic research studies in the Anadarko Basin. Groundwater flow rates in confined deep Anadarko layers at present are considered to be low to no flow (Nelson and Gianoutsos, 2014). Their arguments are based on (1) restricted recharge in the western basin, (2) density barriers to flow in the east, and (3) an overpressure pocket inhibiting flow in the deep basin. Jorgenson (1989) suggested flow could be west to east, driven by potential recharge to elevated units in the west and discharge at lower elevation outcrops in the east. The CFA CO_2 injection and production operations have negligible likelihood of causing water to flow to outcrops of the late Carboniferous (Pennsylvanian) time period that extend from Brownwood, Texas, to the Jacksboro/Bowie, Texas, area, which are hundreds of miles away (The Paleontology Portal).

The Carboniferous is a geologic period and system that covers 60 million years from the Devonian Period 358.9 million years ago, to the beginning of the Permian Period, 298.9 million years ago. As noted in the Section 2.2.2.1, the Morrowan and Atokan intervals of the CFA were deposited approximately 315-300 million years ago and are contained in the Carboniferous period.

2.3 Description of the Injection Process

Figure 2.3-1 depicts a simplified flow diagram of the facilities and equipment within the boundaries of the CFA. CO_2 captured from the ethanol plant fermentation process is delivered via pipeline to the field for injection. The Arkalon plant in Liberal, Kansas is the only source of CO_2 to the field. The amount delivered is dependent on the production of CO_2 produced from the fermentation process. This amount will vary but should average 12 MMCFD. Once CO_2 enters the CFA there are three main processes involved in EOR operations. These processes are shown in Figure 2.3-1 and include:

1. CO_2 distribution and injection. Purchased CO_2 is combined with recycled CO_2 from the CFA central tank battery (CTB) and sent through the main CO_2 distribution system to various water alternating gas (WAG) injectors.

2. Produced Fluids Handling. Full well stream fluids are produced to the “all well test” (AWT) site. The AWT site has two major purposes; 1) to individually test a well’s performance by separating and metering oil, gas, and water, and 2) to separate all gas from liquid then send these two phases to the CTB for final separation; while only the gas from NPU is sent to the CTB the NPU oil and water remains in Texas.

3. Produced Gas Processing. All gases from the AWT sites are transferred to the CTB to separate the oil, gas, and water using a series of vessels and storage tanks.

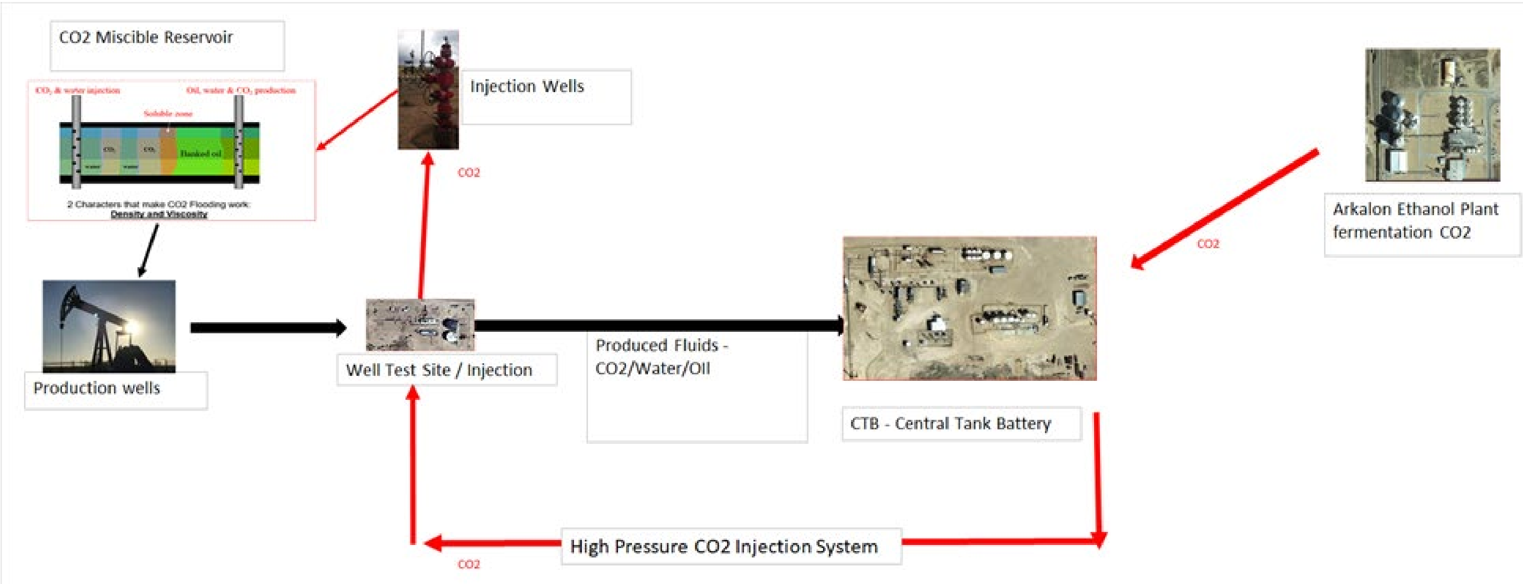


Figure 2.3–1. Simplified flow diagram of the facilities and equipment within the boundaries of the CFA.

2.3.1 CO_2 Distribution and Injection

CapturePoint purchases CO_2 from Conestoga Energy Partners, the parent company of the Arkalon Ethanol plant located in Liberal, Kansas. A custody transfer meter is located in the compression facility owned and operated by CapturePoint. The purchased CO_2 from the fermentation process is transported via a United States Department of Transportation (DOT) regulated pipeline to the CFA. A totalizer meter, for the purchased CO_2, is located in the field where instantaneous data is summed into a 24-hour flow rate which is recorded. A totalizer meter is a meter approved by the American Gas Association (AGA) Report #3 to measure the flowrate of gases. The actual measurements taken are temperature, line pressure, and differential pressure across the meter. Gas produced, which contains recycled CO_2, from the wells is compressed and metered by a similar totalizer meter as the purchase CO_2 meter and is recorded daily.

CapturePoint currently has seven active injection manifolds and approximately 29 active injection wells that the CO_2 is distributed through. When the MRV plan becomes active, the daily injection volume of the combined purchased CO_2 and recycled CO_2 will be approximately 24 MMCFD. Of this volume 12 MMCFD is purchased CO_2 and 12 MMCFD is recycled CO_2. This ratio of purchased CO_2 to recycled CO_2 is expected to change over time, with the percentage of recycled CO_2 increasing and purchased CO_2 decreasing. The current reservoir management plan projects that CO_2 purchases will remain constant at 12 MMCFD for 12 years and cease after 2034. A reservoir management plan is an integrated process using various surveillance techniques, economic evaluations, and accepted petroleum technical practices to efficiently operate enhanced oil recovery projects.

The seven injection manifolds currently in the field distribute the CO_2 to the field. These manifolds have valves to switch to water when the time is called for. Depending on the reservoir management plan, the WAG cycle will be adjusted to maximize oil recovery and minimize CO_2 utilization in each injection pattern. At each injection well pad there is a totalizer to measure the volumes injected every 24 hours. This data is collected daily by the field personnel and input into the data warehouse to be allocated for the pattern injection.

The two totalizer meters as described above will be used to determine the total volume injected used in section 7 for the mass balance equations necessary to determine annual and cumulative volumes of the stored CO_2.

2.3.2 Produced Fluids Handling

As injected CO_2 and water migrate through the reservoir; a mixture of oil, gas, and water (referred to as "produced fluids") flows to the production wells. Gathering lines bring the produced fluids from each production well to the AWT sites. CapturePoint has approximately 32 active production wells producing at any time. Each AWT has two separators. The first separator is used for testing individual wells to separate the gas, oil, and water produced from an individual well. This gas, oil, and water is subsequently measured and recorded for the well. Each producing well is production tested every 30 to 60 days after the last production test, or after the well is returned to production. Depending on the reservoir management plan, well testing can be more frequent to obtain data. The second separator is used to separate the gas from the oil/water mixture from the other wells producing into the AWT, and the gas and liquids are displaced from the vessel in separate lines. Leaving the AWT sites are two lines transporting produced fluids. One line is used for the liquid phase, a mixture of oil and water, and one line is used for the gas phase. However, the AWT in NPU does not transfer oil or gas to the CTB, it only transfers gas while reinjecting water with pumps at the NPU AWT and sells oil at the NPU AWT.

When gas and liquid lines enter the CTB, a series of vessels separate the oil, gas, and water to be accounted for and distributed for sales or reinjected. The liquid phase line has vessels to separate the oil from the water using density and residence time. The gas phase vessels collect any free liquids entrained with the gas. These free liquids are then combined back into the liquid phase line. All gas and water are reinjected, and the oil, which contains an estimated 2,360 ppm CO_2 (0.236%) for CU and 4,540 ppm CO_2 (0.454%) for NPU, is sold out of tanks. Annually, the oil from the stock tank is analyzed by a laboratory using ASTM crude oil analysis methods to determine the CO_2 content in the oil being sold.

After separation, the gas phase, which is approximately 92-95% CO_2, is mixed with reservoir volatile components, compressed, and distributed throughout the high-pressure distribution system using reciprocal compression and high-pressure horizontal pumps.

The water is transferred from the separation vessels to tanks for reinjection. After the water is conditioned, it is either reinjected at the WAG skids or disposed of into permitted disposal wells. Although CapturePoint is not required to determine or report the amount of dissolved CO_2 in the water as it is reinjected into the ground and not emitted to the atmosphere. The analyses have shown the water typically contains <690 ppm (0.069%) CO_2.

CFA production has trace amounts of hydrogen sulfide (H_2S), which is toxic. There are approximately 8-10 workers on the ground in the CFA at any given time, and all field and contractor personnel are always required to wear H_2S detectors. The primary purpose of the H_2S detectors is protecting people from the risk of being harmed. The detection limit of the H_2S detectors is quantified for readings in the range of 0-100 ppm and will sound an alarm above 10 ppm. The secondary purpose of the H_2S detectors would be to provide an indication of emissions of gas from a pipeline or surface equipment, that might go unnoticed by other observations or measurements. No gas volumes can be calculated based on the detector reading or alarm; only a H_2S leakage is detected and located. Once identified, a further response will be initiated and CO_2 volumes will be quantified as discussed in sections 4.5, 4.6, 5.4, and 8.1.5 of this MRV plan.

2.3.3 Produced Gas Handling

Produced gas separated at the CTB is stripped by a series of vessels of entrained and free water. The water content has been recorded to be < 20 pounds mass per MMCF, thus dehydration is not necessary. The gas is then sent to a centralized compression system to be compressed and placed in the high-pressure distribution system. This compression turns the CO_2 into a variable density liquid, which is then transported out via high pressure lines to the AWT sites where a manifold splits this dense CO_2 to the wells that are on CO_2 injection at that time.

2.3.4 Facilities Locations

The locations of the AWT sites are positioned in the field to access both injection distribution and production gathering. The CTB is where the final separation and injection equipment is maintained and operated. The water injection station is where the horizontal pumps are located to reinject the produced brine.

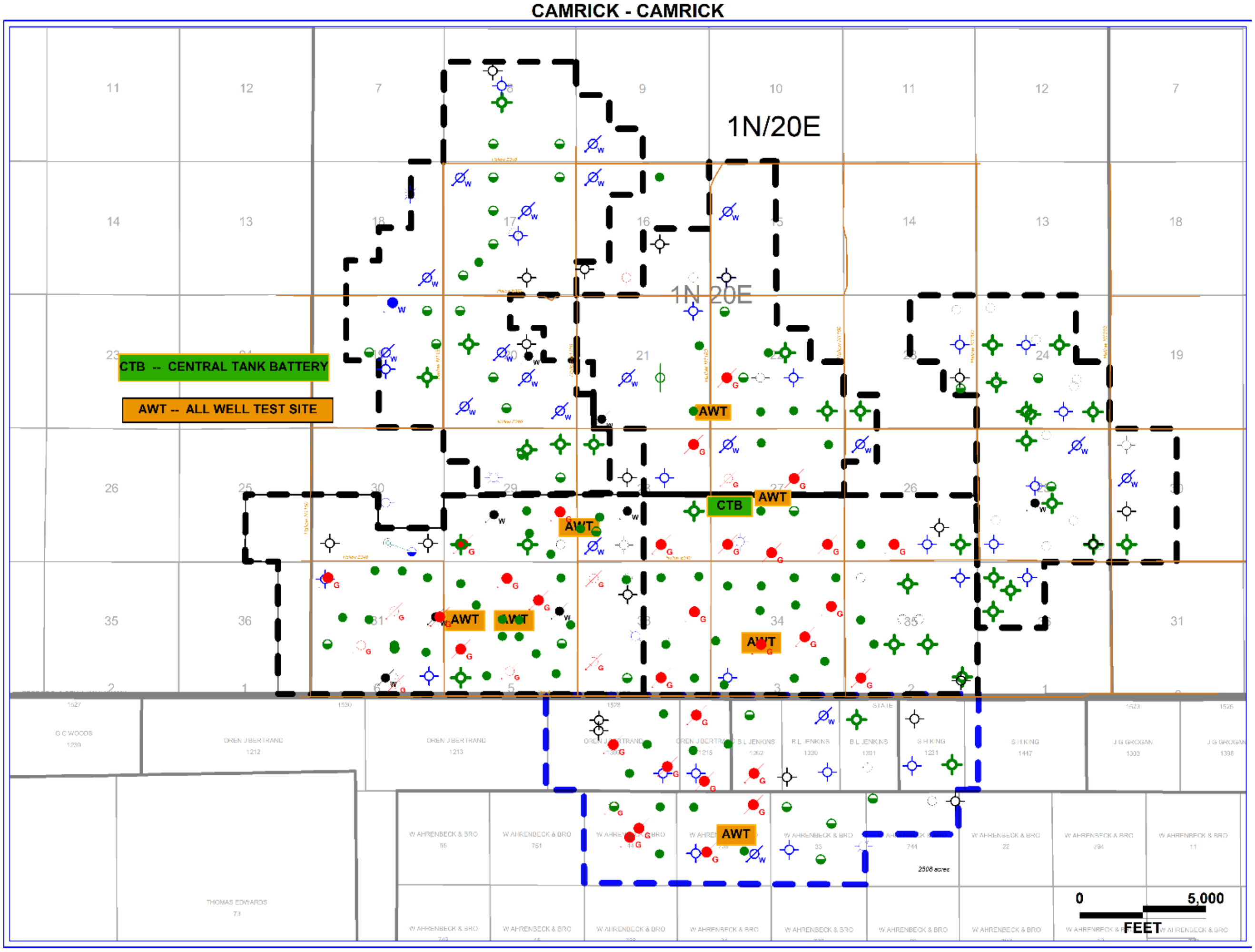


Figure 2.3-2. Location of AWT sites and CTB in the CFA

2.3.5 Water Conditioning and Injection

Produced water collected at the CTB is collected in a series of vessels and tanks in a cascade system. This allows any entrained oil to further separate to the top of the tanks because of the density difference. This oil is skimmed off and put back in the oil separation system. The clean water is then transferred to the water injection system where it is boosted in pressure and sent out to the AWT sites for distribution to all wells that are currently on water injection.

2.3.6 Well Operation and Permitting

The OCC and TRRC rules (Appendix 2) govern well location, construction, operation, maintenance, and plugging for all wells in permitted units and wells. CapturePoint follows these rules and regulations to maintain safe and efficient operations. This includes complying with all current and updated information for mechanical integrity testing, well repairs for injection wells, drilling and completion, permitting, and reporting.

Briefly, the following bulleted list is what the current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface waters.
- That wells file a completion report including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore).
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.
- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location, and setting of plugs.

2.3.7 Number, Location, and Depth of Wells

CapturePoint's CFA injection wells are listed in Appendix 1. Injection is into the Upper Morrowan, a lenticular bedded sandstone trending northwest to southeast with the average top of sand at 7,250 feet, true vertical depth. The Upper Morrowan is described in section 2.2.2.1 above.

2.4 Reservoir Characterization

2.4.1 Reservoir Description

The target reservoir CFA Morrow B is a sandstone formation overlain by the Morrow shale and the Thirteen Finger limestone, which serve as excellent seals for injected CO_2 as determined by Farnsworth data (Ampomah et al., 2016a). The Morrow B sandstone reservoir is at a depth between 6,800 feet and 7,600 feet subsurface with an average dip of less than one degree (Figure 2.4-1). The productive limit of the CFA is about 80 to 90 percent of the total operated surface acreage, which is 14,652.315 acres. The maximum pay thickness is 56 feet with an average of 15 feet and does diminish to zero in spots.

The CFA is approximately eight miles by seven miles with areas that exhibit different reservoir behavior. The southwest portion of CU was most prolific oil producing area of the CFA under primary and secondary production; whereas the western portion of NPU is now responding to CO_2 better than historical operations would have indicated.

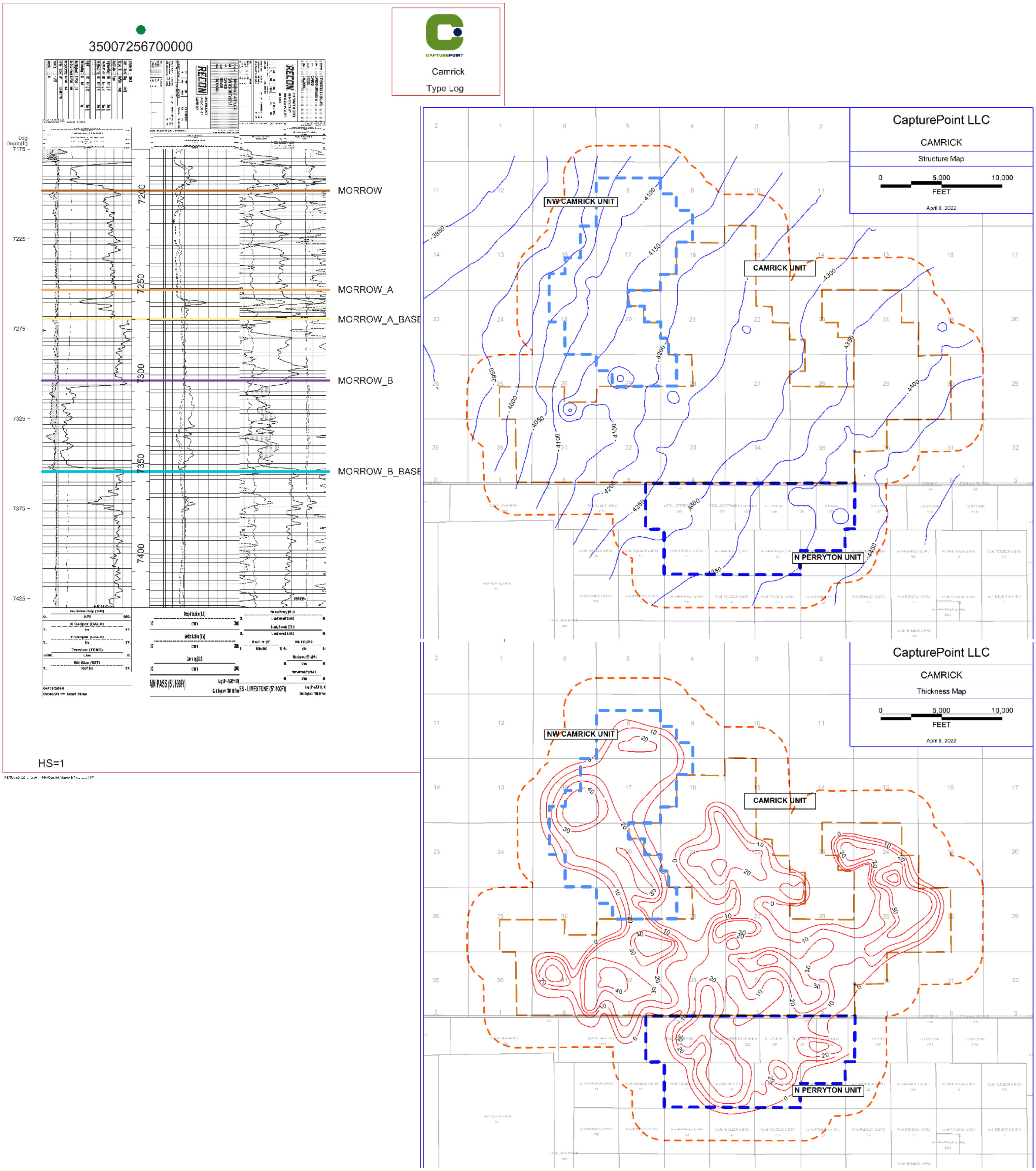


Figure 2.4-1. (Left) Type log of CFA caprock and reservoir, (Upper Right) Surface contour of Morrow top, (Lower Right) Thickness map of Morrow sands.

2.4.2 Reservoir Fluid Modeling

The compositional fluid model was constructed for the CapturePoint operated Farnsworth Unit. From laboratory compositional analysis an equation of state was tuned (Gunda et al., 2015). The minimum miscibility pressure (MMP) experiment was then simulated using a one-dimensional model (Figure 2.4.3). The simulated Farnworth Unit MMP of 4,009 psia compared to an MMP value of 4,200 psia derived from laboratory experiments provided by the operator represents a less than 5% error (Gunda et al., 2015).

The reservoir temperature in the CFA is 152 degrees Fahrenheit or 16 degrees lower than the temperature at Farnsworth Unit of 168 degrees. Using parameters of the Alston empirical correlation (1985), the MMP would be 170 psia lower at the CFA or 3,510 psia compared to 3,680 psia at the Farnsworth Unit (Figure 2.4.4).

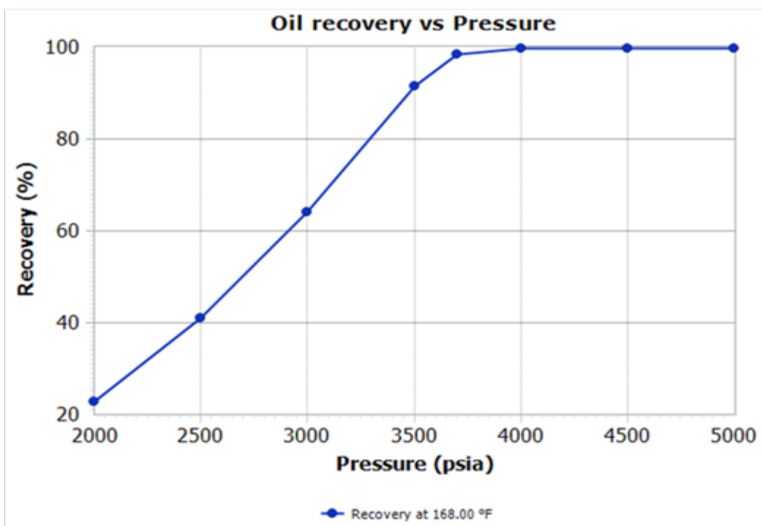


Figure 2.4-4. Oil recovery plot for 1D slim tube test for Farnsworth Unit.

2.4.3 CO_2 Analogy Field Study

Based on similar geologic, petrophysical, engineering, and operational parameters between the Farnsworth Unit and the CFA, the oil recovery performance of both fields is expected to be similar. Due to the stratigraphic nature of the Morrow channel sands, the potential movement of CO_2 is severely limited. The CFA area has contained the free phase CO_2 plume in a very confined area since March 2001 as exhibited by oil, water, and CO_2 recovery performance. Also, during CFA drilling and production operations, no reports exist which would indicate any plume has moved outside of the MMA. The Farnsworth Unit MRV and the CFA data justifies the conclusion that CO_2 will continue to be contained inside the MMA at the end of the CO_2 injection year t + 5, per §98.449 definitions.

2.4.4 CO_2 – EOR Performance Projections

For years, the oil industry has used dimensionless equations to predict the amount of oil that can be recovered using CO_2 for flooding oil reservoirs (Lee et al, 2018, Stell 2010). The

amount of oil recovered from projects is plotted as a decimal fraction of the original-oil-in-place versus the decimal fraction of the hydrocarbon pore volume (HPV) of CO_2 injected into the oil reservoir as measured in reservoir barrels (RB).

The CFA has been injecting CO_2 since March 2001. The dimensionless curves were matched to historical performance through early 2020 (Figure 2.4.5). The supply of CO_2 was curtailed from March 2020 until present, due to oil price uncertainty, and will resume after the Arkalon Plant upgrade that will be finished in the 4th quarter of 2022.

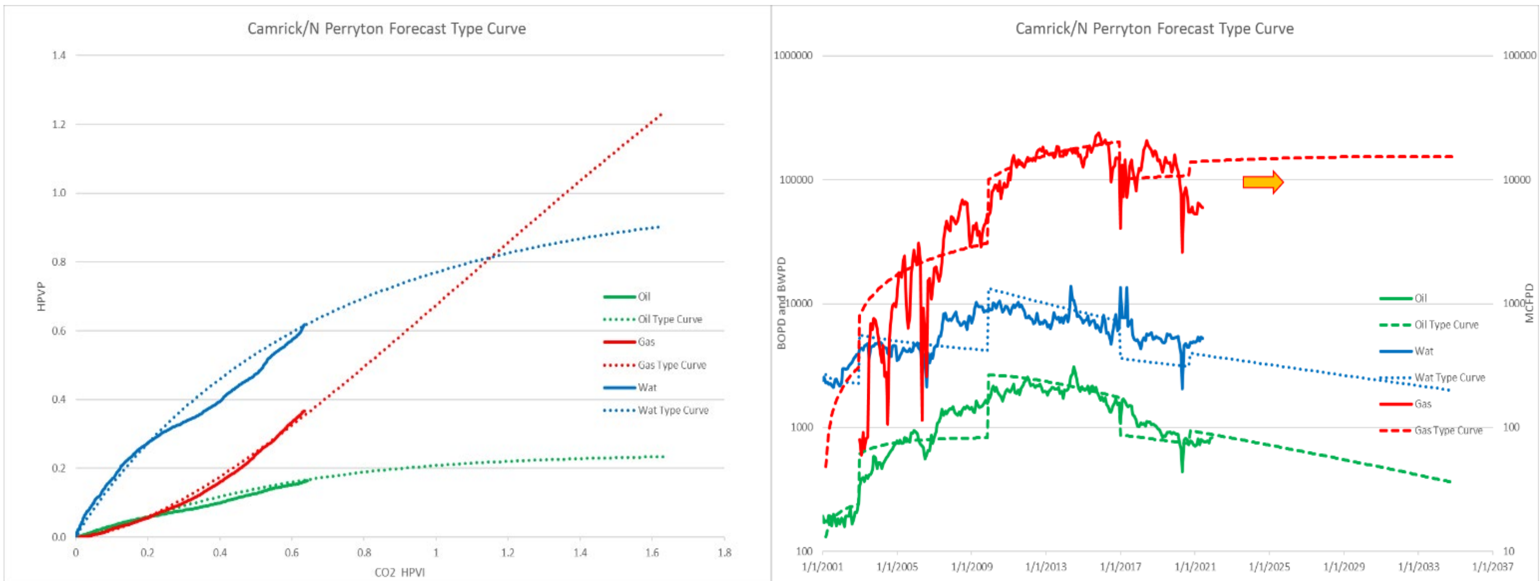


Figure 2.4-5. Dimensionless curves for CO_2 injection (left) with rate time curves (right).

The dimensionless water oil ratio and the gas oil ratio trends (Figure 2.4.6) for the CFA flooded acreage are very similar to what was forecasted by simulation in the Farnsworth Field as expected because of the porosity, permeability, and sand similarities.

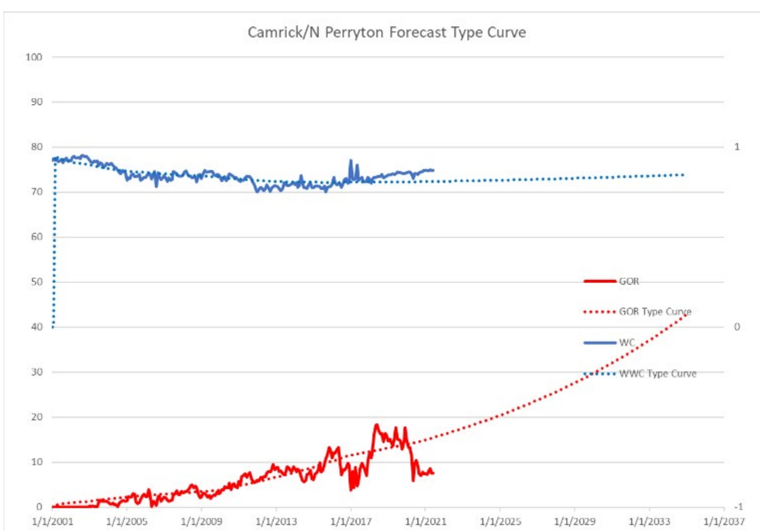


Figure 2.4-6. Dimensionless water cut and GOR vs. observed EOR data.

The CO_2 storage volumes for Arkalon fermentation CO_2 were also forecasted (Figure 2.4.7) using the same dimensionless technique. This technique indicates that the flooded acreage still has significant additional storage potential. The maximum CO_2 storage is limited to the amount of space available by the removal of the produced hydrocarbon. The projection indicates that there is pore space available to store approximately 0.4 to 0.5 decimal fraction of HPV amounting to 30 to 40 MMB.

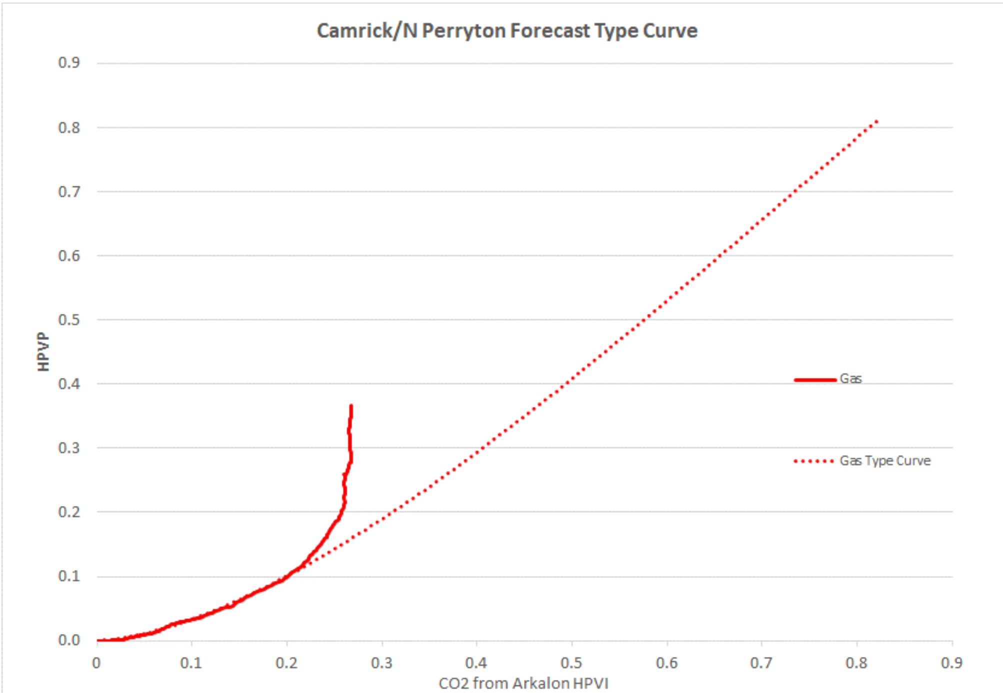


Figure 2.4-7. Dimensionless CO_2 Fermentation Curves

The barrels of reservoir volume were converted to standard cubic feet of gas and is displayed in the CFA Purchase CO_2, or Fermentation CO_2, vs Time chart (Figure 2.4.8).

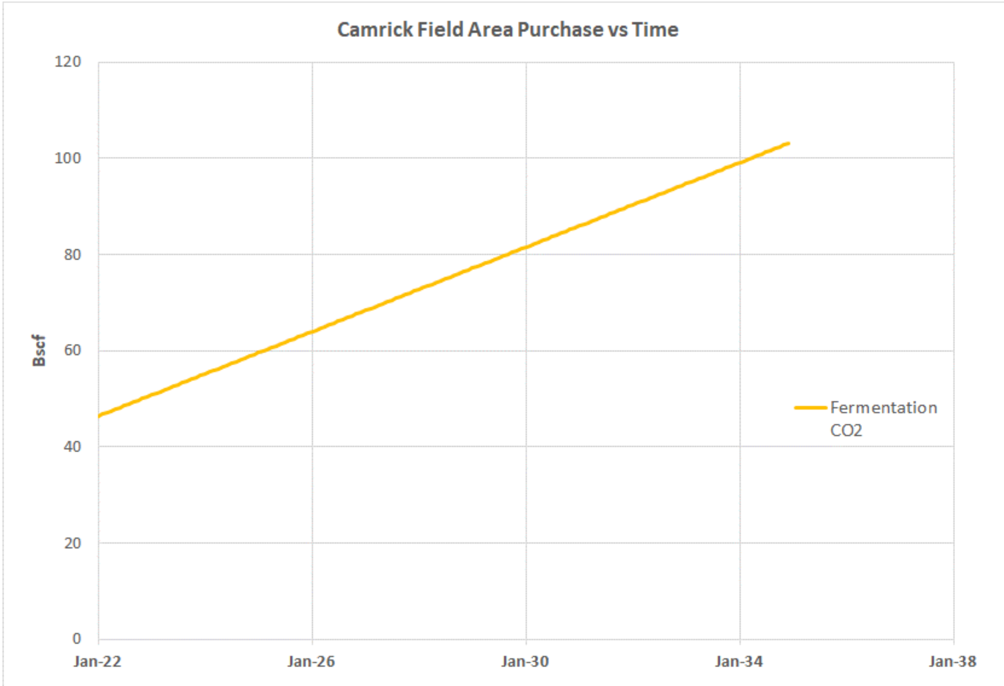


Figure 2.4-8. CO_2 Fermentation Volume.

3 Delineation of Monitoring Area

3.1 MMA

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The purchase volumes that are displayed in figure 2.4.7 were mapped and are displayed in Section 3.1.1 indicates that CO_2 storage pore space is available, barring unforeseen future operational issues. Therefore, CapturePoint is defining the MMA as the boundary of the CFA plus an additional one-half mile buffer zone. This will allow for operational expansion throughout the CFA for the next 12 years, the anticipated life of the project.

3.1.1 Determination of Storage Volumes

Figure 3.1-1 displays wells that have CO_2 retention on the 4,800 acres that have been under EOR injection in the CFA since project initialization. The volume of the oil recovered since August 1955, resulted in a voidage space of 36 MMscf of CO_2 per acre of surface area that was later filled with water during waterflood. The average decimal fraction of CO_2 injection to hydrocarbon pore volume left in the ground after accounting for CO_2 production through 2021 is 0.29. The lateral extent of CO_2 in the injection zone or the CO_2 storage radius for each well was estimated based on cumulative CO_2 injected times the decimal fraction of CO_2 remaining divided by the voidage space. The largest CO_2 storage areas are around wells that injected CO_2 for the most years.

Figure 3.1.2 displays the potential area of the reservoir that can be filled with CO_2 with the existing injection wells. This assumed that only 78 percent of the average injection pattern area or 80 acres could be filled. There are 49 injectors identified for further injection that have room for an additional 90 Bscf of CO_2 storage volume or 140 Bscf total storage.

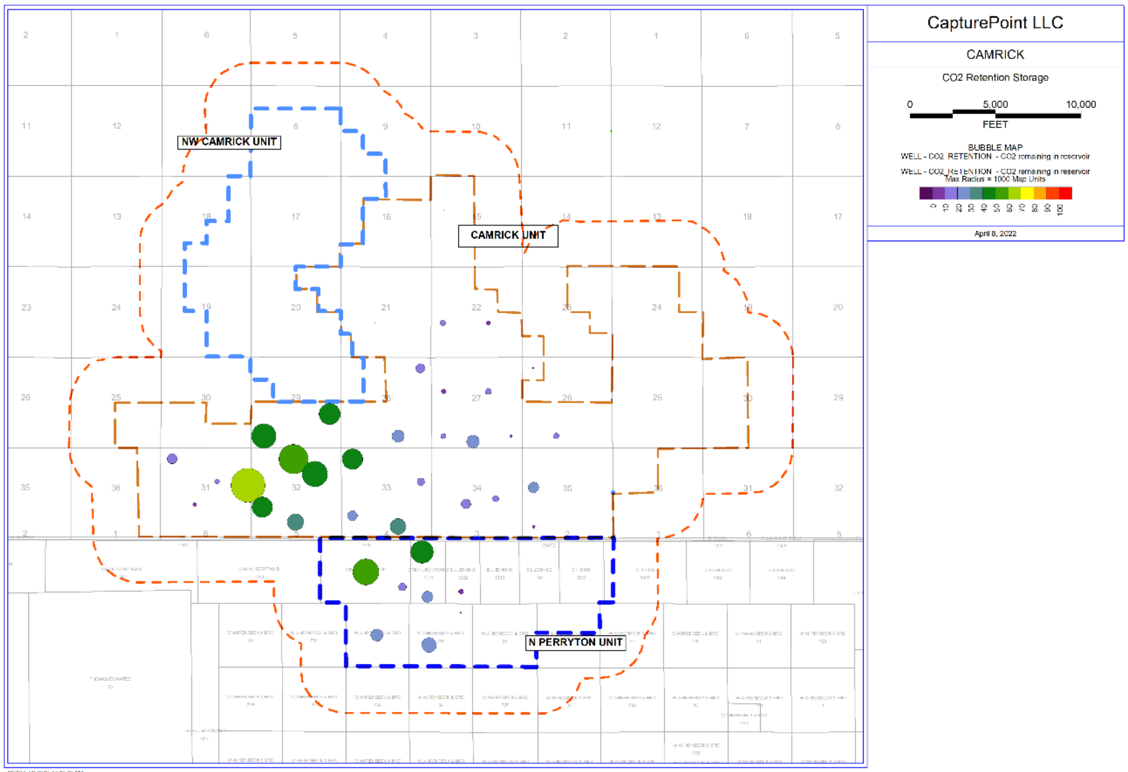


Figure 3.1.1. Estimated CO_2 storage as of 2021 in CFA.

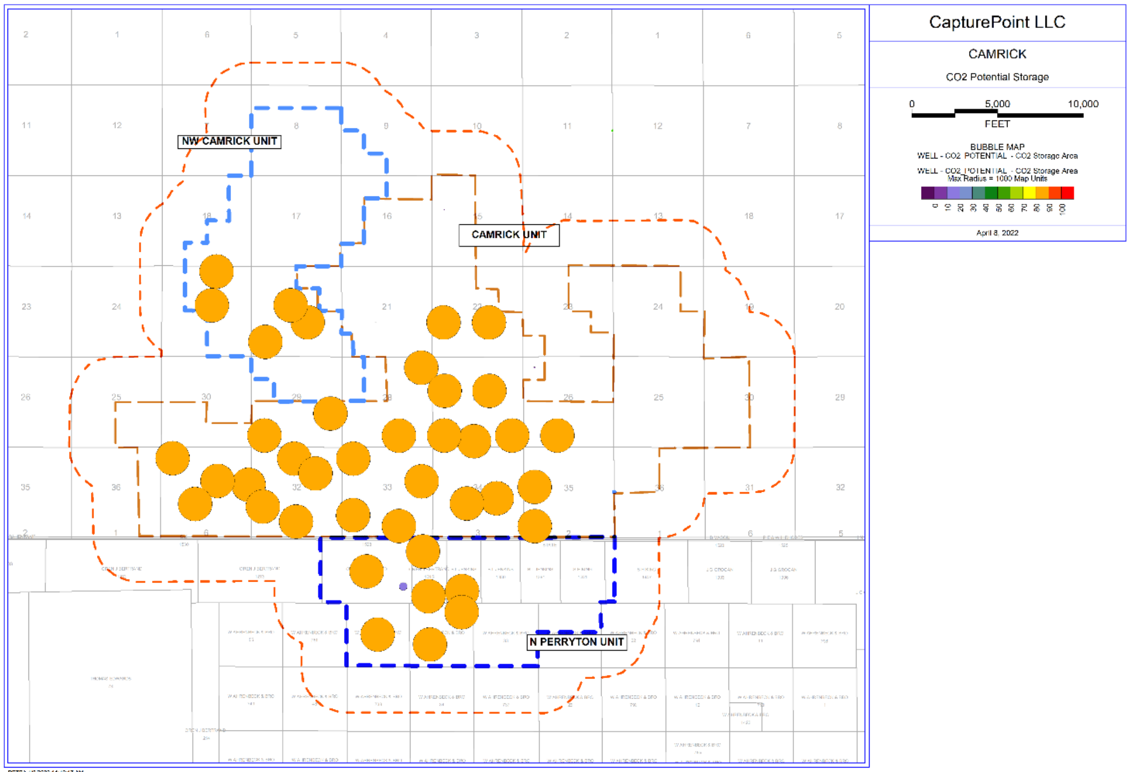


Figure 3.1.2. Potential Total CO_2 Storage in the CFA.

3.1.2 Determination of Buffer Zone

CapturePoint intends to implement a buffer zone of one-half mile around the CFA, the minimum required by Subpart RR, because the site characterization of the Morrow did not reveal any leakage pathways that would allow free-phase CO_2 to migrate laterally thereby warranting a buffer zone greater than one-half mile.

3.2 AMA

Currently, CapturePoint's operations are focused on the western portion of the CFA. However, it is anticipated as the project develops, additional activity will occur in the NWCU of the CFA; therefore, requiring active monitoring in that area. However, project development is driven by the market price of oil so CapturePoint is unable to provide a specific time in the future when the eastern portion of the CFA will be actively monitored. Therefore, for the purposes of this MRV plan, CapturePoint has chosen to include the entire CFA in the AMA.

4 Identification and Evaluation of Leakage Pathways

Since its discovery in 1955, the unitization of the different units from 1969 to 1972, and the commencement of CO_2 EOR in 2001; the CFA is an analogous field to the Farnsworth Unit, which has undergone extensive investigation and documentation as indicated in Section 2. From this body of work, CapturePoint has identified the following potential pathways of CO_2 leakage to the surface. This section will also address detection, verification, and quantification of leakage from each pathway.

4.1 Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO_2 EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment via personnel instructed on how to detect surface leaks and other equipment failure minimizes releases. In addition, the Oil and Gas Division requirements of the OAC rules of the OCC and the TAC rules of the TRRC to report and quantify leaks, both serve to minimize leakage of GHG from surface equipment. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. As described in Section 6.4 below, should leakage from surface equipment occur it will be quantified according to the procedures in Subpart W of the GHGRP.

4.2 Leakage from Wells

CapturePoint has identified 68 abandoned wells, 49 injection wells (29 active) and 94 production wells (59 active) within the MMA and assessed their potential for leakage of CO_2 to the surface as listed in Appendix 1.

4.2.1 Abandoned Wells

Figure 4.2-1 shows all wells plugged and abandoned in the CFA. Because the CFA was unitized in 1969 to 1972, all plugging and abandonment activities of wells within the CFA have been conducted under the regulations of the OCC and the TRRC for plugging wells. The cement used to plug wells when exposed to CO_2 will form colloidal gels that further reduce any flow. CapturePoint concludes that leakage of CO_2 to the surface through abandoned wells is unlikely. However, strategies for leak detection are in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

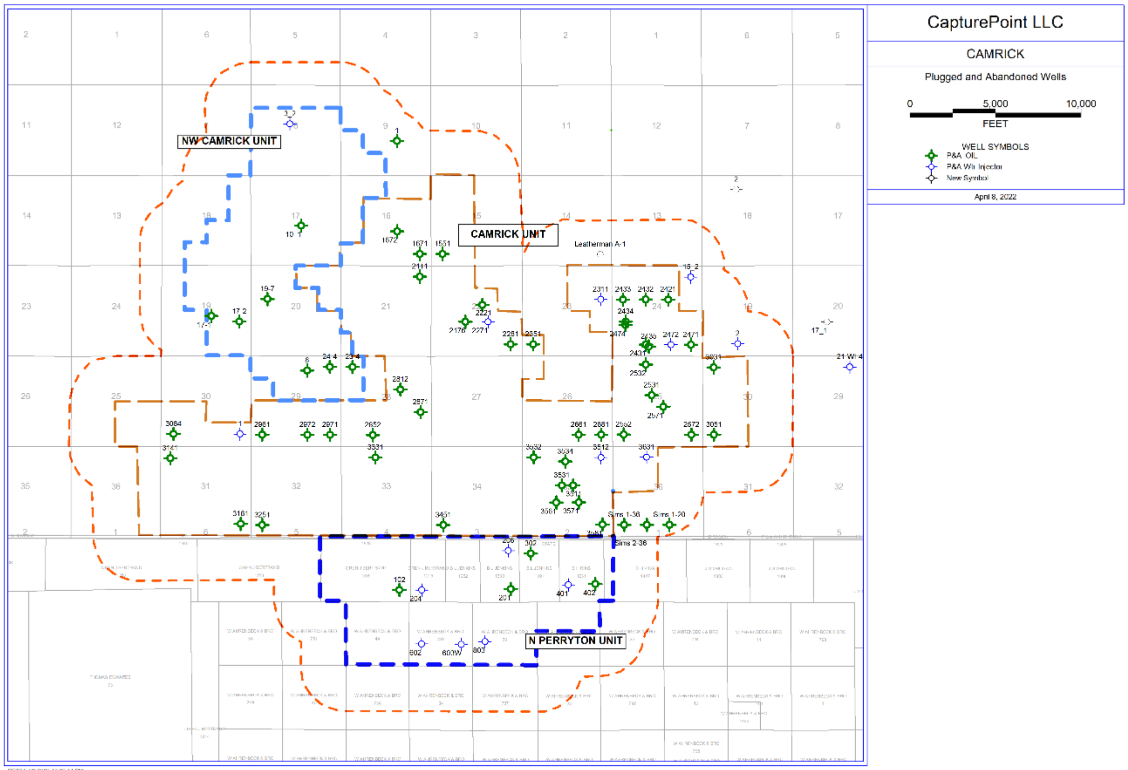
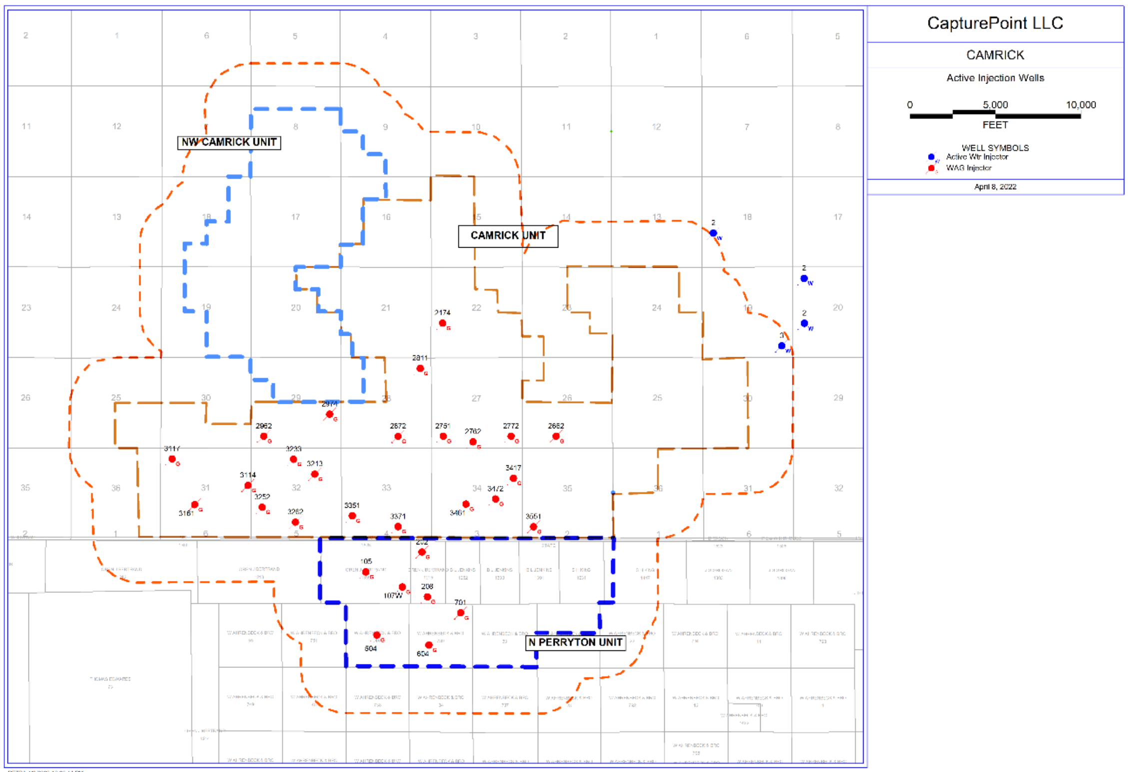


Figure 4.2-1. Plugged and Abandoned Wells in the CFA.

4.2.2 Injection Wells

Mechanical integrity testing (MIT) is an essential requirement of the UIC program in demonstrating that injection wells themselves do not act as conduits for leakage into underground sources of drinking water (USDW) and to the surface environment. TRRC Rule 46 requirements include special equipment requirements (e.g., tubing and packer) and modification; records maintenance; monitoring and reporting; testing; plugging; and penalties for violations of the rule. Permit revocation may result as a consequence of noncompliance. (See Section 2.3.6) The TRRC and the OCC detail all the requirements for the Class II permits issued to CapturePoint. These rules ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Figure 4.2-2 shows the active injection wells in the CFA. CapturePoint concludes that leakage of CO_2 to the surface through active injection wells is unlikely.



4.2-2. Active Injection Wells in the CFA.

4.2.3 Production Wells

Figure 4.2-3 shows the active oil production wells in the CFA. Once EOR operations commence, the energy content of the produced gas drops and cannot be sold; therefore, no gas wells are identified. However, as the project develops in the CFA additional production wells may be added and will be constructed according to the relevant rules of the OCC and the TRRC. Additionally, inactive wells may become active according to the rules of the OCC and the TRRC.

During production, oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure where the bottom hole wellbore pressure is less than the reservoir pressure. These lower pressure fluids, which also contains CO_2, are contained by the casing, tubing, wellhead, and flowline all the way to the CTB. CapturePoint concludes that leakage of CO_2 to the surface through production wells is unlikely.

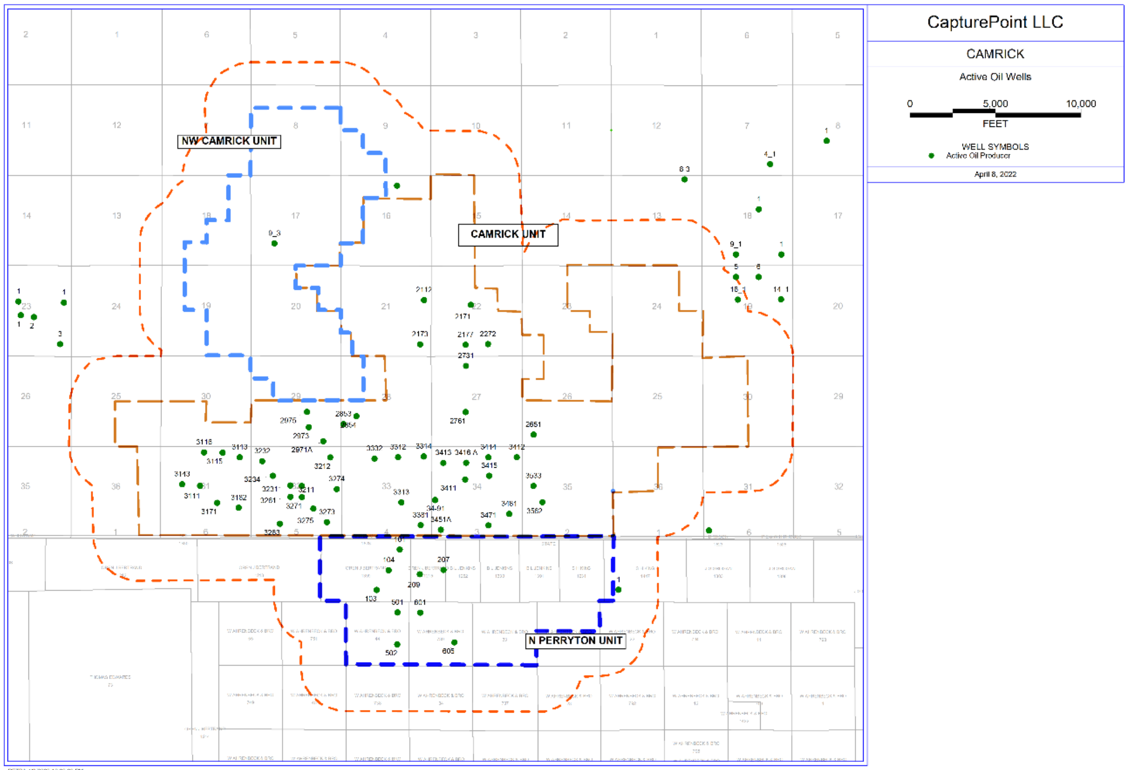


Figure 4.2-3. Active Oil Production Wells in the CFA.

4.2.4 Inactive Wells

Figure 4.2-4 shows all of the inactive wells in the CFA. The OCC has regulations for temporally abandoned/not plugged (TA) and terminated order wells/UIC not plugged (TM) and likewise the TRRC has regulations for inactive wells.

Inactive wells have a cast iron bridge plug set or long cement plugs placed above the existing perforations to isolate reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. CapturePoint concludes that leakage of CO_2 to the surface through inactive wells is unlikely.

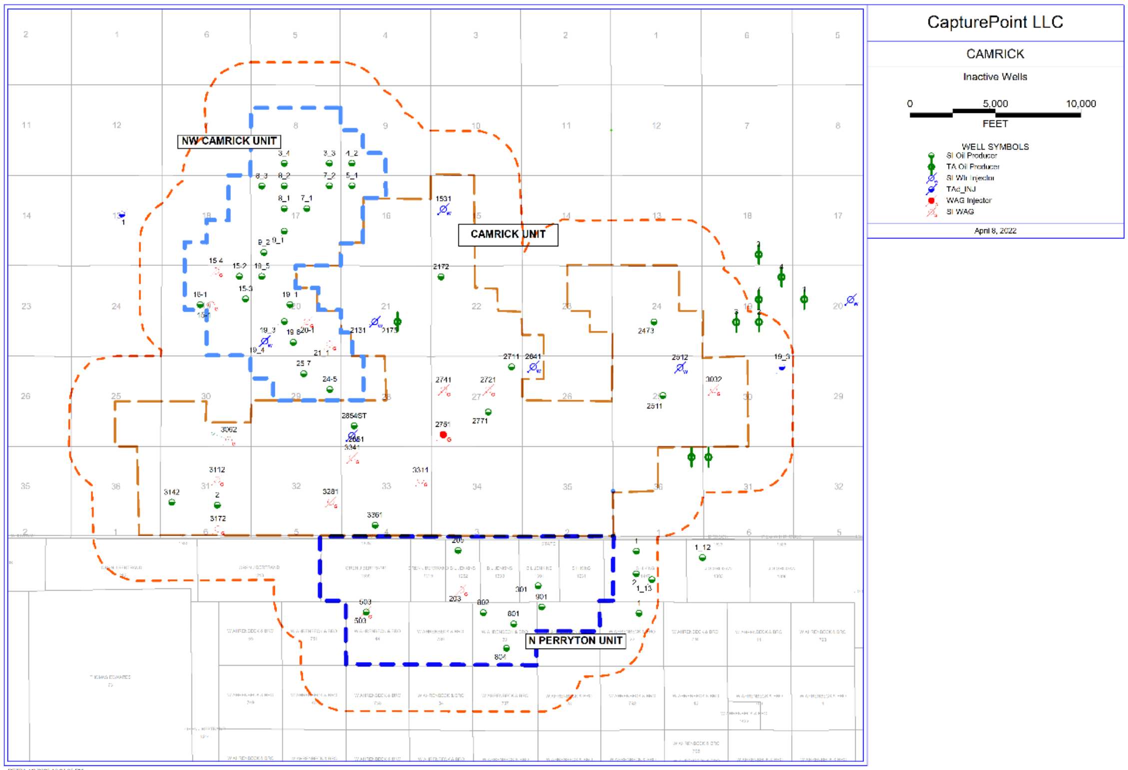


Figure 4.2-4. Inactive wells in the CFA

4.2.5 New Wells

As the project develops, new production wells and injection wells may be added to the CFA. All new wells will be constructed according to the relevant rules for the OCC and the TRRC which ensure protection of subsurface and surface resources, and the environment.

All wells in Oklahoma oilfields and all wells in Texas oilfields, including both injection and production wells, are regulated by the OCC and the TRRC, respectively, which has primacy to implement the UIC Class II programs.

Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Briefly current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface water.
- That wells file a completion report including basic electric logs.
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.

- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.

New well construction is based on existing best practices, established during the drilling of existing wells in CFA and follows the OCC and the TRRC rules, which significantly limits any potential leakage from well pathways. Additionally, the existing wells followed the OCC and the TRRC rules.

In public databases, the area of CFA plus one mile past the unit boundary contains over 100 wells that were drilled deeper than the Morrow formation and none of these wells were productive in reservoirs deeper than the Morrow. Therefore, it is very unlikely that anyone will ever drill through the AMA reservoir in the future. In the event a well is drilled within the AMA, the operator would be required to follow all the OCC and the TRRC rules and procedures in the drilling the well and the potential for leakage would be similar to any well that CapturePoint drills within the AMA. In addition, CapturePoint's visual inspection process during routine field operation will identify any unapproved drilling activity in the CFA.

4.3 Leakage from Faults and Bedding Plane Partings

Primary seals at CFA have been demonstrated to be mechanically very competent (see Section 2.2.2), thus the main concern of CO_2 migration at CFA is via seal bypass systems along fracture networks. The following lines of analysis have been used to assess this risk in the area.

4.3.1 Prescence of Hydrocarbons

The first and foremost argument against present day up-fault transmissibility is the 75 MMB of oil that was found trapped in the reservoir. If significant escape pathways existed, oil would have drained from the reservoir prior to the current day.

4.3.2 Fracture analysis

At the CFA, the work done at the Farnsworth Unit is analagous, where small aperture fractures were noted but not common in most of the reservoir cores examined but most of these fractures appear to be drilling induced. Fractures in the Thirteen Finger limestone caprock were described using an industry-standard format for fracture class type, orientation, fracture dip, type of mineral fill, fracture porosity, fracture spacing, and intensity. Again, drilling induced fractures are most common. Natural mineral-filled fractures are quite rare, were formed during diagenesis at shallow depths, and are of late Carboniferous age. Unless significantly damaged by large changes in reservoir pressure, they are highly unlikely to provide migration pathways.

In the unlikely event CO_2 leakage occurs as a result of leakage through the faults and fractures, it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.4 Lateral Fluid Movement

The Morrow strata in the Oklahoma and Texas Panhandle was primarily a deltaic sequence that prograded toward the southeast, resulting in deposition of mainly shales with lenticular, discontinuous coarse sandstones separated with very fine sandstone, minor conglomerates, and shale. The likelihood of any extensive migration of fluid outside of the AMA is very low.

Since CO_2 is lighter than the water remaining in the reservoir, it will migrate to the top of each lenticular structure as it is filled. The producing wells, which create low pressure points in the field, will drain the water and keep the CO_2 within each discontinuous sandstone.

4.5 Leakage through Confining/Seal system

At the CFA, the work done at the Farnsworth Unit will apply, where a variety of analytical methods were used for caprock (confining system) analysis, and the results should be the same for the CFA. Petrologic examination included standard thin section petrography and backscattered electron microscopy. Petrophysical analytical methods include retort analysis, pulse-decay permeability measurement, pressure decay permeability analysis for tight rocks, and mercury injection porosimetry, which is also known as mercury injection capillary pressure (MICP). Geomechanical analysis involved a standard series of mechanical tests: Brazil tension, unconfined compression, triaxial compression, and multi-stress compression.

Results of the MICP analysis show that the mudstone lithologies in the Morrow Shale and Thirteen Finger Limestone can support CO_2 column heights of ~1,000 to 10,000 feet. At an order of magnitude over the thickness of the Morrow reservoir, this should prove an effective seal for CO_2 storage in the Morrow B injection horizon.

Failure analyses show that the Morrow B sands are weaker than overlying lithologies, so that any fracture initiation around the injection well would not be expected to propagate into the overlying sealing units. Mechanical properties of the overlying shale and limestones provide an interesting and effective combination of strength and elasticity. Limestone layers are strong but brittle, while the shale layers are weaker but sufficiently ductile to prevent extensive fracture propagation.

It is unlikely for hydrocarbon migration pathways that charged the Morrow reservoir to be potential CO_2 migration pathways via primary pore networks today. Any potential CO_2 migration would be most likely due to leakage from wellbores or bypass through fault and fracture networks, discussed in Sections 4.2 and 4.3.

In the unlikely event CO_2 leakage occurs as a result of leakage through the confining seal it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.6 Natural and Induced Seismic Activity

Figure 4.6 shows the map of earthquakes with magnitudes measured at greater than 2.5 as defined by the United States Geological Survey (USGS). While past earthquake data cannot predict future earthquakes, the small number of events near CFA after the waterflood operations were initiated in 1969 implies the area is not seismically sensitive to injection. Also, no documentation exists that any of the distant earthquake events caused a disruption in injectivity or damage to any of the wellbores in CFA.

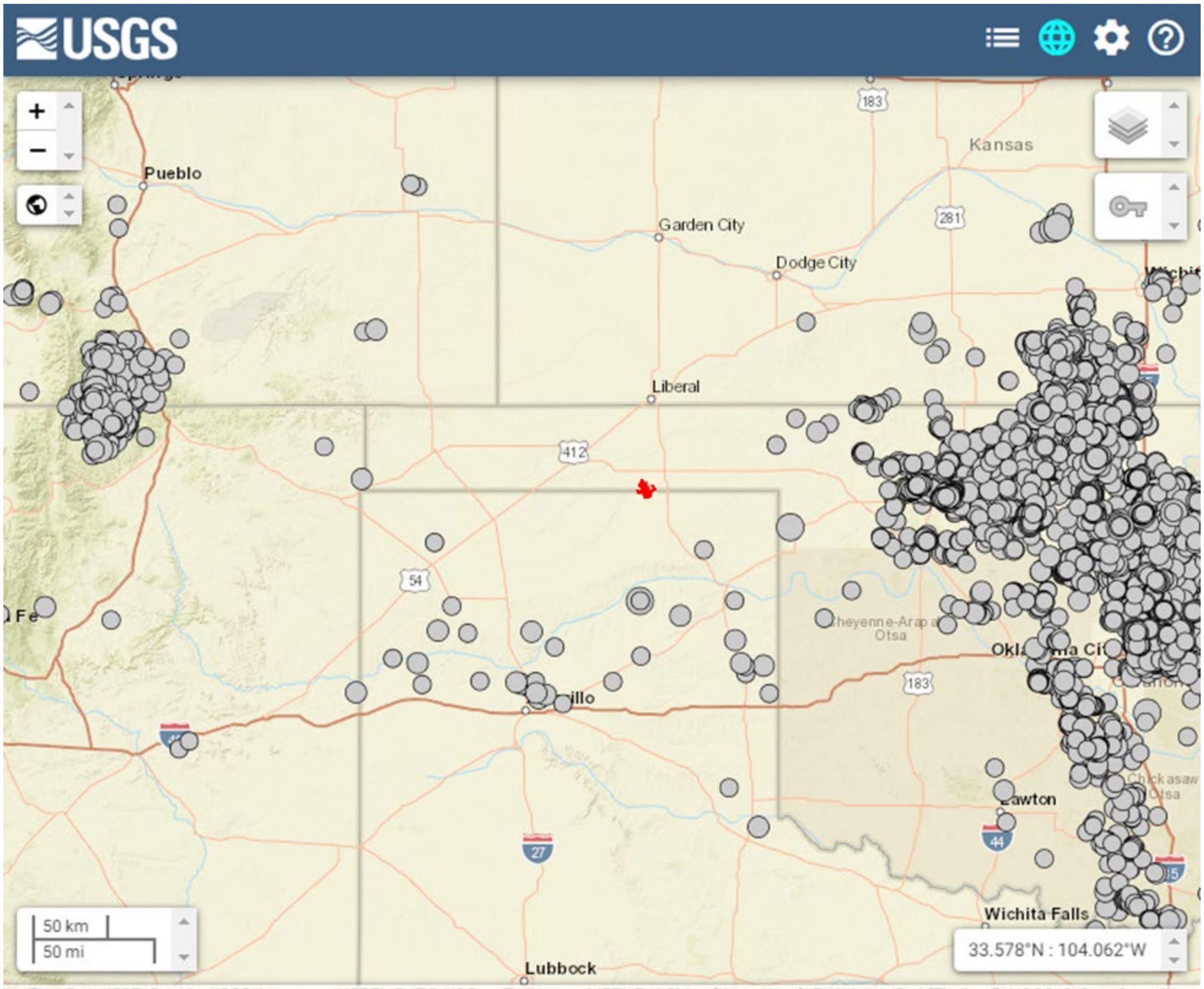


Figure 4.6. USGS earthquakes (+2.5 magnitude) for last 40 years with CFA highlighted red.

There is no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the CFA.

In the unlikely event that induced seismicity resulted in a pathway for material amounts of CO_2 to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would lead to further investigation.

4.7 Strategy for Detection and Response to 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 (well bores), and unique events such as induced fractures. Table 1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks,

CapturePoint's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO_2 losses discussed in the table are identified by type. Once the type is reported to a response manager the correct resources and personnel can be mobilized to develop the optimal response procedure. The procedure will address and mitigate further CO_2 leakage.

Table 1 Response Plan for CO_2 Loss

Known Potential Leakage Risks	Monitoring Methods and Frequency	Anticipated Response Plan
Tubing Leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days
Casing Leak	Weekly field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days
Wellhead Leak	Weekly field inspection	Workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations (weekly inspection but field personnel present daily)	Maintain well kill procedures
Unplanned wells drilled through Morrow	Weekly field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Re-enter and reseal abandoned wells
Pumps, values, etc.	Weekly field inspection	Workover crews respond within days
Leakage along faults	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near faults
Leakage laterally	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Fluid management along lease lines
Leakage through induced fractures	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near seismic event

4.8 Strategy for Quantifying CO_2 loss

Major CO_2 losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. CapturePoint will use Subpart W techniques to estimate leakages only on equipment and ensure those results are consistently represented in the Subpart RR report. Any event-driven leakage quantification reported in Subpart RR for surface leaks will use other techniques.

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 CO_2 that would be most appropriate. In the event leakage occurs, CapturePoint will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission.

Any volume of CO_2 detected leaking to the 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, CapturePoint's field experience, and other factors such as the frequency of inspection. As indicated in Section 6.4, leaks will be documented, and the records of leakage events will be retained in the electronic environmental documentation and reporting system.

Available studies of actual well leaks and natural analogs (e.g., naturally occurring CO_2 geysers) suggest that the amount released from routine leaks would be small as compared to the amount of CO_2 that would remain stored in the formation.

5 Strategy for Determining CO_2 Baselines for CO_2 Monitoring

Atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values for soil measurement in the CFA area, per the characterization, monitoring and well data collected by the Southwest Regional Partnership on Carbon Sequestration (SWP) in the analogous Farnsworth Unit.

5.1 Site Characterization and Monitoring

As described in Sections 2.2.2 and 2.4, the Morrow B sandstone is isolated both above and below by shale units of the Morrow. The primary seal consists of 180 – 200 ft of Morrow shale and Thirteen Finger Limestone which in turn is overlain by over a thousand feet of younger shale and limestone. These units provide a suitable seal to prevent the migration of CO_2 out of the injection reservoir. Additionally, no significant faults or fracture zones that cut across the seal units have been identified in the CFA, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented.

5.2 Groundwater monitoring

CapturePoint does not routinely pull water samples from the Ogallala water wells. However, samples are pulled when OCC injection permits are submitted in Oklahoma. No indication of fluid leakage has been identified from any of these in the CFA area. CapturePoint is unlikely to continue monitoring USDW wells for CO_2 or brine contamination, as characterization of the Morrow (see section 5.1) has suggested minimal risk of groundwater contamination from CO_2 leakage from this depth.

5.3 Soil CO_2 monitoring

Atmospheric CO_2 values at the Farnsworth Unit have been determined by a SWP eddy tower installation. In winter 2019, the eddy system malfunctioned and has not been repaired due to COVID travel restrictions. However, the atmospheric CO_2 concentration data from the eddy tower were in very good agreement with values obtained from the NOAA Global Monitoring Laboratory station in Moody, Texas (Station: WKT). Since the CFA area is in close proximity to the Farnsworth Unit, atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values.

5.4 Visual Inspection

CapturePoint operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage.

5.5 Well Surveillance

CapturePoint adheres to the requirements of OAC Title 165:10-5 for the OCC and of TAC Rule 46 for the TRRC governing fluid injection into productive reservoirs. Rule 46 includes requirements for monitoring, reporting, and testing of Class II injection wells. Furthermore, the OCC and the TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well if they are deemed necessary.

CapturePoint also adheres to the requirements of OAC Title 165:10-7 for the OCC and TAC Rule 20 for the TRRC governing the notification of fires, breaks, leaks, or escapes. Rule 20 requires that all operators report leaks to the OCC or the TRRC including measured or estimated quantities of product leaked.

6 Site specific considerations for determining the Mass of CO_2 Sequestered

Of the twelve RR equations in 98.443 of Subpart RR, the following are relevant to CapturePoint's operations.

6.1 Determining Mass of CO_2 received

CapturePoint currently receives CO_2 at its CFA facility through its own pipeline from the Arkalon Ethanol plant in Liberal, Kansas. CapturePoint also recycles CO_2 from its production wells in the CFA.

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

where:

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

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into the well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

6.2 Determining Mass of CO_2 Injected

CapturePoint injects CO_2 into the injection wells listed in Appendix 1.

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

where:

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

$Q_{p,u}$= Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

6.3 Determining Mass of CO_2 produced from Oil Wells

CapturePoint also recycles CO_2 from its production wells which are part of its operations in the CFA. Therefore, the following equation is relevant to its operations.

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

Where:

$CO_{2,w}$ = Annual CO_2 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 CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,w}}$ = CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator.

To aggregate production data, CapturePoint will sum the mass of all of the CO_2 separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 below:

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

Where:

CO_{2P} = Total annual CO_2 mass produced (metric tons) through all separators in the reporting year.

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction), CU is 0.00236 and NPU is 0.00454 at the last sample.

w = Separator.

6.4 Determining Mass of CO_2 emitted by Surface Leakage

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations.

CapturePoint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below:

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

where:

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

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

x = Leakage pathway.

6.5 Determining Mass of CO_2 sequestered

The following Equation RR-11 pertains to facilities that are actively producing oil or natural gas.

$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP}$ (Equation RR-11)

Where:

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

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

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

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

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

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

7 Estimated Schedule for Implementation of MRV plan

CapturePoint expects to begin implementing the approved MRV plan when the new CO_2 capture facility is operational, November 1, 2022.

8 GHG monitoring and Quality Assurance Program

CapturePoint will meet the monitoring and QA/QC requirements of 98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 98.444 (d).

8.1 GHG monitoring

As required by 40 CFR 98.3(g)(5)(i), CapturePoint's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.
- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.
- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

8.1.1 General

Measurement of CO_2 *Concentration* – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GSA) standards.

Measurement of CO_2 *Volume* – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. CapturePoint will adhere to the American Gas Association (AGA) Report #3 – (ORIFICE METERING OF NATURAL GAS AND OTHER RELATED HYDROCARBON FLUIDS)

8.1.2 CO_2 Received

Daily fermentation CO_2 purchased is received via the pipeline from the Arkalon ethanol plant in Liberal, Kansas, and is measured using a volumetric totalizer, which uses accepted flow calculations for CO_2 according to the AGA Report #3.

8.1.3 CO_2 Injected

Daily CO_2 injection is recorded by combining the totals for the recycle compressor meter and the received CO_2 meter from Arkalon based on what's delivered on a 24-hour basis. This data is taken from the meter daily and stored in CapturePoint's data warehouse for records and reservoir management.

8.1.4 CO_2 Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO_2. The produced gas is sampled at least quarterly for the CO_2 content.

8.1.5 CO_2 Emissions from equipment leaks and vented emissions of CO_2

As required by 98.444 (d), CapturePoint will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead and between the flow meter used to measure production quantity and the production wellhead.

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6 Measurement Devices

As required by 40 CFR 98.444(e), CapturePoint will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration.
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.
- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meters are National Institute of Standards and Technology (NIST) traceable.

8.2 QA/QC procedures

CapturePoint will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

8.3 Estimating missing data

CapturePoint will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

A quarterly flow rate of CO_2 received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.

A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.

A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

8.4 Revisions of the MRV plan

CapturePoint will revise the MRV Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

9 Records Retention

CapturePoint will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, CapturePoint will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.
(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
    (i) The GHG emissions calculations and methods used.
    (ii) Analytical results for the development of site-specific emissions factors, if applicable.
    (iii) The results of all required analyses.
    (iv) Any facility operating data or process information used for the GHG emission calculations.
(3) The annual GHG reports.
(4) Missing data computations. For each missing data event, CapturePoint will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.
(5) A copy of the most recent revision of this MRV Plan.
(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.
(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(9) Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(10) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
(11) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
(12) 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.
(13) 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.
(14) Any other records as specified for retention in this EPA-approved MRV plan.

10 Appendices

Appendix 1 – CFA Wells

Table A1.1 – Production Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2112	35007353570000	Oil Prod	Active	CO_2	1	0
CU 2171	35007354120000	Oil Prod	Active	CO_2	1	0
CU 2173	35007354140000	Oil Prod	Active	CO_2	1	0
CU 2177	35007222340000	Oil Prod	Active	CO_2	1	0
CU 2272	35007224530000	Oil Prod	Active	CO_2	1	0
CU 2651	35007362650000	Oil Prod	Active	CO_2	1	0
CU 2731	35007359750000	Oil Prod	Active	CO_2	1	0
CU 2761	35007350590000	Oil Prod	Active	CO_2	1	0
CU 2853	35007250840000	Oil Prod	Active	CO_2	1	0
CU 2854	35007250850000	Oil Prod	Active	CO_2	1	0
CU 2971A	35007256700000	Oil Prod	Active	CO_2	1	0
CU 2973	35007213750000	Oil Prod	Active	CO_2	1	0
CU 2975	35007223730000	Oil Prod	Active	CO_2	1	0
CU 3111	35007350600000	Oil Prod	Active	CO_2	1	0
CU 3113	35007359460000	Oil Prod	Active	CO_2	1	0
CU 3115	35007251710000	Oil Prod	Active	CO_2	1	0
CU 3116	35007252570000	Oil Prod	Active	CO_2	1	0
CU 3143	35007250860000	Oil Prod	Active	CO_2	1	0
CU 3171	35007359600000	Oil Prod	Active	CO_2	1	0
CU 3182	35007249250000	Oil Prod	Active	CO_2	1	0
CU 3211	35007352150000	Oil Prod	Active	CO_2	1	0
CU 3212	35007352690000	Oil Prod	Active	CO_2	1	0
CU 3231	35007001820000	Oil Prod	Active	CO_2	1	0
CU 3232	35007352720000	Oil Prod	Active	CO_2	1	0
CU 3234	35007212010000	Oil Prod	Active	CO_2	1	0
CU 3261	35007352170000	Oil Prod	Active	CO_2	1	0
CU 3263	35007251640000	Oil Prod	Active	CO_2	1	0
CU 3271	35007352160000	Oil Prod	Active	CO_2	1	0
CU 3273	35007252580000	Oil Prod	Active	CO_2	1	0
CU 3274	35007253140000	Oil Prod	Active	CO_2	1	0
CU 3275	35007254040000	Oil Prod	Active	CO_2	1	0
CU 3312	35007360800000	Oil Prod	Active	CO_2	1	0
CU 3313	35007254370000	Oil Prod	Active	CO_2	1	0
CU 3314	35007254030000	Oil Prod	Active	CO_2	1	0
CU 3332	35007254020000	Oil Prod	Active	CO_2	1	0
CU 3381	35007360780000	Oil Prod	Active	CO_2	1	0
CU 3411	35007351700000	Oil Prod	Active	CO_2	1	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3412	35007351720000	Oil Prod	Active	CO_2	1	0
CU 3413	35007351730000	Oil Prod	Active	CO_2	1	0
CU 3414	35007005220000	Oil Prod	Active	CO_2	1	0
CU 3415	35007211170000	Oil Prod	Active	CO_2	1	0
CU 3416A	35007252590000	Oil Prod	Active	CO_2	1	0
CU 3451A	35007256710000	Oil Prod	Active	CO_2	1	0
CU 3471	35007351750000	Oil Prod	Active	CO_2	1	0
CU 3481	35007351710001	Oil Prod	Active	CO_2	1	0
CU 3491	35007254330000	Oil Prod	Active	CO_2	1	0
CU 3533	35007206880000	Oil Prod	Active	CO_2	1	0
CU 3562	35007255050000	Oil Prod	Active	CO_2	1	0
NPU 101	42357010440000	Oil Prod	Active	CO_2	1	0
NPU 103	42357010060000	Oil Prod	Active	CO_2	1	0
NPU 104	42357000050000	Oil Prod	Active	CO_2	1	0
NPU 207	42357302000000	Oil Prod	Active	CO_2	1	0
NPU 209	42357333830000	Oil Prod	Active	CO_2	1	0
NPU 501	42357009140000	Oil Prod	Active	CO_2	1	0
NPU 502	42357024100000	Oil Prod	Active	CO_2	1	0
NPU 601	42357008420000	Oil Prod	Active	CO_2	1	0
NPU 605	42357333840000	Oil Prod	Active	CO_2	1	0
NWCU 3-1	35007360850000	Gas Prod	Active	CO_2	1	0
NWCU 9-3	35007249430000	Oil Prod	Active	CO_2	1	0
CU 2172	35007354130000	Oil Prod	Inactive	CO_2	0	0
CU 2175	35007354160000	Oil Prod	Inactive	CO_2	0	0
CU 2473	35007211990000	Oil Prod	Inactive	CO_2	0	0
CU 2511	35007350790000	Oil Prod	Inactive	CO_2	0	0
CU 2711	35007359260000	Oil Prod	Inactive	CO_2	0	0
CU 2771	35007359850000	Oil Prod	Inactive	CO_2	0	0
CU 3142	35007222350000	Oil Prod	Inactive	CO_2	0	0
CU 3361	35007352670000	Oil Prod	Inactive	CO_2	0	0
NPU 205	42357008070000	Oil Prod	Inactive	CO_2	0	0
NPU 301	42357022080000	Oil Prod	Inactive	CO_2	0	0
NPU 801	42357004630000	Oil Prod	Inactive	CO_2	0	0
NPU 802	42357004620000	Oil Prod	Inactive	CO_2	0	0
NPU 804	42357201730000	Oil Prod	Inactive	CO_2	0	0
NPU 901	42357000660000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-2	35007350870000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-3	35007210790000	Oil Prod	Inactive	CO_2	0	0
NWCU 16-1	35007350720000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-1	35007360900000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-3	35007360920000	Oil Prod	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
NWCU 19-4	35007360930000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-5	35007360940000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-6	35007211250000	Oil Prod	Inactive	CO_2	0	0
NWCU 24-5	35007222710000	Oil Prod	Inactive	CO_2	0	0
NWCU 25-7	35007228000000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-3	35007360870000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-4	35007360880000	Oil Prod	Inactive	CO_2	0	0
NWCU 4-2	35007360740000	Oil Prod	Inactive	CO_2	0	0
NWCU 5-1	35007361050000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-1	35007360980000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-2	35007360990000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-1	35007360810000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-2	35007360820000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-3	35007208260000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-1	35007360950000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-2	35007360960000	Oil Prod	Inactive	CO_2	0	0
CU 1551	35007350740000	Oil Prod	P&A	CO_2	0	0
CU 1671	35007352180000	Oil Prod	P&A	CO_2	0	0
CU 2111	35007353560000	Oil Prod	P&A	CO_2	0	0
CU 2176	35007358870000	Oil Prod	P&A	CO_2	0	0
CU 2221	35007000490000	Oil Prod	P&A	CO_2	0	0
CU 2281	35007359220000	Oil Prod	P&A	CO_2	0	0
CU 2421	35007359350000	Oil Prod	P&A	CO_2	0	0
CU 2431	35007350330000	Oil Prod	P&A	CO_2	0	0
CU 2432	35007350340000	Oil Prod	P&A	CO_2	0	0
CU 2433	35007350350000	Oil Prod	P&A	CO_2	0	0
CU 2434	35007350360000	Oil Prod	P&A	CO_2	0	0
CU 2435	35007218800000	Oil Prod	P&A	CO_2	0	0
CU 2471	35007359080000	Oil Prod	P&A	CO_2	0	0
CU 2531	35007361090000	Oil Prod	P&A	CO_2	0	0
CU 2532	35007361100000	Oil Prod	P&A	CO_2	0	0
CU 2552	35007359760000	Oil Prod	P&A	CO_2	0	0
CU 2571	35007350730000	Oil Prod	P&A	CO_2	0	0
CU 2572	35007359320000	Oil Prod	P&A	CO_2	0	0
CU 2661	35007361990000	Oil Prod	P&A	CO_2	0	0
CU 2681	35007350320000	Oil Prod	P&A	CO_2	0	0
CU 2852	35007301360000	Oil Prod	P&A	CO_2	0	0
CU 2961	35007358760000	Oil Prod	P&A	CO_2	0	0
CU 2971	35007358750000	Oil Prod	P&A	CO_2	0	0
CU 2972	35007358780000	Oil Prod	P&A	CO_2	0	0
CU 3031	35007359560000	Oil Prod	P&A	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3051	35007300380000	Oil Prod	P&A	CO_2	0	0
CU 3064	35007254270000	Oil Prod	P&A	CO_2	0	0
CU 3141	35007359610000	Oil Prod	P&A	CO_2	0	0
CU 3181	35007359470000	Oil Prod	P&A	CO_2	0	0
CU 3251	35007352710000	Oil Prod	P&A	CO_2	0	0
CU 3331	35007200750000	Oil Prod	P&A	CO_2	0	0
CU 3451	35007351690000	Oil Prod	P&A	CO_2	0	0
CU 3511	35007359730000	Oil Prod	P&A	CO_2	0	0
CU 3531	35007350850000	Oil Prod	P&A	CO_2	0	0
CU 3532	35007359950000	Oil Prod	P&A	CO_2	0	0
CU 3534	35007211180000	Oil Prod	P&A	CO_2	0	0
CU 3561	35007359830000	Oil Prod	P&A	CO_2	0	0
CU 3571	35007359980000	Oil Prod	P&A	CO_2	0	0
CU 3581	35007359970000	Oil Prod	P&A	CO_2	0	0
CU 3631	35007301000000	Oil Prod	P&A	CO_2	0	0
CU 1672	35007352190000	Oil Prod	P&A	CO_2	0	0
CU 2351	35007350370000	Oil Prod	P&A	CO_2	0	0
CU 2474	35007228200000	Oil Prod	P&A	CO_2	0	0
CU 2812	35007352340000	Oil Prod	P&A	CO_2	0	0
CU 2871	35007359060000	Oil Prod	P&A	CO_2	0	0
NPU 102	42357021420000	Oil Prod	P&A	CO_2	0	0
NPU 201	42357001280000	Oil Prod	P&A	CO_2	0	0
NPU 302	42357022290000	Oil Prod	P&A	CO_2	0	0
NPU 402	42357022300000	Oil Prod	P&A	CO_2	0	0
NWCU 17-2	35007359620000	Oil Prod	P&A	CO_2	0	0
NWCU 10-1	35007361010000	Oil Prod	P&A	CO_2	0	0
NWCU 17-1	35007350710000	Oil Prod	P&A	CO_2	0	0
NWCU 19-7	35007224520000	Oil Prod	P&A	CO_2	0	0
NWCU 24-4	35007358770000	Oil Prod	P&A	CO_2	0	0
NWCU 25-6	35007358790000	Oil Prod	P&A	CO_2	0	0

Table A1.2 – Water Alternating Gas (WAG) Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 2662 (INJ)	35007362010000	WAG Inj	Active	CO_2	0	1
CU 2751 (INJ)	35007359440002	WAG Inj	Active	CO_2	0	1
CU 2762 (INJ)	35007213660000	WAG Inj	Active	CO_2	0	1
CU 2772 (INJ)	35007359860001	WAG Inj	Active	CO_2	0	1
CU 2811 (INJ)	35007352200000	WAG Inj	Active	CO_2	0	1
CU 2872 (INJ)	35007359070000	WAG Inj	Active	CO_2	0	1
CU 2962 (INJ)	35007212000000	WAG Inj	Active	CO_2	0	1
CU 2974 (INJ)	35007220770000	WAG Inj	Active	CO_2	0	1
CU 3114 (INJ)	35007206540000	WAG Inj	Active	CO_2	0	1
CU 3117 (INJ)	35007254000000	WAG Inj	Active	CO_2	0	1
CU 3161 (INJ)	35007359590002	WAG Inj	Active	CO_2	0	1
CU 3213 (INJ)	35007224570000	WAG Inj	Active	CO_2	0	1
CU 3233 (INJ)	35007206890000	WAG Inj	Active	CO_2	0	1
CU 3252 (INJ)	35007211020000	WAG Inj	Active	CO_2	0	1
CU 3262 (INJ)	35007206870000	WAG Inj	Active	CO_2	0	1
CU 3351 (INJ)	35007352680000	WAG Inj	Active	CO_2	0	1
CU 3371 (INJ)	35007360770000	WAG Inj	Active	CO_2	0	1
CU 3417 (INJ)	35007255060000	WAG Inj	Active	CO_2	0	1
CU 3461 (INJ)	35007351680000	WAG Inj	Active	CO_2	0	1
CU 3472 (INJ)	35007206940000	WAG Inj	Active	CO_2	0	1
CU 3551 (INJ)	35007359840000	WAG Inj	Active	CO_2	0	1
NPU 105 (INJ)	42357000030000	WAG Inj	Active	CO_2	0	1
NPU 107W (INJ)	42357333770000	WAG Inj	Active	CO_2	0	1
NPU 202WI (INJ)	42357021500000	WAG Inj	Active	CO_2	0	1
NPU 208 (INJ)	42357327410000	WAG Inj	Active	CO_2	0	1
NPU 701 (INJ)	42357008410000	WAG Inj	Active	CO_2	0	1
NPU 504 (INJ)	42357329480000	WAG Inj	Active	CO_2	0	1
NPU 604W (INJ)	42357330870000	WAG Inj	Active	CO_2	0	1
CU 1531 (INJ)	35007359990000	WAG Inj	Inactive	CO_2	0	0
CU 2131 (INJ)	35007362700000	WAG Inj	Inactive	CO_2	0	0
CU 2512 (INJ)	35007350780000	WAG Inj	Inactive	CO_2	0	0
CU 2641 (INJ)	35007359250001	WAG Inj	Inactive	CO_2	0	0
CU 2721 (INJ)	35007359870001	WAG Inj	Inactive	CO_2	0	0
CU 2741 (INJ)	35007359430000	WAG Inj	Inactive	CO_2	0	0
CU 2851 (INJ)	35007355420001	WAG Inj	Inactive	CO_2	0	0
CU 3032 (INJ)	35007359580000	WAG Inj	Inactive	CO_2	0	0
CU 3062 (INJ)	35007253090000	WAG Inj	Inactive	CO_2	0	0
CU 3112 (INJ)	35007359450001	WAG Inj	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 3172 (INJ)	35007251690000	WAG Inj	Inactive	CO_2	0	0
CU 3281 (INJ)	35007352700003	WAG Inj	Inactive	CO_2	0	0
CU 3311 (INJ)	35007360790000	WAG Inj	Inactive	CO_2	0	0
CU 3341 (INJ)	35007353530000	WAG Inj	Inactive	CO_2	0	0
NPU 203W (INJ)	42357008270000	WAG Inj	Inactive	CO_2	0	0
NPU 503 (INJ)	42357009150001	WAG Inj	Inactive	CO_2	0	0
NWCU 15-1 (INJ)	35007350860000	WAG Inj	Inactive	CO_2	0	0
NWCU 15-4 (INJ)	35007224510000	WAG Inj	Inactive	CO_2	0	0
NWCU 20-1 (INJ)	35007360760000	WAG Inj	Inactive	CO_2	0	0
NWCU 21-1 (INJ)	35007361020000	WAG Inj	Inactive	CO_2	0	0
CU 2271 (INJ)	35007359230000	WAG Inj	P&A	CO_2	0	0
CU 2311 (INJ)	35007362000000	WAG Inj	P&A	CO_2	0	0
CU 2472 (INJ)	35007359090000	WAG Inj	P&A	CO_2	0	0
CU 3061 (INJ)	35007359820000	WAG Inj	P&A	CO_2	0	0
CU 3512 (INJ)	35007359740000	WAG Inj	P&A	CO_2	0	0
NPU 204W (INJ)	42357022520000	WAG Inj	P&A	CO_2	0	0
NPU 206W (INJ)	42357022510000	WAG Inj	P&A	CO_2	0	0
NPU 401W (INJ)	42357004520000	WAG Inj	P&A	CO_2	0	0
NPU 602W (INJ)	42357020230000	WAG Inj	P&A	CO_2	0	0
NPU 603W (INJ)	42357201720001	WAG Inj	P&A	CO_2	0	0
NPU 803W (INJ)	42357201710000	WAG Inj	P&A	CO_2	0	0
NWCU 14-1 (INJ)	35007350530000	WAG Inj	P&A	CO_2	0	0
NWCU 3-2 (INJ)	35007360860000	WAG Inj	P&A	CO_2	0	0

Table A1.3 – Water Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU WSW 1	35007355430001	Wtr Inj	Active	CO_2	0	1
NPU W 1W	42357300050002	Wtr Inj	Inactive	CO_2	0	0
CU 2551	35007350750000	Wtr Inj	P&A	CO_2	0	0

Appendix 2 – Referenced Regulations

U.S. Code > Title 26, INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1, NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits >

Section 45Q ..... Credit for carbon oxide sequestration

OCC > Title 165: CORPORATION COMMISSION > UNDERGROUND INJECTION CONTROL

Section

165:10-5-1 .... Classification of underground injection wells
165:10-5-2 .... Approval of injection wells or disposal wells
165:10-5-3 .... Authorization for existing enhanced recovery injection wells and existing disposal wells
165:10-5-4 .... Application for approval of enhanced recovery projects
165:10-5-5 .... Application for approval of injection and disposal operations
165:10-5-6 .... Testing and monitoring requirements for injection wells and disposal wells
165:10-5-7 .... Monitoring and reporting requirements for wells covered by 165:10-5-1
165:10-5-8 .... Liquid hydrocarbon storage wells
165:10-5-9 .... Duration of underground injection well orders or permits
165:10-5-10 ..... Transfer of authority to inject
165:10-5-11 ..... Notarized reports
165:10-5-12 ..... Application for administrative approval for the subsurface injection of onsite reserve pit fluids
165:10-5-13 ..... Application for permit for one time injection of reserve pit fluids
165:10-5-14 ..... Exempt aquifers
165:10-5-15 ..... Application for permit for simultaneous injection well

165:5-7-27 .... Application for approval of injection and disposal wells
165:5-7-29 .... Request for exception to certain underground injection well requirements
165:5-7-30 .... Amending existing orders or permits authorizing injection for injection, disposal, or LPG storage wells

TAC > Title 16 - Economic Regulation> Part 1 TRRC > Chapter 3 – Oil and Gas Division >

Rules

§3.37 .... Statewide Spacing Rule
§3.38 .... Well Densities
§3.39 .... Proration and Drilling Units: Contiguity of Acreage and Exception Thereto
§3.40 .... Assignment of Acreage to Pooled Development and Proration Units
§3.41 .... Application for New Oil or Gas Field Designation and/or Allowable
§3.42 .... Oil Discovery Allowable
§3.43 .... Application for Temporary Field Rules
§3.45 .... Oil Allowables
§3.46 .... Fluid Injection into Productive Reservoirs
§3.47 .... Allowable Transfers for Saltwater Injection Wells
§3.48 .... Capacity Oil Allowables for Secondary or Tertiary Recovery Projects
§3.49 .... Gas-Oil Ratio
§3.50 .... Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive
§3.51 .... Oil Potential Test Forms Required
§3.52 .... Oil Well Allowable Production
§3.53 .... Annual Well Tests and Well Status Reports Required
§3.54 .... Gas Reports Required
§3.55 .... Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering
§3.56 .... Scrubber Oil and Skim Hydrocarbons
§3.57 .... Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials
§3.58 .... Certificate of Compliance and Transportation Authority; Operator Reports
§3.59 .... Oil and Gas Transporter's Reports
§3.60 .... Refinery Reports
§3.61 .... Refinery and Gasoline Plants
§3.62 .... Cycling Plant Control and Reports
§3.63 .... Carbon Black Plant Permits Required
§3.70 .... Pipeline Permits Required
§3.71 .... Pipeline Tariffs
§3.72 .... Obtaining Pipeline Connections
§3.73 .... Pipeline Connection; Cancellation of Certificate of Compliance; Severance
§3.76 .... Commission Approval of Plats for Mineral Development
§3.78 .... Fees and Financial Security Requirements
§3.79 .... Definitions
§3.80 .... Commission Oil and Gas Forms, Applications, and Filing Requirements
§3.81 .... Brine Mining Injection Wells
§3.83 .... Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells
§3.84 .... Gas Shortage Emergency Response
§3.85 .... Manifest to Accompany Each Transport of Liquid Hydrocarbons by Vehicle
§3.86 .... Horizontal Drainhole Wells
§3.91 .... Cleanup of Soil Contaminated by a Crude Oil Spill
§3.93 .... Water Quality Certification Definitions

§3.95 .... Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations
§3.96 .... Underground Storage of Gas in Productive or Depleted Reservoirs
§3.97 .... Underground Storage of Gas in Salt Formations
§3.98 .... Standards for Management of Hazardous Oil and Gas Waste
§3.99 .... Cathodic Protection Wells
§3.100 .... Seismic Holes and Core Holes
§3.101 .... Certification for Severance Tax Exemption or Reduction for Gas Produced From High-Cost Gas Wells
§3.102 .... Tax Reduction for Incremental Production
§3.103 .... Certification for Severance Tax Exemption for Casinghead Gas Previously Vented or Flared
§3.106 .... Sour Gas Pipeline Facility Construction Permit
§3.107 .... Penalty Guidelines for Oil and Gas Violations

Appendix 3 – References

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Appendix 4 – Abbreviations and Acronyms

2D – 2 dimensional
3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
ANSI – American National Standards Institute
API – American Petroleum Institute
AWT – All Well Test
ASTM - American Society for Testing and Materials
Bscf – billion standard cubic feet
B/D – barrels per day
bopd – barrels of oil per day
C4 – butane
C5 – pentane
C7 – heptane
C7+ - standard heptane plus
CCE – constant composition expansion
CCUS – carbon capture utilization and storage
CFA – Camrick Field Area
cf – cubic feet
CH4 – methane
CO_2 – carbon dioxide
EOR – Enhanced Oil Recovery
EOS – Equation of State
EPA – US Environmental Protection Agency
ESD – Emergency Shutdown Device
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
H_2S – hydrogen sulfide
lb – pound
mD – millidarcy(ies)
MICP – mercury injection capillary pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MMB – million barrels
MMP – minimum miscible pressure
MMscf – million standard cubic feet
MMstb – million stock tank barrels
MRV – Monitoring, Reporting, and Verification
MMMT – Million metric tonnes
MT – Metric tonne
NIST – National Institute of Standards and Technology

NAESB – North American Energy Standards Board
OAC – Oklahoma Administrative Code
OCC – Oklahoma Corporation Commission
OOIP – Original Oil-In-Place
OWC – oil water contact
PPM – Parts Per Million
psia – pounds per square inch absolute
PVT – pressure, volume, temperature
QA/QC – quality assurance/quality control
RMS – root mean square
SEM – scanning electron microscope
SWP - Southwest Regional Partnership on Carbon Sequestration
TAC – Texas Administrative Code
TA – Temporally Abandoned/not plugged
TD – total depth
TM – Terminated order wells/UIC not plugged
TRRC – Texas Railroad Commission
TSD – Technical Support Document
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water
WAG – Water Alternating Gas (Gas is recycled CO_2 and purchase CO_2)
XRD – x-ray diffraction

Appendix 5 – Conversion Factors

CapturePoint reports CO_2 at standard conditions of temperature and pressure as defined in the State of Texas in the Texas Administrative Code for the Oil and Gas Division, Rule 3.79 as follows:

> Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit.

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at:

https://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At State of Texas standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.002641684 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2{,}204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2} = 0.002641684$$

$$MW_{CO2} = 44.0095$$

$$Density_{CO2} = 5.2734\ x\ 10^{-5}\frac{MT}{ft^3}\ or\ 5.2734\ x\ 10^{-2}\frac{MT}{Mcf}$$

The conversion factor 5.2734×10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.

Request for Additional Information: Camrick Unit
April 7, 2022 (Response April 25,2022)

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	There is a semi-consistent lack of thousands place separators in numbers throughout the MRV plan. Please add for clarity.	Added the thousands place separators for number and did not change any name that contained a number.
2.	N/A	N/A	Throughout the MRV plan, there is inconsistent spacing between words and following punctuation. For example, see the following passage reproduced from section 3, page 4 of the MRV plan: "Also, all wells in the CFA…" Please correct for clarity.	Removed all double spacing throughout the MRV plan document.
3.	N/A	N/A	There is an inconsistent use of the Oxford comma (and commas in general) throughout the MRV plan. For clarity, we recommend consistent comma use.	Added the Oxford comma throughout the document.
4.	N/A	N/A	There is a tendency to repeat acronym definitions throughout the MRV plan. Please use the acronym each time a phrase is used after an acronym has been defined. Additionally, please ensure that acronyms are defined the first time they are used.	Added acronym definition the first time it is used then only used the acronym definition.
5.	N/A	N/A	Throughout the MRV plan, maps have difficult-to-read legends. We recommend increasing the size and/or resolution of all figures and legends to improve their readability. Examples include Figure 2.4-1 and Figure 3.1.1.	Increased the size of most figures and legends.
6.	N/A	N/A	Throughout the MRV plan, maps have difficult to use scale bars. For example, Figure 2.3-2 has a scale bar for 4,501 feet. We recommend using easily divisible, round numbers for scale bars.	Changed the scale bars to 5000 feet per inch on maps generated by company owned software.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
7.	N/A	1	The title of Section 4 of the MRV is written as "…Leakage Pathway", we suggest changing this to "…Leakage Pathways". Similarly, we suggest changing the title of subsection 4.3 to "….Bedding Plane Partings" and the title of subsection 4.3.1 to "….Hydrocarbons".	Added "s" per suggestion.
8.	Intro.	3	"…with the subsidiary or ancillary…" Is the sequestration of CO_2 subsidiary or ancillary to the EoR operations in the Camrick Unit? These terms have distinctly different meanings, specifically, ancillary suggests that sequestration is necessary for normal operations.	Changed to "with retention of CO2 serving a subsidiary".
9.	Intro.	3	"… and the Oklahoma Corporation Commission OAC 165:10. In this document, the term "gas" usually…" Is "OAC" supposed to be the acronym? If so, please put the acronym in parentheses and check the spelling. We recommend checking the use of "OAC" and "OCC" throughout the document. Additionally, please remove the word "usually" and/or clarify when the term "gas" has a different meaning.	Included Oklahoma Administrative Code (OAC) into document. Checked the use of "OCC" and "OAC". Removed the word "usually from the sentence.
10.	1.1	4	The relationship of the MRV plan to the facilities listed is unclear. For example, does CapturePoint intend to report each unit separately under Subpart RR using its respective facility ID? If so, each facility should have its own MRV Plan. Please provide clarification.	The Camrick Unit, which is in Oklahoma, and the North Perryton Unit, which is in Texas, presently have two separate Greenhouse Gas Program Reporting Identification numbers. However, the two units share only one CO_2 processing injection facility and share the same geologic reservoir. (See Question No. 26) The oil is sold in their respective states as per royalty ownership lease documents. Also, the water remains in the respective states per water board requirement. Should we use one GHG number for Camrick Field Area?

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
11.	1.2	4	"For injection wells (see Appendix 2) that are the subject of this MRV plan, the Oklahoma Conservation Commission (OCC) has rules governing Undergound Injection Control (UIC) Class II injection wells; OAC 165:10-5-1 through OAC 165:10-5-15, OAC 165:5-7-27, OAC 165:5-7-30, the request for an exception to UIC rules under OAC 165:5-7-29, and other rules governing filing forms." As written, this sentence is confusing. We suggest splitting into two sentences such that OAC citations are in one sentence and the remaining references are in a second sentence. Additionally, please check for spelling and grammar.	Changed and split sentence for clarity to "For injection wells (see Appendix 2) that are the subject of this MRV plan, the OCC has rules governing UIC Class II injection wells. These OCC rules are OAC Title 165:10-5-1 through 165:10-5-15, OAC 165:5-7-27, OAC 165:5-7-30, the request for an exception to UIC rules under OAC 165:5-7-29, and other governing filing forms."
12.	2.1.1	4	"…for an additional 12 years…" Please either remove "an additional" or further clarify what this means.	Added additional words to clarify further "The CFA has been injecting CO2 for the last 20+ years and…".
13.	2.1.2	4	"The chart to the left in Figure 2.4-7 in Section 2.4" We suggest either reproducing the chart here or moving it to this location to improve readability. Additionally, this phrase reads awkwardly and feels out of place. We recommend revising it.	Recreated charts for clarity and edited section to improve flow.
14.	2.1.2	4	"For the period September 2020 through October 2034, an additional 52.5 Bscf or 2.77 MMMT will be stored in the CFA." Seeing as this MRV plan was submitted in March 2022, has the above been updated since September 2020? Subpart RR reporters can only begin reporting to subpart RR in the reporting year the MRV plan is approved. Reporters cannot retroactively report quantities of CO2 injected in reporting years prior to the year of MRV approval. Please clarify. Furthermore, will the 52.4 Bscf be in addition to the 100 Bscf in the prior sentence? If so, why split these volumes? Please clarify.	Corrected period "September 2022 through October 2034". Ditto. The total CO_2 volume sequestered and the MRV CO_2 volume sequestered were discussed in Section 2.1.2.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
15.	2.2.2	5	"The geological discussions in Sections 2.2.2 and 4.3-4.4 are based on analysis of logs from both the Farnsworth Unit…" Please explain why the Farnsworth Unit is a good geologic analog for the CFA and update the MRV plan accordingly.	Added sentence describing the similarities.
16.	2.2.2	5	"The descriptions of cores included sections from overlying seals as well as the shale underlying the main reservoirs, petrographic thin section descriptions and point counts as well as a variety of special analytical techniques including X-ray diffraction (XRD), which is the science of determining the atomic and molecular structure of rock crystals with an X-ray beam; scanning electron microscope (SEM) analysis; which uses a beam of electrons to define the surface of crystals; carbon isotope analysis to estimate the age of the sample; and a variety of mechanical tests" This wording is confusing; please rephrase.	Split the sentence and rephrased.
17.	2.2.2	5	"…carbon isotope analysis to estimate the age of the sample…" Our understanding is that carbon isotope analysis only provides accurate dating back to a maximum of approximately 55,000 years in the past. Can you please provide further characterization of its use at the CFA?	Changed to "…carbon isotope analysis to estimate the age of the CO_2 in the sample…" This will determine the presence of Fermentation CO_2.
18.	2.2.2.1	8	"…the Morrow B is described as a relatively coarse-grained subarkosic sandstone and per depositional pathway …" This is not clear. Can you please clarify what is meant by the above phrase?	Removed the following for clarity "and per depositional pathway."
19.	2.2.2.2	9	"The CFA CO2 injection and production operations will not cause water to flow…" Please clarify the likelihood of this scenario.	Changed to "The CFA CO2 injection and production operations have negligible likelihood of causing water to flow…"

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
20.	2.3	9	"CO2 distribution and Injection" It appears there is a capitalization inconsistency in the phrase above, please correct it if so.	Changed the Capitalization on "injection".
21.	2.3	10	Figure 2.3-1 is difficult to follow. We recommend adjusting the sizes and proportions of the pictures, text boxes, and/or arrows for increased clarity.	Increased the size of the graphic.
22.	2.3	10	"…while only the gas from NPU is sent to the CTB the NPU oil and water remains in Texas." Can you please elaborate on this distinction?	See Question 10 above.
23.	2.3.1	10	"…CO2 purchases will remain constant at 12 MMCFD for 12 years and decline after 2034." This statement seems to contradict Figure 2.4.7. Figure 2.4.7 makes it seem as if CO2 purchases will cease during 2034. Please adjust.	Changed the "decline" to "cease".
24.	2.3.2	11	"One for the liquid phase, a mixture of oil and water, and one for the gas phase…" This is not a complete sentence. Please revise and clarify its meaning.	Rephrased sentence.
25.	2.3.2	12	"Although CapturePoint is not required to determine or report the amount of dissolved CO2 in the water…" Equation RR-9 requires the reporting of X, the "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)". Please clarify.	Changed to "CapturePoint is not required to determine or report the amount of dissolved CO2 in the water as it is reinjected into the ground and not emitted to the atmosphere"
26.	2.3.4	13	Can you please provide a more descriptive legend to identify well types for Figure 2.3-2?	The purpose of Figure 2.3-2 is to show the location of the one Central Tank Battery and the location the various "All Well Test" sites. Well identification is displayed in Figures 4.2.1 through 4.2.4.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
27.	2.3.6	13	"**Briefly** current rules require, among other provisions:" Please rephrase or reorganize statement to improve clarity and grammar.	Changed to "Briefly the following bulleted list is what the current rules require, among other provisions:"
28.	2.3.6	13	"…and closure for all wells in permitted units and wells." This sentence is unclear, please revise.	Changed "closure" to "plugging".
29.	2.3.6	14	"And that all wells follow plugging procedures that require advance approval from the Director and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs." It appears there is a formatting issue in the above phrase, specifically it should likely be a final bullet attached to the list preceding it. In addition, the spacing of this bulleted list is not consistent. Please fix.	Reformatted items.
30.	2.4.1	14	"The CFA is approximately 8 mi by 7 mi that have areas that exhibit different reservoir behavior." This wording is confusing; please rephrase. Also, "mi" is spelled out elsewhere in the document. Please review for consistency.	Changed to miles.
31.	2.4.1	14	"The southwest portion of CU was most prolific oil producer…" It appears there is a typo in the phrase above, please correct it if so.	Revised sentence to "The southwest portion of CU was most prolific oil producing area of the CFA under primary and secondary production".
32.	2.4.3	16	"…no production performance exists which indicates any plume will move outside of the MMA at the end of year t + 5, per §98.449 definitions. " This phrase is unclear, please revise.	Revised phrase to "Also, during CFA drilling and production operations, no reports exist which would indicate any plume has moved outside of the MMA. The Farnsworth Unit MRV and the CFA data justifies the conclusion that CO2 will continue to be contained inside the MMA at the end of the CO2 injection year t + 5, per §98.449 definitions."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
33.	2.4.4	17	"…oil ratio and the gas oil ration trends…" It appears there is a typo. Please fix.	Fixed typo.
34.	3.1.1	18	Figure 3.1-1 displays the existing 4,800 acres in the CFA that has been injecting CO2 since March 2001. This is grammatically confusing. Do you mean that the acres "have been under injection?"	Changed to "Figure 3.1-1 displays wells that have CO2 retention on the 4,800 acres that have been under EOR injection in the CFA since project initialization."
35.	3.1.1	18	There are 49 injectors identified for further injection that Have room for an additional 90 Bscf or CO2 storage or 140 Bscf total space. This is unclear. The first "or" should probably be "of." And should "space" more appropriately be "storage volume"?	Changed "or" to "of" Changed "space" to "volume"
36.	4.2.2	21	"Rule 46 and any special conditions pertaining to mechanical integrity testing…" We suggest you provide a brief description of what Rule 46 regulates in this section for clarity.	Added description for clarity "TRRC Rule §3.46 requirements include special equipment requirements (e.g., tubing and packer) and modification, records maintenance; monitoring and reporting; testing; plugging; and penalties for violations of the rule. Permit revocation may result as a consequence of noncompliance. This TRRC and the OCC detail all the…"
37.	4.2.2	21	"Rule 46 and any special conditions pertaining to mechanical integrity testing required by the OCC and the TRRC are included in the Class II permits issued to CapturePoint, ensure that active injection wells operate to be protective of subsurface and surface resources and the environment." The above is a run-on sentence, please revise.	See Question 36.
38.	4.2.3	22	"… shows the active oil production wells in the CFA." Are there only oil wells, or are there also gas wells? Please clarify.	Added clarifying statement "Once EOR operations commence, the energy content of the produced gas drops and cannot be sold; therefore, no gas wells are identified."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
39.	4.2.3	22	This section provides little characterization of the risk and magnitude of potential leakage from production wells. Why does CapturePoint conclude that leakage through production wells is unlikely? Please expand upon this section.	Added "During production, oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure where the bottom hole wellbore pressure is less than the reservoir pressure. These lower pressure fluids, which also contains CO2, are contained by the casing, tubing, wellhead and flowline all the way to the CTB."
40.	4.2.4	23	This section provides no characterization of the risk and magnitude of potential leakage from inactive wells. Please expand upon this section. In general, please ensure that all leakage pathways have a leakage likelihood characterization and evidence to support the characterization.	Added "Inactive wells have a cast iron bridge plug set or long cement plugs placed above the existing perforations to isolate reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change." Added to Section 4.2.1 "The cement used to plug wells when exposed to CO2 will form colloidal gels that further reduce any flow."
41.	4.8	28	"CapturePoint will reconcile the Subpart W report and results from any event-driven quantification to assure that surface leaks are not double counted." Does CapturePoint mean that they intended to use Subpart W techniques to estimate equipment leakages, and ensure those are consistently represented in the Subpart RR report? In addition, the statement should emphasize that this statement only applies to equipment leaks, and not surface leaks. Please address	Changed to "CapturePoint will use Subpart W techniques to estimate leakages only on equipment and ensure those results are consistently represented in the Subpart RR report. Any event-driven leakage quantification reported in Subpart RR for surface leaks will use other techniques." Subpart RR will be consistently represented.
42.	4.8	28	"As indicated in **Sections 6.4**…." It appears there is a typo in the above phrase, please correct it.	Removed "s"
43.	5.2	28	"…characterization of the Morrow (see section 5.1) **have** suggested…" Please review for grammar.	Changed "have" to "has"
44.	6	29-31	The formatting in this section is cluttered and difficult to follow. Please revise it to improve readability. In particular, more spacing between equations and description of variables will dramatically improve readability.	Changed format adding space.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
45.	6.1	29	"CapturePoint currently receives CO_2 **to** its CFA facility through **their** own pipeline from the Arkalon Ethanol plant in Liberal, Kansas. CapturePoint also recycles CO_2 from **their** production wells in the CFA." We recommend reviewing this sentence for grammar.	Changed "to" to "at". Switched back from British English rules to American English rules by changing "their" to "its".
46.	6.2	30	If aggregating CO_2 injection quantities for all wells, you must use RR-6. Please add to Section 6 as necessary.	CapturePoint does not aggregate individual wells. We have master meters at the CTB and allocate injection to individual well. (See Section 2.3.1)
47.	6.2	30	"…(weight percent CO_2, expressed as a decimal fraction)." Although the X factor (entrained CO_2) was reported earlier in the document, we recommend reporting it again here.	Added ", CU is 0.00236 and NPU is 0.00454 at the last sample"
48.	6.4	3.1	"The following Equation RR-12 pertains to facilities… for which a calculation procedure is provided in subpart W of the GHGRP." Please clarify whether Camrick intends to not produce oil or gas in the future. This may represent a material change in operations and necessitate a resubmission of the MRV plan. If equation RR-12 is not applicable to the operations described in this MRV plan, it can be removed from this section.	In the future, CapturePoint intends to maintain Class II status and will continue to evaluate the cash flow of oil and gas operations, but. Removed RR-12 from document.
49.	8	31-33	The formatting in this section is cluttered and difficult to follow. Please revise it to improve readability. In particular, more spacing between equations and description of variables will dramatically improve readability. Please also review other sections of MRV plan for consistent formatting.	Added formatting to add spacing
50.	8.1.2	32	"Daily totalized volumetric flow meters are used to record CO_2 received via pipeline from the Arkalon ethanol plant in Liberal, Kansas. using a volumetric…" It appears there is a typo in the phrase above, please correct it if so.	Changed to "Daily fermentation CO_2 purchased is received via the pipeline from the Arkalon ethanol plant in Liberal, Kansas, and is measured using a volumetric totalizer, which uses accepted flow calculations for CO_2 according to the AGA Report #3"

Camrick Field Area (CFA)

MONITORING, REPORTING AND VERIFICATION PLAN (MRV)

CapturePoint LLC

CAPTUREPOINT

March 2022

Contents

INTRODUCTION

CapturePoint, LLC (CapturePoint) operates the Camrick Field Area (CFA) located in Beaver and Texas Counties, Oklahoma and in Ochiltree County, Texas for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) with a subsidiary or ancillary purpose of geologic sequestration of CO_2 in a subsurface geologic formation. The CFA was discovered in 1955 and is composed of three units, the Camrick Unit (CU) that was unitized by Humble Oil Company on October 14, 1969, the North Perryton Unit (NPU) that was unitized by Humble Oil Company on March 17, 1969 and the Northwest Camrick Unit (NWCU) that was unitized by Atlantic RichField Company on September 15, 1972. The Units were formed for the purpose of waterflooding with salt water sourced from the Wolfcamp formation. The field structure is a lenticular bedding sand trending northwest to southeast with the average top of sand at 7250 feet, true vertical depth. CapturePoint has been operating the CFA since 2017. CapturePoint acquired the CFA from Chaparral Energy LLC, which initiated the CO_2-EOR project in March 2001 for the CU and January 2007 for the NPU. No CO_2 has been injected in the NWCU. CapturePoint intends to continue CO_2-EOR operations until the end of the economic life of the CO_2-EOR program using various Class II injection wells as defined by Underground Injection Control (UIC) regulations and permitted under Texas Railroad Commission Statewide Rule 46 and the Oklahoma Corporation Commission OAC 165:10. In this document, the term "gas" usually means a mixture of hydrocarbon light end components and the CO_2 component that can be produced as part of the EOR process.

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

This MRV Plan contains ten sections:

Section 1 contains facility information.

Section 2 contains the project description including: a detailed description of the injection operation including the duration and volume of CO_2 to be injected; a detailed description of the geology and hydrogeology of the CFA located on the northwest shelf of the Anadarko basin and a detailed characterization of the injection reservoir and modeling techniques employed.

Section 3 contains the delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA), both defined in 40 CFR 98.449, and as required by 40 CFR 98.448(a)(1), Subpart RR of the GHGRP.

Section 4 identifies the potential surface leakage pathways for CO_2 in the MMA and evaluates the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. This section also describes the strategy for detecting, verifying, and quantifying any surface leakage of CO_2 as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Finally, this section also demonstrates that the risk of CO_2 leakage through the identified pathways is minimal.

Section 5 describes the strategy for establishing the expected baselines for monitoring CO_2 surface leakage as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP.

Section 6 provides a summary of the considerations used to calculate site-specific variables for the mass balance equation as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 provides the estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 describes the quality assurance and quality control procedures that will be implemented for each technology applied in the leak detection and quantification process. This section also includes a discussion of the procedures for estimating missing data as detailed in 40 CFR 98.445.

Section 9 describes the records to be retained according to the requirements of 40 CFR 98.3(g) of Subpart A of the GHGRP and 40 CFR 98.447 of Subpart RR of the GRGRP.

Section 10 includes Appendices supporting the narrative of the MRV Plan.

1 Facility

1.1 Reporter Number

The CU CO_2 Flood reports under Greenhouse Gas Reporting Program Identification number 544678 and the NPU CO_2 Flood reports under Greenhouse Gas Reporting Program Identification number 544679.

1.2 UIC Permit Class

For injection wells (see Appendix 2) that are the subject of this MRV plan, the Oklahoma Conservation Commission (OCC) has rules governing Undergound Injection Control (UIC) Class II injection wells; OAC 165:10-5-1 through OAC 165:10-5-15, OAC 165:5-7-27, OAC 165:5-7-30, the request for an exception to UIC rules under OAC 165:5-7-29, and other rules governing filing forms. Also, the Texas Railroad Commission (TRRC) has issued Underground Injection Control (UIC) Class II enhanced recovery permits under its State Rule 46, Texas Administrative Code (TAC) Title 16 Part 1 Chapter 3. Also, all wells in the CFA, including both injection and production wells, are regulated by the OCC and the TRRC, which have primacy to implement the UIC Class II program.

1.3 UIC Injection Well Numbers

A list of the injection wells in the CFA is provided in Appendix 1. The details of the injection process are provided in Section 2.3.

2 Project Description

2.1 Project Characteristics

2.1.1 Estimated years of CO_2 injection

It is currently projected that CapturePoint will inject CO_2 for an additional 12 years.

2.1.2 Estimated volume of CO_2 injected over lifetime of project

The chart to the left in Figure 2.4-7 in Section 2.4 - Forecasted cumulative CO_2 injection volume of approximately 100 billion standard cubic feet (Bscf) or 5.3 million metric tonnes

(MMMT) through October 2034. For the period September 2020 through October 2034, an additional 52.5 Bscf or 2.77 MMMT will be stored in the CFA.

2.2 Environmental Setting of MMA

2.2.1 Boundary of the MMA

CapturePoint has defined the boundary of the MMA as equivalent to the boundary of the CFA plus ½ mile beyond. A discussion of the methods used in delineating the MMA and the AMA are presented in Section 3.

2.2.2 Geology

The geological discussions in Sections 2.2.2 and 4.3-4.4 are based on analysis of logs from both the Farnsworth Unit, which is located 10 miles South-South-West of the CFA, and the CFA. The descriptions of cores included sections from overlying seals as well as the shale underlying the main reservoirs, petrographic thin section descriptions and point counts as well as a variety of special analytical techniques including X-ray diffraction (XRD), which is the science of determining the atomic and molecular structure of rock crystals with an X-ray beam; scanning electron microscope (SEM) analysis; which uses a beam of electrons to define the surface of crystals; carbon isotope analysis to estimate the age of the sample; and a variety of mechanical tests. Two dimensional (2D) and three dimensional (3D) geophysical surveys were also used as part of the Farnsworth Unit MRV Plan (2021). Details of recent geological investigations can be found in Gallagher (2014), Gragg (2016), Rasmussen et al (2019), Rose-Coss et al (2015), Trujillo (2018), Hobbs et al (2019), and Gragg et al (2018).

2.2.2.1 Tectonic Setting and Stratigraphy

The CFA is located on the northwest shelf of the Anadarko basin (Figure 2.2-1) and is one of many oil fields in the area that produce from a sequence of alternating sandstones and mudstones deposited during the late Pennsylvanian Morrowan period. Oil production and CO_2 injection at CFA is restricted to the operationally named Morrow B sandstone; the uppermost Morrow sandstone encountered below the Atokan Thirteen Finger limestone. The primary caprock intervals at CFA are comprised of the upper Morrow shale and the Thirteen Finger limestone (Figure 2.2-2). The Morrowan and Atokan intervals were deposited approximately 315-300 million years ago. Overlying stratigraphy includes Late Pennsylvanian through the middle Permian shales and limestones, with lesser amounts of dolomite, sandstone and evaporites (Ball, 1991). The reservoir is approximately 60 feet thick throughout the field and lies at a depth of approximately 6800-7600 feet. The primary seal rocks of the Morrow shale and the Thirteen Finger Limestone comprise a package of approximately 180-200 feet thick in the field and are overlain by thousands of feet of Atokan and younger limestones and shales.

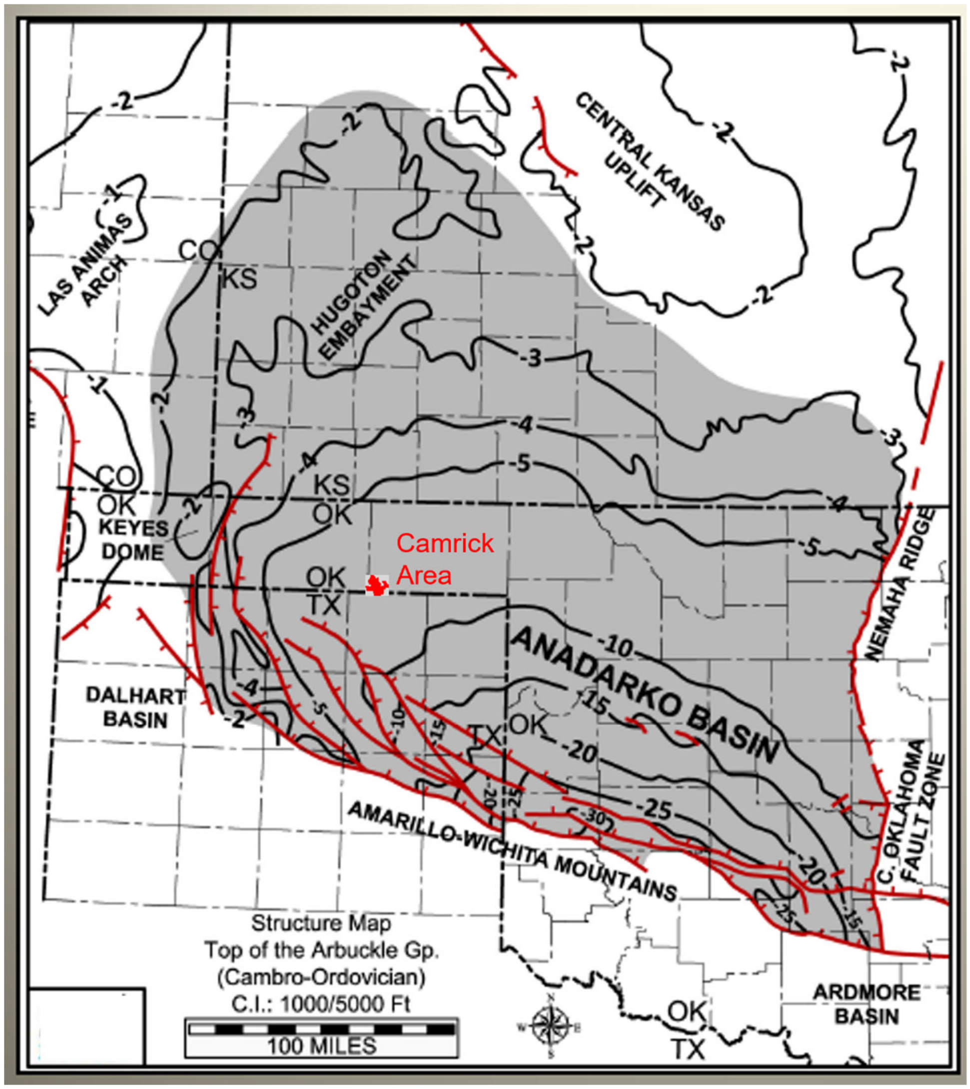


Figure 2.2-1- Location of the Camrick Field Area (CFA) on the Northwest Shelf of the Anadarko Basin in West Texas. Red lines are approximate locations of faults that have been documented in the region.

System	Series	Group	Formation		
Pennsylvanian	Virgilian	Wabaunsee			ANADARKO
		Shawnee	Heebner Endicott Toronto		
		Douglas	Douglas **U. Tonkawa**		
	Missourian	Lansing	L. Tonkawa Cottage Grove Hogshooter	GRANITE WASH	
		Kansas City	Checkerboard **Cleveland**		
	Marmaton	Marmaton	**Marmaton** Oswego		
	Cherokee Shale				
	Atoka	Upper Dornick Hills	**Atoka** Thirteen Finger		
	Morrow	Lower Dornick Hills	Upper Morrow Middle Morrow Lower Morrow		
	Springer				
Mississippian	Chester				
	Meramec	Meramec	St. Genevieve St. Louis Spergan Warsaw		
	Osage				
	Kinderhook				
	Chattanooga				

Figure 2.2-2- Stratigraphic section.

Tectonic Setting

From CFA's location on the western edge of the basin, the Anadarko Basin plunges to the southeast (Figure 2.2-3) where it reaches depths of over 40,000 feet (12,192 meters) adjacent to the Amarillo-Wichita Uplift (Perry, 1989). Maximum rates of subsidence occurred during Morrowan to Atokan times (Evans, 1979; Perry, 1989; Higley, 2014). Positive features that might have influenced deposition within the region include the Ancestral Rockies to the north, the Central Kansas uplift to the northeast, and the Wichita-Amarillo uplift to the south (Evans, 1979; Munson, 1989). Of note is the fact that during the Pennsylvanian time, the CFA was located on the basin shelf in an area that was not affected greatly by tectonic deformation. Although faults have been reported previously in the northwest Anadarko Basin, we found no direct evidence for tectonic faults within the CFA (see Section 4).

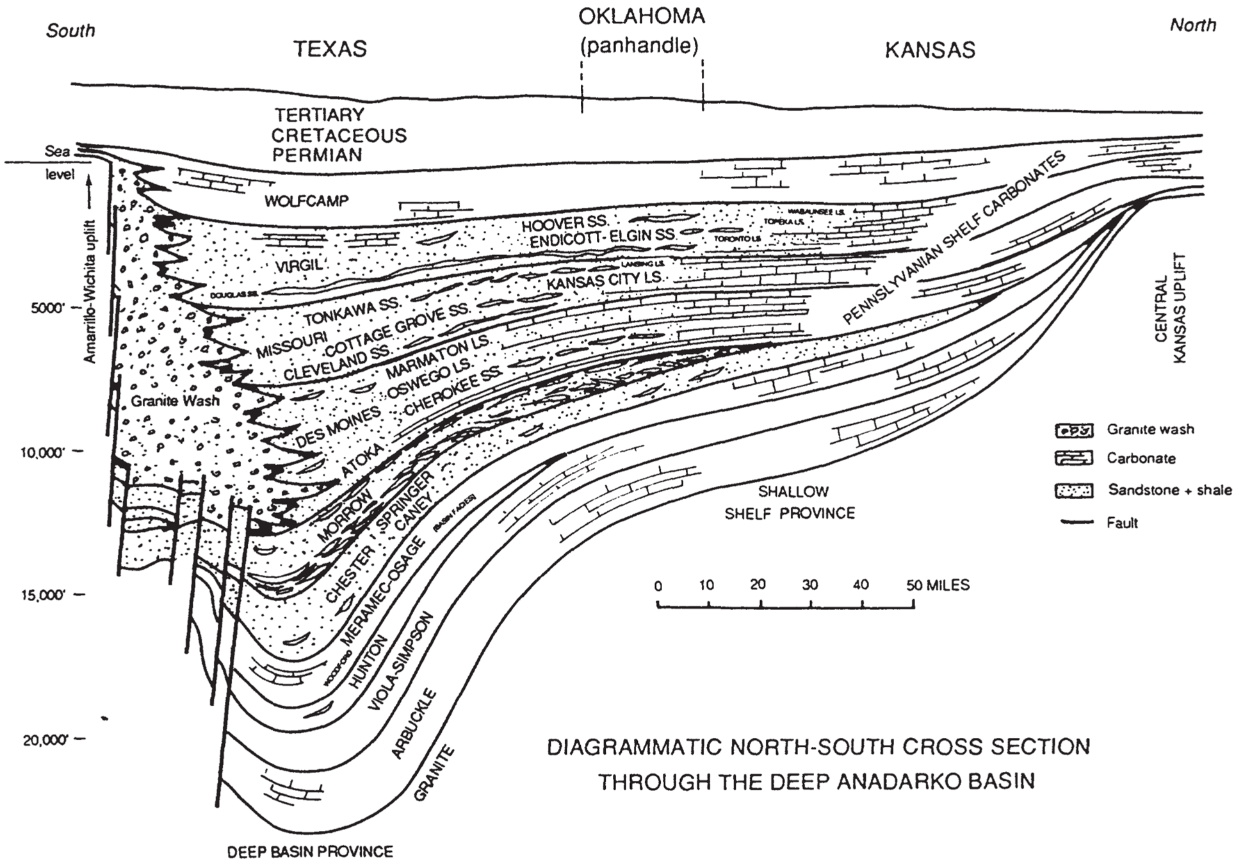


Figure 2.2.3 Diagrammatic North-South Section (Bottom) of the CFA.

Stratigraphy

Reservoir

Upper Morrowan sandstones in the Anadarko Basin margins have long been recognized as fluvial deposits (Swanson, 1979; Sonnenberg, 1985; Munson, 1989; Krystinik and Blakeney, 1990; Bowen et al., 1990; Al-Shaieb et al., 1995; Mckay and Noah, 1996; Puckette et al., 1996; Bowen and Weimer, 2003, 2004; Devries 2005; Puckette et al., 2008; Gallagher, 2014). At the Farnsworth Unit and similarly at the CFA, the Morrow B is described as a relatively coarse-grained subarkosic sandstone and per depositional pathway. The upper Morrowan facies, with sequences of basal conglomerate, coarse-grained sandstone, and fine-grained sandstone appear to be typical of incised valley deposits, as described by Wheeler et al. (1990), Krystinik and Blakeney (1990), Bowen et al. (1990), Blakeney et al. (1990), Sonnenberg et al. (1990) and Puckette et al. (2008).

Primary Seals

The Morrow B sandstones are encased above and below by shales. Contacts with shale both below and above the sandstone are sharp and irregular. The Morrow shale generally fines upwards in a series of thin beds that alternate between upper fine sands and fine to medium muds. Sand content decreases upwards through the section.

The Thirteen Finger limestone formation has two different lithofacies: diagenetic limestone (cementstone) and pyrite and fossil bearing fine to medium mudstone and coal. The two facies are intercalated with each other but tend to cluster in layers dominated more by one or the other.

The entire Thirteen Finger interval is typically 130 feet (39.6 meters) thick, comprised of mudstone, coal, and limestone. The mudstone is calcite rich, with some dolomite, and is completely diagenetic in origin and probably formed relatively soon following deposition.

2.2.2.2 Hydrogeology

Information about Morrowan and Atokan formation water flow during oil operations has not been discovered in any oil or gas company published reports or academic research studies in the Anadarko Basin. Groundwater flow rates in confined deep Anadarko layers at present are considered to be low to no flow (Nelson and Gianoutsos, 2014). Their arguments are based on (1) restricted recharge in the western basin, (2) density barriers to flow in the east, and (3) an overpressure pocket inhibiting flow in the deep basin. Jorgenson (1989) suggested flow could be west to east, driven by potential recharge to elevated units in the west and discharge at lower elevation outcrops in the east. The CFA CO_2 injection and production operations will not cause water to flow to outcrops of the Late Carboniferous (Pennsylvanian) time period that extend from Brownwood, Texas, to the Jacksboro/Bowie, Texas, area, which are hundreds of miles away (The Paleontology Portal).

The Carboniferous is a geologic period and system that covers 60 million years from the Devonian Period 358.9 million years ago, to the beginning of the Permian Period, 298.9 million years ago. As noted in the Section 2.2.2.1, the Morrowan and Atokan intervals of the CFA were deposited approximately 315-300 million years ago and are contained in the Carboniferous period.

2.3 Description of the Injection Process

Figure 2.3-1 depicts a simplified flow diagram of the facilities and equipment within the boundaries of the CFA. CO_2 captured from the ethanol plant fermentation process is delivered via pipeline to the field for injection. The Arkalon plant in Liberal, Kansas is the only source of CO_2 to the field. The amount delivered is dependent on the production of CO_2 produced from the fermentation process. This amount will vary but should average 12 MMCFD. Once CO_2 enters the CFA there are three main processes involved in EOR operations. These processes are shown in Figure 2.3-1 and include:

1. CO_2 distribution and Injection. Purchased CO_2 is combined with recycled CO_2 from the CFA central tank battery (CTB) and sent through the main CO_2 distribution system to various water alternating gas (WAG) injectors.
2. Produced Fluids Handling. Full well stream fluids are produced to the “all well test” (AWT) site. The AWT site has two major purposes; 1) to individually test a well’s

performance by separating and metering oil, gas and water, and 2) to separate all gas from liquid then send these two phases to the CTB for final separation; while only the gas from NPU is sent to the CTB the NPU oil and water remains in Texas.

3. Produced Gas Processing. All gases from the AWT sites are transferred to the CTB to separate the oil, gas and water using a series of vessels and storage tanks.

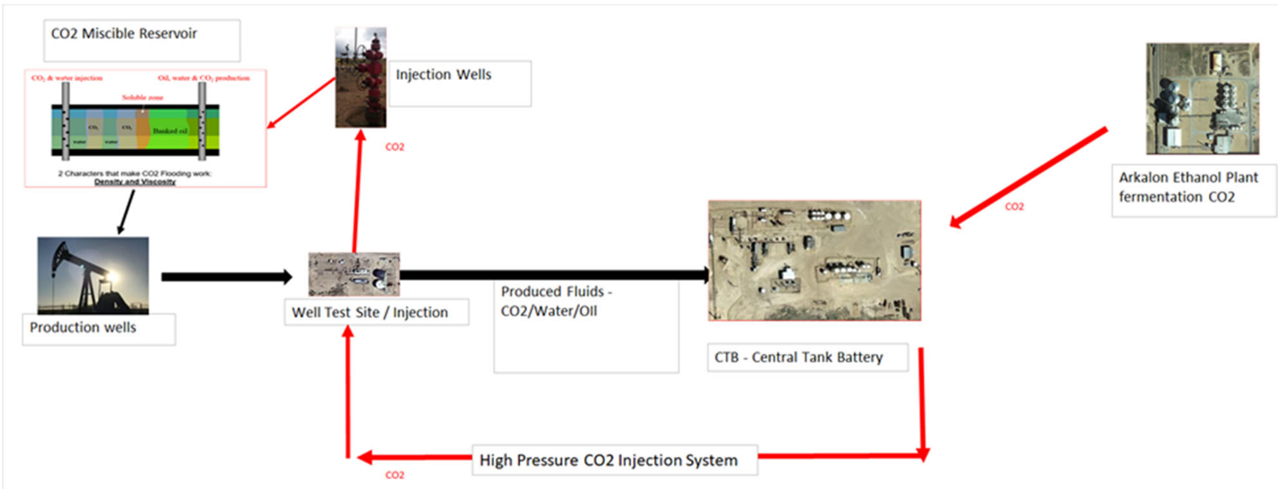


Figure 2.3–1 - Simplified flow diagram of the facilities and equipment within the boundaries of the Camrick Field Area.

2.3.1 CO_2 Distribution and Injection

CapturePoint purchases CO_2 from Conestoga Energy Partners, the parent company of the Arkalon Ethanol plant located in Liberal, Kansas. A custody transfer meter is located in the compression facility owned and operated by CapturePoint. The purchased CO_2 from the fermentation process is transported via a United States Department of Transportation (DOT) regulated pipeline to the CFA. A totalizer meter, for the purchased CO_2, is located in the field where instantaneous data is summed into a 24-hour flow rate which is recorded. A totalizer meter is a meter approved by the American Gas Association (AGA) Report #3 to measure the flowrate of gases. The actual measurements taken are temperature, line pressure and differential pressure across the meter. Gas produced, which contains recycled CO_2, from the wells is compressed and metered by a similar totalizer meter as the purchase CO_2 meter and is recorded daily.

CapturePoint currently has seven active injection manifolds and approximately 29 active injection wells that the CO_2 is distributed through. When the MRV plan becomes active, the daily injection volume of the combined purchased CO_2 and recycled CO_2 will be approximately 24 MMCFD. Of this volume 12 MMCFD is purchased CO_2 and 12 MMCFD is recycled CO_2. This ratio of purchased CO_2 to recycled CO_2 is expected to change over time, with the percentage of recycled CO_2 increasing and purchased CO_2 decreasing. The current reservoir management plan projects that CO_2 purchases will remain constant at 12 MMCFD for 12 years and decline after 2034. A reservoir management plan is an integrated process using various surveillance techniques, economic evaluations, and accepted petroleum technical practices to efficiently operate enhanced oil recovery projects.

The seven injection manifolds currently in the field distribute the CO_2 to the field. These manifolds have valves to switch to water when the time is called for. Depending on the reservoir management plan the WAG cycle will be adjusted to maximize oil recovery and minimize CO_2 utilization in each injection pattern. At each injection well pad there is a totalizer to measure the volumes injected every 24 hours. This data is collected daily by the field personnel and input into the data warehouse to be allocated for the pattern injection.

The two totalizer meters as described above will be used to determine the total volume injected used in section 7 for the mass balance equations necessary to determine annual and cumulative volumes of the stored CO_2.

2.3.2 Produced Fluids Handling

As injected CO_2 and water migrate through the reservoir, a mixture of oil, gas and water (referred to as "produced fluids") flows to the production wells. Gathering lines bring the produced fluids from each production well to the AWT sites. CapturePoint has approximately 32 active production wells producing at any time. Each AWT has two separators. The first separator is used for testing individual wells to separate the gas, oil and water produced from an individual well. This gas, oil and water is subsequently measured and recorded for the well. Each producing well is production tested every 30 to 60 days after the last production test, or after the well is returned to production. Depending on the reservoir management plan well testing can be more frequent to obtain data. The second separator is used to separate the gas from the oil/water mixture from the other wells producing into the AWT and the gas and liquids are displaced from the vessel in separate lines. Leaving the AWT sites are two lines transporting produced fluids. One for the liquid phase, a mixture of oil and water, and one for the gas phase. However, the AWT in NPU does not transfer oil or gas to the CTB, it only transfers gas while reinjecting water with pumps at the NPU AWT and sells oil at the NPU AWT.

When gas and liquid lines enter the CTB a series of vessels separate the oil, gas and water to be accounted for and distributed for sales or reinjected. The liquid phase line has vessels to separate the oil from the water using density and residence time. The gas phase vessels collect any free liquids entrained with the gas. These free liquids are then combined back into the liquid phase line. All gas and water are reinjected, and the oil, which contains an estimated 2,360 ppm CO_2 (0.236%) for CU and 4,540 ppm CO_2 (0.454%) for NPU, is sold out of tanks. Annually, the oil from the stock tank is analyzed by a laboratory using ASTM crude oil analysis methods to determine the CO_2 content in the oil being sold.

After separation, the gas phase, which is approximately 92-95% CO_2, is mixed with reservoir volatile components, compressed, and distributed throughout the high-pressure distribution system using reciprocal compression and high-pressure horizontal pumps.

The water is transferred from the separation vessels to tanks for reinjection. After the water is conditioned, it is either reinjected at the WAG skids or disposed of into permitted disposal wells. Although CapturePoint is not required to determine or report the amount of dissolved CO_2 in the water, analyses have shown the water typically contains <690 ppm (0.069%) CO_2.

CFA production has trace amounts of hydrogen sulfide (H_2S), which is toxic. There are approximately 8-10 workers on the ground in the CFA at any given time, and all field and contractor personnel are always required to wear H_2S detectors. The primary purpose of the H_2S detectors is protecting people from the risk of being harmed. The detection limit of the H_2S detectors is quantified for readings in the range of 0-100 ppm and will sound an alarm above 10 ppm. The secondary purpose of the H_2S detectors would be to provide an indication of emissions of gas from a pipeline or surface equipment, that might go unnoticed by other observations or measurements. No gas volumes can be calculated based on the detector reading or alarm; only a H_2S leakage is detected and located. Once identified, a further response will be initiated and CO_2 volumes will be quantified as discussed in sections 4.5, 4.6, 5.4 and 8.1.5 of this MRV plan.

2.3.3 Produced Gas Handling

Produced gas separated at the CTB is stripped by a series of vessels of entrained and free water. The water content has been recorded to be < 20 pounds mass per MMCF, thus dehydration is not necessary. The gas is then sent to a centralized compression system to be compressed and placed in the high-pressure distribution system. This compression turns the CO_2 into a variable density liquid, which is then transported out via high pressure lines to the AWT sites where a manifold splits this dense CO_2 to the wells that are on CO_2 injection at that time.

2.3.4 Facilities Locations

The locations of the AWT sites are positioned in the field to access both injection distribution and production gathering. The CTB is where the final separation and injection equipment is maintained and operated. The water injection station is where the horizontal pumps are located to reinject the produced brine.

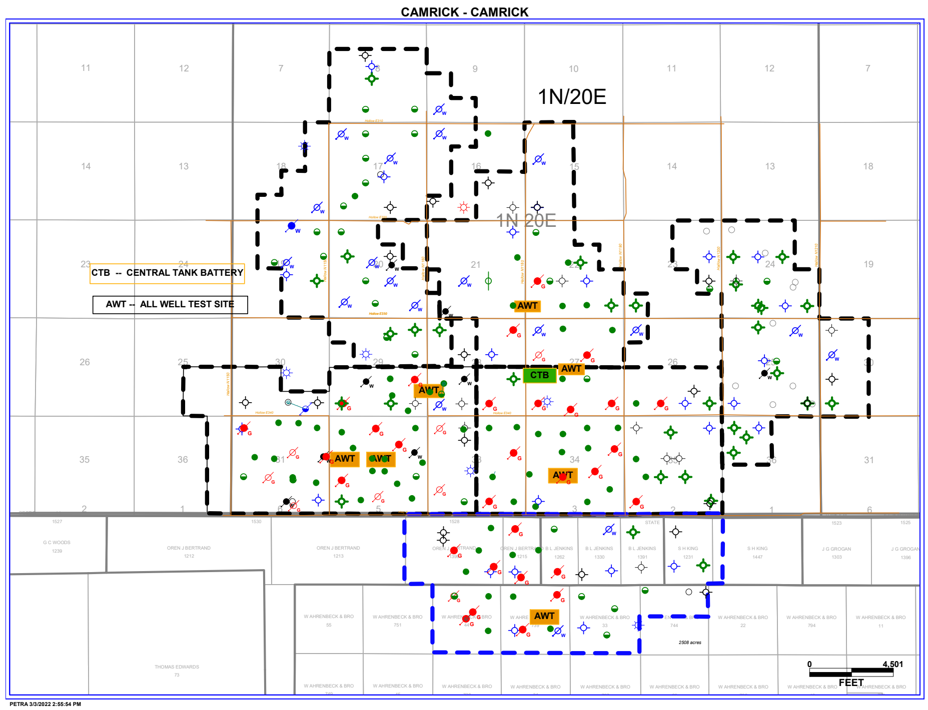


Figure 2.3-2 – Location of All Well Test (AWT) sites and Central Tank Battery (CTB) in the CFA

2.3.5 Water Conditioning and Injection

Produced water collected at the CTB is collected in a series of vessels and tanks in a cascade system. This allows any entrained oil to further separate to the top of the tanks because of the density difference and is skimmed off and put back in the oil separation system. The clean water is then transferred to the water injection system where it is boosted in pressure and sent out to the AWT sites for distribution to all wells that are currently on water injection.

2.3.6 Well Operation and Permitting

The Oklahoma Conservation Commission and Texas Railroad Commission rules (Appendix 2) govern well location, construction, operation, maintenance, and closure for all wells in permitted units and wells. CapturePoint follows these rules and regulations to maintain safe and efficient operations. This includes complying with all current and updated information for mechanical integrity testing, well repairs for injection wells, drilling and completion permitting and reporting.

Briefly current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered.
- That activities governed by the rule cannot result in the pollution of subsurface or surface water.
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface waters.

- That wells file a completion report including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore).
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected.

And that all wells follow plugging procedures that require advance approval from the Director and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.

2.3.7 Number, Location and Depth of Wells

CapturePoint's CFA injection wells are listed in Appendix 1. Injection is into the Upper Morrowan, a lenticular bedded sandstone trending northwest to southeast with the average top of sand at 7250 feet, true vertical depth. The Upper Morrowan is described in section 2.2.2.1 above.

2.4 Reservoir Characterization

2.4.1 Reservoir Description

The target reservoir CFA Morrow B is a sandstone formation overlain by the Morrow shale and Thirteen Finger limestone, which serve as excellent seals for injected CO_2 as determined by Farnsworth data (Ampomah et al., 2016a). The Morrow B sandstone reservoir is at a depth between 6800 feet and 7600 feet subsurface with an average dip of less than one degree (Figure 2.4-1). The productive limit of the CFA is about 80 to 90 percent of the total operated surface acreage, which is 14,652.315 acres. The maximum pay thickness is 56 feet with an average of 15 feet and does diminish to zero in spots.

The CFA is approximately 8 mi by 7 mi that have areas that exhibit different reservoir behavior. The southwest portion of CU was most prolific oil producer under primary and secondary production whereas the western portion of NPU is now responding to CO_2 better than historical operations would have indicated.

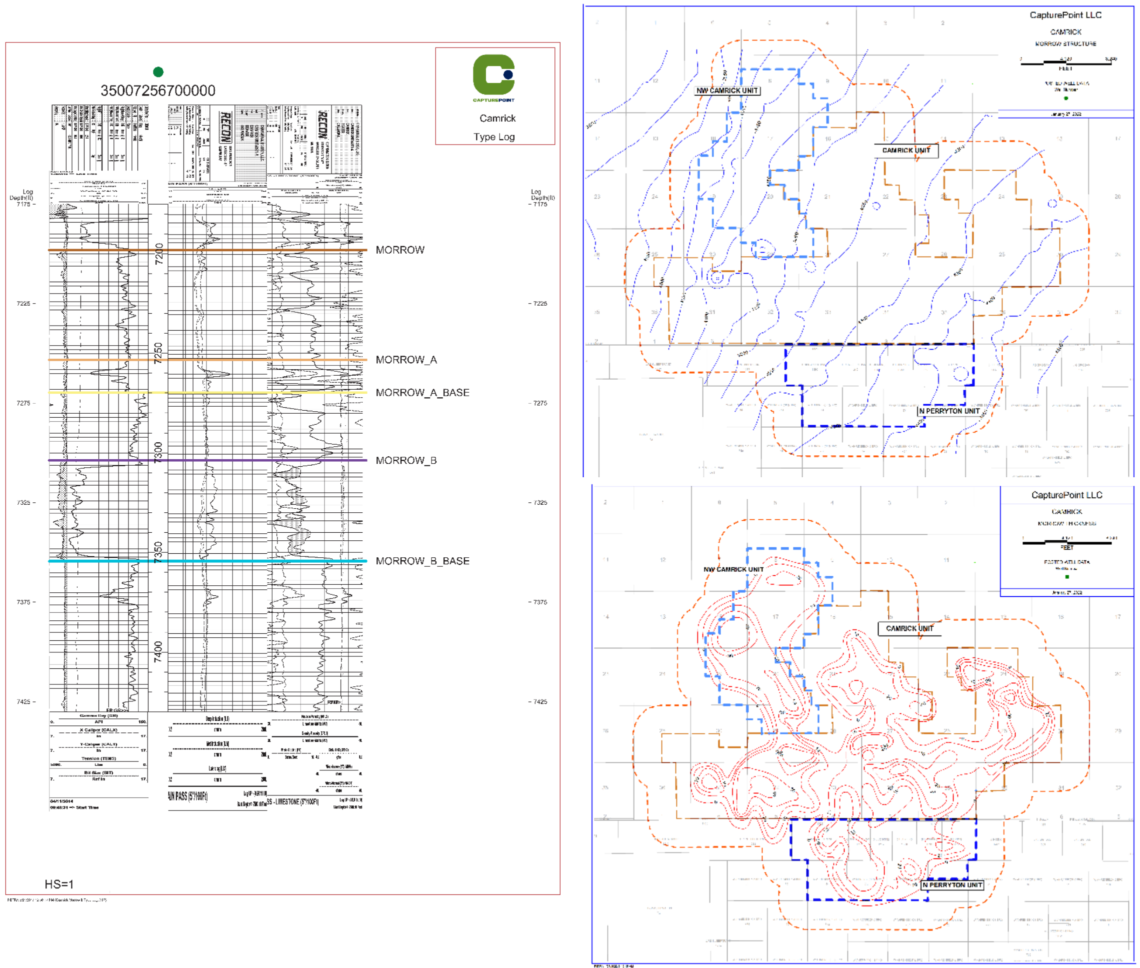


Figure 2.4-1- (Left) Type log of CFA caprock and reservoir. (Upper Right) Surface contour of Morrow top. (Lower right) Thickness map of Morrow sands.

2.4.2 Reservoir Fluid Modeling

The compositional fluid model was constructed for the CapturePoint operated Farnsworth Unit. From laboratory compositional analysis an equation of state was tuned (Gunda et al., 2015). The minimum miscibility pressure (MMP) experiment was then simulated using a one-dimensional model (Figure 2.4.3). The simulated Farnworth Unit MMP of 4009 psia compared to an MMP value of 4200 psia derived from laboratory experiments provided by the operator represents a less than 5% error (Gunda et al., 2015).

The reservoir temperature in the CFA is 152 degrees Fahrenheit or 16 degrees lower than the temperature at Farnsworth Unit of 168 degrees. Using parameters of the Alston empirical correlation (1985), the MMP would be 170 psia lower at the CFA or 3510 psia compared to 3680 psia at the Farnsworth Unit (Figure 2.4.4).

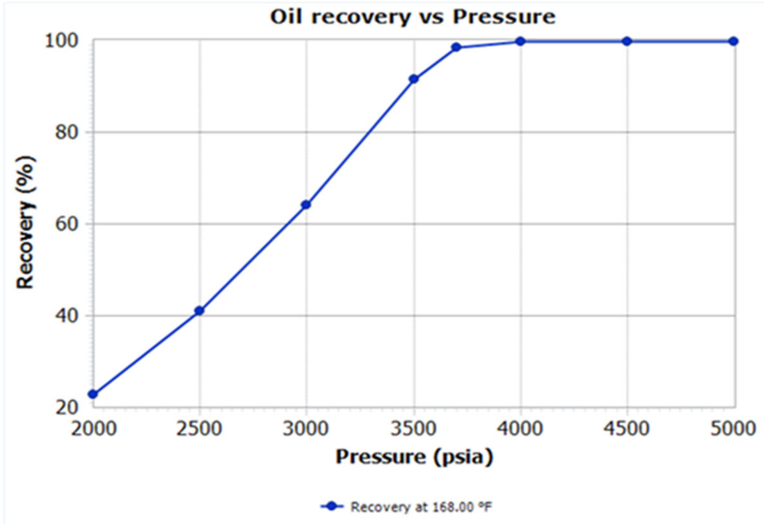


Figure 2.4-4. Oil recovery plot for 1D slim tube test for Farnswoth Unit.

2.4.3 CO_2 Analogy Field Study

Based on similar geologic, petrophysical, engineering and operational parameters between the Farnsworth Unit and the CFA, the oil recovery performance of both fields is expected to be similar. Due to the stratigraphic nature of the Morrow channel sands, the potential movement of CO_2 is severely limited. The CFA area has contained the free phase CO_2 plume in a very confined area since March 2001 as exhibited by oil, water and CO_2 recovery performance. Also, no production performance exists which indicates any plume will move outside of the MMA at the end of year t + 5, per §98.449 definitions.

2.4.4 CO_2 – EOR Performance Projections

For years the oil industry has used dimensionless equations to predict the amount of oil that can be recovered using CO_2 for flooding oil reservoirs (Lee et al, 2018, Stell 2010). The amount of oil recovered from projects is plotted as a decimal fraction of the original-oil-in-place versus the decimal fraction of the hydrocarbon pore volume (HPV) of CO_2 injected into the oil reservoir as measured in reservoir barrels (RB).

The CFA has been injecting CO_2 since March 2001. The dimensionless curves were matched to historical performance through early 2020. (Figure 2.4.5) The supply of CO_2 was curtailed from March 2020 until present, due to oil price uncertainty, and will resume after the Arkalon Plant upgrade that will be finished in the 4th quarter of 2022.

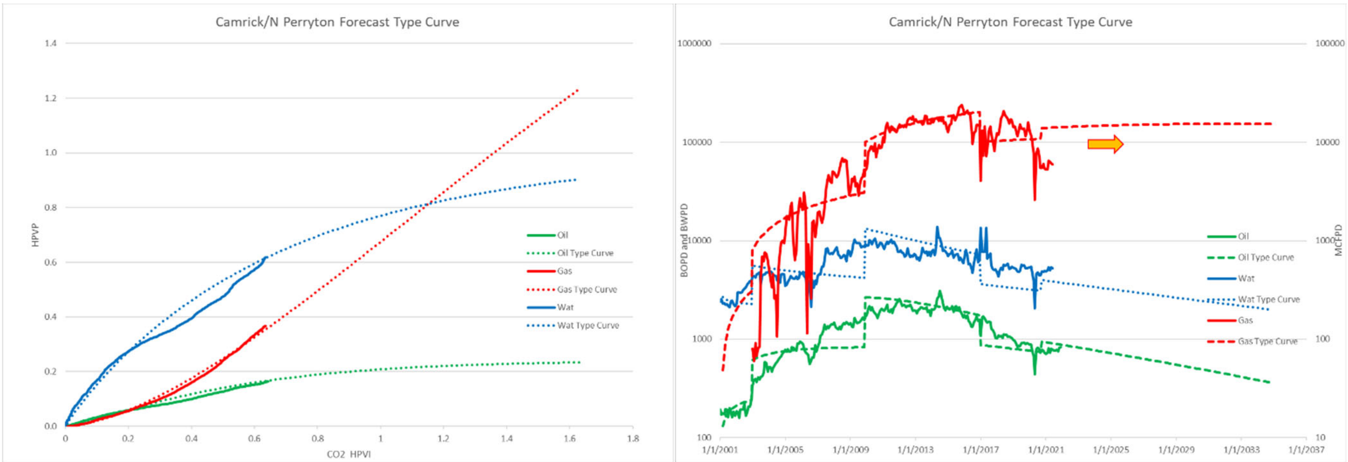


Figure 2.4-5- Dimensionless curves for CO_2 injection (left) with rate time curves (right).

The dimensionless water oil ratio and the gas oil ration trends (Figure 2.4.6) for the CFA flooded acreage are very similar to what was forecasted by simulation in the Farnsworth Field as expected because of the porosity, permeability, and sand similarities.

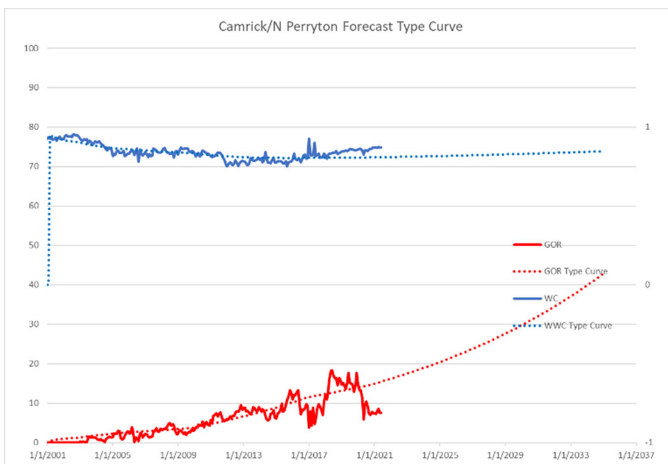


Figure 2.4-6- Dimensionaless water cut and GOR vs. observed EOR data.

The CO_2 storage volumes for Arkalon fermentation CO_2 were also forecasted (Figure 2.4.7) using the same dimensionless technique and indicates that the flooded acreage still has significant additional storage potential. The maximum CO_2 storage is limited to the amount of space available by the removal of the produced oil and should have room to store approximately 0.4 to 0.5 decimal fraction of HPV amounting to 30 to 40 MMB.

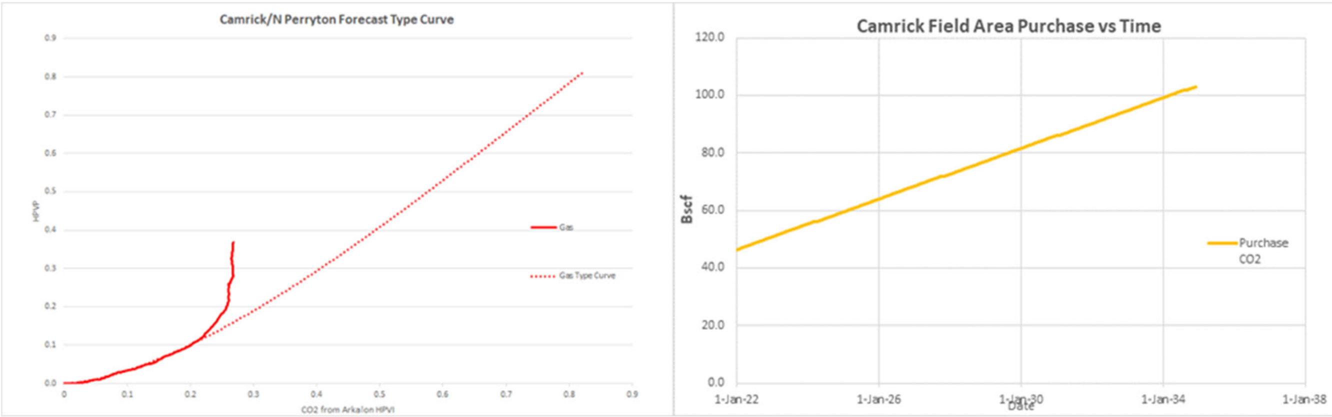


Figure 2.4-7 – Dimensionless CO_2 Fermentation Curves (Left) vs CO_2 Fermentation Volume (Right)

3 Delineation of Monitoring Area

3.1 MMA

As defined in Subpart RR, the maximum monitoring area (MMA) is equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The purchase volumes that are displayed in figure 2.4.7 were mapped and are displayed in Section 3.1.1 indicates that CO_2 storage pore space is available, barring unforeseen future operational issues. Therefore, CapturePoint is defining the MMA as the boundary of the CFA plus an additional one-half mile buffer zone. This will allow for operational expansion throughout the CFA for the next 12 years, the anticipated life of the project.

3.1.1 Determination of Storage Volumes

Figure 3.1-1 displays the existing 4800 acres in the CFA that has been injecting CO_2 since March 2001. The volume of the oil recovered since August 1955, resulted in a voidage space of 36 MMscf of CO_2 per acre of surface area that was later filled with water during waterflood. The average decimal fraction of CO_2 injection to hydrocarbon pore volume left in the ground after accounting for CO_2 production through 2021 is 0.29. The lateral extent of CO_2 in the injection zone or the CO_2 storage radius for each well was estimated based on cumulative CO_2 injected times the decimal fraction of CO_2 remaining divided by the voidage space. The largest CO_2 storage areas are around wells that injected CO_2 for the most years.

Figure 3.1.2 displays the potential area of the reservoir that can be filled with CO_2 with the existing injection wells. This assumed that only 78 percent of the average injection pattern area or 80 acres could be filled. There are 49 injectors identified for further injection that have room for an additional 90 Bscf or CO_2 storage or 140 Bscf total space.

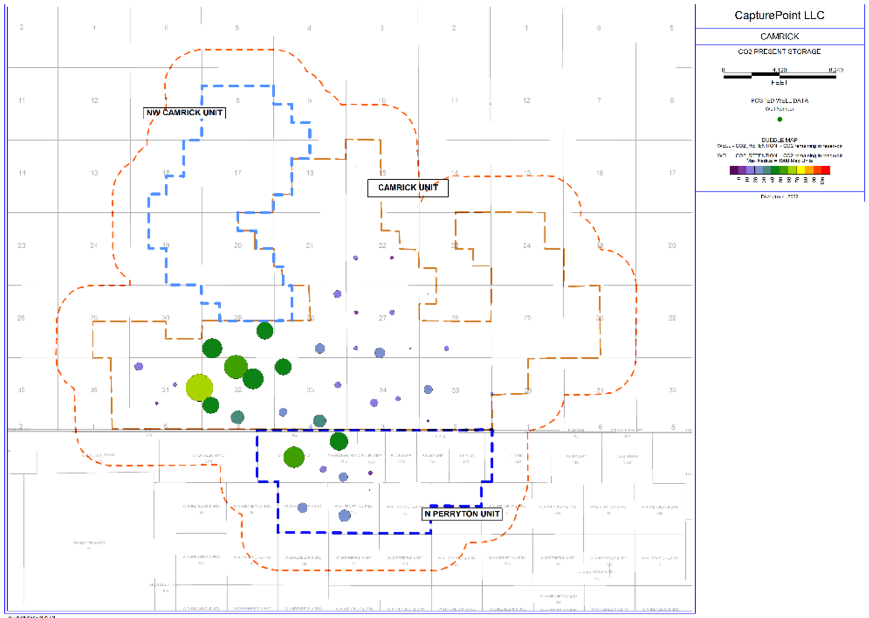


Figure 3.1.1 Estimated CO_2 storage as of 2021 in CFA

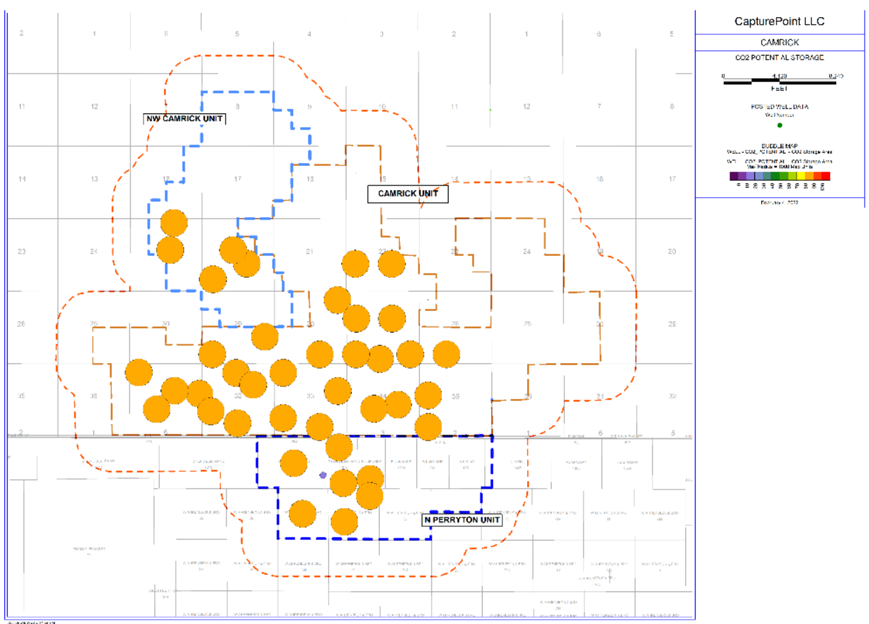


Figure 3.1.2 Potential Total CO_2 Storage in the CFA

3.1.2 Determination of Buffer Zone

CapturePoint intends to implement a buffer zone of one-half mile around the CFA, the minimum required by Subpart RR, because the site characterization of the Morrow did not reveal any leakage pathways that would allow free-phase CO_2 to migrate laterally thereby warranting a buffer zone greater than one-half mile.

3.2 AMA

Currently, CapturePoint's operations are focused in the western portion of the CFA. However, it is anticipated as the project develops, additional activity will occur in the NWCU of the CFA; therefore, requiring active monitoring in that area. However, project development is driven by the market price of oil so CapturePoint is unable to provide a specific time in the future when the eastern portion of the CFA will be actively monitored. Therefore, for the purposes of this MRV plan, CapturePoint has chosen to include the entire CFA in the AMA.

4 Identification and Evaluation of Leakage Pathway

Since its discovery in 1955, the unitization of the different units from 1969 to 1972, and the commencement of CO_2 EOR in 2001; the CFA is an analogous field to the Farnsworth Unit, which has undergone extensive investigation and documentation as indicated in Section 2. From this body of work, CapturePoint has identified the following potential pathways of CO_2 leakage to the surface. This section will also address detection, verification, and quantification of leakage from each pathway.

4.1 Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO_2 EOR projects. Ongoing field surveillance of pipelines, wellheads and other surface equipment via personnel instructed on how to detect surface leaks and other equipment failure minimizes releases. In addition, requirements of the Oklahoma Conservation Commission (OCC) rules and the Texas Administrative Code (TAC) rules for the Texas Railroad Commission (TRRC) Oil and Gas Division to report and quantify leaks, both serve to minimize leakage of GHG from surface equipment. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. As described in Section 6.4 below, should leakage from surface equipment occur it will be quantified according to the procedures in Subpart W of the GHGRP.

4.2 Leakage from Wells

CapturePoint has identified 68 abandoned wells, 49 injection wells (29 active) and 94 production wells (59 active) within the MMA and assessed their potential for leakage of CO_2 to the surface as listed in Appendix 1.

4.2.1 Abandoned Wells

Figure 4.2-1 shows all wells plugged and abandoned in the CFA. Because the CFA was unitized in 1969 to 1972, all plugging and abandonment activities of wells within the CFA have been conducted under the regulations of the OCC and the TRRC for plugging wells. CapturePoint concludes that leakage of CO_2 to the surface through abandoned wells is unlikely. However, strategies for leak detection are in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

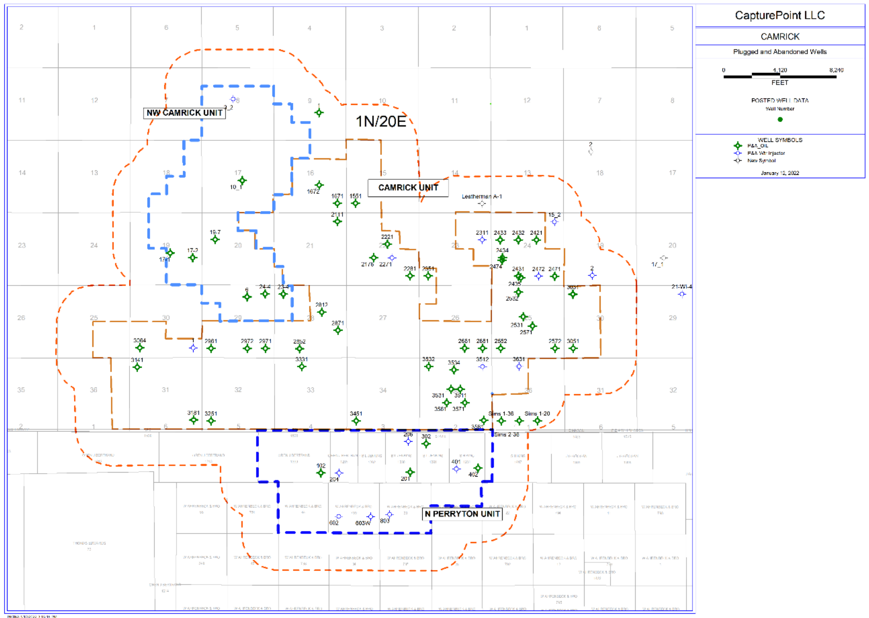
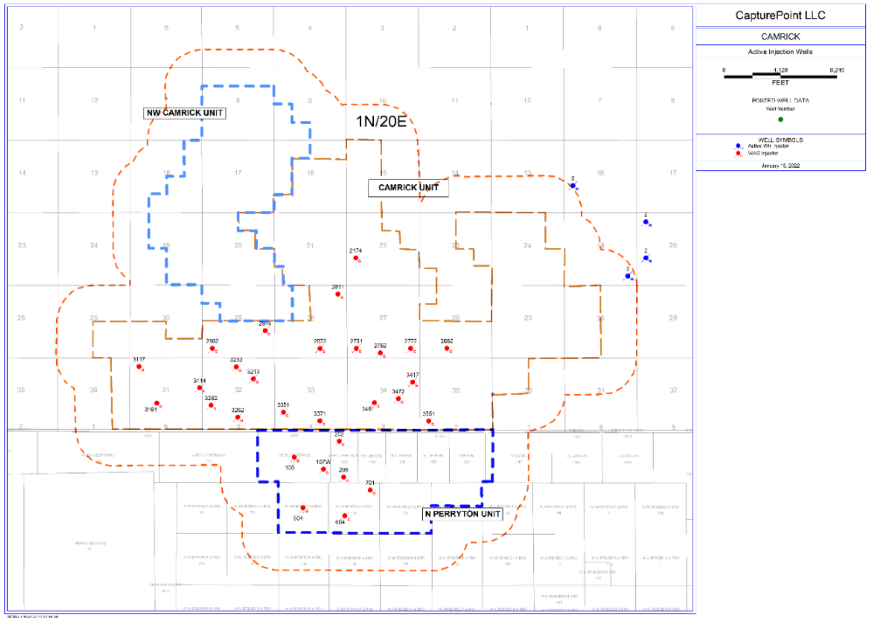


Figure 4.2-1 Plugged and Abandoned Wells in the CFA

4.2.2 Injection Wells

Mechanical integrity testing (MIT) is an essential requirement of the Underground Injection Control (UIC) program in demonstrating that injection wells themselves do not act as conduits for leakage into underground sources of drinking water (USDWs) and to the surface environment. Rule 46 and any special conditions pertaining to mechanical integrity testing required by the OCC and the TRRC are included in the Class II permits issued to CapturePoint, ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Figure 4.2-2 shows the active injection wells in the CFA. CapturePoint concludes that leakage of CO_2 to the surface through active injection wells is unlikely.



4.2-2 Active Injection Wells in the CFA

4.2.3 Production Wells

Figure 4.2-3 shows the active oil production wells in the CFA. However, as the project develops in the CFA additional production wells may be added and will be constructed according to the relevant rules of the OCC and the TRRC. Additionally, inactive wells may become active according to the rules of the OCC and the TRRC. CapturePoint concludes that leakage of CO_2 to the surface through production wells is unlikely.

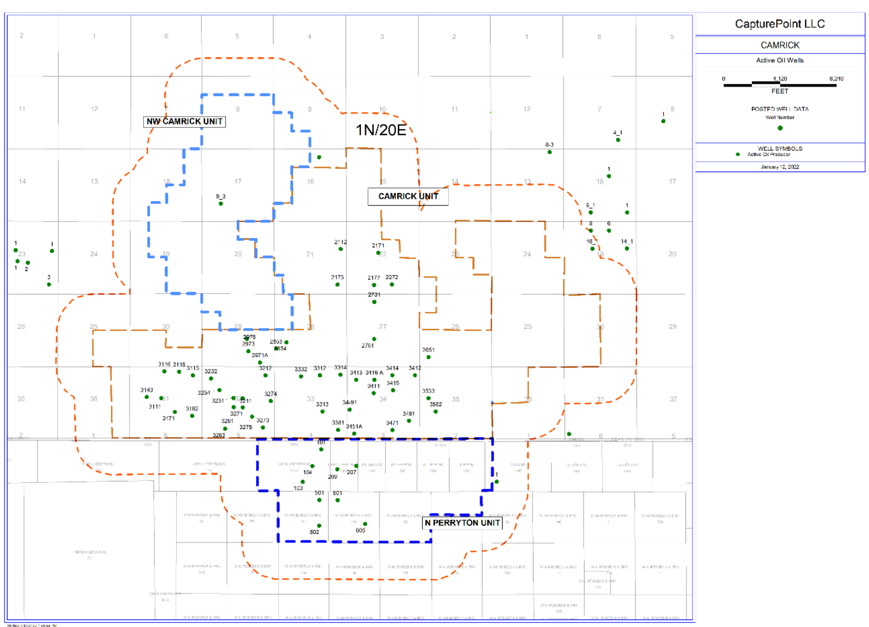


Figure 4.2-3 Active Oil Production Wells in the CFA

4.2.4 Inactive Wells

Figure 4.2-4 shows all of the inactive wells in the CFA. The OCC has regulations for temporally abandoned/not plugged (TA) and terminated order wells/UIC not plugged (TM) and likewise the TRRC has regulations for inactive wells.

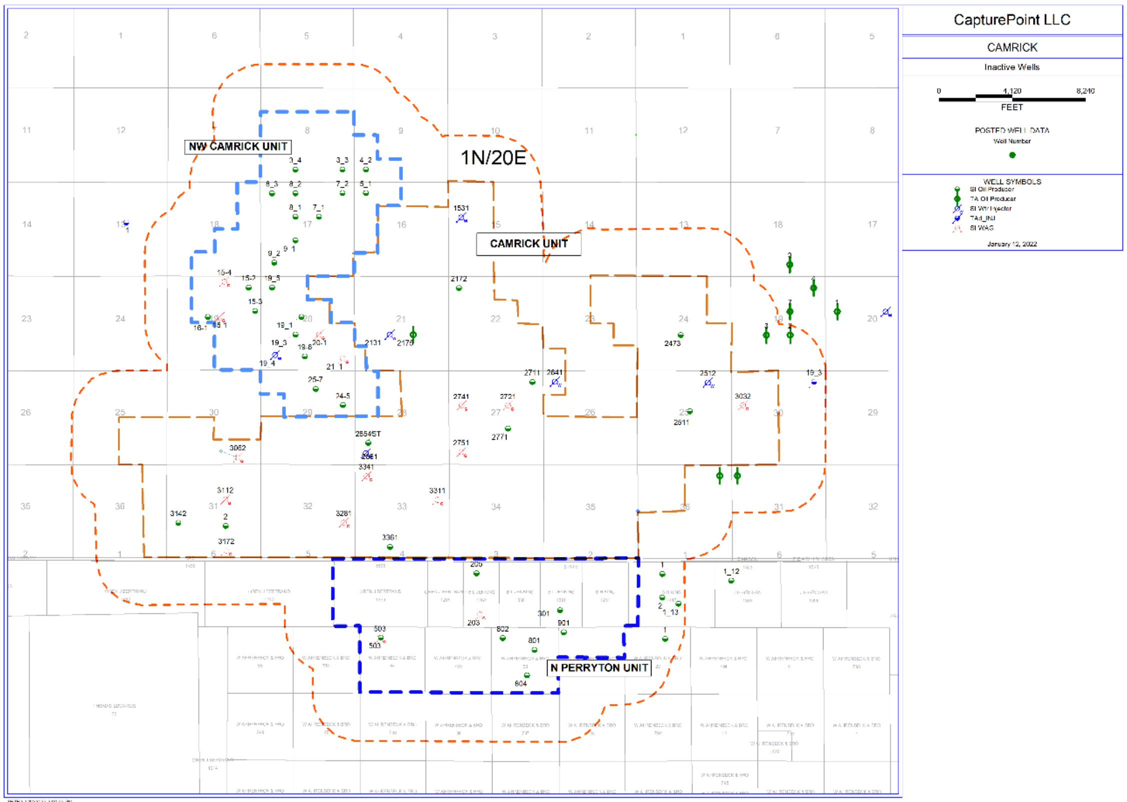


Figure 4.2-4 Inactive wells in the CFA

4.2.5 New Wells

As the project develops, new production wells and injection wells may be added to the CFA. All new wells will be constructed according to the relevant rules for the OCC and the TRRC which ensure protection of subsurface and surface resources and the environment.

All wells in Oklahoma oilfields and all wells in Texas oilfields, including both injection and production wells, are regulated by the OCC and the TRRC, respectively, which has primacy to implement the UIC Class II programs.

Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Briefly current rules require, among other provisions:

- That fluids be constrained in the strata in which they are encountered;
- That activities governed by the rule cannot result in the pollution of subsurface or surface water;
- That wells adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into strata with oil and gas, or into subsurface and surface water;

- That wells file a completion report including basic electric logs;
- That all wells be equipped with a Bradenhead gauge, measure the pressure between casing strings using the Bradenhead gauge, and follow procedures to report and address any instances where pressure on the Bradenhead is detected;
- And that all wells follow plugging procedures that require advance approval from the Regulators and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs.

New well construction is based on existing best practices, established during the drilling of existing wells in CFA and follows the OCC and the TRRC rules, which significantly limits any potential leakage from well pathways. Additionally, the existing wells followed the OCC and the TRRC rules.

In public databases, the area of CFA plus one mile past the unit boundary contains over 100 wells that were drilled deeper than the Morrow formation and none of these wells were productive in reservoirs deeper than the Morrow. Therefore, it is very unlikely that anyone will ever drill through the AMA reservoir in the future. In the event a well is drilled within the AMA, the operator would be required to follow all the OCC and the TRRC rules and procedures in the drilling the well and the potential for leakage would be similar to any well that CapturePoint drills within the AMA. In addition, CapturePoint's visual inspection process during routine field operation will identify any unapproved drilling activity in the CFA.

4.3 Leakage from Faults and Bedding Plane Parting

Primary seals at CFA have been demonstrated to be mechanically very competent (see Section 2.2.2), thus the main concern of CO_2 migration at CFA is via seal bypass systems along fracture networks. The following lines of analysis have been used to assess this risk in the area.

4.3.1 Prescence of Hydrocarbon

The first and foremost argument against present day up-fault transmissibility is the 75 MMB of oil that was found trapped in the reservoir. If significant escape pathways existed, oil would have drained from the reservoir prior to the current day.

4.3.2 Fracture analysis

At the CFA the work done at the Farnsworth Unit is analagous, where small aperture fractures were noted but not common in most of the reservoir cores examined but most of these fractures appear to be drilling induced. Fractures in the Thirteen Finger limestone caprock were described using an industry-standard format for fracture class type, orientation, fracture dip, type of mineral fill, fracture porosity, fracture spacing, and intensity. Again, drilling induced fractures are most common. Natural mineral-filled fractures are quite rare, were formed during diagenesis at shallow depths, and are of Late

Carboniferous age. Unless significantly damaged by large changes in reservoir pressure they are highly unlikely to provide migration pathways.

In the unlikely event CO_2 leakage occurs as a result of leakage through the faults and fractures it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.4 Lateral Fluid Movement

The Morrow strata in the Oklahoma and Texas Panhandle was primarily a deltaic sequence that prograded toward the southeast, resulting in deposition of mainly shales with lenticular, discontinuous coarse sandstones separated with very fine sandstone, minor conglomerates and shale. The likelihood of any extensive migration of fluid outside of the AMA is very low.

Since CO_2 is lighter than the water remaining in the reservoir it will migrate to the top of each lenticular structure as it is filled. The producing wells, which create low pressure points in the field, will drain the water and keep the CO_2 within each discontinuous sandstone.

4.5 Leakage through Confining/Seal system

At the CFA the work done at the Farnsworth Unit will apply, where a variety of analytical methods were used for caprock (confining system) analysis, and the results should be the same for the CFA. Petrologic examination included standard thin section petrography and backscattered electron microscopy. Petrophysical analytical methods include retort analysis, pulse-decay permeability measurement, pressure decay permeability analysis for tight rocks, and mercury injection porosimetry, which is also known as mercury injection capillary pressure (MICP). Geomechanical analysis involved a standard series of mechanical tests: Brazil tension, unconfined compression, triaxial compression, and multi-stress compression.

Results of the MICP analysis show that the mudstone lithologies in the Morrow Shale and Thirteen Finger Limestone can support CO_2 column heights of ~1,000 to 10,000 feet. At an order of magnitude over the thickness of the Morrow reservoir, this should prove an effective seal for CO_2 storage in the Morrow B injection horizon.

Failure analyses show that the Morrow B sands are weaker than overlying lithologies, so that any fracture initiation around the injection well would not be expected to propagate into the overlying sealing units. Mechanical properties of the overlying shale and limestones provide an interesting and effective combination of strength and elasticity. Limestone layers are strong but brittle, while the shale layers are weaker but sufficiently ductile to prevent extensive fracture propagation.

It is unlikely for hydrocarbon migration pathways that charged the Morrow reservoir to be potential CO_2 migration pathways via primary pore networks today. Any potential CO_2 migration would be most likely due to leakage from wellbores or bypass through fault and fracture networks, discussed in Sections 4.2 and 4.3.

In the unlikely event CO_2 leakage occurs as a result of leakage through the confining seal it is unlikely that the leak would result in surface leakage. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.5 and the strategy to quantify the leak is discussed in Section 4.6.

4.6 Natural and Induced Seismic Activity

Figure 4.6 shows the map of earthquakes with magnitudes measured at greater than 2.5 as defined by the United States Geological Survey (USGS). While past earthquake data cannot predict future earthquakes, the small number of events near CFA after the waterflood operations were initiated in 1969 implies the area is not seismically sensitive to injection. Also, no documentation exists that any of the distant earthquake events caused a disruption in injectivity or damage to any of the wellbores in CFA.

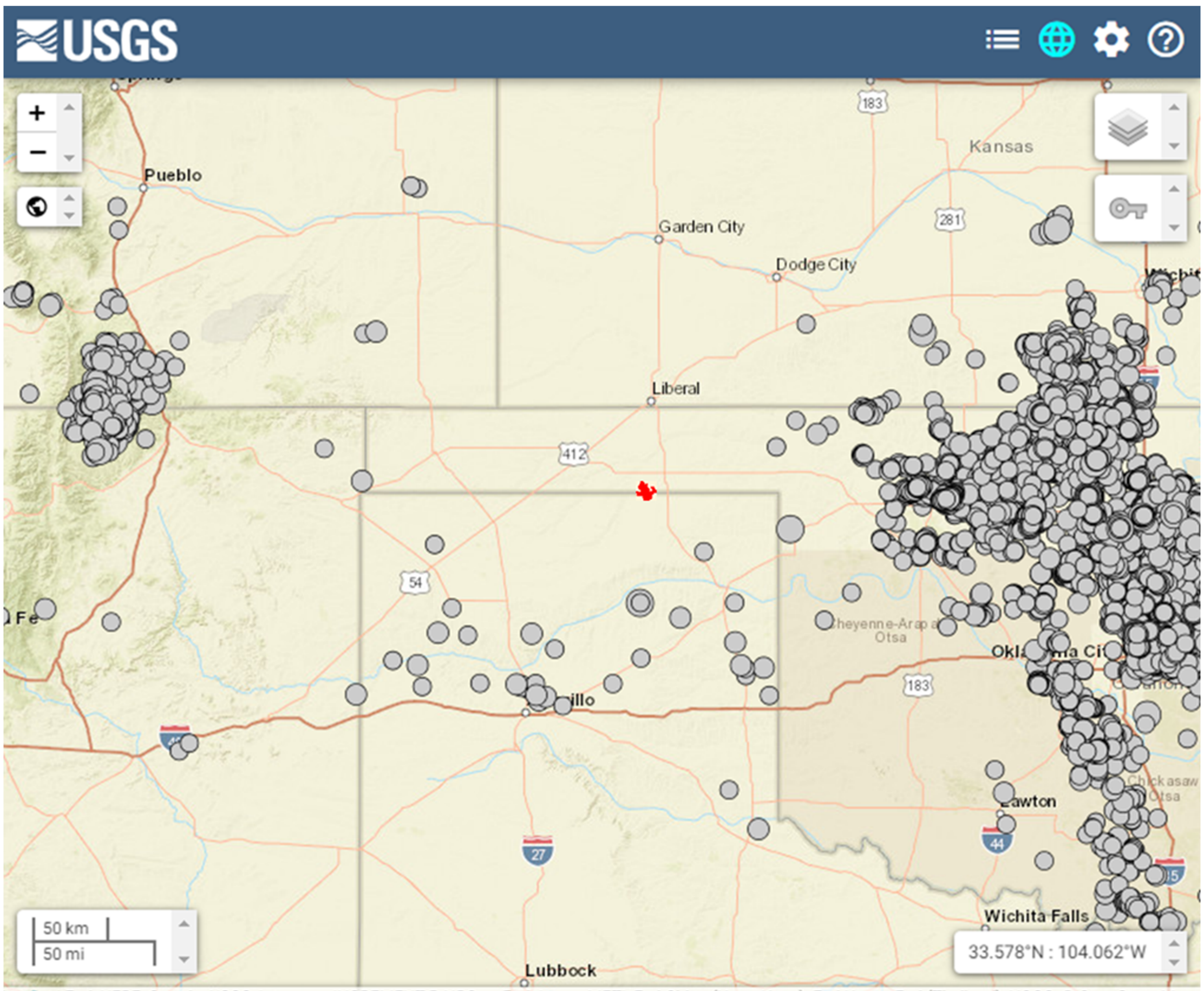


Figure 4.6: USGS earthquakes (+2.5 magnitude) for last 40 years with CFA highlighted red

There is no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the CFA.

In the unlikely event that induced seismicity resulted in a pathway for material amounts of CO_2 to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would lead to further investigation.

4.7 Strategy for Detection and Response to 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 (well bores), and unique events such as induced fractures. Table 1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, CapturePoint's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO_2 losses discussed in the table are identified by type. Once the type is reported to a response manager the correct resources and personnel can be mobilized to develop the optimal response procedure. The procedure will address and mitigate further CO_2 leakage.

Table 1 Response Plan for CO_2 Loss

Known Potential Leakage Risks	Monitoring Methods and Frequency	Anticipated Response Plan
Tubing Leak	Monitor changes in annulus pressure; MIT for injectors	Workover crews respond within days
Casing Leak	Weekly field inspection; MIT for injectors; extra attention to high-risk wells	Workover crews respond within days
Wellhead Leak	Weekly field inspection	Workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations (weekly inspection but field personnel present daily)	Maintain well kill procedures
Unplanned wells drilled through Morrow	Weekly field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells.	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Re-enter and reseal abandoned wells
Pumps, values, etc.	Weekly field inspection	Workover crews respond within days
Leakage along faults	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near faults
Leakage laterally	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Fluid management along lease lines
Leakage through induced fractures	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Continuous monitoring of pressure in WAG skids; high pressure found in new wells as drilled	Shut in injectors near seismic event

4.8 Strategy for Quantifying CO_2 loss

Major CO_2 losses are typically event-driven and require a process to assess, address, track, and if applicable, quantify potential CO_2 leakage to the surface. CapturePoint will reconcile the Subpart W report and results from any event-driven quantification to assure that surface leaks are not double counted.

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 CO_2 that would be most appropriate. In the event leakage occurs, CapturePoint will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission.

Any volume of CO_2 detected leaking to the 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, CapturePoint's field experience, and other factors such as the frequency of inspection. As indicated in Sections 6.4, leaks will be documented, and the 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.

Available studies of actual well leaks and natural analogs (e.g., naturally occurring CO_2 geysers) suggest that the amount released from routine leaks would be small as compared to the amount of CO_2 that would remain stored in the formation.

5 Strategy for Determining CO_2 Baselines for CO_2 Monitoring

Atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values for soil measurement in the CFA area, per the characterization, monitoring and well data collected by the Southwest Regional Partnership on Carbon Sequestration (SWP) in the analogous Farnsworth Unit.

5.1 Site Characterization and Monitoring

As described in Sections 2.2.2 and 2.4, the Morrow B sandstone is isolated both above and below by shale units of the Morrow. The primary seal consists of 180 – 200 ft of Morrow shale and Thirteen Finger Limestone which in turn is overlain by over a thousand feet of younger shale and limestone. These units provide a suitable seal to prevent the migration of CO_2 out of the injection reservoir. Additionally, no significant faults or fracture zones that cut across the seal units have been identified in the CFA, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented.

5.2 Groundwater monitoring

CapturePoint does not routinely pull water samples from the Ogallala water wells. However, samples are pulled when OCC injection permits are submitted in Oklahoma. No indication of fluid leakage has been identified from any of these in the CFA area. CapturePoint is unlikely to continue monitoring USDW wells for CO_2 or brine contamination, as characterization of the Morrow (see section 5.1) have suggested minimal risk of groundwater contamination from CO_2 leakage from this depth.

5.3 Soil CO_2 monitoring

Atmospheric CO_2 values at the Farnsworth Unit have been determined by a SWP eddy tower installation. In winter 2019, the eddy system malfunctioned and has not been repaired due to COVID travel restrictions. However, the atmospheric CO_2 concentration data from the eddy tower were in very good agreement with values obtained from the NOAA Global Monitoring Laboratory station in Moody, Texas (Station: WKT). Since the CFA area is in close proximity to the Farnsworth Unit, atmospheric CO_2 concentrations from the Moody, Texas station can be used for background CO_2 values.

5.4 Visual Inspection

CapturePoint operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage.

5.5 Well Surveillance

CapturePoint adheres to the requirements of Rule 165:10-5 for the OCC and of Rule 46 for the TRRC governing fluid injection into productive reservoirs. Rule 46 includes requirements for monitoring, reporting, and testing of Class II injection wells. Furthermore, the OCC and the TRRC includes special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well if they are deemed necessary.

CapturePoint also adheres to the requirements of Rule 165:10-7 for the OCC and of Rule 20 for the TRRC governing the notification of fires, breaks, leaks, or escapes. Rule 20 requires that all operators report leaks to the OCC or the TRRC including measured or estimated quantities of product leaked.

6 Site specific considerations for determining the Mass of CO_2 Sequestered

Of the twelve RR equations in 98.443 of Subpart RR, the following are relevant to CapturePoint's operations

6.1 Determining Mass of CO_2 received

CapturePoint currently receives CO_2 to its CFA facility through their own pipeline from the Arkalon Ethanol plant in Liberal, Kansas. CapturePoint also recycles CO_2 from their production wells in the CFA.

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

where:

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

$Q_{r,p}$ *= Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).*

$S_{r,p}$ *= Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).*

D *= Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.*

$C_{CO_{2,p,r}}$ *= Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).*

p *= Quarter of the year.*

r *= Receiving flow meter.*

6.2 Determining Mass of CO_2 Injected

CapturePoint injects CO_2 into the injection wells listed in Appendix 1.

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

where:

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

$Q_{p,u}$*= Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).*

D *= Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.*

$C_{CO_{2,p,u}}$ *= CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).*

p *= Quarter of the year.*

u *= Flow meter.*

6.3 Determining Mass of CO_2 produced from Oil Wells

CapturePoint also recycles CO_2 from its production wells which are part of its operations in the CFA. Therefore, the following equation is relevant to its operations.

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

Where:

$CO_{2,w}$ *= Annual CO_2 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 CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.*

$C_{CO_{2,p,w}}$ *= CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).*

p *= Quarter of the year.*

w *= Separator.*

To aggregate production data, CapturePoint will sum the mass of all of the CO_2 separated at each gas-liquid separator in accordance with the procedure specified in Equation RR-9 below:

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

Where:

CO_{2P} *= Total annual CO_2 mass produced (metric tons) through all separators in the reporting year.*

$CO_{2,w}$ *= Annual CO_2 mass produced (metric tons) through separator w in the reporting year.*

X *= Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction).*

w *= Separator.*

6.4 Determining Mass of CO_2 emitted by Surface Leakage

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations.

CapturePoint will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below:

$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$ *(Equation RR-10)*

where:

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

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

6.5 Determining Mass of CO_2 sequestered

The following Equation RR-11 pertains to facilities that are actively producing oil or natural gas.

$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP}$ *(Equation RR-11)*

Where:

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

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

CO_{2P} *= Total annual CO_2 mass produced (metric tons) in the reporting year.*

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

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

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

The following Equation RR-12 pertains to facilities that are not actively producing oil or natural gas. This equation may become relevant to CapturePoint's operation as it evolves in the future. However, this does not apply to CapturePoint's current operations.

$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$ *(Equation RR-12)*

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

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

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

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

7 Estimated Schedule for Implementation of MRV plan

CapturePoint expects to begin implementing the approved MRV plan when the new CO_2 capture facility is operational, November 1, 2022.

8 GHG monitoring and Quality Assurance Program

CapturePoint will meet the monitoring and QA/QC requirements of 98.444 of Subpart RR including those of Subpart W for emissions from surface equipment as required by 98.444 (d).

8.1 GHG monitoring

As required by 40 CFR 98.3(g)(5)(i), CapturePoint's internal documentation regarding the collection of emissions data includes the following:

- Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.

- Explanation of the processes and methods used to collect the necessary data for the GHG calculations.

- Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

8.1.1 General

Measurement of CO_2 *Concentration* – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as the Gas Producers Association (GSA) standards.
Measurement of CO_2 *Volume* – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5 and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. CapturePoint will adhere to the American Gas Association (AGA) Report #3 – (ORIFICE METERING OF NATURAL GAS AND OTHER RELATED HYDROCARBON FLUIDS)

8.1.2 CO_2 Received

Daily totalized volumetric flow meters are used to record CO_2 received via pipeline from the Arkalon ethanol plant in Liberal, Kansas. using a volumetric totalizer using accepted flow calculations for CO_2 according to the AGA Report #3.

8.1.3 CO_2 Injected

Daily CO_2 injection is recorded by combining the totals for the recycle compressor meter and the received CO_2 meter from Arkalon based on what's delivered on a 24-hour basis. This data is taken from the meter daily and stored in CapturePoint's data warehouse for records and reservoir management.

8.1.4 CO_2 Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO_2. The produced gas is sampled at least quarterly for the CO_2 content.

8.1.5 CO_2 emissions from equipment leaks and vented emissions of CO_2

As required by 98.444 (d), CapturePoint will follow the monitoring and QA/QC requirements specified in Subpart W of the GHGRP for equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead and between the flow meter used to measure production quantity and the production wellhead.

As required by 98.448 (d) of Subpart RR, CapturePoint will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233 (r) (2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6 Measurement Devices

As required by 40 CFR 98.444(e), CapturePoint will ensure that:

- All flow meters are operated continuously except as necessary for maintenance and calibration.
- All flow meters used to measure quantities reported are calibrated according to the calibration and accuracy requirements in 40 CFR 98.3(i) of Subpart A of the GHGRP.

- All measurement devices are operated according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the Gas Producers Association (GPA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).
- All flow meters are National Institute of Standards and Technology (NIST) traceable.

8.2 QA/QC procedures

CapturePoint will adhere to all QA/QC requirements in Subparts A, RR, and W of the GHGRP, as required in the development of this MRV plan under Subpart RR. Any measurement devices used to acquire data will be operated and maintained according to the relevant industry standards.

8.3 Estimating missing data

CapturePoint will estimate any missing data according to the following procedures in 40 CFR 98.445 of Subpart RR of the GHGRP, as required.

A quarterly flow rate of CO_2 received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.

A quarterly CO_2 concentration of a CO_2 stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.

A quarterly quantity of CO_2 injected that is missing would be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.

The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

8.4 Revisions of the MRV plan

CapturePoint will revise the MRV Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

9 Records Retention

CapturePoint will meet the recordkeeping requirements of paragraph 40 CFR 98.3 (g) of Subpart A of the GHGRP. As required by 40 CFR 98.3 (g) and 40 CFR 98.447, CapturePoint will retain the following documents:

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:

(i) The GHG emissions calculations and methods used.

(ii) Analytical results for the development of site-specific emissions factors, if applicable.

(iii) The results of all required analyses.

(iv) Any facility operating data or process information used for the GHG emission calculations.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, CapturePoint will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) A copy of the most recent revision of this MRV Plan.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

(8) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(9) Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(10) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(11) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

(12) 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.

(13) 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.

(14) Any other records as specified for retention in this EPA-approved MRV plan.

10 Appendices

Appendix 1 – CFA Wells

Table A1.1 – Production Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2112	35007353570000	Oil Prod	Active	CO_2	1	0
CU 2171	35007354120000	Oil Prod	Active	CO_2	1	0
CU 2173	35007354140000	Oil Prod	Active	CO_2	1	0
CU 2177	35007222340000	Oil Prod	Active	CO_2	1	0
CU 2272	35007224530000	Oil Prod	Active	CO_2	1	0
CU 2651	35007362650000	Oil Prod	Active	CO_2	1	0
CU 2731	35007359750000	Oil Prod	Active	CO_2	1	0
CU 2761	35007350590000	Oil Prod	Active	CO_2	1	0
CU 2853	35007250840000	Oil Prod	Active	CO_2	1	0
CU 2854	35007250850000	Oil Prod	Active	CO_2	1	0
CU 2971A	35007256700000	Oil Prod	Active	CO_2	1	0
CU 2973	35007213750000	Oil Prod	Active	CO_2	1	0
CU 2975	35007223730000	Oil Prod	Active	CO_2	1	0
CU 3111	35007350600000	Oil Prod	Active	CO_2	1	0
CU 3113	35007359460000	Oil Prod	Active	CO_2	1	0
CU 3115	35007251710000	Oil Prod	Active	CO_2	1	0
CU 3116	35007252570000	Oil Prod	Active	CO_2	1	0
CU 3143	35007250860000	Oil Prod	Active	CO_2	1	0
CU 3171	35007359600000	Oil Prod	Active	CO_2	1	0
CU 3182	35007249250000	Oil Prod	Active	CO_2	1	0
CU 3211	35007352150000	Oil Prod	Active	CO_2	1	0
CU 3212	35007352690000	Oil Prod	Active	CO_2	1	0
CU 3231	35007001820000	Oil Prod	Active	CO_2	1	0
CU 3232	35007352720000	Oil Prod	Active	CO_2	1	0
CU 3234	35007212010000	Oil Prod	Active	CO_2	1	0
CU 3261	35007352170000	Oil Prod	Active	CO_2	1	0
CU 3263	35007251640000	Oil Prod	Active	CO_2	1	0
CU 3271	35007352160000	Oil Prod	Active	CO_2	1	0
CU 3273	35007252580000	Oil Prod	Active	CO_2	1	0
CU 3274	35007253140000	Oil Prod	Active	CO_2	1	0
CU 3275	35007254040000	Oil Prod	Active	CO_2	1	0
CU 3312	35007360800000	Oil Prod	Active	CO_2	1	0
CU 3313	35007254370000	Oil Prod	Active	CO_2	1	0
CU 3314	35007254030000	Oil Prod	Active	CO_2	1	0
CU 3332	35007254020000	Oil Prod	Active	CO_2	1	0
CU 3381	35007360780000	Oil Prod	Active	CO_2	1	0
CU 3411	35007351700000	Oil Prod	Active	CO_2	1	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3412	35007351720000	Oil Prod	Active	CO_2	1	0
CU 3413	35007351730000	Oil Prod	Active	CO_2	1	0
CU 3414	35007005220000	Oil Prod	Active	CO_2	1	0
CU 3415	35007211170000	Oil Prod	Active	CO_2	1	0
CU 3416A	35007252590000	Oil Prod	Active	CO_2	1	0
CU 3451A	35007256710000	Oil Prod	Active	CO_2	1	0
CU 3471	35007351750000	Oil Prod	Active	CO_2	1	0
CU 3481	35007351710001	Oil Prod	Active	CO_2	1	0
CU 3491	35007254330000	Oil Prod	Active	CO_2	1	0
CU 3533	35007206880000	Oil Prod	Active	CO_2	1	0
CU 3562	35007255050000	Oil Prod	Active	CO_2	1	0
NPU 101	42357010440000	Oil Prod	Active	CO_2	1	0
NPU 103	42357010060000	Oil Prod	Active	CO_2	1	0
NPU 104	42357000050000	Oil Prod	Active	CO_2	1	0
NPU 207	42357302000000	Oil Prod	Active	CO_2	1	0
NPU 209	42357333830000	Oil Prod	Active	CO_2	1	0
NPU 501	42357009140000	Oil Prod	Active	CO_2	1	0
NPU 502	42357024100000	Oil Prod	Active	CO_2	1	0
NPU 601	42357008420000	Oil Prod	Active	CO_2	1	0
NPU 605	42357333840000	Oil Prod	Active	CO_2	1	0
NWCU 3-1	35007360850000	Gas Prod	Active	CO_2	1	0
NWCU 9-3	35007249430000	Oil Prod	Active	CO_2	1	0
CU 2172	35007354130000	Oil Prod	Inactive	CO_2	0	0
CU 2175	35007354160000	Oil Prod	Inactive	CO_2	0	0
CU 2473	35007211990000	Oil Prod	Inactive	CO_2	0	0
CU 2511	35007350790000	Oil Prod	Inactive	CO_2	0	0
CU 2711	35007359260000	Oil Prod	Inactive	CO_2	0	0
CU 2771	35007359850000	Oil Prod	Inactive	CO_2	0	0
CU 3142	35007222350000	Oil Prod	Inactive	CO_2	0	0
CU 3361	35007352670000	Oil Prod	Inactive	CO_2	0	0
NPU 205	42357008070000	Oil Prod	Inactive	CO_2	0	0
NPU 301	42357022080000	Oil Prod	Inactive	CO_2	0	0
NPU 801	42357004630000	Oil Prod	Inactive	CO_2	0	0
NPU 802	42357004620000	Oil Prod	Inactive	CO_2	0	0
NPU 804	42357201730000	Oil Prod	Inactive	CO_2	0	0
NPU 901	42357000660000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-2	35007350870000	Oil Prod	Inactive	CO_2	0	0
NWCU 15-3	35007210790000	Oil Prod	Inactive	CO_2	0	0
NWCU 16-1	35007350720000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-1	35007360900000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-3	35007360920000	Oil Prod	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
NWCU 19-4	35007360930000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-5	35007360940000	Oil Prod	Inactive	CO_2	0	0
NWCU 19-6	35007211250000	Oil Prod	Inactive	CO_2	0	0
NWCU 24-5	35007222710000	Oil Prod	Inactive	CO_2	0	0
NWCU 25-7	35007228000000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-3	35007360870000	Oil Prod	Inactive	CO_2	0	0
NWCU 3-4	35007360880000	Oil Prod	Inactive	CO_2	0	0
NWCU 4-2	35007360740000	Oil Prod	Inactive	CO_2	0	0
NWCU 5-1	35007361050000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-1	35007360980000	Oil Prod	Inactive	CO_2	0	0
NWCU 7-2	35007360990000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-1	35007360810000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-2	35007360820000	Oil Prod	Inactive	CO_2	0	0
NWCU 8-3	35007208260000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-1	35007360950000	Oil Prod	Inactive	CO_2	0	0
NWCU 9-2	35007360960000	Oil Prod	Inactive	CO_2	0	0
CU 1551	35007350740000	Oil Prod	P&A	CO_2	0	0
CU 1671	35007352180000	Oil Prod	P&A	CO_2	0	0
CU 2111	35007353560000	Oil Prod	P&A	CO_2	0	0
CU 2176	35007358870000	Oil Prod	P&A	CO_2	0	0
CU 2221	35007000490000	Oil Prod	P&A	CO_2	0	0
CU 2281	35007359220000	Oil Prod	P&A	CO_2	0	0
CU 2421	35007359350000	Oil Prod	P&A	CO_2	0	0
CU 2431	35007350330000	Oil Prod	P&A	CO_2	0	0
CU 2432	35007350340000	Oil Prod	P&A	CO_2	0	0
CU 2433	35007350350000	Oil Prod	P&A	CO_2	0	0
CU 2434	35007350360000	Oil Prod	P&A	CO_2	0	0
CU 2435	35007218800000	Oil Prod	P&A	CO_2	0	0
CU 2471	35007359080000	Oil Prod	P&A	CO_2	0	0
CU 2531	35007361090000	Oil Prod	P&A	CO_2	0	0
CU 2532	35007361100000	Oil Prod	P&A	CO_2	0	0
CU 2552	35007359760000	Oil Prod	P&A	CO_2	0	0
CU 2571	35007350730000	Oil Prod	P&A	CO_2	0	0
CU 2572	35007359320000	Oil Prod	P&A	CO_2	0	0
CU 2661	35007361990000	Oil Prod	P&A	CO_2	0	0
CU 2681	35007350320000	Oil Prod	P&A	CO_2	0	0
CU 2852	35007301360000	Oil Prod	P&A	CO_2	0	0
CU 2961	35007358760000	Oil Prod	P&A	CO_2	0	0
CU 2971	35007358750000	Oil Prod	P&A	CO_2	0	0
CU 2972	35007358780000	Oil Prod	P&A	CO_2	0	0
CU 3031	35007359560000	Oil Prod	P&A	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 3051	35007300380000	Oil Prod	P&A	CO_2	0	0
CU 3064	35007254270000	Oil Prod	P&A	CO_2	0	0
CU 3141	35007359610000	Oil Prod	P&A	CO_2	0	0
CU 3181	35007359470000	Oil Prod	P&A	CO_2	0	0
CU 3251	35007352710000	Oil Prod	P&A	CO_2	0	0
CU 3331	35007200750000	Oil Prod	P&A	CO_2	0	0
CU 3451	35007351690000	Oil Prod	P&A	CO_2	0	0
CU 3511	35007359730000	Oil Prod	P&A	CO_2	0	0
CU 3531	35007350850000	Oil Prod	P&A	CO_2	0	0
CU 3532	35007359950000	Oil Prod	P&A	CO_2	0	0
CU 3534	35007211180000	Oil Prod	P&A	CO_2	0	0
CU 3561	35007359830000	Oil Prod	P&A	CO_2	0	0
CU 3571	35007359980000	Oil Prod	P&A	CO_2	0	0
CU 3581	35007359970000	Oil Prod	P&A	CO_2	0	0
CU 3631	35007301000000	Oil Prod	P&A	CO_2	0	0
CU 1672	35007352190000	Oil Prod	P&A	CO_2	0	0
CU 2351	35007350370000	Oil Prod	P&A	CO_2	0	0
CU 2474	35007228200000	Oil Prod	P&A	CO_2	0	0
CU 2812	35007352340000	Oil Prod	P&A	CO_2	0	0
CU 2871	35007359060000	Oil Prod	P&A	CO_2	0	0
NPU 102	42357021420000	Oil Prod	P&A	CO_2	0	0
NPU 201	42357001280000	Oil Prod	P&A	CO_2	0	0
NPU 302	42357022290000	Oil Prod	P&A	CO_2	0	0
NPU 402	42357022300000	Oil Prod	P&A	CO_2	0	0
NWCU 17-2	35007359620000	Oil Prod	P&A	CO_2	0	0
NWCU 10-1	35007361010000	Oil Prod	P&A	CO_2	0	0
NWCU 17-1	35007350710000	Oil Prod	P&A	CO_2	0	0
NWCU 19-7	35007224520000	Oil Prod	P&A	CO_2	0	0
NWCU 24-4	35007358770000	Oil Prod	P&A	CO_2	0	0
NWCU 25-6	35007358790000	Oil Prod	P&A	CO_2	0	0

Table A1.2 – Water Alternating Gas (WAG) Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 2662 (INJ)	35007362010000	WAG Inj	Active	CO_2	0	1
CU 2751 (INJ)	35007359440002	WAG Inj	Active	CO_2	0	1
CU 2762 (INJ)	35007213660000	WAG Inj	Active	CO_2	0	1
CU 2772 (INJ)	35007359860001	WAG Inj	Active	CO_2	0	1
CU 2811 (INJ)	35007352200000	WAG Inj	Active	CO_2	0	1
CU 2872 (INJ)	35007359070000	WAG Inj	Active	CO_2	0	1
CU 2962 (INJ)	35007212000000	WAG Inj	Active	CO_2	0	1
CU 2974 (INJ)	35007220770000	WAG Inj	Active	CO_2	0	1
CU 3114 (INJ)	35007206540000	WAG Inj	Active	CO_2	0	1
CU 3117 (INJ)	35007254000000	WAG Inj	Active	CO_2	0	1
CU 3161 (INJ)	35007359590002	WAG Inj	Active	CO_2	0	1
CU 3213 (INJ)	35007224570000	WAG Inj	Active	CO_2	0	1
CU 3233 (INJ)	35007206890000	WAG Inj	Active	CO_2	0	1
CU 3252 (INJ)	35007211020000	WAG Inj	Active	CO_2	0	1
CU 3262 (INJ)	35007206870000	WAG Inj	Active	CO_2	0	1
CU 3351 (INJ)	35007352680000	WAG Inj	Active	CO_2	0	1
CU 3371 (INJ)	35007360770000	WAG Inj	Active	CO_2	0	1
CU 3417 (INJ)	35007255060000	WAG Inj	Active	CO_2	0	1
CU 3461 (INJ)	35007351680000	WAG Inj	Active	CO_2	0	1
CU 3472 (INJ)	35007206940000	WAG Inj	Active	CO_2	0	1
CU 3551 (INJ)	35007359840000	WAG Inj	Active	CO_2	0	1
NPU 105 (INJ)	42357000030000	WAG Inj	Active	CO_2	0	1
NPU 107W (INJ)	42357333770000	WAG Inj	Active	CO_2	0	1
NPU 202WI (INJ)	42357021500000	WAG Inj	Active	CO_2	0	1
NPU 208 (INJ)	42357327410000	WAG Inj	Active	CO_2	0	1
NPU 701 (INJ)	42357008410000	WAG Inj	Active	CO_2	0	1
NPU 504 (INJ)	42357329480000	WAG Inj	Active	CO_2	0	1
NPU 604W (INJ)	42357330870000	WAG Inj	Active	CO_2	0	1
CU 1531 (INJ)	35007359990000	WAG Inj	Inactive	CO_2	0	0
CU 2131 (INJ)	35007362700000	WAG Inj	Inactive	CO_2	0	0
CU 2512 (INJ)	35007350780000	WAG Inj	Inactive	CO_2	0	0
CU 2641 (INJ)	35007359250001	WAG Inj	Inactive	CO_2	0	0
CU 2721 (INJ)	35007359870001	WAG Inj	Inactive	CO_2	0	0
CU 2741 (INJ)	35007359430000	WAG Inj	Inactive	CO_2	0	0
CU 2851 (INJ)	35007355420001	WAG Inj	Inactive	CO_2	0	0
CU 3032 (INJ)	35007359580000	WAG Inj	Inactive	CO_2	0	0
CU 3062 (INJ)	35007253090000	WAG Inj	Inactive	CO_2	0	0
CU 3112 (INJ)	35007359450001	WAG Inj	Inactive	CO_2	0	0

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU 2174 (INJ)	**35007354150000**	**WAG Inj**	**Active**	**CO_2**	**0**	**1**
CU 3172 (INJ)	35007251690000	WAG Inj	Inactive	CO_2	0	0
CU 3281 (INJ)	35007352700003	WAG Inj	Inactive	CO_2	0	0
CU 3311 (INJ)	35007360790000	WAG Inj	Inactive	CO_2	0	0
CU 3341 (INJ)	35007353530000	WAG Inj	Inactive	CO_2	0	0
NPU 203W (INJ)	42357008270000	WAG Inj	Inactive	CO_2	0	0
NPU 503 (INJ)	42357009150001	WAG Inj	Inactive	CO_2	0	0
NWCU 15-1 (INJ)	35007350860000	WAG Inj	Inactive	CO_2	0	0
NWCU 15-4 (INJ)	35007224510000	WAG Inj	Inactive	CO_2	0	0
NWCU 20-1 (INJ)	35007360760000	WAG Inj	Inactive	CO_2	0	0
NWCU 21-1 (INJ)	35007361020000	WAG Inj	Inactive	CO_2	0	0
CU 2271 (INJ)	35007359230000	WAG Inj	P&A	CO_2	0	0
CU 2311 (INJ)	35007362000000	WAG Inj	P&A	CO_2	0	0
CU 2472 (INJ)	35007359090000	WAG Inj	P&A	CO_2	0	0
CU 3061 (INJ)	35007359820000	WAG Inj	P&A	CO_2	0	0
CU 3512 (INJ)	35007359740000	WAG Inj	P&A	CO_2	0	0
NPU 204W (INJ)	42357022520000	WAG Inj	P&A	CO_2	0	0
NPU 206W (INJ)	42357022510000	WAG Inj	P&A	CO_2	0	0
NPU 401W (INJ)	42357004520000	WAG Inj	P&A	CO_2	0	0
NPU 602W (INJ)	42357020230000	WAG Inj	P&A	CO_2	0	0
NPU 603W (INJ)	42357201720001	WAG Inj	P&A	CO_2	0	0
NPU 803W (INJ)	42357201710000	WAG Inj	P&A	CO_2	0	0
NWCU 14-1 (INJ)	35007350530000	WAG Inj	P&A	CO_2	0	0
NWCU 3-2 (INJ)	35007360860000	WAG Inj	P&A	CO_2	0	0

Table A1.3 – Water Injection Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
CU WSW 1	35007355430001	Wtr Inj	Active	CO_2	0	1
NPU W 1W	42357300050002	Wtr Inj	Inactive	CO_2	0	0
CU 2551	35007350750000	Wtr Inj	P&A	CO_2	0	0

Appendix 2 – Referenced Regulations

U.S. Code > Title 26. INTERNAL REVENUE CODE > Subtitle A. Income Taxes > Chapter 1. NORMAL TAXES AND SURTAXES > Subchapter A. Determination of Tax Liability > Part IV. CREDITS AGAINST TAX > Subpart D. Business Related Credits > Section 45Q - Credit for carbon oxide sequestration

OKLAHOMA CONSERVATION COMMISSION > Title 165: CORPORATION COMMISSION > CHAPTER 10: OIL AND GAS CONSERVATION
SUBCHAPTER 5. UNDERGROUND INJECTION CONTROL

Section
165:10-5-1. Classification of underground injection wells
165:10-5-2. Approval of injection wells or disposal wells
165:10-5-3. Authorization for existing enhanced recovery injection wells and existing disposal wells
165:10-5-4. Application for approval of enhanced recovery projects
165:10-5-5. Application for approval of injection and disposal operations
165:10-5-6. Testing and monitoring requirements for injection wells and disposal wells
165:10-5-7. Monitoring and reporting requirements for wells covered by 165:10-5-1
165:10-5-8. Liquid hydrocarbon storage wells
165:10-5-9. Duration of underground injection well orders or permits
165:10-5-10. Transfer of authority to inject
165:10-5-11. Notarized reports
165:10-5-12. Application for administrative approval for the subsurface injection of onsite reserve pit fluids
165:10-5-13. Application for permit for one time injection of reserve pit fluids
165:10-5-14. Exempt aquifers
165:10-5-15. Application for permit for simultaneous injection well

165:5-7-27. Application for approval of injection and disposal wells
165:5-7-29. Request for exception to certain underground injection well requirements
165:5-7-30. Amending existing orders or permits authorizing injection for injection, disposal, or LPG storage wells

Texas Administrative Code (TAC) > Title 16 - Economic Regulation> Part 1 – Railroad Commission of Texas > Chapter 3 – Oil and Gas Division

Rules

§3.1 Organization Report; Retention of Records; Notice Requirements

§3.2 Commission Access to Properties

§3.3 Identification of Properties, Wells, and Tanks

§3.4 Oil and Geothermal Lease Numbers and Gas Well ID Numbers Required on All Forms

§3.5 Application to Drill, Deepen, Reenter, or Plug Back

§3.6 Application for Multiple Completion

§3.7 Strata to Be Sealed Off

§3.8 Water Protection

§3.9 Disposal Wells

§3.10 Restriction of Production of Oil and Gas from Different Strata

§3.11 Inclination and Directional Surveys Required

§3.12 Directional Survey Company Report

§3.13 Casing, Cementing, Drilling, Well Control, and Completion Requirements

§3.14 Plugging

§3.15 Surface Equipment Removal Requirements and Inactive Wells

§3.16 Log and Completion or Plugging Report

§3.17 Pressure on Bradenhead

§3.18 Mud Circulation Required

§3.19 Density of Mud-Fluid

§3.20 Notification of Fire Breaks, Leaks, or Blow-outs

§3.21 Fire Prevention and Swabbing

§3.22 Protection of Birds

§3.23 Vacuum Pumps

§3.24 Check Valves Required

§3.25 Use of Common Storage

§3.26 Separating Devices, Tanks, and Surface Commingling of Oil

§3.27 Gas to be Measured and Surface Commingling of Gas

§3.28 Potential and Deliverability of Gas Wells to be Ascertained and Reported

§3.29 Hydraulic Fracturing Chemical Disclosure Requirements

§3.30 Memorandum of Understanding between the Railroad Commission of Texas (RRC) and the Texas Commission on Environmental Quality (TCEQ)

§3.31 Gas Reservoirs and Gas Well Allowable

§3.32 Gas Well Gas and Casinghead Gas Shall Be Utilized for Legal Purposes

§3.33 Geothermal Resource Production Test Forms Required

§3.34 Gas To Be Produced and Purchased Ratably

§3.35 Procedures for Identification and Control of Wellbores in Which Certain Logging Tools Have Been Abandoned

§3.36 Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas

§3.37 Statewide Spacing Rule
§3.38 Well Densities
§3.39 Proration and Drilling Units: Contiguity of Acreage and Exception Thereto
§3.40 Assignment of Acreage to Pooled Development and Proration Units
§3.41 Application for New Oil or Gas Field Designation and/or Allowable
§3.42 Oil Discovery Allowable
§3.43 Application for Temporary Field Rules
§3.45 Oil Allowables
§3.46 Fluid Injection into Productive Reservoirs
§3.47 Allowable Transfers for Saltwater Injection Wells
§3.48 Capacity Oil Allowables for Secondary or Tertiary Recovery Projects
§3.49 Gas-Oil Ratio
§3.50 Enhanced Oil Recovery Projects--Approval and Certification for Tax Incentive
§3.51 Oil Potential Test Forms Required
§3.52 Oil Well Allowable Production
§3.53 Annual Well Tests and Well Status Reports Required
§3.54 Gas Reports Required
§3.55 Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering
§3.56 Scrubber Oil and Skim Hydrocarbons
§3.57 Reclaiming Tank Bottoms, Other Hydrocarbon Wastes, and Other Waste Materials
§3.58 Certificate of Compliance and Transportation Authority; Operator Reports
§3.59 Oil and Gas Transporter's Reports
§3.60 Refinery Reports
§3.61 Refinery and Gasoline Plants
§3.62 Cycling Plant Control and Reports
§3.63 Carbon Black Plant Permits Required
§3.70 Pipeline Permits Required
§3.71 Pipeline Tariffs
§3.72 Obtaining Pipeline Connections
§3.73 Pipeline Connection; Cancellation of Certificate of Compliance; Severance
§3.76 Commission Approval of Plats for Mineral Development
§3.78 Fees and Financial Security Requirements
§3.79 Definitions
§3.80 Commission Oil and Gas Forms, Applications, and Filing Requirements
§3.81 Brine Mining Injection Wells
§3.83 Tax Exemption for Two-Year Inactive Wells and Three-Year Inactive Wells
§3.84 Gas Shortage Emergency Response
§3.85 Manifest to Accompany Each Transport of Liquid Hydrocarbons by Vehicle
§3.86 Horizontal Drainhole Wells
§3.91 Cleanup of Soil Contaminated by a Crude Oil Spill
§3.93 Water Quality Certification Definitions
§3.95 Underground Storage of Liquid or Liquefied Hydrocarbons in Salt Formations

§3.96 Underground Storage of Gas in Productive or Depleted Reservoirs

§3.97 Underground Storage of Gas in Salt Formations

§3.98 Standards for Management of Hazardous Oil and Gas Waste

§3.99 Cathodic Protection Wells

§3.100 Seismic Holes and Core Holes

§3.101 Certification for Severance Tax Exemption or Reduction for Gas Produced From High-Cost Gas Wells

§3.102 Tax Reduction for Incremental Production

§3.103 Certification for Severance Tax Exemption for Casinghead Gas Previously Vented or Flared

§3.106 Sour Gas Pipeline Facility Construction Permit

§3.107 Penalty Guidelines for Oil and Gas Violations

Appendix 3 – References

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Appendix 4 – Abbreviations and Acronyms

2D – 2 dimensional
3D – 3 dimensional
AGA – American Gas Association
AMA – Active Monitoring Area
ANSI – American National Standards Institute
API – American Petroleum Institute
AWT – All Well Test
ASTM - American Society for Testing and Materials
Bscf – billion standard cubic feet
B/D – barrels per day
bopd – barrels of oil per day
C4 – butane
C5 – pentane
C7 – heptane
C7+ - standard heptane plus
CCE – constant composition expansion
CCUS – carbon capture utilization and storage
CFA – Camrick Field Area
cf – cubic feet
CH4 – methane
CO_2 – carbon dioxide
EOR – Enhanced Oil Recovery
EOS – Equation of State
EPA – US Environmental Protection Agency
ESD – Emergency Shutdown Device
GHG – Greenhouse Gas
GHGRP – Greenhouse Gas Reporting Program
GPA – Gas Producers Association
H_2S – hydrogen sulfide
mD – millidarcy(ies)
MICP – mercury injection capillary pressure
MIT – mechanical integrity test
MMA – maximum monitoring area
MMB – million barrels
MMP – minimum miscible pressure
MMscf – million standard cubic feet
MMstb – million stock tank barrels
MRV – Monitoring, Reporting, and Verification
MMMT – Million metric tonnes
MT -- Metric tonne
NIST - National Institute of Standards and Technology
NAESB – North American Energy Standards Board

OCC – Oklahoma Conservation Commission
OOIP – Original Oil-In-Place
OWC – oil water contact
PPM – Parts Per Million
psia – pounds per square inch absolute
PVT – pressure, volume, temperature
QA/QC – quality assurance/quality control
RMS – root mean square
SEM – scanning electron microscope
SWP - Southwest Regional Partnership on Carbon Sequestration
TAC – Texas Administrative Code
TA - Temporally Abandoned/not plugged
TD – total depth
TM - Terminated order wells/UIC not plugged
TRRC – Texas Railroad Commission
TSD – Technical Support Document
TVDSS – True Vertical Depth Subsea
UIC – Underground Injection Control
USDW – Underground Source of Drinking Water
WAG – Water Alternating Gas (Gas is recycled CO_2 and purchase CO_2)
XRD – x-ray diffraction

Appendix 5 – Conversion Factors

CapturePoint reports CO_2 at standard conditions of temperature and pressure as defined in the State of Texas in the Texas Administrative Code for the Oil and Gas Division, Rule 3.79 as follows:

> Cubic foot of gas or standard cubic foot of gas--The volume of gas contained in one cubic foot of space at a standard pressure base and at a standard temperature base. The standard pressure base shall be 14.65 pounds per square inch absolute, and the standard temperature base shall be 60 degrees Fahrenheit.

To calculate CO_2 mass from CO_2 volume, EPA recommends using the database of thermodynamic properties developed by the National Institute of Standards and Technology (NIST). This online database is available at:

https://webbook.nist.gov/chemistry/fluid/

It provides density of CO_2 using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At State of Texas standard conditions, the Span and Wagner EOS gives a density of CO_2 of 0.002641684 lb-moles per cubic foot. Converting the CO_2 density in units of metric tonnes per cubic foot:

$$Density_{CO2}\left(\frac{MT}{ft^3}\right) = Density_{CO2}\left(\frac{lb - moles}{ft^3}\right) \times MW_{CO2} \times \frac{1\ MT}{2204.62\ lbs}$$

Where:

$$Density_{CO2} = Density\ of\ CO2\ in\ metric\ tonnes\ (MT)\ per\ cubic\ foot$$

$$Density_{CO2}\ =\ 0.002641684$$

$$MW_{CO2}\ =\ 44.0095$$

$$Density_{CO2} =\ 5.2734\ x\ 10^{-5}\frac{MT}{ft^3}\ \ or\ \ 5.2734\ x\ 10^{-2}\ \frac{MT}{Mcf}$$

The conversion factor 5.2734×10^{-2} MT/Mcf is used to convert CO_2 volumes in standard cubic feet to CO_2 mass in metric tonnes.