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Booker Field Area (BFA)

MONITORING, REPORTING AND VERIFICATION PLAN (MRV)

CapturePoint LLC

November 2023

Contents

INTRODUCTION

CapturePoint, LLC (CapturePoint) operates the Booker Field Area (BFA) located in Ochiltree and Lipscomb Counties, 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 BFA was discovered in 1982 and is composed of three units, the Booker Trosper Upper Morrow Unit (BTUMU) that was unitized by Vintage Petroleum Company, Inc., on September 12, 1995, the Albert Spicer Upper Morrow Unit (ASUMU) that was unitized by Vintage Petroleum Company, Inc., on September 15, 1995, and the Gramstorff Upper Morrow Unit (GUMU) that was unitized by Vintage Petroleum Company, Inc., on May 15, 1995. The Units were formed for the purpose of waterflooding with water pumped from water wells on the Units. The field structure is a lenticular bedding sand trending northwest to southeast with the average top of sand at 8,000 feet, true vertical depth. CapturePoint has been operating the BFA since 2017. CapturePoint acquired the BFA from Chaparral Energy LLC, which initiated the CO_2-EOR project in June 2009. 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).

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 that includes the duration and volume of CO_2 to be injected; a detailed description of the geology and hydrogeology of the BFA 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 BTUMU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544681, the ASUMU CO_2 flood had reported under Greenhouse Gas Reporting Program identification number 544680, and the GUMU CO_2 Flood had reported under Greenhouse Gas Reporting Program Identification number 544682. The EPA has been notified that the ASUMU and the GUMU will not be reporting for 2023, and that these two facilities have been merged into the Booker Field Area Facility Identification number 544681.

1.2 UIC Permit Class

For injection wells (see Appendix 2) that are the subject of this MRV plan, the TRRC has rules governing UIC Class II injection wells. 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 BFA, including both injection and production wells, are regulated by 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 BFA 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 BFA has been injecting CO_2 for the last 12+ 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 43 billion standard cubic feet (Bscf) or 2.27 million metric tonnes (MMMT) from the start of CO_2 injection through August 2035. During the MRV plan, the period July 2023 through August 2035, 21 Bscf or 1.1 MMMT will be stored in the BFA. (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 BFA 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 Section 2.2.2, Section 4.3, and Section 4.4 are based on analysis of logs from both the Farnsworth Unit, which is located 30 miles Southwest of the BFA, and the BFA (Figure 2.2-1). 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).

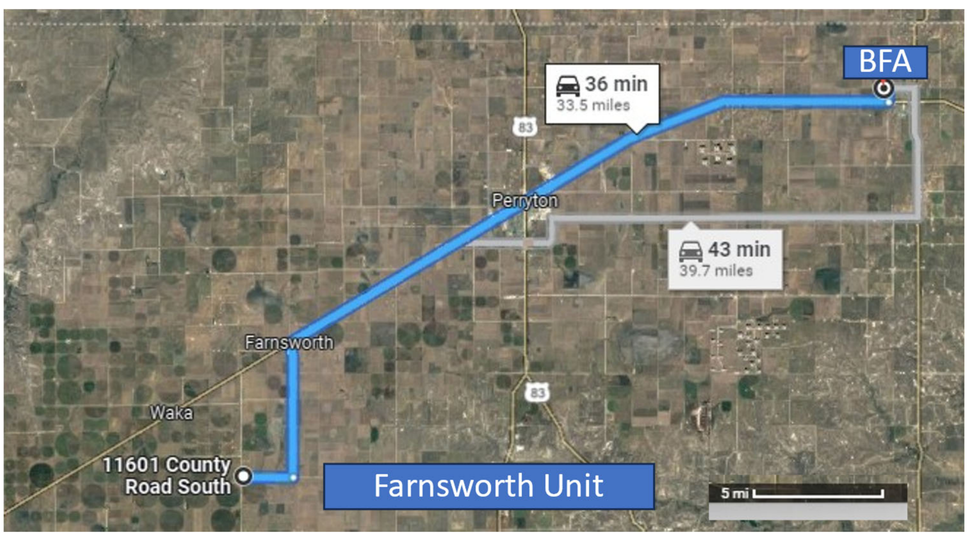

Figure 2.2-1. Direction Map from Farnsworth to BFA.

2.2.2.1 Tectonic Setting and Stratigraphy

The BFA is located on the northwest shelf of the Anadarko basin (Figure 2.2-2) 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 BFA is restricted to the operationally named Morrow sandstone; the uppermost Morrow sandstone encountered below the Atokan Thirteen Finger limestone. The primary caprock intervals at BFA are comprised of the upper Morrow shale and the

Thirteen Finger limestone (Figure 2.2-3). The Morrowan and Atokan intervals were deposited approximately 315 to 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 30 feet thick throughout the field and lies at a depth of approximately 8,000 to 8,200 feet. The primary seal rocks of the Morrow shale and the Thirteen Finger Limestone comprise a package of approximately 30 to 50 feet thick in the field and are overlain by thousands of feet of Atokan and younger limestones and shales.

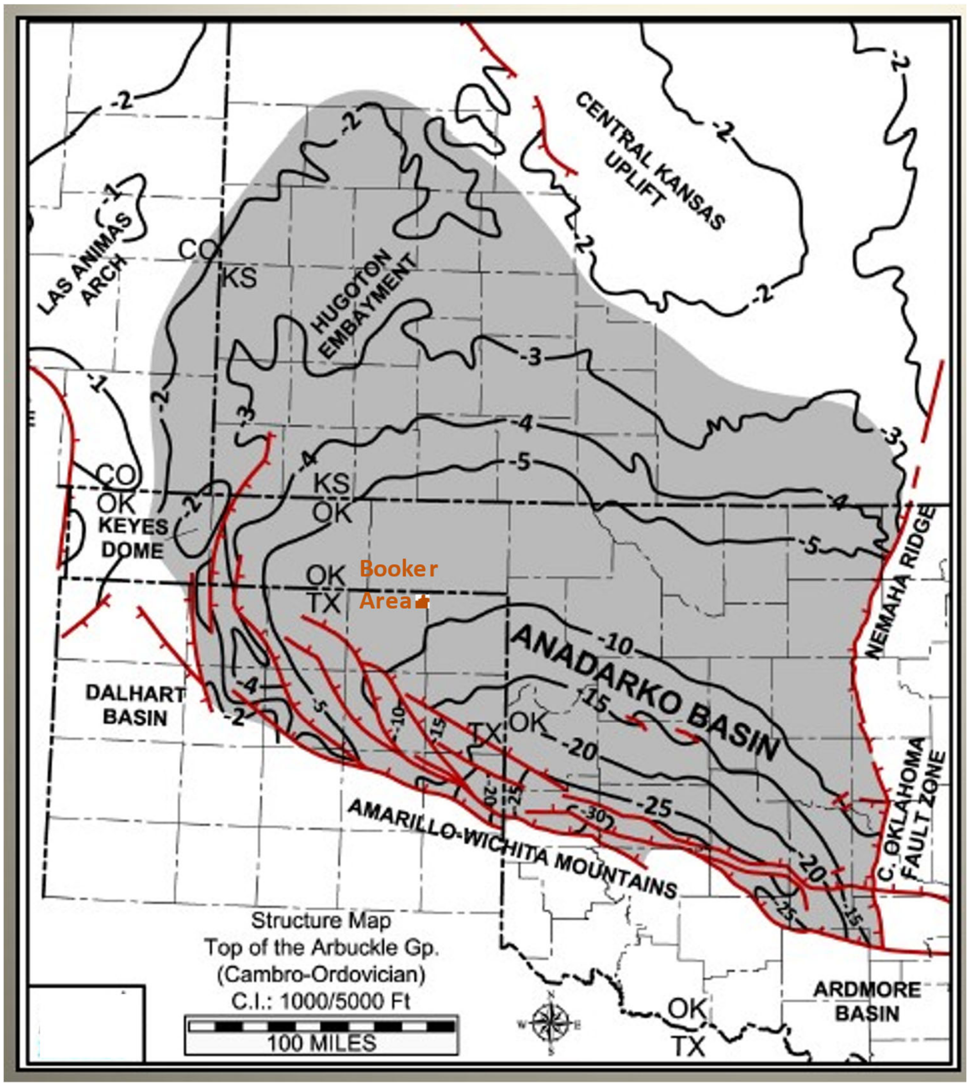

Figure 2.2-2. Location of the BFA on the Northwest Shelf of the Anadarko Basin in West Texas. Red lines are approximate locations of faults that have been documented in the region.

<table>
<tr><th>System</th><th>Series</th><th>Group</th><th>Formation</th><th colspan="2"></th></tr>
<tr><td rowspan="10">Pennsylvanian</td><td rowspan="3">Virgilian</td><td colspan="2">Wabaunsee</td><td rowspan="3"></td><td rowspan="15">ANADARKO</td></tr>
<tr><td>Shawnee</td><td>Heebner
Endicott
Toronto</td></tr>
<tr><td>Douglas</td><td>Douglas
U. Tonkawa</td></tr>
<tr><td rowspan="2">Missourian</td><td>Lansing</td><td>L. Tonkawa
Cottage Grove
Hogshooter</td><td rowspan="5">GRANITE WASH</td></tr>
<tr><td>Kansas City</td><td>Checkerboard
Cleveland</td></tr>
<tr><td>Marmaton</td><td>Marmaton</td><td>Marmaton
Oswego</td></tr>
<tr><td colspan="3">Cherokee Shale</td></tr>
<tr><td>Atoka</td><td>Upper Dornick Hills</td><td>Atoka
Thirteen Finger</td></tr>
<tr><td>Morrow</td><td>Lower Dornick Hills</td><td>Upper Morrow
Middle Morrow
Lower Morrow</td><td rowspan="7"></td></tr>
<tr><td colspan="3">Springer</td></tr>
<tr><td rowspan="5">Mississippian</td><td colspan="3">Chester</td></tr>
<tr><td>Meramec</td><td>Meramec</td><td>St. Genevieve
St. Louis
Spergan
Warsaw</td></tr>
<tr><td colspan="3">Osage</td></tr>
<tr><td colspan="3">Kinderhook</td></tr>
<tr><td colspan="3">Chattanooga</td></tr>
</table>

Figure 2.2-3. Stratigraphic section.

Tectonic Setting

From BFA's location on the western edge of the basin, the Anadarko Basin plunges to the southeast (Figure 2.2-4) 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 BFA 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 BFA (see Section 4).

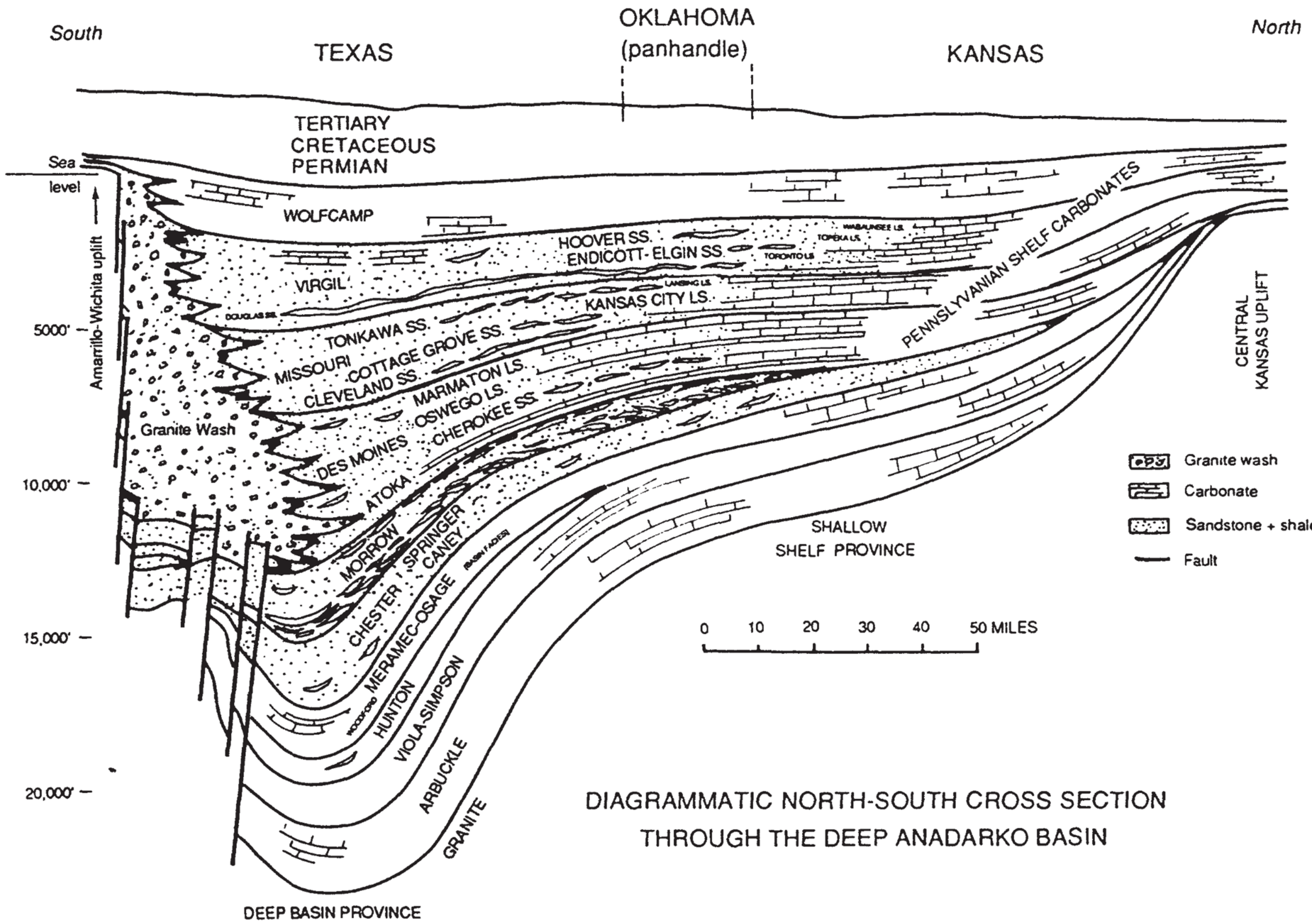

Figure 2.2-4. Diagrammatic North-South Section (Bottom) of the BFA.

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 BFA, the Morrow 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 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 BFA 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 Section 2.2.2.1, the Morrowan and Atokan intervals of the BFA were deposited approximately 315 to 300 million years ago and are contained in the Carboniferous period.

2.3 Description of the CO_2 Injection Process

Figure 2.3-1 depicts a simplified flow diagram of the facilities and equipment within the boundaries of the BFA. 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 reach a maximum of 5 MMCFD. Once CO_2 enters the BFA there are three main processes involved in CO_2-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 BFA 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. See Figure 2.3-2

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.

Metering of gas. The produced gas is metered at the AWT. During any compressor upset, part of the inlet gas is diverted to the flare pipelines and has a certified meter for measurement. Normally, all the produced gas goes through the compressor where it is recycled back to the field for injection and uses a certified meter for measurement. The purchase or fermentation CO_2 goes through a certified meter prior to entering the high-pressure CO_2 injection system.

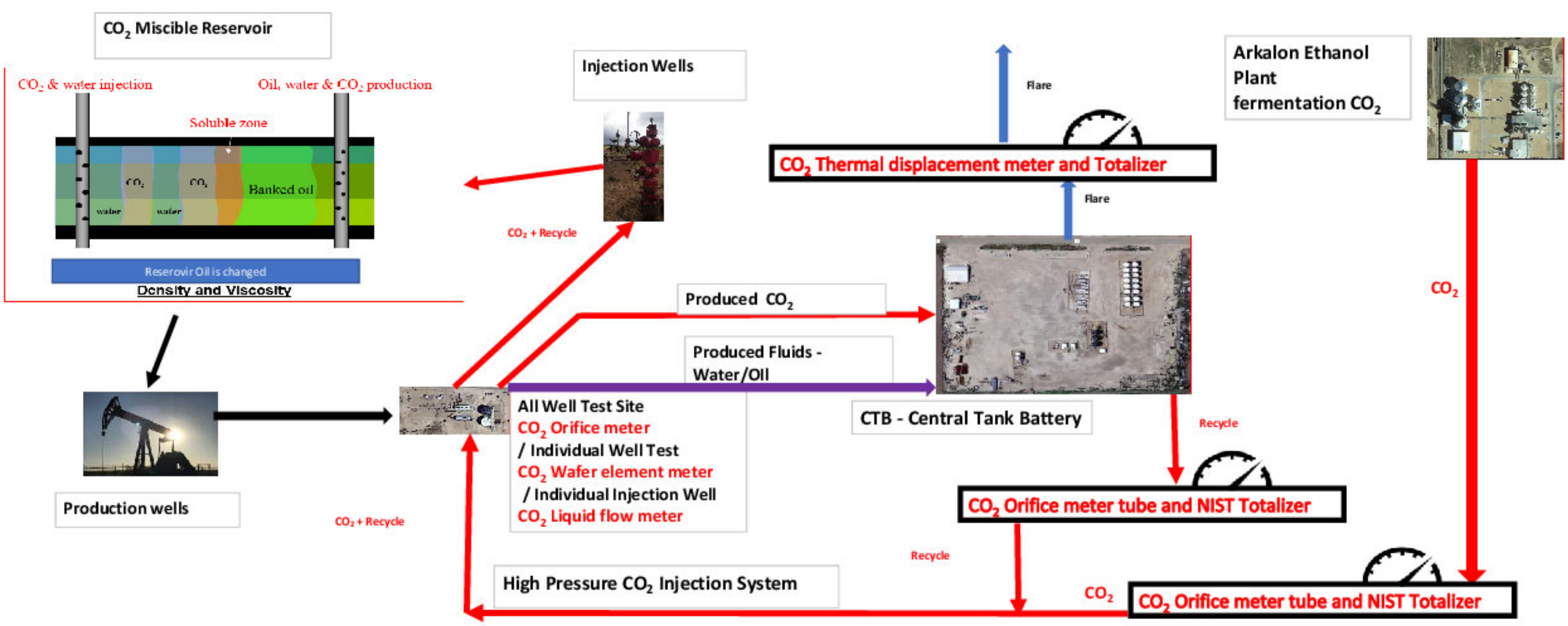

Figure 2.3–1. Simplified flow diagram of the facilities and equipment within the boundaries of the BFA.

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 by Serendipity on March 7, 2023, 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 BFA. A totalizer meter, for the purchased CO_2, is located at the field where instantaneous data is summed into a 24-hour flow rate, which is then recorded daily. A totalizer meter is a meter approved by prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate to measure the flowrate of gases. The actual measurements taken are temperature, line pressure, and differential pressure across the meter.

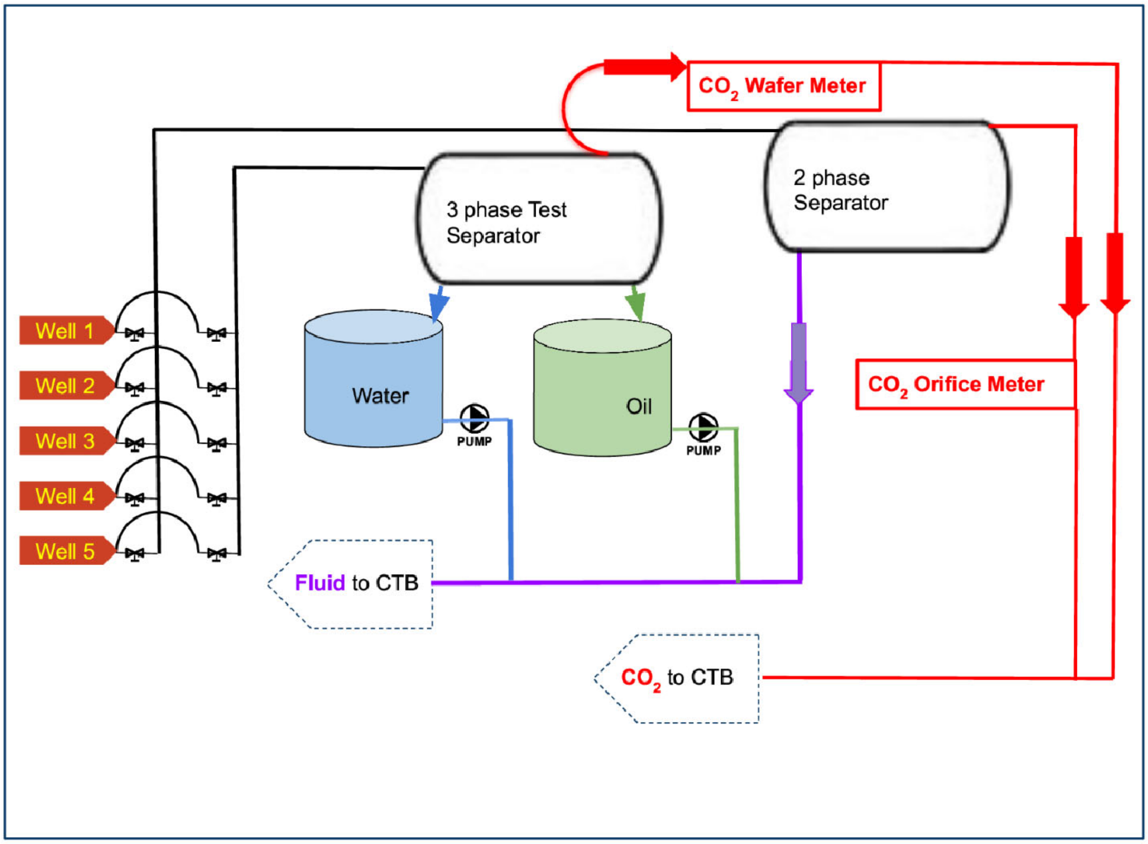

Figure 2.3-2 Flow of Well Fluids through AWT

2.3.1 CO_2 Collection and Distribution

A simple CO_2 flow diagram showing the movement of CO_2 from the production wells to leases, from the leases to recycle facility, and then onto injection wells. (Figure 2.3-3). Also, included are flared emissions and purchases that change the volume of the stream. CO_2 is measured at all points in the diagram.

Gas produced, which contains recycled CO_2, from the individual production wells is measured with a wafer element meter during a well test. That CO_2 and gas is routed to the AWT with other wells and the total AWT CO_2 is measured with an orifice meter. All BFA produced gas and CO_2 is routed to the CTB. Any CO_2 and gas that must be flared, or emitted, due to operational issues is measured with a thermal displacement meter. The remaining CO_2 and gas stream is compressed, and this high-pressure CO_2 and gas is measured with an orifice meter that uses a totalizer with an NIST library. This high-pressure stream and the flare stream are master measurements that are used to normalize and allocate the individual AWT and the production well metered streams. Added CO_2, or purchase CO_2, is also a master measurement with an orifice meter that uses a totalizer with an NIST library. This high-pressure recycle plus purchase CO_2 is allocated to individual injection wells and is proportional to the liquid flow turbine meters rates.

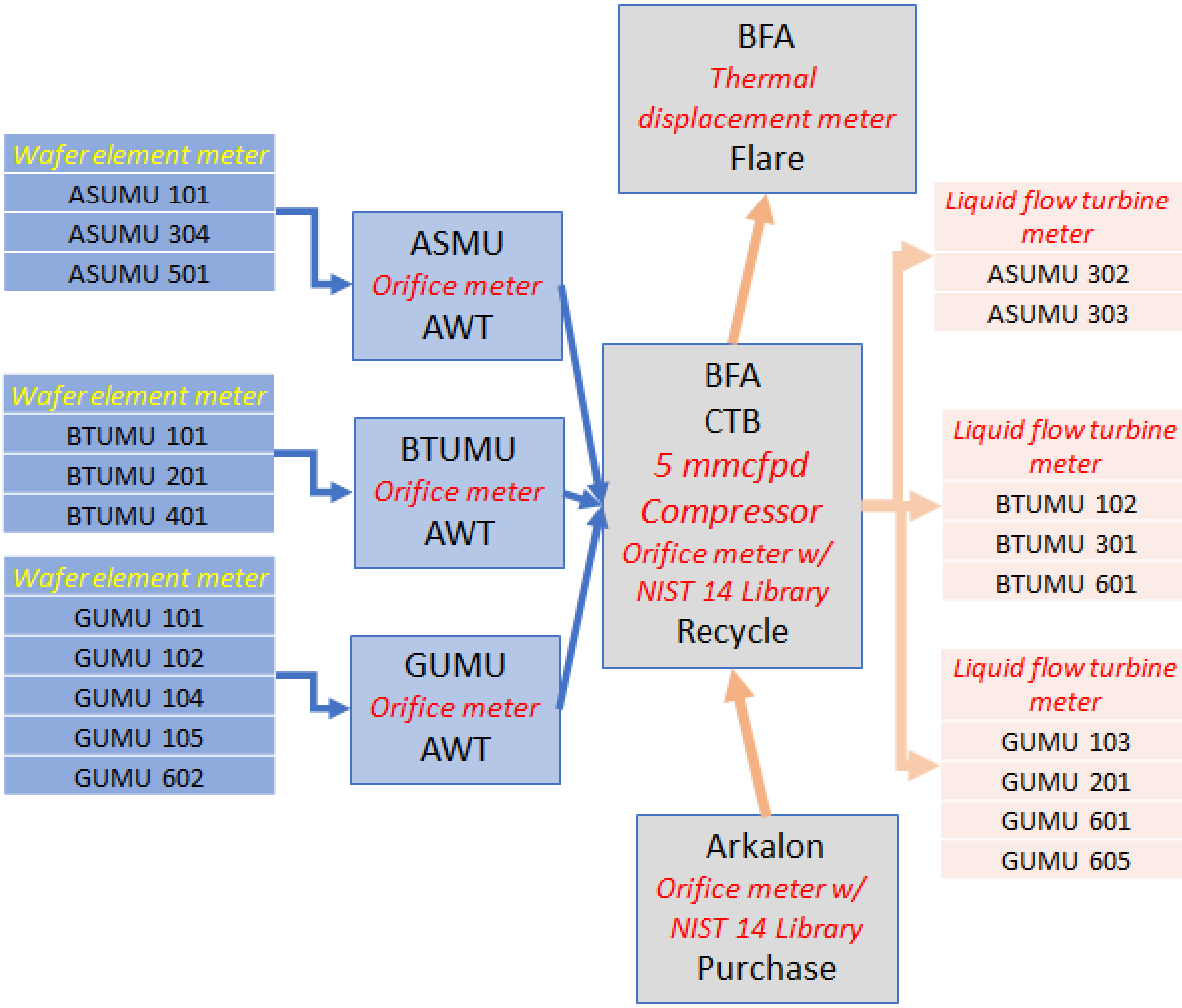

Figure 2.3-3. CO_2 Flow from Production Wells through Facilities back to Injection Wells

CapturePoint currently has three active injection manifolds and approximately nine 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 9 MMCFD. Of this volume, 5 MMCFD is purchased CO_2 and 4 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 5 MMCFD for 12 years and cease after 2035. 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 three 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 turbine meter and 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 (recycle and purchase meters) as described above will be used to determine the total volume injected that is 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 11 active production wells producing at any time. Each AWT site 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 site, 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.

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 1,685 ppm CO_2 (0.169%) for BFA 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 93% to 96% 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 <1280 ppm (0.128%) CO_2.

BFA production has trace amounts of hydrogen sulfide (H_2S), which is toxic. There are approximately 2-6 workers on the ground in the BFA 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 to 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 4.7, 4.8, 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 (Figure 2.3-4).

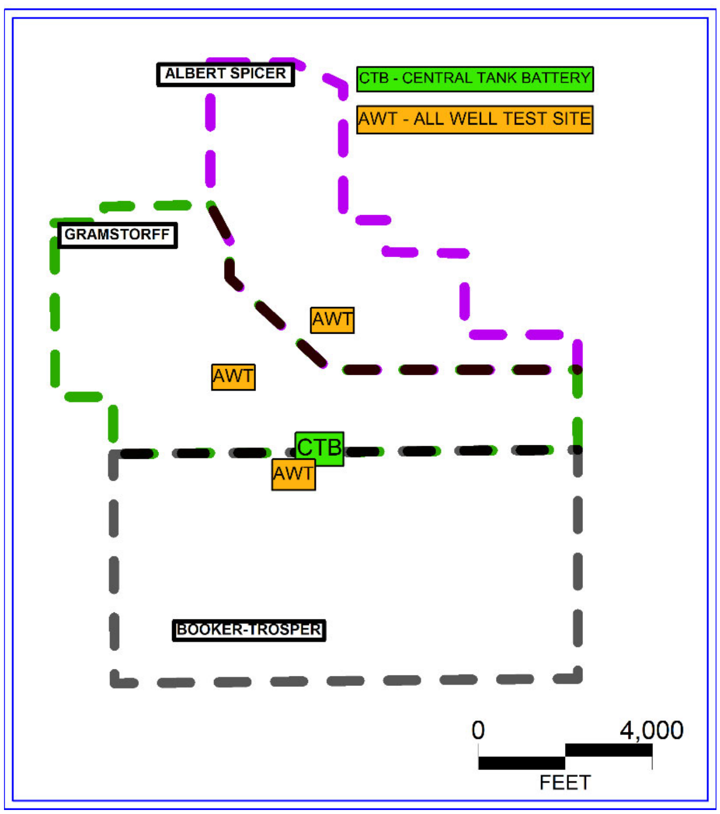

Figure 2.3-4. Location of AWT sites and CTB in the BFA

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 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 BFA 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 8,035 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 BFA Morrow 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 sandstone reservoir is at a depth between 7,960 feet and 8,200 feet subsurface with an average dip of less than one degree (Figure 2.4-1). The productive limit of the BFA is about 40 to 60 percent of the total operated surface acreage, which is 2,800 acres. The maximum pay thickness is 35 feet with an average of 15 feet and does diminish to zero in spots.

The BFA is approximately two miles by two miles with areas that exhibit different reservoir behavior. The entire BFA is now responding to CO_2 better than historical operations would have indicated.

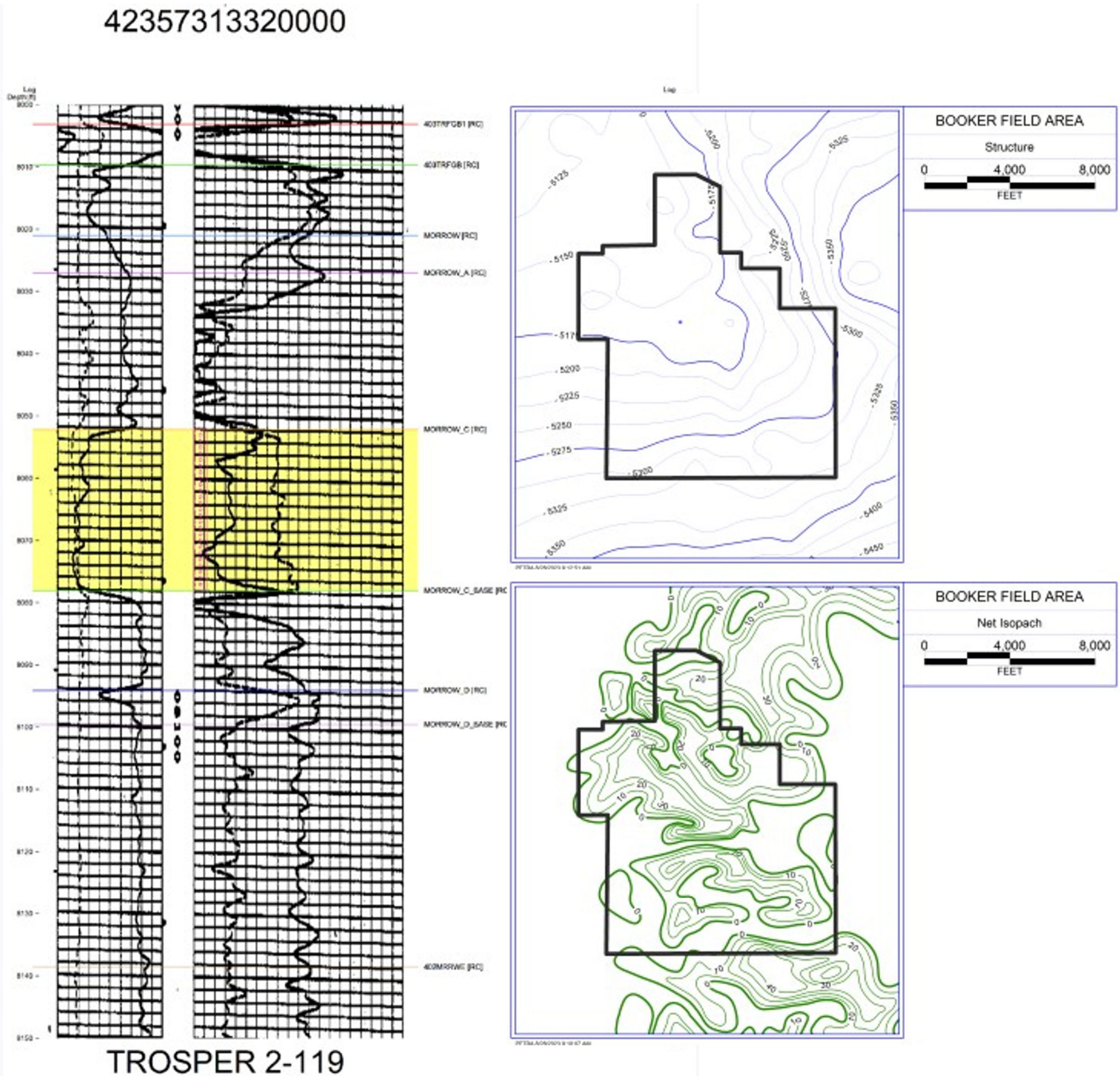

Figure 2.4-1. (Left) Type log of BFA caprock and reservoir, (Upper Right) Surface contour of Morrow top, (Lower Right) Thickness map of Morrow sands.

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 BFA is 172 degrees Fahrenheit or 4 degrees higher than the temperature at Farnsworth Unit of 168 degrees. Using parameters of the Alston empirical correlation (1985), the MMP would be 50 psia higher at the BFA or 3,730 psia compared to 3,680 psia at the Farnsworth Unit (Figure 2.4-2).

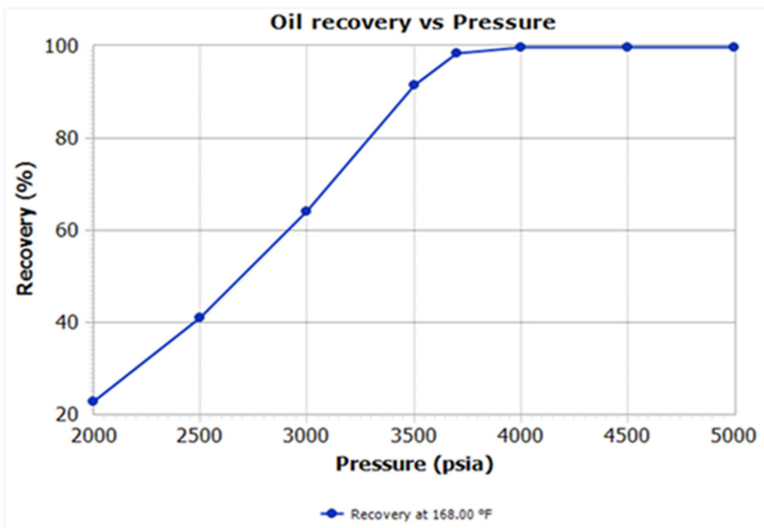

Figure 2.4-2. Oil recovery plot for 1D slim tube test for Farnsworth Unit.

2.4.3 CO_2 Analogy Field Study

Based on similar geologic, petrophysical, engineering, and operational parameters between the Farnsworth Unit and the BFA, the oil recovery performance of both fields is expected to be similar. The formations are easy to correlate across distance and the descriptions of rock are similar as are the porosity and permeability (Figure 2.4-3). Due to the stratigraphic nature of the Morrow channel sands, the potential movement of CO_2 is severely limited. The BFA area has contained the free phase CO_2 plume in a very confined area since June 2009 as exhibited by oil, water, and CO_2 recovery performance. Also, during BFA drilling and production operations, no reports exist which would indicate any plume has moved outside of the MMA. The Farnsworth Unit MRV and the BFA data justify 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.

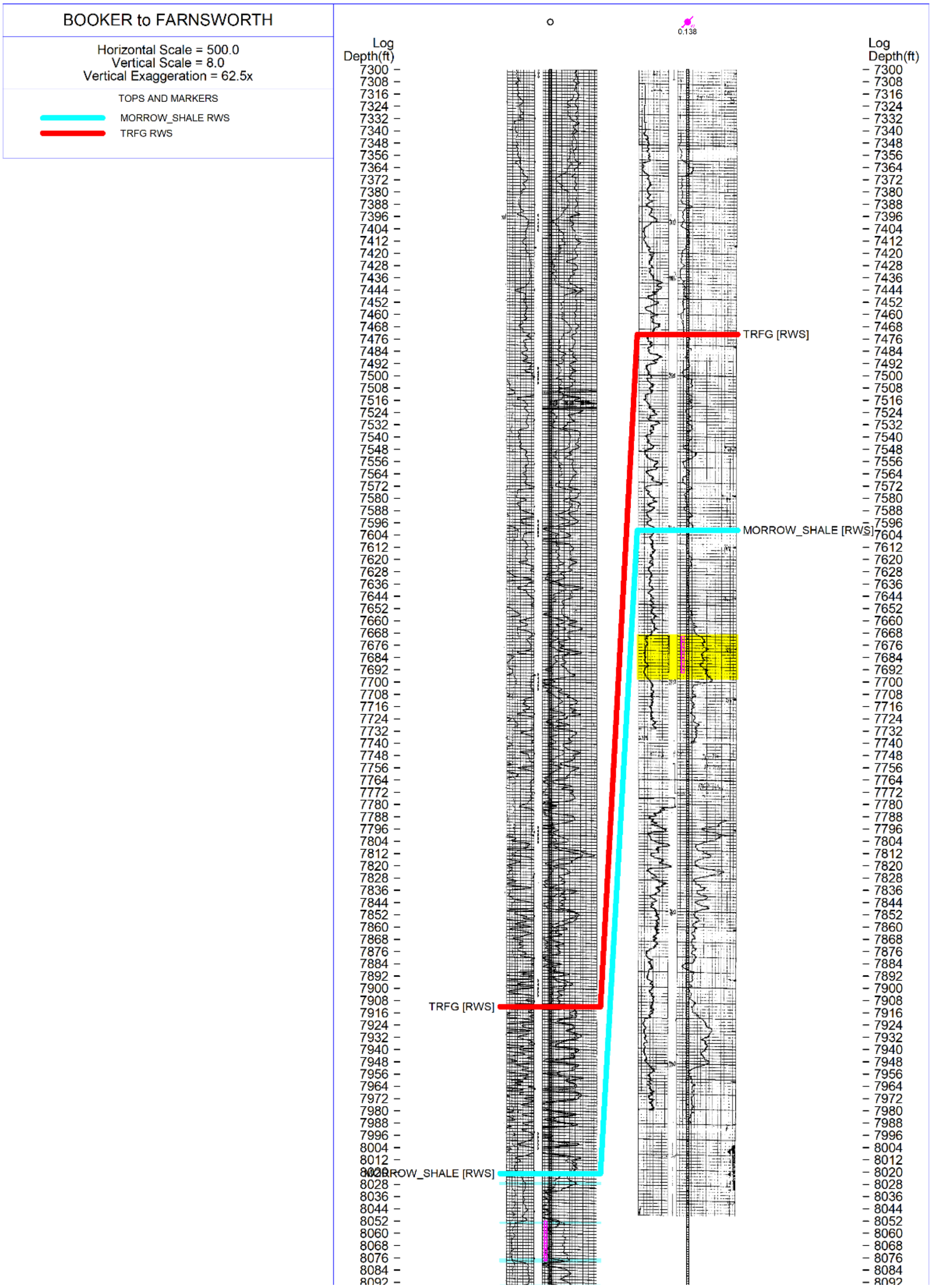

Figure 2.4-3 Cross-section showing log correlation of the Thirteen Fingers formation and the Morrow formation from BFA to Farnsworth Unit.

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 BFA has been injecting CO_2 since June 2009. The dimensionless curves were matched to historical performance through early 2020 (Figure 2.4-4). 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 1st quarter of 2023.

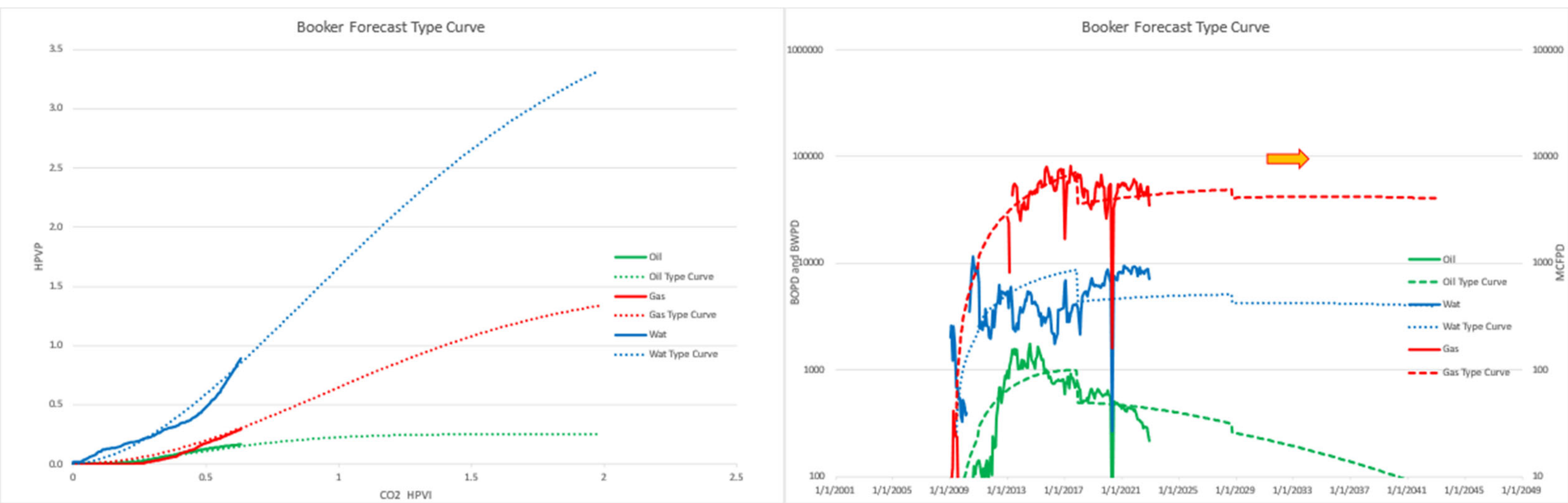

Figure 2.4-4. Dimensionless curves for CO_2 injection (left) with rate time curves (right).

The dimensionless water oil ratio and the gas oil ratio trends (Figure 2.4-5) for the BFA flooded acreage are very similar to what was forecasted by simulation in the Farnsworth Field, which was expected because of the porosity, permeability, and sand similarities.

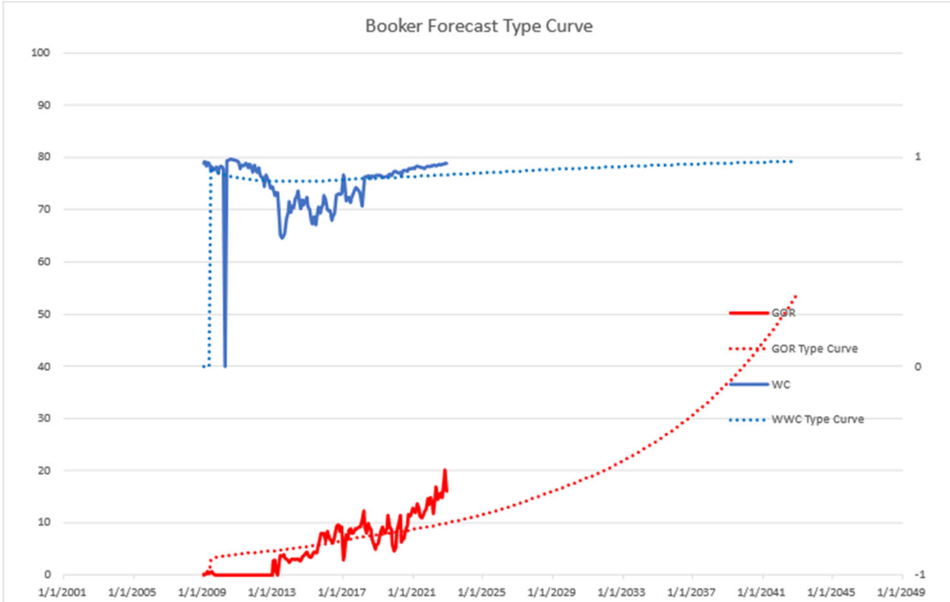

Figure 2.4-5. Dimensionless water cut and GOR vs. observed CO_2-EOR data.

The CO_2 storage volumes for Arkalon fermentation CO_2 were also forecasted (Figure 2.4-6) 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.

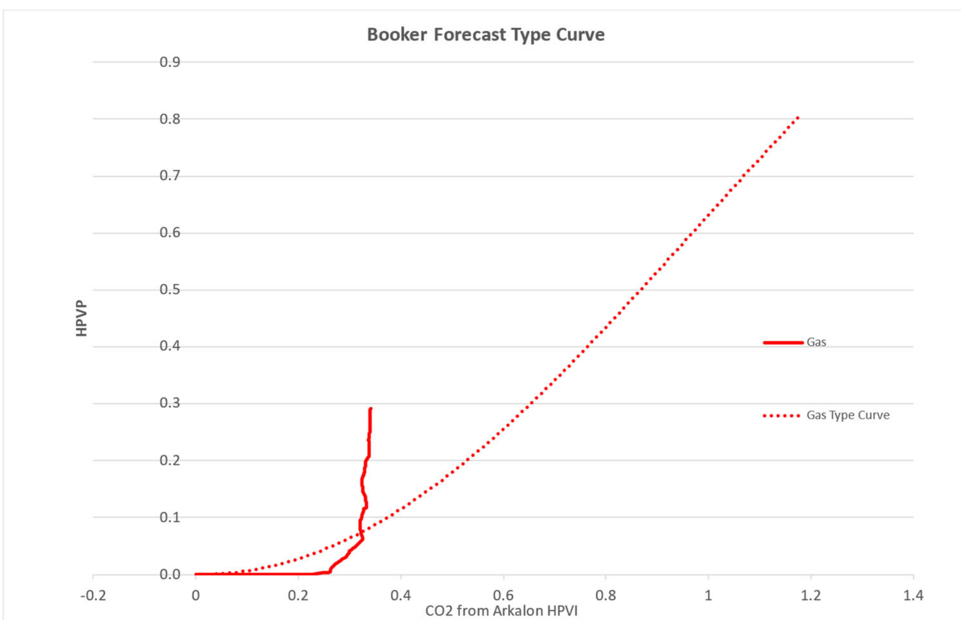

Figure 2.4-6. Dimensionless CO_2 Purchase (Fermentation) Curves

The barrels of reservoir volume were converted to standard cubic feet of gas and is displayed in the BFA Purchase CO_2, or Fermentation CO_2, vs Time chart (Figure 2.4-7).

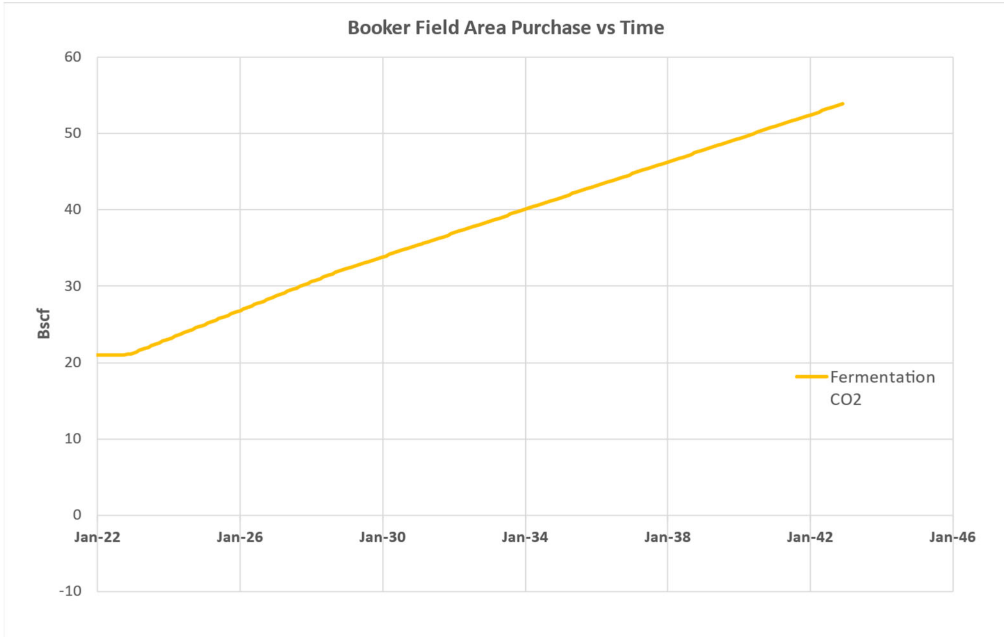

Figure 2.4-7. CO_2 Purchase (Fermentation) Volume.

3 Delineation of Monitoring Area

3.1 CO_2 Storage

3.1.1 Determination of Storage Volumes

Figure 3.1-1 displays wells that have CO_2 retention on the developed 1,400 acres that have been under CO_2-EOR injection in the BFA since project initialization (2,800 acres are in the BFA). 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 9 patterns identified for continued injection indicates an additional 22 Bscf of CO_2 can be stored and with 21 Bscf already stored results in 43 Bscf of total storage. With the anticipated 5 MMCFD rate of purchased CO_2, this storage volume will only be 60 percent utilized. As delineated in this MRV plan, the MMA accounts for an injected volume of up to 43 Bscf and includes all areas of the BFA that could be utilized in the future for CO_2 injection.

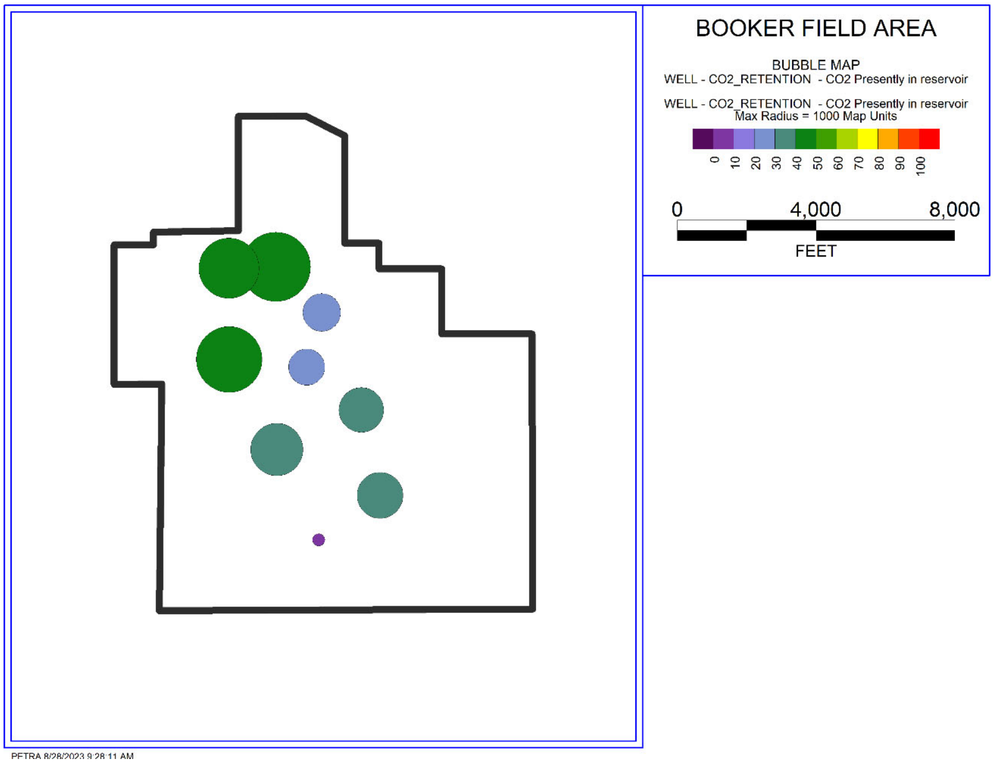

Figure 3.1-1. Estimated CO_2 storage as of 2021 in BFA.

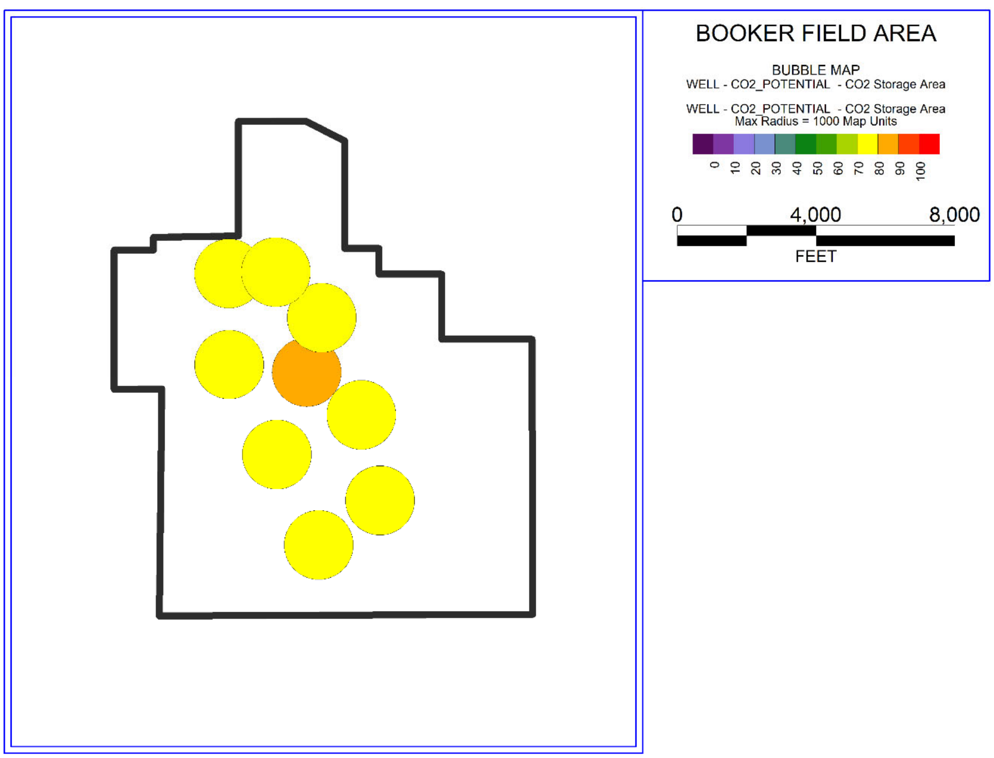

Figure 3.1-2. Potential Total CO_2 Storage in the BFA.

3.2 AMA

The AMA is shown in Figure 3.2-1. It is an area defined by the boundary of the BFA plus the required ½ mile buffer. The AMA is consistent with the requirements in 40 CFR 98.449 because it is the area projected:

1. to contain the free phase CO2 plume for the duration of the project (year t), plus an all-around buffer zone of one-half mile.
2. to contain the free phase CO2 plume for at least 5 years after injection ceases (year t + 5).

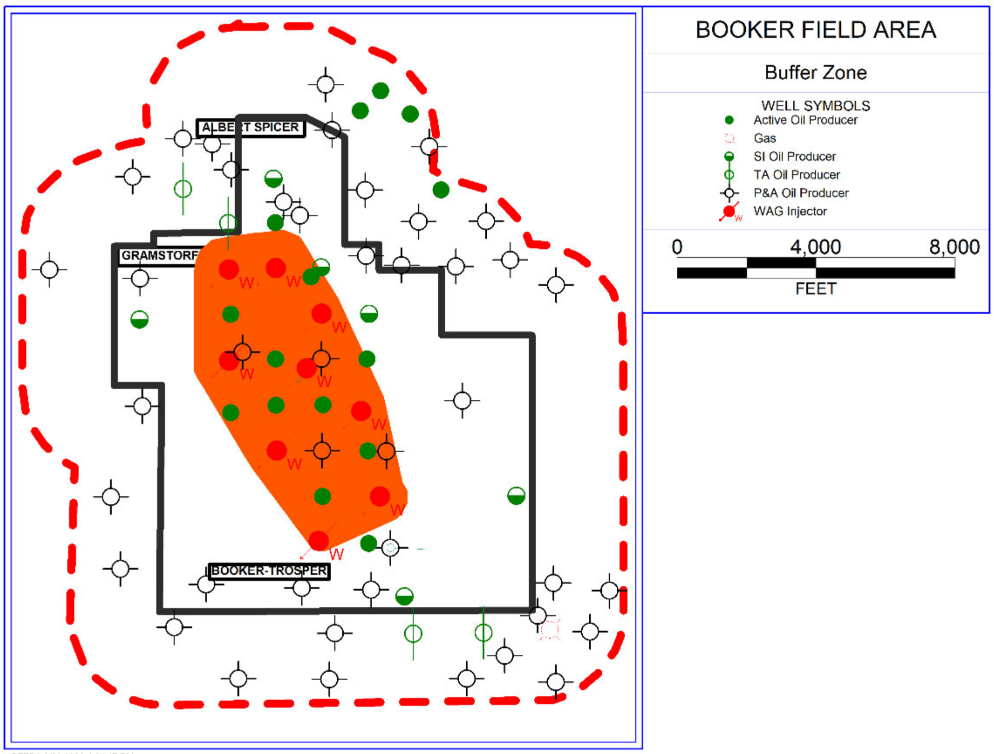

Figure 3.2-1. BFA boundary (black) with the ½ mile buffer boundary (dotted red), and final projected plume area (orange polygon).

3.2.1 Determination of Buffer Zone

CapturePoint intends to implement a buffer zone of one-half mile around the BFA, 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.

CapturePoint's has the exclusive right to operate the BFA unitized leases, as described in the INTRODUCTION. Currently, CapturePoint's operations cover the entire BFA. Any 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 unitized BFA. Based on our projections, CapturePoint expects the free phase CO_2 plume to remain within the BFA for the entire length of the project and through year [t + 5].

Therefore, the AMA is 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 BFA.

3.3 MMA

As defined in Subpart RR, the 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 3.2 indicating that CO_2 storage pore space is available, barring unforeseen future operational issues. Therefore, CapturePoint defines the MMA as the boundary of the BFA plus an additional one-half mile buffer zone.

4 Identification and Evaluation of Leakage Pathways

Since its discovery in 1982, the unitization of the different units in 1995, and the commencement of CO_2-EOR in 2009; the BFA 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. Surface equipment leaks have a low risk of occurring based on design standards that are followed, and any leak would have insubstantial results. In addition, the TAC rules of the TRRC to report and quantify leaks, both serve to minimize leakage of GHG from surface equipment. Under these rules operators must determine if any leak that can be seen, heard, or felt, and which is in a location that may endanger the general public or property, take prompt action to eliminate the hazard, and do post-inspection or repairs. 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. While efforts to ensure all equipment is maintained and tested, surface equipment leaks randomly occur. The magnitude of surface equipment leaks will range from 0.1 to 2 MT yearly and are addressed within 6-12 hours of occurring.

4.2 Leakage from Wells

CapturePoint has identified 9 active injection wells, 11 operated active production wells, and 5 inactive wells within the AMA 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 MMA of the BFA. Because the BFA was unitized in 1995, all plugging and abandonment activities of wells within the BFA have been conducted under the regulations of 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 4.7 and the strategy to quantify the leak is discussed in Section 4.8.

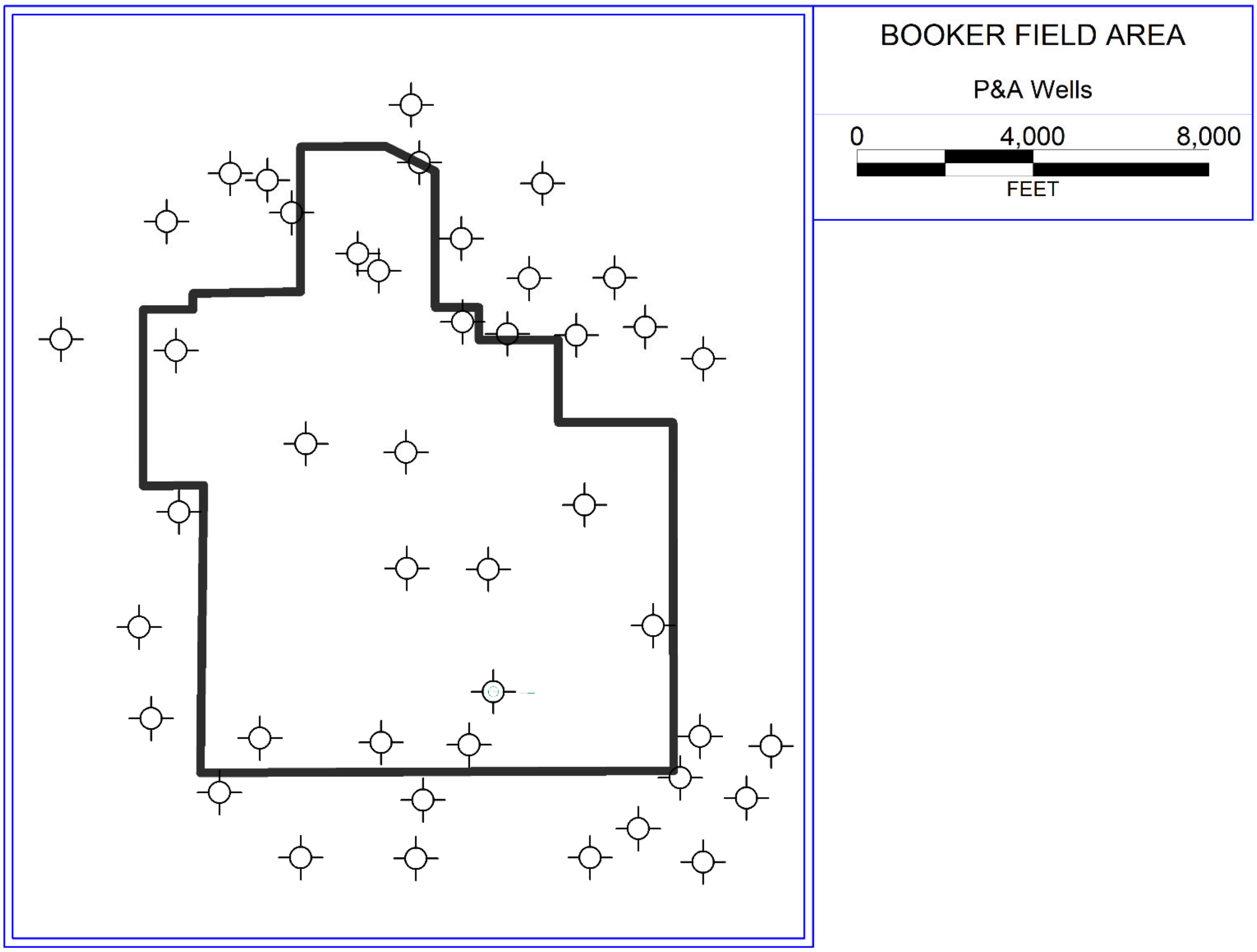

Figure 4.2-1. Plugged and Abandoned Wells in the BFA.

4.2.2 Injection Wells

Figure 4.2-2 shows the 9 active injection wells in the AMA of the BFA. 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 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 BFA. CapturePoint concludes that leakage of CO_2 to the surface through active injection wells is unlikely.

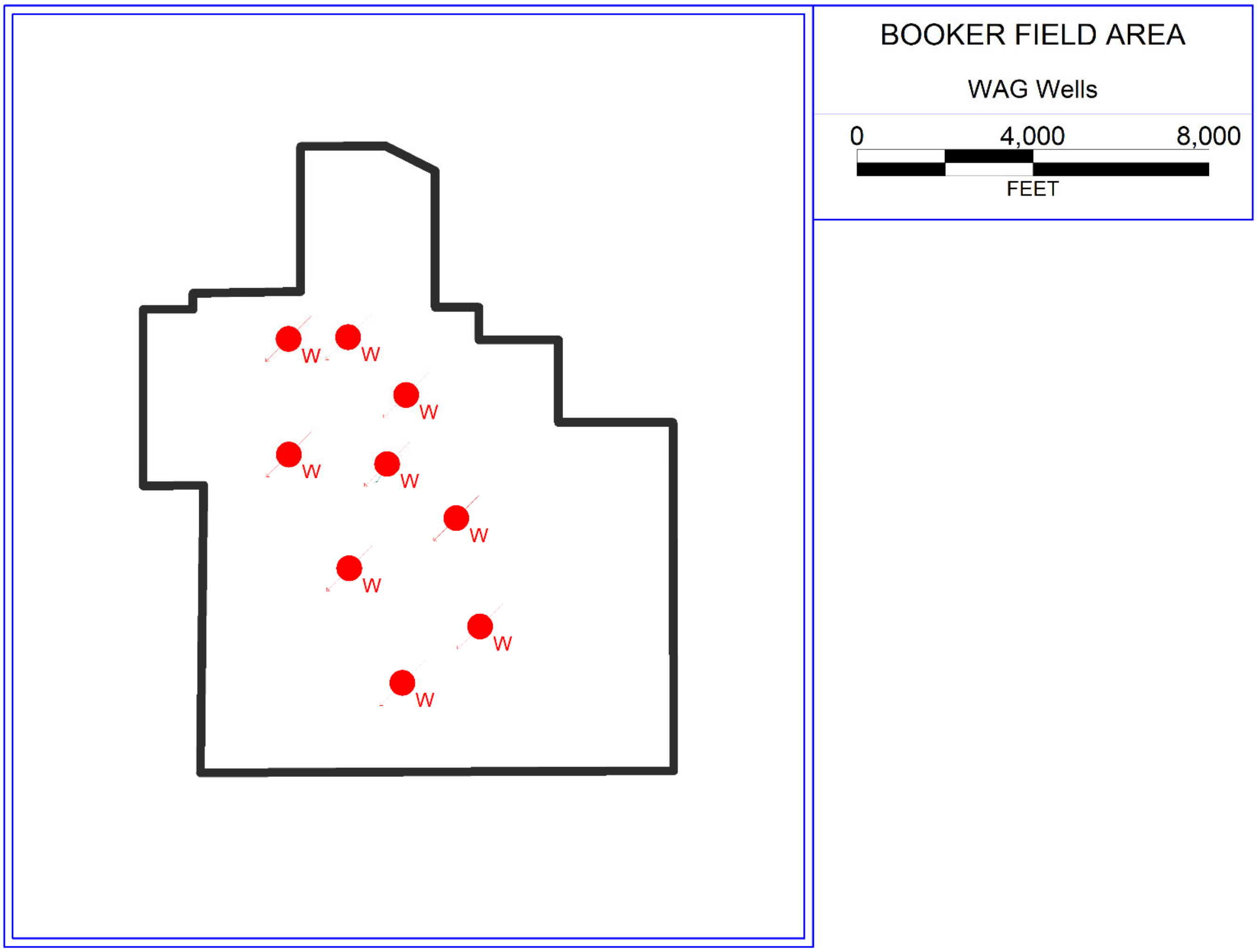

Figure 4.2-2. Active Injection Wells in the BFA.

4.2.3 Production Wells

Figure 4.2-3 shows the 11 active oil production wells in the AMA and 15 active oil production wells in the MMA of the BFA. However, as the project develops in the BFA additional production wells may be added and will be constructed according to the relevant rules of the TRRC. Additionally, inactive wells may become active according to the rules of 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 contain 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.

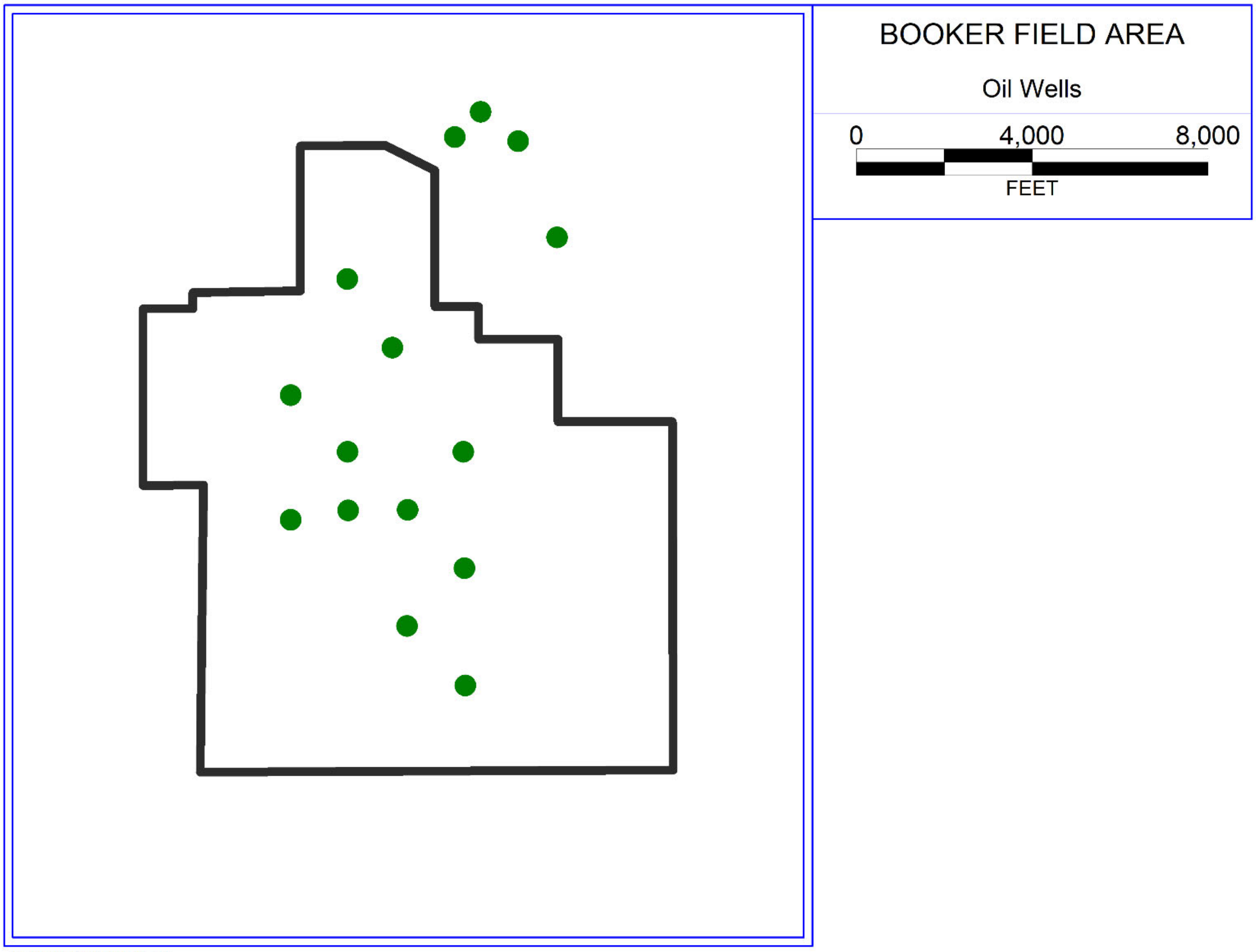

Figure 4.2-3. Active Oil Production Wells in the BFA.

4.2.4 Inactive Wells

Figure 4.2-4 shows 5 inactive wells in the AMA, which were all oil producers, and 10 inactive wells in the MMA, which consists of the 5 oil producers, 4 temporally abandoned (TA) wells, and one gas well, of the BFA. 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, will range from 5 to 20 MT once every 50 years.

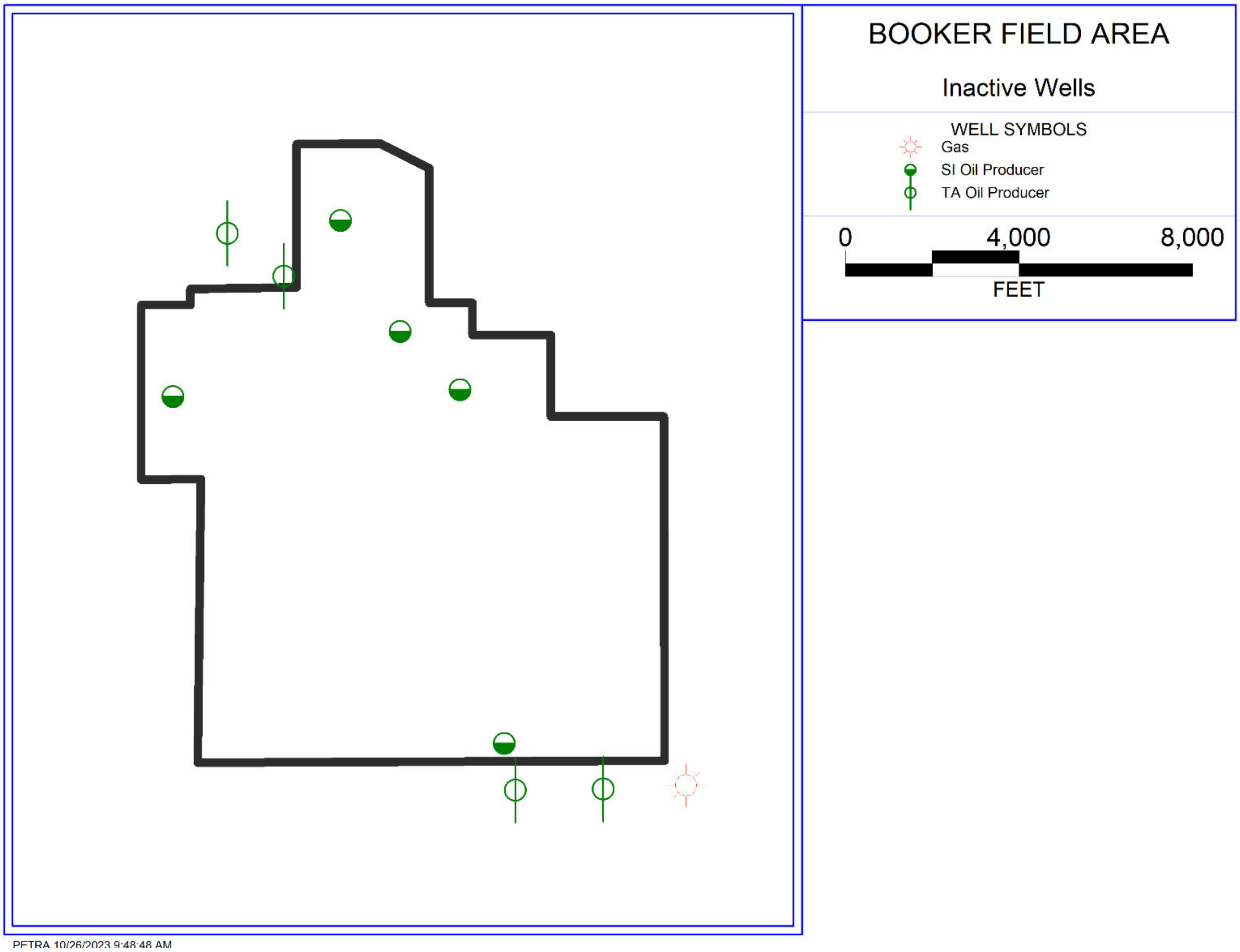

Figure 4.2-4. Inactive wells in the BFA

4.2.5 Timing, Magnitude and Addressing Leaks

Legacy wells include the plugged and abandoned wells, the active WAG wells, the active oil wells, and the inactive wells. Leakage for legacy wellbores is unlikely but possible. If it did occur, the magnitude of legacy wellbore leaks will range from 5 to 20 MT once every 50 years and will be addressed within 2 to 6 months of discovery to allow for obtaining drilling permits and contractor equipment mobilization.

4.2.6 New Wells

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

All wells in Texas oilfields, including both injection and production wells, are regulated by 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 BFA and follows the TRRC rules, which significantly limits any potential leakage from well pathways. Additionally, the existing wells followed the TRRC rules.

In public databases, the area of BFA 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 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 BFA.

4.3 Leakage from Faults and Bedding Plane Partings

Primary seals at BFA have been demonstrated to be mechanically very competent (see Section 2.2.2), thus the main concern of CO_2 migration at BFA 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 BFA, 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 because of leakage through the faults and fractures but could be 5 to 20 MT once every 50 years. It is unlikely or improbable that the leak would result in surface leakage anytime during operations. Dispersion of CO_2 would occur in any of the Pennsylvanian Shelf Carbonates encountered prior to reaching the surface. As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.7 and the strategy to quantify the leak is discussed in Section 4.8.

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. It is estimated that the total mass of stored CO2 will be considerably less than the calculated storage capacity and once production operations cease, very small lateral movement can occur.

4.5 Leakage through Confining/Seal system

At the BFA, 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 BFA. The 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 injection horizon.

Failure analyses show that the Morrow 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. If it did occur, the magnitude of the confining seal leaks will range from 5 to 20 MT once every 50 years and will be addressed within 2 to 6 months of discovery to allow for obtaining drilling permits and contractor equipment mobilization As with any CO_2 leakage, CapturePoint has strategies for leak detection in place that are discussed in Section 4.7 and the strategy to quantify the leak is discussed in Section 4.8.

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 BFA after the waterflood operations were initiated in 1995 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 BFA.

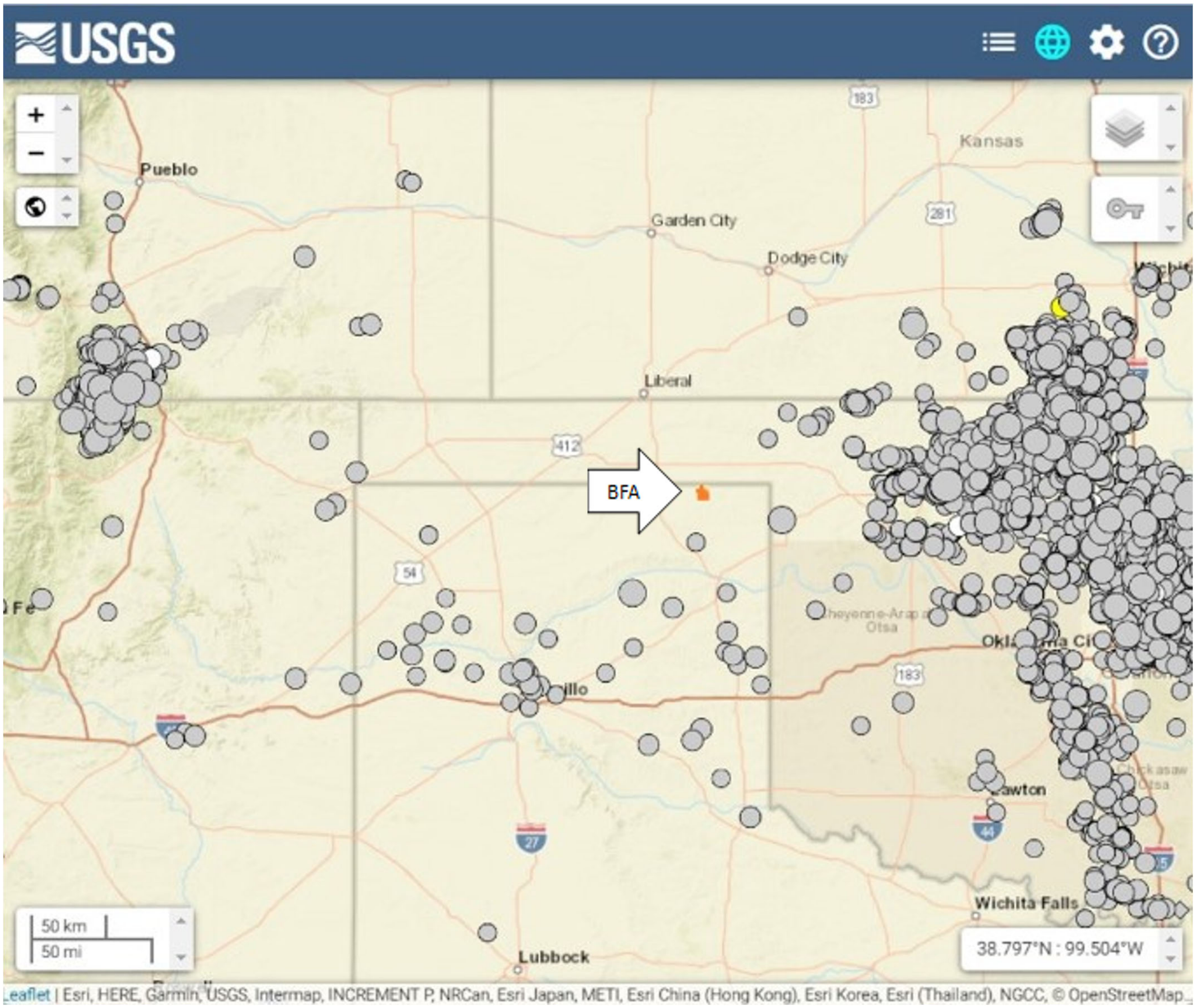

Figure 4.6-1. USGS earthquakes (+2.5 magnitude) for last 40 years with BFA highlighted orange.

There is no direct evidence that natural seismic activity poses a significant risk for loss of CO_2 to the surface in the BFA. Per TRRC Form H-10, the TRRC procedure limits the maximum injection pressure to ½ psig per foot of depth to the top of the injection zone. CapturePoint monitors and follows the reporting cycle required by the TRRC's technical staff.

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. An example methodology would be to place a flux box or ring tent over the surface leak to measure the flow rate and gather gas samples for analysis. The volume of CO_2 in the soil can also be used with this technique.

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 BFA area, per the characterization, monitoring and well data collected by the Southwest Regional Partnership on Carbon Sequestration (SWP) in the analogous Farnsworth Unit. Ongoing operational monitoring of well pressures and rates has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO_2 leakage. Data systems are used primarily for operational control and monitoring and as such are set to capture more information than is necessary for reporting in the Annual Subpart RR Report. Each of these is discussed in more detail below.

5.1 Site Characterization and Monitoring

As described in Sections 2.2.2 and 2.4, the Morrow sandstone is isolated both above and below by shale units of the Morrow. The primary seal consists of 50 – 60 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 BFA, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented. After ~40 years of oil recovery operations, no wellbore leaks were noted, therefore wellbore leaks are unlikely to happen. CapturePoint adheres to the requirements of TAC Rule 46 for the TRRC which require a periodic wellbore Mechanical Integrity Test (MIT) and submits the results per TRRC form H5.

5.2 Groundwater monitoring

CapturePoint does not routinely pull water samples from the Ogallala water wells. CapturePoint has not monitored 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. While groundwater contamination is unlikely to happen, any change in groundwater that is brought to the attention of CapturePoint will be investigated to eliminate the pathway. Texas Water Development Board (TWDB) maintains a Groundwater Database, which has measured Ogallala CO_2 concentration for Ochiltree County, Texas. "Texas Water Development Board (TWDB), Groundwater Database (GWDB), Well Information Report for State Well Number, 04-36-201" is located inside the BFA and had water analysis performed prior to CO_2 injection. Any Ogallala water sampled in the BFA AMA that does not align with these values will be addressed.

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 BFA area is in close proximity to the Farnsworth Unit, atmospheric CO_2 concentrations from the NOAA Global Monitoring Laboratory data can be used for background CO_2 values. If a subsurface leak event is identified, soil flux rings will be installed on a surface location close to the event. The soil will be monitored for CO_2 concentrations and compared to the NOAA Global Monitoring Laboratory CO_2 air concentration data.

5.4 Visual Inspection

CapturePoint operational field personnel visually inspect surface equipment daily and report and act upon any event indicating leakage. Visual inspection consists of finding evidence of stains, unusual accumulation of frost, washouts exposing buried pipe, dead rodents, birds or reptiles, and changes to vegetation. In addition to looking for evidence of leaks, look for conditions that could lead to equipment failure such as public utility digging, ditching, settling of backfill, boring and tunneling.

5.5 Well Surveillance

CapturePoint adheres to the requirements 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 TRRC rules include special conditions regarding monitoring, reporting, and testing in the individual permits for each injection well if they are deemed necessary. The TRRC requires a wellbore MIT every 5 years or after wellbore work actions and the results are submitted per TRRC form H5.

5.6 Injection Well Rates, Pressures and Volumes

Target injection rates and pressures for each injector are developed within the permitted limits based on the results of ongoing pattern surveillance. The field operations staff monitor equpment readings and investigate any departures from the permitted limits which could have resulted in a surface CO_2 leak. CapturePoint also adheres to the requirements of 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 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 BFA facility through its own pipeline from the Arkalon Ethanol plant in Liberal, Kansas. CapturePoint also recycles CO_2 from its production wells in the BFA.

$CO_{2T,r} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}}$ (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 BFA. 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), BFA is 0.00169 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 CO_2-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, April 1, 2023.

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 (GPA) 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 and #8 – (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 and #8.

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 98.444 (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 CO_2-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) and European Gas Research Group (GERG) 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. 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.
(2) The annual GHG reports.
(3) 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.
(4) A copy of the most recent revision of this MRV Plan.
(5) 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.
(6) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.
(7) 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.
(8) 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.
(9) 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.
(10) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
(11) 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.
(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 production wellhead and the flow meter used to measure production quantity.
(13) Any other records as specified for retention in this EPA-approved MRV plan.

10 List of Figures

11 Appendices

Appendix 1 – BFA Wells

Table A1.1 – Production Wells

Well Name	API	Well Type	Status	Gas Makeup	Active Production	Active Injection
ASUMU 101	42-357-31372	Oil Prod	Active	CO_2	1	0
ASUMU 304	42-357-31960	Oil Prod	Active	CO_2	1	0
ASUMU 501	42-357-31313	Oil Prod	Active	CO_2	1	0
BTUMU 101	42-357-31329	Oil Prod	Active	CO_2	1	0
BTUMU 201	42-357-31309	Oil Prod	Active	CO_2	1	0
BTUMU 401	42-357-31333	Oil Prod	Active	CO_2	1	0
GUMU 101	42-357-31304	Oil Prod	Active	CO_2	1	0
GUMU 102	42-357-31376	Oil Prod	Active	CO_2	1	0
GUMU 104	42-357-31476	Oil Prod	Active	CO_2	1	0
GUMU 105	42-357-33376	Oil Prod	Active	CO_2	1	0
GUMU 602	42-357-31453	Oil Prod	Active	CO_2	1	0
ASUMU 201	42-357-31401	Oil Prod	Inactive	CO_2	0	0
ASUMU 301	42-357-31280	Oil Prod	Inactive	CO_2	0	0
ASUMU 502	42-357-31336	Oil Prod	Inactive	CO_2	0	0
GUMU 501	42-357-31496	Oil Prod	Inactive	CO_2	0	0
SB TS 1	42-295-31512	TA Prod	Inactive	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
ASUMU 302	42-357-31343	WAG Inj	Active	CO_2	0	1
ASUMU 303	42-357-31444	WAG Inj	Active	CO_2	0	1
BTUMU 102	42-357-31551	WAG Inj	Active	CO_2	0	1
BTUMU 301	42-357-31286	WAG Inj	Active	CO_2	0	1
BTUMU 601	42-357-31318	WAG Inj	Active	CO_2	0	1
GUMU 103	42-357-31445	WAG Inj	Active	CO_2	0	1
GUMU 201	42-357-31298	WAG Inj	Active	CO_2	0	1
GUMU 601	42-357-31443	WAG Inj	Active	CO_2	0	1
GUMU 605	42-357-33375	WAG Inj	Active	CO_2	0	1

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

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

Rules

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§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
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§3.41 .... Application for New Oil or Gas Field Designation and/or Allowable
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§3.55 .... Reports on Gas Wells Commingling Liquid Hydrocarbons before Metering
§3.56 .... Scrubber Oil and Skim Hydrocarbons
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§3.58 .... Certificate of Compliance and Transportation Authority; Operator Reports
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§3.78 .... Fees and Financial Security Requirements
§3.79 .... Definitions
§3.80 .... Commission Oil and Gas Forms, Applications, and Filing Requirements

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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
ASUMU – Albert Spicer Upper Morrow Unit
AWT – All Well Test
ASTM - American Society for Testing and Materials
BFA – Booker Field Area
Bscf – billion standard cubic feet
BTUMU – Booker Trosper Upper Morrow Unit
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
CFR – Code of Federal Regulations
cf – cubic feet
CH4 – methane
CO_2 – carbon dioxide
CO_2-EOR – Carbon dioxide Enhanced Oil Recovery
CTB – Central Tank Battery
EOR – Enhanced Oil Recovery
EOS – Equation of State
EPA – US Environmental Protection Agency
ESD – Emergency Shutdown Device
GUMU – Gramstorff Upper Morrow Unit
GERG – European Gas Research Group
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
OOIP – Original Oil-In-Place
OWC – oil water contact
PPM – Parts Per Million
psia – pounds per square inch absolute
psig – pounds per square inch gauge
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
TRRC – Texas Railroad Commission
TSD – Technical Support Document
TVDSS – True Vertical Depth Subsea
TWDB – Texas Water Development Board
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 pressure, 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.