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OFFICE OF ATMOSPHERIC PROTECTION

WASHINGTON, D.C. 20460

October 15, 2024

Mr. Carl Thunem
CapturePoint, LLC
1101 Central Expressway South
Suite 150
Allen, Texas 75013

Re: Monitoring, Reporting and Verification (MRV) Plan for Denver City Fields

Dear Mr. Thunem:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Denver City Fields, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Denver City Fields on July 29, 2024, as the final MRV plan. The MRV Plan Approval Number is 1013859-1. This decision is effective October 20, 2024 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78. In conjunction with this MRV plan approval, we recommend reviewing the Subpart PP regulations to determine whether your facility is required to report data as a supplier of carbon dioxide. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

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

Sincerely,



Julius Banks
Supervisor, Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for Denver City Fields (DCF)

October 2024

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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 for the Denver City Fields (DCF) carbon dioxide (CO₂)-enhanced oil recovery (EOR) project in the Permian-aged Denver City Field in Gaines County, Texas. Note that this evaluation pertains only to the subpart RR MRV plan, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of this project, technologies, or parties involved.

1 Overview of Project

As described in the MRV plan, CapturePoint, LLC currently operates a CO₂-EOR project in the Denver City Field located in Gaines County, Texas, approximately four miles southwest of the town of Denver City, Texas for the primary purpose of EOR using CO₂, with retention of CO₂ serving a subsidiary purpose of geologic sequestration of CO₂ in a subsurface geologic formation. The DCF is comprised of the George Allen Unit (GAU), which contains the Ruth Hudson Lease (RH). The MRV plan states that one MRV plan was developed for the GAU and RH because the two are adjacent to each other, produce oil and gas from the same geologic formations and structure, and are both under the sole ownership of CapturePoint. The GAU and RH also share the same geology, facilities/equipment, and operational procedures. Production for both properties is from the San Andres Formation at an average depth of 5,000 feet. The DCF first produced oil more than 60 years ago. The MRV plan also states that water flooding was initiated in the GAU in 1989 and CO₂ flooding was initiated in 2007. Water flooding was initiated in 2008 in the RH, while CO₂ flooding was initiated in 2012. Under this MRV plan, the DCF plans to inject approximately 2.0 million tonnes of CO₂ over the duration of the project. 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 CO₂ sequestered at the DCF.

The MRV plan states that all EOR injection wells in the DCF are currently classified as UIC Class II wells permitted by the Texas Railroad Commission (TRRC). The TRRC has primacy to implement the UIC Class II program in the state. Wells in the DCF are identified by name, American Petroleum Institute (API) number, type, and status. The list of wells as of March 2023 is included in Section 12.1 of the MRV plan. The DCF recognizes that any changes in wells will be indicated in the annual subpart RR monitoring report submission.

The DCF is located in the northeast portion of the Central Basin Platform in West Texas. As stated in the MRV plan, the field is a smaller oil accumulation with a thin mobile oil column trapped by a low relief anticlinal structure. The productive formation, the San Andres Formation, is a Permian dolomite reservoir. The MRV plan states that the Upper Permian consists of a dominate thick and porous shallow marine carbonate facies that was later dolomitized as the San Andres Group prograded into the basin. Continuation of the regressive sequence during the Upper Permian, defined as the Whitehorse Group, caps the San Andres Group with tidal flat muds and tight exposed shelf carbonates, along with restricted evaporites. These facies within the Grayburg, Queen, and Seven Rivers Formations serve as widespread and efficient seals for both hydrocarbons and CO₂ trapping. More specifically, the MRV plan states that

the first seal will be the Upper San Andres Formation, which consists of dense, fine crystalline dolomite and anhydrite devoid of any porosity or permeability. It was deposited on tidal flats of a broad, restricted shelf. Above the Upper San Andres Formation, a series of restricted/exposed shelf facies consisting of tight, anhydritic dolomite, anhydrite, salt, and thin sandstones of the Upper Guadalupian, Grayburg, Queen, Seven Rivers, Yates, and Tansill Formations serve as the secondary seal. Above the Tansill, the Ochoan, Upper Permian evaporites of the Salado and Rustler Formations provide additional containment.

According to the MRV plan, both natural and anthropogenic CO₂ is delivered to the DCF from the Trinity CO₂ pipeline delivery system via the Kinder Morgan CO₂ pipeline network. The mass of CO₂ received at the DCF is metered and calculated through Custody Transfer Meters located at the pipeline delivery point. The mass of CO₂ received is combined with a recycled CO₂/hydrocarbon gas mix from the recycle compression facility (RCF) and distributed to the water alternating gas (WAG) headers for injection according to the pre-programmed injection plan for each well pattern. The MRV plan states that the DCF is an EOR project and reservoir pressure must be maintained above minimum miscibility pressure. Therefore, injection pressure must be sufficiently high to allow injectants to enter the reservoir, but below formation parting pressure (FPP).

The MRV plan states that the total pore space within the DCF, from the top of the reservoir down to the base of the residual oil zone (ROZ), is calculated to be 188.0 million reservoir barrels (MRB). This is more than enough pore space to sequester the planned CO₂ injection of 27.8 MRB. The MRV plan also states that the DCF CO₂-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Additionally, reservoir pressure in the DCF is managed by maintaining an injection-to-withdrawal ratio (IWR) of approximately one. Injection pressure is also maintained below the FPP, which is measured using step-rate tests.

The MRV plan states that produced fluids from the production wells (oil, hydrocarbon gas, water, CO₂, and other constituents including nitrogen and hydrogen sulfide (H₂S)) are gathered and sent to satellite test stations (SAT) for separation into a gas/CO₂ mix and a produced fluids mix of water, oil, gas, and CO₂. The produced gas, which is composed primarily of CO₂ and minor hydrocarbons, is sent to the RCF for dehydration and recompression before reinjection into the reservoir. An operations meter at the RCF is used to determine the total volume of produced gas that is reinjected. The MRV plan also states that separated oil is metered through the Custody Transfer Meter located at the central tank battery and sold into a pipeline.

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

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

As part of the MRV plan, the reporter must identify and delineate both the maximum monitoring area (MMA) and active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines 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 CO₂ plume until the CO₂ 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 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.” See 40 CFR 98.449.

The MRV plan states a long-term forecast for both the GAU and RH was developed using a dimensionless performance curve (DPC) approach. Using this approach, approximately 2.0 million tonnes of stored CO₂ is forecasted over the life of the project. The MRV plan also states DPCs derived from actual field performance from the analogous Wason San Andres Field were used to project CO₂-EOR in the DCF. Like Wason, the DCF is located on the Northwest shelf of the Permian Basin and produces from the San Andres dolomite reservoir at a depth of about 5,000 feet making them analogous. This DPC was used on each well pattern in the DCF and then summed up to the full field. This technique indicates that the flooded acreage still has significant additional storage potential. The maximum CO₂ storage volume (254.0 billion cubic feet (BCF)) is limited to the amount of pore space made available by the removal of the produced fluids. The calculated storage projection used by the DCF indicates that there is enough pore space available to store approximately 0.15 decimal fraction of hydrocarbon pore volume (HCPV), which amounts to 37.5 BCF.

According to the MRV plan, the lateral extent of CO₂ in the injection zone or the CO₂ storage radius for each well was estimated by calculating a storage radius based on the forecasted CO₂ storage volume of 37.5 BCF. The MRV plan explains that this calculation showed that approximately 166 acres would be needed to store 37.5 BCF, which is significantly less than the 1,133 acres in the DCF outline. Therefore, the CO₂ plume is expected to remain contained in the GAU and RH boundaries at the end of year (t+5).

The MRV plan states that the AMA is defined by the GAU and RH boundaries plus the required one-half mile buffer. The CO₂ storage volume calculations show the CO₂ to remain within the unit boundaries in the timeframe associated with the AMA, which is the year 2037. It also states that the CO₂ plume (Figure 4-1 in the MRV plan) is expected to be contained within the GAU and RH boundaries which will be actively monitored. The MRV plan states that the MMA is defined by the GAU and RH boundaries plus the required one-half mile buffer. Therefore, the DCF defines the MMA as the same as the AMA since the plume location is less than the unit area.

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

3 Identification of Potential Surface Leakage Pathways

As part of the MRV plan, the reporter must identify potential surface leakage pathways for CO₂ in the MMA, and the likelihood, magnitude, and timing of surface leakage of CO₂ through these pathways pursuant to 40 CFR 98.448(a)(2). The facility identified the following as potential leakage pathways in Section 5 of their MRV plan that required consideration:

1. Existing Wells
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the DCF
7. Drilling through the CO₂ Area
8. Diffuse Leakage through the Seal

3.1 Leakage through Existing Wells

According to the MRV plan, an extensive review of all the DCF penetrations was completed to determine the potential need for corrective action. This analysis showed that all penetrations have either been adequately plugged and abandoned or, if in use, do not require corrective action. The MRV plan also states that all wells in the DCF were constructed and are operated in compliance with TRRC rules. As part of routine risk management, the DCF identified and evaluated the potential risk of leakage associated with CO₂ flood electrical submersible pump (ESP) producing wells, CO₂ flood beam pumped producing wells, and CO₂ injector wells.

The risk assessment, as described in the MRV plan, classified the risk associated with leakage occurring through existing wells as low risk, i.e., less than 1% likelihood to occur and having a consequence that is insubstantial. The MRV plan further states that the risks were classified as low because the DCF geology is well suited for CO₂ sequestration with an extensive confining zone that is free of fractures and faults that could be potential conduits for CO₂ migration. The DCF claims that any risks are further mitigated because the DCF is operated in a manner that maintains, monitors, and documents the integrity of the reservoir. Furthermore, the DCF states that the potential risk of wellbore CO₂ leakage is mitigated through:

- Adhering to regulatory requirements for well drilling and testing.
- Implementing best practices that CapturePoint has developed through its extensive operating experience.
- Monitoring injection/production performance, wellbores, and the surface.
- Maintaining surface equipment.

The MRV plan states that if leakage did occur, the magnitude of leaks will range from 5 to 20 metric tons (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.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected through existing wells.

3.2 Leakage through Faults or Fractures

According to the MRV plan, there are no known faults or fractures that transect the San Andres reservoir in the project area. As a result, the DCF claims that there is minimal risk (less than 1%) of leakage due to fractures or faults. This low risk therefore infers a very low magnitude if leaked.

Nevertheless, the DCF states that they routinely update measurements to determine the FPP and reservoir pressure. The MRV plan states that this data will be used to manage injection patterns so that the injection pressure will not exceed FPP. The MRV plan describes that the DCF maintains an IWR at or near one based on consistent reservoir pressure measurements. The DCF believes that these procedures mitigate the potential for inducing faults or fractures.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected through faults or fractures.

3.3 Leakage through Natural or Induced Seismicity

According to the MRV plan, there is no direct evidence that natural seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF. As a result, the DCF claims that there is no indication of seismic activity posing a risk for loss of CO₂ to the surface within the MMA. The TRRC approved injection pressures in the DCF are maintained and monitored so that injection pressure is kept well below the TRRC approved injection pressures which are significantly below the fracture initiation pressure. The MRV plan states that this ensures that there will be no induced seismicity. Therefore, the DCF concludes that leakage of sequestered CO₂ through seismicity is unlikely and less than 1% and of a very low magnitude.

The DCF reviewed the nature and location of seismic events in West Texas. The DCF states that while some of the recorded earthquakes in West Texas are judged to be from natural causes, others have occurred near oil fields or water disposal wells and were placed in the category of earthquakes in close association with human enterprise. Using the United States Geologic Survey (USGS) database of recorded earthquakes within the Permian Basin since 1956, the DCF's review showed that no magnitude (M) 1.0 or greater earthquakes have occurred in the DCF. The closest M1.0 or greater earthquake occurred approximately 38 miles away in 2020.

Furthermore, the MRV plan states that the DCF is not aware of any reported loss of injectant (brine water or CO₂) leakage to the surface. The DCF states that there is no direct evidence to suggest that induced seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and

specifically in the DCF. TRRC approved injection pressures are kept well below the reservoir fracture gradient to ensure seismicity is not induced.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected through natural or induced seismicity.

3.4 Leakage from Previous Operations

As stated in the MRV plan, CO₂ flooding was initiated in the DCF in 2007. To obtain permits for CO₂ flooding, the DCF states that the area of review (AOR) around all CO₂ injector wells was evaluated to determine if there were any unknown penetrations and to assess if corrective action was required at any well. This evaluation reviewed the identified penetrations and determined that no additional corrective action was needed. The DCF claims that their standard practice for drilling new wells includes a rigorous review of nearby wells to ensure that drilling will not cause damage to or interfere with existing wells. Additionally, the MRV plan states that requirements to construct wells with materials that are designed for CO₂ injection are adhered to at the DCF. Therefore, the DCF maintains that these practices ensure that there are no unknown wells within the DCF and that the risk of migration from older wells has been sufficiently mitigated via location definition and daily on-site monitoring of rates and pressures. Based on well construction requirements and the history of no leakage events at the DCF, the MRV plan states that the likelihood of CO₂ leakage is less than 1% and the magnitude would be low with a timely response and remediation.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected from previous operations.

3.5 Leakage from Pipelines and Surface Equipment

The MRV plan states that the DCF anticipates that the use of prevailing design and construction practices and compliance with applicable laws will reduce, to the maximum extent possible, the risk of unplanned leakage from surface facilities. The DCF states that they will continue to utilize materials of construction and control processes that are standard for CO₂-EOR projects in the oil and gas industry. The MRV plan states that surface equipment leaks have a low risk of occurring based on design standards, and any leak would have insubstantial results. The DCF states that the magnitude of surface equipment leaks will range from 0.1 to 2 MT yearly and will be addressed within 6-12 hours of occurring. Because of materials selection, the risk is once again low, and the DCF concludes that leakage of CO₂ through surface equipment is unlikely.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected from pipelines and surface equipment.

3.6 Leakage from Lateral Migration Outside the DCF

The MRV plan states that it is highly unlikely that injected CO₂ will migrate downdip and laterally outside the DCF because of the nature of the geology and the approach used for injection. The MRV plan describes that over prolonged periods of time, injected CO₂ will tend to rise vertically towards the Upper San Andres and continue towards the point in the DCF with the highest elevation. The DCF states that the total volume of fluids contained in the DCF will stay relatively constant. For these reasons, the DCF believes that leakage from lateral migration outside the DCF is unlikely. Since the stored volume is less than the calculated capacity, the likelihood and magnitude of lateral migration are very low and would happen only in the late life of injection.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected from lateral migration outside the DCF.

3.7 Leakage from Drilling through the CO₂ Area

The MRV plan states that leakage during drilling operations is unlikely but possible when reservoir pressure is high. Drilling mud weight is designed to control that leakage therefore making the potential very low with volumes leaked kept at low levels. In accordance with TRRC rules, well casings shall be securely anchored in the hole to effectively control the well at all times, all useable quality water zones shall be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flow zones, and zones with corrosive formation fluids shall be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. Where TRRC rules do not detail specific methods to achieve these objectives, the DCF claims that they will make every effort to follow the intent of the section, using good engineering practices and the best currently available technology. Finally, the DCF intends to operate the DCF for several more years and will continue to be vigilant about protecting the integrity of its assets and maximizing the potential of its resources, including oil, gas, and CO₂. Therefore, the MRV plan states that the risks associated with third parties penetrating the DCF are negligible.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected from drilling through the CO₂ area.

3.8 Diffuse Leakage through the Seal

The MRV plan states that diffuse leakage through the seal formed by the Upper San Andres is highly unlikely. There are several sections above the reservoir that are impermeable and serve as reliable barriers to prevent fluids from moving upwards towards the surface. The MRV plan also states that the injection monitoring program assures that no breach of the seal will be created. Furthermore, the DCF states that wellbores that penetrate the seal make use of cement and steel construction that is closely regulated to ensure that no leakage takes place. As a result, the MRV plan states the potential for CO₂

leakage again is very low (less than 1%), and the magnitude of any leakage would be in the several thousand standard cubic feet (MCF) range into other formations, but not to the surface.

Thus, the MRV plan provides an acceptable characterization of CO₂ leakage that could be expected through the seal.

The MRV plan concludes that, based on a careful assessment of the potential risk of release of CO₂ from the subsurface, it has been determined that there are no leakage pathways at the DCF that are likely to result in significant loss of CO₂ to the atmosphere. Thus, the MRV plan provides an acceptable characterization of potential CO₂ leakage pathways as required by 40 CFR 98.448(a)(2).

4 Strategy for Detecting and Quantifying Surface Leakage of CO₂ 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 CO₂, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring CO₂ surface leakage. Sections 5 and 6 of the MRV plan detail the DCF's strategies for detecting and quantifying CO₂ leakage and Section 7 details strategies for establishing expected baselines for monitoring CO₂ surface leakage. The DCF's approach for detecting and quantifying surface leakage of CO₂ primarily includes routine field inspections, Supervisory Control and Data Acquisition (SCADA) system monitoring of wellhead pressures, Mechanical Integrity Testing (MIT), monitoring reservoir pressure in WAG headers, modeling, and engineering estimates.

A summary table of the facility's strategies for monitoring and responding to any possible CO₂ leakage can be found in Table 5.1 of the MRV plan and is reproduced below.

Risk	Monitoring Plan	Response Plan
Tubing Leak	Monitor changes in tubing and annulus pressure; MIT for injectors	Well is shut in and workover crews respond within days
Casing Leak	Routine Field inspection; Monitor changes in annulus pressure, MIT for injectors; extra attention to high risk wells	Well is shut in and workover crews respond within days
Wellhead Leak	Routine Field inspection, SCADA system monitors wellhead pressure	Well is shut in and workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations	Maintain well kill procedures
Unplanned wells drilled through San Andres	Routine Field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells.	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Reservoir pressure in WAG headers; high pressure found in new wells	Re-enter and reseal abandoned wells
Pumps, valves, etc.	Routine Field inspection, SCADA	Workover crews respond within days
Overfill beyond spill points	Reservoir pressure in WAG headers; high pressure found in new wells	Fluid management along lease lines
Leakage through induced fractures	Reservoir pressure in WAG headers; high pressure found in new wells	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Reservoir pressure in WAG headers; high pressure found in new wells	Shut in injectors near seismic event
Diffuse leakage through the seal	Monitor injection pressure for unexplained changes in injection pressure that might indicate leakage	Investigate to determine if cement and steel construction is the issue. Well is shut in and workover crews respond within days.

4.1 Detection of Leakage through Existing Wells

Section 5.1 of the MRV plan states that continual and routine monitoring of the wells and site operations will be used to detect leaks or other potential well problems. The MRV plan describes the following monitoring methods:

- Pressure in injection wells is monitored daily. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. CapturePoint's experience, from over 10 years of operating CO₂-EOR projects, is that such leakage has not occurred.
- Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a SAT. There is a routine well testing cycle, with each well being tested approximately once every month. If production is off plan, the DCF states that it will investigate the change and address any identified issues.
- Personal H₂S monitors are designed to detect leaked fluids around production wells during well inspections as well as various permanent H₂S monitors throughout the field at ground level.

- Field inspections are conducted on a routine basis by field personnel. Since leaking CO₂ is very cold and leads to formation of bright white clouds and ice, it is easy for personnel to identify surface leakage. Any CO₂ leakage detected will be documented, quantified, and reported.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, the DCF concludes that the risk of CO₂ leakage through wellbores is mitigated by detecting problems as they arise and quantifying any leakage that does occur.

Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected through existing wellbores. Thus, the MRV plan provides adequate characterization of the DCF's approach to detect potential leakage through existing wells as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through Faults or Fractures

As stated in the MRV plan, there is minimal risk of leakage through fractures or faults. Still, the DCF routinely updates measurements to determine FPP and reservoir pressure of the DCF. This information is used to manage injection patterns so that the injection pressure will not exceed FPP. Furthermore, the DCF states that WAG skids are continuously monitored.

Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected through faults or fractures. Thus, the MRV plan provides adequate characterization of the DCF's approach to detect potential leakage through faults or fractures as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage through Natural or Induced Seismicity

The MRV plan states that the DCF concluded that there is no direct evidence that natural seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, specifically in the DCF. In addition, the MRV plan states that the DCF is not aware of any reported loss of injectant (brine water or CO₂) to the surface above the DCF associated with any seismic activity. The MRV plan also states that the DCF monitors the USGS earthquake monitoring Geographical Information System (GIS) site for seismic signals that could indicate the creation of potential leakage pathways in the DCF. If induced seismicity resulted in a pathway for material amounts of CO₂ to migrate from the injection zone, the DCF's other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would detect the migration and lead to further investigation.

Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected through natural or induced seismicity. Thus, the MRV plan provides adequate characterization of the DCF's approach to detect potential leakage through natural or induced seismicity as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage from Previous Operations

As stated in the MRV plan, the DCF's investigation into previous operations determined that no additional corrective action was needed. Therefore, the MRV plan states that the risk of migration from older wells has been sufficiently mitigated via location identification and daily on-site monitoring of rates and pressures. The MRV plan states that reservoir pressure in WAG headers and high pressures found in new wells will be indicative of leakage from previous operations.

Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected from previous operations. Thus, the MRV plan provides adequate characterization of the DCF's approach to detect potential leakage from previous operations as required by 40 CFR 98.448(a)(3).

4.5 Detection of Leakage from Pipelines and Surface Equipment

As stated in the MRV plan, the use of prevailing design and construction practices and compliance with applicable laws will reduce the risk of unplanned leakage from surface facilities. The MRV plan states that field personnel are trained to look for and report potential leaks from pipeline and surface equipment as part of their routine activities. Should surface leakage be detected from pipeline or surface equipment, the mass of CO₂ surface leakage will be quantified by the DCF following the requirements of subpart W of EPA's GHGRP.

Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected from pipelines and surface equipment. Thus, the MRV plan provides adequate characterization of the DCF's approach to detect potential leakage from pipelines and surface equipment as required by 40 CFR 98.448(a)(3).

4.6 Detection of Leakage from Lateral Migration Outside the DCF

The MRV plan explains that the nature of the geology and the approach used for injection at the DCF make it highly unlikely that injected CO₂ will migrate laterally outside the DCF. Reservoir pressure in WAG headers and high pressure found in new wells will be indicative of leakage from lateral migration outside of the DCF.

Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected from lateral migration outside the DCF. Thus, the MRV plan provides adequate characterization of the DCF's approach to detect potential leakage from lateral migration outside the DCF as required by 40 CFR 98.448(a)(3).

4.7 Detection of Leakage from Drilling through the CO₂ Area

As stated in the MRV plan, all well drilling activity at the DCF is conducted in accordance with TRRC rules. The DCF's visual inspection process, including routine site visits, will identify any unapproved drilling activity in the DCF.

Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected from drilling through the CO₂ area. Thus, the MRV plan provides adequate characterization of the DCF's approach to detect potential leakage from drilling through the CO₂ area as required by 40 CFR 98.448(a)(3).

4.8 Detection of Leakage through the Seal

As stated in the MRV plan, diffuse leakage through the seal formed by the upper San Andres is highly unlikely. The DCF states that their injection monitoring program assures that no breach of the seal will be created and that they continuously monitor injection pressure. The MRV plan also states that unexplained changes in injection pressure might indicate leakage, which would trigger investigation as to the cause.

Table 5.1 of the MRV plan provides a detailed characterization of detecting CO₂ leakage that could be expected through the seal. Thus, the MRV plan provides adequate characterization of the DCF's approach to detect potential leakage through the seal as required by 40 CFR 98.448(a)(3).

4.9 Quantification of Potential CO₂ Leakage

As described in Section 5.9 of the MRV plan, the potential sources of leakage include issues such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment (e.g., wellbores), and unique events such as induced fractures. The DCF will use an event-driven process to assess, address, track, and, if applicable, quantify potential CO₂ leakage. The MRV plan states that given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the DCF will determine the most appropriate methods for quantifying the volume of leaked CO₂ on a case-by-case basis using all metering and measurement equipment from each wellhead through the output of the tanks and recycle facility. In the event leakage occurs, the most appropriate methods for quantifying the volume leaked will be determined and it will be reported as required as part of the annual subpart RR monitoring report submission.

- For leakage through wellbores, daily monitoring of flow rates will provide the basis to determine duration and the amount of CO₂ loss.
- For leakage from surface equipment and pipelines, daily monitoring of flow rates and acceptable emission factors, such as those in 40 CFR Part 98 subpart W, provide the basis to determine duration and the amount of CO₂ loss.
- For leakage related to the competency of the confining layer, reservoir modeling and engineering estimates provided the basis for determining the amount of CO₂ loss.

The MRV plan also states that any volume of CO₂ 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, field experience, and other factors such as

the frequency of inspection. Finally, the DCF states that leaks will be documented, evaluated, and addressed in a timely manner.

4.10 Determination of Baselines

According to Section 7 of the MRV plan, ongoing operational monitoring has helped to establish baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO₂ leakage. The DCF states that 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. Finally, the MRV plan states that the necessary system guidelines to capture the information that is relevant to identify possible CO₂ leakage will be developed. The DCF's approaches for collecting this information include:

Visual Inspections

The MRV plan states that the Field Foreman is notified for maintenance activities that cannot be addressed on the spot during routine field inspections and repairs. Each incident will be flagged for review by the person responsible for MRV documentation. As such, the MRV plan states that the annual subpart RR report will provide an estimate of CO₂ leakage.

Personal H₂S Monitors

The DCF states that H₂S monitors are worn by all field personnel. The H₂S monitors detect concentrations of H₂S up to 500 parts per million (ppm) in 0.1 ppm increments and will sound an alarm if the detection limit exceeds 10 ppm. If an H₂S alarm is triggered, the immediate response is to protect the safety of the personnel, and the next step is to safely investigate the source of persistent alarms. Therefore, the DCF considers H₂S to be a proxy for potential CO₂ leaks in the field. As such, the MRV plan states that the annual subpart RR report will provide an estimate of the amount of CO₂ emitted from any such incidents.

Injection Rates, Pressures and Volumes

The MRV plan states that a target injection rate and pressure are developed for each injector within the permitted limits based on the results of ongoing pattern balancing. Field operations flag whenever statistically significant deviations from the targeted ranges are identified. For purposes of subpart RR reporting, flags (or excursions) will be screened to determine if they could lead to CO₂ leakage to the surface. As such, the MRV plan states that the person responsible for MRV documentation will receive notice of excursions. Finally, the annual subpart RR report will provide an estimate of these CO₂ emissions.

Production Volumes and Compositions

The MRV plan states that a general forecast of production volumes and composition is developed which is used to periodically evaluate performance, refine current and projected injection plans, and the forecast. This information is used to make operational decisions but is not recorded in an automated

data system. As such, the MRV plan states that any impact to subpart RR reporting will be addressed, if deemed necessary.

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

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

5.1 Calculation of Mass of CO₂ Received

Section 8.1 of the MRV plan states that Equation RR-2 in subpart RR §98.443 will be used to calculate the mass of CO₂ received at the receiving custody transfer meter from the Trinity CO₂ pipeline delivery system. The volumetric flow at standard conditions will be multiplied by the CO₂ concentration and the density of CO₂ at standard conditions to determine mass.

$$CO_2T_{,r} = \sum_{p=1}^4 (Q_{p,r} - S_{r,p}) * D * C_{CO_2,r,p} \quad (\text{Eq. RR-2})$$

where:

$CO_{2T,r}$ = Net annual mass of CO₂ received through flow meter r (metric tons).

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

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

p = Quarter of the year.

r = Receiving flow meter.

The MRV plan also states that all CO₂ delivered to the DCF is used within the unit so there is no quarterly flow redelivered and S_{r,p} will be zero.

DCF provides an acceptable approach for calculating the mass of CO₂ received under subpart RR requirements.

5.2 Calculation of Mass of CO₂ Injected

Section 8.2 of the MRV plan states that the mass of CO₂ injected into the Subsurface at the DCF is equal to the sum of the mass of CO₂ received as calculated in RR-2 of \$98.443 and the mass of CO₂ recycled calculated using measurements taken from the flow meter located at the outlet of the RCF. The mass of CO₂ recycled will be determined using equations RR-5 as follows:

$$CO_{2u} = \sum_{p=1}^4 Q_{p,u} * D * C_{CO_2,p,u} \quad (\text{Eq. RR-5})$$

where:

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter):
0.0018682.

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

p = Quarter of the year.

u = Flow meter.

The total mass of CO₂ injected will be the sum of the mass of CO₂ received (RR-2) and mass of CO₂ recycled (RR-5).

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

where:

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

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

u = Flow meter.

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

5.3 Mass of CO_2 Produced

Section 8.3 of the MRV plan states that the mass of CO_2 produced at the DCF will be calculated using the measurements from the flow meters at the inlet to RCF and the custody transfer meter for oil sales rather than the metered data from each production well. Equation RR-8 in §98.443 will be used to calculate the mass of CO_2 produced from all production wells as follows:

$$CO_{2w} = \sum_{p=1}^4 Q_{p,w} * D * C_{CO_2,p,w} \quad (\text{Eq. RR-8})$$

where:

CO_{2w} = 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.

For Equation RR-9 in §98.443 the variable X will be measured as follows:

$$CO_{2P} = (1 + X_{oil}) * \sum_{w=1}^W CO_{2w} \quad (\text{Eq. RR-9})$$

where:

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

CO_{2w} = 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.

DCF provides an acceptable approach for calculating the mass of CO_2 produced under subpart RR requirements.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

Section 8.4 of the MRV Plan states that the mass of CO_2 emitted by surface leakage will be calculated and reported using an approach that is tailored to specific leakage events including calculation methodologies in 40 CFR Part 98 subpart W for emissions and leaks from equipment. Estimates of the amount of CO_2 leaked to the surface will depend on several site-specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage. The MRV plan also states that in the event leakage to the surface occurs, leakage amounts would be quantified and reported, and records that describe the methods used to estimate or measure the volume leaked as reported in the annual subpart RR report would be retained. Volumes for CO_{2E} and CO_{2FI} are calculated separately and differently. Equation RR-10 in §98.443 will be used to calculate the total annual mass of CO_2 emitted through surface leakage as follows:

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

where:

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

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

x = Leakage pathway.

DCF provides an acceptable approach for calculating the mass of CO_2 emitted by surface leakage under subpart RR requirements.

5.5 Calculation of Mass of CO_2 Emitted by Facility Emergency Vent

Section 8.5 of the MRV plan states the mass of CO_2 emitted by facility emergency vent at the DCF will be calculated using the measurements from the flow meter at the vent, and that volume will be added to CO_{2FI} . Equation RR-8 in §98.443 will be used to calculate the mass of CO_2 emitted by the emergency vent as follows:

$$CO_{2w} = \sum_{p=1}^4 Q_{p,w} * D * C_{CO_2,p,w} \quad (\text{Eq. RR-8})$$

where:

CO_{2w} = 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.

DCF provides an acceptable approach for calculating the mass of CO₂ emitted by facility emergency vent under subpart RR requirements.

5.6 Calculation of Mass of CO₂ Sequestered in Subsurface Geologic Formation

Section 8.6 of the MRV Plan states that Equation RR-11 in §98.443 will be used to calculate the mass of CO₂ sequestered in subsurface geologic formations as follows:

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

where:

CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

CO_{2P} = Total annual CO₂ mass produced (metric tons) in the reporting year.

CO_{2E} = Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

CO_{2FP} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

DCF provides an acceptable approach for calculating the mass of CO₂ sequestered under subpart RR requirements.

6 Summary of Findings

The subpart RR MRV plan for the Denver City Fields meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the DCF MRV plan.

Subpart RR MRV Plan Requirement	Denver City Fields MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 4 of the MRV plan delineates and defines the MMA and AMA. The MMA and AMA share the same boundary and are both defined by the GAU and RH boundaries plus the required ½ mile buffer. The DCF states that the plume will be contained within the unit boundaries through year t + 5. Therefore, the DCF defines the MMA and AMA as the same.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO ₂ in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO ₂ through these pathways.	Section 5 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: existing wells, faults or fractures, natural or induced seismicity, previous operations; pipelines and surface equipment, lateral migration outside the DCF, drilling through the CO ₂ area, and diffuse leakage through the seal. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways. The DCF determined that leakage through these pathways is not likely at the DCF.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO ₂ .	Sections 5 and 6 of the MRV plan describe the strategies that the DCF will use to detect and quantify potential CO ₂ leakage to the surface should it occur. The MRV plan identifies the following detection and quantification strategies: MITs, SCADA systems, routine field inspections, monitoring reservoir pressure in WAG headers, modeling, engineering estimates, and direct measurements. Section 5 of the MRV plan also states that quantification will be determined on a case-by-case basis using all metering and measurement equipment.

40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO ₂ surface leakage.	Section 7 of the MRV plan describes the strategies that the DCF will use to establish baselines against which monitoring results can be compared to assess potential surface leakage. The MRV identifies the following strategies: visual inspections, personal H ₂ S monitors, the monitoring of injection rates, pressures, and volumes, and the monitoring of production volumes and compositions.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 8 of the MRV plan describes the DCF's approach to determining the total amount of CO ₂ sequestered using the subpart RR mass balance equations, including calculation of the 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.	Section 12 (Appendix) of the MRV plan provides well identification number for all active wells in the DCF. The MRV plan specifies that all injection wells in the DCF are permitted by the TRRC as UIC Class II wells.
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 9 of the MRV plan states that the DCF will commence collecting data for calculating the total amount of CO ₂ sequestered according to Equation RR-11 of this subpart starting in January 2024 or within 90 days of EPA approval.

Appendix A: Final MRV Plan

CAPTUREPOINT LLC
DENVER CITY FIELD
SUBPART RR MONITORING, REPORTING AND
VERIFICATION (MRV) PLAN

July 2024

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1 Introduction

CapturePoint LLC operates a Carbon Dioxide Enhanced Oil Recovery (CO₂-EOR) project in the Denver City Field (DCF) located in Gaines County, Texas, approximately four miles southwest of the town of Denver City, Texas and less than two miles west of the Denver Unit of the giant Wasson San Andres Fields for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO₂) with a subsidiary or ancillary purpose of geologic sequestration of CO₂ in a subsurface geologic formation. The DCF is comprised of the George Allen Unit (GAU) which contains the Ruth Hudson Lease (RH). Like Wasson production is from the San Andres formation at an average depth of 5,000 feet. The Monitoring, Reporting and Verification (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 CO₂ sequestered at the Denver City Fields during a specified period of injection.

2 Facility Information

2.1 Reporter Number

576482 – Denver City Fields

2.2 UIC Permit Class

The Oil and Gas Division of the Texas Railroad Commission (TRRC) regulates oil and gas activity in Texas. All wells in the DCF (including production, injection, and monitoring wells) are permitted by TRRC through Texas Administrative Code (TAC) Title 16 Chapter 3. TRRC has primacy to implement the Underground Injection Control (UIC) Class II program in the state for injection wells. All EOR injection wells in the DCF are currently classified as UIC Class II wells.

2.3 Existing Wells

Wells in the DCF are identified by name and number, American Petroleum Institute (API) number, type, and status. The list of wells as of March 2023 is included in Section 12.1. Any changes in wells will be indicated in the annual subpart RR submission.

3 Project Description

This project takes place in the DCF, an oil field located in West Texas that was first produced more than 60 years ago. The DCF is comprised of the GAU which contains the RH. The two are adjacent to each other, produce oil and gas from the same geologic formations and structure, and are under the sole operatorship of CapturePoint LLC. The geology, facilities/equipment, and operational procedures are similar for both in the DCF. In addition, the two properties share the same CO₂ recycle and water injection facilities as well as the injection piping system for both CO₂ and water. Because of these common facilities and common reservoir, one MRV Plan is being prepared for the two properties in the DCF and any important differences between the two properties will be noted in the MRV plan. CO₂ flooding was initiated in 2007 in the GAU and in 2012 in the RH. The field is well characterized and is suitable for secure geologic storage in the San Andres formation. CapturePoint LLC uses a water alternating with gas (WAG) injection process and maintains an injection to withdrawal ratio (IWR) at or near 1.

3.1 Project Characteristics

The DCF was discovered in 1956 and started production in the same year. The DCF consists of one unit (GAU) and one lease (RH). The GAU began to produce in May 1956 and the waterflood was initiated in September 1989. CO₂ flooding was initiated in December 2007, in both the Main Pay and Residual Oil Zone (ROZ). The RH initiated a waterflood in March 2008 and began to produce in November 2008. CO₂ flooding was initiated in December 2012, also in the Main Pay and ROZ.

A long-term forecast for both the GAU and RH was developed using a dimensionless performance curve (DPC) approach. Using this approach, approximately 2.0 million tonnes of stored CO₂ is forecasted over the life of the project. Figure 3-1 shows actual and projected CO₂ injection, production, and stored volumes in DCF.

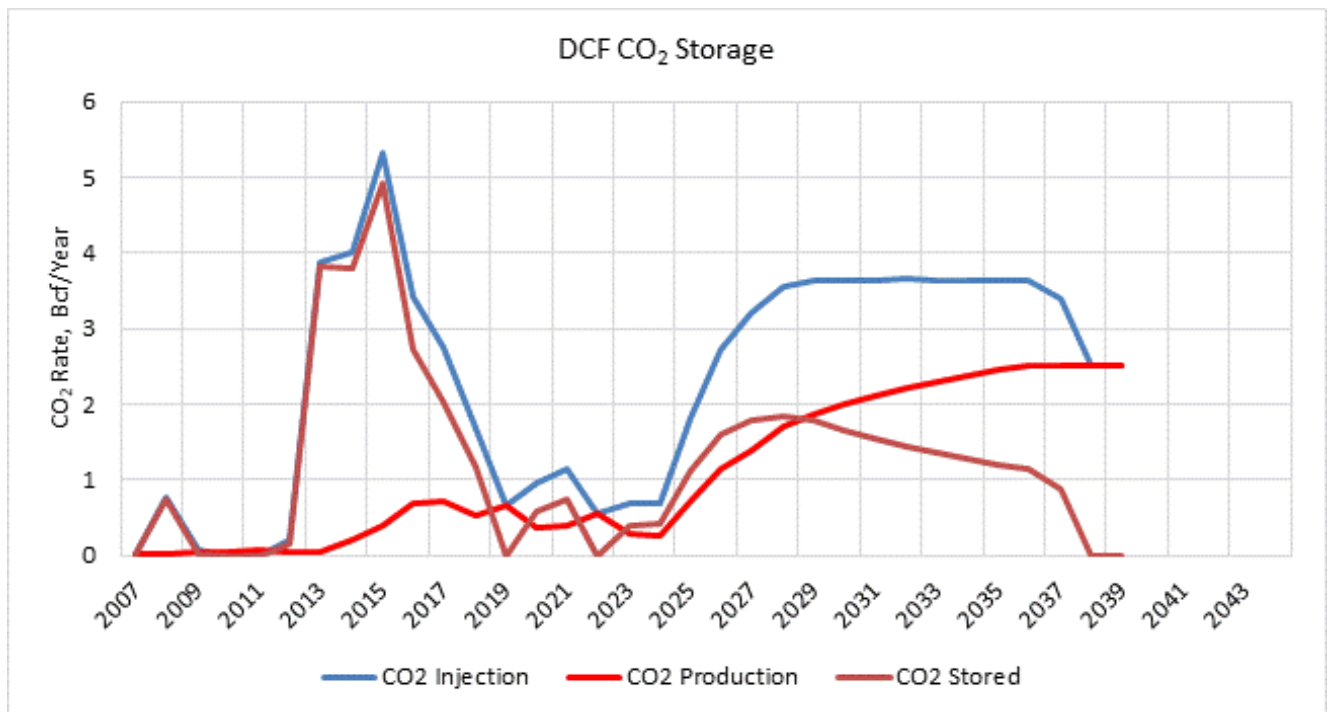


Figure 3-1 DCF Historic and Forecast CO₂ Injection, Production, and Storage

3.2 Environmental Setting

The DCF is located in the NE portion of the Central Basin Platform in West Texas (See Figure 3-2). This map also shows the location of the Denver Unit and other Wasson San Andres Units. The DCF is shown by the green dot.

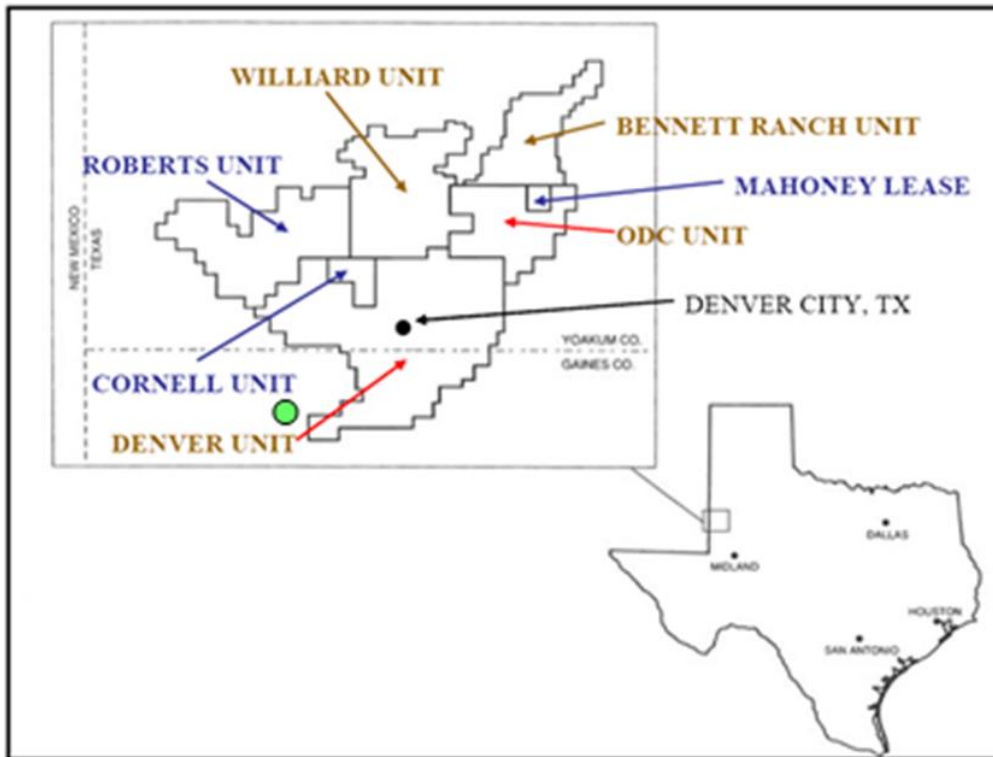


Figure 3-2 Location of DCF in West Texas

Like Wasson, the DCF produces from a San Andres dolomite reservoir at a depth of about 5,000 feet. In contrast to Wasson, DCF is a smaller oil accumulation with a thin mobile oil column trapped by a low relief anticlinal structure as shown in Figure 3-3. The Wasson field has produced over two billion barrels of oil to date from the San Andres while the DCF has produced 2.06 million barrels of oil to 2022.

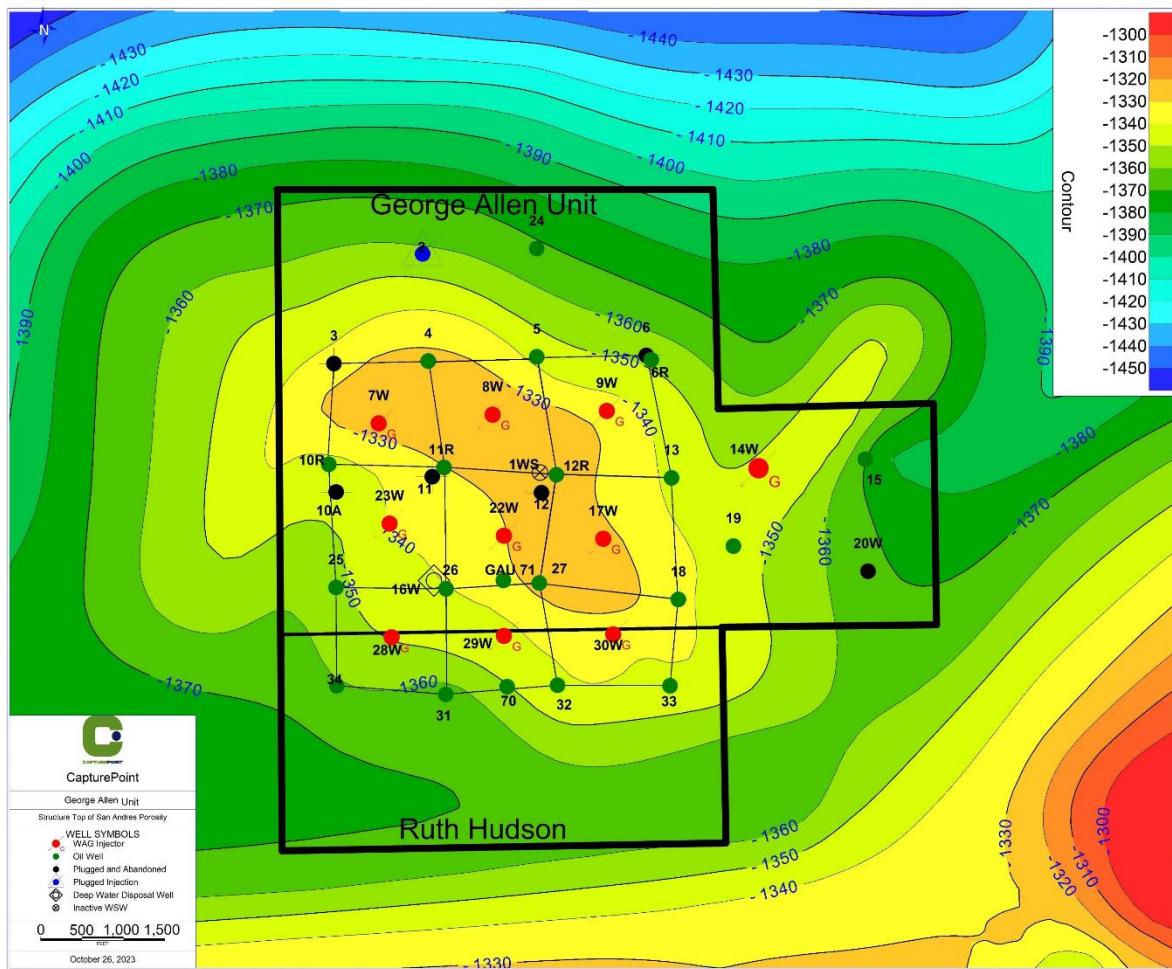


Figure 3-3 Local Area Structure on Top of San Andres for DCF

In the DCF there is a thin mobile oil column. Beneath the conventional oil column there is a thick, porous section with transition zone/residual oil (TZ/ROZ) that can only be produced via tertiary recovery methods, primarily CO₂ injection. This thick TZ/ROZ zone as found in the Wasson field gives a sizeable target for tertiary recovery (over 300 feet gross thickness).

Oil in the TZ/ROZ is currently being produced via CO₂ injection. Nine 40-acre patterns were prepared to inject CO₂ in this zone in the DCF. The presence of thick residual zones in the San Andres of the Permian Basin is widespread. Lindsay (2001), Melzer (2005), Melzer (2006), and Koperna and Kuuskraa (2006; 1&2) discuss the possible origins and the extent of residual oil zones in the Permian Basin. Brown (2001) discusses the ROZ in the area and its possible origin. The residual zone in the DCF has better porosity and permeability and is much thicker than the mobile oil zone which produced during primary and secondary (waterflood) recovery. This is often the case in residual oil zones, particularly those found in smaller fields with thinner oil columns. This gives us a large resource in which to economically sequester large volumes of CO₂, as CO₂ can both be stored and utilized for oil recovery in the extensive residual oil zones found in the San Andres in the Permian Basin.

The oil saturation profile found in the DCF/Wasson area is shown below in Figure 3-4 from Koperna and Kuuskraa (2006; 2):

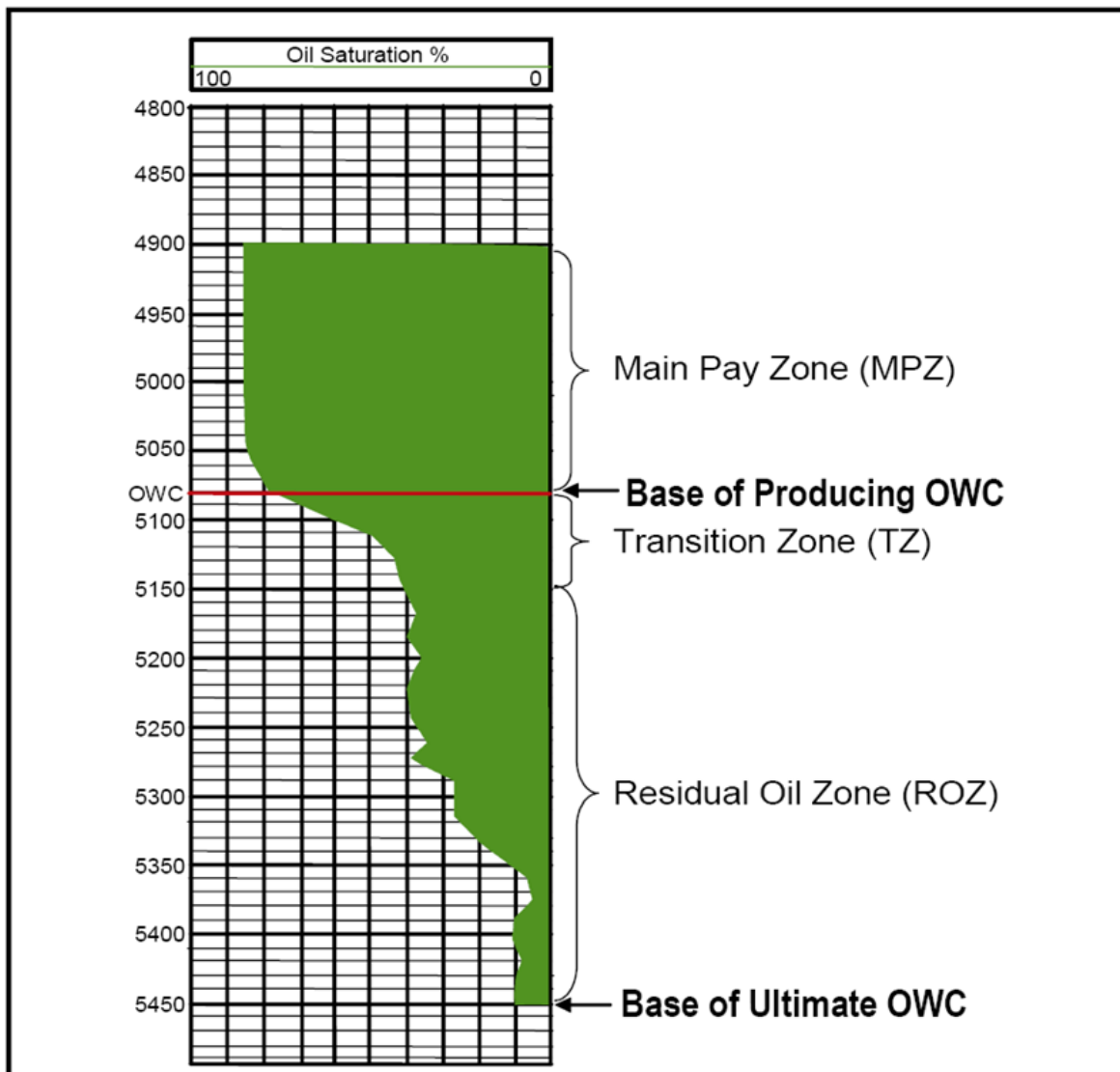


Figure 3-4 Saturation Profile of San Andres

Due to hydrodynamic flow in the San Andres aquifer, a ROZ was created and is under CO₂ flood along with the Main Pay Zone in the San Andres Formation.

Once the CO₂ flood is complete and injection ceases, the remaining mobile CO₂ will rise slowly upward, driven by buoyancy forces. There is more than enough pore space (188 million reservoir barrels (MRB)) to sequester the planned CO₂ injection (27.8 million reservoir barrels). The amount of CO₂ injected will not exceed the reservoir's secure storage capacity and, consequently, the risk that CO₂ could migrate to other reservoirs in the Central Basin Platform is negligible. The volume of CO₂ storage is based on the estimated total pore space within the DCF. The total pore space within the DCF, from the top of the reservoir down to the base of the ROZ, is calculated to be 188 million reservoir barrels (MRB). This is the volume of rock multiplied by porosity. Table 3-1 below shows the conversion of this amount of pore space into an estimated maximum volume of

approximately 254 billion cubic feet (Bcf) (13.4 million tonnes) of CO₂ storage in the reservoir. CO₂ will occupy only 15% of the total calculated storage capacity by the year 2037 based on the projected forecast.

Table 3-1 Calculation of Maximum Volume of CO₂ Storage Capacity at DCF

Top of Main Pay to Bottom of Residual Oil Zone (ROZ)	
Variables	DCF Outline
Pore Volume (RB)	188,396,478
BCO₂ (RB/MCF)	0.407
S_{wirr}	0.35
S_{or CO₂}	0.10
Max CO₂ (MCF)	254,589,835
Max CO₂ (BCF)	254

$$\text{Max CO}_2 = \text{Pore Volume} * (1 - S_{wirr} - S_{or CO_2}) / BCO_2$$

Where:

Max CO₂ = the maximum amount of storage capacity

Pore Volume = Total pore space in reservoir barrels (RB)

BCO₂ = the formation volume factor for CO₂

S_{wirr} = the irreducible water saturation

S_{or CO₂} = the irreducible oil saturation

Reservoir management is employed on a constant basis to obtain the maximum possible economic recovery from a reservoir based on facts, information, and knowledge. A reservoir management strategy that is used in CO₂ floods is the implementation of water curtain injectors. This will be utilized in the DCF to create a pressure barrier or “curtain” to contain the injected CO₂ to the area selected for production. Water curtain injection is an efficient method of maintaining and controlling lateral migration of fluids to assure that CO₂ does not cross structurally deficient locations. Injected fluids (CO₂) stay in the reservoir within the DCF unit boundary and do not move to adjacent areas.

Given that in DCF the confining zone has proved competent over both millions of years and in the current CO₂ flooding, and that the DCF has ample storage capacity, there is confidence that stored CO₂ will be contained securely within the reservoir.

3.3 Geologic Setting/Stratigraphic Column

The George Allen/Wasson San Andres fields are located on the Northwest shelf of the Permian Basin (Figure 3-5).

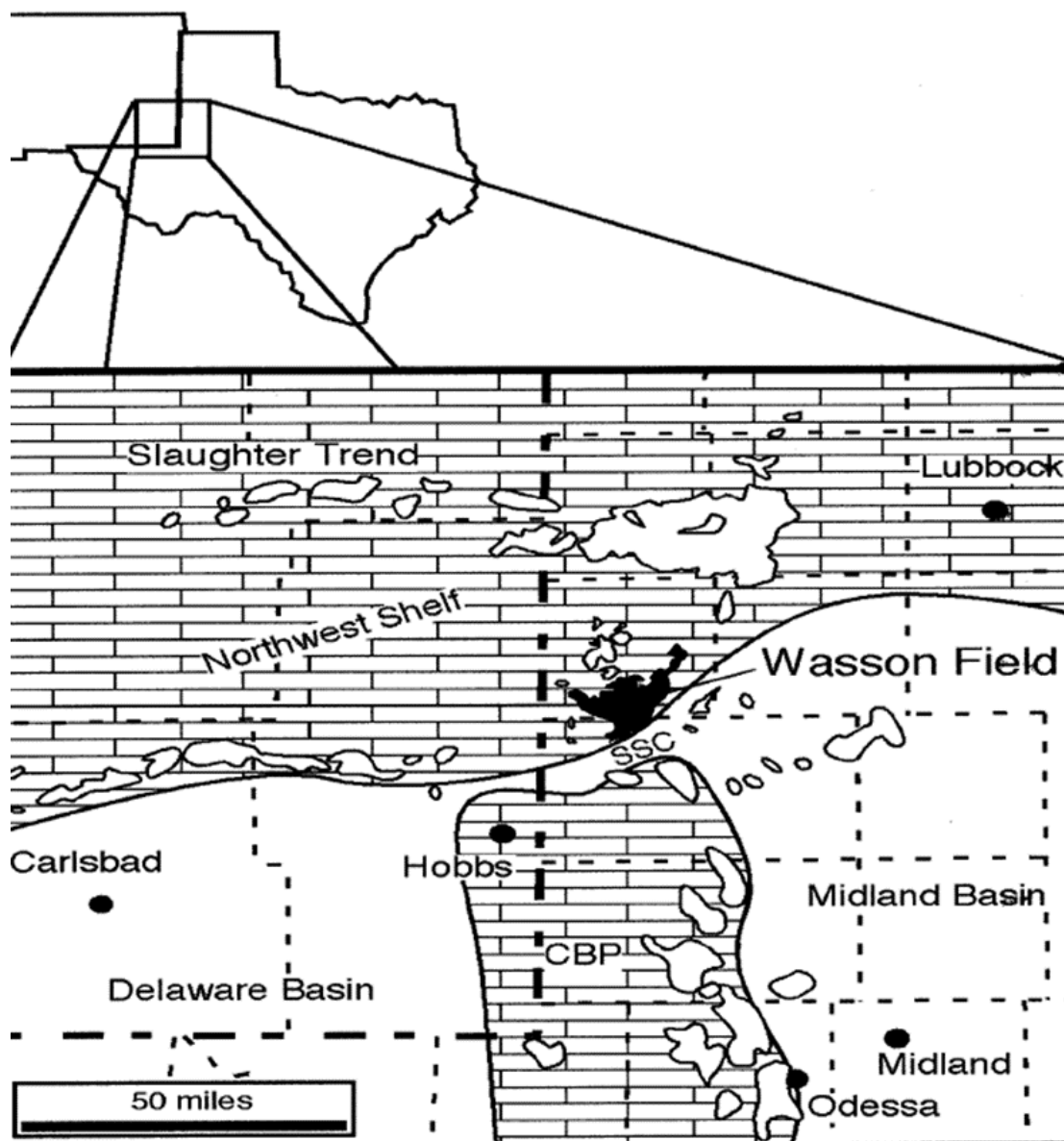


Figure 3-5 Map of Northwest shelf of the Permian Basin

The Wason field is shown in black. Other San Andres fields are outlined. San Andres “shelf” facies are indicated by the brick pattern. “CBP” refers to the “Central Basin Platform” a major structural feature that separates the Delaware Basin from the Midland Basin. “SSC” refers to the “San Simon Channel” a feature which allowed seawater circulation between the shallow restricted shelf areas of the Northwest Shelf and the Central Basin Platform.

Figure 3-6 below shows the thickness and broad extent of the porous facies in the San Andres formation.

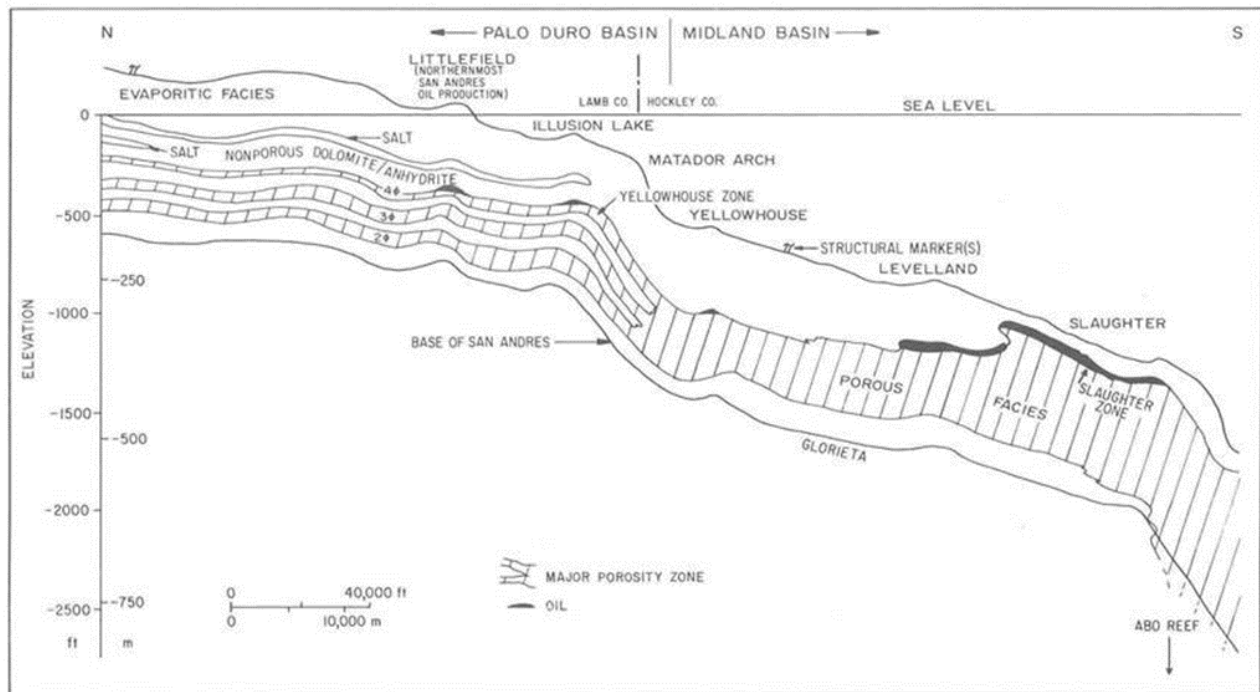


Figure 3-6 Cross section of lower San Andres Formation, Northern Shelf, showing porosity relationships.

A typical stratigraphic section for the area is shown below in Figure 3-7.

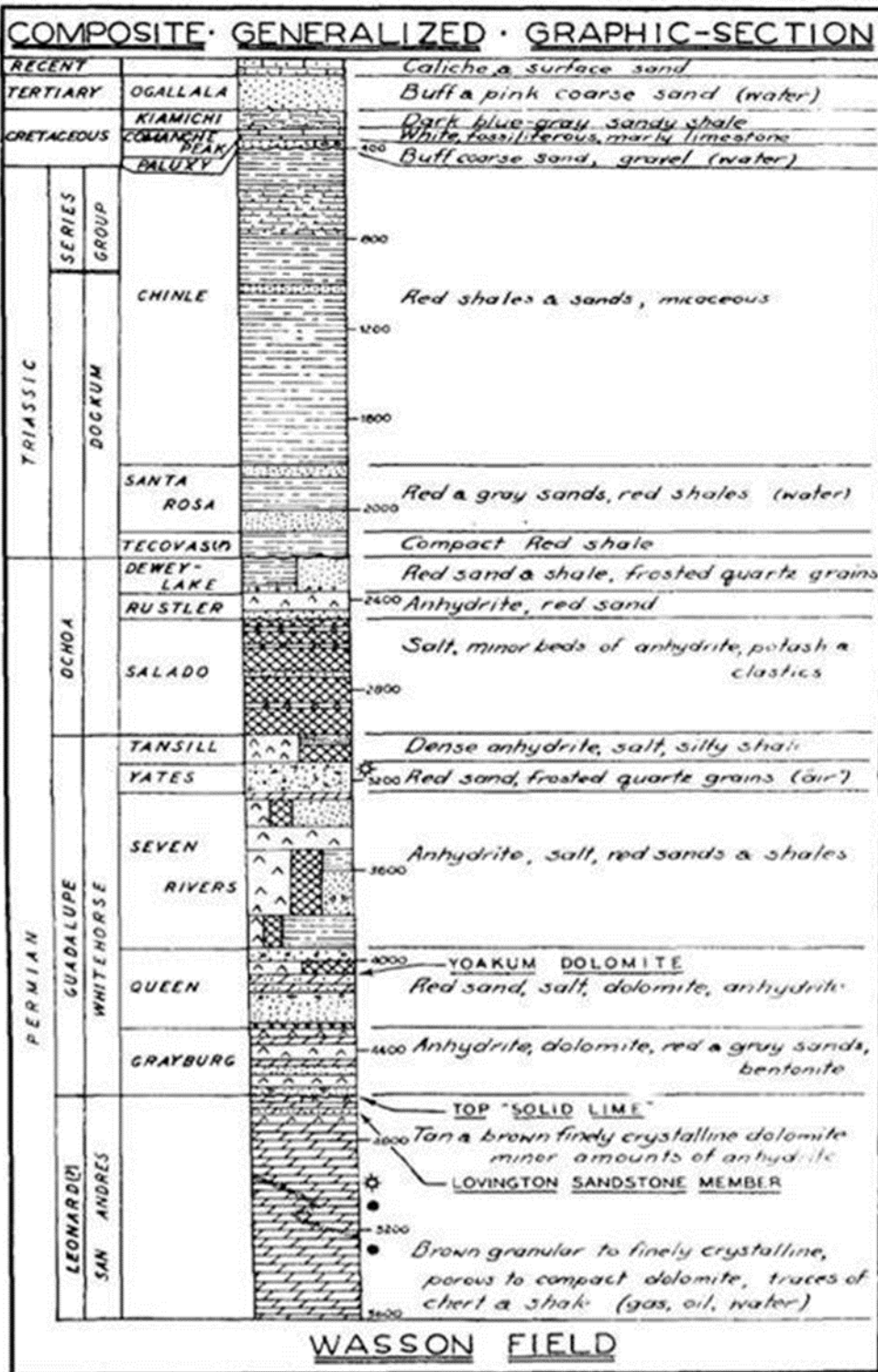


Figure 3-7 Composite generalized stratigraphic section.

The stratigraphy and facies of the Upper Permian on the Northwest Shelf and Central Basin Platform is quite uniform. The Upper Permian consists of a dominate thick and porous shallow marine carbonate facies that was later dolomitized as the San Andres Group prograded out into the basin. Continuation of the regressive sequence during the Upper Permian, defined as the Whitehorse group, caps the San Andres Group with tidal flat muds and tight exposed shelf

carbonates, along with restricted evaporites. These facies within the Grayburg, Queen and Seven Rivers formation serve as widespread and efficient seals for both hydrocarbons and CO₂ trapping.

The notable thing about the Upper Permian rocks described here is that there are multiple and thick intervals that should eliminate the possibility of any vertical migration of fluids or gases from the San Andres reservoir to the surface.

The first seal is the Upper San Andres which consists of dense, fine crystalline dolomite and anhydrite, devoid of any porosity or permeability, deposited on the tidal flats of a broad, restricted shelf. Where the porous, shallow water carbonate facies of the Lower San Andres pinch out and interfinger with these rocks a series of stratigraphic traps is formed in the northern part of the Northwest Shelf. The Levelland-Slaughter-Chaveroo-Cato San Andres fields are found in this trend. A similar porosity pinches out, on the interior of the Central Basin platform, controls the widespread San Andres production found on the eastern margin of the Central Basin platform. These widespread producing trends attest to sealing capacity of the Upper San Andres anhydrous dolomite facies both vertically and laterally.

Above the San Andres are a series of restricted/exposed shelf facies consisting of tight, anhydrous dolomite, anhydrite, salt, and thin sandstones of the Upper Guadalupian Grayburg, Queen, Seven Rivers, Yates and Tansill formations. The sandstones sometimes have porosity and permeability but are often cemented by salt and are non-permeable. Where permeable, they offer no chance for vertical migration of fluids or gases as they are inter-layered with impermeable salt, anhydrite, and anhydrous dolomite.

Following the Tansill, the Ochoan, Upper Permian evaporites of the Salado and Rustler formations exist. The Salado is roughly 600-700 feet thick in the Wasson/George Allen area and consists dominantly of halite with some thin beds of potash and anhydrite and a few very thin layers of red mud, silt, and fine sand. Being widespread, thick, and impermeable, this formation alone should certainly stop the vertical migration of any fluids or gases from the subsurface to the surface. Even if fractured, the salt will flow and seal any open cracks. It is followed by the Rustler formation; 60 feet of dense, white anhydrite at the top overlying 30 feet of red shale interbedded with anhydrite; another capstone, on top a over 2,500 feet of mostly impermeable rock.

The Permian ends with the Dewey Lake formation which consists of red gypsum cemented sandstone and red shales.

Above the Permian unconformity are the Triassic Tecovas red shale and then the Santa Rosa formation which contains fresh water bearing sandstones. These deposits are followed by the micaceous red shales and sands of the Chinle formation. A major unconformity separates the Triassic Chinle from the overlying Cretaceous sediments that consists of coarse sand and gravel, white marly limestone, and dark, blue-gray sandy shale.

An important aquifer, the Tertiary Ogallala formation overlies these Cretaceous sediments. It consists of coarse sands and vari-colored gravels, all loose or poorly consolidated, which are followed by recent wind-blown sand and caliche.

3.4 Description of CO₂-EOR Project Facilities and the Injection Process

Figure 3-8 shows a simplified process flow diagram of the project facilities and equipment in the DCF. CO₂ will be delivered to the DCF from Trinity, via the Kinder Morgan CO₂ pipeline network. The CO₂ will be supplied by several different sources including both natural and anthropogenic CO₂ sources. Specified amounts will be drawn from an outside source pipeline based on contractual arrangements among suppliers of CO₂, purchasers of CO₂, and the pipeline operator. The Specified amount of CO₂ required in addition to the produced gas to meet target CO₂ injection rates are forecasted using the DPC approach.

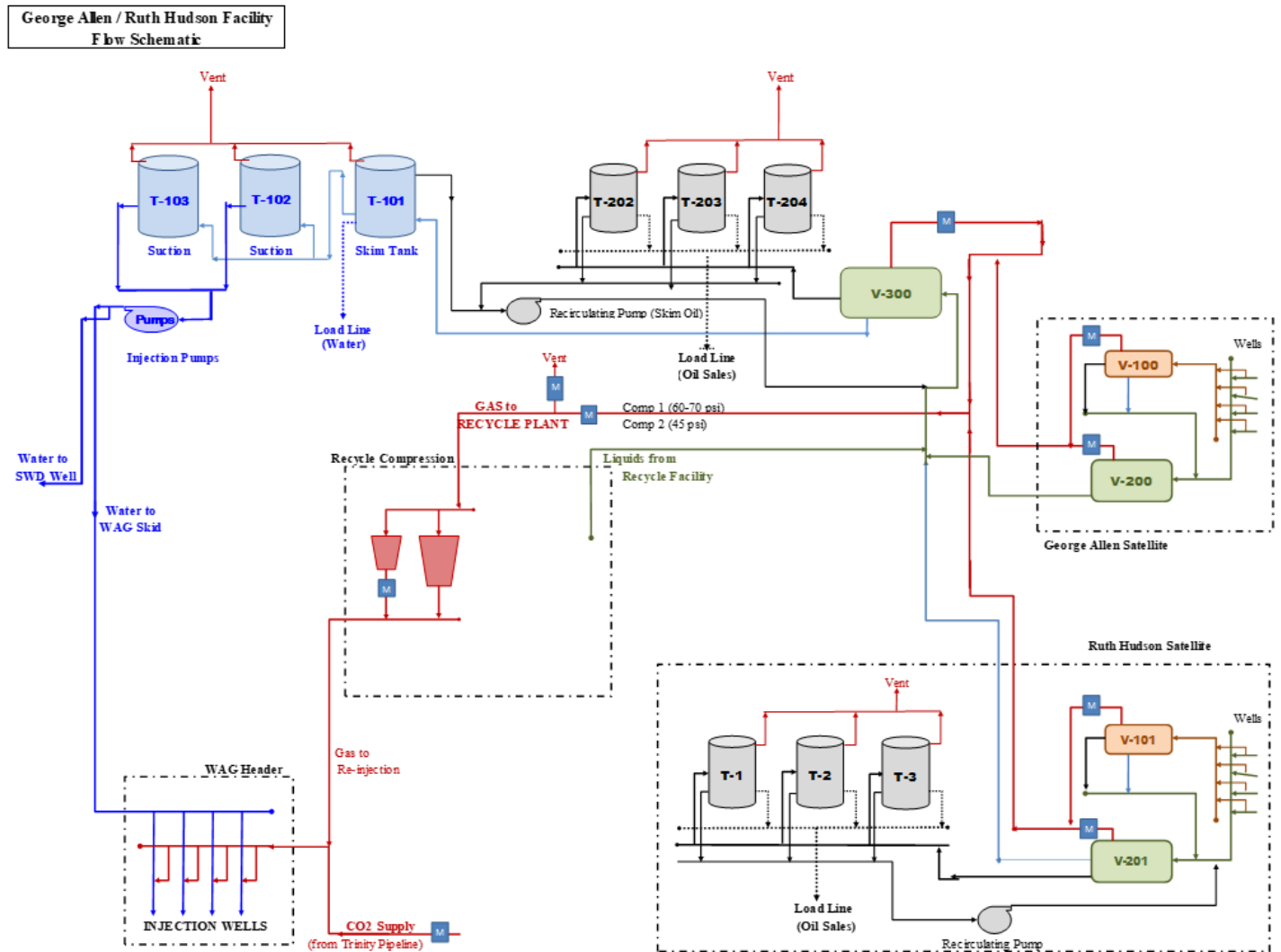


Figure 3-8 DCF Process Flow Diagram

Once CO₂ enters the DCF there are three main processes involved in CO₂-EOR operations:

- i. CO₂ Distribution and Injection: The mass of CO₂ received at the DCF is metered and calculated through the Custody Transfer Meter located at the pipeline delivery point. The mass of CO₂ received is combined with recycled CO₂ / hydrocarbon gas mix from the recycle compression facility (RCF) and distributed to the WAG headers for injection into the injection wells according to the pre-programmed injection plan for each well pattern which alternates between water and CO₂ injection. WAG headers are manually operated and can inject either CO₂ or water at various rates and injection pressures as specified in the injection plans. This is an EOR project and reservoir pressure must be maintained above minimum miscibility pressure. Therefore, injection pressure must be sufficiently high to allow injectants to enter the reservoir, but below formation parting pressure (FPP)
- ii. Produced Fluids Handling: Produced fluids from the production wells are a mixture of oil, hydrocarbon gas, water, CO₂, and trace amounts of other constituents in the field including nitrogen and Hydrogen Sulfide (H₂S) as discussed in Section 7. They are gathered and sent to Satellite Test Stations (SAT) for separation into a gas/CO₂ mix and a produced fluids mix of water, oil, gas, and CO₂. The produced gas, which is composed primarily of CO₂ and minor hydrocarbons, is sent to the RCF for dehydration and recompression before reinjection into the reservoir. An operations meter at the RCF is used to determine the total volume of produced gas that is reinjected. The separated oil is sent to two separate tanks (one at GAU and one at RH) where is then sold via truck.
- iii. Water Treatment and Injection: Water is recovered for reuse and forwarded to the water injection station for reinjection or disposal.

3.4.1 Wells in the Denver City Fields

The TRRC has broad authority over oil and gas operations including primacy to implement UIC Class II wells. The rules are found in TAC Title 16, Part 1, Chapter 3 and are also explained in a TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual (See Appendix 12-2). TRRC rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields.

Briefly, TRRC rules include the following requirements:

- Fluids must be constrained in the strata in which they are encountered,
- activities cannot result in the pollution of subsurface or surface water,
- wells must adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata that are encountered into other strata with oil and gas, or into subsurface and surface waters,
- completion report for each well including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore) must be prepared,
- operators must follow plugging procedures that require advance approval from the TRRC Director and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs; and,
- injection well operators must identify an Area of Review (AoR), use compatible materials and equipment, test, and maintain well records.

Table 3-2 provides a well count by type and status. All these wells are in material compliance with TRRC rules.

Table 3-2 DCF Well Penetrations by Type and Status

TYPE	ACTIVE	INACTIVE	P & A	Total
PROD_OIL	16	3		19
INJ_WTR	0	1		1
INJ_WAG	8	0		8
INJ_SWD*	0	0		0
WSW	0	0		0
P&A			3	3
TOTAL	24	4	3	31

PROD_OIL = Production Wells

INJ_WRT = Water injection wells

INJ_WAG = WAG injection wells

INJ_SWD = Saltwater disposal wells

WSW = Water source wells

P&A = Plugged and Abandoned wells.

As indicated in Figure 3-9, wells are distributed across the DCF. The well patterns currently undergoing CO₂ flooding are identified by black 5-spot pattern outlines and CO₂ will be injected across the entire unit over the project life.

DCF CO₂-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Reservoir pressure in the DCF is managed by maintaining an IWR of approximately 1.0. To maintain the IWR, fluid injection and production are monitored and managed to ensure that reservoir pressure does not increase to a level that would compromise the reservoir seal or otherwise damage the integrity of the oil field.

Injection pressure is also maintained below the FPP, which is measured using step-rate tests.

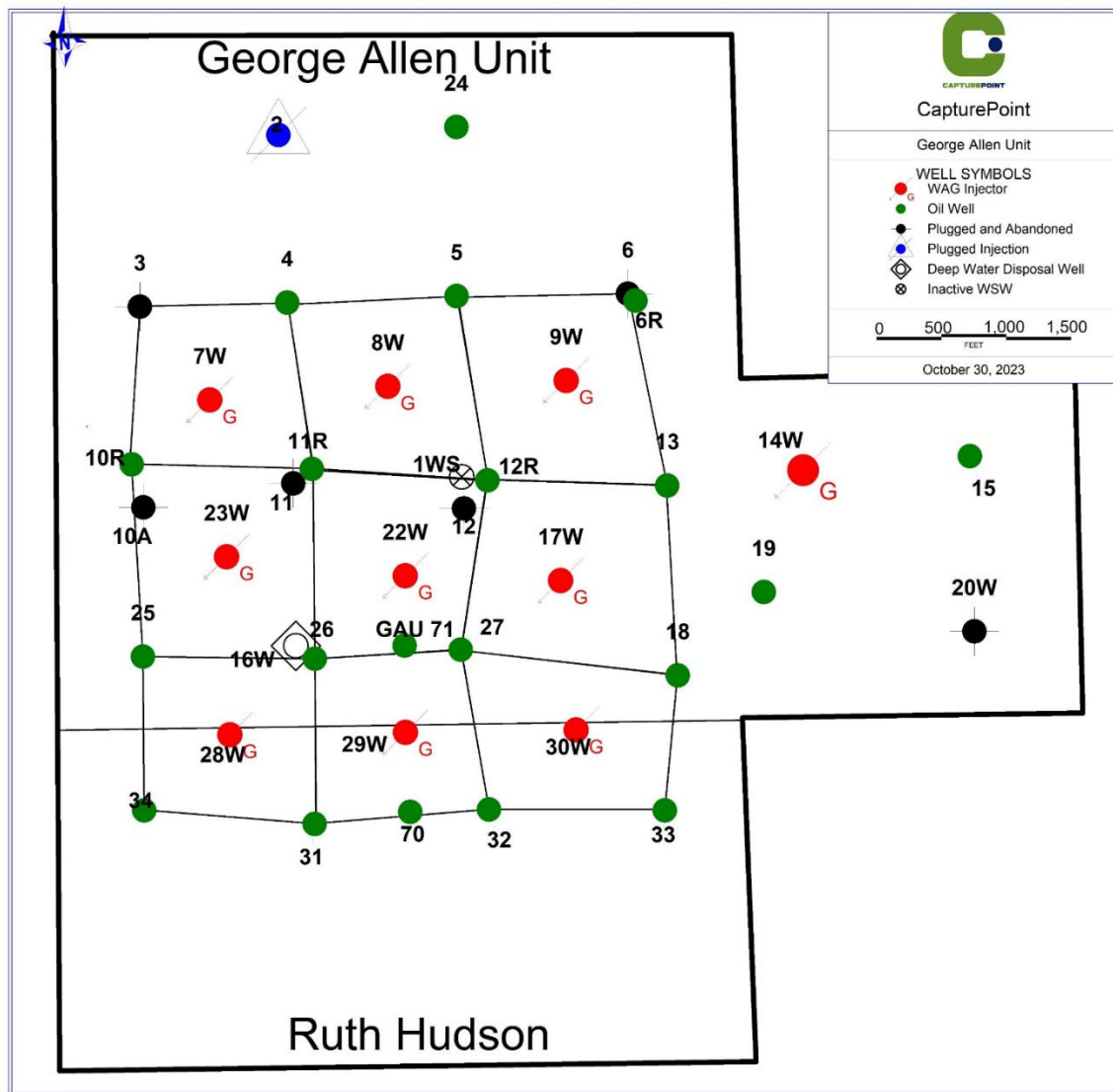


Figure 3-9 DCF Wells and Injection Patterns

3.5 Reservoir Forecasting

DPCs derived from the analogous Wasson San Andres field were used to project CO₂-EOR in the Denver City Field. Most DPCs are derived from geologic and reservoir models. In the DCF case the DPC was derived from actual field performance from the Wasson San Andres field. Like Wasson, the DCF is located on the Northwest shelf of the Permian Basin and produces from the San Andres dolomite reservoir at a depth of about 5,000 feet making them analogous.

A DPC is a plot where injection and production volumes for CO₂, water, and hydrocarbon phases are normalized by dividing by Hydrocarbon Pore Volume (HCPV). See Figure 3-10. The dimensioned projections for the oil, CO₂, and water production are relative to the CO₂ and water injection and are calculated using the original oil in place of an area of interest.

HCPV of Produced:
CO₂, Oil or Water

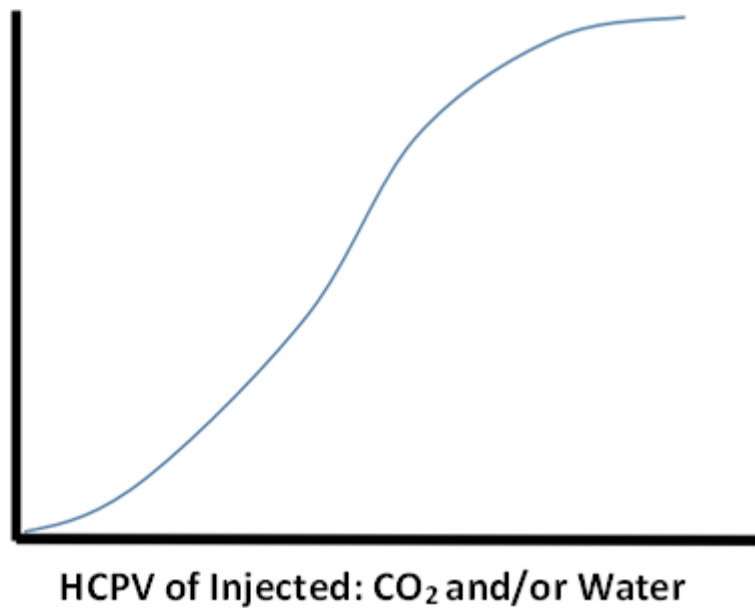


Figure 3-10 DPC plot

The DCF DPC was calculated from the cumulative production and injection from an analogous field. This DPC was used on each pattern in the DCF and then summed up to full field. This method allows you to use different start times and implement different field implementation speeds.

The DPCs are the basis for future performance prediction scenarios but are additionally a means of evaluating the reservoir process efficiencies. In a similar manner to history matching in reservoir simulation, deviations from expected performance can indicate errors in the geologic model of the pore volume, growth of the CO₂ plume, or metering and production allocation errors.

4 Delineation of Monitoring Area and Timeframes

4.1 Active Monitoring Area

The Active Monitoring Area (AMA) is defined by the GAU and RH boundaries plus the required $\frac{1}{2}$ mile zone. Based on our projections, CapturePoint expects the free phase CO₂ plume to remain within the GAU and RH boundaries for the entire length of the project and through year [t+5]. The CO₂ storage volume calculations show the CO₂ to remain within the unit boundaries in the period associated with the AMA, which is year 2037.

The AMA is shown in Figure 4-1. It is an area defined by the boundary of the DCF plus the required $\frac{1}{2}$ 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).

4.1.1 Discussion of CO₂ Storage Volumes in AMA

The CO₂ injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO₂-EOR. Maintenance of an Injection to Withdrawal ratio of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

Figure 3-9 displays wells that have CO₂ retention on the 370 acres that have been under CO₂ injection since project initialization. The CO₂ storage volumes were forecasted using the DPC approach. This technique indicates that the flooded acreage still has significant storage potential. The maximum CO₂ storage (254 BCF) is limited to the amount of space available by the removal of the produced hydrocarbon and water. The projection indicates that there is pore space available to store approximately 0.15 decimal fraction of HCPV amounting to 27.8 million reservoir barrels of oil (MMRB) (37.5 BCF).

The lateral extent of CO₂ in the injection zone or the CO₂ storage radius for each well was estimated by calculating a storage radius based on the forecasted CO₂ storage volume of 37.5 BCF. Figure 4-1 shows the map of the storage area outline for each pattern (dashed red line). This calculation showed 166 acres (this calculates to 18 acres per pattern) would be needed to store 37.5 BCF. This is significantly less than the 1133 acres in the DCF outline.

CO₂ injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO₂-EOR. Namely, maintenance of an IWR of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

4.2 Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined by the GAU and RH boundaries plus the required $\frac{1}{2}$ mile buffer as required by 40 CFR §98.440-449 (Subpart RR). The CO₂ plume (Figure 4-1) is expected to be contained within the GAU and RH boundaries which will be actively

monitored. Therefore, CapturePoint defines the MMA as the same as the AMA since the plume location is less than the unit area. 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 FR 98.448(d)(1).

4.3 Monitoring Timeframes

The primary purpose for injecting CO₂ is to produce oil that would otherwise remain trapped in the reservoir and not, as in UIC Class VI, “specifically for the purpose of geologic storage.”¹ During a Specified Period, there will be a subsidiary purpose of establishing the long-term containment of CO₂ in the DCF. The Specified Period is the timeframe that CO₂ storage will occur. In the DCF, CO₂ storage will occur until 2037 at which point CO₂ injection will equal CO₂ production. Specified Period will be shorter than the period of production from the DCF.

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted with a demonstration that current monitoring and model(s) show that the cumulative mass of CO₂ reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration after the Specified Period ends based upon monitoring data.

The reservoir pressure in the DCF is collected for use in operations management. Reservoir pressure is not forecasted to change appreciably since the IWR will be maintained at approximately 1. Once injection ceases, reservoir pressure is predicted to stabilize within one year.

¹ EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b). A

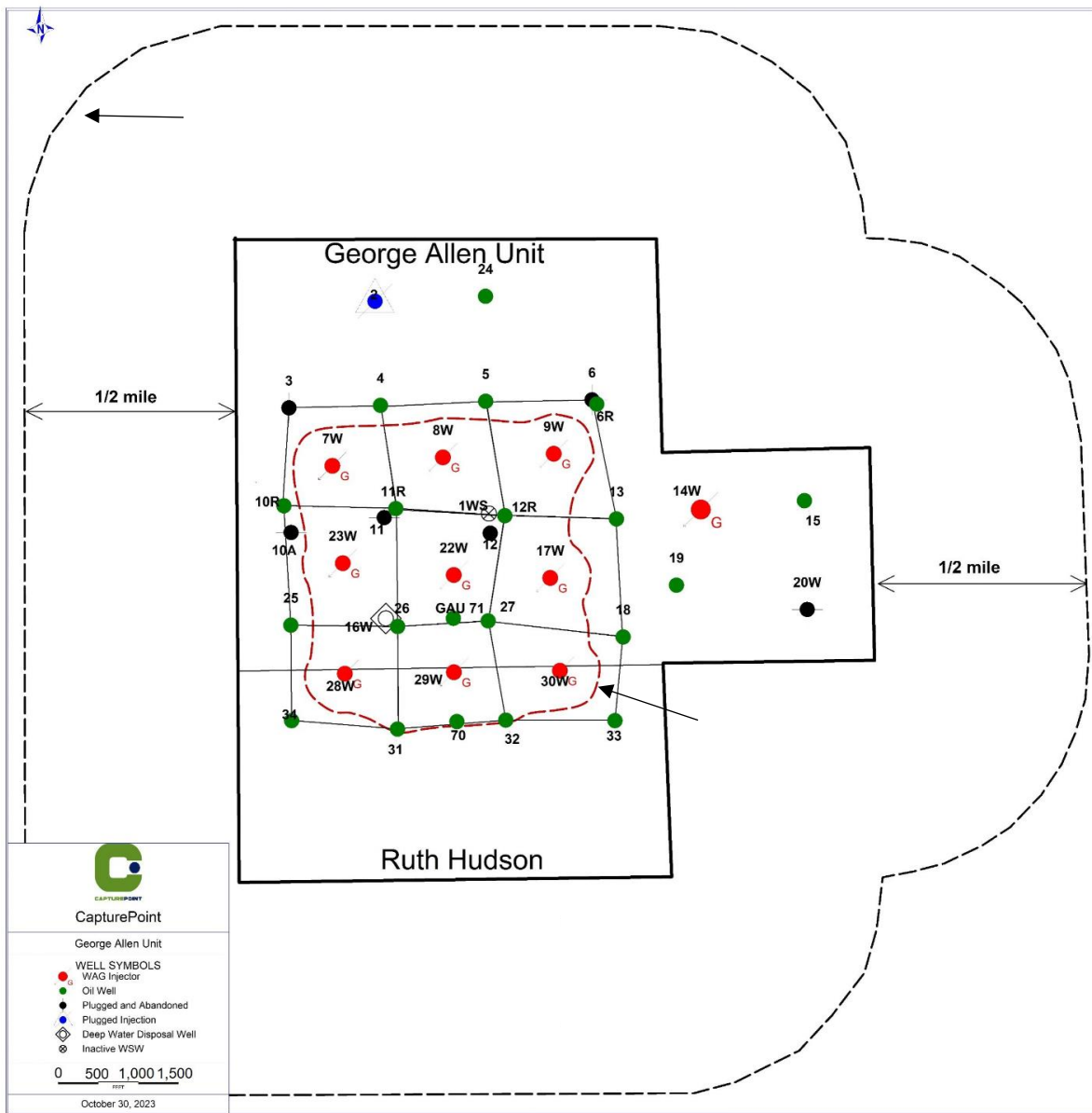


Figure 4-1 Projected CO₂ Storage area

5 Evaluation of Potential Pathways for Leakage to the Surface, Leakage Detection, Verification, and Quantification

In the roughly 60 years since the DCF was discovered, the reservoir has been studied extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO₂ to the surface including:

1. Existing Wells
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the DCF
7. Drilling Through the CO₂ Area
8. Diffuse Leakage Through the Seal
9. Leakage Detection, Verification, and Quantification

This analysis shows that leakage through wellbores and surface equipment pose the only meaningful potential leakage pathways. The monitoring program to detect and quantify leakage is based on this assessment as discussed below.

5.1 Existing Wells

As part of the TRRC requirement to initiate CO₂ flooding, an extensive review of all the DCF penetrations was completed to determine the need for corrective action. That analysis showed that all penetrations have either been adequately plugged and abandoned or, if in use, do not require corrective action. All wells in the DCF were constructed and are operated in compliance with TRRC rules.

As part of routine risk management, the potential risk of leakage associated with the following were identified and evaluated:

- CO₂ flood electrical submersible pump (ESP) producing wells,
- CO₂ flood beam pumped producing wells, and
- CO₂ injector wells.

The risk assessment classified all risks associated with subsurface as low risk, i.e., less than 1% likelihood to occur and having a consequence that is insubstantial. The risks were classified as low risk because DCF geology is well suited to CO₂ sequestration with an extensive confining zone that is free of fractures and faults that could be potential conduits for CO₂ migration. Any risks are further mitigated because the DCF is operated in a manner that maintains, monitors, and documents the integrity of the reservoir.

The risk of well leakage is mitigated through:

- Adhering to regulatory requirements for well drilling and testing,
- implementing best practices that CapturePoint has developed through its extensive operating experience,
- monitoring injection/production performance, wellbores, and the surface; and,
- maintaining surface equipment.

Continual and routine monitoring of the wellbores and site operations will be used to detect leaks or other potential well problems, as follows:

- Pressure in injection wells is monitored daily. The injection plans for each pattern are provided to field operations to govern the rate, pressure, and duration of either water or CO₂ injection. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such events occur, they would be investigated and addressed. CapturePoint's experience, from over 10 years of operating CO₂-EOR projects, is that such leakage has not occurred.
- Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a SAT. There is a routine well testing cycle for each SAT, with each well being tested approximately once every month. During this cycle, each production well is diverted to the well test equipment for a period sufficient to measure and sample produced fluids (generally 12-24 hours). These tests are the basis for allocating a portion of the produced fluids measured at the SAT to each production well, assessing the composition of produced fluids by location, and assessing the performance of each well. Performance data are reviewed on a routine basis to ensure that CO₂ flooding efficiency is optimized. If production is off plan, it is investigated, and any identified issues addressed. Leakage to the outside of production wells is not considered a major risk because of the reduced pressure in the casing. Further, the personal H₂S monitors are designed to detect leaked fluids around production wells during well inspections as well as various permanent H₂S monitors throughout the field at ground level.
- Field inspections are conducted on a routine basis by field personnel. Leaking CO₂ is very cold and leads to the formation of bright white clouds and ice that are easily spotted. All field personnel are trained to identify leaking CO₂ and other potential problems at wellbores and in the field. Any CO₂ leakage detected will be documented, quantified, and reported.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, it is concluded that the risk of CO₂ leakage through wellbores is being mitigated by detecting problems as they arise and quantifying any leakage that does occur. If leakage did occur, the magnitude of 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.

5.2 Faults and Fractures

After reviewing geologic, seismic, operating, and other evidence, it has been concluded that there are no known faults or fractures that transect the San Andres reservoir in the project area. As a result, there is minimal risk (less than 1%) of leakage due to fractures or faults. This low risk therefore infers a very low magnitude if leaked.

Measurements to determine FPP and reservoir pressure are routinely updated. This information is used to manage injection patterns so that the injection pressure will not exceed FPP. An IWR at or near 1 is also maintained. Both procedures mitigate the potential for inducing faults or fractures. As a safeguard, WAG skids are continuously monitored.

5.3 Natural and Induced Seismicity

After reviewing the literature and actual operating experience; it is concluded that there is no direct evidence that natural seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF. There is no indication of seismic activity posing a risk for loss of CO₂ to the surface within the MMA. The TRRC approved injection pressures in the DCF are maintained and monitored so that injection pressure is kept well below the TRRC approved injection pressures which are significantly below the fracture initiation pressure. This ensures that there will be no induced seismicity. Therefore, CapturePoint concludes that leakage of sequestered CO₂ through seismicity is unlikely and less than 1% and of a very low magnitude.

To evaluate this potential risk at the DCF, CapturePoint has reviewed the nature and location of seismic events in West Texas. While some of the recorded earthquakes in West Texas are judged to be from natural causes, others are near oil fields or water disposal wells and are placed in the category of “quakes in close association with human enterprise.”² A review of the United States Geological Survey (USGS) database of recorded earthquakes at M1.0 or greater in the Permian Basin since 1956 indicates that none have occurred in the DCF; the closest took place in 2020 approximately 38 miles away. See Figure 5-1.

The concern about induced seismicity is that it could lead to fractures in the seal providing a pathway for CO₂ leakage to the surface. CapturePoint is not aware of any reported loss of injectant (brine water or CO₂) to the surface associated with any induced seismic activity. There is no direct evidence to suggest that induced seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF. RRC approved injection pressures are kept well below the reservoir fracture gradient to ensure seismicity is not induced. If induced seismicity resulted in a pathway for material amounts of CO₂ to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would detect the migration and lead to further investigation.

² Frohlich, Cliff (2012) “Induced or Triggered Earthquakes in Texas: Assessment of Current Knowledge and Suggestions for Future Research”, Final Technical Report, Institute for Geophysics, University of Texas at Austin, Office of Sponsored Research.

CapturePoint monitors the USGS earthquake monitoring Geographical Information System (GIS) site³ for seismic signals that could indicate the creation of potential leakage pathways in the DCF.

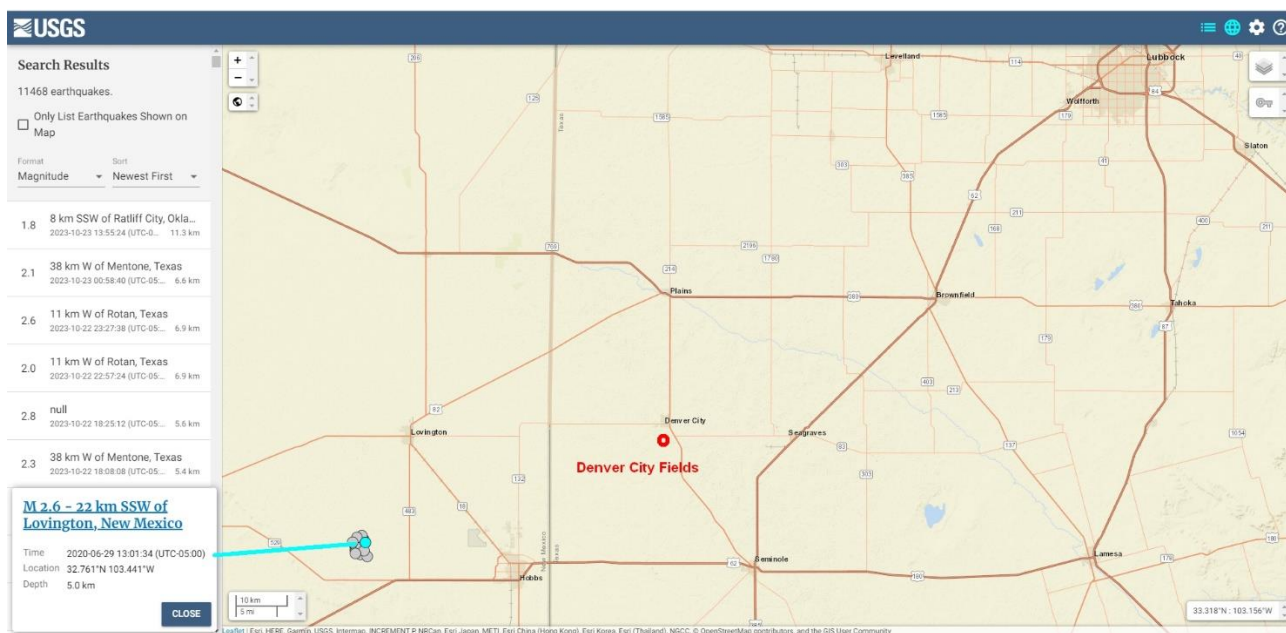


Figure 5-1 USGS earthquakes (+1.0 magnitude) for last 57 years)

5.4 Previous Operations

CO₂ flooding was initiated in the DCF in 2007. To obtain permits for CO₂ flooding, the AoR around all CO₂ injector wells was evaluated to determine if there were any unknown penetrations and to assess if corrective action was required at any wells. As indicated in Section 5.1, this evaluation reviewed the identified penetrations and determined that no additional corrective action was needed. Further, CapturePoint's standard practice for drilling new wells includes a rigorous review of nearby wells to ensure that drilling will not cause damage to or interfere with existing wells. Additionally, requirements to construct wells with materials that are designed for CO₂ injection are adhered to at the DCF. These practices ensure that there are no unknown wells within the DCF and that the risk of migration from older wells has been sufficiently mitigated via location identification and daily on-site monitoring of rates and pressures. The successful experience with CO₂ flooding in the DCF demonstrates that the confining zone has not been impaired by previous operations. Based on this history of no leakage events and well construction requirements, the likelihood is less the 1% and the magnitude would be low with a timely response and remediation.

5.5 Pipelines and Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO₂. CapturePoint anticipates that the use of prevailing design and construction practices and compliance with applicable laws will reduce to the maximum extent practicable the risk of

³ <https://earthquake.usgs.gov/earthquakes/map/>

unplanned leakage from surface facilities. The facilities and pipelines currently utilize and will continue to utilize materials of construction and control processes that are standard for CO₂-EOR projects in the oil and gas industry. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. Field personnel are trained to look for and report potential leaks from pipeline and surface equipment as part of their routine activities. Surface equipment leaks have a low risk of occurring based on design standards that are followed, and any leak would have insubstantial results. The magnitude of surface equipment leaks will range from 0.1 to 2 MT yearly and are addressed within 6-12 hours of occurring. Should leakage be detected from pipeline or surface equipment, the volume of released CO₂ will be quantified following the requirements of Subpart W of the Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP). Because of materials selection, the risk is once again low, and CapturePoint concludes that leakage of CO₂ through the surface equipment is unlikely.

5.6 Lateral Migration Outside the Denver City Fields

It is highly unlikely that injected CO₂ will migrate downdip and laterally outside the DCF because of the nature of the geology and the approach used for injection. Over prolonged periods of time, injected CO₂ will tend to rise vertically towards the Upper San Andres and continue towards the point in the DCF with the highest elevation. Second, the planned injection volumes and active fluid management during injection operations will prevent CO₂ from migrating laterally out of the structure. Finally, the total volume of fluids contained in the DCF will stay constant. Based on site characterization and planned and projected operations it is estimated that the total volume of stored CO₂ will be less than the calculated capacity. Since the stored volume is less than the calculated capacity, the likelihood and magnitude of lateral migration are very low and would happen only in the late life of injection.

5.7 Drilling in the Denver City Fields

The TRRC regulates well drilling activity in Texas. Pursuant to TRRC rules, well casing shall be securely anchored in the hole to effectively control the well at all times, all usable-quality water zones shall be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flow zones, and zones with corrosive formation fluids shall be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. Where TRRC rules do not detail specific methods to achieve these objectives, operators shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology. The TRRC requires applications and approvals before a well is drilled, recompleted, or reentered. Well drilling activity at the DCF is conducted in accordance with TRRC rules. CapturePoint's visual inspection process, including routine site visits, will identify unapproved drilling activity in the DCF. Leakage during drilling operations is unlikely but possible. It would occur when reservoir pressure is high. Drilling mud weight is designed to control that leakage therefore making the potential very low with volumes leaked kept at low levels.

In addition, CapturePoint intends to operate the DCF for several more years and will continue to be vigilant about protecting the integrity of its assets and maximizing the potential of its

resources, including oil, gas, and CO₂. Consequently, the risks associated with third parties penetrating the DCF are negligible.

5.8 Diffuse Leakage Through the Seal

Diffuse leakage through the seal formed by the upper San Andres is highly unlikely. There are a number of sections above the reservoir that are impermeable and serve as reliable barriers to prevent fluids from moving upwards towards the surface. These barriers are referred to as seals because they effectively seal fluids within the formations beneath them.

Our injection pattern monitoring program assures that no breach of the seal will be created. The seal is highly impermeable. Wellbores that penetrate the seal make use of cement and steel construction that is closely regulated to ensure that no leakage takes place. Injection pressure is continuously monitored and unexplained changes in injection pressure that might indicate leakage would trigger investigation as to the cause. The potential for leakage again is very low (less than 1%) the magnitude of which would be in the several MCF range into other formations but not to the surface.

5.9 Leakage Detection, Verification, and Quantification

As discussed above, the potential sources of leakage include issues, such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment (wellbores), and unique events such as induced fractures. An event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage is used. Table 5.1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, the standard response, and other applicable regulatory programs requiring similar reporting.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods for quantifying the volume of leaked CO₂ will be determined on a case-by-case basis using all metering and measurement equipment from each wellhead through the output of the tanks and recycle. In the event leakage occurs, the most appropriate methods for quantifying the volume leaked will be determined and it will be reported as required as part of the annual Subpart RR submission.

- For leakage through wellbores, daily monitoring of flow rates will provide the basis to determine duration and the amount of CO₂ loss;
- For leakage from surface equipment and pipelines, daily monitoring of flow rates and acceptable emission factors, such as those in 40 CFR Part §98 Subpart W, provide the basis to determine duration and the amount of CO₂ loss;
- For leakage related to the competency of the confining layer, reservoir modeling and engineering estimates provided the basis for determining the amount of CO₂ loss.

Any volume of CO₂ detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as the frequency of inspection. Leaks will be documented, evaluated, and addressed in a timely manner.

Records of leakage events will be retained in an electronic environmental documentation and reporting system. The Field Foreman is notified for maintenance activities that cannot be addressed on the spot.

Table 5-1 Response Plan for CO₂ Loss

Risk	Monitoring Plan	Response Plan
Tubing Leak	Monitor changes in tubing and annulus pressure; MIT for injectors	Well is shut in and workover crews respond within days
Casing Leak	Routine Field inspection; Monitor changes in annulus pressure, MIT for injectors; extra attention to high risk wells	Well is shut in and workover crews respond within days
Wellhead Leak	Routine Field inspection, SCADA system monitors wellhead pressure	Well is shut in and workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations	Maintain well kill procedures
Unplanned wells drilled through San Andres	Routine Field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells.	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Reservoir pressure in WAG headers; high pressure found in new wells	Re-enter and reseal abandoned wells
Pumps, valves, etc.	Routine Field inspection, SCADA	Workover crews respond within days
Overfill beyond spill points	Reservoir pressure in WAG headers; high pressure found in new wells	Fluid management along lease lines
Leakage through induced fractures	Reservoir pressure in WAG headers; high pressure found in new wells	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Reservoir pressure in WAG headers; high pressure found in new wells	Shut in injectors near seismic event
Diffuse leakage through the seal	Monitor injection pressure for unexplained changes in injection pressure that might indicate leakage	Investigate to determine if cement and steel construction is the issue. Well is shut in and workover crews respond within days.

5.10 Summary

The structure and stratigraphy of the San Andres reservoir in the DCF is ideally suited for the injection and storage of CO₂. The stratigraphy within the CO₂ injection zones is porous, permeable, and thick, providing ample capacity for long-term CO₂ storage. The reservoir is overlain by several intervals of impermeable geologic zones that form effective seals or “caps” to fluids in the reservoir.

In summary, based on a careful assessment of the potential risk of release of CO₂ from the subsurface, it has been determined that there are no leakage pathways at the DCF that are likely

to result in significant loss of CO₂ to the atmosphere. Further, given the detailed knowledge of the field and its operating protocols, it is concluded that any CO₂ leakage to the surface that could arise through either identified or unexpected leakage pathways would be detected and quantified.

6 Monitoring and Considerations for Calculating Site Specific Variables

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

6.1 For the Mass Balance Equation

6.1.1 General Monitoring Procedures

Flow rate, pressure, and gas composition data are monitored and collected from the DCF in centralized data management systems as part of ongoing operations. This data is monitored by qualified technicians who follow response and reporting protocols when the systems deliver notifications that data exceed statistically acceptable boundaries.

Metering protocols used at DCF follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association, and the Gas Processors Association, as appropriate. This approach is consistent with EPA GHGRP's Subpart RR, section §98.444(e)(3). These meters will be maintained routinely, operated continually, and will feed data directly to the centralized data collection systems. The meters meet the industry standard for custody transfer meter accuracy and calibration frequency.

6.1.2 CO₂ Received

As indicated in Figure 3-8, the volume of received CO₂ is measured using a commercial custody transfer meter at the point at which custody of the CO₂ from the Kinder Morgan CO₂ pipeline delivery system is transferred to the DCF. This meter measures flow rate continually. The transfer is a commercial transaction that is documented. CO₂ composition is governed by contract and the gas is routinely sampled. Fluid composition will be determined, at a minimum, quarterly, consistent with EPA GHGRP's Subpart RR, section §98.447(a). All meter and composition data are documented, and records will be retained for at least three years. No CO₂ is received in containers.

6.1.3 CO₂ Injected in the Subsurface

Injected CO₂ will be calculated using the flow meter volumes at the operations meter at the outlet of the RCF and the custody transfer meter at the CO₂ off-take point from the Kinder Morgan CO₂ Pipeline Delivery System.

6.1.4 CO₂ Produced, Entrained in Products, and Recycled

The following measurements are used for the mass balance equations in Section 8:

- CO₂ produced in the gaseous stage is calculated using the volumetric flow meters at the outlet of the separation facility (Figure 3-8 vessels, V-100, V-101, V-200, V-201, and V-300),
- CO₂ that is entrained in produced oil, as indicated in Figure 3-8, is calculated from routinely captured samples and volume is measured by the truck flow meter,
- Recycled CO₂ is calculated using the volumetric flow meter at the outlet of the RCF, which is an operations meter.

6.1.5 CO₂ Emitted by Surface Leakage

CapturePoint uses 40 CFR Part 98 Subpart W to estimate surface leaks from equipment at the DCF. Subpart W uses a factor-driven approach to estimate equipment leakage. An event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage to the surface is used. Additionally, CapturePoint uses 40 CFR Part 98 Subpart RR to report equipment leaks and vented emissions separately for injection and production.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet two objectives: 1) to detect problems before CO₂ leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the volumes of CO₂ leaked to the surface.

Monitoring for Potential Leakage from the Injection/Production Zone

In addition to the measures discussed in Section 5.9, both injection into and production from the reservoir will be monitored as a means of early identification of potential anomalies that could indicate leakage from the subsurface.

Injection plans (fluid rate, pressure, volume) are given to operations on a weekly basis. If injection pressure or rate measurements are outside the specified set points determined as part of each pattern injection plan, reservoir engineering will notify field personnel and they will investigate and resolve the problem. These excursions will be reviewed by well management personnel to determine if CO₂ leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or some other minor action is required), and there is no threat of CO₂ leakage. In the case of issues that are not readily resolved, more detailed investigation and response would be initiated, and support staff would provide additional assistance and evaluation.

Likewise, a forecast of the rate and composition of produced fluids is developed. Each producer well is assigned to a specific SAT and is isolated during each cycle for a well production test. This data is reviewed on a periodic basis to confirm that production is at the level forecasted. If there is a significant deviation from the plan, well management personnel investigate. If the issue

cannot be resolved quickly, a more detailed investigation and response would be initiated. If leakage in the flood zone were detected, an appropriate method would be used to quantify the involved volume of CO₂. This might include use of material balance equations based on known injected quantities and monitored pressures in the injection zone to estimate the volume of CO₂ involved.

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

In the event leakage from the subsurface occurred diffusely through the seals, the leaked gas would include H₂S, which would trigger the alarm on the personal monitors worn by field personnel as well as the various permanent H₂S monitors throughout the field at ground level. Such a diffuse leak from the subsurface has not occurred in the DCF. In the event such a leak was detected, personnel would determine how to address the problem. The personnel might use modeling, engineering estimates, and direct measurements to assess, address, and quantify the leakage.

Monitoring of Wellbores

DCF wells are monitored through daily pressure monitoring of the injection zone, monitoring of the annular pressure in wellheads, and routine maintenance and inspection.

Leaks from wellbores would be detected through the follow-up investigation of pressure anomalies, visual inspection, or the use of personal H₂S monitors and various permanent H₂S monitors throughout the field at ground level.

Anomalies in injection zone pressure may not indicate a leak, as discussed above. However, if an investigation leads to a need for further study, field personnel would inspect the equipment in question and determine the nature of the problem. If it is a simple matter, the repair would be made, and the volume of leaked CO₂ would be included in the 40 CFR Part 98 Subpart W report for the DCF. If more extensive repair were needed, the appropriate approach for quantifying leaked CO₂ using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be determined.

Anomalies in annular pressure or other issues detected during routine maintenance inspections would be treated in the same way. Field personnel would inspect the equipment in question and determine the nature of the problem. For simple matters the repair would be made at the time of inspection and the volume of leaked CO₂ would be included in the 40 CFR Part 98 Subpart W report for the DCF. If more extensive repairs were needed, the well would be shut in, a work order would be generated and the appropriate approach for quantifying leaked CO₂ using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be determined. The work order would serve as the basis for tracking the event for Green House Gas (GHG) reporting.

Because leaking CO₂ at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a visual inspection process in the area of the DCF is employed to detect unexpected releases from wellbores. Field personnel visit the surface facilities on a routine basis. Inspections may include tank levels, equipment status, lube oil levels, pressures and flow rates in the facility, and valves. Field personnel also check that injectors are on the proper WAG schedule and observe the facility for visible CO₂ or fluid line leaks.

Finally, the data collected by the H₂S monitors, which are always worn by field personnel and are located permanently throughout the field at ground level, is used as a last method to detect leakage from wellbores. The H₂S monitor's detection limit is 10 ppm; if an H₂S alarm is triggered, the first response is to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. As noted previously, H₂S is considered a proxy for potential CO₂ leaks in the field. Thus, detected H₂S leaks will be investigated to determine and, if needed, quantify potential CO₂ leakage.

Other Potential Leakage at the Surface

The same visual inspection process and H₂S monitoring system will be used to detect other potential leakage at the surface as it does for leakage from wellbores. Routine visual inspections are used to detect significant loss of CO₂ to the surface. Field personnel routinely visit surface facilities to conduct a visual inspection. Inspections may include review of tank level, equipment status, lube oil levels, pressures and flow rates in the facility, valves, ensuring that injectors are on the proper WAG schedule, and also conducting a general observation of the facility for visible CO₂ or fluid line leaks. If problems are detected, field personnel would investigate, and complete any maintenance that is required. In addition to these visual inspections, the results of the personal H₂S monitors worn by field personnel and the permanent H₂S monitors throughout the field at ground level will be used as a supplement for smaller leaks that may escape visual detection.

If CO₂ leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, steps are taken to prevent further leaks.

6.1.6 CO₂ emitted from equipment leaks and vented emissions of CO₂ from surface equipment located between the injection flow meter and the injection wellhead

CapturePoint evaluates and estimates leaks from injection equipment and the CO₂ content of any vented CO₂, as required under 40 CFR Part 98 Subpart W.

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

CapturePoint evaluates and estimates leaks from production equipment and the CO₂ content of produced oil, and any vented CO₂, as required under 40 CFR Part 98 Subpart W.

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

At the end of the Specified Period, injecting CO₂ for the subsidiary purpose of establishing the long-term storage of CO₂ in the DCF will cease. Sometime after the end of the Specified Period, a request to discontinue monitoring and reporting will be submitted. The request will demonstrate that the amount of CO₂ reported under 40 CFR §98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage.

At that time, the request will be supported with years of data collected during the Specified Period. This demonstration will provide the information necessary for the EPA Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

- Data comparing actual performance to predicted performance (purchase, injection, production) over the monitoring period,
- An assessment of the CO₂ leakage detected, including the discussion of the estimated amount of CO₂ leaked and the distribution of emissions by leakage pathway,
- A demonstration that future operations will not release the volume of stored CO₂ to the surface,
- A demonstration that there has been no significant leakage of CO₂; and,
- An evaluation of the reservoir pressure demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

7 Determination of Baselines

Ongoing operational monitoring has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO₂ leakage. Data systems are used primarily for operational control and monitoring, which are set to capture more information than is necessary for reporting in the Annual Subpart RR Report. The necessary system guidelines to capture the information that is relevant to identify possible CO₂ leakage will be developed. The following describes the approach to collecting this information.

Visual Inspections

As field operators conduct routine inspections and repairs, the Field Foreman is notified for maintenance activities that cannot be addressed on the spot. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation (the responsible party will be provided in the monitoring plan, as required under Subpart A, §98.3(g)). The Annual Subpart RR Report will provide an estimate of CO₂ emissions. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

Personal H₂S Monitors

H₂S monitors are worn by all field personnel. The H₂S monitors detect concentrations of H₂S up to 500 ppm in 0.1 ppm increments and will sound an alarm if the detection limit exceeds 10 ppm. The current H₂S concentration in the produced gas is 5,709 ppm taken from the recycle compressor inlet and 205 ppm in the produced oil. If an H₂S alarm is triggered, the immediate response is to protect the safety of the personnel, and the next step is to safely investigate the source of persistent alarms. CapturePoint considers H₂S to be a proxy for potential CO₂ leaks in the field. The person responsible for MRV documentation will receive notice of all incidents where H₂S is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO₂ emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

As stated before, there are various permanent H₂S monitors throughout the field at ground level to detect H₂S and alarm if a limit is reached.

Injection Rates, Pressures and Volumes

Target injection rate and pressure for each injector are developed within the permitted limits based on the results of ongoing pattern balancing. The injection targets are submitted to field operations. Field operations flags whenever statistically significant deviations from the targeted ranges are identified. The set points are designed to be conservative, because it is preferable to have too many flags rather than too few. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO₂ leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions. The Annual Subpart RR Report will provide an estimate of CO₂ emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

Production Volumes and Compositions

A general forecast of production volumes and composition is developed which is used to periodically evaluate performance, refine current and projected injection plans, and the forecast. This information is used to make operational decisions but is not recorded in an automated data system. The MRV plan implementation lead will review the data and identify those that could result in CO₂ leakage. Should such events occur, leakage volumes would be calculated following the approaches described in Sections 5 and 6. Impact to Subpart RR reporting will be addressed, if deemed necessary.

8 Determination of Sequestration Volumes Using Mass Balance Equations

Per subpart RR requirements, all flow meters for CO₂ and oil measurement are located directly downstream of each separation point. To account for the potential error that would result if volume data from flow meters at each injection and production well were utilized, the data from custody transfer meters, operations meters on the main system pipelines, and at all points of separation, is used to determine injection and production volumes used in the mass balance of the system. This issue arises because while each meter has a small but acceptable margin of error,

this error would become significant if data were taken from all the well head meters within the DCF (See Figure 3-8).

The following sections describe how each element of the mass-balance equation (Equation RR-11) will be calculated.

8.1 Mass of CO₂ Received

Equation RR-2 will be used as indicated in Subpart RR §98.443 to calculate the mass of CO₂ at the receiving custody transfer meter from the Trinity CO₂ pipeline delivery system. The volumetric flow at standard conditions will be multiplied by the CO₂ concentration and the density of CO₂ at standard conditions to determine mass.

The Mass of the CO₂ Received will be determined using Equation RR-2 as follows:

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

where:

$CO_{2T,r}$ = Net annual mass of CO₂ received through flow meter r (metric tons).

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO₂ concentration measurement in flow for flow meter r in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

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

- All delivery to the DCF is used within the unit so no quarterly flow redelivered, and $S_{r,p}$ will be zero ("0").
- Quarterly CO₂ concentration will be taken from the gas measurements.

8.2 Mass of CO₂ Injected into the Subsurface

The equation for calculating the Mass of CO₂ Injected into the Subsurface at the DCF is equal to the sum of the Mass of CO₂ Received as calculated in RR-2 of §98.443 (section 8.1 above) and the Mass of CO₂ Recycled calculated using measurements taken from the flow meter located at the outlet of the RCF (see Figure 3-8). As previously explained, using data at each injection well would give an inaccurate estimate of total injection volume due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

The Mass of CO₂ Recycled will be determined using equations RR-5 as follows:

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

where:

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = CO₂ concentration measurement in flow for flow meter u in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

The total Mass of CO₂ Injected will be the sum of the Mass of CO₂ Received (RR-2) and Mass of CO₂ Recycled (RR-5).

The Mass of CO₂ Injected will be determined using equations RR-6 as follows:

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

where:

CO_{2I} = Total annual CO₂ mass injected (metric tons) through all injection wells.

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

u = Flow meter.

8.3 Mass of CO₂ Produced

The Mass of CO₂ Produced at the DCF will be calculated using the measurements from the flow meters at the inlet to RCF and the custody transfer meter for oil sales rather than the metered data from each production well. Again, using the data at each production well would give an inaccurate estimate of total injection due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

Equation RR-8 in §98.443 will be used to calculate the Mass of CO₂ Produced from all production wells as follows:

$$CO_{2,w} = \sum_{p=1}^4 (Q_{p,w}) * D * C_{CO_2,p,w} \quad (\text{Eq. RR-8})$$

Where:

$CO_{2,w}$ = Annual CO₂ mass produced (metric tons) through separator w.

$Q_{p,w}$ = Volumetric gas flow rate measurement for separator w in quarter p at standard conditions (standard cubic meters).

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

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

p = Quarter of the year.

w = Separator.

For Equation RR-9 in §98.443 the variable X will be measured as follows:

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

Where:

CO_{2P} = Total annual CO₂ mass produced (metric tons) through all separators in the reporting year.

$CO_{2,w}$ = Annual CO₂ mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO₂ in produced oil or other fluid divided by the CO₂ separated through all separators in the reporting year (weight percent CO₂, expressed as a decimal fraction)

w = Separator

8.4 Mass of CO₂ Emitted by Surface Leakage

Surface Leakage will be calculated and reported using an approach that is tailored to specific leakage events including calculation methodologies in 40 CFR Part 98 Subpart W for emissions and leaks from equipment. CapturePoint is prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO₂ leaked to the surface will depend on several site- specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

The process for quantifying leakage will entail using the best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are described in Sections 5.9 and 6. In the event leakage to the surface occurs, leakage amounts would be quantified and reported, and records that describe the methods used to estimate or measure the volume leaked as reported in the Annual Subpart

RR Report would be retained. Volumes for CO_{2E} (surface leakage) and CO_{2FI} (equipment leakage and vented emissions) are calculated separately and differently.

Equation RR-10 in §98.443 will be used to calculate and report the Mass of CO₂ emitted by Surface Leakage:

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

Where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

8.5 Mass of CO₂ Emitted by Facility Emergency Vent

The Mass of CO₂ emitted by the Emergency Vent at the DCF will be calculated using the measurements from the flow meter at the vent. That volume will be added to CO_{2FI} which is the total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

Equation RR-8 in §98.443 will be used to calculate the Mass of CO₂ emitted through the emergency vent as follows:

$$CO_{2w} = \sum_{p=1}^4 (Q_{p,w}) * D * C_{CO_2,p,w} \quad (\text{Eq. RR-8})$$

Where:

CO_{2w} = Annual CO₂ mass produced (metric tons) through separator w.

Q_{p,w} = Volumetric gas flow rate measurement for separator w in quarter p at standard conditions (standard cubic meters).

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

CCO_{2,p,w} = CO₂ concentration measurement in flow for separator w in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator

8.6 Mass of CO₂ Sequestered and Reported in Subsurface Geologic Formation

Equation RR-11 in §98.443 will be used to calculate the Mass of CO₂ Sequestered and Reported in Subsurface Geologic Formations in the Reporting Year as follows:

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

where:

CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

CO_{2P} = Total annual CO₂ mass produced (metric tons) in the reporting year.

CO_{2E} = Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

CO_{2FP} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

9 MRV Plan Implementation Schedule

This MRV plan will be implemented starting October 2023 or within 90 days of EPA approval, whichever occurs later. Other GHGRP reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. It is

anticipated that the MRV plan will be in effect during the Specified Period, during which time the DCF will be operated with the subsidiary purpose of establishing long-term containment of a measurable quantity of CO₂ in subsurface geological formations at the DCF. It is anticipated to establish that a measurable amount of CO₂ injected during the Specified Period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be prepared and a request to discontinue monitoring and reporting under this MRV plan will be submitted. See 40 C.F.R. §98.441(b)(2)(ii).

10 Quality Assurance (QA) Program

10.1 QA Procedures

The requirements of §98.444 (a) – (d) have been incorporated in the discussion of mass balance equations. These include the following provisions.

CO₂ Received and Injected

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

CO₂ Produced

- The point of measurement for the quantity of CO₂ produced from oil or other fluid production wells is a flow meter directly downstream of each separator that sends a stream of gas into a recycle or end use system.
- The produced gas stream is sampled annually downstream of the flow meter used to measure flow rate of that gas stream and measure the CO₂ concentration of the sample.

CO₂ Emissions from Equipment Leaks and Vented Emissions of CO₂

These volumes are measured in conformance with the monitoring and QA requirements specified in subpart W of 40 CFR Part 98.

Flow Meter Provisions

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

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

Concentration of CO₂

CO₂ concentration is measured using an appropriate standard method. Further, all measured volumes of CO₂ have been converted to standard cubic meters at a temperature of 60 degrees

Fahrenheit and at an absolute pressure of 1 atmosphere, including those used in Equations RR-2, RR-5, and RR-8 in Section 8.

10.2 Missing Data Procedures

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

- A quarterly flow rate of CO₂ received that is missing would be estimated using invoices or using a representative flow rate value from the previous measured period.
- A quarterly CO₂ concentration of a CO₂ stream received that is missing would be estimated using invoices or using a representative concentration value from the previous measured period.
- A quarterly quantity of CO₂ injected that is missing would be estimated using a representative quantity of CO₂ injected from the previous measured period at a similar injection pressure.
- For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.
- The quarterly quantity of CO₂ produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO₂ produced from the previous measured period.

10.3 MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters of the CO₂-EOR operations in the DCF that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in §98.448(d).

11 Records Retention

The record retention requirements specified by §98.3(g) will be followed. In addition, the requirements in Subpart RR §98.447 will be met by maintaining the following records for at least three years:

- Quarterly records of CO₂ received at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of produced CO₂, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO₂ including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
- Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

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

12 Appendix

12.1 Well Identification Numbers

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

The following terms are used:

Well Type:

- SWS refers to wells that supply water.
- PROD_OIL refers to wells that produce oil.
- INJ_WAG refers to wells that inject water or CO₂.
- INJ_SWD refers to wells that inject water for disposal.
- P&A refers to plugged and abandoned wells.

Well Status:

- ACTIVE refers to active wells.
- INACTIVE refers to wells that have been completed but are not in use.
- SHUT_IN refers to wells that have been temporarily idled or shut in.
- TEMP_AB refers to wells that have been temporarily abandoned.

Table 12-1 Well Status Table

Well Name	API Number	Well Type	Status
GAU #1WS	42165339890000	SWS	INACTIVE
GAU #2W	42165106400000	P&A	INACTIVE
GAU #3	42165106340000	P&A	INACTIVE
GAU #4	42165103790000	PROD_OIL	SHUT_IN
GAU #5	42165106070000	PROD_OIL	INACTIVE
GAU #6	42165106530000	P&A	INACTIVE
GAU #6R	42165367760000	PROD_OIL	INACTIVE
GAU #7W	42165339900000	INJ_WAG	ACTIVE
GAU #8W	42165339910000	INJ_WAG	SHUT_IN
GAU #9W	42165339920000	INJ_WAG	ACTIVE
GAU #10	42165106510000	P&A	INACTIVE
GAU #10R	42165367820000	PROD_OIL	ACTIVE
GAU #11	42165106060000	P&A	INACTIVE
GAU #11R	42165367490000	PROD_OIL	ACTIVE
GAU #12	42165102070000	P&A	INACTIVE
GAU #12R	42165367510000	PROD_OIL	ACTIVE
GAU #13	42165003830000	PROD_OIL	ACTIVE

Well Name	API Number	Well Type	Status
GAU #14W	42165317930000	INJ_WAG	SHUT_IN
GAU #15	42165101300000	PROD_OIL	INACTIVE
GAU #16W	42165106270000	INJ_SWD	ACTIVE
GAU #17W	42165339930000	INJ_WAG	ACTIVE
GAU #18	42165103780000	PROD_OIL	ACTIVE
GAU #19	42165106460000	PROD_OIL	SHUT_IN
GAU #20W	42165008790000	P&A	INACTIVE
GAU #22W	42165352720000	INJ_WAG	ACTIVE
GAU #23W	42165367500000	INJ_WAG	ACTIVE
GAU #24	42165106440000	PROD_OIL	INACTIVE
GAU #25	42165367550000	PROD_OIL	ACTIVE
GAU #26	42165367530000	PROD_OIL	ACTIVE
GAU #27	42165367540000	PROD_OIL	ACTIVE
GAU #71	42165384590000	PROD_OIL	ACTIVE
RH #28W	42165367610000	INJ_WAG	ACTIVE
RH #29W	42165367620000	INJ_WAG	ACTIVE
RH #30W	42165367630000	INJ_WAG	ACTIVE
RH #31	42165367660000	PROD_OIL	ACTIVE
RH #32	42165367670000	PROD_OIL	ACTIVE
RH #33	42165367520000	PROD_OIL	ACTIVE
RH #34	42165367890000	PROD_OIL	SHUT_IN
RH #70	42165384430000	PROD_OIL	ACTIVE

12.2 Regulatory References

Regulations cited in this plan:

- TAC Title 16 Part 1 Chapter 3 Oil & Gas Division

[https://texreg.sos.state.tx.us/public/readtac\\$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y](https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y)

- TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual

<https://www.rrc.texas.gov/oil-and-gas/publications-and-notices/manuals/injection-storage-manual/>

12.3 Abbreviations and Acronyms

AMA - Active Monitoring Area

API - American Petroleum Institute

AoR - Area of Review

Bcf – 1 Billion Standard Cubic Feet of Gas

CO₂ - Carbon Dioxide

DCF – Denver City Fields

DPC - Dimensionless Performance Curve

EPA - Environmental Protection Agency

EOR - Enhanced Oil Recovery

ESP - Electrical Submersible Pump

FPP - Formation Parting Pressure (psi)

GAU - George Allen Unit

GHGRP - Greenhouse Gas Reporting Program

H₂S – Hydrogen Sulfide

HCPV - Hydrocarbon Pore Volume

IWR - Injection to Withdrawal Ratio

MMA - Maximum Monitoring Area

MRV Plan - Monitoring, Reporting and Verification Plan

MCF – 1 Thousand Standard Cubic Feet of Gas

MIT – Mechanical Integrity Test

MMCF – 1 Million Standard Cubic Feet of Gas

NIST - National Institute of Standards and Technology

QA – Quality Assurance

RB - Reservoir Barrels

RCF - Recycle Compression Facility

RH - Ruth Hudson Lease

SAT – Satellite Test

TAC - Texas Administrative Code

TRRC - Texas Railroad Commission - Oil and Gas Division

UIC – Underground Injection Control

12.4 Conversion Factors

CapturePoint reports CO₂ 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 CO₂ mass from CO₂ 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 CO₂ 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 CO₂ of 0.002641684 lb-moles per cubic foot. Converting the CO₂ density in units of metric tonnes per cubic foot:

$$Density_{CO_2} \left(\frac{MT}{ft^3} \right) = Density_{CO_2} \left(\frac{lb - moles}{ft^3} \right) \times MW_{CO_2} \times \frac{1 MT}{2,204.62 lbs}$$

Where:

$Density_{CO_2}$ = Density of CO₂ in metric tonnes (MT) per cubic foot

$Density_{CO_2}$ = 0.002641684

MW_{CO_2} = 44.0095

$Density_{CO_2} = 5.2734 \times 10^{-5} \frac{MT}{ft^3}$ or $5.2734 \times 10^{-2} \frac{MT}{Mcf}$

The conversion factor 5.2734×10^{-2} MT/Mcf is used to convert CO₂ volumes in standard cubic feet to CO₂ mass in metric tonnes.

Appendix B: Submissions and Responses to Requests for Additional Information

CAPTUREPOINT LLC
DENVER CITY FIELD
SUBPART RR MONITORING, REPORTING AND
VERIFICATION (MRV) PLAN

July 2024

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1 Introduction

CapturePoint LLC operates a Carbon Dioxide Enhanced Oil Recovery (CO₂-EOR) project in the Denver City Field (DCF) located in Gaines County, Texas, approximately four miles southwest of the town of Denver City, Texas and less than two miles west of the Denver Unit of the giant Wasson San Andres Fields for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO₂) with a subsidiary or ancillary purpose of geologic sequestration of CO₂ in a subsurface geologic formation. The DCF is comprised of the George Allen Unit (GAU) which contains the Ruth Hudson Lease (RH). Like Wasson production is from the San Andres formation at an average depth of 5,000 feet. The Monitoring, Reporting and Verification (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 CO₂ sequestered at the Denver City Fields during a specified period of injection.

2 Facility Information

2.1 Reporter Number

576482 – Denver City Fields

2.2 UIC Permit Class

The Oil and Gas Division of the Texas Railroad Commission (TRRC) regulates oil and gas activity in Texas. All wells in the DCF (including production, injection, and monitoring wells) are permitted by TRRC through Texas Administrative Code (TAC) Title 16 Chapter 3. TRRC has primacy to implement the Underground Injection Control (UIC) Class II program in the state for injection wells. All EOR injection wells in the DCF are currently classified as UIC Class II wells.

2.3 Existing Wells

Wells in the DCF are identified by name and number, American Petroleum Institute (API) number, type, and status. The list of wells as of March 2023 is included in Section 12.1. Any changes in wells will be indicated in the annual subpart RR submission.

3 Project Description

This project takes place in the DCF, an oil field located in West Texas that was first produced more than 60 years ago. The DCF is comprised of the GAU which contains the RH. The two are adjacent to each other, produce oil and gas from the same geologic formations and structure, and are under the sole operatorship of CapturePoint LLC. The geology, facilities/equipment, and operational procedures are similar for both in the DCF. In addition, the two properties share the same CO₂ recycle and water injection facilities as well as the injection piping system for both CO₂ and water. Because of these common facilities and common reservoir, one MRV Plan is being prepared for the two properties in the DCF and any important differences between the two properties will be noted in the MRV plan. CO₂ flooding was initiated in 2007 in the GAU and in 2012 in the RH. The field is well characterized and is suitable for secure geologic storage in the San Andres formation. CapturePoint LLC uses a water alternating with gas (WAG) injection process and maintains an injection to withdrawal ratio (IWR) at or near 1.

3.1 Project Characteristics

The DCF was discovered in 1956 and started production in the same year. The DCF consists of one unit (GAU) and one lease (RH). The GAU began to produce in May 1956 and the waterflood was initiated in September 1989. CO₂ flooding was initiated in December 2007, in both the Main Pay and Residual Oil Zone (ROZ). The RH initiated a waterflood in March 2008 and began to produce in November 2008. CO₂ flooding was initiated in December 2012, also in the Main Pay and ROZ.

A long-term forecast for both the GAU and RH was developed using a dimensionless performance curve (DPC) approach. Using this approach, approximately 2.0 million tonnes of stored CO₂ is forecasted over the life of the project. Figure 3-1 shows actual and projected CO₂ injection, production, and stored volumes in DCF.

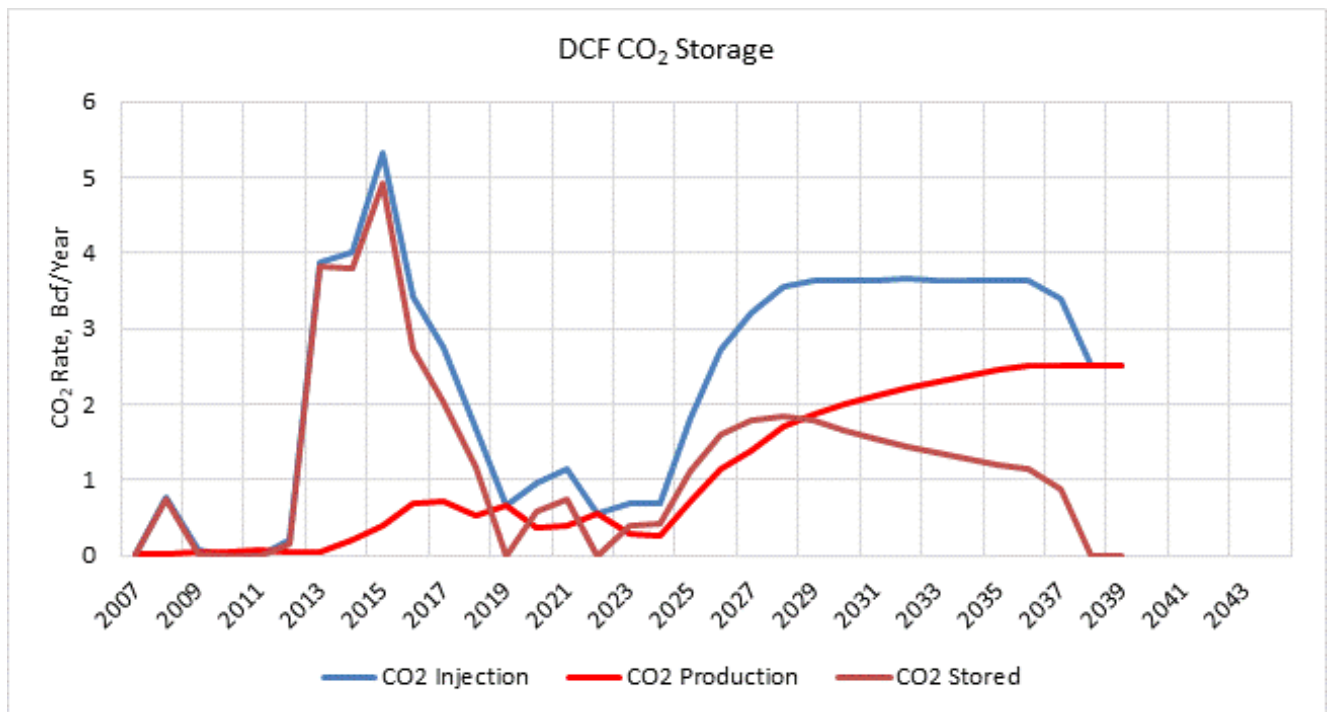


Figure 3-1 DCF Historic and Forecast CO₂ Injection, Production, and Storage

3.2 Environmental Setting

The DCF is located in the NE portion of the Central Basin Platform in West Texas (See Figure 3-2). This map also shows the location of the Denver Unit and other Wasson San Andres Units. The DCF is shown by the green dot.

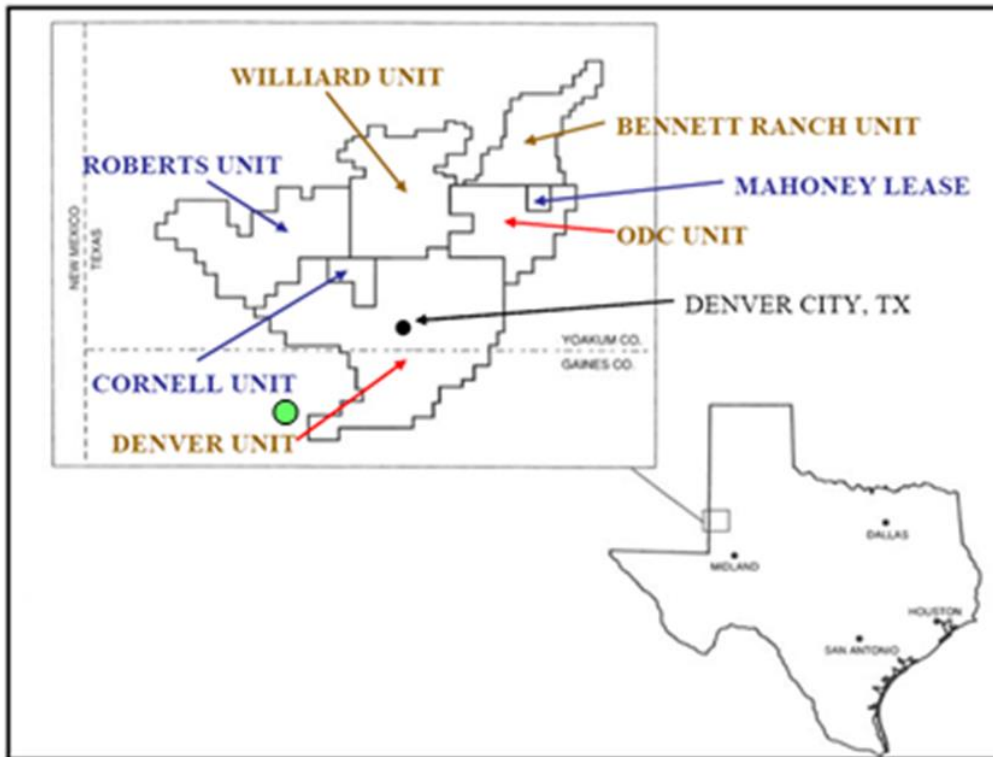


Figure 3-2 Location of DCF in West Texas

Like Wasson, the DCF produces from a San Andres dolomite reservoir at a depth of about 5,000 feet. In contrast to Wasson, DCF is a smaller oil accumulation with a thin mobile oil column trapped by a low relief anticlinal structure as shown in Figure 3-3. The Wasson field has produced over two billion barrels of oil to date from the San Andres while the DCF has produced 2.06 million barrels of oil to 2022.

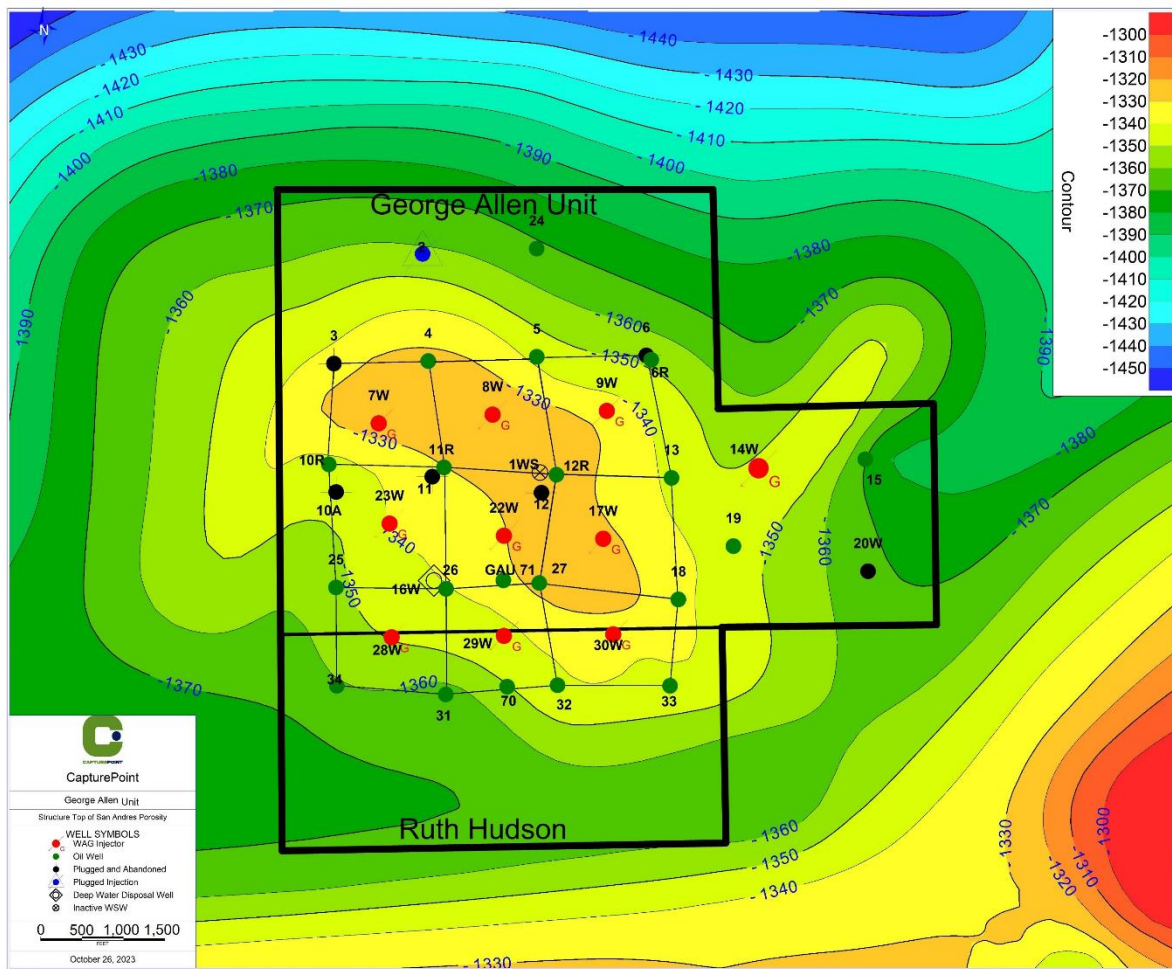


Figure 3-3 Local Area Structure on Top of San Andres for DCF

In the DCF there is a thin mobile oil column. Beneath the conventional oil column there is a thick, porous section with transition zone/residual oil (TZ/ROZ) that can only be produced via tertiary recovery methods, primarily CO₂ injection. This thick TZ/ROZ zone as found in the Wasson field gives a sizeable target for tertiary recovery (over 300 feet gross thickness).

Oil in the TZ/ROZ is currently being produced via CO₂ injection. Nine 40-acre patterns were prepared to inject CO₂ in this zone in the DCF. The presence of thick residual zones in the San Andres of the Permian Basin is widespread. Lindsay (2001), Melzer (2005), Melzer (2006), and Koperna and Kuuskraa (2006; 1&2) discuss the possible origins and the extent of residual oil zones in the Permian Basin. Brown (2001) discusses the ROZ in the area and its possible origin. The residual zone in the DCF has better porosity and permeability and is much thicker than the mobile oil zone which produced during primary and secondary (waterflood) recovery. This is often the case in residual oil zones, particularly those found in smaller fields with thinner oil columns. This gives us a large resource in which to economically sequester large volumes of CO₂, as CO₂ can both be stored and utilized for oil recovery in the extensive residual oil zones found in the San Andres in the Permian Basin.

The oil saturation profile found in the DCF/Wasson area is shown below in Figure 3-4 from Koperna and Kuuskraa (2006; 2):

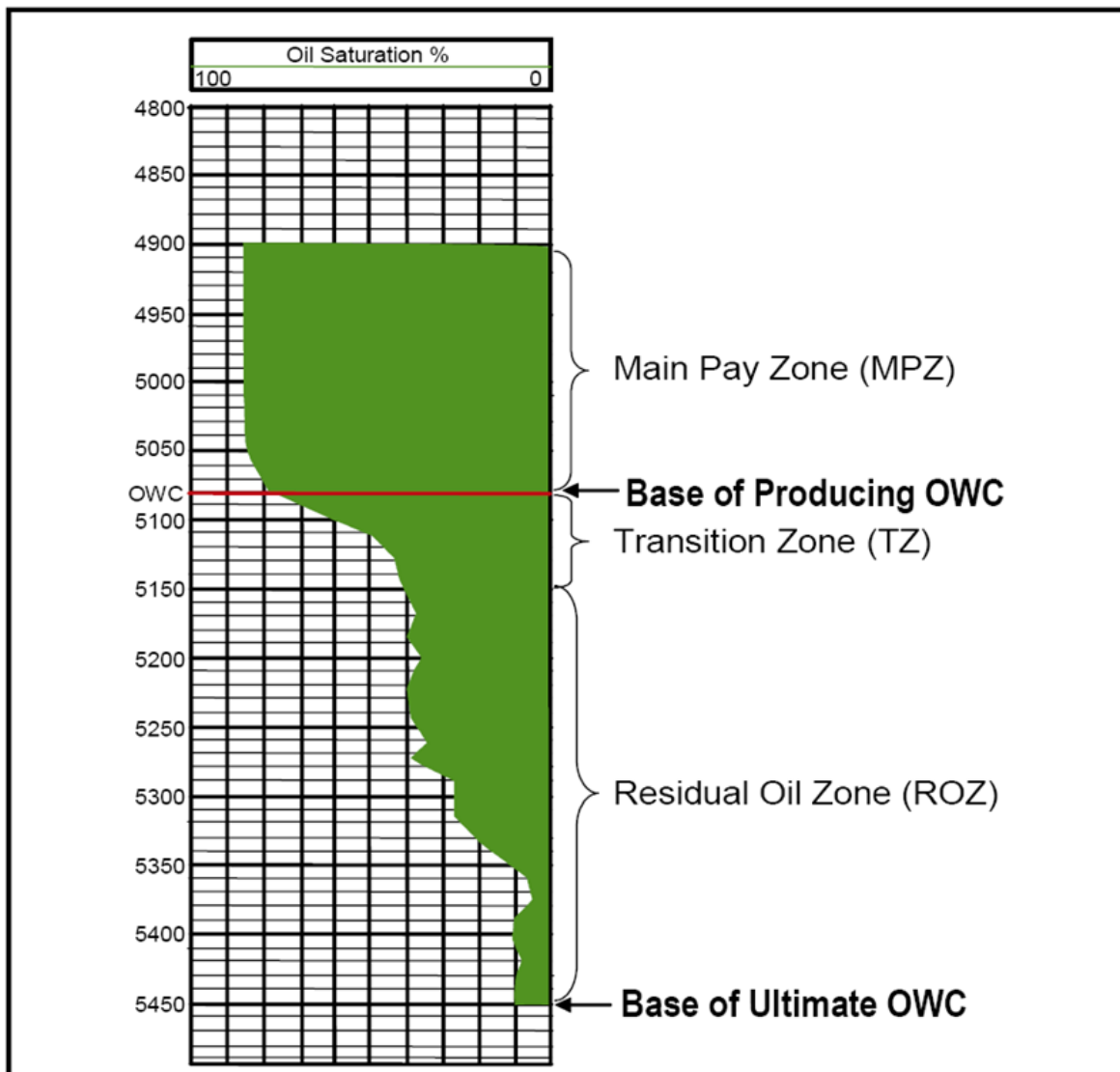


Figure 3-4 Saturation Profile of San Andres

Due to hydrodynamic flow in the San Andres aquifer, a ROZ was created and is under CO₂ flood along with the Main Pay Zone in the San Andres Formation.

Once the CO₂ flood is complete and injection ceases, the remaining mobile CO₂ will rise slowly upward, driven by buoyancy forces. There is more than enough pore space (188 million reservoir barrels (MRB)) to sequester the planned CO₂ injection (27.8 million reservoir barrels). The amount of CO₂ injected will not exceed the reservoir's secure storage capacity and, consequently, the risk that CO₂ could migrate to other reservoirs in the Central Basin Platform is negligible. The volume of CO₂ storage is based on the estimated total pore space within the DCF. The total pore space within the DCF, from the top of the reservoir down to the base of the ROZ, is calculated to be 188 million reservoir barrels (MRB). This is the volume of rock multiplied by porosity. Table 3-1 below shows the conversion of this amount of pore space into an estimated maximum volume of

approximately 254 billion cubic feet (Bcf) (13.4 million tonnes) of CO₂ storage in the reservoir. CO₂ will occupy only 15% of the total calculated storage capacity by the year 2037 based on the projected forecast.

Table 3-1 Calculation of Maximum Volume of CO₂ Storage Capacity at DCF

Top of Main Pay to Bottom of Residual Oil Zone (ROZ)	
Variables	DCF Outline
Pore Volume (RB)	188,396,478
BCO₂ (RB/MCF)	0.407
S_{wirr}	0.35
S_{or} CO₂	0.10
Max CO₂ (MCF)	254,589,835
Max CO₂ (BCF)	254

$$\text{Max CO}_2 = \text{Pore Volume} * (1 - S_{wirr} - S_{or} \text{ CO}_2) / \text{BCO}_2$$

Where:

Max CO₂ = the maximum amount of storage capacity

Pore Volume = Total pore space in reservoir barrels (RB)

BCO₂ = the formation volume factor for CO₂

S_{wirr} = the irreducible water saturation

S_{or} CO₂ = the irreducible oil saturation

Reservoir management is employed on a constant basis to obtain the maximum possible economic recovery from a reservoir based on facts, information, and knowledge. A reservoir management strategy that is used in CO₂ floods is the implementation of water curtain injectors. This will be utilized in the DCF to create a pressure barrier or “curtain” to contain the injected CO₂ to the area selected for production. Water curtain injection is an efficient method of maintaining and controlling lateral migration of fluids to assure that CO₂ does not cross structurally deficient locations. Injected fluids (CO₂) stay in the reservoir within the DCF unit boundary and do not move to adjacent areas.

Given that in DCF the confining zone has proved competent over both millions of years and in the current CO₂ flooding, and that the DCF has ample storage capacity, there is confidence that stored CO₂ will be contained securely within the reservoir.

3.3 Geologic Setting/Stratigraphic Column

The George Allen/Wasson San Andres fields are located on the Northwest shelf of the Permian Basin (Figure 3-5).

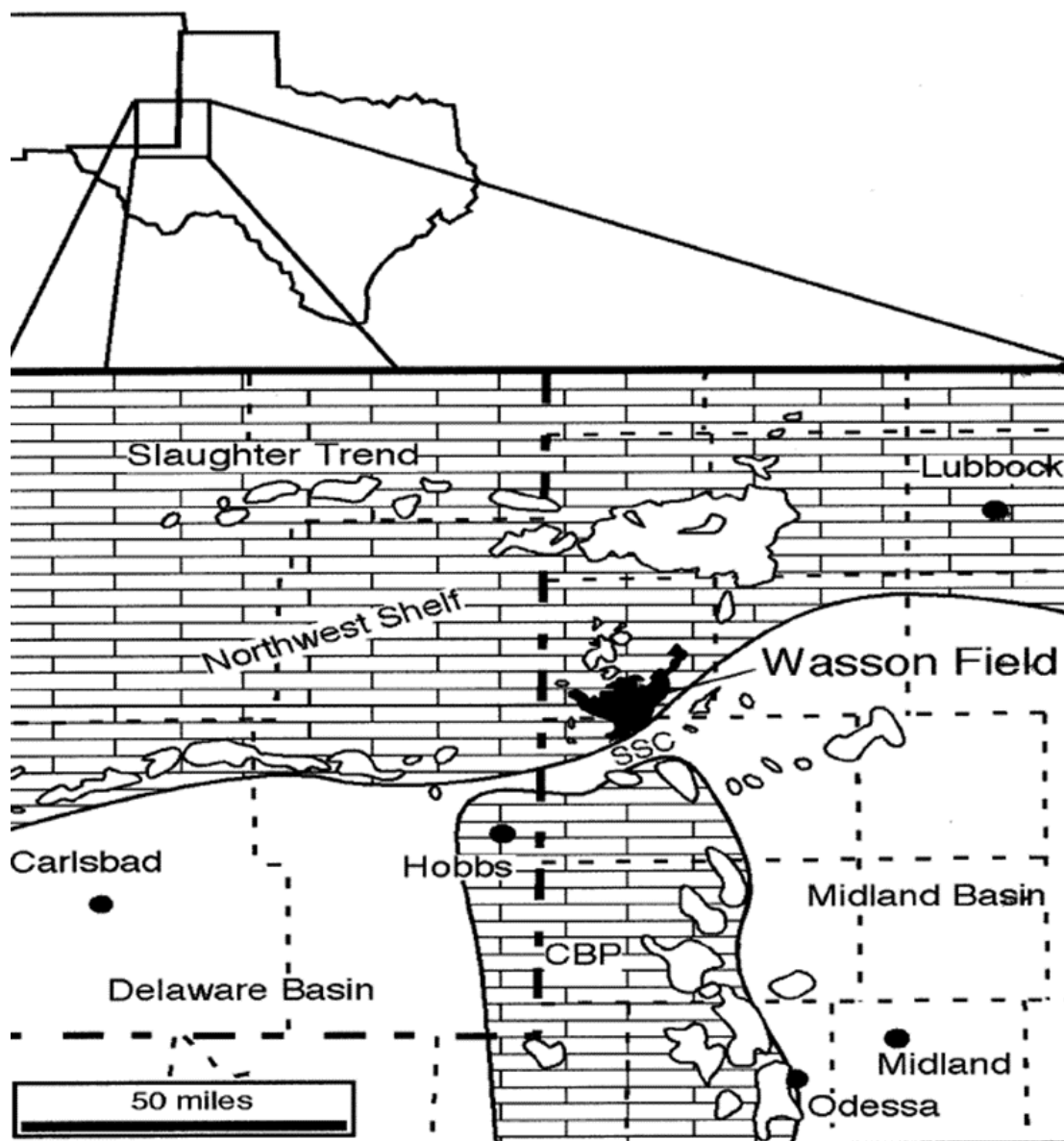


Figure 3-5 Map of Northwest shelf of the Permian Basin

The Wasson field is shown in black. Other San Andres fields are outlined. San Andres “shelf” facies are indicated by the brick pattern. “CBP” refers to the “Central Basin Platform” a major structural feature that separates the Delaware Basin from the Midland Basin. “SSC” refers to the “San Simon Channel” a feature which allowed seawater circulation between the shallow restricted shelf areas of the Northwest Shelf and the Central Basin Platform.

Figure 3-6 below shows the thickness and broad extent of the porous facies in the San Andres formation.

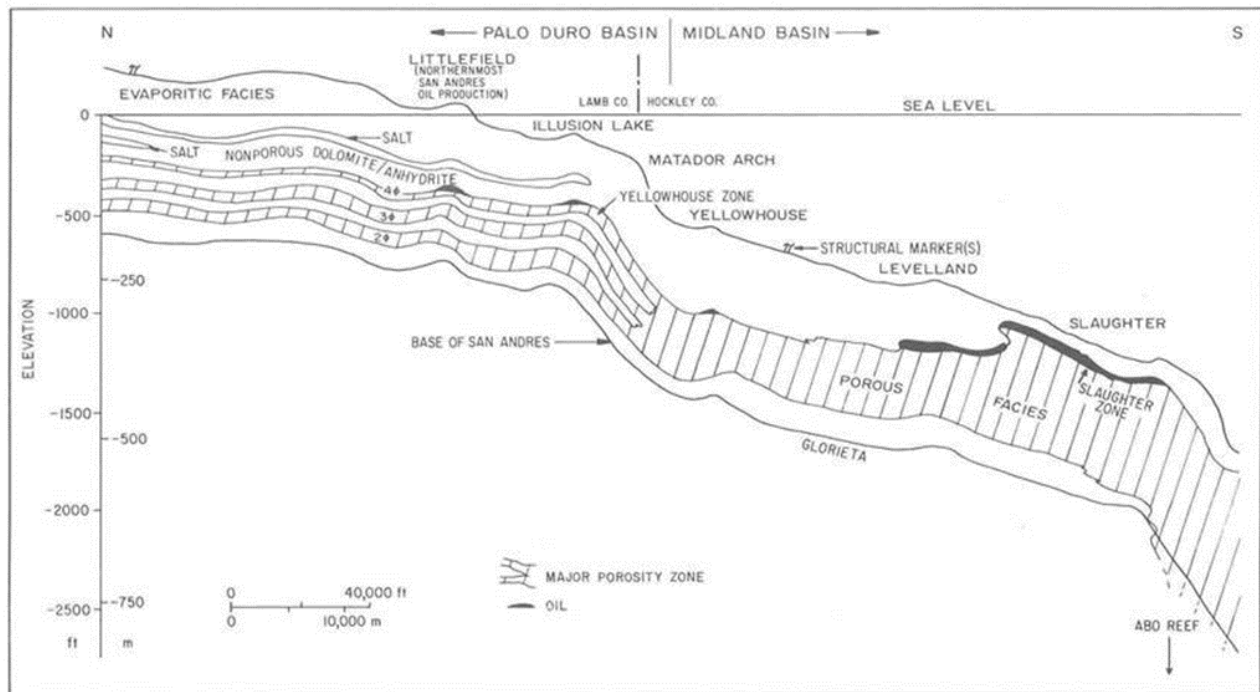


Figure 3-6 Cross section of lower San Andres Formation, Northern Shelf, showing porosity relationships.

A typical stratigraphic section for the area is shown below in Figure 3-7.

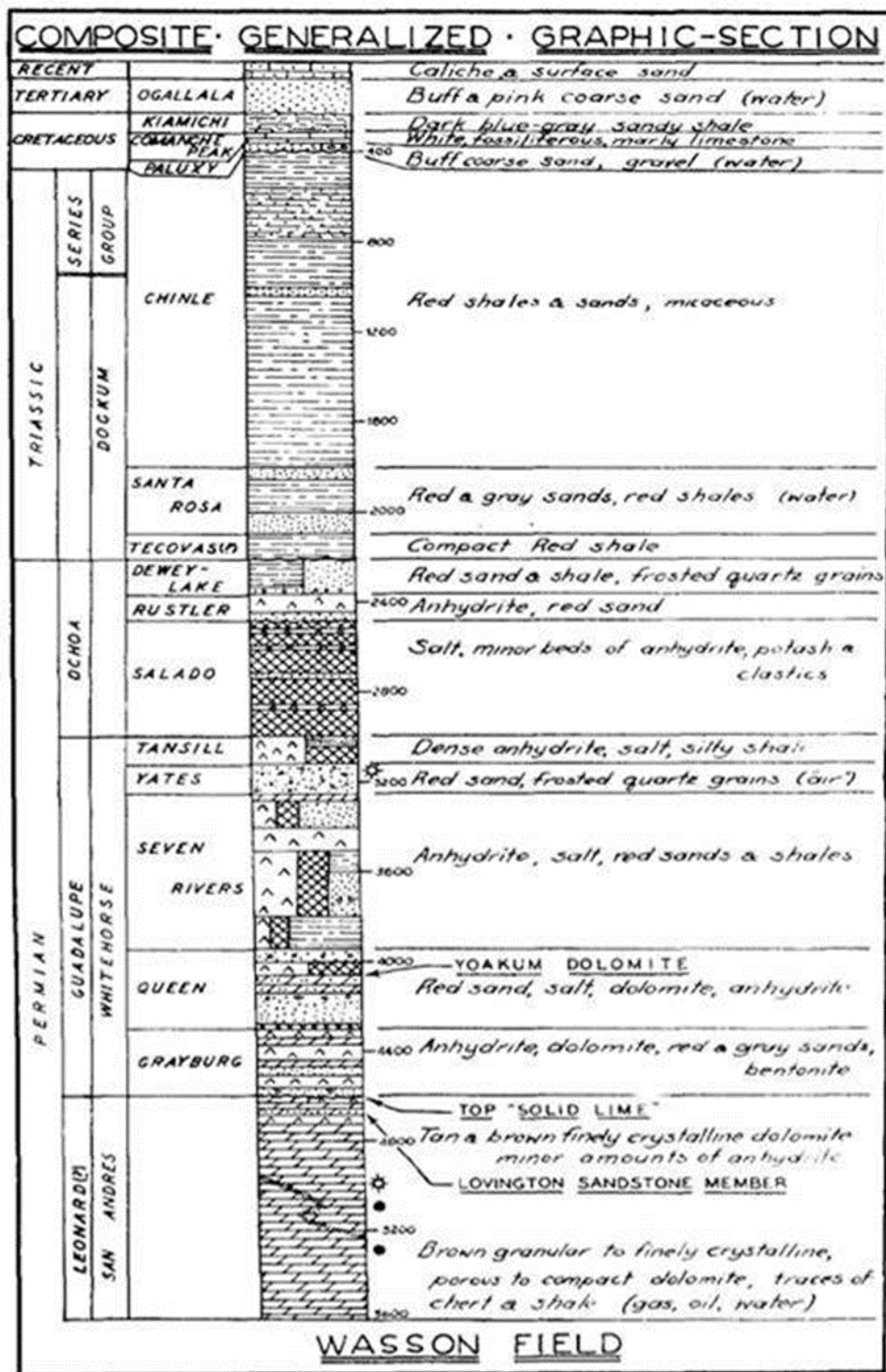


Figure 3-7 Composite generalized stratigraphic section.

The stratigraphy and facies of the Upper Permian on the Northwest Shelf and Central Basin Platform is quite uniform. The Upper Permian consists of a dominate thick and porous shallow marine carbonate facies that was later dolomitized as the San Andres Group prograded out into the basin. Continuation of the regressive sequence during the Upper Permian, defined as the Whitehorse group, caps the San Andres Group with tidal flat muds and tight exposed shelf

carbonates, along with restricted evaporites. These facies within the Grayburg, Queen and Seven Rivers formation serve as widespread and efficient seals for both hydrocarbons and CO₂ trapping.

The notable thing about the Upper Permian rocks described here is that there are multiple and thick intervals that should eliminate the possibility of any vertical migration of fluids or gases from the San Andres reservoir to the surface.

The first seal is the Upper San Andres which consists of dense, fine crystalline dolomite and anhydrite, devoid of any porosity or permeability, deposited on the tidal flats of a broad, restricted shelf. Where the porous, shallow water carbonate facies of the Lower San Andres pinch out and interfinger with these rocks a series of stratigraphic traps is formed in the northern part of the Northwest Shelf. The Levelland-Slaughter-Chaveroo-Cato San Andres fields are found in this trend. A similar porosity pinches out, on the interior of the Central Basin platform, controls the widespread San Andres production found on the eastern margin of the Central Basin platform. These widespread producing trends attest to sealing capacity of the Upper San Andres anhydrous dolomite facies both vertically and laterally.

Above the San Andres are a series of restricted/exposed shelf facies consisting of tight, anhydrous dolomite, anhydrite, salt, and thin sandstones of the Upper Guadalupian Grayburg, Queen, Seven Rivers, Yates and Tansill formations. The sandstones sometimes have porosity and permeability but are often cemented by salt and are non-permeable. Where permeable, they offer no chance for vertical migration of fluids or gases as they are inter-layered with impermeable salt, anhydrite, and anhydrous dolomite.

Following the Tansill, the Ochoan, Upper Permian evaporites of the Salado and Rustler formations exist. The Salado is roughly 600-700 feet thick in the Wasson/George Allen area and consists dominantly of halite with some thin beds of potash and anhydrite and a few very thin layers of red mud, silt, and fine sand. Being widespread, thick, and impermeable, this formation alone should certainly stop the vertical migration of any fluids or gases from the subsurface to the surface. Even if fractured, the salt will flow and seal any open cracks. It is followed by the Rustler formation; 60 feet of dense, white anhydrite at the top overlying 30 feet of red shale interbedded with anhydrite; another capstone, on top a over 2,500 feet of mostly impermeable rock.

The Permian ends with the Dewey Lake formation which consists of red gypsum cemented sandstone and red shales.

Above the Permian unconformity are the Triassic Tecovas red shale and then the Santa Rosa formation which contains fresh water bearing sandstones. These deposits are followed by the micaceous red shales and sands of the Chinle formation. A major unconformity separates the Triassic Chinle from the overlying Cretaceous sediments that consists of coarse sand and gravel, white marly limestone, and dark, blue-gray sandy shale.

An important aquifer, the Tertiary Ogallala formation overlies these Cretaceous sediments. It consists of coarse sands and vari-colored gravels, all loose or poorly consolidated, which are followed by recent wind-blown sand and caliche.

3.4 Description of CO₂-EOR Project Facilities and the Injection Process

Figure 3-8 shows a simplified process flow diagram of the project facilities and equipment in the DCF. CO₂ will be delivered to the DCF from Trinity, via the Kinder Morgan CO₂ pipeline network. The CO₂ will be supplied by several different sources including both natural and anthropogenic CO₂ sources. Specified amounts will be drawn from an outside source pipeline based on contractual arrangements among suppliers of CO₂, purchasers of CO₂, and the pipeline operator. The Specified amount of CO₂ required in addition to the produced gas to meet target CO₂ injection rates are forecasted using the DPC approach.

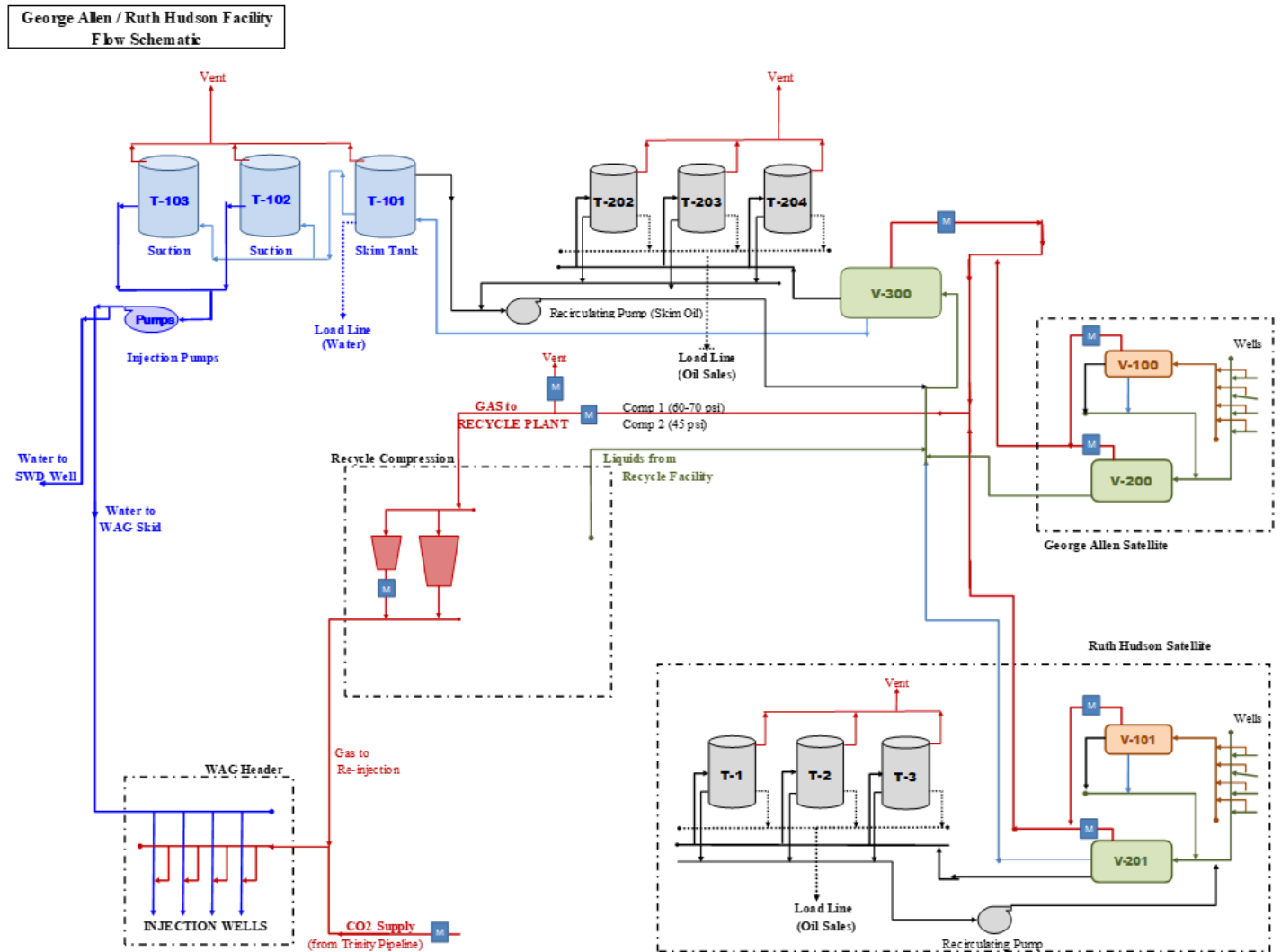


Figure 3-8 DCF Process Flow Diagram

Once CO₂ enters the DCF there are three main processes involved in CO₂-EOR operations:

- i. CO₂ Distribution and Injection: The mass of CO₂ received at the DCF is metered and calculated through the Custody Transfer Meter located at the pipeline delivery point. The mass of CO₂ received is combined with recycled CO₂ / hydrocarbon gas mix from the recycle compression facility (RCF) and distributed to the WAG headers for injection into the injection wells according to the pre-programmed injection plan for each well pattern which alternates between water and CO₂ injection. WAG headers are manually operated and can inject either CO₂ or water at various rates and injection pressures as specified in the injection plans. This is an EOR project and reservoir pressure must be maintained above minimum miscibility pressure. Therefore, injection pressure must be sufficiently high to allow injectants to enter the reservoir, but below formation parting pressure (FPP)
- ii. Produced Fluids Handling: Produced fluids from the production wells are a mixture of oil, hydrocarbon gas, water, CO₂, and trace amounts of other constituents in the field including nitrogen and Hydrogen Sulfide (H₂S) as discussed in Section 7. They are gathered and sent to Satellite Test Stations (SAT) for separation into a gas/CO₂ mix and a produced fluids mix of water, oil, gas, and CO₂. The produced gas, which is composed primarily of CO₂ and minor hydrocarbons, is sent to the RCF for dehydration and recompression before reinjection into the reservoir. An operations meter at the RCF is used to determine the total volume of produced gas that is reinjected. The separated oil is sent to two separate tanks (one at GAU and one at RH) where is then sold via truck.
- iii. Water Treatment and Injection: Water is recovered for reuse and forwarded to the water injection station for reinjection or disposal.

3.4.1 Wells in the Denver City Fields

The TRRC has broad authority over oil and gas operations including primacy to implement UIC Class II wells. The rules are found in TAC Title 16, Part 1, Chapter 3 and are also explained in a TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual (See Appendix 12-2). TRRC rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields.

Briefly, TRRC rules include the following requirements:

- Fluids must be constrained in the strata in which they are encountered,
- activities cannot result in the pollution of subsurface or surface water,
- wells must adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata that are encountered into other strata with oil and gas, or into subsurface and surface waters,
- completion report for each well including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore) must be prepared,
- operators must follow plugging procedures that require advance approval from the TRRC Director and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs; and,
- injection well operators must identify an Area of Review (AoR), use compatible materials and equipment, test, and maintain well records.

Table 3-2 provides a well count by type and status. All these wells are in material compliance with TRRC rules.

Table 3-2 DCF Well Penetrations by Type and Status

TYPE	ACTIVE	INACTIVE	P & A	Total
PROD_OIL	16	3		19
INJ_WTR	0	1		1
INJ_WAG	8	0		8
INJ_SWD*	0	0		0
WSW	0	0		0
P&A			3	3
TOTAL	24	4	3	31

PROD_OIL = Production Wells

INJ_WRT = Water injection wells

INJ_WAG = WAG injection wells

INJ_SWD = Saltwater disposal wells

WSW = Water source wells

P&A = Plugged and Abandoned wells.

As indicated in Figure 3-9, wells are distributed across the DCF. The well patterns currently undergoing CO₂ flooding are identified by black 5-spot pattern outlines and CO₂ will be injected across the entire unit over the project life.

DCF CO₂-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Reservoir pressure in the DCF is managed by maintaining an IWR of approximately 1.0. To maintain the IWR, fluid injection and production are monitored and managed to ensure that reservoir pressure does not increase to a level that would compromise the reservoir seal or otherwise damage the integrity of the oil field.

Injection pressure is also maintained below the FPP, which is measured using step-rate tests.

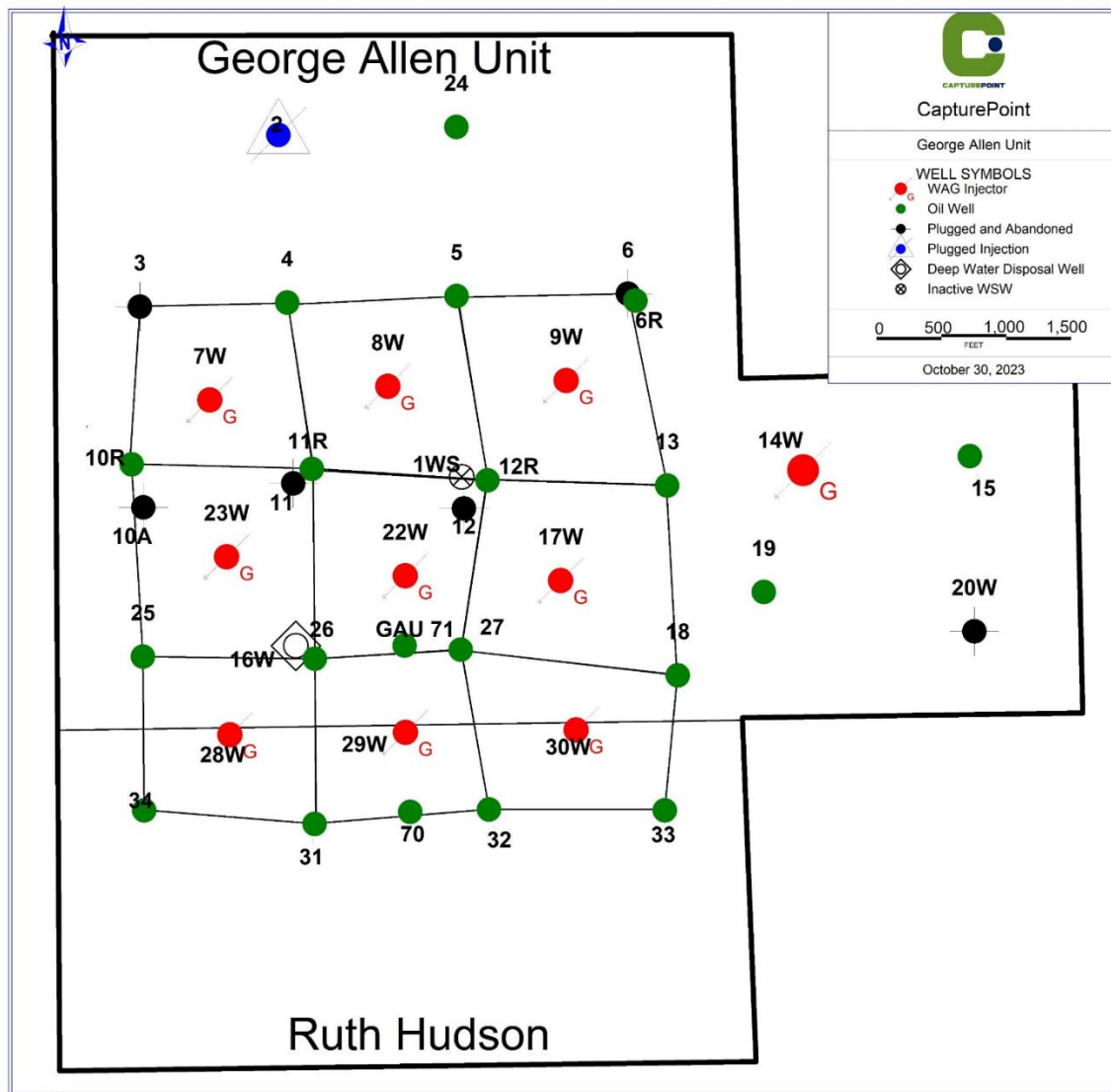


Figure 3-9 DCF Wells and Injection Patterns

3.5 Reservoir Forecasting

DPCs derived from the analogous Wasson San Andres field were used to project CO₂-EOR in the Denver City Field. Most DPCs are derived from geologic and reservoir models. In the DCF case the DPC was derived from actual field performance from the Wasson San Andres field. Like Wasson, the DCF is located on the Northwest shelf of the Permian Basin and produces from the San Andres dolomite reservoir at a depth of about 5,000 feet making them analogous.

A DPC is a plot where injection and production volumes for CO₂, water, and hydrocarbon phases are normalized by dividing by Hydrocarbon Pore Volume (HCPV). See Figure 3-10. The dimensioned projections for the oil, CO₂, and water production are relative to the CO₂ and water injection and are calculated using the original oil in place of an area of interest.

HCPV of Produced:
CO₂, Oil or Water

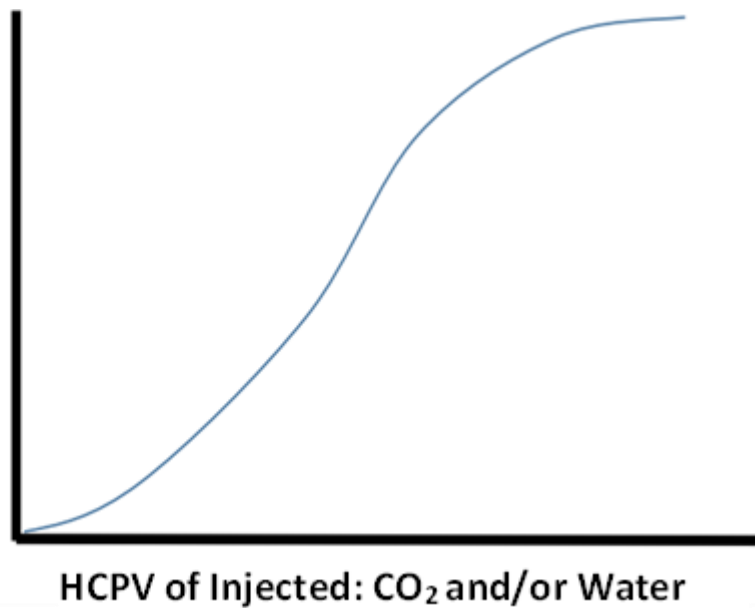


Figure 3-10 DPC plot

The DCF DPC was calculated from the cumulative production and injection from an analogous field. This DPC was used on each pattern in the DCF and then summed up to full field. This method allows you to use different start times and implement different field implementation speeds.

The DPCs are the basis for future performance prediction scenarios but are additionally a means of evaluating the reservoir process efficiencies. In a similar manner to history matching in reservoir simulation, deviations from expected performance can indicate errors in the geologic model of the pore volume, growth of the CO₂ plume, or metering and production allocation errors.

4 Delineation of Monitoring Area and Timeframes

4.1 Active Monitoring Area

The Active Monitoring Area (AMA) is defined by the GAU and RH boundaries plus the required ½ mile zone. Based on our projections, CapturePoint expects the free phase CO₂ plume to remain within the GAU and RH boundaries for the entire length of the project and through year [t+5]. The CO₂ storage volume calculations show the CO₂ to remain within the unit boundaries in the period associated with the AMA, which is year 2037.

The AMA is shown in Figure 4-1. It is an area defined by the boundary of the DCF 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).

4.1.1 Discussion of CO₂ Storage Volumes in AMA

The CO₂ injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO₂-EOR. Maintenance of an Injection to Withdrawal ratio of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

Figure 3-9 displays wells that have CO₂ retention on the 370 acres that have been under CO₂ injection since project initialization. The CO₂ storage volumes were forecasted using the DPC approach. This technique indicates that the flooded acreage still has significant storage potential. The maximum CO₂ storage (254 BCF) is limited to the amount of space available by the removal of the produced hydrocarbon and water. The projection indicates that there is pore space available to store approximately 0.15 decimal fraction of HCPV amounting to 27.8 million reservoir barrels of oil (MMRB) (37.5 BCF).

The lateral extent of CO₂ in the injection zone or the CO₂ storage radius for each well was estimated by calculating a storage radius based on the forecasted CO₂ storage volume of 37.5 BCF. Figure 4-1 shows the map of the storage area outline for each pattern (dashed red line). This calculation showed 166 acres (this calculates to 18 acres per pattern) would be needed to store 37.5 BCF. This is significantly less than the 1133 acres in the DCF outline.

CO₂ injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO₂-EOR. Namely, maintenance of an IWR of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

4.2 Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined by the GAU and RH boundaries plus the required ½ mile buffer as required by 40 CFR §98.440-449 (Subpart RR). The CO₂ plume (Figure 4-1) is expected to be contained within the GAU and RH boundaries which will be actively

monitored. Therefore, CapturePoint defines the MMA as the same as the AMA since the plume location is less than the unit area. 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 FR 98.448(d)(1).

4.3 Monitoring Timeframes

The primary purpose for injecting CO₂ is to produce oil that would otherwise remain trapped in the reservoir and not, as in UIC Class VI, “specifically for the purpose of geologic storage.”¹ During a Specified Period, there will be a subsidiary purpose of establishing the long-term containment of CO₂ in the DCF. The Specified Period is the timeframe that CO₂ storage will occur. In the DCF, CO₂ storage will occur until 2037 at which point CO₂ injection will equal CO₂ production. Specified Period will be shorter than the period of production from the DCF.

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted with a demonstration that current monitoring and model(s) show that the cumulative mass of CO₂ reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration after the Specified Period ends based upon monitoring data.

The reservoir pressure in the DCF is collected for use in operations management. Reservoir pressure is not forecasted to change appreciably since the IWR will be maintained at approximately 1. Once injection ceases, reservoir pressure is predicted to stabilize within one year.

¹ EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b). A

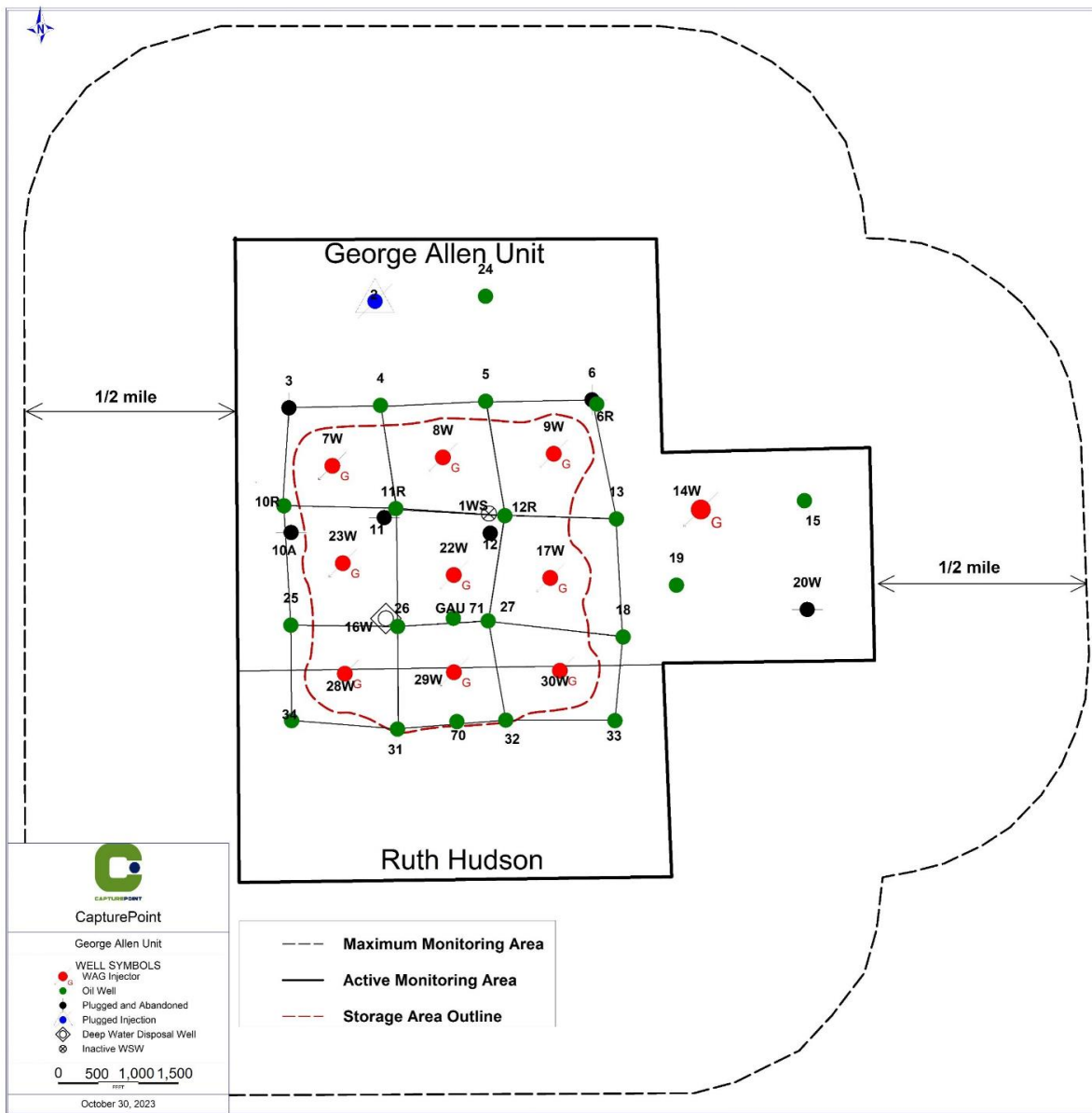


Figure 4-1 Projected CO₂ Storage area

5 Evaluation of Potential Pathways for Leakage to the Surface, Leakage Detection, Verification, and Quantification

In the roughly 60 years since the DCF was discovered, the reservoir has been studied extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO₂ to the surface including:

1. Existing Wells
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the DCF
7. Drilling Through the CO₂ Area
8. Diffuse Leakage Through the Seal
9. Leakage Detection, Verification, and Quantification

This analysis shows that leakage through wellbores and surface equipment pose the only meaningful potential leakage pathways. The monitoring program to detect and quantify leakage is based on this assessment as discussed below.

5.1 Existing Wells

As part of the TRRC requirement to initiate CO₂ flooding, an extensive review of all the DCF penetrations was completed to determine the need for corrective action. That analysis showed that all penetrations have either been adequately plugged and abandoned or, if in use, do not require corrective action. All wells in the DCF were constructed and are operated in compliance with TRRC rules.

As part of routine risk management, the potential risk of leakage associated with the following were identified and evaluated:

- CO₂ flood electrical submersible pump (ESP) producing wells,
- CO₂ flood beam pumped producing wells, and
- CO₂ injector wells.

The risk assessment classified all risks associated with subsurface as low risk, i.e., less than 1% likelihood to occur and having a consequence that is insubstantial. The risks were classified as low risk because DCF geology is well suited to CO₂ sequestration with an extensive confining zone that is free of fractures and faults that could be potential conduits for CO₂ migration. Any risks are further mitigated because the DCF is operated in a manner that maintains, monitors, and documents the integrity of the reservoir.

The risk of well leakage is mitigated through:

- Adhering to regulatory requirements for well drilling and testing,
- implementing best practices that CapturePoint has developed through its extensive operating experience,
- monitoring injection/production performance, wellbores, and the surface; and,
- maintaining surface equipment.

Continual and routine monitoring of the wellbores and site operations will be used to detect leaks or other potential well problems, as follows:

- Pressure in injection wells is monitored daily. The injection plans for each pattern are provided to field operations to govern the rate, pressure, and duration of either water or CO₂ injection. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such events occur, they would be investigated and addressed. CapturePoint's experience, from over 10 years of operating CO₂-EOR projects, is that such leakage has not occurred.
- Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a SAT. There is a routine well testing cycle for each SAT, with each well being tested approximately once every month. During this cycle, each production well is diverted to the well test equipment for a period sufficient to measure and sample produced fluids (generally 12-24 hours). These tests are the basis for allocating a portion of the produced fluids measured at the SAT to each production well, assessing the composition of produced fluids by location, and assessing the performance of each well. Performance data are reviewed on a routine basis to ensure that CO₂ flooding efficiency is optimized. If production is off plan, it is investigated, and any identified issues addressed. Leakage to the outside of production wells is not considered a major risk because of the reduced pressure in the casing. Further, the personal H₂S monitors are designed to detect leaked fluids around production wells during well inspections as well as various permanent H₂S monitors throughout the field at ground level.
- Field inspections are conducted on a routine basis by field personnel. Leaking CO₂ is very cold and leads to the formation of bright white clouds and ice that are easily spotted. All field personnel are trained to identify leaking CO₂ and other potential problems at wellbores and in the field. Any CO₂ leakage detected will be documented, quantified, and reported.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, it is concluded that the risk of CO₂ leakage through wellbores is being mitigated by detecting problems as they arise and quantifying any leakage that does occur. If leakage did occur, the magnitude of 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.

5.2 Faults and Fractures

After reviewing geologic, seismic, operating, and other evidence, it has been concluded that there are no known faults or fractures that transect the San Andres reservoir in the project area. As a result, there is minimal risk (less than 1%) of leakage due to fractures or faults. This low risk therefore infers a very low magnitude if leaked.

Measurements to determine FPP and reservoir pressure are routinely updated. This information is used to manage injection patterns so that the injection pressure will not exceed FPP. An IWR at or near 1 is also maintained. Both procedures mitigate the potential for inducing faults or fractures. As a safeguard, WAG skids are continuously monitored.

5.3 Natural and Induced Seismicity

After reviewing the literature and actual operating experience; it is concluded that there is no direct evidence that natural seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF. There is no indication of seismic activity posing a risk for loss of CO₂ to the surface within the MMA. The TRRC approved injection pressures in the DCF are maintained and monitored so that injection pressure is kept well below the TRRC approved injection pressures which are significantly below the fracture initiation pressure. This ensures that there will be no induced seismicity. Therefore, CapturePoint concludes that leakage of sequestered CO₂ through seismicity is unlikely and less than 1% and of a very low magnitude.

To evaluate this potential risk at the DCF, CapturePoint has reviewed the nature and location of seismic events in West Texas. While some of the recorded earthquakes in West Texas are judged to be from natural causes, others are near oil fields or water disposal wells and are placed in the category of “quakes in close association with human enterprise.”² A review of the United States Geological Survey (USGS) database of recorded earthquakes at M1.0 or greater in the Permian Basin since 1956 indicates that none have occurred in the DCF; the closest took place in 2020 approximately 38 miles away. See Figure 5-1.

The concern about induced seismicity is that it could lead to fractures in the seal providing a pathway for CO₂ leakage to the surface. CapturePoint is not aware of any reported loss of injectant (brine water or CO₂) to the surface associated with any induced seismic activity. There is no direct evidence to suggest that induced seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF. RRC approved injection pressures are kept well below the reservoir fracture gradient to ensure seismicity is not induced. If induced seismicity resulted in a pathway for material amounts of CO₂ to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would detect the migration and lead to further investigation.

² Frohlich, Cliff (2012) “Induced or Triggered Earthquakes in Texas: Assessment of Current Knowledge and Suggestions for Future Research”, Final Technical Report, Institute for Geophysics, University of Texas at Austin, Office of Sponsored Research.

CapturePoint monitors the USGS earthquake monitoring Geographical Information System (GIS) site³ for seismic signals that could indicate the creation of potential leakage pathways in the DCF.

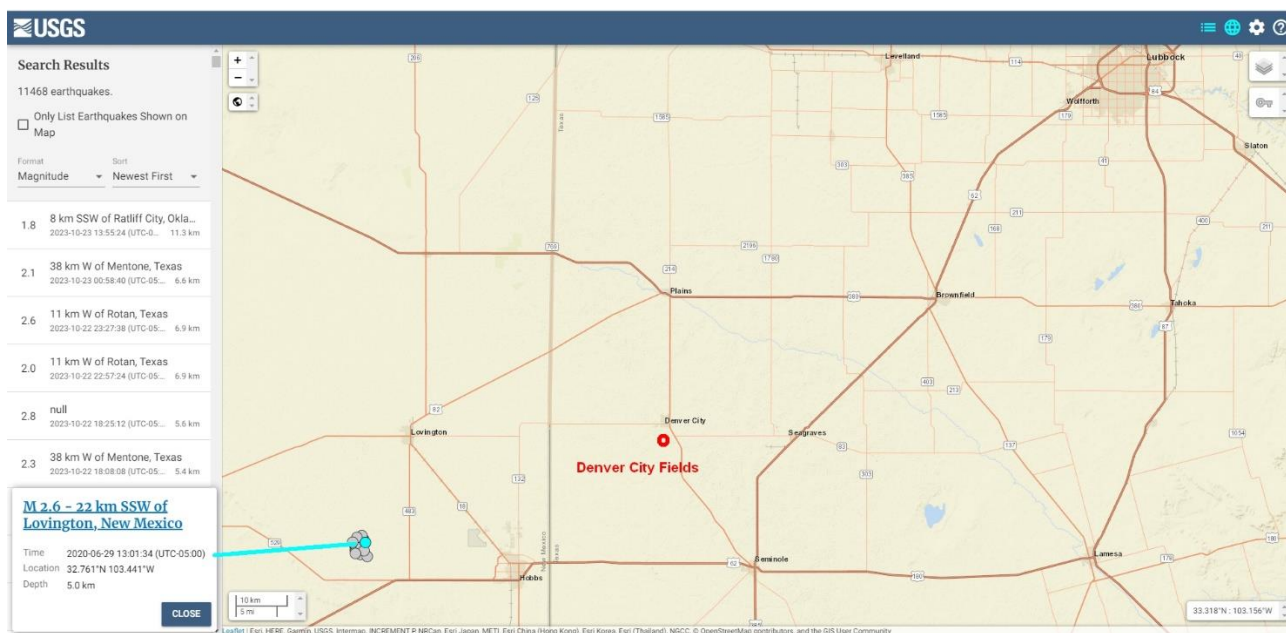


Figure 5-1 USGS earthquakes (+1.0 magnitude) for last 57 years)

5.4 Previous Operations

CO₂ flooding was initiated in the DCF in 2007. To obtain permits for CO₂ flooding, the AoR around all CO₂ injector wells was evaluated to determine if there were any unknown penetrations and to assess if corrective action was required at any wells. As indicated in Section 5.1, this evaluation reviewed the identified penetrations and determined that no additional corrective action was needed. Further, CapturePoint's standard practice for drilling new wells includes a rigorous review of nearby wells to ensure that drilling will not cause damage to or interfere with existing wells. Additionally, requirements to construct wells with materials that are designed for CO₂ injection are adhered to at the DCF. These practices ensure that there are no unknown wells within the DCF and that the risk of migration from older wells has been sufficiently mitigated via location identification and daily on-site monitoring of rates and pressures. The successful experience with CO₂ flooding in the DCF demonstrates that the confining zone has not been impaired by previous operations. Based on this history of no leakage events and well construction requirements, the likelihood is less the 1% and the magnitude would be low with a timely response and remediation.

5.5 Pipelines and Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO₂. CapturePoint anticipates that the use of prevailing design and construction practices and compliance with applicable laws will reduce to the maximum extent practicable the risk of

³ <https://earthquake.usgs.gov/earthquakes/map/>

unplanned leakage from surface facilities. The facilities and pipelines currently utilize and will continue to utilize materials of construction and control processes that are standard for CO₂-EOR projects in the oil and gas industry. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. Field personnel are trained to look for and report potential leaks from pipeline and surface equipment as part of their routine activities. Surface equipment leaks have a low risk of occurring based on design standards that are followed, and any leak would have insubstantial results. The magnitude of surface equipment leaks will range from 0.1 to 2 MT yearly and are addressed within 6-12 hours of occurring. Should leakage be detected from pipeline or surface equipment, the volume of released CO₂ will be quantified following the requirements of Subpart W of the Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP). Because of materials selection, the risk is once again low, and CapturePoint concludes that leakage of CO₂ through the surface equipment is unlikely.

5.6 Lateral Migration Outside the Denver City Fields

It is highly unlikely that injected CO₂ will migrate downdip and laterally outside the DCF because of the nature of the geology and the approach used for injection. Over prolonged periods of time, injected CO₂ will tend to rise vertically towards the Upper San Andres and continue towards the point in the DCF with the highest elevation. Second, the planned injection volumes and active fluid management during injection operations will prevent CO₂ from migrating laterally out of the structure. Finally, the total volume of fluids contained in the DCF will stay constant. Based on site characterization and planned and projected operations it is estimated that the total volume of stored CO₂ will be less than the calculated capacity. Since the stored volume is less than the calculated capacity, the likelihood and magnitude of lateral migration are very low and would happen only in the late life of injection.

5.7 Drilling in the Denver City Fields

The TRRC regulates well drilling activity in Texas. Pursuant to TRRC rules, well casing shall be securely anchored in the hole to effectively control the well at all times, all usable-quality water zones shall be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flow zones, and zones with corrosive formation fluids shall be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. Where TRRC rules do not detail specific methods to achieve these objectives, operators shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology. The TRRC requires applications and approvals before a well is drilled, recompleted, or reentered. Well drilling activity at the DCF is conducted in accordance with TRRC rules. CapturePoint's visual inspection process, including routine site visits, will identify unapproved drilling activity in the DCF. Leakage during drilling operations is unlikely but possible. It would occur when reservoir pressure is high. Drilling mud weight is designed to control that leakage therefore making the potential very low with volumes leaked kept at low levels.

In addition, CapturePoint intends to operate the DCF for several more years and will continue to be vigilant about protecting the integrity of its assets and maximizing the potential of its

resources, including oil, gas, and CO₂. Consequently, the risks associated with third parties penetrating the DCF are negligible.

5.8 Diffuse Leakage Through the Seal

Diffuse leakage through the seal formed by the upper San Andres is highly unlikely. There are a number of sections above the reservoir that are impermeable and serve as reliable barriers to prevent fluids from moving upwards towards the surface. These barriers are referred to as seals because they effectively seal fluids within the formations beneath them.

Our injection pattern monitoring program assures that no breach of the seal will be created. The seal is highly impermeable. Wellbores that penetrate the seal make use of cement and steel construction that is closely regulated to ensure that no leakage takes place. Injection pressure is continuously monitored and unexplained changes in injection pressure that might indicate leakage would trigger investigation as to the cause. The potential for leakage again is very low (less than 1%) the magnitude of which would be in the several MCF range into other formations but not to the surface.

5.9 Leakage Detection, Verification, and Quantification

As discussed above, the potential sources of leakage include issues, such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment (wellbores), and unique events such as induced fractures. An event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage is used. Table 5.1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, the standard response, and other applicable regulatory programs requiring similar reporting.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods for quantifying the volume of leaked CO₂ will be determined on a case-by-case basis using all metering and measurement equipment from each wellhead through the output of the tanks and recycle. In the event leakage occurs, the most appropriate methods for quantifying the volume leaked will be determined and it will be reported as required as part of the annual Subpart RR submission.

- For leakage through wellbores, daily monitoring of flow rates will provide the basis to determine duration and the amount of CO₂ loss;
- For leakage from surface equipment and pipelines, daily monitoring of flow rates and acceptable emission factors, such as those in 40 CFR Part §98 Subpart W, provide the basis to determine duration and the amount of CO₂ loss;
- For leakage related to the competency of the confining layer, reservoir modeling and engineering estimates provided the basis for determining the amount of CO₂ loss.

Any volume of CO₂ detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as the frequency of inspection. Leaks will be documented, evaluated, and addressed in a timely manner.

Records of leakage events will be retained in an electronic environmental documentation and reporting system. The Field Foreman is notified for maintenance activities that cannot be addressed on the spot.

Table 5-1 Response Plan for CO₂ Loss

Risk	Monitoring Plan	Response Plan
Tubing Leak	Monitor changes in tubing and annulus pressure; MIT for injectors	Well is shut in and workover crews respond within days
Casing Leak	Routine Field inspection; Monitor changes in annulus pressure, MIT for injectors; extra attention to high risk wells	Well is shut in and workover crews respond within days
Wellhead Leak	Routine Field inspection, SCADA system monitors wellhead pressure	Well is shut in and workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations	Maintain well kill procedures
Unplanned wells drilled through San Andres	Routine Field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells.	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Reservoir pressure in WAG headers; high pressure found in new wells	Re-enter and reseal abandoned wells
Pumps, valves, etc.	Routine Field inspection, SCADA	Workover crews respond within days
Overfill beyond spill points	Reservoir pressure in WAG headers; high pressure found in new wells	Fluid management along lease lines
Leakage through induced fractures	Reservoir pressure in WAG headers; high pressure found in new wells	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Reservoir pressure in WAG headers; high pressure found in new wells	Shut in injectors near seismic event
Diffuse leakage through the seal	Monitor injection pressure for unexplained changes in injection pressure that might indicate leakage	Investigate to determine if cement and steel construction is the issue. Well is shut in and workover crews respond within days.

5.10 Summary

The structure and stratigraphy of the San Andres reservoir in the DCF is ideally suited for the injection and storage of CO₂. The stratigraphy within the CO₂ injection zones is porous, permeable, and thick, providing ample capacity for long-term CO₂ storage. The reservoir is overlain by several intervals of impermeable geologic zones that form effective seals or “caps” to fluids in the reservoir.

In summary, based on a careful assessment of the potential risk of release of CO₂ from the subsurface, it has been determined that there are no leakage pathways at the DCF that are likely

to result in significant loss of CO₂ to the atmosphere. Further, given the detailed knowledge of the field and its operating protocols, it is concluded that any CO₂ leakage to the surface that could arise through either identified or unexpected leakage pathways would be detected and quantified.

6 Monitoring and Considerations for Calculating Site Specific Variables

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

6.1 For the Mass Balance Equation

6.1.1 General Monitoring Procedures

Flow rate, pressure, and gas composition data are monitored and collected from the DCF in centralized data management systems as part of ongoing operations. This data is monitored by qualified technicians who follow response and reporting protocols when the systems deliver notifications that data exceed statistically acceptable boundaries.

Metering protocols used at DCF follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association, and the Gas Processors Association, as appropriate. This approach is consistent with EPA GHGRP's Subpart RR, section §98.444(e)(3). These meters will be maintained routinely, operated continually, and will feed data directly to the centralized data collection systems. The meters meet the industry standard for custody transfer meter accuracy and calibration frequency.

6.1.2 CO₂ Received

As indicated in Figure 3-8, the volume of received CO₂ is measured using a commercial custody transfer meter at the point at which custody of the CO₂ from the Kinder Morgan CO₂ pipeline delivery system is transferred to the DCF. This meter measures flow rate continually. The transfer is a commercial transaction that is documented. CO₂ composition is governed by contract and the gas is routinely sampled. Fluid composition will be determined, at a minimum, quarterly, consistent with EPA GHGRP's Subpart RR, section §98.447(a). All meter and composition data are documented, and records will be retained for at least three years. No CO₂ is received in containers.

6.1.3 CO₂ Injected in the Subsurface

Injected CO₂ will be calculated using the flow meter volumes at the operations meter at the outlet of the RCF and the custody transfer meter at the CO₂ off-take point from the Kinder Morgan CO₂ Pipeline Delivery System.

6.1.4 CO₂ Produced, Entrained in Products, and Recycled

The following measurements are used for the mass balance equations in Section 8:

- CO₂ produced in the gaseous stage is calculated using the volumetric flow meters at the outlet of the separation facility (Figure 3-8 vessels, V-100, V-101, V-200, V-201, and V-300),
- CO₂ that is entrained in produced oil, as indicated in Figure 3-8, is calculated from routinely captured samples and volume is measured by the truck flow meter,
- Recycled CO₂ is calculated using the volumetric flow meter at the outlet of the RCF, which is an operations meter.

6.1.5 CO₂ Emitted by Surface Leakage

CapturePoint uses 40 CFR Part 98 Subpart W to estimate surface leaks from equipment at the DCF. Subpart W uses a factor-driven approach to estimate equipment leakage. An event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage to the surface is used. Additionally, CapturePoint uses 40 CFR Part 98 Subpart RR to report equipment leaks and vented emissions separately for injection and production.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet two objectives: 1) to detect problems before CO₂ leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the volumes of CO₂ leaked to the surface.

Monitoring for Potential Leakage from the Injection/Production Zone

In addition to the measures discussed in Section 5.9, both injection into and production from the reservoir will be monitored as a means of early identification of potential anomalies that could indicate leakage from the subsurface.

Injection plans (fluid rate, pressure, volume) are given to operations on a weekly basis. If injection pressure or rate measurements are outside the specified set points determined as part of each pattern injection plan, reservoir engineering will notify field personnel and they will investigate and resolve the problem. These excursions will be reviewed by well management personnel to determine if CO₂ leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or some other minor action is required), and there is no threat of CO₂ leakage. In the case of issues that are not readily resolved, more detailed investigation and response would be initiated, and support staff would provide additional assistance and evaluation.

Likewise, a forecast of the rate and composition of produced fluids is developed. Each producer well is assigned to a specific SAT and is isolated during each cycle for a well production test. This data is reviewed on a periodic basis to confirm that production is at the level forecasted. If there is a significant deviation from the plan, well management personnel investigate. If the issue

cannot be resolved quickly, a more detailed investigation and response would be initiated. If leakage in the flood zone were detected, an appropriate method would be used to quantify the involved volume of CO₂. This might include use of material balance equations based on known injected quantities and monitored pressures in the injection zone to estimate the volume of CO₂ involved.

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

In the event leakage from the subsurface occurred diffusely through the seals, the leaked gas would include H₂S, which would trigger the alarm on the personal monitors worn by field personnel as well as the various permanent H₂S monitors throughout the field at ground level. Such a diffuse leak from the subsurface has not occurred in the DCF. In the event such a leak was detected, personnel would determine how to address the problem. The personnel might use modeling, engineering estimates, and direct measurements to assess, address, and quantify the leakage.

Monitoring of Wellbores

DCF wells are monitored through daily pressure monitoring of the injection zone, monitoring of the annular pressure in wellheads, and routine maintenance and inspection.

Leaks from wellbores would be detected through the follow-up investigation of pressure anomalies, visual inspection, or the use of personal H₂S monitors and various permanent H₂S monitors throughout the field at ground level.

Anomalies in injection zone pressure may not indicate a leak, as discussed above. However, if an investigation leads to a need for further study, field personnel would inspect the equipment in question and determine the nature of the problem. If it is a simple matter, the repair would be made, and the volume of leaked CO₂ would be included in the 40 CFR Part 98 Subpart W report for the DCF. If more extensive repair were needed, the appropriate approach for quantifying leaked CO₂ using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be determined.

Anomalies in annular pressure or other issues detected during routine maintenance inspections would be treated in the same way. Field personnel would inspect the equipment in question and determine the nature of the problem. For simple matters the repair would be made at the time of inspection and the volume of leaked CO₂ would be included in the 40 CFR Part 98 Subpart W report for the DCF. If more extensive repairs were needed, the well would be shut in, a work order would be generated and the appropriate approach for quantifying leaked CO₂ using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be determined. The work order would serve as the basis for tracking the event for Green House Gas (GHG) reporting.

Because leaking CO₂ at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a visual inspection process in the area of the DCF is employed to detect unexpected releases from wellbores. Field personnel visit the surface facilities on a routine basis. Inspections may include tank levels, equipment status, lube oil levels, pressures and flow rates in the facility, and valves. Field personnel also check that injectors are on the proper WAG schedule and observe the facility for visible CO₂ or fluid line leaks.

Finally, the data collected by the H₂S monitors, which are always worn by field personnel and are located permanently throughout the field at ground level, is used as a last method to detect leakage from wellbores. The H₂S monitor's detection limit is 10 ppm; if an H₂S alarm is triggered, the first response is to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. As noted previously, H₂S is considered a proxy for potential CO₂ leaks in the field. Thus, detected H₂S leaks will be investigated to determine and, if needed, quantify potential CO₂ leakage.

Other Potential Leakage at the Surface

The same visual inspection process and H₂S monitoring system will be used to detect other potential leakage at the surface as it does for leakage from wellbores. Routine visual inspections are used to detect significant loss of CO₂ to the surface. Field personnel routinely visit surface facilities to conduct a visual inspection. Inspections may include review of tank level, equipment status, lube oil levels, pressures and flow rates in the facility, valves, ensuring that injectors are on the proper WAG schedule, and also conducting a general observation of the facility for visible CO₂ or fluid line leaks. If problems are detected, field personnel would investigate, and complete any maintenance that is required. In addition to these visual inspections, the results of the personal H₂S monitors worn by field personnel and the permanent H₂S monitors throughout the field at ground level will be used as a supplement for smaller leaks that may escape visual detection.

If CO₂ leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, steps are taken to prevent further leaks.

6.1.6 CO₂ emitted from equipment leaks and vented emissions of CO₂ from surface equipment located between the injection flow meter and the injection wellhead

CapturePoint evaluates and estimates leaks from injection equipment and the CO₂ content of any vented CO₂, as required under 40 CFR Part 98 Subpart W.

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

CapturePoint evaluates and estimates leaks from production equipment and the CO₂ content of produced oil, and any vented CO₂, as required under 40 CFR Part 98 Subpart W.

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

At the end of the Specified Period, injecting CO₂ for the subsidiary purpose of establishing the long-term storage of CO₂ in the DCF will cease. Sometime after the end of the Specified Period, a request to discontinue monitoring and reporting will be submitted. The request will demonstrate that the amount of CO₂ reported under 40 CFR §98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage.

At that time, the request will be supported with years of data collected during the Specified Period. This demonstration will provide the information necessary for the EPA Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

- Data comparing actual performance to predicted performance (purchase, injection, production) over the monitoring period,
- An assessment of the CO₂ leakage detected, including the discussion of the estimated amount of CO₂ leaked and the distribution of emissions by leakage pathway,
- A demonstration that future operations will not release the volume of stored CO₂ to the surface,
- A demonstration that there has been no significant leakage of CO₂; and,
- An evaluation of the reservoir pressure demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

7 Determination of Baselines

Ongoing operational monitoring has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO₂ leakage. Data systems are used primarily for operational control and monitoring, which are set to capture more information than is necessary for reporting in the Annual Subpart RR Report. The necessary system guidelines to capture the information that is relevant to identify possible CO₂ leakage will be developed. The following describes the approach to collecting this information.

Visual Inspections

As field operators conduct routine inspections and repairs, the Field Foreman is notified for maintenance activities that cannot be addressed on the spot. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation (the responsible party will be provided in the monitoring plan, as required under Subpart A, §98.3(g)). The Annual Subpart RR Report will provide an estimate of CO₂ emissions. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

Personal H₂S Monitors

H₂S monitors are worn by all field personnel. The H₂S monitors detect concentrations of H₂S up to 500 ppm in 0.1 ppm increments and will sound an alarm if the detection limit exceeds 10 ppm. The current H₂S concentration in the produced gas is 5,709 ppm taken from the recycle compressor inlet and 205 ppm in the produced oil. If an H₂S alarm is triggered, the immediate response is to protect the safety of the personnel, and the next step is to safely investigate the source of persistent alarms. CapturePoint considers H₂S to be a proxy for potential CO₂ leaks in the field. The person responsible for MRV documentation will receive notice of all incidents where H₂S is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO₂ emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

As stated before, there are various permanent H₂S monitors throughout the field at ground level to detect H₂S and alarm if a limit is reached.

Injection Rates, Pressures and Volumes

Target injection rate and pressure for each injector are developed within the permitted limits based on the results of ongoing pattern balancing. The injection targets are submitted to field operations. Field operations flags whenever statistically significant deviations from the targeted ranges are identified. The set points are designed to be conservative, because it is preferable to have too many flags rather than too few. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO₂ leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions. The Annual Subpart RR Report will provide an estimate of CO₂ emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

Production Volumes and Compositions

A general forecast of production volumes and composition is developed which is used to periodically evaluate performance, refine current and projected injection plans, and the forecast. This information is used to make operational decisions but is not recorded in an automated data system. The MRV plan implementation lead will review the data and identify those that could result in CO₂ leakage. Should such events occur, leakage volumes would be calculated following the approaches described in Sections 5 and 6. Impact to Subpart RR reporting will be addressed, if deemed necessary.

8 Determination of Sequestration Volumes Using Mass Balance Equations

Per subpart RR requirements, all flow meters for CO₂ and oil measurement are located directly downstream of each separation point. To account for the potential error that would result if volume data from flow meters at each injection and production well were utilized, the data from custody transfer meters, operations meters on the main system pipelines, and at all points of separation, is used to determine injection and production volumes used in the mass balance of the system. This issue arises because while each meter has a small but acceptable margin of error,

this error would become significant if data were taken from all the well head meters within the DCF (See Figure 3-8).

The following sections describe how each element of the mass-balance equation (Equation RR-11) will be calculated.

8.1 Mass of CO₂ Received

Equation RR-2 will be used as indicated in Subpart RR §98.443 to calculate the mass of CO₂ at the receiving custody transfer meter from the Trinity CO₂ pipeline delivery system. The volumetric flow at standard conditions will be multiplied by the CO₂ concentration and the density of CO₂ at standard conditions to determine mass.

The Mass of the CO₂ Received will be determined using Equation RR-2 as follows:

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

where:

$CO_{2T,r}$ = Net annual mass of CO₂ received through flow meter r (metric tons).

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO₂ concentration measurement in flow for flow meter r in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

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

- All delivery to the DCF is used within the unit so no quarterly flow redelivered, and $S_{r,p}$ will be zero ("0").
- Quarterly CO₂ concentration will be taken from the gas measurements.

8.2 Mass of CO₂ Injected into the Subsurface

The equation for calculating the Mass of CO₂ Injected into the Subsurface at the DCF is equal to the sum of the Mass of CO₂ Received as calculated in RR-2 of §98.443 (section 8.1 above) and the Mass of CO₂ Recycled calculated using measurements taken from the flow meter located at the outlet of the RCF (see Figure 3-8). As previously explained, using data at each injection well would give an inaccurate estimate of total injection volume due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

The Mass of CO₂ Recycled will be determined using equations RR-5 as follows:

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

where:

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = CO₂ concentration measurement in flow for flow meter u in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

The total Mass of CO₂ Injected will be the sum of the Mass of CO₂ Received (RR-2) and Mass of CO₂ Recycled (RR-5).

The Mass of CO₂ Injected will be determined using equations RR-6 as follows:

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

where:

CO_{2I} = Total annual CO₂ mass injected (metric tons) through all injection wells.

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

u = Flow meter.

8.3 Mass of CO₂ Produced

The Mass of CO₂ Produced at the DCF will be calculated using the measurements from the flow meters at the inlet to RCF and the custody transfer meter for oil sales rather than the metered data from each production well. Again, using the data at each production well would give an inaccurate estimate of total injection due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

Equation RR-8 in §98.443 will be used to calculate the Mass of CO₂ Produced from all production wells as follows:

$$CO_{2,w} = \sum_{p=1}^4 (Q_{p,w}) * D * C_{CO_2,p,w} \quad (\text{Eq. RR-8})$$

Where:

$CO_{2,w}$ = Annual CO₂ mass produced (metric tons) through separator w.

$Q_{p,w}$ = Volumetric gas flow rate measurement for separator w in quarter p at standard conditions (standard cubic meters).

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

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

p = Quarter of the year.

w = Separator.

For Equation RR-9 in §98.443 the variable X will be measured as follows:

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

Where:

CO_{2P} = Total annual CO₂ mass produced (metric tons) through all separators in the reporting year.

$CO_{2,w}$ = Annual CO₂ mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO₂ in produced oil or other fluid divided by the CO₂ separated through all separators in the reporting year (weight percent CO₂, expressed as a decimal fraction)

w = Separator

8.4 Mass of CO₂ Emitted by Surface Leakage

Surface Leakage will be calculated and reported using an approach that is tailored to specific leakage events including calculation methodologies in 40 CFR Part 98 Subpart W for emissions and leaks from equipment. CapturePoint is prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO₂ leaked to the surface will depend on several site- specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

The process for quantifying leakage will entail using the best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are described in Sections 5.9 and 6. In the event leakage to the surface occurs, leakage amounts would be quantified and reported, and records that describe the methods used to estimate or measure the volume leaked as reported in the Annual Subpart

RR Report would be retained. Volumes for CO_{2E} (surface leakage) and CO_{2FI} (equipment leakage and vented emissions) are calculated separately and differently.

Equation RR-10 in §98.443 will be used to calculate and report the Mass of CO₂ emitted by Surface Leakage:

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

Where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

8.5 Mass of CO₂ Emitted by Facility Emergency Vent

The Mass of CO₂ emitted by the Emergency Vent at the DCF will be calculated using the measurements from the flow meter at the vent. That volume will be added to CO_{2FI} which is the total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

Equation RR-8 in §98.443 will be used to calculate the Mass of CO₂ emitted through the emergency vent as follows:

$$CO_{2w} = \sum_{p=1}^4 (Q_{p,w}) * D * C_{CO_2,p,w} \quad (\text{Eq. RR-8})$$

Where:

CO_{2w} = Annual CO₂ mass produced (metric tons) through separator w.

Q_{p,w} = Volumetric gas flow rate measurement for separator w in quarter p at standard conditions (standard cubic meters).

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

CCO_{2,p,w} = CO₂ concentration measurement in flow for separator w in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator

8.6 Mass of CO₂ Sequestered and Reported in Subsurface Geologic Formation

Equation RR-11 in §98.443 will be used to calculate the Mass of CO₂ Sequestered and Reported in Subsurface Geologic Formations in the Reporting Year as follows:

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

where:

CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

CO_{2P} = Total annual CO₂ mass produced (metric tons) in the reporting year.

CO_{2E} = Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

CO_{2FP} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

9 MRV Plan Implementation Schedule

This MRV plan will be implemented starting October 2023 or within 90 days of EPA approval, whichever occurs later. Other GHGRP reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. It is

anticipated that the MRV plan will be in effect during the Specified Period, during which time the DCF will be operated with the subsidiary purpose of establishing long-term containment of a measurable quantity of CO₂ in subsurface geological formations at the DCF. It is anticipated to establish that a measurable amount of CO₂ injected during the Specified Period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be prepared and a request to discontinue monitoring and reporting under this MRV plan will be submitted. See 40 C.F.R. §98.441(b)(2)(ii).

10 Quality Assurance (QA) Program

10.1 QA Procedures

The requirements of §98.444 (a) – (d) have been incorporated in the discussion of mass balance equations. These include the following provisions.

CO₂ Received and Injected

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

CO₂ Produced

- The point of measurement for the quantity of CO₂ produced from oil or other fluid production wells is a flow meter directly downstream of each separator that sends a stream of gas into a recycle or end use system.
- The produced gas stream is sampled annually downstream of the flow meter used to measure flow rate of that gas stream and measure the CO₂ concentration of the sample.

CO₂ Emissions from Equipment Leaks and Vented Emissions of CO₂

These volumes are measured in conformance with the monitoring and QA requirements specified in subpart W of 40 CFR Part 98.

Flow Meter Provisions

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

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

Concentration of CO₂

CO₂ concentration is measured using an appropriate standard method. Further, all measured volumes of CO₂ have been converted to standard cubic meters at a temperature of 60 degrees

Fahrenheit and at an absolute pressure of 1 atmosphere, including those used in Equations RR-2, RR-5, and RR-8 in Section 8.

10.2 Missing Data Procedures

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

- A quarterly flow rate of CO₂ received that is missing would be estimated using invoices or using a representative flow rate value from the previous measured period.
- A quarterly CO₂ concentration of a CO₂ stream received that is missing would be estimated using invoices or using a representative concentration value from the previous measured period.
- A quarterly quantity of CO₂ injected that is missing would be estimated using a representative quantity of CO₂ injected from the previous measured period at a similar injection pressure.
- For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.
- The quarterly quantity of CO₂ produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO₂ produced from the previous measured period.

10.3 MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters of the CO₂-EOR operations in the DCF that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in §98.448(d).

11 Records Retention

The record retention requirements specified by §98.3(g) will be followed. In addition, the requirements in Subpart RR §98.447 will be met by maintaining the following records for at least three years:

- Quarterly records of CO₂ received at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of produced CO₂, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO₂ including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
- Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

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

12 Appendix

12.1 Well Identification Numbers

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

The following terms are used:

Well Type:

- SWS refers to wells that supply water.
- PROD_OIL refers to wells that produce oil.
- INJ_WAG refers to wells that inject water or CO₂.
- INJ_SWD refers to wells that inject water for disposal.
- P&A refers to plugged and abandoned wells.

Well Status:

- ACTIVE refers to active wells.
- INACTIVE refers to wells that have been completed but are not in use.
- SHUT_IN refers to wells that have been temporarily idled or shut in.
- TEMP_AB refers to wells that have been temporarily abandoned.

Table 12-1 Well Status Table

Well Name	API Number	Well Type	Status
GAU #1WS	42165339890000	SWS	INACTIVE
GAU #2W	42165106400000	P&A	INACTIVE
GAU #3	42165106340000	P&A	INACTIVE
GAU #4	42165103790000	PROD_OIL	SHUT_IN
GAU #5	42165106070000	PROD_OIL	INACTIVE
GAU #6	42165106530000	P&A	INACTIVE
GAU #6R	42165367760000	PROD_OIL	INACTIVE
GAU #7W	42165339900000	INJ_WAG	ACTIVE
GAU #8W	42165339910000	INJ_WAG	SHUT_IN
GAU #9W	42165339920000	INJ_WAG	ACTIVE
GAU #10	42165106510000	P&A	INACTIVE
GAU #10R	42165367820000	PROD_OIL	ACTIVE
GAU #11	42165106060000	P&A	INACTIVE
GAU #11R	42165367490000	PROD_OIL	ACTIVE
GAU #12	42165102070000	P&A	INACTIVE
GAU #12R	42165367510000	PROD_OIL	ACTIVE
GAU #13	42165003830000	PROD_OIL	ACTIVE

Well Name	API Number	Well Type	Status
GAU #14W	42165317930000	INJ_WAG	SHUT_IN
GAU #15	42165101300000	PROD_OIL	INACTIVE
GAU #16W	42165106270000	INJ_SWD	ACTIVE
GAU #17W	42165339930000	INJ_WAG	ACTIVE
GAU #18	42165103780000	PROD_OIL	ACTIVE
GAU #19	42165106460000	PROD_OIL	SHUT_IN
GAU #20W	42165008790000	P&A	INACTIVE
GAU #22W	42165352720000	INJ_WAG	ACTIVE
GAU #23W	42165367500000	INJ_WAG	ACTIVE
GAU #24	42165106440000	PROD_OIL	INACTIVE
GAU #25	42165367550000	PROD_OIL	ACTIVE
GAU #26	42165367530000	PROD_OIL	ACTIVE
GAU #27	42165367540000	PROD_OIL	ACTIVE
GAU #71	42165384590000	PROD_OIL	ACTIVE
RH #28W	42165367610000	INJ_WAG	ACTIVE
RH #29W	42165367620000	INJ_WAG	ACTIVE
RH #30W	42165367630000	INJ_WAG	ACTIVE
RH #31	42165367660000	PROD_OIL	ACTIVE
RH #32	42165367670000	PROD_OIL	ACTIVE
RH #33	42165367520000	PROD_OIL	ACTIVE
RH #34	42165367890000	PROD_OIL	SHUT_IN
RH #70	42165384430000	PROD_OIL	ACTIVE

12.2 Regulatory References

Regulations cited in this plan:

- TAC Title 16 Part 1 Chapter 3 Oil & Gas Division

[https://texreg.sos.state.tx.us/public/readtac\\$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y](https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y)

- TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual

<https://www.rrc.texas.gov/oil-and-gas/publications-and-notices/manuals/injection-storage-manual/>

12.3 Abbreviations and Acronyms

AMA - Active Monitoring Area

API - American Petroleum Institute

AoR - Area of Review

Bcf – 1 Billion Standard Cubic Feet of Gas

CO₂ - Carbon Dioxide

DCF – Denver City Fields

DPC - Dimensionless Performance Curve

EPA - Environmental Protection Agency

EOR - Enhanced Oil Recovery

ESP - Electrical Submersible Pump

FPP - Formation Parting Pressure (psi)

GAU - George Allen Unit

GHGRP - Greenhouse Gas Reporting Program

H₂S – Hydrogen Sulfide

HCPV - Hydrocarbon Pore Volume

IWR - Injection to Withdrawal Ratio

MMA - Maximum Monitoring Area

MRV Plan - Monitoring, Reporting and Verification Plan

MCF – 1 Thousand Standard Cubic Feet of Gas

MIT – Mechanical Integrity Test

MMCF – 1 Million Standard Cubic Feet of Gas

NIST - National Institute of Standards and Technology

QA – Quality Assurance

RB - Reservoir Barrels

RCF - Recycle Compression Facility

RH - Ruth Hudson Lease

SAT – Satellite Test

TAC - Texas Administrative Code

TRRC - Texas Railroad Commission - Oil and Gas Division

UIC – Underground Injection Control

12.4 Conversion Factors

CapturePoint reports CO₂ 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 CO₂ mass from CO₂ 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 CO₂ 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 CO₂ of 0.002641684 lb-moles per cubic foot. Converting the CO₂ density in units of metric tonnes per cubic foot:

$$Density_{CO_2} \left(\frac{MT}{ft^3} \right) = Density_{CO_2} \left(\frac{lb - moles}{ft^3} \right) \times MW_{CO_2} \times \frac{1 MT}{2,204.62 lbs}$$

Where:

$Density_{CO_2}$ = Density of CO₂ in metric tonnes (MT) per cubic foot

$Density_{CO_2}$ = 0.002641684

MW_{CO_2} = 44.0095

$Density_{CO_2} = 5.2734 \times 10^{-5} \frac{MT}{ft^3}$ or $5.2734 \times 10^{-2} \frac{MT}{Mcf}$

The conversion factor 5.2734×10^{-2} MT/Mcf is used to convert CO₂ volumes in standard cubic feet to CO₂ mass in metric tonnes.

Request for Additional Information: Denver City Fields
February 5, 2024

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.	3.5	17	“DPCs derived from the analogous Wasson San Andres field were used to project CO2-EOR in the Denver City Field” In the MRV plan, please elaborate/explain why these fields can be considered analogous for this purpose.	Included “Like Wasson, the DCF is located on the Northwest shelf of the Permian Basin and produces from a San Andres dolomite reservoir at a depth of about 5,000 feet making them analogous.
2.	5.0	22-28	In the previous RFAI, the following was asked: “In addition to listing the possible leakage pathways and their monitoring strategies, please provide a clear characterization of the likelihood, magnitude, and timing of leakage for each potential leakage pathway, specifically for pipelines and surface equipment. For example, Section 5.4 states that the risk of migration from older wells has been sufficiently mitigated, but it does not discuss the likelihood, magnitude, or timing of potential CO₂ leakage through previous operations.” Sections 5.2, 5.3, and 5.6 still do not provide a clear characterization of the magnitude of leakage for the potential leakage pathways discussed therein. See 40 CFR 98.488(a)(2). These characterizations should address not only the likelihood of leakage but also the expected timing in which they could occur and the anticipated magnitude that could occur.	Added language to Sections 5.2, 5.3 and 5.6 indicating that the magnitude of leakage is very low.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	6.1.5, 8.4	30, 38	In the previous RFAI, the following was asked: “Please review the MRV plan to ensure that it is clear that the variables CO_{2E} (surface leakage) and CO_{2FI} (equipment leakage and vented emissions) are calculated separately and differently See 40 CFR 98.443(f)(1). Furthermore, please note that emissions reported under subpart W are not duplicative with leakage/emissions used in subpart RR. Emissions reported in subpart RR are used in calculating a net sequestration amount and are not added to a facility’s total emissions. Please revise the above statement as necessary to reflect this.” However, the following phrases still appear in the text. We recommend removing or clarifying them, as emissions from surface leakage reported under subpart RR are not rolled up into a facility’s total emissions. It is possible that the same emissions would be accounted under both subpart RR and subpart W. <i>“The Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.”</i> <i>“Further, the Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.”</i>	Removed both comments.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	8.5	39	<i>"Q_{p,w} = Volumetric gas flow rate measurement for meter w in quarter p at standard conditions (standard cubic meters)."</i> <i>"CCO_{2,p,w} = CO₂ concentration measurement in flow for meter w in quarter p (vol. percent CO₂, expressed as a decimal fraction)."</i> Per 40 CFR 98.443(d)(2), this variable should be, "Q_{p,w} = Volumetric gas flow rate measurement for separator w in quarter p at standard conditions (standard cubic meters)," and "CCO_{2,p,w} = CO₂ concentration measurement in flow for separator w in quarter p (vol. percent CO₂, expressed as a decimal fraction)." Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Corrected both from "meter" to "separator": Q_{p,w} = Volumetric gas flow rate measurement for separator w in quarter p at standard conditions (standard cubic meters). CCO_{2,p,w} = CO₂ concentration measurement in flow for separator w in quarter p (vol. percent CO₂, expressed as a decimal fraction).

CAPTUREPOINT LLC
DENVER CITY FIELD
SUBPART RR MONITORING, REPORTING AND
VERIFICATION (MRV) PLAN

October 2023

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1 Introduction

CapturePoint LLC operates a Carbon Dioxide Enhanced Oil Recovery (CO₂-EOR) project in the Denver City Field (DCF) located in Gaines County, Texas, approximately four miles southwest of the town of Denver City, Texas and less than two miles west of the Denver Unit of the giant Wasson San Andres Fields for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO₂) with a subsidiary or ancillary purpose of geologic sequestration of CO₂ in a subsurface geologic formation. The DCF is comprised of the George Allen Unit (GAU) which contains the Ruth Hudson Lease (RH). Like Wasson production is from the San Andres formation at an average depth of 5,000 feet. The Monitoring, Reporting and Verification (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 CO₂ sequestered at the Denver City Fields during a specified period of injection.

2 Facility Information

2.1 Reporter Number

576482 – Denver City Fields

2.2 UIC Permit Class

The Oil and Gas Division of the Texas Railroad Commission (TRRC) regulates oil and gas activity in Texas. All wells in the DCF (including production, injection, and monitoring wells) are permitted by TRRC through Texas Administrative Code (TAC) Title 16 Chapter 3. TRRC has primacy to implement the Underground Injection Control (UIC) Class II program in the state for injection wells. All EOR injection wells in the DCF are currently classified as UIC Class II wells.

2.3 Existing Wells

Wells in the DCF are identified by name and number, American Petroleum Institute (API) number, type, and status. The list of wells as of March 2023 is included in Section 12.1. Any changes in wells will be indicated in the annual subpart RR submission.

3 Project Description

This project takes place in the DCF, an oil field located in West Texas that was first produced more than 60 years ago. The DCF is comprised of the GAU which contains the RH. The two are adjacent to each other, produce oil and gas from the same geologic formations and structure, and are under the sole operatorship of CapturePoint LLC. The geology, facilities/equipment, and operational procedures are similar for both in the DCF. In addition, the two properties share the same CO₂ recycle and water injection facilities as well as the injection piping system for both CO₂ and water. Because of these common facilities and common reservoir, one MRV Plan is being prepared for the two properties in the DCF and any important differences between the two properties will be noted in the MRV plan. CO₂ flooding was initiated in 2007 in the GAU and in 2012 in the RH. The field is well characterized and is suitable for secure geologic storage in the San Andres formation. CapturePoint LLC uses a water alternating with gas (WAG) injection process and maintains an injection to withdrawal ratio (IWR) at or near 1.

3.1 Project Characteristics

The DCF was discovered in 1956 and started production in the same year. The DCF consists of one unit (GAU) and one lease (RH). The GAU began to produce in May 1956 and the waterflood was initiated in September 1989. CO₂ flooding was initiated in December 2007, in both the Main Pay and Residual Oil Zone (ROZ). The RH initiated a waterflood in March 2008 and began to produce in November 2008. CO₂ flooding was initiated in December 2012, also in the Main Pay and ROZ.

A long-term forecast for both the GAU and RH was developed using a dimensionless performance curve (DPC) approach. Using this approach, approximately 2.0 million tonnes of stored CO₂ is forecasted over the life of the project. Figure 3-1 shows actual and projected CO₂ injection, production, and stored volumes in DCF.

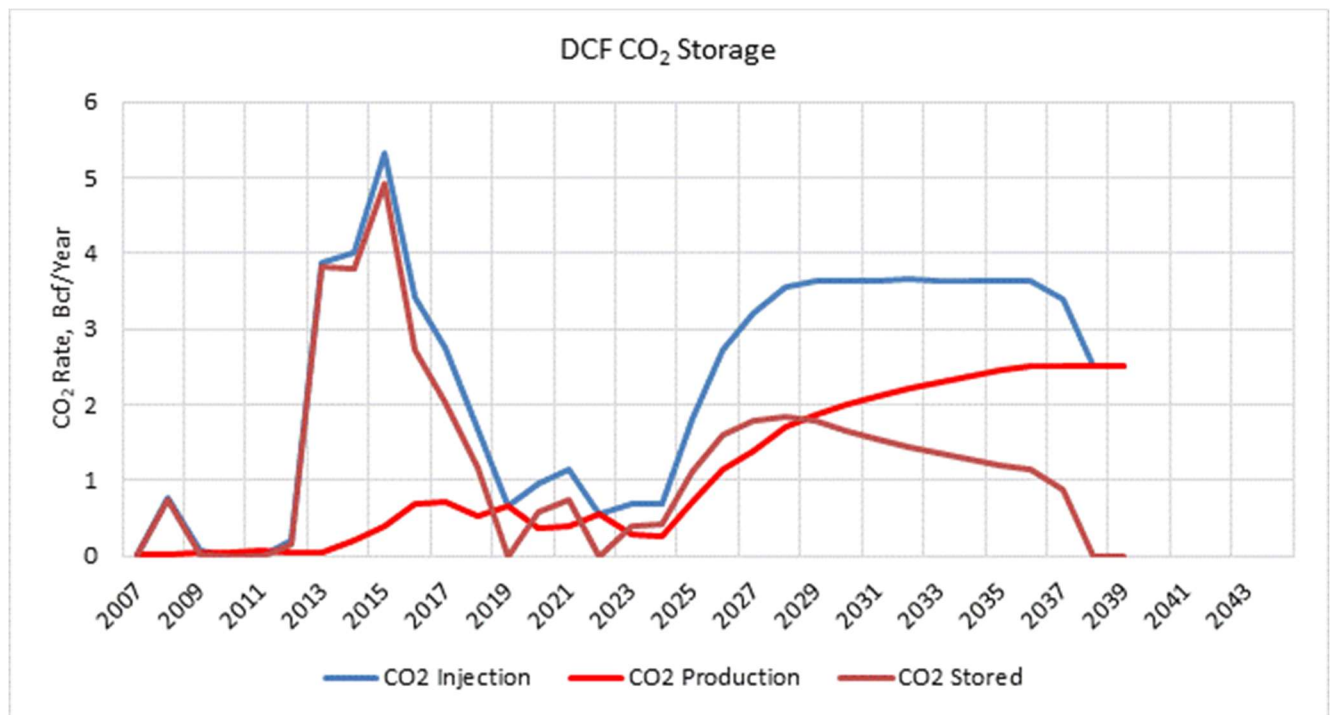


Figure 3-1 DCF Historic and Forecast CO₂ Injection, Production, and Storage

3.2 Environmental Setting

The DCF is located in the NE portion of the Central Basin Platform in West Texas (See Figure 3-2). This map also shows the location of the Denver Unit and other Wasson San Andres Units. The DCF is shown by the green dot.

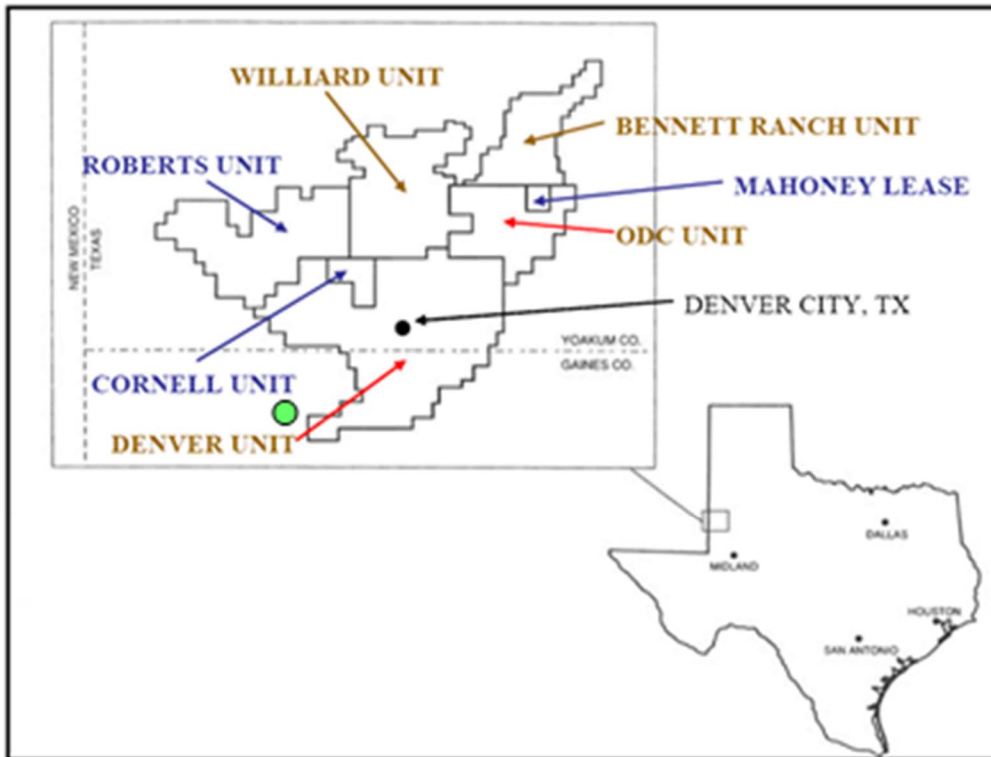


Figure 3-2 Location of DCF in West Texas

Like Wasson, the DCF produces from a San Andres dolomite reservoir at a depth of about 5,000 feet. In contrast to Wasson, DCF is a smaller oil accumulation with a thin mobile oil column trapped by a low relief anticlinal structure as shown in Figure 3-3. The Wasson field has produced over two billion barrels of oil to date from the San Andres while the DCF has produced 2.06 million barrels of oil to 2022.

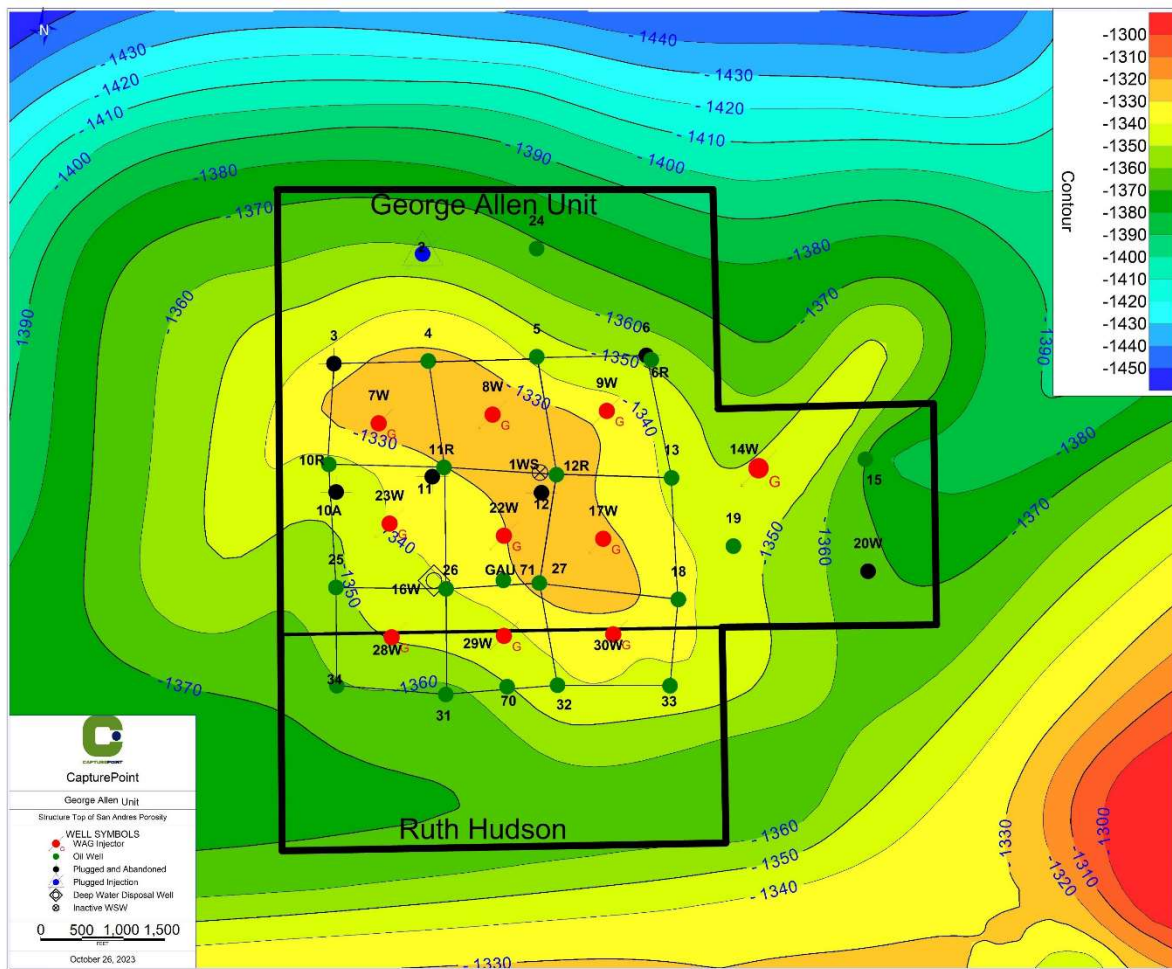


Figure 3-3 Local Area Structure on Top of San Andres for DCF

In the DCF there is a thin mobile oil column. Beneath the conventional oil column there is a thick, porous section with transition zone/residual oil (TZ/ROZ) that can only be produced via tertiary recovery methods, primarily CO₂ injection. This thick TZ/ROZ zone as found in the Wasson field gives a sizeable target for tertiary recovery (over 300 feet gross thickness).

Oil in the TZ/ROZ is currently being produced via CO₂ injection. Nine 40-acre patterns were prepared to inject CO₂ in this zone in the DCF. The presence of thick residual zones in the San Andres of the Permian Basin is widespread. Lindsay (2001), Melzer (2005), Melzer (2006), and Koperna and Kuuskraa (2006; 1&2) discuss the possible origins and the extent of residual oil zones in the Permian Basin. Brown (2001) discusses the ROZ in the area and its possible origin. The residual zone in the DCF has better porosity and permeability and is much thicker than the mobile oil zone which produced during primary and secondary (waterflood) recovery. This is often the case in residual oil zones, particularly those found in smaller fields with thinner oil columns. This gives us a large resource in which to economically sequester large volumes of CO₂, as CO₂ can both be stored and utilized for oil recovery in the extensive residual oil zones found in the San Andres in the Permian Basin.

The oil saturation profile found in the DCF/Wasson area is shown below in Figure 3-4 from Koperna and Kuuskraa (2006; 2):

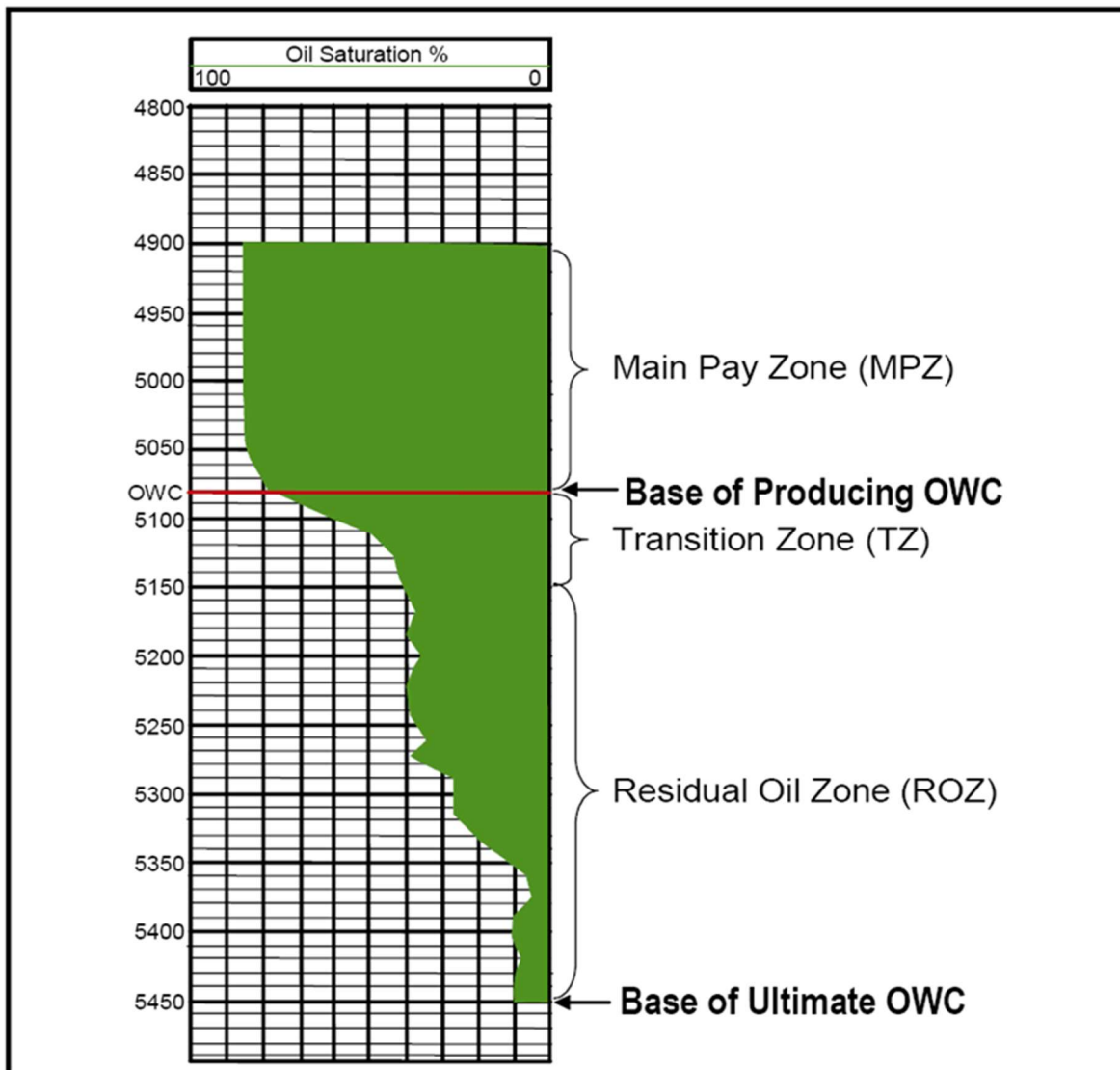


Figure 3-4 Saturation Profile of San Andres

Due to hydrodynamic flow in the San Andres aquifer, a ROZ was created and is under CO₂ flood along with the Main Pay Zone in the San Andres Formation.

Once the CO₂ flood is complete and injection ceases, the remaining mobile CO₂ will rise slowly upward, driven by buoyancy forces. There is more than enough pore space (188 million reservoir barrels (MRB)) to sequester the planned CO₂ injection (27.8 million reservoir barrels). The amount of CO₂ injected will not exceed the reservoir's secure storage capacity and, consequently, the risk that CO₂ could migrate to other reservoirs in the Central Basin Platform is negligible. The volume of CO₂ storage is based on the estimated total pore space within the DCF. The total pore space within the DCF, from the top of the reservoir down to the base of the ROZ, is calculated to be 188 million reservoir barrels (MRB). This is the volume of rock multiplied by porosity. Table 3-1 below shows the conversion of this amount of pore space into an estimated maximum volume of

approximately 254 billion cubic feet (Bcf) (13.4 million tonnes) of CO₂ storage in the reservoir. CO₂ will occupy only 15% of the total calculated storage capacity by the year 2037 based on the projected forecast.

Table 3-1 Calculation of Maximum Volume of CO₂ Storage Capacity at DCF

Top of Main Pay to Bottom of Residual Oil Zone (ROZ)	
Variables	DCF Outline
Pore Volume (RB)	188,396,478
BCO₂ (RB/MCF)	0.407
S_{wirr}	0.35
S_{or} CO₂	0.10
Max CO₂ (MCF)	254,589,835
Max CO₂ (BCF)	254

$$\text{Max CO}_2 = \text{Pore Volume} * (1 - S_{wirr} - S_{or} \text{ CO}_2) / \text{BCO}_2$$

Where:

Max CO₂ = the maximum amount of storage capacity

Pore Volume = Total pore space in reservoir barrels (RB)

BCO₂ = the formation volume factor for CO₂

S_{wirr} = the irreducible water saturation

S_{or} CO₂ = the irreducible oil saturation

Reservoir management is employed on a constant basis to obtain the maximum possible economic recovery from a reservoir based on facts, information, and knowledge. A reservoir management strategy that is used in CO₂ floods is the implementation of water curtain injectors. This will be utilized in the DCF to create a pressure barrier or “curtain” to contain the injected CO₂ to the area selected for production. Water curtain injection is an efficient method of maintaining and controlling lateral migration of fluids to assure that CO₂ does not cross structurally deficient locations. Injected fluids (CO₂) stay in the reservoir within the DCF unit boundary and do not move to adjacent areas.

Given that in DCF the confining zone has proved competent over both millions of years and in the current CO₂ flooding, and that the DCF has ample storage capacity, there is confidence that stored CO₂ will be contained securely within the reservoir.

3.3 Geologic Setting/Stratigraphic Column

The George Allen/Wasson San Andres fields are located on the Northwest shelf of the Permian Basin (Figure 3-5).

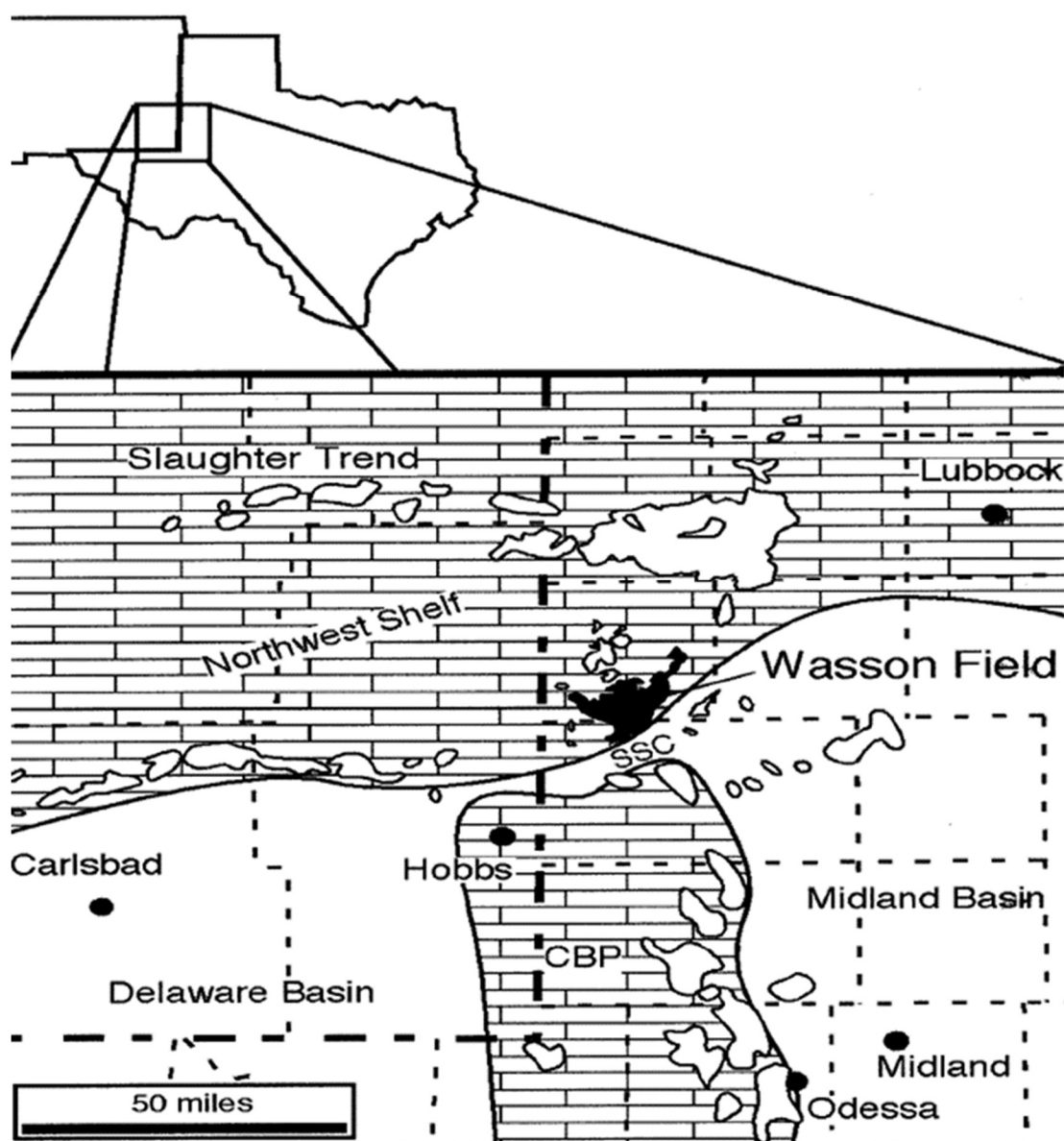


Figure 3-5 Map of Northwest shelf of the Permian Basin

The Wason field is shown in black. Other San Andres fields are outlined. San Andres "shelf" facies are indicated by the brick pattern. "CBP" refers to the "Central Basin Platform" a major structural feature that separates the Delaware Basin from the Midland Basin. "SSC" refers to the "San Simon Channel" a feature which allowed seawater circulation between the shallow restricted shelf areas of the Northwest Shelf and the Central Basin Platform.

Figure 3-6 below shows the thickness and broad extent of the porous facies in the San Andres formation.

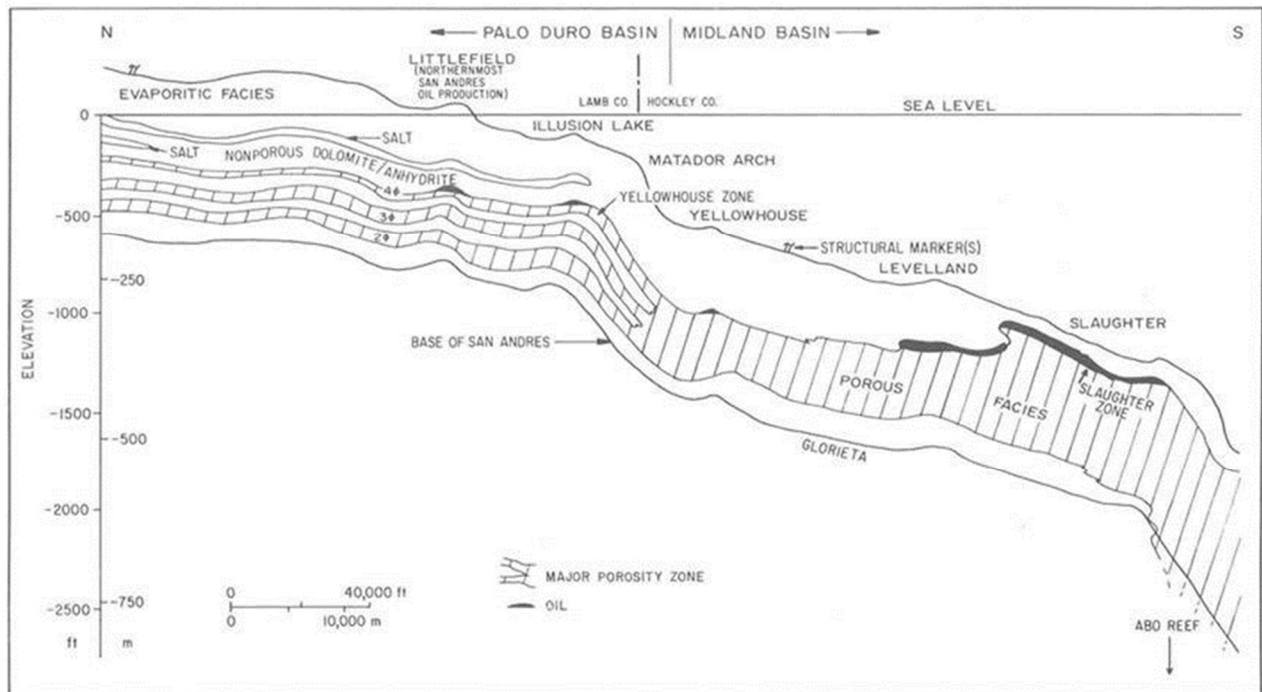


Figure 3-6 Cross section of lower San Andres Formation, Northern Shelf, showing porosity relationships.

A typical stratigraphic section for the area is shown below in Figure 3-7.

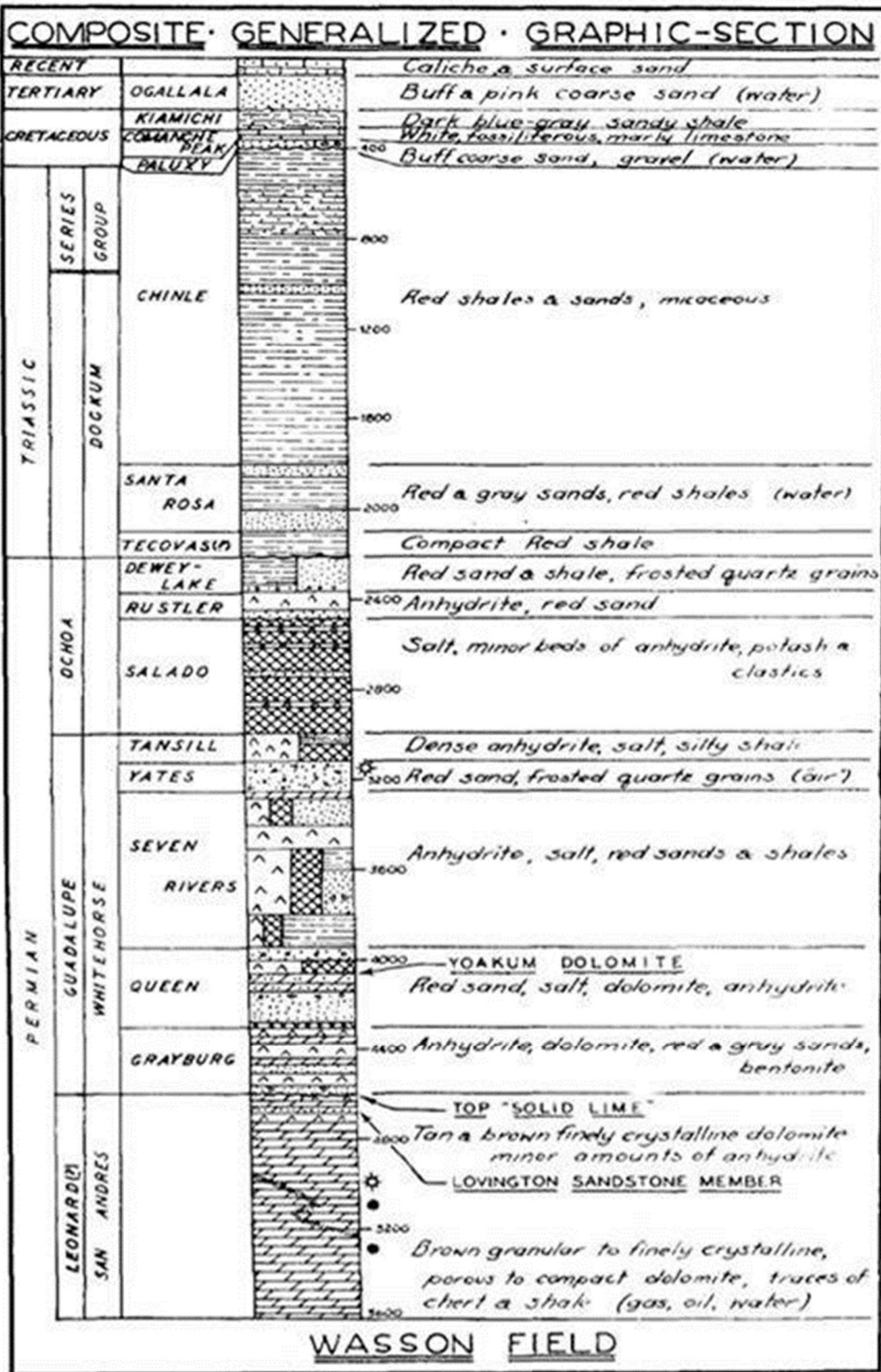


Figure 3-7 Composite generalized stratigraphic section.

The stratigraphy and facies of the Upper Permian on the Northwest Shelf and Central Basin Platform is quite uniform. The Upper Permian consists of a dominate thick and porous shallow marine carbonate facies that was later dolomitized as the San Andres Group prograded out into the basin. Continuation of the regressive sequence during the Upper Permian, defined as the Whitehorse group, caps the San Andres Group with tidal flat muds and tight exposed shelf

carbonates, along with restricted evaporites. These facies within the Grayburg, Queen and Seven Rivers formation serve as widespread and efficient seals for both hydrocarbons and CO₂ trapping.

The notable thing about the Upper Permian rocks described here is that there are multiple and thick intervals that should eliminate the possibility of any vertical migration of fluids or gases from the San Andres reservoir to the surface.

The first seal is the Upper San Andres which consists of dense, fine crystalline dolomite and anhydrite, devoid of any porosity or permeability, deposited on the tidal flats of a broad, restricted shelf. Where the porous, shallow water carbonate facies of the Lower San Andres pinch out and interfinger with these rocks a series of stratigraphic traps is formed in the northern part of the Northwest Shelf. The Levelland-Slaughter-Chaveroo-Cato San Andres fields are found in this trend. A similar porosity pinches out, on the interior of the Central Basin platform, controls the widespread San Andres production found on the eastern margin of the Central Basin platform. These widespread producing trends attest to sealing capacity of the Upper San Andres anhydrous dolomite facies both vertically and laterally.

Above the San Andres are a series of restricted/exposed shelf facies consisting of tight, anhydrous dolomite, anhydrite, salt, and thin sandstones of the Upper Guadalupian Grayburg, Queen, Seven Rivers, Yates and Tansill formations. The sandstones sometimes have porosity and permeability but are often cemented by salt and are non-permeable. Where permeable, they offer no chance for vertical migration of fluids or gases as they are inter-layered with impermeable salt, anhydrite, and anhydrous dolomite.

Following the Tansill, the Ochoan, Upper Permian evaporites of the Salado and Rustler formations exist. The Salado is roughly 600-700 feet thick in the Wasson/George Allen area and consists dominantly of halite with some thin beds of potash and anhydrite and a few very thin layers of red mud, silt, and fine sand. Being widespread, thick, and impermeable, this formation alone should certainly stop the vertical migration of any fluids or gases from the subsurface to the surface. Even if fractured, the salt will flow and seal any open cracks. It is followed by the Rustler formation; 60 feet of dense, white anhydrite at the top overlying 30 feet of red shale interbedded with anhydrite; another capstone, on top a over 2,500 feet of mostly impermeable rock.

The Permian ends with the Dewey Lake formation which consists of red gypsum cemented sandstone and red shales.

Above the Permian unconformity are the Triassic Tecovas red shale and then the Santa Rosa formation which contains fresh water bearing sandstones. These deposits are followed by the micaceous red shales and sands of the Chinle formation. A major unconformity separates the Triassic Chinle from the overlying Cretaceous sediments that consists of coarse sand and gravel, white marly limestone, and dark, blue-gray sandy shale.

An important aquifer, the Tertiary Ogallala formation overlies these Cretaceous sediments. It consists of coarse sands and vari-colored gravels, all loose or poorly consolidated, which are followed by recent wind-blown sand and caliche.

3.4 Description of CO₂-EOR Project Facilities and the Injection Process

Figure 3-8 shows a simplified process flow diagram of the project facilities and equipment in the DCF. CO₂ will be delivered to the DCF from Trinity, via the Kinder Morgan CO₂ pipeline network. The CO₂ will be supplied by several different sources including both natural and anthropogenic CO₂ sources. Specified amounts will be drawn from an outside source pipeline based on contractual arrangements among suppliers of CO₂, purchasers of CO₂, and the pipeline operator. The Specified amount of CO₂ required in addition to the produced gas to meet target CO₂ injection rates are forecasted using the DPC approach.

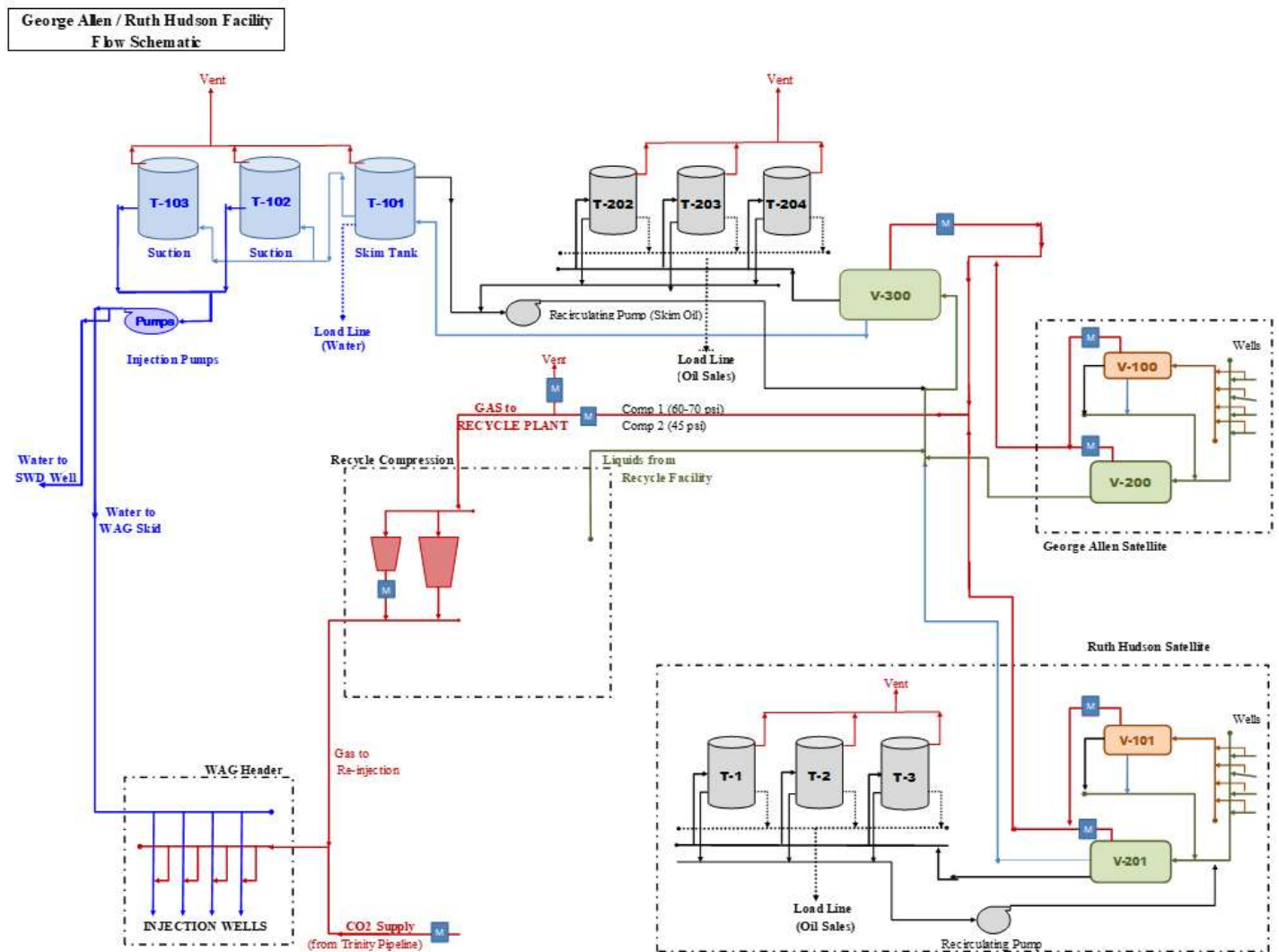


Figure 3-8 DCF Process Flow Diagram

Once CO₂ enters the DCF there are three main processes involved in CO₂-EOR operations:

- i. CO₂ Distribution and Injection: The mass of CO₂ received at the DCF is metered and calculated through the Custody Transfer Meter located at the pipeline delivery point. The mass of CO₂ received is combined with recycled CO₂ / hydrocarbon gas mix from the recycle compression facility (RCF) and distributed to the WAG headers for injection into the injection wells according to the pre-programmed injection plan for each well pattern which alternates between water and CO₂ injection. WAG headers are manually operated and can inject either CO₂ or water at various rates and injection pressures as specified in the injection plans. This is an EOR project and reservoir pressure must be maintained above minimum miscibility pressure. Therefore, injection pressure must be sufficiently high to allow injectants to enter the reservoir, but below formation parting pressure (FPP)
- ii. Produced Fluids Handling: Produced fluids from the production wells are a mixture of oil, hydrocarbon gas, water, CO₂, and trace amounts of other constituents in the field including nitrogen and Hydrogen Sulfide (H₂S) as discussed in Section 7. They are gathered and sent to Satellite Test Stations (SAT) for separation into a gas/CO₂ mix and a produced fluids mix of water, oil, gas, and CO₂. The produced gas, which is composed primarily of CO₂ and minor hydrocarbons, is sent to the RCF for dehydration and recompression before reinjection into the reservoir. An operations meter at the RCF is used to determine the total volume of produced gas that is reinjected. The separated oil is sent to two separate tanks (one at GAU and one at RH) where is then sold via truck.
- iii. Water Treatment and Injection: Water is recovered for reuse and forwarded to the water injection station for reinjection or disposal.

3.4.1 Wells in the Denver City Fields

The TRRC has broad authority over oil and gas operations including primacy to implement UIC Class II wells. The rules are found in TAC Title 16, Part 1, Chapter 3 and are also explained in a TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual (See Appendix 12-2). TRRC rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields.

Briefly, TRRC rules include the following requirements:

- Fluids must be constrained in the strata in which they are encountered,
- activities cannot result in the pollution of subsurface or surface water,
- wells must adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata that are encountered into other strata with oil and gas, or into subsurface and surface waters,
- completion report for each well including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore) must be prepared,
- operators must follow plugging procedures that require advance approval from the TRRC Director and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs; and,
- injection well operators must identify an Area of Review (AoR), use compatible materials and equipment, test, and maintain well records.

Table 3-2 provides a well count by type and status. All these wells are in material compliance with TRRC rules.

Table 3-2 DCF Well Penetrations by Type and Status

TYPE	ACTIVE	INACTIVE	P & A	Total
PROD_OIL	16	3		19
INJ_WTR	0	1		1
INJ_WAG	8	0		8
INJ_SWD*	0	0		0
WSW	0	0		0
P&A			3	3
TOTAL	24	4	3	31

PROD_OIL = Production Wells

INJ_WRT = Water injection wells

INJ_WAG = WAG injection wells

INJ_SWD = Saltwater disposal wells

WSW = Water source wells

P&A = Plugged and Abandoned wells.

As indicated in Figure 3-9, wells are distributed across the DCF. The well patterns currently undergoing CO₂ flooding are identified by black 5-spot pattern outlines and CO₂ will be injected across the entire unit over the project life.

DCF CO₂-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Reservoir pressure in the DCF is managed by maintaining an IWR of approximately 1.0. To maintain the IWR, fluid injection and production are monitored and managed to ensure that reservoir pressure does not increase to a level that would compromise the reservoir seal or otherwise damage the integrity of the oil field.

Injection pressure is also maintained below the FPP, which is measured using step-rate tests.

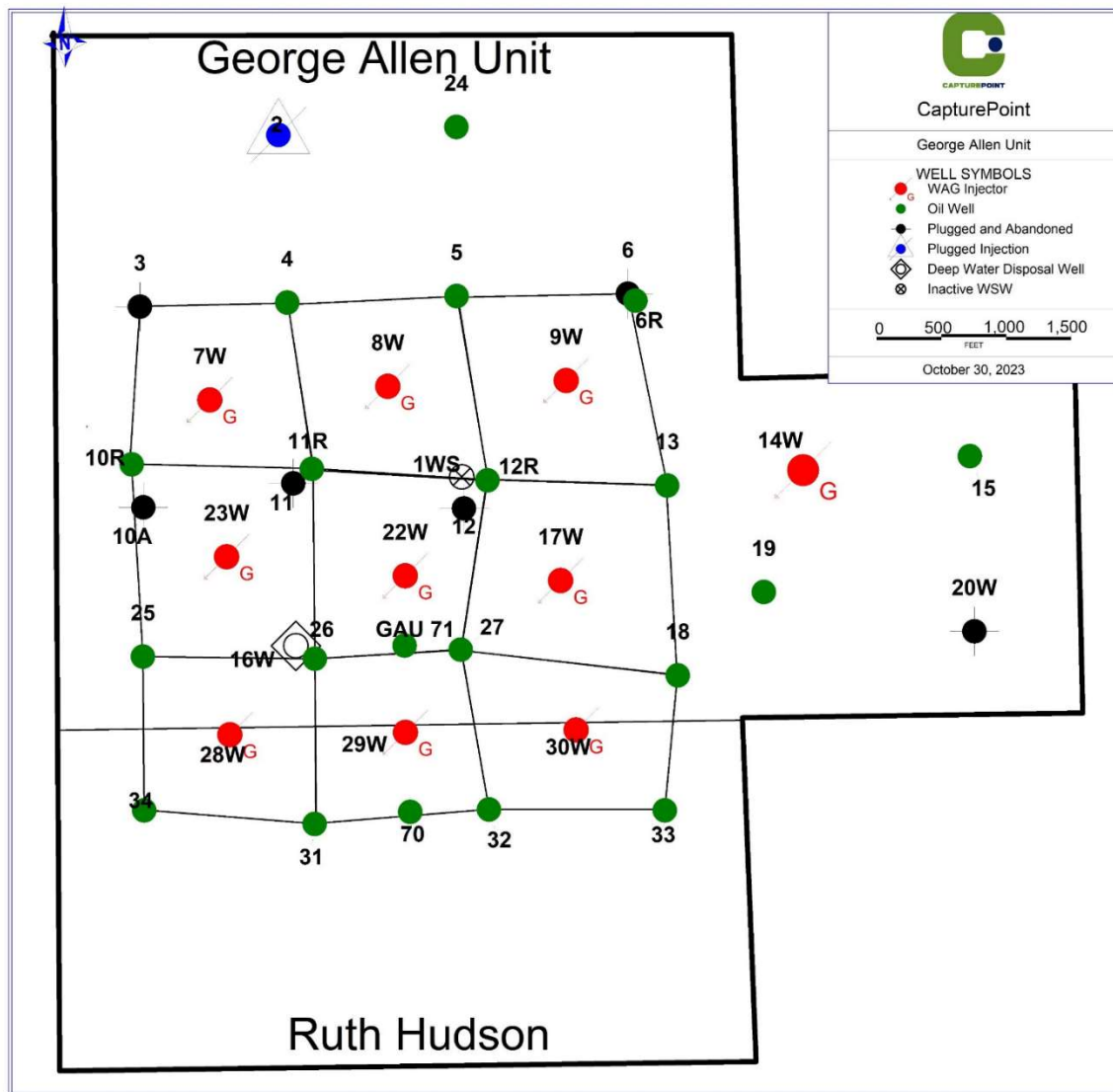


Figure 3-9 DCF Wells and Injection Patterns

3.5 Reservoir Forecasting

DPCs derived from the analogous Wasson San Andres field were used to project CO₂-EOR in the Denver City Field. Most DPCs are derived from geologic and reservoir models. In the DCF case the DPC was derived from actual field performance from the Wasson San Andres field.

A DPC is a plot where injection and production volumes for CO₂, water, and hydrocarbon phases are normalized by dividing by Hydrocarbon Pore Volume (HCPV). See Figure 3-10. The dimensioned projections for the oil, CO₂, and water production are relative to the CO₂ and water injection and are calculated using the original oil in place of an area of interest.

HCPV of Produced:
CO₂, Oil or Water

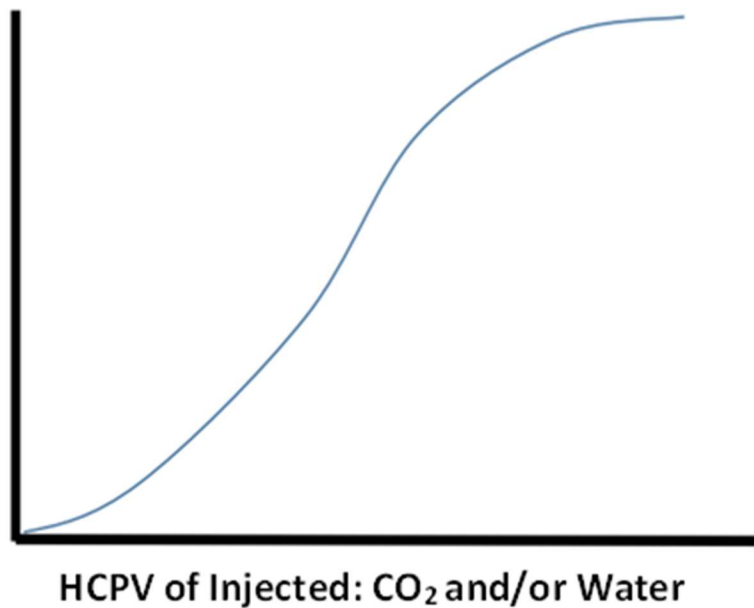


Figure 3-10 DPC plot

The DCF DPC was calculated from the cumulative production and injection from an analogous field. This DPC was used on each pattern in the DCF and then summed up to full field. This method allows you to use different start times and implement different field implementation speeds.

The DPCs are the basis for future performance prediction scenarios but are additionally a means of evaluating the reservoir process efficiencies. In a similar manner to history matching in reservoir simulation, deviations from expected performance can indicate errors in the geologic model of the pore volume, growth of the CO₂ plume, or metering and production allocation errors.

4 Delineation of Monitoring Area and Timeframes

4.1 Active Monitoring Area

The Active Monitoring Area (AMA) is defined by the GAU and RH boundaries plus the required $\frac{1}{2}$ mile zone. Based on our projections, CapturePoint expects the free phase CO₂ plume to remain within the GAU and RH boundaries for the entire length of the project and through year [t+5]. The CO₂ storage volume calculations show the CO₂ to remain within the unit boundaries in the period associated with the AMA, which is year 2037.

The AMA is shown in Figure 4-1. It is an area defined by the boundary of the DCF plus the required $\frac{1}{2}$ 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).

4.1.1 Discussion of CO₂ Storage Volumes in AMA

The CO₂ injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO₂-EOR. Maintenance of an Injection to Withdrawal ratio of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

Figure 3-9 displays wells that have CO₂ retention on the 370 acres that have been under CO₂ injection since project initialization. The CO₂ storage volumes were forecasted using the DPC approach. This technique indicates that the flooded acreage still has significant storage potential. The maximum CO₂ storage (254 BCF) is limited to the amount of space available by the removal of the produced hydrocarbon and water. The projection indicates that there is pore space available to store approximately 0.15 decimal fraction of HCPV amounting to 27.8 million reservoir barrels of oil (MMRB) (37.5 BCF).

The lateral extent of CO₂ in the injection zone or the CO₂ storage radius for each well was estimated by calculating a storage radius based on the forecasted CO₂ storage volume of 37.5 BCF. Figure 4-1 shows the map of the storage area outline for each pattern (dashed red line). This calculation showed 166 acres (this calculates to 18 acres per pattern) would be needed to store 37.5 BCF. This is significantly less than the 1133 acres in the DCF outline.

CO₂ injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO₂-EOR. Namely, maintenance of an IWR of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

4.2 Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined by the GAU and RH boundaries plus the required $\frac{1}{2}$ mile buffer as required by 40 CFR §98.440-449 (Subpart RR). The CO₂ plume (Figure 4-1) is expected to be contained within the GAU and RH boundaries which will be actively

monitored. Therefore, CapturePoint defines the MMA as the same as the AMA since the plume location is less than the unit area. 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 FR 98.448(d)(1).

4.3 Monitoring Timeframes

The primary purpose for injecting CO₂ is to produce oil that would otherwise remain trapped in the reservoir and not, as in UIC Class VI, “specifically for the purpose of geologic storage.”¹ During a Specified Period, there will be a subsidiary purpose of establishing the long-term containment of CO₂ in the DCF. The Specified Period is the timeframe that CO₂ storage will occur. In the DCF, CO₂ storage will occur until 2037 at which point CO₂ injection will equal CO₂ production. Specified Period will be shorter than the period of production from the DCF.

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted with a demonstration that current monitoring and model(s) show that the cumulative mass of CO₂ reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration after the Specified Period ends based upon monitoring data.

The reservoir pressure in the DCF is collected for use in operations management. Reservoir pressure is not forecasted to change appreciably since the IWR will be maintained at approximately 1. Once injection ceases, reservoir pressure is predicted to stabilize within one year.

¹ EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b). A

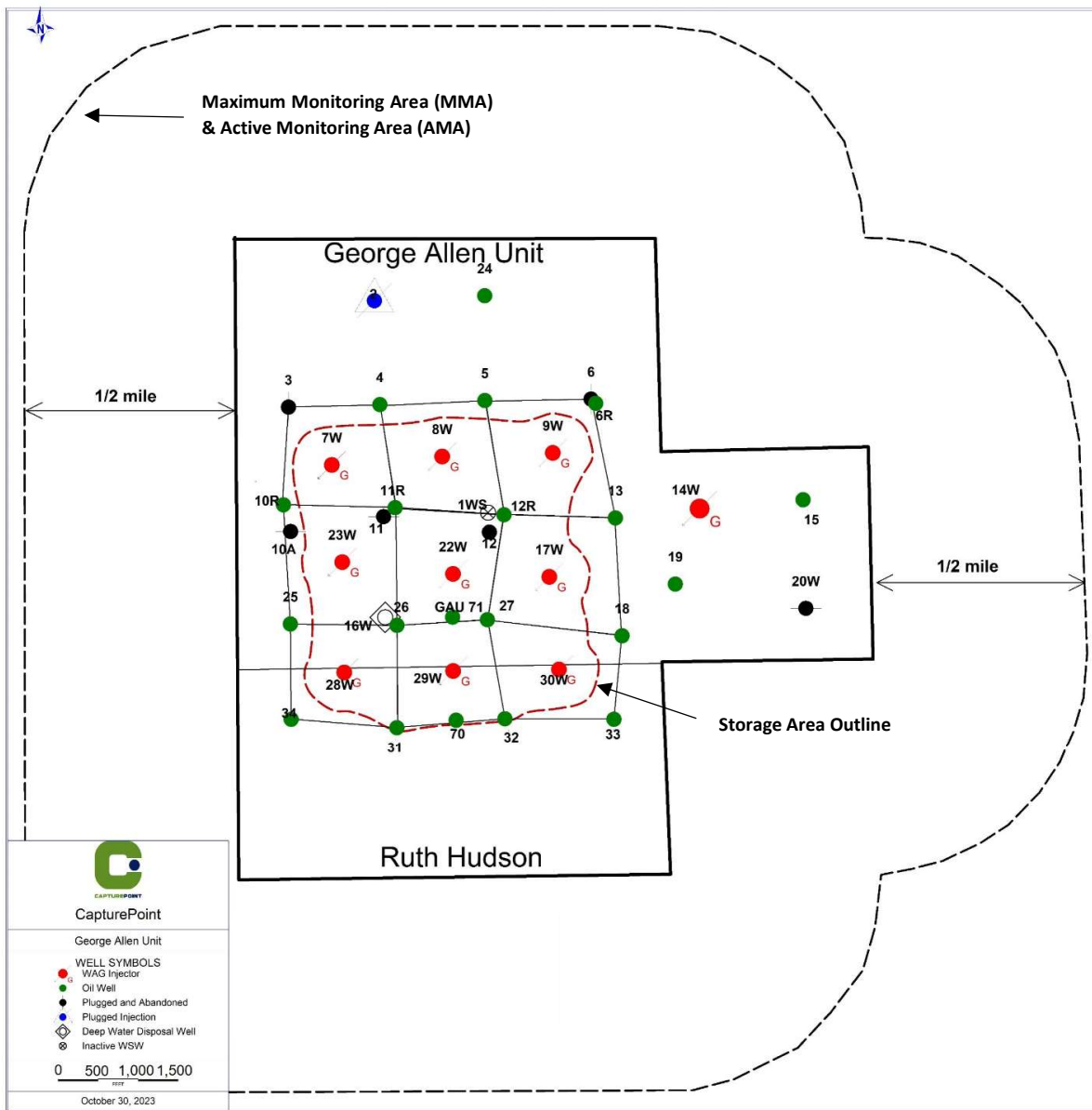


Figure 4-1 Projected CO₂ Storage area

5 Evaluation of Potential Pathways for Leakage to the Surface, Leakage Detection, Verification, and Quantification

In the roughly 60 years since the DCF was discovered, the reservoir has been studied extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO₂ to the surface including:

1. Existing Wells
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the DCF
7. Drilling Through the CO₂ Area
8. Diffuse Leakage Through the Seal
9. Leakage Detection, Verification, and Quantification

This analysis shows that leakage through wellbores and surface equipment pose the only meaningful potential leakage pathways. The monitoring program to detect and quantify leakage is based on this assessment as discussed below.

5.1 Existing Wells

As part of the TRRC requirement to initiate CO₂ flooding, an extensive review of all the DCF penetrations was completed to determine the need for corrective action. That analysis showed that all penetrations have either been adequately plugged and abandoned or, if in use, do not require corrective action. All wells in the DCF were constructed and are operated in compliance with TRRC rules.

As part of routine risk management, the potential risk of leakage associated with the following were identified and evaluated:

- CO₂ flood electrical submersible pump (ESP) producing wells,
- CO₂ flood beam pumped producing wells, and
- CO₂ injector wells.

The risk assessment classified all risks associated with subsurface as low risk, i.e., less than 1% likelihood to occur and having a consequence that is insubstantial. The risks were classified as low risk because DCF geology is well suited to CO₂ sequestration with an extensive confining zone that is free of fractures and faults that could be potential conduits for CO₂ migration. Any risks are further mitigated because the DCF is operated in a manner that maintains, monitors, and documents the integrity of the reservoir.

The risk of well leakage is mitigated through:

- Adhering to regulatory requirements for well drilling and testing,
- implementing best practices that CapturePoint has developed through its extensive operating experience,
- monitoring injection/production performance, wellbores, and the surface; and,
- maintaining surface equipment.

Continual and routine monitoring of the wellbores and site operations will be used to detect leaks or other potential well problems, as follows:

- Pressure in injection wells is monitored daily. The injection plans for each pattern are provided to field operations to govern the rate, pressure, and duration of either water or CO₂ injection. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such events occur, they would be investigated and addressed. CapturePoint's experience, from over 10 years of operating CO₂-EOR projects, is that such leakage has not occurred.
- Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a SAT. There is a routine well testing cycle for each SAT, with each well being tested approximately once every month. During this cycle, each production well is diverted to the well test equipment for a period sufficient to measure and sample produced fluids (generally 12-24 hours). These tests are the basis for allocating a portion of the produced fluids measured at the SAT to each production well, assessing the composition of produced fluids by location, and assessing the performance of each well. Performance data are reviewed on a routine basis to ensure that CO₂ flooding efficiency is optimized. If production is off plan, it is investigated, and any identified issues addressed. Leakage to the outside of production wells is not considered a major risk because of the reduced pressure in the casing. Further, the personal H₂S monitors are designed to detect leaked fluids around production wells during well inspections as well as various permanent H₂S monitors throughout the field at ground level.
- Field inspections are conducted on a routine basis by field personnel. Leaking CO₂ is very cold and leads to the formation of bright white clouds and ice that are easily spotted. All field personnel are trained to identify leaking CO₂ and other potential problems at wellbores and in the field. Any CO₂ leakage detected will be documented, quantified, and reported.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, it is concluded that the risk of CO₂ leakage through wellbores is being mitigated by detecting problems as they arise and quantifying any leakage that does occur. If leakage did occur, the magnitude of 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.

5.2 Faults and Fractures

After reviewing geologic, seismic, operating, and other evidence, it has been concluded that there are no known faults or fractures that transect the San Andres reservoir in the project area. As a result, there is minimal risk (less than 1%) of leakage due to fractures or faults.

Measurements to determine FPP and reservoir pressure are routinely updated. This information is used to manage injection patterns so that the injection pressure will not exceed FPP. An IWR at or near 1 is also maintained. Both procedures mitigate the potential for inducing faults or fractures. As a safeguard, WAG skids are continuously monitored.

5.3 Natural and Induced Seismicity

After reviewing the literature and actual operating experience; it is concluded that there is no direct evidence that natural seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF. Therefore, CapturePoint concludes that leakage of sequestered CO₂ through seismicity is unlikely.

To evaluate this potential risk at the DCF, CapturePoint has reviewed the nature and location of seismic events in West Texas. While some of the recorded earthquakes in West Texas are judged to be from natural causes, others are near oil fields or water disposal wells and are placed in the category of “quakes in close association with human enterprise.”² A review of the United States Geological Survey (USGS) database of recorded earthquakes at M1.0 or greater in the Permian Basin since 1956 indicates that none have occurred in the DCF; the closest took place in 2020 approximately 38 miles away. See Figure 5-1.

The concern about induced seismicity is that it could lead to fractures in the seal providing a pathway for CO₂ leakage to the surface. CapturePoint is not aware of any reported loss of injectant (brine water or CO₂) to the surface associated with any induced seismic activity. There is no direct evidence to suggest that induced seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF. RRC approved injection pressures are kept well below the reservoir fracture gradient to ensure seismicity is not induced. If induced seismicity resulted in a pathway for material amounts of CO₂ to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would detect the migration and lead to further investigation. CapturePoint monitors the USGS earthquake monitoring Geographical Information System (GIS) site³ for seismic signals that could indicate the creation of potential leakage pathways in the DCF.

² Frohlich, Cliff (2012) “Induced or Triggered Earthquakes in Texas: Assessment of Current Knowledge and Suggestions for Future Research”, Final Technical Report, Institute for Geophysics, University of Texas at Austin, Office of Sponsored Research.

³ <https://earthquake.usgs.gov/earthquakes/map/>



Figure 5-1 USGS earthquakes (+1.0 magnitude) for last 57 years)

5.4 Previous Operations

CO₂ flooding was initiated in the DCF in 2007. To obtain permits for CO₂ flooding, the AoR around all CO₂ injector wells was evaluated to determine if there were any unknown penetrations and to assess if corrective action was required at any wells. As indicated in Section 5.1, this evaluation reviewed the identified penetrations and determined that no additional corrective action was needed. Further, CapturePoint's standard practice for drilling new wells includes a rigorous review of nearby wells to ensure that drilling will not cause damage to or interfere with existing wells. Additionally, requirements to construct wells with materials that are designed for CO₂ injection are adhered to at the DCF. These practices ensure that there are no unknown wells within the DCF and that the risk of migration from older wells has been sufficiently mitigated via location identification and daily on-site monitoring of rates and pressures. The successful experience with CO₂ flooding in the DCF demonstrates that the confining zone has not been impaired by previous operations. Based on this history of no leakage events and well construction requirements, the likelihood is less the 1% and the magnitude would be low with a timely response and remediation.

5.5 Pipelines and Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO₂. CapturePoint anticipates that the use of prevailing design and construction practices and compliance with applicable laws will reduce to the maximum extent practicable the risk of unplanned leakage from surface facilities. The facilities and pipelines currently utilize and will continue to utilize materials of construction and control processes that are standard for CO₂-EOR projects in the oil and gas industry. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. Field personnel are trained to look for and report potential leaks from pipeline and surface equipment as part of their routine activities.

Surface equipment leaks have a low risk of occurring based on design standards that are followed, and any leak would have insubstantial results. The magnitude of surface equipment leaks will range from 0.1 to 2 MT yearly and are addressed within 6-12 hours of occurring. Should leakage be detected from pipeline or surface equipment, the volume of released CO₂ will be quantified following the requirements of Subpart W of the Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP). Because of materials selection, the risk is once again low, and CapturePoint concludes that leakage of CO₂ through the surface equipment is unlikely.

5.6 Lateral Migration Outside the Denver City Fields

It is highly unlikely that injected CO₂ will migrate downdip and laterally outside the DCF because of the nature of the geology and the approach used for injection. Over prolonged periods of time, injected CO₂ will tend to rise vertically towards the Upper San Andres and continue towards the point in the DCF with the highest elevation. Second, the planned injection volumes and active fluid management during injection operations will prevent CO₂ from migrating laterally out of the structure. Finally, the total volume of fluids contained in the DCF will stay constant. Based on site characterization and planned and projected operations it is estimated that the total volume of stored CO₂ will be less than the calculated capacity.

5.7 Drilling in the Denver City Fields

The TRRC regulates well drilling activity in Texas. Pursuant to TRRC rules, well casing shall be securely anchored in the hole to effectively control the well at all times, all usable-quality water zones shall be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flow zones, and zones with corrosive formation fluids shall be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. Where TRRC rules do not detail specific methods to achieve these objectives, operators shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology. The TRRC requires applications and approvals before a well is drilled, recompleted, or reentered. Well drilling activity at the DCF is conducted in accordance with TRRC rules. CapturePoint's visual inspection process, including routine site visits, will identify unapproved drilling activity in the DCF. Leakage during drilling operations is unlikely but possible. It would occur when reservoir pressure is high. Drilling mud weight is designed to control that leakage therefore making the potential very low with volumes leaked kept at low levels.

In addition, CapturePoint intends to operate the DCF for several more years and will continue to be vigilant about protecting the integrity of its assets and maximizing the potential of its resources, including oil, gas, and CO₂. Consequently, the risks associated with third parties penetrating the DCF are negligible.

5.8 Diffuse Leakage Through the Seal

Diffuse leakage through the seal formed by the upper San Andres is highly unlikely. There are a number of sections above the reservoir that are impermeable and serve as reliable barriers to

prevent fluids from moving upwards towards the surface. These barriers are referred to as seals because they effectively seal fluids within the formations beneath them.

Our injection pattern monitoring program assures that no breach of the seal will be created. The seal is highly impermeable. Wellbores that penetrate the seal make use of cement and steel construction that is closely regulated to ensure that no leakage takes place. Injection pressure is continuously monitored and unexplained changes in injection pressure that might indicate leakage would trigger investigation as to the cause. The potential for leakage again is very low (less than 1%) the magnitude of which would be in the several MCF range into other formations but not to the surface.

5.9 Leakage Detection, Verification, and Quantification

As discussed above, the potential sources of leakage include issues, such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment (wellbores), and unique events such as induced fractures. An event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage is used. Table 5.1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, the standard response, and other applicable regulatory programs requiring similar reporting.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods for quantifying the volume of leaked CO₂ will be determined on a case-by-case basis using all metering and measurement equipment from each wellhead through the output of the tanks and recycle. In the event leakage occurs, the most appropriate methods for quantifying the volume leaked will be determined and it will be reported as required as part of the annual Subpart RR submission.

- For leakage through wellbores, daily monitoring of flow rates will provide the basis to determine duration and the amount of CO₂ loss;
- For leakage from surface equipment and pipelines, daily monitoring of flow rates and acceptable emission factors, such as those in 40 CFR Part §98 Subpart W, provide the basis to determine duration and the amount of CO₂ loss;
- For leakage related to the competency of the confining layer, reservoir modeling and engineering estimates provided the basis for determining the amount of CO₂ loss.

Any volume of CO₂ detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as the frequency of inspection. Leaks will be documented, evaluated, and addressed in a timely manner.

Records of leakage events will be retained in an electronic environmental documentation and reporting system. The Field Foreman is notified for maintenance activities that cannot be addressed on the spot.

Table 5-1 Response Plan for CO₂ Loss

Risk	Monitoring Plan	Response Plan
Tubing Leak	Monitor changes in tubing and annulus pressure; MIT for injectors	Well is shut in and workover crews respond within days
Casing Leak	Routine Field inspection; Monitor changes in annulus pressure, MIT for injectors; extra attention to high risk wells	Well is shut in and workover crews respond within days
Wellhead Leak	Routine Field inspection, SCADA system monitors wellhead pressure	Well is shut in and workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations	Maintain well kill procedures
Unplanned wells drilled through San Andres	Routine Field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells.	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Reservoir pressure in WAG headers; high pressure found in new wells	Re-enter and reseal abandoned wells
Pumps, valves, etc.	Routine Field inspection, SCADA	Workover crews respond within days
Overfill beyond spill points	Reservoir pressure in WAG headers; high pressure found in new wells	Fluid management along lease lines
Leakage through induced fractures	Reservoir pressure in WAG headers; high pressure found in new wells	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Reservoir pressure in WAG headers; high pressure found in new wells	Shut in injectors near seismic event
Diffuse leakage through the seal	Monitor injection pressure for unexplained changes in injection pressure that might indicate leakage	Investigate to determine if cement and steel construction is the issue. Well is shut in and workover crews respond within days.

5.10 Summary

The structure and stratigraphy of the San Andres reservoir in the DCF is ideally suited for the injection and storage of CO₂. The stratigraphy within the CO₂ injection zones is porous, permeable, and thick, providing ample capacity for long-term CO₂ storage. The reservoir is overlain by several intervals of impermeable geologic zones that form effective seals or “caps” to fluids in the reservoir.

In summary, based on a careful assessment of the potential risk of release of CO₂ from the subsurface, it has been determined that there are no leakage pathways at the DCF that are likely to result in significant loss of CO₂ to the atmosphere. Further, given the detailed knowledge of the field and its operating protocols, it is concluded that any CO₂ leakage to the surface that could arise through either identified or unexpected leakage pathways would be detected and quantified.

6 Monitoring and Considerations for Calculating Site Specific Variables

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

6.1 For the Mass Balance Equation

6.1.1 General Monitoring Procedures

Flow rate, pressure, and gas composition data are monitored and collected from the DCF in centralized data management systems as part of ongoing operations. This data is monitored by qualified technicians who follow response and reporting protocols when the systems deliver notifications that data exceed statistically acceptable boundaries.

Metering protocols used at DCF follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association, and the Gas Processors Association, as appropriate. This approach is consistent with EPA GHGRP's Subpart RR, section §98.444(e)(3). These meters will be maintained routinely, operated continually, and will feed data directly to the centralized data collection systems. The meters meet the industry standard for custody transfer meter accuracy and calibration frequency.

6.1.2 CO₂ Received

As indicated in Figure 3-8, the volume of received CO₂ is measured using a commercial custody transfer meter at the point at which custody of the CO₂ from the Kinder Morgan CO₂ pipeline delivery system is transferred to the DCF. This meter measures flow rate continually. The transfer is a commercial transaction that is documented. CO₂ composition is governed by contract and the gas is routinely sampled. Fluid composition will be determined, at a minimum, quarterly, consistent with EPA GHGRP's Subpart RR, section §98.447(a). All meter and composition data are documented, and records will be retained for at least three years. No CO₂ is received in containers.

6.1.3 CO₂ Injected in the Subsurface

Injected CO₂ will be calculated using the flow meter volumes at the operations meter at the outlet of the RCF and the custody transfer meter at the CO₂ off-take point from the Kinder Morgan CO₂ Pipeline Delivery System.

6.1.4 CO₂ Produced, Entrained in Products, and Recycled

The following measurements are used for the mass balance equations in Section 8:

- CO₂ produced in the gaseous stage is calculated using the volumetric flow meters at the outlet of the separation facility (Figure 3-8 vessels, V-100, V-101, V-200, V-201, and V-300),
- CO₂ that is entrained in produced oil, as indicated in Figure 3-8, is calculated from routinely captured samples and volume is measured by the truck flow meter,
- Recycled CO₂ is calculated using the volumetric flow meter at the outlet of the RCF, which is an operations meter.

6.1.5 CO₂ Emitted by Surface Leakage

CapturePoint uses 40 CFR Part 98 Subpart W to estimate surface leaks from equipment at the DCF. Subpart W uses a factor-driven approach to estimate equipment leakage. An event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage to the surface is used. The Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted. Additionally, CapturePoint uses 40 CFR Part 98 Subpart RR to report equipment leaks and vented emissions separately for injection and production.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet two objectives: 1) to detect problems before CO₂ leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the volumes of CO₂ leaked to the surface.

Monitoring for Potential Leakage from the Injection/Production Zone

In addition to the measures discussed in Section 5.9, both injection into and production from the reservoir will be monitored as a means of early identification of potential anomalies that could indicate leakage from the subsurface.

Injection plans (fluid rate, pressure, volume) are given to operations on a weekly basis. If injection pressure or rate measurements are outside the specified set points determined as part of each pattern injection plan, reservoir engineering will notify field personnel and they will investigate and resolve the problem. These excursions will be reviewed by well management personnel to determine if CO₂ leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or some other minor action is required), and there is no threat of CO₂ leakage. In the case of issues that are not readily resolved, more detailed investigation and response would be initiated, and support staff would provide additional assistance and evaluation.

Likewise, a forecast of the rate and composition of produced fluids is developed. Each producer well is assigned to a specific SAT and is isolated during each cycle for a well production test. This

data is reviewed on a periodic basis to confirm that production is at the level forecasted. If there is a significant deviation from the plan, well management personnel investigate. If the issue cannot be resolved quickly, a more detailed investigation and response would be initiated. If leakage in the flood zone were detected, an appropriate method would be used to quantify the involved volume of CO₂. This might include use of material balance equations based on known injected quantities and monitored pressures in the injection zone to estimate the volume of CO₂ involved.

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

In the event leakage from the subsurface occurred diffusely through the seals, the leaked gas would include H₂S, which would trigger the alarm on the personal monitors worn by field personnel as well as the various permanent H₂S monitors throughout the field at ground level. Such a diffuse leak from the subsurface has not occurred in the DCF. In the event such a leak was detected, personnel would determine how to address the problem. The personnel might use modeling, engineering estimates, and direct measurements to assess, address, and quantify the leakage.

Monitoring of Wellbores

DCF wells are monitored through daily pressure monitoring of the injection zone, monitoring of the annular pressure in wellheads, and routine maintenance and inspection.

Leaks from wellbores would be detected through the follow-up investigation of pressure anomalies, visual inspection, or the use of personal H₂S monitors and various permanent H₂S monitors throughout the field at ground level.

Anomalies in injection zone pressure may not indicate a leak, as discussed above. However, if an investigation leads to a need for further study, field personnel would inspect the equipment in question and determine the nature of the problem. If it is a simple matter, the repair would be made, and the volume of leaked CO₂ would be included in the 40 CFR Part 98 Subpart W report for the DCF. If more extensive repair were needed, the appropriate approach for quantifying leaked CO₂ using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be determined.

Anomalies in annular pressure or other issues detected during routine maintenance inspections would be treated in the same way. Field personnel would inspect the equipment in question and determine the nature of the problem. For simple matters the repair would be made at the time of inspection and the volume of leaked CO₂ would be included in the 40 CFR Part 98 Subpart W report for the DCF. If more extensive repairs were needed, the well would be shut in, a work order would be generated and the appropriate approach for quantifying leaked CO₂ using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be

determined. The work order would serve as the basis for tracking the event for Green House Gas (GHG) reporting.

Because leaking CO₂ at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a visual inspection process in the area of the DCF is employed to detect unexpected releases from wellbores. Field personnel visit the surface facilities on a routine basis. Inspections may include tank levels, equipment status, lube oil levels, pressures and flow rates in the facility, and valves. Field personnel also check that injectors are on the proper WAG schedule and observe the facility for visible CO₂ or fluid line leaks.

Finally, the data collected by the H₂S monitors, which are always worn by field personnel and are located permanently throughout the field at ground level, is used as a last method to detect leakage from wellbores. The H₂S monitor's detection limit is 10 ppm; if an H₂S alarm is triggered, the first response is to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. As noted previously, H₂S is considered a proxy for potential CO₂ leaks in the field. Thus, detected H₂S leaks will be investigated to determine and, if needed, quantify potential CO₂ leakage.

Other Potential Leakage at the Surface

The same visual inspection process and H₂S monitoring system will be used to detect other potential leakage at the surface as it does for leakage from wellbores. Routine visual inspections are used to detect significant loss of CO₂ to the surface. Field personnel routinely visit surface facilities to conduct a visual inspection. Inspections may include review of tank level, equipment status, lube oil levels, pressures and flow rates in the facility, valves, ensuring that injectors are on the proper WAG schedule, and also conducting a general observation of the facility for visible CO₂ or fluid line leaks. If problems are detected, field personnel would investigate, and complete any maintenance that is required. In addition to these visual inspections, the results of the personal H₂S monitors worn by field personnel and the permanent H₂S monitors throughout the field at ground level will be used as a supplement for smaller leaks that may escape visual detection.

If CO₂ leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, steps are taken to prevent further leaks.

6.1.6 CO₂ emitted from equipment leaks and vented emissions of CO₂ from surface equipment located between the injection flow meter and the injection wellhead

CapturePoint evaluates and estimates leaks from injection equipment and the CO₂ content of any vented CO₂, as required under 40 CFR Part 98 Subpart W.

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

CapturePoint evaluates and estimates leaks from production equipment and the CO₂ content of produced oil, and any vented CO₂, as required under 40 CFR Part 98 Subpart W.

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

At the end of the Specified Period, injecting CO₂ for the subsidiary purpose of establishing the long-term storage of CO₂ in the DCF will cease. Sometime after the end of the Specified Period, a request to discontinue monitoring and reporting will be submitted. The request will demonstrate that the amount of CO₂ reported under 40 CFR §98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage.

At that time, the request will be supported with years of data collected during the Specified Period. This demonstration will provide the information necessary for the EPA Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

- Data comparing actual performance to predicted performance (purchase, injection, production) over the monitoring period,
- An assessment of the CO₂ leakage detected, including the discussion of the estimated amount of CO₂ leaked and the distribution of emissions by leakage pathway,
- A demonstration that future operations will not release the volume of stored CO₂ to the surface,
- A demonstration that there has been no significant leakage of CO₂; and,
- An evaluation of the reservoir pressure demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

7 Determination of Baselines

Ongoing operational monitoring has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO₂ leakage. Data systems are used primarily for operational control and monitoring, which are set to capture more information than is necessary for reporting in the Annual Subpart RR Report. The necessary system guidelines to capture the information that is relevant to identify possible CO₂ leakage will be developed. The following describes the approach to collecting this information.

Visual Inspections

As field operators conduct routine inspections and repairs, the Field Foreman is notified for maintenance activities that cannot be addressed on the spot. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation (the responsible party will be provided in the monitoring plan, as required under Subpart A, §98.3(g)). The Annual Subpart RR Report will provide an estimate of CO₂ emissions. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

Personal H₂S Monitors

H₂S monitors are worn by all field personnel. The H₂S monitors detect concentrations of H₂S up to 500 ppm in 0.1 ppm increments and will sound an alarm if the detection limit exceeds 10 ppm. The current H₂S concentration in the produced gas is 5,709 ppm taken from the recycle compressor inlet and 205 ppm in the produced oil. If an H₂S alarm is triggered, the immediate response is to protect the safety of the personnel, and the next step is to safely investigate the source of persistent alarms. CapturePoint considers H₂S to be a proxy for potential CO₂ leaks in the field. The person responsible for MRV documentation will receive notice of all incidents where H₂S is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO₂ emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

As stated before, there are various permanent H₂S monitors throughout the field at ground level to detect H₂S and alarm if a limit is reached.

Injection Rates, Pressures and Volumes

Target injection rate and pressure for each injector are developed within the permitted limits based on the results of ongoing pattern balancing. The injection targets are submitted to field operations. Field operations flags whenever statistically significant deviations from the targeted ranges are identified. The set points are designed to be conservative, because it is preferable to have too many flags rather than too few. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO₂ leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions. The Annual Subpart RR Report will provide an estimate of CO₂ emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

Production Volumes and Compositions

A general forecast of production volumes and composition is developed which is used to periodically evaluate performance, refine current and projected injection plans, and the forecast. This information is used to make operational decisions but is not recorded in an automated data system. The MRV plan implementation lead will review the data and identify those that could result in CO₂ leakage. Should such events occur, leakage volumes would be calculated following the approaches described in Sections 5 and 6. Impact to Subpart RR reporting will be addressed, if deemed necessary.

8 Determination of Sequestration Volumes Using Mass Balance Equations

Per subpart RR requirements, all flow meters for CO₂ and oil measurement are located directly downstream of each separation point. To account for the potential error that would result if volume data from flow meters at each injection and production well were utilized, the data from custody transfer meters, operations meters on the main system pipelines, and at all points of separation, is used to determine injection and production volumes used in the mass balance of the system. This issue arises because while each meter has a small but acceptable margin of error,

this error would become significant if data were taken from all the well head meters within the DCF (See Figure 3-8).

The following sections describe how each element of the mass-balance equation (Equation RR-11) will be calculated.

8.1 Mass of CO₂ Received

Equation RR-2 will be used as indicated in Subpart RR §98.443 to calculate the mass of CO₂ at the receiving custody transfer meter from the Trinity CO₂ pipeline delivery system. The volumetric flow at standard conditions will be multiplied by the CO₂ concentration and the density of CO₂ at standard conditions to determine mass.

The Mass of the CO₂ Received will be determined using Equation RR-2 as follows:

$$CO_{2T,r} = \sum_{p=1}^4 (Q_{p,r} - S_{r,p}) * D * C_{CO_2,p,r} \quad (\text{Eq. RR-2})$$

where:

$CO_{2T,r}$ = Net annual mass of CO₂ received through flow meter r (metric tons).

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

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

p = Quarter of the year.

r = Receiving flow meters.

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

- All delivery to the DCF is used within the unit so no quarterly flow redelivered, and $S_{r,p}$ will be zero ("0").
- Quarterly CO₂ concentration will be taken from the gas measurements.

8.2 Mass of CO₂ Injected into the Subsurface

The equation for calculating the Mass of CO₂ Injected into the Subsurface at the DCF is equal to the sum of the Mass of CO₂ Received as calculated in RR-2 of §98.443 (section 8.1 above) and the Mass of CO₂ Recycled calculated using measurements taken from the flow meter located at the outlet of the RCF (see Figure 3-8). As previously explained, using data at each injection well would give an inaccurate estimate of total injection volume due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

The Mass of CO₂ Recycled will be determined using equations RR-5 as follows:

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

where:

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = CO₂ concentration measurement in flow for flow meter u in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

The total Mass of CO₂ Injected will be the sum of the Mass of CO₂ Received (RR-2) and Mass of CO₂ Recycled (RR-5).

The Mass of CO₂ Injected will be determined using equations RR-6 as follows:

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

where:

CO_{2I} = Total annual CO₂ mass injected (metric tons) through all injection wells.

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

u = Flow meter.

8.3 Mass of CO₂ Produced

The Mass of CO₂ Produced at the DCF will be calculated using the measurements from the flow meters at the inlet to RCF and the custody transfer meter for oil sales rather than the metered data from each production well. Again, using the data at each production well would give an inaccurate estimate of total injection due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

Equation RR-8 in §98.443 will be used to calculate the Mass of CO₂ Produced from all production wells as follows:

$$CO_{2w} = \sum_{p=1}^4 (Q_{p,w}) * D * C_{CO_2,p,w} \quad (\text{Eq. RR-8})$$

Where:

CO_{2w} = Annual CO₂ mass produced (metric tons) through separator w.

$Q_{p,w}$ = Volumetric gas flow rate measurement for separator w in quarter p at standard conditions (standard cubic meters).

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

$CCO_{2,p,w}$ = CO₂ concentration measurement in flow for separator w in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator.

For Equation RR-9 in §98.443 the variable X will be measured as follows:

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

Where:

CO_{2p} = Total annual CO₂ mass produced (metric tons) through all separators in the reporting year.

$CO_{2,w}$ = Annual CO₂ mass produced (metric tons) through separator w in the reporting year.

X = Entrained CO₂ in produced oil or other fluid divided by the CO₂ separated through all separators in the reporting year (weight percent CO₂, expressed as a decimal fraction)

w = Separator

8.4 Mass of CO₂ Emitted by Surface Leakage

Surface Leakage will be calculated and reported using an approach that is tailored to specific leakage events including calculation methodologies in 40 CFR Part 98 Subpart W for emissions and leaks from equipment. CapturePoint is prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO₂ leaked to the surface will depend on several site- specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

The process for quantifying leakage will entail using the best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are described in Sections 5.9 and 6. In the event leakage to the surface occurs, leakage amounts would be quantified and reported, and records that describe the methods used to estimate or measure the volume leaked as reported in the Annual Subpart RR Report would be retained. Further, the Subpart W report and results from any event-driven

quantification will be reconciled to assure that surface leaks are not double counted. Volumes for CO_{2E} (surface leakage) and CO_{2FI} (equipment leakage and vented emissions) are calculated separately and differently.

Equation RR-10 in §98.443 will be used to calculate and report the Mass of CO₂ emitted by Surface Leakage:

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

Where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

8.5 Mass of CO₂ Emitted by Facility Emergency Vent

The Mass of CO₂ emitted by the Emergency Vent at the DCF will be calculated using the measurements from the flow meter at the vent. That volume will be added to CO_{2FI} which is the total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

Equation RR-8 in §98.443 will be used to calculate the Mass of CO₂ emitted through the emergency vent as follows:

$$CO_{2w} = \sum_{p=1}^4 (Q_{p,w}) * D * C_{CO_2,p,w} \quad (\text{Eq. RR-8})$$

Where:

CO_{2w} = Annual CO₂ mass produced (metric tons) through separator w.

$Q_{p,w}$ = Volumetric gas flow rate measurement for meter w in quarter p at standard conditions (standard cubic meters).

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

$CCO_{2,p,w}$ = CO₂ concentration measurement in flow for meter w in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator

8.6 Mass of CO₂ Sequestered and Reported in Subsurface Geologic Formation

Equation RR-11 in §98.443 will be used to calculate the Mass of CO₂ Sequestered and Reported in Subsurface Geologic Formations in the Reporting Year as follows:

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

where:

CO_2 = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

CO_{2P} = Total annual CO₂ mass produced (metric tons) in the reporting year.

CO_{2E} = Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

CO_{2FP} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

9 MRV Plan Implementation Schedule

This MRV plan will be implemented starting October 2023 or within 90 days of EPA approval, whichever occurs later. Other GHGRP reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. It is

anticipated that the MRV plan will be in effect during the Specified Period, during which time the DCF will be operated with the subsidiary purpose of establishing long-term containment of a measurable quantity of CO₂ in subsurface geological formations at the DCF. It is anticipated to establish that a measurable amount of CO₂ injected during the Specified Period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be prepared and a request to discontinue monitoring and reporting under this MRV plan will be submitted. See 40 C.F.R. §98.441(b)(2)(ii).

10 Quality Assurance (QA) Program

10.1 QA Procedures

The requirements of §98.444 (a) – (d) have been incorporated in the discussion of mass balance equations. These include the following provisions.

CO₂ Received and Injected

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

CO₂ Produced

- The point of measurement for the quantity of CO₂ produced from oil or other fluid production wells is a flow meter directly downstream of each separator that sends a stream of gas into a recycle or end use system.
- The produced gas stream is sampled annually downstream of the flow meter used to measure flow rate of that gas stream and measure the CO₂ concentration of the sample.

CO₂ Emissions from Equipment Leaks and Vented Emissions of CO₂

These volumes are measured in conformance with the monitoring and QA requirements specified in subpart W of 40 CFR Part 98.

Flow Meter Provisions

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

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

Concentration of CO₂

CO₂ concentration is measured using an appropriate standard method. Further, all measured volumes of CO₂ have been converted to standard cubic meters at a temperature of 60 degrees

Fahrenheit and at an absolute pressure of 1 atmosphere, including those used in Equations RR-2, RR-5, and RR-8 in Section 8.

10.2 Missing Data Procedures

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

- A quarterly flow rate of CO₂ received that is missing would be estimated using invoices or using a representative flow rate value from the previous measured period.
- A quarterly CO₂ concentration of a CO₂ stream received that is missing would be estimated using invoices or using a representative concentration value from the previous measured period.
- A quarterly quantity of CO₂ injected that is missing would be estimated using a representative quantity of CO₂ injected from the previous measured period at a similar injection pressure.
- For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.
- The quarterly quantity of CO₂ produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO₂ produced from the previous measured period.

10.3 MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters of the CO₂-EOR operations in the DCF that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in §98.448(d).

11 Records Retention

The record retention requirements specified by §98.3(g) will be followed. In addition, the requirements in Subpart RR §98.447 will be met by maintaining the following records for at least three years:

- Quarterly records of CO₂ received at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of produced CO₂, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO₂ including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
- Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

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

12 Appendix

12.1 Well Identification Numbers

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

The following terms are used:

Well Type:

- SWS refers to wells that supply water.
- PROD_OIL refers to wells that produce oil.
- INJ_WAG refers to wells that inject water or CO₂.
- INJ_SWD refers to wells that inject water for disposal.
- P&A refers to plugged and abandoned wells.

Well Status:

- ACTIVE refers to active wells.
- INACTIVE refers to wells that have been completed but are not in use.
- SHUT_IN refers to wells that have been temporarily idled or shut in.
- TEMP_AB refers to wells that have been temporarily abandoned.

Table 12-1 Well Status Table

Well Name	API Number	Well Type	Status
GAU #1WS	42165339890000	SWS	INACTIVE
GAU #2W	42165106400000	P&A	INACTIVE
GAU #3	42165106340000	P&A	INACTIVE
GAU #4	42165103790000	PROD_OIL	SHUT_IN
GAU #5	42165106070000	PROD_OIL	INACTIVE
GAU #6	42165106530000	P&A	INACTIVE
GAU #6R	42165367760000	PROD_OIL	INACTIVE
GAU #7W	42165339900000	INJ_WAG	ACTIVE
GAU #8W	42165339910000	INJ_WAG	SHUT_IN
GAU #9W	42165339920000	INJ_WAG	ACTIVE
GAU #10	42165106510000	P&A	INACTIVE
GAU #10R	42165367820000	PROD_OIL	ACTIVE
GAU #11	42165106060000	P&A	INACTIVE
GAU #11R	42165367490000	PROD_OIL	ACTIVE
GAU #12	42165102070000	P&A	INACTIVE
GAU #12R	42165367510000	PROD_OIL	ACTIVE
GAU #13	42165003830000	PROD_OIL	ACTIVE

Well Name	API Number	Well Type	Status
GAU #14W	42165317930000	INJ_WAG	SHUT_IN
GAU #15	42165101300000	PROD_OIL	INACTIVE
GAU #16W	42165106270000	INJ_SWD	ACTIVE
GAU #17W	42165339930000	INJ_WAG	ACTIVE
GAU #18	42165103780000	PROD_OIL	ACTIVE
GAU #19	42165106460000	PROD_OIL	SHUT_IN
GAU #20W	42165008790000	P&A	INACTIVE
GAU #22W	42165352720000	INJ_WAG	ACTIVE
GAU #23W	42165367500000	INJ_WAG	ACTIVE
GAU #24	42165106440000	PROD_OIL	INACTIVE
GAU #25	42165367550000	PROD_OIL	ACTIVE
GAU #26	42165367530000	PROD_OIL	ACTIVE
GAU #27	42165367540000	PROD_OIL	ACTIVE
GAU #71	42165384590000	PROD_OIL	ACTIVE
RH #28W	42165367610000	INJ_WAG	ACTIVE
RH #29W	42165367620000	INJ_WAG	ACTIVE
RH #30W	42165367630000	INJ_WAG	ACTIVE
RH #31	42165367660000	PROD_OIL	ACTIVE
RH #32	42165367670000	PROD_OIL	ACTIVE
RH #33	42165367520000	PROD_OIL	ACTIVE
RH #34	42165367890000	PROD_OIL	SHUT_IN
RH #70	42165384430000	PROD_OIL	ACTIVE

12.2 Regulatory References

Regulations cited in this plan:

- TAC Title 16 Part 1 Chapter 3 Oil & Gas Division

[https://texreg.sos.state.tx.us/public/readtac\\$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y](https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y)

- TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual

<https://www.rrc.texas.gov/oil-and-gas/publications-and-notices/manuals/injection-storage-manual/>

12.3 Abbreviations and Acronyms

AMA - Active Monitoring Area

API - American Petroleum Institute

AoR - Area of Review

Bcf – 1 Billion Standard Cubic Feet of Gas

CO₂ - Carbon Dioxide

DCF – Denver City Fields

DPC - Dimensionless Performance Curve

EPA - Environmental Protection Agency

EOR - Enhanced Oil Recovery

ESP - Electrical Submersible Pump

FPP - Formation Parting Pressure (psi)

GAU - George Allen Unit

GHGRP - Greenhouse Gas Reporting Program

H₂S – Hydrogen Sulfide

HCPV - Hydrocarbon Pore Volume

IWR - Injection to Withdrawal Ratio

MMA - Maximum Monitoring Area

MRV Plan - Monitoring, Reporting and Verification Plan

MCF – 1 Thousand Standard Cubic Feet of Gas

MIT – Mechanical Integrity Test

MMCF – 1 Million Standard Cubic Feet of Gas

NIST - National Institute of Standards and Technology

QA – Quality Assurance

RB - Reservoir Barrels

RCF - Recycle Compression Facility

RH - Ruth Hudson Lease

SAT – Satellite Test

TAC - Texas Administrative Code

TRRC - Texas Railroad Commission - Oil and Gas Division

UIC – Underground Injection Control

12.4 Conversion Factors

CapturePoint reports CO₂ 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 CO₂ mass from CO₂ 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 CO₂ 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 CO₂ of 0.002641684 lb-moles per cubic foot. Converting the CO₂ density in units of metric tonnes per cubic foot:

$$Density_{CO_2} \left(\frac{MT}{ft^3} \right) = Density_{CO_2} \left(\frac{lb - moles}{ft^3} \right) \times MW_{CO_2} \times \frac{1 MT}{2,204.62 lbs}$$

Where:

$Density_{CO_2}$ = Density of CO₂ in metric tonnes (MT) per cubic foot

$Density_{CO_2}$ = 0.002641684

MW_{CO_2} = 44.0095

$Density_{CO_2} = 5.2734 \times 10^{-5} \frac{MT}{ft^3}$ or $5.2734 \times 10^{-2} \frac{MT}{Mcf}$

The conversion factor 5.2734×10^{-2} MT/Mcf is used to convert CO₂ volumes in standard cubic feet to CO₂ mass in metric tonnes.

Request for Additional Information: Denver City Fields
December 12, 2023

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	3.3	12	<i>"The thick, porous, shallow water, carbonate facies that prograded basinward over time are overlain and interfingered with tidal flat, and restricted/exposed the shelf facies, which serve as widespread and efficient seals."</i> We recommend rewording this sentence for clarity.	Corrected in the MRV with additional context from Keith B. "The Upper Permian consists of a dominate thick and porous shallow marine carbonate facies that was later dolomitized as the San Andres Group prograde out into the basin. Continuation of the regressive sequence during the Upper Permian, defined as the Whitehorse group, caps the San Andres Group with tidal flat muds and tight exposed shelf carbonates, along with restricted evaporites. These facies within the Grayburg, Queen and Seven Rivers formation serve as widespread and efficient seals for both hydrocarbons and CO2 trapping."
2.	3.5	17	<i>"DPCs derived from analogous fields were used to project CO2-EOR in the Denver City Fields."</i> In the MRV plan, please elaborate on what analogous fields were used to derive the DPCs and explain why these fields can be considered analogous.	Corrected to reference the Wasson San Andres field.
3.	5.0	22	<i>"1. Existing Wellbores"</i> The Table of Contents (TOC) and the heading of Section 5.1 were both changed to "Existing Wells," however the Section 5.0 TOC was not updated. Please review the MRV plan to ensure that all section headings reflect the TOC.	Corrected in the MRV to "Existing Wells" instead of "Existing Wellbores"
4.	5.3	24	Please clarify whether there will be any operational protocols to ensure seismicity is not induced. For example, will injection pressures be kept below a specific limit?	"Injection pressures are kept below the reservoir fracture gradient to ensure seismicity is not induced."

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	5.4	25	In the previous RFAI, the following was asked: “In addition to listing the possible leakage pathways and their monitoring strategies, please provide a clear characterization of the likelihood, magnitude, and timing of leakage for each potential leakage pathway, specifically for pipelines and surface equipment. For example, Section 5.4 states that the risk of migration from older wells has been sufficiently mitigated, but it does not discuss the likelihood, magnitude, or timing of potential CO₂ leakage through previous operations.” While Section 5.1 provides a clear characterization of leakage from pipelines and surface equipment, please review sections 5.2 through 5.8 to ensure that the likelihood, magnitude, and timing of leakage is discussed for each identified potential pathway.	Added language to the MRV plan addressing leakage and magnitude in sections 5.2-5.8.
6.	6.1	30	“CO₂ produced in the gaseous stage is calculated using the volumetric flow meters at the outlet of the separation facility (Figure 3-8 vessels, V-100, V-101, V-200, V-201, V-300, and V-400).” Volumetric flow meter V-400 mentioned in the statement above is not referenced anywhere else in the MRV plan and does not appear in Figure 3-8. Please clarify.	V-400 does not exist and verbiage has been removed from the MRV.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
7.	8.1	35	$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into a site well in quarter p (standard cubic meters). Per 40 CFR 98.443(a)(2), this variable should be, "$S_{r,p}$ = 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)." Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Corrected in the MRV. Changed to "your"
8.	8.2	35	The MRV plan states that, "The equation for calculating the Mass of CO₂ Injected into the Subsurface at the DCF is equal to the sum of the Mass of CO₂ Received as calculated in RR-2 of §98.443 (section 8.1 above) and the Mass of CO₂ Recycled calculated using measurements taken from the flow meter located at the inlet of the RCF (see Figure 3-8)." However, page 30 of the MRV plan also states that, "Recycled CO₂ is calculated using the volumetric flow meter at the outlet of the RCF, which is an operations meter. Please review the MRV plan to ensure that all references to meter locations are consistent.	Corrected in the MRV. Changed to "outlet"
9.	8.2	36	$CCO_{2,p,u}$ = Quarterly CO₂ concentration measurement in flow for flow meter u in quarter p (vol. percent CO₂, expressed as a decimal fraction)." Per 40 CFR 98.443(c)(3), this variable should be, "$CCO_{2,p,u}$ = CO₂ concentration measurement in flow for flow meter u in quarter p (vol. percent CO₂, expressed as a decimal fraction)." Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Corrected in the MRV. Removed the word "Quarterly"

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
10.	8.3	37	“CO_{2,w} = Annual CO₂ produced (metric tons) through all separators in the reporting year.” Per 40 CFR 98.443(d)(3), this variable should be, “CO_{2,w} = Annual CO₂ mass produced (metric tons) through separator w in the reporting year.” Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Corrected in the MRV to: “CO _{2,w} = Annual CO ₂ mass produced (metric tons) through separator w in the reporting year.”
11.	8.4	37	“...The Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.” Please review the MRV plan to ensure that it is clear that the variables CO₂E (surface leakage) and CO₂FI (equipment leakage and vented emissions) are calculated separately and differently (see https://www.ecfr.gov/current/title-40/part-98/subpart-RR#p-98.443(f)(2)). Furthermore, please note that emissions reported under subpart W are not duplicative with leakage/emissions used in subpart RR. Emissions reported in subpart RR are used in calculating a net sequestration amount and are not added to a facility’s total emissions. Please revise the above statement as necessary to reflect this.	Added to page 38 of the MRV plan: “Volumes for CO ₂ E (surface leakage) and CO ₂ FI (equipment leakage and vented emissions) are calculated separately and differently.”

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
12.	8.6	39	In the previous RFAI, the following was asked: “CO_{2P} = Total annual CO₂ mass produced (metric tons) net of CO₂ entrained in oil in the reporting year.’ Per 40 CFR 98.443(f)(1), this variable should be, “CO_{2P} = Total annual CO₂ mass produced (metric tons) in the reporting year.” Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.” Variable CO_{2P} in Equation RR-11 is still defined incorrectly. See https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-RR/section-98.443 for reference.	Corrected in the MRV.

**CAPTUREPOINT LLC DENVER CITY FIELDS
SUBPART RR MONITORING, REPORTING AND
VERIFICATION (MRV) PLAN**

October 2023

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1 Introduction

CapturePoint LLC operates a Carbon Dioxide Enhanced Oil Recovery (CO₂-EOR) project in the Denver City Field (DCF) located in Gaines County, Texas, approximately four miles southwest of the town of Denver City, Texas and less than two miles west of the Denver Unit of the giant Wasson San Andres Fields for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO₂) with a subsidiary or ancillary purpose of geologic sequestration of CO₂ in a subsurface geologic formation. The DCF is comprised of the George Allen Unit (GAU) which contains the Ruth Hudson Lease (RH). Like Wasson production is from the San Andres formation at an average depth of 5,000 feet. The Monitoring, Reporting and Verification (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 CO₂ sequestered at the Denver City Fields during a specified period of injection.

2 Facility Information

2.1 Reporter Number

576482 – Denver City Fields

2.2 UIC Permit Class

The Oil and Gas Division of the Texas Railroad Commission (TRRC) regulates oil and gas activity in Texas. All wells in the DCF (including production, injection, and monitoring wells) are permitted by TRRC through Texas Administrative Code (TAC) Title 16 Chapter 3. TRRC has primacy to implement the Underground Injection Control (UIC) Class II program in the state for injection wells. All EOR injection wells in the DCF are currently classified as UIC Class II wells.

2.3 Existing Wells

Wells in the DCF are identified by name and number, American Petroleum Institute (API) number, type, and status. The list of wells as of March 2023 is included in Section 12.1. Any changes in wells will be indicated in the annual subpart RR submission.

3 Project Description

This project takes place in the DCF, an oil field located in West Texas that was first produced more than 60 years ago. The DCF is comprised of the GAU which contains the RH. The two are adjacent to each other, produce oil and gas from the same geologic formations and structure, and are under the sole operatorship of CapturePoint LLC. The geology, facilities/equipment, and operational procedures are similar for both in the DCF. In addition, the two properties share the same CO₂ recycle and water injection facilities as well as the injection piping system for both CO₂ and water. Because of these common facilities and common reservoir, one MRV Plan is being prepared for the two properties in the DCF and any important differences between the two properties will be noted in the MRV plan. CO₂ flooding was initiated in 2007 in the GAU and in 2012 in the RH. The field is well characterized and is suitable for secure geologic storage in the San Andres formation. CapturePoint LLC uses a water alternating with gas (WAG) injection process and maintains an injection to withdrawal ratio (IWR) at or near 1.

3.1 Project Characteristics

The DCF was discovered in 1956 and started production in the same year. The DCF consists of one unit (GAU) and one lease (RH). The GAU began to produce in May 1956 and the waterflood was initiated in September 1989. CO₂ flooding was initiated in December 2007, in both the Main Pay and Residual Oil Zone (ROZ). The RH initiated a waterflood in March 2008 and began to produce in November 2008. CO₂ flooding was initiated in December 2012, also in the Main Pay and ROZ.

A long-term forecast for both the GAU and RH was developed using a dimensionless performance curve (DPC) approach. Using this approach, approximately 2.0 million tonnes of stored CO₂ is forecasted over the life of the project. Figure 3-1 shows actual and projected CO₂ injection, production, and stored volumes in DCF.

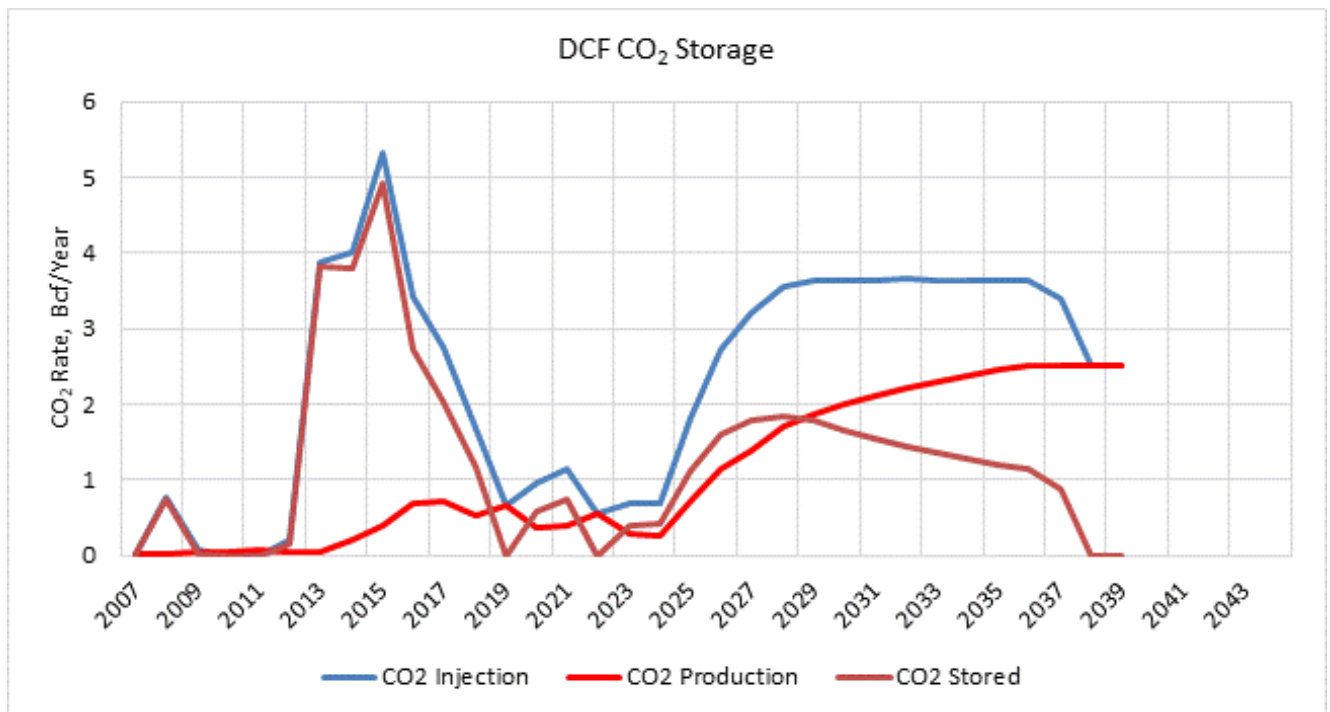


Figure 3-1 DCF Historic and Forecast CO₂ Injection, Production, and Storage

3.2 Environmental Setting

The DCF is located in the NE portion of the Central Basin Platform in West Texas (See Figure 3-2). This map also shows the location of the Denver Unit and other Wasson San Andres Units. The DCF is shown by the green dot.

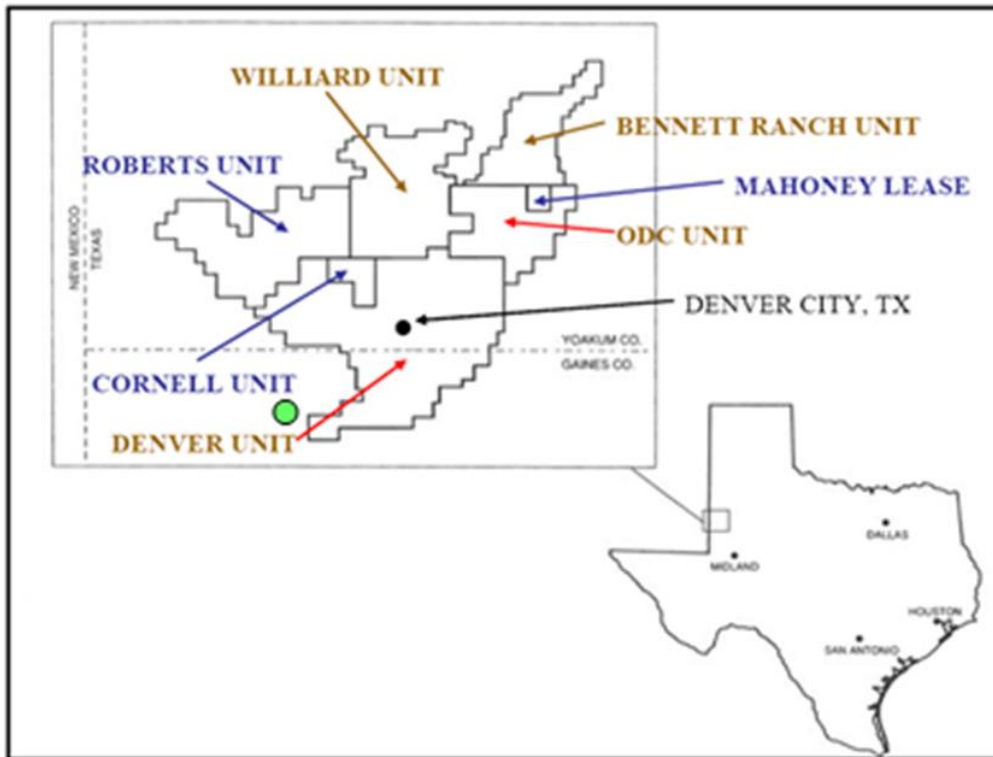


Figure 3-2 Location of DCF in West Texas

Like Wasson, the DCF produces from a San Andres dolomite reservoir at a depth of about 5,000 feet. In contrast to Wasson, DCF is a smaller oil accumulation with a thin mobile oil column trapped by a low relief anticlinal structure as shown in Figure 3-3. The Wasson field has produced over two billion barrels of oil to date from the San Andres while the DCF has produced 2.06 million barrels of oil to 2022.

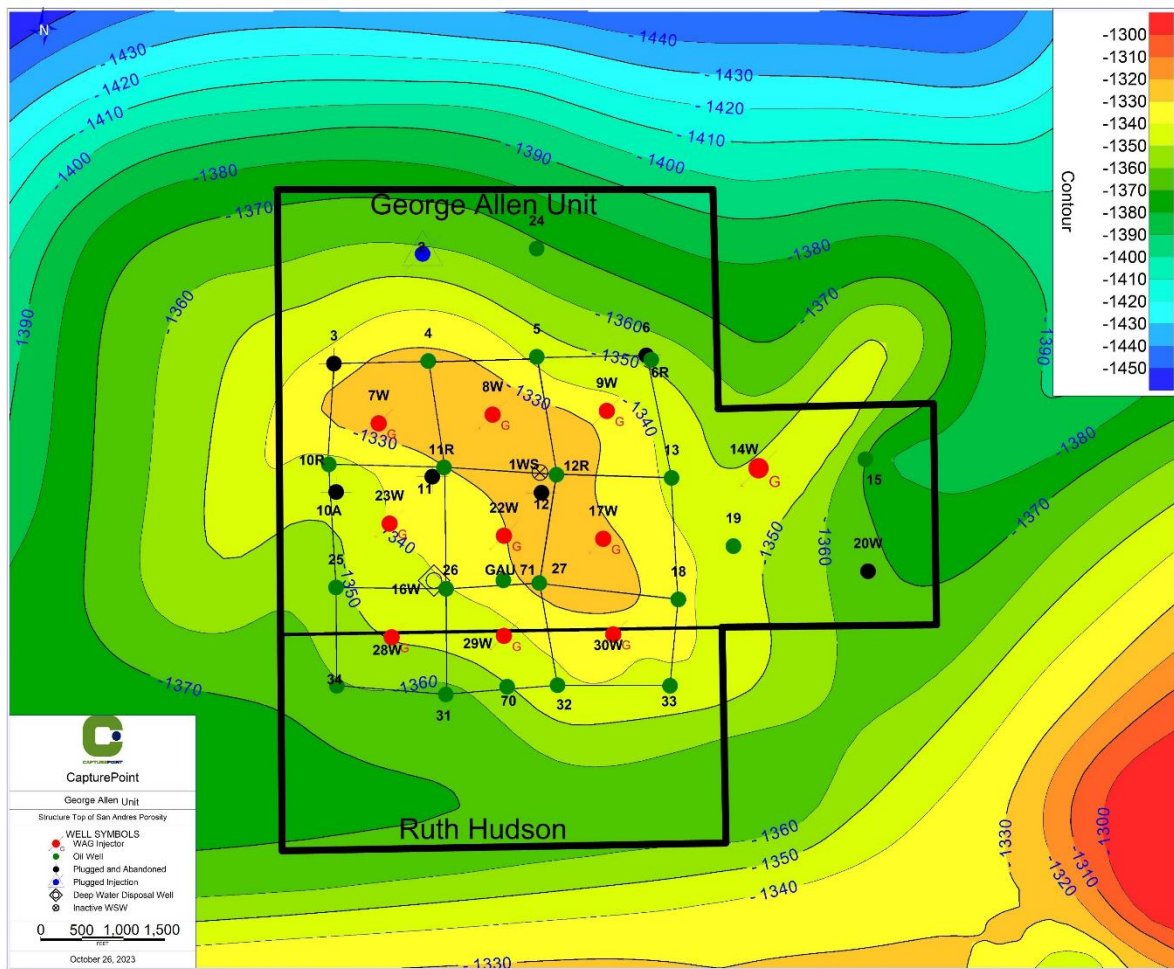


Figure 3-3 Local Area Structure on Top of San Andres for DCF

In the DCF there is a thin mobile oil column. Beneath the conventional oil column there is a thick, porous section with transition zone/residual oil (TZ/ROZ) that can only be produced via tertiary recovery methods, primarily CO₂ injection. This thick TZ/ROZ zone as found in the Wasson field gives a sizeable target for tertiary recovery (over 300 feet gross thickness).

Oil in the TZ/ROZ is currently being produced via CO₂ injection. Nine 40-acre patterns were prepared to inject CO₂ in this zone in the DCF. The presence of thick residual zones in the San Andres of the Permian Basin is widespread. Lindsay (2001), Melzer (2005), Melzer (2006), and Koperna and Kuuskraa (2006; 1&2) discuss the possible origins and the extent of residual oil zones in the Permian Basin. Brown (2001) discusses the ROZ in the area and its possible origin. The residual zone in the DCF has better porosity and permeability and is much thicker than the mobile oil zone which produced during primary and secondary (waterflood) recovery. This is often the case in residual oil zones, particularly those found in smaller fields with thinner oil columns. This gives us a large resource in which to economically sequester large volumes of CO₂, as CO₂ can both be stored and utilized for oil recovery in the extensive residual oil zones found in the San Andres in the Permian Basin.

The oil saturation profile found in the DCF/Wasson area is shown below in Figure 3-4 from Koperna and Kuuskraa (2006; 2):

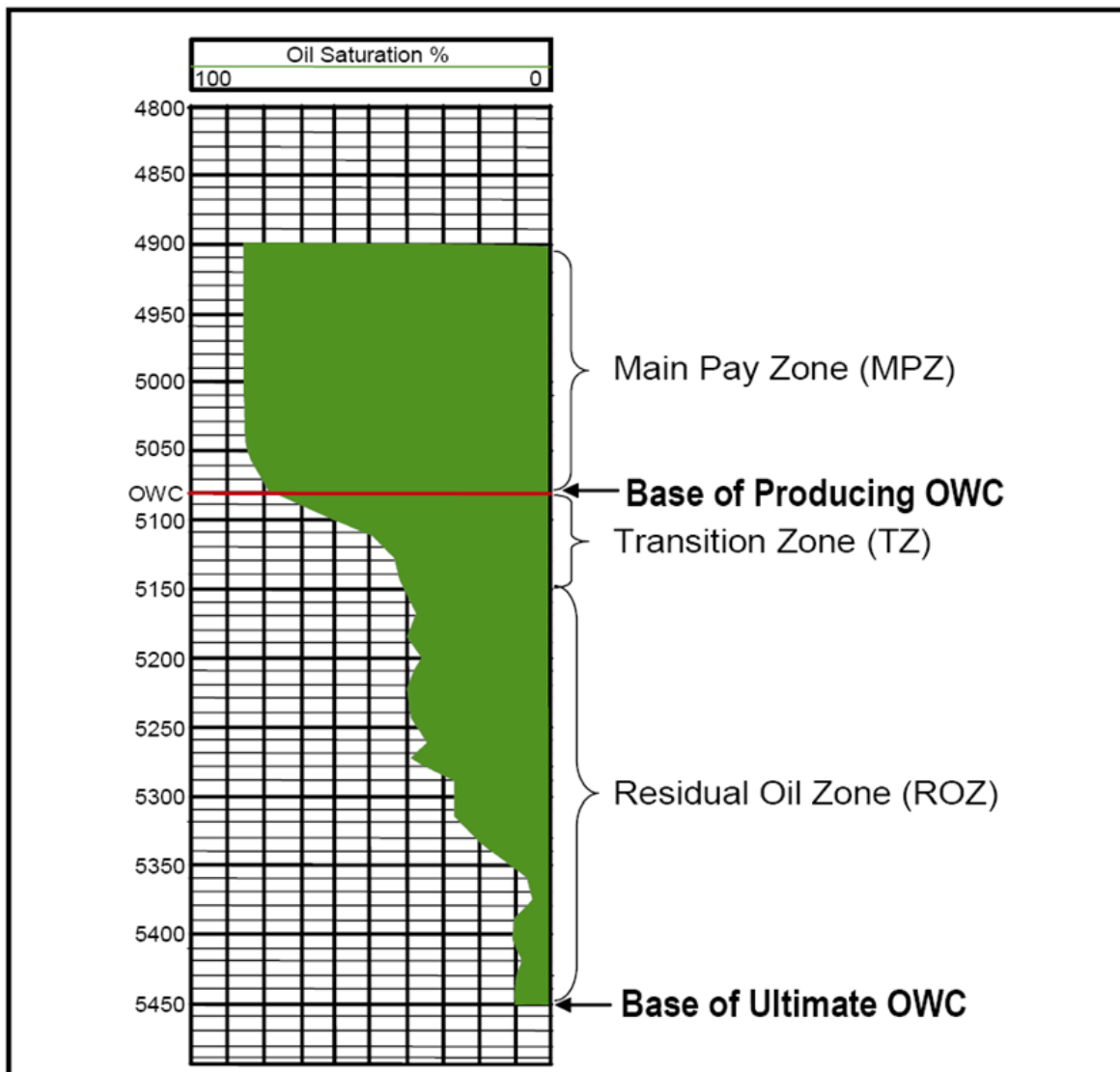


Figure 3-4 Saturation Profile of San Andres

Due to hydrodynamic flow in the San Andres aquifer, a ROZ was created and is under CO₂ flood along with the Main Pay Zone in the San Andres Formation.

Once the CO₂ flood is complete and injection ceases, the remaining mobile CO₂ will rise slowly upward, driven by buoyancy forces. There is more than enough pore space (188 million reservoir barrels (MRB)) to sequester the planned CO₂ injection (27.8 million reservoir barrels). The amount of CO₂ injected will not exceed the reservoir's secure storage capacity and, consequently, the risk that CO₂ could migrate to other reservoirs in the Central Basin Platform is negligible. The volume of CO₂ storage is based on the estimated total pore space within the DCF. The total pore space within the DCF, from the top of the reservoir down to the base of the ROZ, is calculated to be 188 million reservoir barrels (MRB). This is the volume of rock multiplied by porosity. Table 3-1 below shows the conversion of this amount of pore space into an estimated maximum volume of

approximately 254 billion cubic feet (Bcf) (13.4 million tonnes) of CO₂ storage in the reservoir. CO₂ will occupy only 15% of the total calculated storage capacity by the year 2037 based on the projected forecast.

Table 3-1 Calculation of Maximum Volume of CO₂ Storage Capacity at DCF

Top of Main Pay to Bottom of Residual Oil Zone (ROZ)	
Variables	DCF Outline
Pore Volume (RB)	188,396,478
BCO₂ (RB/MCF)	0.407
S_{wirr}	0.35
S_{or CO₂}	0.10
Max CO₂ (MCF)	254,589,835
Max CO₂ (BCF)	254

$$\text{Max CO}_2 = \text{Pore Volume} * (1 - S_{wirr} - S_{or CO_2}) / BCO_2$$

Where:

Max CO₂ = the maximum amount of storage capacity

Pore Volume = Total pore space in reservoir barrels (RB)

BCO₂ = the formation volume factor for CO₂

S_{wirr} = the irreducible water saturation

S_{or CO₂} = the irreducible oil saturation

Reservoir management is employed on a constant basis to obtain the maximum possible economic recovery from a reservoir based on facts, information, and knowledge. A reservoir management strategy that is used in CO₂ floods is the implementation of water curtain injectors. This will be utilized in the DCF to create a pressure barrier or “curtain” to contain the injected CO₂ to the area selected for production. Water curtain injection is an efficient method of maintaining and controlling lateral migration of fluids to assure that CO₂ does not cross structurally deficient locations. Injected fluids (CO₂) stay in the reservoir within the DCF unit boundary and do not move to adjacent areas.

Given that in DCF the confining zone has proved competent over both millions of years and in the current CO₂ flooding, and that the DCF has ample storage capacity, there is confidence that stored CO₂ will be contained securely within the reservoir.

3.3 Geologic Setting/Stratigraphic Column

The George Allen/Wasson San Andres fields are located on the Northwest shelf of the Permian Basin (Figure 3-5).

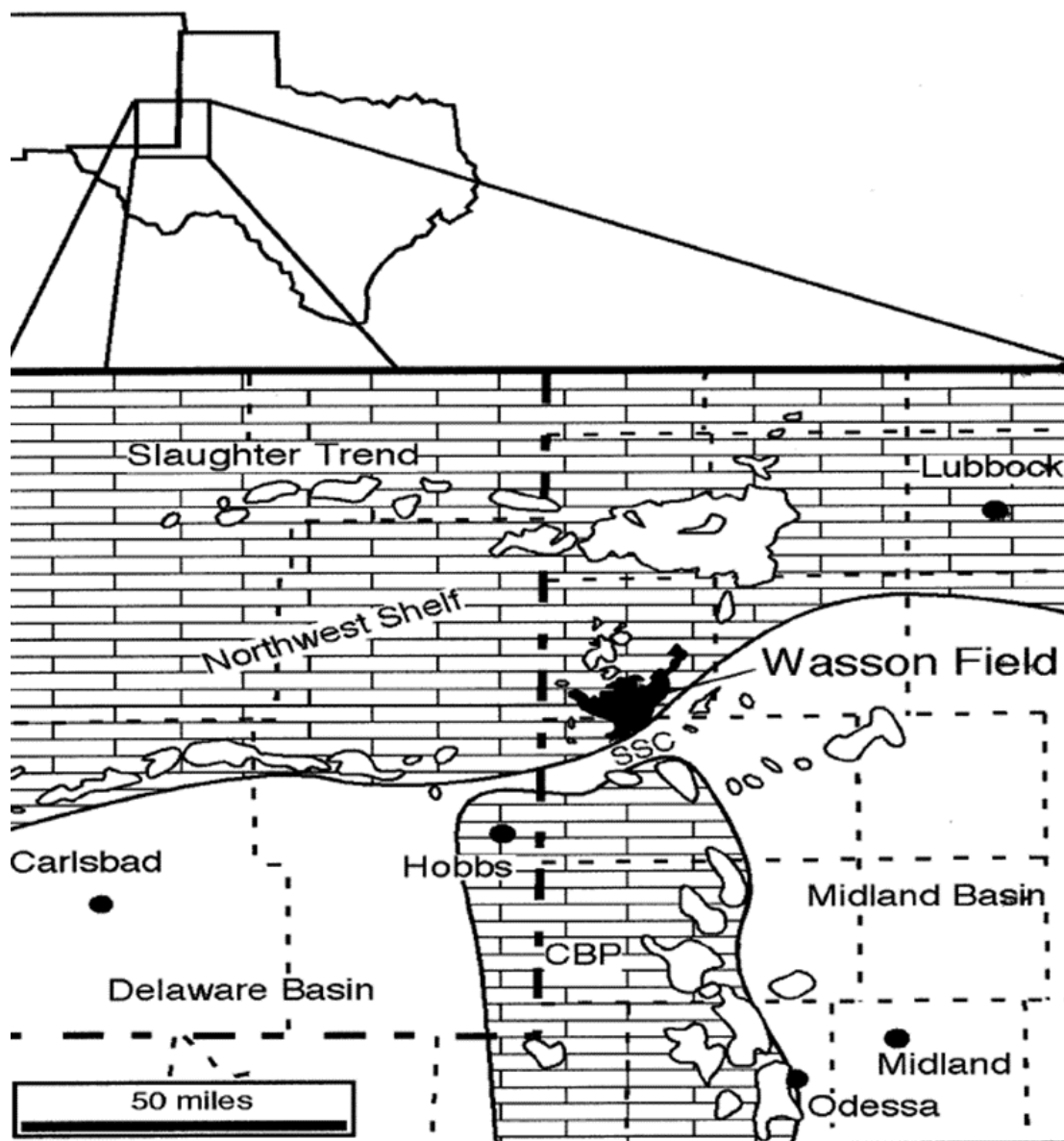


Figure 3-5 Map of Northwest shelf of the Permian Basin

The Wasson field is shown in black. Other San Andres fields are outlined. San Andres “shelf” facies are indicated by the brick pattern. “CBP” refers to the “Central Basin Platform” a major structural feature that separates the Delaware Basin from the Midland Basin. “SSC” refers to the “San Simon Channel” a feature which allowed seawater circulation between the shallow restricted shelf areas of the Northwest Shelf and the Central Basin Platform.

Figure 3-6 below shows the thickness and broad extent of the porous facies in the San Andres formation.

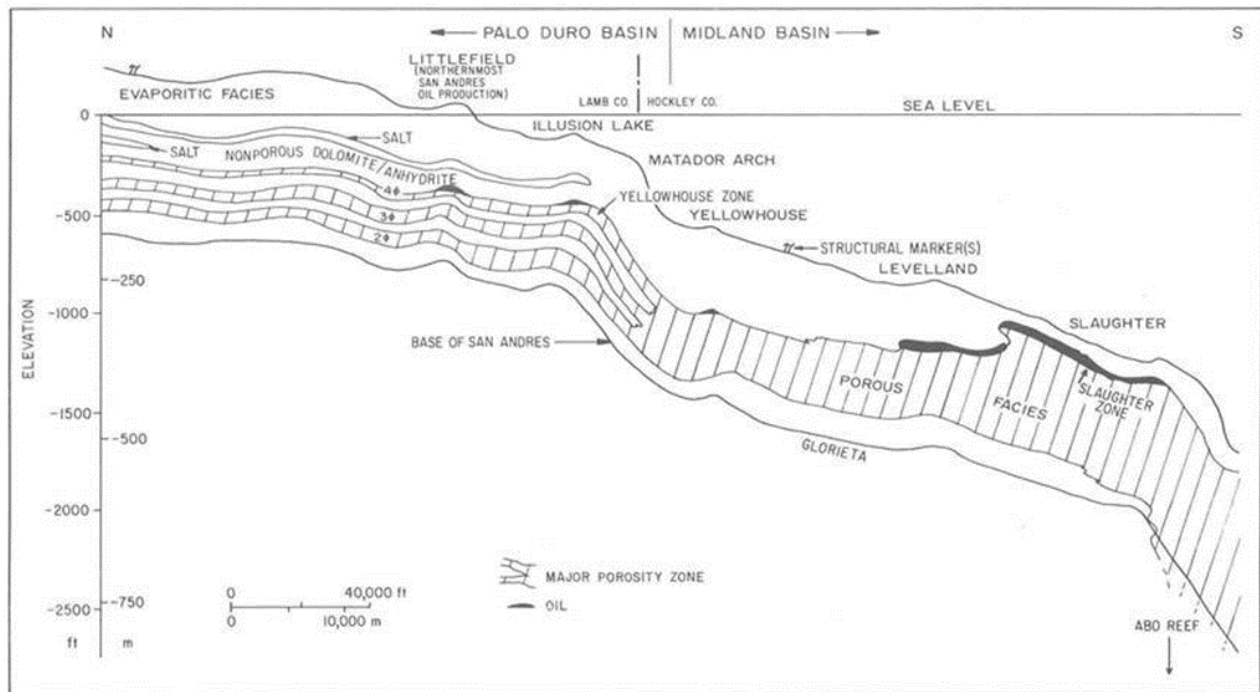


Figure 3-6 Cross section of lower San Andres Formation, Northern Shelf, showing porosity relationships.

A typical stratigraphic section for the area is shown below in Figure 3-7.

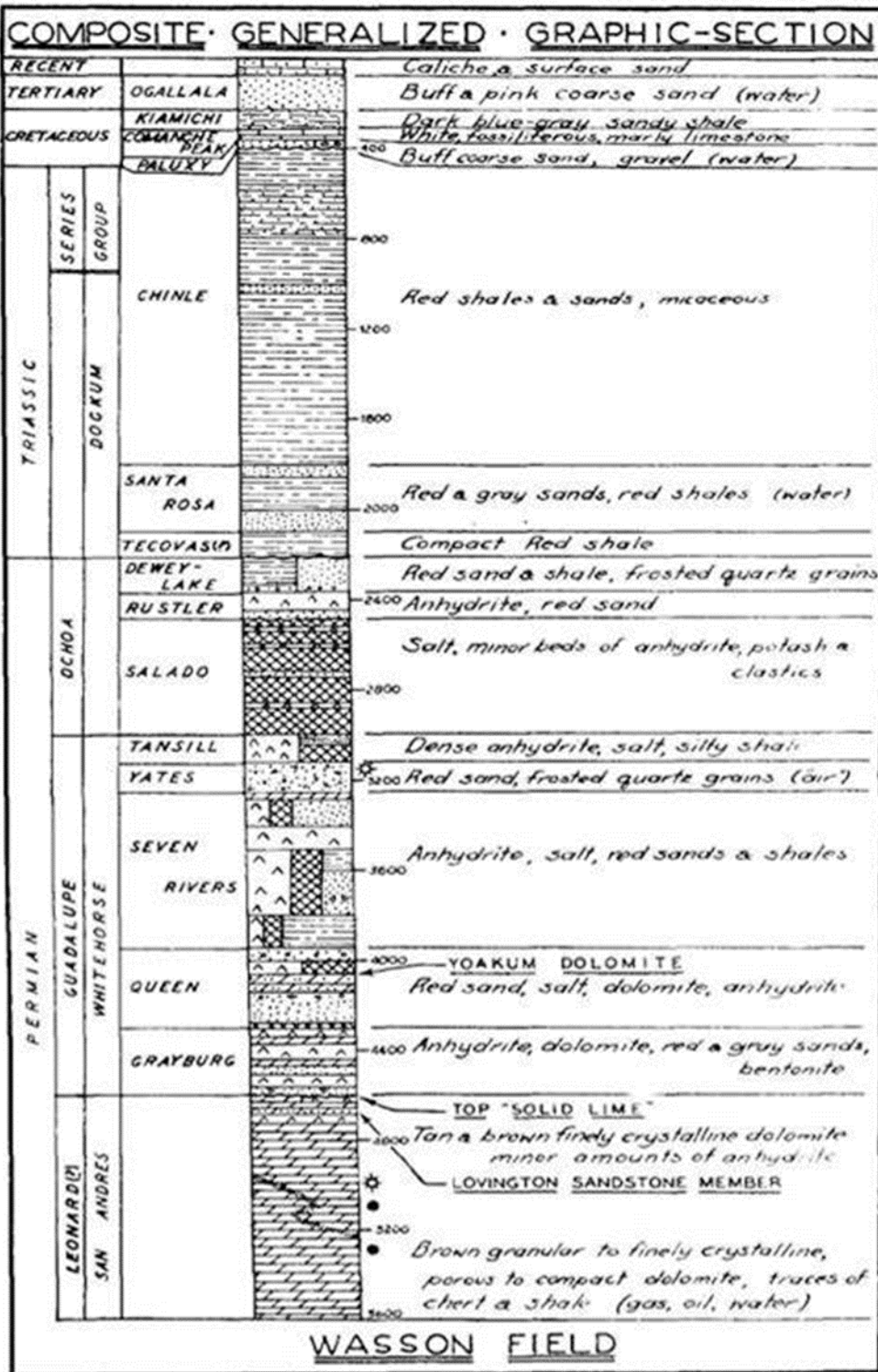


Figure 3-7 Composite generalized stratigraphic section.

The stratigraphy and facies of the Upper Permian on the Northwest Shelf and Central Basin Platform is quite uniform and serves as an ideal setting for trapping hydrocarbons, For the same reasons is an ideal setting for trapping/sequestering CO₂. The thick, porous, shallow water, carbonate facies that prograded basinward over time are overlain and interfingered with tidal flat, and restricted/exposed the shelf facies, which serve as widespread and efficient seals. The

notable thing about the Upper Permian rocks described here is that there are multiple and thick intervals that should eliminate the possibility of any vertical migration of fluids or gases from the San Andres reservoir to the surface.

The first seal is the Upper San Andres which consists of dense, fine crystalline dolomite and anhydrite, devoid of any porosity or permeability, deposited on the tidal flats of a broad, restricted shelf. Where the porous, shallow water carbonate facies of the Lower San Andres pinch out and interfinger with these rocks a series of stratigraphic traps is formed in the northern part of the Northwest Shelf. The Levelland-Slaughter-Chaveroo-Cato San Andres fields are found in this trend. A similar porosity pinches out, on the interior of the Central Basin platform, controls the widespread San Andres production found on the eastern margin of the Central Basin platform. These widespread producing trends attest to sealing capacity of the Upper San Andres anhydrous dolomite facies both vertically and laterally.

Above the San Andres are a series of restricted/exposed shelf facies consisting of tight, anhydrous dolomite, anhydrite, salt, and thin sandstones of the Upper Guadalupian Grayburg, Queen, Seven Rivers, Yates and Tansill formations. The sandstones sometimes have porosity and permeability but are often cemented by salt and are non-permeable. Where permeable, they offer no chance for vertical migration of fluids or gases as they are inter-layered with impermeable salt, anhydrite, and anhydrous dolomite.

Following the Tansill, the Ochoan, Upper Permian evaporites of the Salado and Rustler formations exist. The Salado is roughly 600-700 feet thick in the Wasson/George Allen area and consists dominantly of halite with some thin beds of potash and anhydrite and a few very thin layers of red mud, silt, and fine sand. Being widespread, thick, and impermeable, this formation alone should certainly stop the vertical migration of any fluids or gases from the subsurface to the surface. Even if fractured, the salt will flow and seal any open cracks. It is followed by the Rustler formation; 60 feet of dense, white anhydrite at the top overlying 30 feet of red shale interbedded with anhydrite; another capstone, on top a over 2,500 feet of mostly impermeable rock.

The Permian ends with the Dewey Lake formation which consists of red gypsum cemented sandstone and red shales.

Above the Permian unconformity are the Triassic Tecovas red shale and then the Santa Rosa formation which contains fresh water bearing sandstones. These deposits are followed by the micaceous red shales and sands of the Chinle formation. A major unconformity separates the Triassic Chinle from the overlying Cretaceous sediments that consists of coarse sand and gravel, white marly limestone, and dark, blue-gray sandy shale.

An important aquifer, the Tertiary Ogallala formation overlies these Cretaceous sediments. It consists of coarse sands and vari-colored gravels, all loose or poorly consolidated, which are followed by recent wind-blown sand and caliche.

3.4 Description of CO₂-EOR Project Facilities and the Injection Process

Figure 3-8 shows a simplified process flow diagram of the project facilities and equipment in the DCF. CO₂ will be delivered to the DCF from Trinity, via the Kinder Morgan CO₂ pipeline network. The CO₂ will be supplied by several different sources including both natural and anthropogenic CO₂ sources. Specified amounts will be drawn from an outside source pipeline based on contractual arrangements among suppliers of CO₂, purchasers of CO₂, and the pipeline operator. The Specified amount of CO₂ required in addition to the produced gas to meet target CO₂ injection rates are forecasted using the DPC approach.

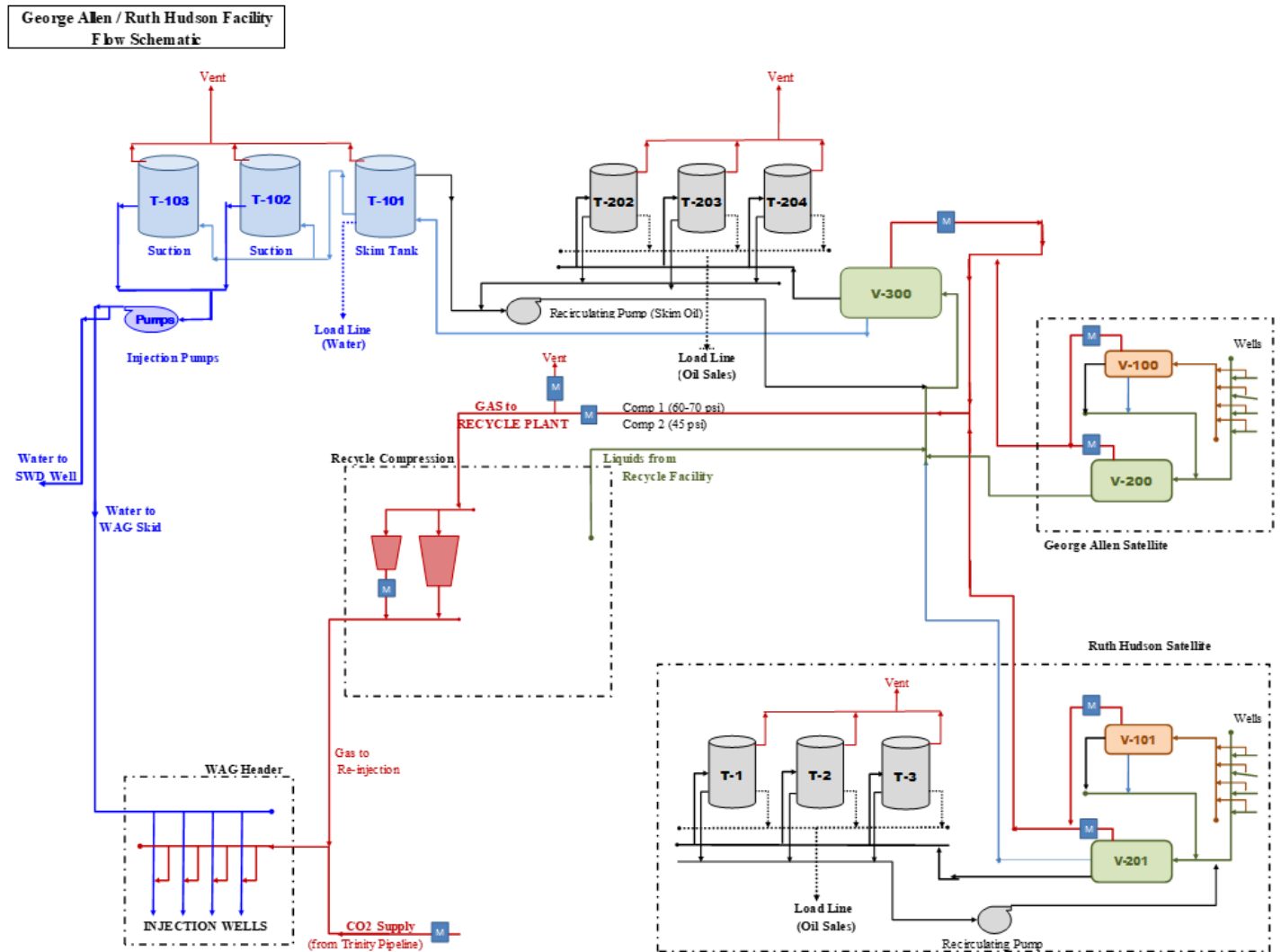


Figure 3-8 DCF Process Flow Diagram

Once CO₂ enters the DCF there are three main processes involved in CO₂-EOR operations:

- i. CO₂ Distribution and Injection: The mass of CO₂ received at the DCF is metered and calculated through the Custody Transfer Meter located at the pipeline delivery point. The mass of CO₂ received is combined with recycled CO₂ / hydrocarbon gas mix from the recycle compression facility (RCF) and distributed to the WAG headers for injection into the injection wells according to the pre-programmed injection plan for each well pattern which alternates between water and CO₂ injection. WAG headers are manually operated and can inject either CO₂ or water at various rates and injection pressures as specified in the injection plans. This is an EOR project and reservoir pressure must be maintained above minimum miscibility pressure. Therefore, injection pressure must be sufficiently high to allow injectants to enter the reservoir, but below formation parting pressure (FPP)
- ii. Produced Fluids Handling: Produced fluids from the production wells are a mixture of oil, hydrocarbon gas, water, CO₂, and trace amounts of other constituents in the field including nitrogen and Hydrogen Sulfide (H₂S) as discussed in Section 7. They are gathered and sent to Satellite Test Stations (SAT) for separation into a gas/CO₂ mix and a produced fluids mix of water, oil, gas, and CO₂. The produced gas, which is composed primarily of CO₂ and minor hydrocarbons, is sent to the RCF for dehydration and recompression before reinjection into the reservoir. An operations meter at the RCF is used to determine the total volume of produced gas that is reinjected. The separated oil is sent to two separate tanks (one at GAU and one at RH) where is then sold via truck.
- iii. Water Treatment and Injection: Water is recovered for reuse and forwarded to the water injection station for reinjection or disposal.

3.4.1 Wells in the Denver City Fields

The TRRC has broad authority over oil and gas operations including primacy to implement UIC Class II wells. The rules are found in TAC Title 16, Part 1, Chapter 3 and are also explained in a TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual (See Appendix 12-2). TRRC rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields.

Briefly, TRRC rules include the following requirements:

- Fluids must be constrained in the strata in which they are encountered,
- activities cannot result in the pollution of subsurface or surface water,
- wells must adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata that are encountered into other strata with oil and gas, or into subsurface and surface waters,
- completion report for each well including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore) must be prepared,
- operators must follow plugging procedures that require advance approval from the TRRC Director and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs; and,
- injection well operators must identify an Area of Review (AoR), use compatible materials and equipment, test, and maintain well records.

Table 3-2 provides a well count by type and status. All these wells are in material compliance with TRRC rules.

Table 3-2 DCF Well Penetrations by Type and Status

TYPE	ACTIVE	INACTIVE	P & A	Total
PROD_OIL	16	3		19
INJ_WTR	0	1		1
INJ_WAG	8	0		8
INJ_SWD*	0	0		0
WSW	0	0		0
P&A			3	3
TOTAL	24	4	3	31

PROD_OIL = Production Wells

INJ_WRT = Water injection wells

INJ_WAG = WAG injection wells

INJ_SWD = Saltwater disposal wells

WSW = Water source wells

P&A = Plugged and Abandoned wells.

As indicated in Figure 3-9, wells are distributed across the DCF. The well patterns currently undergoing CO₂ flooding are identified by black 5-spot pattern outlines and CO₂ will be injected across the entire unit over the project life.

DCF CO₂-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Reservoir pressure in the DCF is managed by maintaining an IWR of approximately 1.0. To maintain the IWR, fluid injection and production are monitored and managed to ensure that reservoir pressure does not increase to a level that would compromise the reservoir seal or otherwise damage the integrity of the oil field.

Injection pressure is also maintained below the FPP, which is measured using step-rate tests.

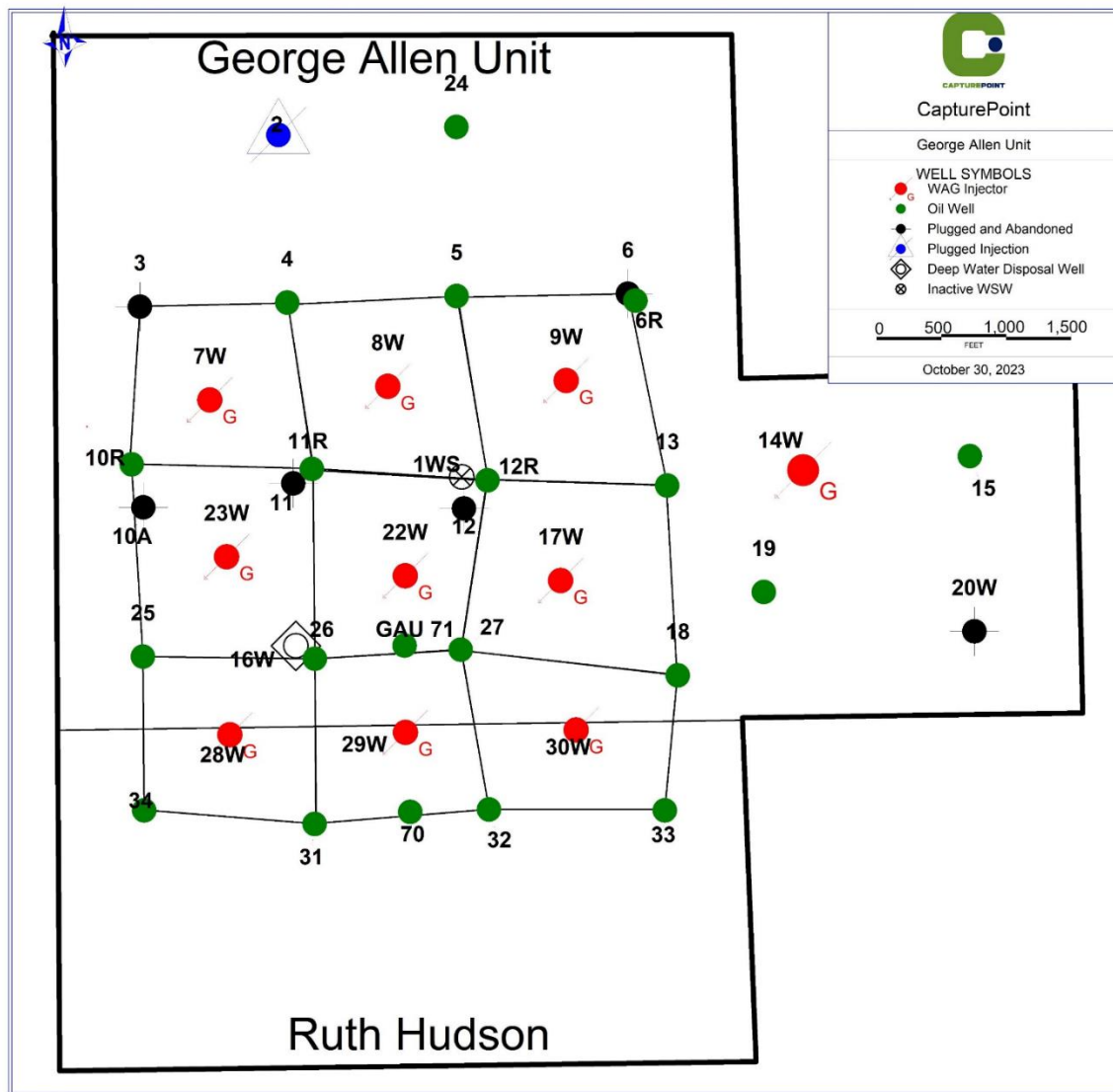


Figure 3-9 DCF Wells and Injection Patterns

3.5 Reservoir Forecasting

DPCs derived from analogous fields were used to project CO₂-EOR in the Denver City Fields. Most DPC are derived from geologic and reservoir models. In the DCF case the DPC was derived from actual field performance from an analogous field.

A DPC is a plot where injection and production volumes for CO₂, water, and hydrocarbon phases are normalized by dividing by Hydrocarbon Pore Volume (HCPV). See Figure 3-10. The dimensioned projections for the oil, CO₂, and water production are relative to the CO₂ and water injection and are calculated using the original oil in place of an area of interest.

HCPV of Produced:
CO₂, Oil or Water

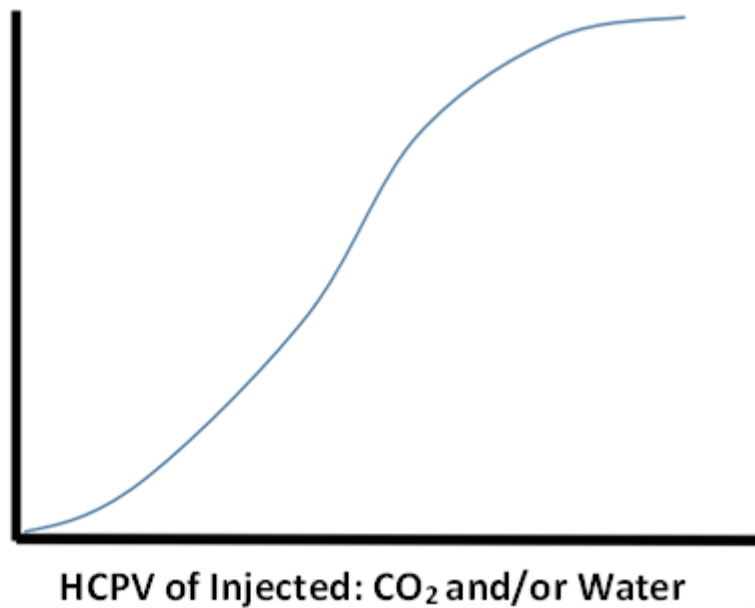


Figure 3-10 DPC plot

The DCF DPC was calculated from the cumulative production and injection from an analogous field. This DPC was used on each pattern in the DCF and then summed up to full field. This method allows you to use different start times and implement different field implementation speeds.

The DPCs are the basis for future performance prediction scenarios but are additionally a means of evaluating the reservoir process efficiencies. In a similar manner to history matching in reservoir simulation, deviations from expected performance can indicate errors in the geologic model of the pore volume, growth of the CO₂ plume, or metering and production allocation errors.

4 Delineation of Monitoring Area and Timeframes

4.1 Active Monitoring Area

The Active Monitoring Area (AMA) is defined by the GAU and RH boundaries plus the required $\frac{1}{2}$ mile zone. Based on our projections, CapturePoint expects the free phase CO₂ plume to remain within the GAU and RH boundaries for the entire length of the project and through year [t+5]. The CO₂ storage volume calculations show the CO₂ to remain within the unit boundaries in the period associated with the AMA, which is year 2037.

The AMA is shown in Figure 4-1. It is an area defined by the boundary of the DCF plus the required $\frac{1}{2}$ 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).

4.1.1 Discussion of CO₂ Storage Volumes in AMA

The CO₂ injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO₂-EOR. Maintenance of an Injection to Withdrawal ratio of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

Figure 3-9 displays wells that have CO₂ retention on the 370 acres that have been under CO₂ injection since project initialization. The CO₂ storage volumes were forecasted using the DPC approach. This technique indicates that the flooded acreage still has significant storage potential. The maximum CO₂ storage (254 BCF) is limited to the amount of space available by the removal of the produced hydrocarbon and water. The projection indicates that there is pore space available to store approximately 0.15 decimal fraction of HCPV amounting to 27.8 million reservoir barrels of oil (MMRB) (37.5 BCF).

The lateral extent of CO₂ in the injection zone or the CO₂ storage radius for each well was estimated by calculating a storage radius based on the forecasted CO₂ storage volume of 37.5 BCF. Figure 4-1 shows the map of the storage area outline for each pattern (dashed red line). This calculation showed 166 acres (this calculates to 18 acres per pattern) would be needed to store 37.5 BCF. This is significantly less than the 1133 acres in the DCF outline.

CO₂ injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO₂-EOR. Namely, maintenance of an IWR of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

4.2 Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined by the GAU and RH boundaries plus the required $\frac{1}{2}$ mile buffer as required by 40 CFR §98.440-449 (Subpart RR). The CO₂ plume (Figure 4-1) is expected to be contained within the GAU and RH boundaries which will be actively

monitored. Therefore, CapturePoint defines the MMA as the same as the AMA since the plume location is less than the unit area. 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 FR 98.448(d)(1).

4.3 Monitoring Timeframes

The primary purpose for injecting CO₂ is to produce oil that would otherwise remain trapped in the reservoir and not, as in UIC Class VI, “specifically for the purpose of geologic storage.”¹ During a Specified Period, there will be a subsidiary purpose of establishing the long-term containment of CO₂ in the DCF. The Specified Period is the timeframe that CO₂ storage will occur. In the DCF, CO₂ storage will occur until 2037 at which point CO₂ injection will equal CO₂ production. Specified Period will be shorter than the period of production from the DCF.

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted with a demonstration that current monitoring and model(s) show that the cumulative mass of CO₂ reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration after the Specified Period ends based upon monitoring data.

The reservoir pressure in the DCF is collected for use in operations management. Reservoir pressure is not forecasted to change appreciably since the IWR will be maintained at approximately 1. Once injection ceases, reservoir pressure is predicted to stabilize within one year.

¹ EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b). A

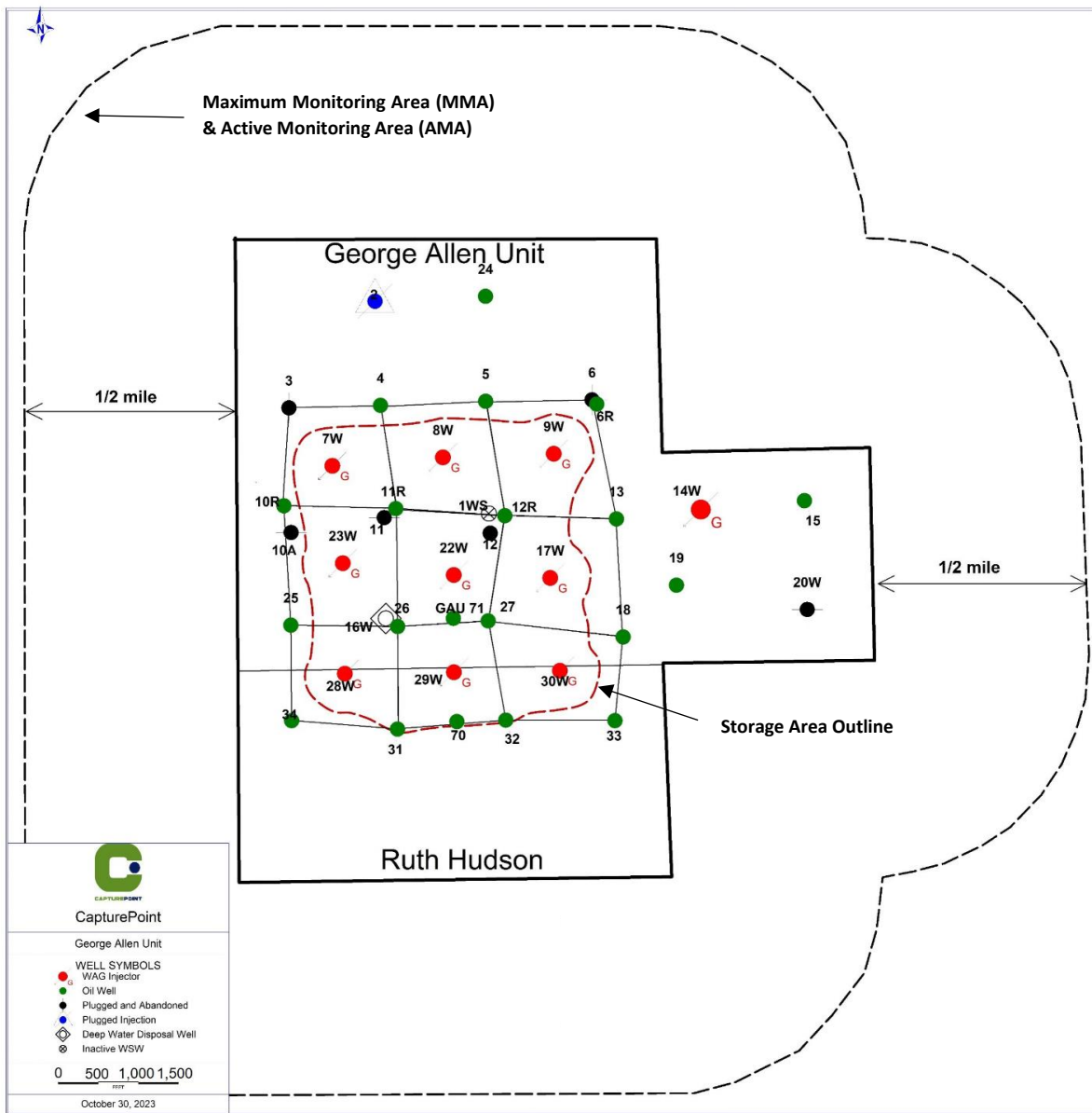


Figure 4-1 Projected CO₂ Storage area

5 Evaluation of Potential Pathways for Leakage to the Surface, Leakage Detection, Verification, and Quantification

In the roughly 60 years since the DCF oil field was discovered, the reservoir has been studied extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO₂ to the surface including:

1. Existing Wellbores
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the DCF
7. Drilling Through the CO₂ Area
8. Diffuse Leakage Through the Seal
9. Leakage Detection, Verification, and Quantification

This analysis shows that leakage through wellbores and surface equipment pose the only meaningful potential leakage pathways. The monitoring program to detect and quantify leakage is based on this assessment as discussed below.

5.1 Existing Wells

As part of the TRRC requirement to initiate CO₂ flooding, an extensive review of all the DCF penetrations was completed to determine the need for corrective action. That analysis showed that all penetrations have either been adequately plugged and abandoned or, if in use, do not require corrective action. All wells in the DCF were constructed and are operated in compliance with TRRC rules.

As part of routine risk management, the potential risk of leakage associated with the following were identified and evaluated:

- CO₂ flood electrical submersible pump (ESP) producing wells,
- CO₂ flood beam pumped producing wells, and
- CO₂ injector wells.

The risk assessment classified all risks associated with subsurface as low risk, i.e., less than 1% likelihood to occur and having a consequence that is insubstantial. The risks were classified as low risk because DCF geology is well suited to CO₂ sequestration with an extensive confining zone that is free of fractures and faults that could be potential conduits for CO₂ migration. Any risks are further mitigated because the DCF is operated in a manner that maintains, monitors, and documents the integrity of the reservoir.

The risk of well leakage is mitigated through:

- Adhering to regulatory requirements for well drilling and testing,
- implementing best practices that CapturePoint has developed through its extensive operating experience,
- monitoring injection/production performance, wellbores, and the surface; and,
- maintaining surface equipment.

Continual and routine monitoring of the wellbores and site operations will be used to detect leaks or other potential well problems, as follows:

- Pressure in injection wells is monitored daily. The injection plans for each pattern are provided to field operations to govern the rate, pressure, and duration of either water or CO₂ injection. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such events occur, they would be investigated and addressed. CapturePoint's experience, from over 10 years of operating CO₂-EOR projects, is that such leakage has not occurred.
- Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a SAT. There is a routine well testing cycle for each SAT, with each well being tested approximately once every month. During this cycle, each production well is diverted to the well test equipment for a period sufficient to measure and sample produced fluids (generally 12-24 hours). These tests are the basis for allocating a portion of the produced fluids measured at the SAT to each production well, assessing the composition of produced fluids by location, and assessing the performance of each well. Performance data are reviewed on a routine basis to ensure that CO₂ flooding efficiency is optimized. If production is off plan, it is investigated, and any identified issues addressed. Leakage to the outside of production wells is not considered a major risk because of the reduced pressure in the casing. Further, the personal H₂S monitors are designed to detect leaked fluids around production wells during well inspections as well as various permanent H₂S monitors throughout the field at ground level.
- Field inspections are conducted on a routine basis by field personnel. Leaking CO₂ is very cold and leads to the formation of bright white clouds and ice that are easily spotted. All field personnel are trained to identify leaking CO₂ and other potential problems at wellbores and in the field. Any CO₂ leakage detected will be documented, quantified, and reported.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, it is concluded that the risk of CO₂ leakage through wellbores is being mitigated by detecting problems as they arise and quantifying any leakage that does occur. If leakage did occur, the magnitude of 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.

5.2 Faults and Fractures

After reviewing geologic, seismic, operating, and other evidence, it has been concluded that there are no known faults or fractures that transect the San Andres reservoir in the project area. As a result, there is minimal risk of leakage due to fractures or faults.

Measurements to determine FPP and reservoir pressure are routinely updated. This information is used to manage injection patterns so that the injection pressure will not exceed FPP. An IWR at or near 1 is also maintained. Both procedures mitigate the potential for inducing faults or fractures. As a safeguard, WAG skids are continuously monitored.

5.3 Natural and Induced Seismicity

After reviewing the literature and actual operating experience; it is concluded that there is no direct evidence that natural seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF.

To evaluate this potential risk at the DCF, CapturePoint has reviewed the nature and location of seismic events in West Texas. While some of the recorded earthquakes in West Texas are judged to be from natural causes, others are near oil fields or water disposal wells and are placed in the category of “quakes in close association with human enterprise.”² A review of the United States Geological Survey (USGS) database of recorded earthquakes at M1.0 or greater in the Permian Basin since 1956 indicates that none have occurred in the DCF; the closest took place in 2020 approximately 38 miles away. See Figure 5-1.

The concern about induced seismicity is that it could lead to fractures in the seal providing a pathway for CO₂ leakage to the surface. CapturePoint is not aware of any reported loss of injectant (brine water or CO₂) to the surface associated with any seismic activity. There is no direct evidence to suggest that natural seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF. If induced seismicity resulted in a pathway for material amounts of CO₂ to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would detect the migration and lead to further investigation. CapturePoint monitors the USGS earthquake monitoring Geographical Information System (GIS) site³ for seismic signals that could indicate the creation of potential leakage pathways in the DCF.

² Frohlich, Cliff (2012) “Induced or Triggered Earthquakes in Texas: Assessment of Current Knowledge and Suggestions for Future Research”, Final Technical Report, Institute for Geophysics, University of Texas at Austin, Office of Sponsored Research.

³ <https://earthquake.usgs.gov/earthquakes/map/>

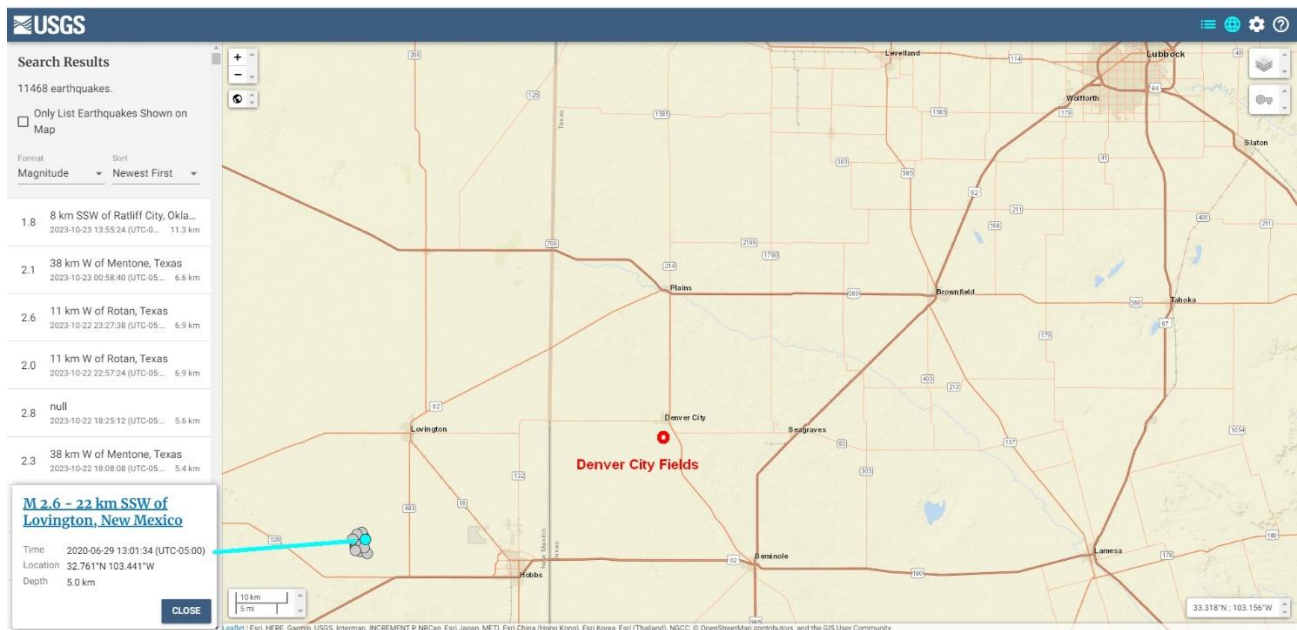


Figure 5-1 USGS earthquakes (+1.0 magnitude) for last 57 years)

5.4 Previous Operations

CO₂ flooding was initiated in the DCF in 2007. To obtain permits for CO₂ flooding, the AoR around all CO₂ injector wells was evaluated to determine if there were any unknown penetrations and to assess if corrective action was required at any wells. As indicated in Section 5.1, this evaluation reviewed the identified penetrations and determined that no additional corrective action was needed. Further, CapturePoint's standard practice for drilling new wells includes a rigorous review of nearby wells to ensure that drilling will not cause damage to or interfere with existing wells. Additionally, requirements to construct wells with materials that are designed for CO₂ injection are adhered to at the DCF. These practices ensure that there are no unknown wells within the DCF and that the risk of migration from older wells has been sufficiently mitigated via location identification and daily on-site monitoring of rates and pressures. The successful experience with CO₂ flooding in the DCF demonstrates that the confining zone has not been impaired by previous operations.

5.5 Pipelines and Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO₂. CapturePoint anticipates that the use of prevailing design and construction practices and compliance with applicable laws will reduce to the maximum extent practicable the risk of unplanned leakage from surface facilities. The facilities and pipelines currently utilize and will continue to utilize materials of construction and control processes that are standard for CO₂-EOR projects in the oil and gas industry. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. Field personnel are trained to look for and report potential leaks from pipeline and surface equipment as part of their routine activities. Surface equipment leaks have a low risk of occurring based on design standards that are followed, and any leak would have insubstantial results. The magnitude of surface equipment leaks will

range from 0.1 to 2 MT yearly and are addressed within 6-12 hours of occurring. Should leakage be detected from pipeline or surface equipment, the volume of released CO₂ will be quantified following the requirements of Subpart W of the Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP).

5.6 Lateral Migration Outside the Denver City Fields

It is highly unlikely that injected CO₂ will migrate downdip and laterally outside the DCF because of the nature of the geology and the approach used for injection. Over prolonged periods of time, injected CO₂ will tend to rise vertically towards the Upper San Andres and continue towards the point in the DCF with the highest elevation. Second, the planned injection volumes and active fluid management during injection operations will prevent CO₂ from migrating laterally out of the structure. Finally, the total volume of fluids contained in the DCF will stay constant. Based on site characterization and planned and projected operations it is estimated that the total volume of stored CO₂ will be less than the calculated capacity.

5.7 Drilling in the Denver City Fields

The TRRC regulates well drilling activity in Texas. Pursuant to TRRC rules, well casing shall be securely anchored in the hole to effectively control the well at all times, all usable-quality water zones shall be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flow zones, and zones with corrosive formation fluids shall be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. Where TRRC rules do not detail specific methods to achieve these objectives, operators shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology. The TRRC requires applications and approvals before a well is drilled, recompleted, or reentered. Well drilling activity at the DCF is conducted in accordance with TRRC rules. CapturePoint's visual inspection process, including routine site visits, will identify unapproved drilling activity in the DCF.

In addition, CapturePoint intends to operate the DCF for several more years and will continue to be vigilant about protecting the integrity of its assets and maximizing the potential of its resources, including oil, gas, and CO₂. Consequently, the risks associated with third parties penetrating the DCF are negligible.

5.8 Diffuse Leakage Through the Seal

Diffuse leakage through the seal formed by the upper San Andres is highly unlikely. There are a number of sections above the reservoir that are impermeable and serve as reliable barriers to prevent fluids from moving upwards towards the surface. These barriers are referred to as seals because they effectively seal fluids within the formations beneath them.

Our injection pattern monitoring program assures that no breach of the seal will be created. The seal is highly impermeable. Wellbores that penetrate the seal make use of cement and steel construction that is closely regulated to ensure that no leakage takes place. Injection pressure is continuously monitored and unexplained changes in injection pressure that might indicate leakage would trigger investigation as to the cause.

5.9 Leakage Detection, Verification, and Quantification

As discussed above, the potential sources of leakage include issues, such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment (wellbores), and unique events such as induced fractures. An event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage is used. Table 5.1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, the standard response, and other applicable regulatory programs requiring similar reporting.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods for quantifying the volume of leaked CO₂ will be determined on a case-by-case basis using all metering and measurement equipment from each wellhead through the output of the tanks and recycle. In the event leakage occurs, the most appropriate methods for quantifying the volume leaked will be determined and it will be reported as required as part of the annual Subpart RR submission.

- For leakage through wellbores, daily monitoring of flow rates will provide the basis to determine duration and the amount of CO₂ loss;
- For leakage from surface equipment and pipelines, daily monitoring of flow rates and acceptable emission factors, such as those in 40 CFR Part §98 Subpart W, provide the basis to determine duration and the amount of CO₂ loss;
- For leakage related to the competency of the confining layer, reservoir modeling and engineering estimates provided the basis for determining the amount of CO₂ loss.

Any volume of CO₂ detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as the frequency of inspection. Leaks will be documented, evaluated, and addressed in a timely manner.

Records of leakage events will be retained in an electronic environmental documentation and reporting system. The Field Foreman is notified for maintenance activities that cannot be addressed on the spot.

Table 5-1 Response Plan for CO₂ Loss

Risk	Monitoring Plan	Response Plan
Tubing Leak	Monitor changes in tubing and annulus pressure; MIT for injectors	Well is shut in and workover crews respond within days
Casing Leak	Routine Field inspection; Monitor changes in annulus pressure, MIT for injectors; extra attention to high risk wells	Well is shut in and workover crews respond within days
Wellhead Leak	Routine Field inspection, SCADA system monitors wellhead pressure	Well is shut in and workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations	Maintain well kill procedures
Unplanned wells drilled through San Andres	Routine Field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells.	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Reservoir pressure in WAG headers; high pressure found in new wells	Re-enter and reseal abandoned wells
Pumps, valves, etc.	Routine Field inspection, SCADA	Workover crews respond within days
Overfill beyond spill points	Reservoir pressure in WAG headers; high pressure found in new wells	Fluid management along lease lines
Leakage through induced fractures	Reservoir pressure in WAG headers; high pressure found in new wells	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Reservoir pressure in WAG headers; high pressure found in new wells	Shut in injectors near seismic event
Diffuse leakage through the seal	Monitor injection pressure for unexplained changes in injection pressure that might indicate leakage	Investigate to determine if cement and steel construction is the issue. Well is shut in and workover crews respond within days.

5.10 Summary

The structure and stratigraphy of the San Andres reservoir in the DCF is ideally suited for the injection and storage of CO₂. The stratigraphy within the CO₂ injection zones is porous, permeable, and thick, providing ample capacity for long-term CO₂ storage. The reservoir is overlain by several intervals of impermeable geologic zones that form effective seals or “caps” to fluids in the reservoir.

In summary, based on a careful assessment of the potential risk of release of CO₂ from the subsurface, it has been determined that there are no leakage pathways at the DCF that are likely to result in significant loss of CO₂ to the atmosphere. Further, given the detailed knowledge of the field and its operating protocols, it is concluded that any CO₂ leakage to the surface that could arise through either identified or unexpected leakage pathways would be detected and quantified.

6 Monitoring and Considerations for Calculating Site Specific Variables

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

6.1 For the Mass Balance Equation

6.1.1 General Monitoring Procedures

Flow rate, pressure, and gas composition data are monitored and collected from the DCF in centralized data management systems as part of ongoing operations. This data is monitored by qualified technicians who follow response and reporting protocols when the systems deliver notifications that data exceed statistically acceptable boundaries.

Metering protocols used at DCF follow the prevailing industry standard(s) for custody transfer as currently promulgated by the API, the American Gas Association, and the Gas Processors Association, as appropriate. This approach is consistent with EPA GHGRP's Subpart RR, section §98.444(e)(3). These meters will be maintained routinely, operated continually, and will feed data directly to the centralized data collection systems. The meters meet the industry standard for custody transfer meter accuracy and calibration frequency.

6.1.2 CO₂ Received

As indicated in Figure 3-8, the volume of received CO₂ is measured using a commercial custody transfer meter at the point at which custody of the CO₂ from the Kinder Morgan CO₂ pipeline delivery system is transferred to the DCF. This meter measures flow rate continually. The transfer is a commercial transaction that is documented. CO₂ composition is governed by contract and the gas is routinely sampled. Fluid composition will be determined, at a minimum, quarterly, consistent with EPA GHGRP's Subpart RR, section §98.447(a). All meter and composition data are documented, and records will be retained for at least three years. No CO₂ is received in containers.

6.1.3 CO₂ Injected in the Subsurface

Injected CO₂ will be calculated using the flow meter volumes at the operations meter at the outlet of the RCF and the custody transfer meter at the CO₂ off-take point from the Kinder Morgan CO₂ Pipeline Delivery System.

6.1.4 CO₂ Produced, Entrained in Products, and Recycled

The following measurements are used for the mass balance equations in Section 8:

- CO₂ produced in the gaseous stage is calculated using the volumetric flow meters at the outlet of the separation facility (Figure 3-8 vessels, V-100, V-101, V-200, V201, V300, and V400),
- CO₂ that is entrained in produced oil, as indicated in Figure 3-8, is calculated from routinely captured samples and volume is measured by the truck flow meter,
- Recycled CO₂ is calculated using the volumetric flow meter at the outlet of the RCF, which is an operations meter.

6.1.5 CO₂ Emitted by Surface Leakage

CapturePoint uses 40 CFR Part 98 Subpart W to estimate surface leaks from equipment at the DCF. Subpart W uses a factor-driven approach to estimate equipment leakage. An event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage to the surface is used. The Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted. Additionally, CapturePoint uses 40 CFR Part 98 Subpart RR to report equipment leaks and vented emissions separately for injection and production.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet two objectives: 1) to detect problems before CO₂ leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the volumes of CO₂ leaked to the surface.

Monitoring for Potential Leakage from the Injection/Production Zone

In addition to the measures discussed in Section 5.9, both injection into and production from the reservoir will be monitored as a means of early identification of potential anomalies that could indicate leakage from the subsurface.

Injection plans (fluid rate, pressure, volume) are given to operations on a weekly basis. If injection pressure or rate measurements are outside the specified set points determined as part of each pattern injection plan, reservoir engineering will notify field personnel and they will investigate and resolve the problem. These excursions will be reviewed by well management personnel to determine if CO₂ leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or some other minor action is required), and there is no threat of CO₂ leakage. In the case of issues that are not readily resolved, more detailed investigation and response would be initiated, and support staff would provide additional assistance and evaluation.

Likewise, a forecast of the rate and composition of produced fluids is developed. Each producer well is assigned to a specific SAT and is isolated during each cycle for a well production test. This

data is reviewed on a periodic basis to confirm that production is at the level forecasted. If there is a significant deviation from the plan, well management personnel investigate. If the issue cannot be resolved quickly, a more detailed investigation and response would be initiated. If leakage in the flood zone were detected, an appropriate method would be used to quantify the involved volume of CO₂. This might include use of material balance equations based on known injected quantities and monitored pressures in the injection zone to estimate the volume of CO₂ involved.

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

In the event leakage from the subsurface occurred diffusely through the seals, the leaked gas would include H₂S, which would trigger the alarm on the personal monitors worn by field personnel as well as the various permanent H₂S monitors throughout the field at ground level. Such a diffuse leak from the subsurface has not occurred in the DCF. In the event such a leak was detected, personnel would determine how to address the problem. The personnel might use modeling, engineering estimates, and direct measurements to assess, address, and quantify the leakage.

Monitoring of Wellbores

DCF wells are monitored through daily pressure monitoring of the injection zone, monitoring of the annular pressure in wellheads, and routine maintenance and inspection.

Leaks from wellbores would be detected through the follow-up investigation of pressure anomalies, visual inspection, or the use of personal H₂S monitors and various permanent H₂S monitors throughout the field at ground level.

Anomalies in injection zone pressure may not indicate a leak, as discussed above. However, if an investigation leads to a need for further study, field personnel would inspect the equipment in question and determine the nature of the problem. If it is a simple matter, the repair would be made, and the volume of leaked CO₂ would be included in the 40 CFR Part 98 Subpart W report for the DCF. If more extensive repair were needed, the appropriate approach for quantifying leaked CO₂ using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be determined.

Anomalies in annular pressure or other issues detected during routine maintenance inspections would be treated in the same way. Field personnel would inspect the equipment in question and determine the nature of the problem. For simple matters the repair would be made at the time of inspection and the volume of leaked CO₂ would be included in the 40 CFR Part 98 Subpart W report for the DCF. If more extensive repairs were needed, the well would be shut in, a work order would be generated and the appropriate approach for quantifying leaked CO₂ using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be

determined. The work order would serve as the basis for tracking the event for Green House Gas (GHG) reporting.

Because leaking CO₂ at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a visual inspection process in the area of the DCF is employed to detect unexpected releases from wellbores. Field personnel visit the surface facilities on a routine basis. Inspections may include tank levels, equipment status, lube oil levels, pressures and flow rates in the facility, and valves. Field personnel also check that injectors are on the proper WAG schedule and observe the facility for visible CO₂ or fluid line leaks.

Finally, the data collected by the H₂S monitors, which are always worn by field personnel and are located permanently throughout the field at ground level, is used as a last method to detect leakage from wellbores. The H₂S monitor's detection limit is 10 ppm; if an H₂S alarm is triggered, the first response is to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. As noted previously, H₂S is considered a proxy for potential CO₂ leaks in the field. Thus, detected H₂S leaks will be investigated to determine and, if needed, quantify potential CO₂ leakage.

Other Potential Leakage at the Surface

The same visual inspection process and H₂S monitoring system will be used to detect other potential leakage at the surface as it does for leakage from wellbores. Routine visual inspections are used to detect significant loss of CO₂ to the surface. Field personnel routinely visit surface facilities to conduct a visual inspection. Inspections may include review of tank level, equipment status, lube oil levels, pressures and flow rates in the facility, valves, ensuring that injectors are on the proper WAG schedule, and also conducting a general observation of the facility for visible CO₂ or fluid line leaks. If problems are detected, field personnel would investigate, and complete any maintenance that is required. In addition to these visual inspections, the results of the personal H₂S monitors worn by field personnel and the permanent H₂S monitors throughout the field at ground level will be used as a supplement for smaller leaks that may escape visual detection.

If CO₂ leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, steps are taken to prevent further leaks.

6.1.6 CO₂ emitted from equipment leaks and vented emissions of CO₂ from surface equipment located between the injection flow meter and the injection wellhead

CapturePoint evaluates and estimates leaks from injection equipment and the CO₂ content of any vented CO₂, as required under 40 CFR Part 98 Subpart W.

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

CapturePoint evaluates and estimates leaks from production equipment and the CO₂ content of produced oil, and any vented CO₂, as required under 40 CFR Part 98 Subpart W.

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

At the end of the Specified Period, injecting CO₂ for the subsidiary purpose of establishing the long-term storage of CO₂ in the DCF will cease. Sometime after the end of the Specified Period, a request to discontinue monitoring and reporting will be submitted. The request will demonstrate that the amount of CO₂ reported under 40 CFR §98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage.

At that time, the request will be supported with years of data collected during the Specified Period. This demonstration will provide the information necessary for the EPA Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

- Data comparing actual performance to predicted performance (purchase, injection, production) over the monitoring period,
- An assessment of the CO₂ leakage detected, including the discussion of the estimated amount of CO₂ leaked and the distribution of emissions by leakage pathway,
- A demonstration that future operations will not release the volume of stored CO₂ to the surface,
- A demonstration that there has been no significant leakage of CO₂; and,
- An evaluation of the reservoir pressure demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

7 Determination of Baselines

Ongoing operational monitoring has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO₂ leakage. Data systems are used primarily for operational control and monitoring, which are set to capture more information than is necessary for reporting in the Annual Subpart RR Report. The necessary system guidelines to capture the information that is relevant to identify possible CO₂ leakage will be developed. The following describes the approach to collecting this information.

Visual Inspections

As field operators conduct routine inspections and repairs, the Field Foreman is notified for maintenance activities that cannot be addressed on the spot. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation (the responsible party will be provided in the monitoring plan, as required under Subpart A, §98.3(g)). The Annual Subpart RR Report will provide an estimate of CO₂ emissions. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

Personal H₂S Monitors

H₂S monitors are worn by all field personnel. The H₂S monitors detect concentrations of H₂S up to 500 ppm in 0.1 ppm increments and will sound an alarm if the detection limit exceeds 10 ppm. The current H₂S concentration in the produced gas is 5,709 ppm taken from the recycle compressor inlet and 205 ppm in the produced oil. If an H₂S alarm is triggered, the immediate response is to protect the safety of the personnel, and the next step is to safely investigate the source of persistent alarms. CapturePoint considers H₂S to be a proxy for potential CO₂ leaks in the field. The person responsible for MRV documentation will receive notice of all incidents where H₂S is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO₂ emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

As stated before, there are various permanent H₂S monitors throughout the field at ground level to detect H₂S and alarm if a limit is reached.

Injection Rates, Pressures and Volumes

Target injection rate and pressure for each injector are developed within the permitted limits based on the results of ongoing pattern balancing. The injection targets are submitted to field operations. Field operations flags whenever statistically significant deviations from the targeted ranges are identified. The set points are designed to be conservative, because it is preferable to have too many flags rather than too few. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO₂ leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions. The Annual Subpart RR Report will provide an estimate of CO₂ emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

Production Volumes and Compositions

A general forecast of production volumes and composition is developed which is used to periodically evaluate performance, refine current and projected injection plans, and the forecast. This information is used to make operational decisions but is not recorded in an automated data system. The MRV plan implementation lead will review the data and identify those that could result in CO₂ leakage. Should such events occur, leakage volumes would be calculated following the approaches described in Sections 5 and 6. Impact to Subpart RR reporting will be addressed, if deemed necessary.

8 Determination of Sequestration Volumes Using Mass Balance Equations

Per subpart RR requirements, all flow meters for CO₂ and oil measurement are located directly downstream of each separation point. To account for the potential error that would result if volume data from flow meters at each injection and production well were utilized, the data from custody transfer meters, operations meters on the main system pipelines, and at all points of separation, is used to determine injection and production volumes used in the mass balance of the system. This issue arises because while each meter has a small but acceptable margin of error,

this error would become significant if data were taken from all the well head meters within the DCF (See Figure 3-8).

The following sections describe how each element of the mass-balance equation (Equation RR-11) will be calculated.

8.1 Mass of CO₂ Received

Equation RR-2 will be used as indicated in Subpart RR §98.443 to calculate the mass of CO₂ at the receiving custody transfer meter from the Trinity CO₂ pipeline delivery system. The volumetric flow at standard conditions will be multiplied by the CO₂ concentration and the density of CO₂ at standard conditions to determine mass.

The Mass of the CO₂ Received will be determined using Equation RR-2 as follows:

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

where:

$CO_{2T,r}$ = Net annual mass of CO₂ received through flow meter r (metric tons).

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,r}}$ = Quarterly CO₂ concentration measurement in flow for flow meter r in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meters.

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

- All delivery to the DCF is used within the unit so no quarterly flow redelivered, and $S_{r,p}$ will be zero ("0").
- Quarterly CO₂ concentration will be taken from the gas measurements.

8.2 Mass of CO₂ Injected into the Subsurface

The equation for calculating the Mass of CO₂ Injected into the Subsurface at the DCF is equal to the sum of the Mass of CO₂ Received as calculated in RR-2 of §98.443 (section 8.1 above) and the Mass of CO₂ Recycled calculated using measurements taken from the flow meter located at the inlet of the RCF (see Figure 3-8). As previously explained, using data at each injection well would give an inaccurate estimate of total injection volume due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

The Mass of CO₂ Recycled will be determined using equations RR-5 as follows:

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

where:

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO_{2,p,u}}$ = Quarterly CO₂ concentration measurement in flow for flow meter u in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

The total Mass of CO₂ Injected will be the sum of the Mass of CO₂ Received (RR-2) and Mass of CO₂ Recycled (RR-5).

The Mass of CO₂ Injected will be determined using equations RR-6 as follows:

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

where:

CO_{2I} = Total annual CO₂ mass injected (metric tons) through all injection wells.

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

u = Flow meter.

8.3 Mass of CO₂ Produced

The Mass of CO₂ Produced at the DCF will be calculated using the measurements from the flow meters at the inlet to RCF and the custody transfer meter for oil sales rather than the metered data from each production well. Again, using the data at each production well would give an inaccurate estimate of total injection due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

Equation RR-8 in §98.443 will be used to calculate the Mass of CO₂ Produced from all production wells as follows:

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

Where:

CO_{2w} = Annual CO₂ mass produced (metric tons) through separator w.

Q_{p,w} = Volumetric gas flow rate measurement for separator w in quarter p at standard conditions (standard cubic meters).

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

CCO_{2,p,w} = CO₂ concentration measurement in flow for separator w in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator.

For Equation RR-9 in §98.443 the variable X will be measured as follows:

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

Where:

CO_{2p} = Total annual CO₂ mass produced (metric tons) through all separators in the reporting year.

CO_{2,w} = Annual CO₂ produced (metric tons) through all separators in the reporting year.

X = Entrained CO₂ in produced oil or other fluid divided by the CO₂ separated through all separators in the reporting year (weight percent CO₂, expressed as a decimal fraction)

w = Separator

8.4 Mass of CO₂ Emitted by Surface Leakage

Surface Leakage will be calculated and reported using an approach that is tailored to specific leakage events including calculation methodologies in 40 CFR Part 98 Subpart W for emissions and leaks from equipment. CapturePoint is prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO₂ leaked to the surface will depend on several site- specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

The process for quantifying leakage will entail using the best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are described in Sections 5.9 and 6. In the event leakage to the surface occurs, leakage amounts would be quantified and reported, and records that describe the methods used to estimate or measure the volume leaked as reported in the Annual Subpart RR Report would be retained. Further, the Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

Equation RR-10 in §98.443 will be used to calculate and report the Mass of CO₂ emitted by Surface Leakage:

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

Where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2,x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year

X = Leakage pathway

8.5 Mass of CO₂ Emitted by Facility Emergency Vent

The Mass of CO₂ emitted by the Emergency Vent at the DCF will be calculated using the measurements from the flow meter at the vent. That volume will be added to CO_{2FI} which is the total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

Equation RR-8 in §98.443 will be used to calculate the Mass of CO₂ emitted through the emergency vent as follows:

$$CO_{2w} = \sum_{p=1}^4 (Q_{p,w}) * D * C_{CO_2,p,w} \quad (\text{Eq. RR-8})$$

Where:

CO_{2w} = Annual CO₂ mass produced (metric tons) through separator w.

$Q_{p,w}$ = Volumetric gas flow rate measurement for meter w in quarter p at standard conditions (standard cubic meters).

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682.

$CCO_{2,p,w}$ = CO₂ concentration measurement in flow for meter w in quarter p (vol. percent CO₂, expressed as a decimal fraction).

p = Quarter of the year.

w = Separator

8.6 Mass of CO₂ Sequestered and Reported in Subsurface Geologic Formation

Equation RR-11 in §98.443 will be used to calculate the Mass of CO₂ Sequestered and Reported in Subsurface Geologic Formations in the Reporting Year as follows:

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

where:

CO_2 = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

CO_{2P} = Total annual CO₂ mass produced (metric tons) in oil in the reporting year.

CO_{2E} = Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

CO_{2FP} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of part 98 of Mandatory Greenhouse Reporting.

9 MRV Plan Implementation Schedule

This MRV plan will be implemented starting October 2023 or within 90 days of EPA approval, whichever occurs later. Other GHGRP reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. It is

anticipated that the MRV plan will be in effect during the Specified Period, during which time the DCF will be operated with the subsidiary purpose of establishing long-term containment of a measurable quantity of CO₂ in subsurface geological formations at the DCF. It is anticipated to establish that a measurable amount of CO₂ injected during the Specified Period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be prepared and a request to discontinue monitoring and reporting under this MRV plan will be submitted. See 40 C.F.R. §98.441(b)(2)(ii).

10 Quality Assurance (QA) Program

10.1 QA Procedures

The requirements of §98.444 (a) – (d) have been incorporated in the discussion of mass balance equations. These include the following provisions.

CO₂ Received and Injected

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

CO₂ Produced

- The point of measurement for the quantity of CO₂ produced from oil or other fluid production wells is a flow meter directly downstream of each separator that sends a stream of gas into a recycle or end use system.
- The produced gas stream is sampled annually downstream of the flow meter used to measure flow rate of that gas stream and measure the CO₂ concentration of the sample.

CO₂ Emissions from Equipment Leaks and Vented Emissions of CO₂

These volumes are measured in conformance with the monitoring and QA requirements specified in subpart W of 40 CFR Part 98.

Flow Meter Provisions

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

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

Concentration of CO₂

CO₂ concentration is measured using an appropriate standard method. Further, all measured volumes of CO₂ have been converted to standard cubic meters at a temperature of 60 degrees

Fahrenheit and at an absolute pressure of 1 atmosphere, including those used in Equations RR-2, RR-5, and RR-8 in Section 8.

10.2 Missing Data Procedures

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

- A quarterly flow rate of CO₂ received that is missing would be estimated using invoices or using a representative flow rate value from the previous measured period.
- A quarterly CO₂ concentration of a CO₂ stream received that is missing would be estimated using invoices or using a representative concentration value from the previous measured period.
- A quarterly quantity of CO₂ injected that is missing would be estimated using a representative quantity of CO₂ injected from the previous measured period at a similar injection pressure.
- For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.
- The quarterly quantity of CO₂ produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO₂ produced from the previous measured period.

10.3 MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters of the CO₂-EOR operations in the DCF that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in §98.448(d).

11 Records Retention

The record retention requirements specified by §98.3(g) will be followed. In addition, the requirements in Subpart RR §98.447 will be met by maintaining the following records for at least three years:

- Quarterly records of CO₂ received at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of produced CO₂, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Quarterly records of injected CO₂ including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.
- Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.
- Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

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

12 Appendix

12.1 Well Identification Numbers

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

The following terms are used:

Well Type:

- SWS refers to wells that supply water.
- PROD_OIL refers to wells that produce oil.
- INJ_WAG refers to wells that inject water or CO₂.
- INJ_SWD refers to wells that inject water for disposal.
- P&A refers to plugged and abandoned wells.

Well Status:

- ACTIVE refers to active wells.
- INACTIVE refers to wells that have been completed but are not in use.
- SHUT_IN refers to wells that have been temporarily idled or shut in.
- TEMP_AB refers to wells that have been temporarily abandoned.

Table 12-1 Well Status Table

Well Name	API Number	Well Type	Status
GAU #1WS	42165339890000	SWS	INACTIVE
GAU #2W	42165106400000	P&A	INACTIVE
GAU #3	42165106340000	P&A	INACTIVE
GAU #4	42165103790000	PROD_OIL	SHUT_IN
GAU #5	42165106070000	PROD_OIL	INACTIVE
GAU #6	42165106530000	P&A	INACTIVE
GAU #6R	42165367760000	PROD_OIL	INACTIVE
GAU #7W	42165339900000	INJ_WAG	ACTIVE
GAU #8W	42165339910000	INJ_WAG	SHUT_IN
GAU #9W	42165339920000	INJ_WAG	ACTIVE
GAU #10	42165106510000	P&A	INACTIVE
GAU #10R	42165367820000	PROD_OIL	ACTIVE
GAU #11	42165106060000	P&A	INACTIVE
GAU #11R	42165367490000	PROD_OIL	ACTIVE
GAU #12	42165102070000	P&A	INACTIVE
GAU #12R	42165367510000	PROD_OIL	ACTIVE
GAU #13	42165003830000	PROD_OIL	ACTIVE

Well Name	API Number	Well Type	Status
GAU #14W	42165317930000	INJ_WAG	SHUT_IN
GAU #15	42165101300000	PROD_OIL	INACTIVE
GAU #16W	42165106270000	INJ_SWD	ACTIVE
GAU #17W	42165339930000	INJ_WAG	ACTIVE
GAU #18	42165103780000	PROD_OIL	ACTIVE
GAU #19	42165106460000	PROD_OIL	SHUT_IN
GAU #20W	42165008790000	P&A	INACTIVE
GAU #22W	42165352720000	INJ_WAG	ACTIVE
GAU #23W	42165367500000	INJ_WAG	ACTIVE
GAU #24	42165106440000	PROD_OIL	INACTIVE
GAU #25	42165367550000	PROD_OIL	ACTIVE
GAU #26	42165367530000	PROD_OIL	ACTIVE
GAU #27	42165367540000	PROD_OIL	ACTIVE
GAU #71	42165384590000	PROD_OIL	ACTIVE
RH #28W	42165367610000	INJ_WAG	ACTIVE
RH #29W	42165367620000	INJ_WAG	ACTIVE
RH #30W	42165367630000	INJ_WAG	ACTIVE
RH #31	42165367660000	PROD_OIL	ACTIVE
RH #32	42165367670000	PROD_OIL	ACTIVE
RH #33	42165367520000	PROD_OIL	ACTIVE
RH #34	42165367890000	PROD_OIL	SHUT_IN
RH #70	42165384430000	PROD_OIL	ACTIVE

12.2 Regulatory References

Regulations cited in this plan:

- TAC Title 16 Part 1 Chapter 3 Oil & Gas Division

[https://texreg.sos.state.tx.us/public/readtac\\$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y](https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y)

- TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual

<https://www.rrc.texas.gov/oil-and-gas/publications-and-notices/manuals/injection-storage-manual/>

12.3 Abbreviations and Acronyms

AMA - Active Monitoring Area

API - American Petroleum Institute

AoR - Area of Review

Bcf – 1 Billion Standard Cubic Feet of Gas

CO₂ - Carbon Dioxide

DCF – Denver City Fields

DPC - Dimensionless Performance Curve

EPA - Environmental Protection Agency

EOR - Enhanced Oil Recovery

ESP - Electrical Submersible Pump

FPP - Formation Parting Pressure (psi)

GAU - George Allen Unit

GHGRP - Greenhouse Gas Reporting Program

H₂S – Hydrogen Sulfide

HCPV - Hydrocarbon Pore Volume

IWR - Injection to Withdrawal Ratio

MMA - Maximum Monitoring Area

MRV Plan - Monitoring, Reporting and Verification Plan

MCF – 1 Thousand Standard Cubic Feet of Gas

MIT – Mechanical Integrity Test

MMCF – 1 Million Standard Cubic Feet of Gas

NIST - National Institute of Standards and Technology

QA – Quality Assurance

RB - Reservoir Barrels

RCF - Recycle Compression Facility

RH - Ruth Hudson Lease

SAT – Satellite Test

TAC - Texas Administrative Code

TRRC - Texas Railroad Commission - Oil and Gas Division

UIC – Underground Injection Control

12.4 Conversion Factors

CapturePoint reports CO₂ 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 CO₂ mass from CO₂ 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 CO₂ 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 CO₂ of 0.002641684 lb-moles per cubic foot. Converting the CO₂ density in units of metric tonnes per cubic foot:

$$Density_{CO_2} \left(\frac{MT}{ft^3} \right) = Density_{CO_2} \left(\frac{lb - moles}{ft^3} \right) \times MW_{CO_2} \times \frac{1 MT}{2,204.62 lbs}$$

Where:

$Density_{CO_2}$ = Density of CO₂ in metric tonnes (MT) per cubic foot

$Density_{CO_2}$ = 0.002641684

MW_{CO_2} = 44.0095

$Density_{CO_2} = 5.2734 \times 10^{-5} \frac{MT}{ft^3}$ or $5.2734 \times 10^{-2} \frac{MT}{Mcf}$

The conversion factor 5.2734×10^{-2} MT/Mcf is used to convert CO₂ volumes in standard cubic feet to CO₂ mass in metric tonnes.

Request for Additional Information: Denver City Fields
September 21, 2023

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	3.4	15	The MRV plan states that CO ₂ will be delivered to the DCF via the Kinder Morgan CO ₂ pipeline network, however, Figure 3-8 lists the Trinity pipeline. Please clarify.	We purchase the CO ₂ from Trinity, and it is transported to the Denver City Field by the Kinder Morgan CO ₂ pipeline network. Updated
2.	3.4	15	Figure 3-8 shows a gas flow line that is labeled “Gas to OXY Sales,” but this is not discussed anywhere in the MRV plan. Please clarify whether this is relevant to the subpart RR monitoring or calculations.	Removed due to lack of relevance

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	4.1	20	Per 40 CFR 98.449, active monitoring area is defined as the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase 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. While the MRV plan defines the AMA unit boundaries, the AMA does not account for the ½ mile buffer as described in 40 CFR 98.449. Please update the MRV plan as necessary to ensure the AMA meets the definitions in 40 CFR 98.449. Additionally, please specify whether CO₂ will remain within the unit boundaries at year t with a ½ mile buffer superimposed over the extent of the plume at year t+5 as required in the above definitions. Please also clarify whether the year 2037 is intended to represent year (t), year (t + 5), or something else.	Reworded and reordered text to address concerns over the AMA boundary and buffer zone as well as future plume limits.
4.	4.2	20	<i>“The MMA would be the same as the AMA since the plume location is less than the unit area.”</i> Figure 4-1 identifies the AMA and the MMA boundaries; however, it does not show them as equal as stated above. Please revise the MRV plan to ensure that all references to the AMA and MMA, including figures, are consistent.	Reworded and corrected figure 4-1.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	5.1	24	“CapturePoint’s experience, from over 10 years of operating this CO2-EOR project, is that such leakage has not occurred at GAU_RH.” GAU_RH is not defined in the MRV plan. Please address.	GAU_RH = George Allen Unit and Ruth Hudson aka the Denver City Field. Changed from GAU_RH to Denver City Field
6.	5.3	25	“Some of the recorded earthquakes in West Texas are far removed from any injection operation.” Please clarify what is meant by “some” as it appears in the MRV plan. Have there been earthquakes near the injection operations?	Corrected to: While some of the recorded earthquakes in West Texas are judged to be from natural causes, others are near oil fields or water disposal wells and are placed in the category of “quakes in close association with human enterprise.”
7.	5.4	27	In addition to listing the possible leakage pathways and their monitoring strategies, please provide a clear characterization of the likelihood, magnitude, and timing of leakage for each potential leakage pathway, specifically for pipelines and surface equipment. For example, Section 5.4 states that the risk of migration from older wells has been sufficiently mitigated, but it does not discuss the likelihood, magnitude, or timing of potential CO2 leakage through previous operations.	Corrected to: These practices ensure that there are no unknown wells within the DCF and that the risk of migration from older wells has been sufficiently mitigated via location identification and daily on-site monitoring of rates and pressures. Any potential migration from existing wellbores is expected to be minimal and rare.
8.	5.9	28	“Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods for quantifying the volume of leaked CO2 will be determined on a case-by-case basis using all metering and measurement equipment from each wellhead through the output of the tanks and recycle.” In the previous RFAI, it was requested that example quantification strategies be provided within the MRV plan. While one example quantification strategy was added to the MRV plan, please provide example quantification strategies that may be applied for each of the most likely leakage pathways identified in the plan.	Added • For leakage through wellbores, daily monitoring of flow rates will provide the basis to determine duration and the amount of CO2 loss; • For leakage from surface equipment and pipelines, daily monitoring of flow rates and acceptable emission factors, such as those in 40 CFR Part §98 Subpart W, provide the basis to determine duration and the amount of CO2 loss; • For leakage related to the competency of the confining layer, reservoir modeling and engineering estimates provided the basis for determining the amount of CO2 loss.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
9.	6.1.5	31	“CapturePoint uses 40 CFR Part 98 Subpart W to estimate surface leaks from equipment at the DCF. Subpart W uses a factor-driven approach to estimate equipment leakage. In addition, an event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage to the surface is used. The Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.” Subpart RR requires equipment leaks and vented emissions for injection and production to be reported separately (see https://www.ecfr.gov/current/title-40/chapter-I/subchapterC/part-98/subpart-RR#p-98.446(f)(3)). Please update the MRV plan as necessary to reflect that these are separate data elements.	Corrected to: Additionally, CapturePoint uses 40 CFR Part 98 Subpart RR to report equipment leaks and vented emissions separately for injection and production.
10.	8	36	“To account for the potential error that would result if volume data from flow meters at each injection and production well were utilized, the data from custody transfer meters, operations meters on the main system pipelines, and at all points of separation, is used to determine injection and production volumes used in the mass balance of the system, per subpart RR requirements. This issue arises because while each meter has a small but acceptable margin of error, this error would become significant if data were taken from all the well head meters within the DCF.” Subpart RR requires that “The point of measurement for the quantity of CO₂ produced from oil or other fluid production wells is a flow meter directly downstream of each separator that sends a stream of gas into a recycle or end use system.” Please explain in the MRV plan whether the proposed flowmeters follow 40 CFR 98.444, and/or revise this section of the MRV plan as necessary. See https://www.ecfr.gov/current/title-40/part-98/section-98.444#p-98.444(c) for reference.	Corrected to: Per subpart RR requirements, all flow meters for CO₂ and oil measurement are located directly downstream of each separation point. To account for the potential error that would result if volume data from flow meters at each injection and production well were utilized, the data from custody transfer meters, operations meters on the main system pipelines, and at all points of separation, is used to determine injection and production volumes used in the mass balance of the system. See figure 3.8 for reference

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
11.	8.2	37	“The total Mass of CO₂ Injected will be the sum of the Mass of CO₂ Received (RR-2) and Mass of CO₂ Recycled (modified RR-5).” Please remove the word “modified” from the statement above. Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Corrected
12.	8.3	38	“CO_{2w} = Annual CO₂ mass produced (metric tons)” “w = Inlet meter to RCF” Per 40 CFR 98.443(d)(2), these variables should be, “CO_{2w} = Annual CO₂ mass produced (metric tons) through separator w,” and “w = Separator.” Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Corrected
13.	8.3	38	“Xoil = Mass of entrained CO₂ in oil in the reporting year measured utilizing commercial meters and electronic flow-measurement devices at each point of custody transfer. The mass of CO₂ will be calculated by multiplying the total volumetric rate by the CO₂ concentration.” Per 40 CFR 98.443(d)(3), this variable should be. “X = Entrained CO₂ in produced oil or other fluid divided by the CO₂ separated through all separators in the reporting year (weight percent CO₂, expressed as a decimal fraction).” Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Corrected

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
14.	8.4	39	“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.” 40 CFR 98.448(d) discusses MRV plan revisions. Please review the MRV plan to ensure that all references to the Subpart RR regulations are correct.	Surface Leakage will be calculated and reported using an approach that is tailored to specific leakage events including calculation methodologies in 40 CFR Part 98 Subpart W for emissions and leaks from equipment. CapturePoint is prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO₂ leaked to the surface will depend on several site- specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage. The process for quantifying leakage will entail using the best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are described in Sections 5.9 and 6. In the event leakage to the surface occurs, leakage amounts would be quantified and reported, and records that describe the methods used to estimate or measure the volume leaked as reported in the Annual Subpart RR Report would be retained. Further, the Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.
15.	8.5	39	“CO_{2P} = Total annual CO₂ mass produced (metric tons) net of CO₂ entrained in oil in the reporting year” Per 40 CFR 98.443(f)(1), this variable should be, “CO_{2P} = Total annual CO₂ mass produced (metric tons) in the reporting year.” Equations and variables cannot be modified from the regulations. Please revise this section of the MRV plan and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Corrected

**CapturePoint LLC Denver City Fields
Subpart RR Monitoring, Reporting and
Verification (MRV) Plan**

July 31st, 2023

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1. Introduction

CapturePoint LLC operates a Carbon Dioxide Enhanced Oil Recovery (CO₂-EOR) project in the Denver City Fields (DCF) located in Gaines County, Texas, approximately four miles southwest of the town of Denver City, Texas and less than two miles west of the Denver Unit of the giant Wasson San Andres Fields for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO₂) with a subsidiary or ancillary purpose of geologic sequestration of CO₂ in a subsurface geologic formation. The DCF is comprised of the George Allen Unit (GAU) and the Ruth Hudson Lease (RH). Like Wasson production is from the San Andres formation at an average depth of 5000 feet. The Monitoring, Reporting and Verification (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 CO₂ sequestered at the Denver City Fields during a specified period of injection.

2. Facility Information

2.1. Reporter Number

576482 – Denver City Fields

2.2. UIC Permit Class

The Oil and Gas Division of the Texas Railroad Commission (TRRC) regulates oil and gas activity in Texas. All wells in the DCF (including production, injection, and monitoring wells) are permitted by TRRC through Texas Administrative Code (TAC) Title 16 Chapter 3. TRRC has primacy to implement the Underground Injection Control (UIC) Class II program in the state for injection wells. All EOR injection wells in the DCF are currently classified as UIC Class II wells.

2.3. Existing Wells

Wells in the DCF are identified by name and number, API number, type, and status. The list of wells as of March 2023 is included in Section 12.1. Any changes in wells will be indicated in the annual subpart RR submission.

3. Project Description

This project takes place in the DCF, an oil field located in West Texas that was first produced more than 60 years ago. The DCF is comprised of the George Allen Unit (GAU) and the Ruth Hudson (RH) Lease. The two abut each other, produce oil and gas from the same geologic formations and structure, and are under the sole operatorship of CapturePoint LLC. The geology, facilities/equipment, and operational procedures are similar for both in the DCF. In addition, the two properties share the same CO₂ recycle and water injection facilities as well as the injection piping system for both CO₂ and water. Because of these common facilities and common reservoir, one MRV Plan is being prepared for the two properties in the DCF and any important differences between the two properties will be noted in the MRV plan. CO₂ flooding was initiated in 2007 in the GAU

and in 2012 in the RH. The field is well characterized and is suitable for secure geologic storage in the San Andres formation. CapturePoint LLC uses a water alternating with gas (WAG) injection process and maintains an injection to withdrawal ratio (IWR) at or near 1.0.

3.1. Project Characteristics

The DCF was discovered in 1956 and started production in the same year. The DCF consists of one unit (GAU) and one lease (RH). The GAU began to produce in May 1956 and the waterflood was initiated in September 1989. CO₂ flooding was initiated in December 2007, in both the Main Pay and Residual Oil Zone (ROZ). The RH initiated a waterflood in March 2008 and began to produce in November 2008. CO₂ flooding was initiated in December 2012, also in the Main Pay and ROZ.

A long-term forecast for both the GAU and RH was developed using a dimensionless curve approach. Using this approach, approximately 2.0 million tonnes of stored CO₂ is forecasted over the life of the project. Figure 3-1 shows actual and projected CO₂ injection, production, and stored volumes in DCF.

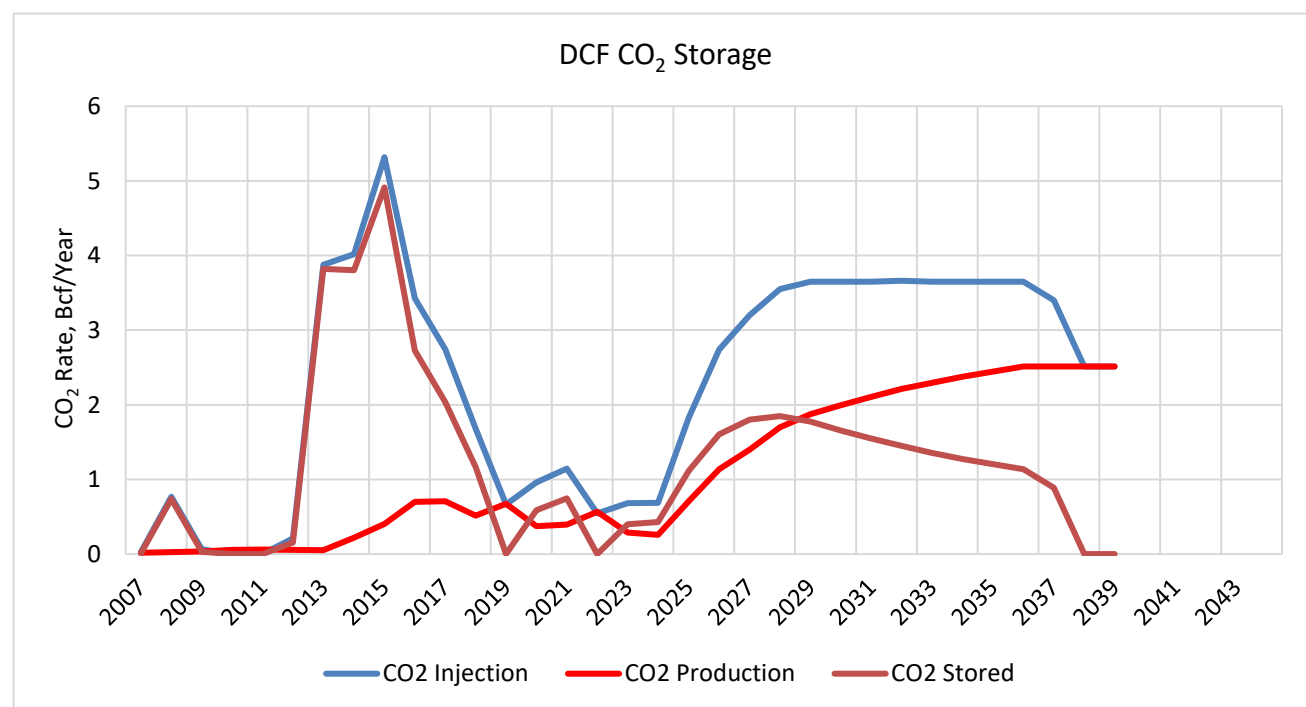


Figure 3-1 DCF Historic and Forecast CO₂ Injection, Production, and Storage

3.2. Environmental Setting

The DCF is located in the NE portion of the Central Basin Platform in West Texas (See Figure 3-2). This map also shows the location of the Denver Unit and other Wasson San Andres Units. The Denver City Fields are shown by the green dot.

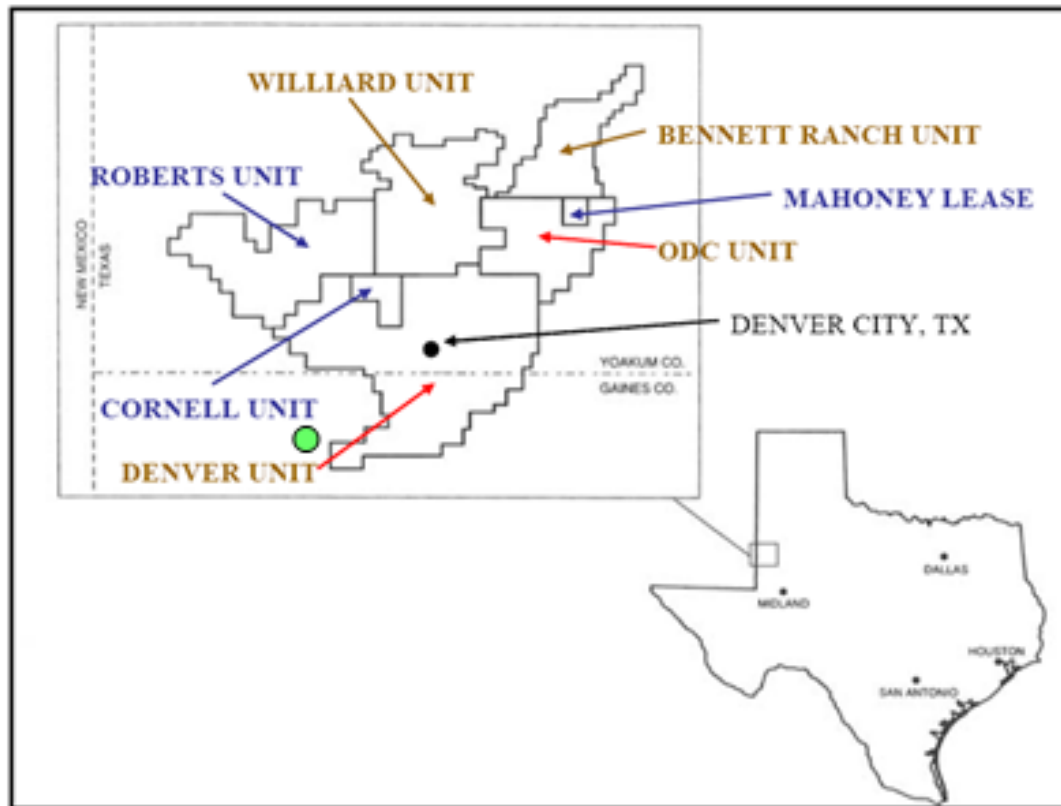


Figure 3-2 Location of Denver City Fields in West Texas

Like Wasson, the DCF produces from a San Andres dolomite reservoir at a depth of about 5000 feet. In contrast to Wasson, DCF is an insignificant oil accumulation with a thin mobile oil column trapped by a very low relief anticlinal structure as shown in figure 3-3. The Wasson field has produced over 2 billion barrels of oil to date from the San Andres while the DCF has produced 2.06 million barrels of oil to 1-1-2022.

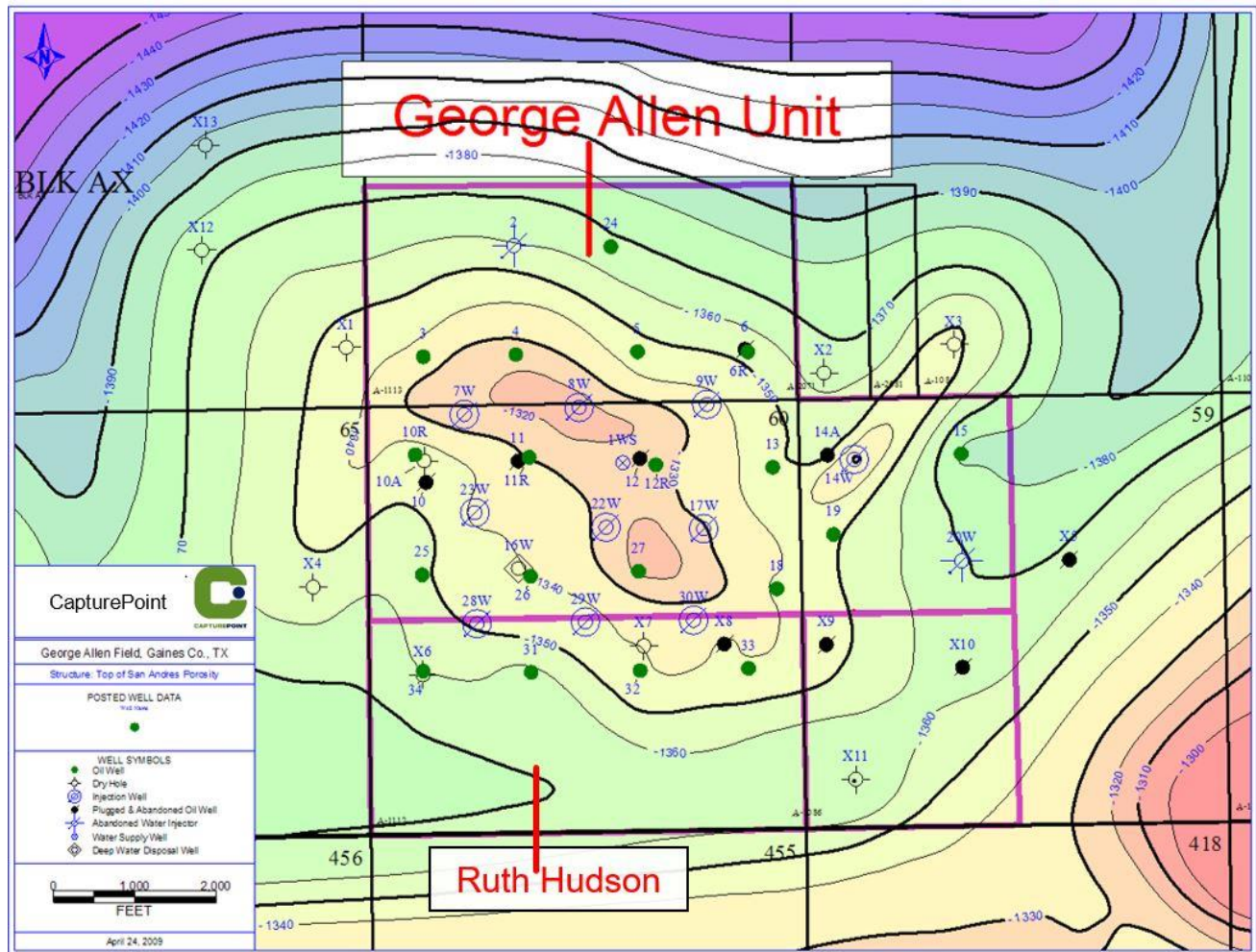


Figure 3-3 Local Area Structure on Top of San Andres

In the DCF there is a thin mobile oil column. Beneath the conventional oil column there is a thick, porous section with transition zone/residual oil (TZ/ROZ) that can only be produced via tertiary recovery methods, primarily CO₂ injection. This thick TZ/ROZ zone as found in the Wasson field gives a sizeable target for tertiary recovery (over 300 feet gross thickness).

Oil in the TZ/ROZ is currently being produced via CO₂ injection. Nine 40-acre patterns were prepared to inject CO₂ in this zone in the DCF. The presence of thick residual zones in the San Andres of the Permian Basin is widespread. Lindsay (2001), Melzer (2005), Melzer (2006), and Koperna and Kuuskraa (2006; 1&2) discuss the possible origins and the extent of residual oil zones in the Permian Basin. Brown (2001) discusses the ROZ in the area and its possible origin. The residual zone in the DCF has better porosity and permeability and is much thicker than the mobile oil zone which produced during primary and secondary (waterflood) recovery. This is often the case in residual oil zones, particularly those found in smaller fields with thinner oil columns. This gives us a large resource in which to economically sequester large volumes of CO₂, as CO₂ can both be stored and utilized for oil recovery in the extensive residual oil zones found in the San Andres in the Permian Basin.

The oil saturation profile found in the DCF/Wasson area is shown below in figure 3-4 from Koperna

and Kuuskraa (2006; 2):

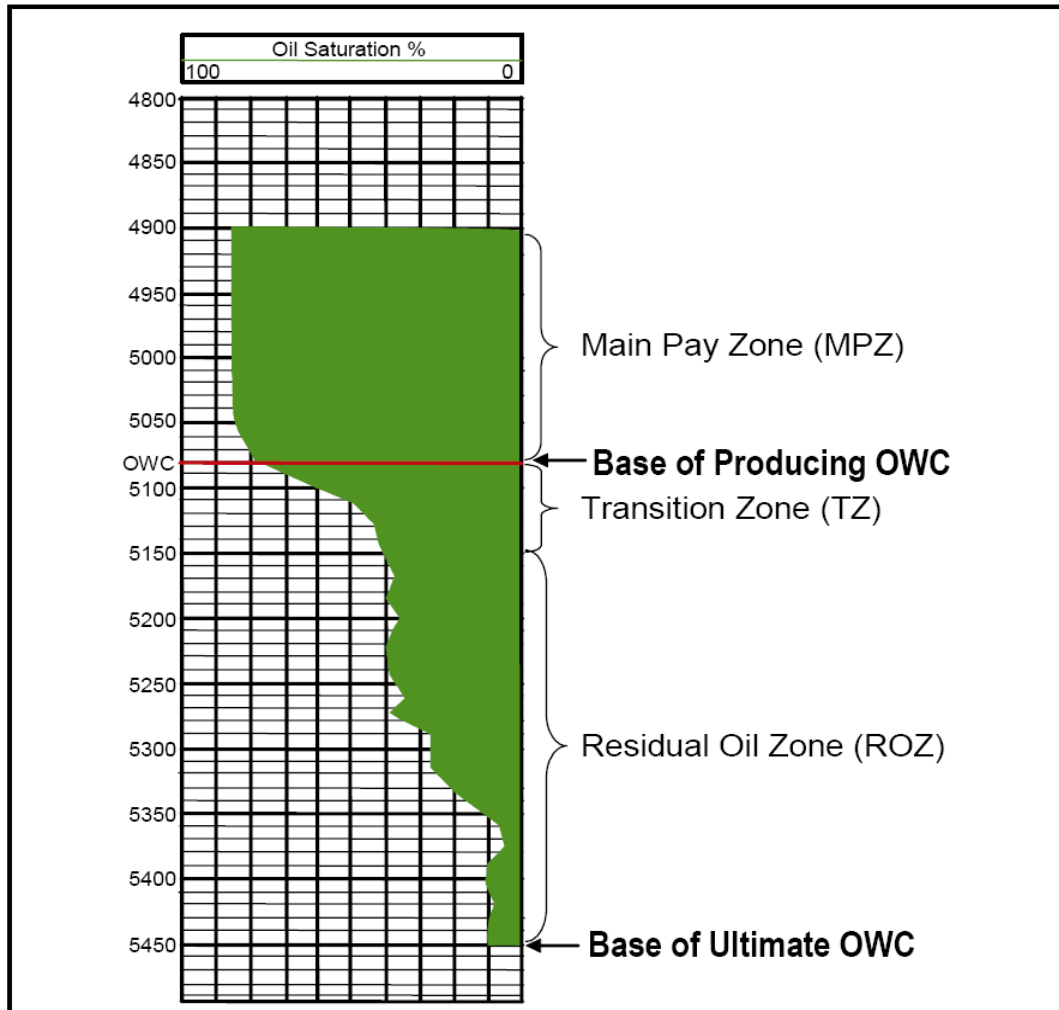


Figure 3-4 Local Area Structure on Top of San Andres

Due to hydrodynamic flow in the San Andres aquifer, a ROZ was created and is under CO₂ flood along with the Main Pay Zone in the San Andres Formation.

Once the CO₂ flood is complete and injection ceases, the remaining mobile CO₂ will rise slowly upward, driven by buoyancy forces. There is more than enough pore space (188 million reservoir barrels (MRB)) to sequester the planned CO₂ injection (27.8 million reservoir barrels). The amount of CO₂ injected will not exceed the reservoir's secure storage capacity and, consequently, the risk that CO₂ could migrate to other reservoirs in the Central Basin Platform is negligible. The volume of CO₂ storage is based on the estimated total pore space within the DCF. The total pore space within the DCF, from the top of the reservoir down to the base of the ROZ, is calculated to be 188 million reservoir barrels (MRB). This is the volume of rock multiplied by porosity. Table 3-1 below shows the conversion of this amount of pore space into an estimated maximum volume of approximately 254

billion cubic feet (Bcf) (13.4 million tonnes) of CO₂ storage in the reservoir. CO₂ will occupy only 15% of the total calculated storage capacity by the year 2037 based on the projected forecast.

Table 3-1 Calculation of Maximum Volume of CO₂ Storage Capacity at DCF

Top of Main Pay to Bottom of Residual Oil Zone (ROZ)	
Variables	DCF Outline
Pore Volume (RB)	188,396,478
B _{CO₂} (RB/Mscf)	0.407
S _{wirr}	0.35
S _{or CO₂}	0.10
Max CO ₂ (MCF)	254,589,835
Max CO ₂ (BCF)	254

$$\text{Max CO}_2 = \text{Volume (RB)} * (1 - S_{wirr} - S_{or CO_2}) / B_{CO_2}$$

where:

Max CO₂ = the maximum amount of storage capacity

B_{CO₂} = the formation volume factor for CO₂

S_{wirr} = the irreducible water saturation

S_{or CO₂} = the irreducible oil saturation

Reservoir management is employed on a constant basis to obtain the maximum possible economic recovery from a reservoir based on facts, information, and knowledge. A reservoir management strategy that is used in CO₂ floods is the implementation of water curtain injectors. This will be utilized in the DCF to create a pressure barrier or “curtain” to contain the injected CO₂ to the area selected for production. Water curtain injection is an efficient method of maintaining and controlling lateral migration of fluids to assure that CO₂ does not cross structurally deficient locations. Injected fluids (CO₂) stay in the reservoir within the DCF unit boundary and do not move to adjacent areas.

Given that in DCF the confining zone has proved competent over both millions of years and in the current CO₂ flooding, and that the DCF has ample storage capacity, there is confidence that stored CO₂ will be contained securely within the reservoir.

3.3. Geologic Setting/Stratigraphic Column

The George Allen/Wasson San Andres fields are located on the Northwest shelf of the Permian Basin (Figure 3-5).

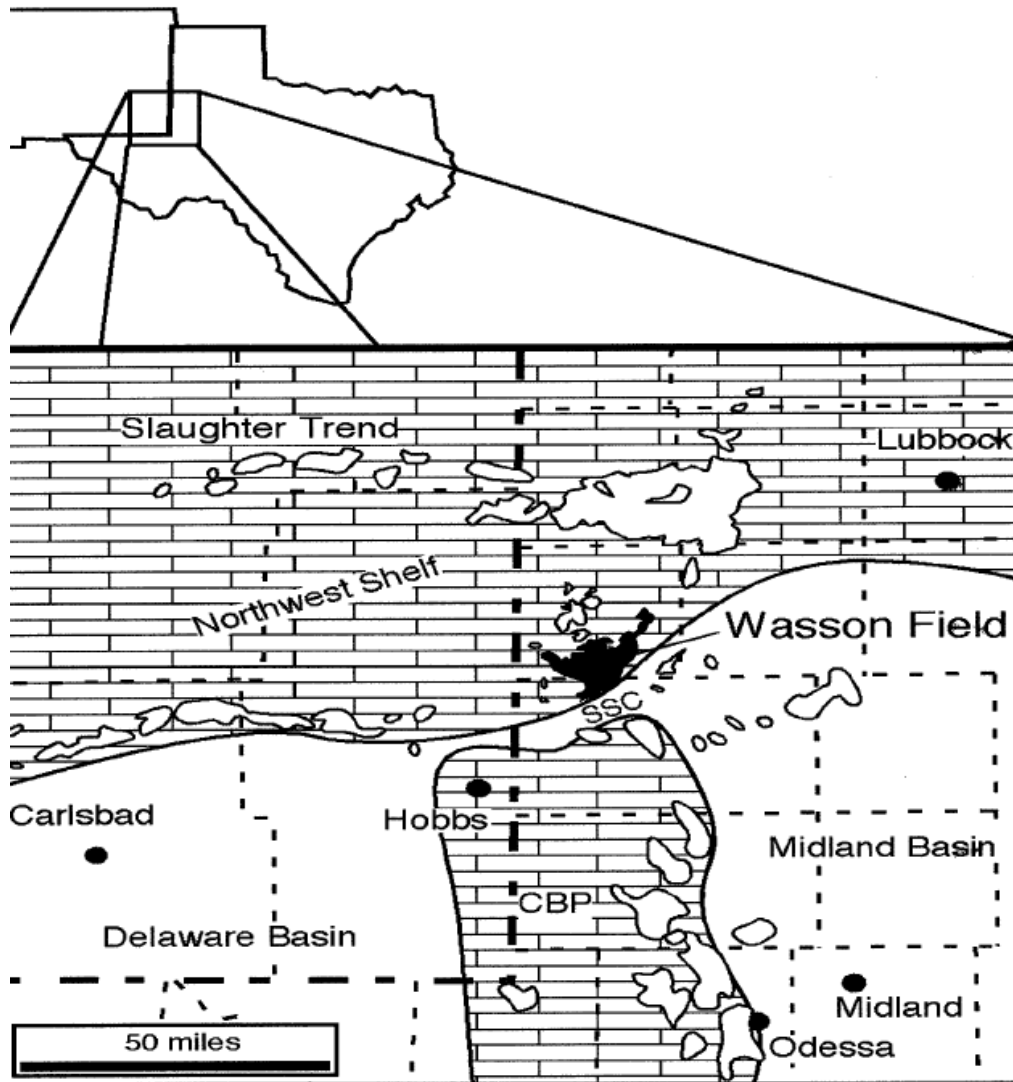


Figure 3-5 Map of Northwest shelf of the Permian Basin

The Wasson field is shown in black. Other San Andres fields are outlined. San Andres “shelf” facies are indicated by the brick pattern. “CBP” refers to the “Central Basin Platform” a major structural feature that separates the Delaware Basin from the Midland Basin. “SSC” refers to the “San Simon Channel” a feature which allowed seawater circulation between the shallow restricted shelf areas of the Northwest Shelf and the Central Basin Platform.

Figure 3-6 below shows the thickness and broad extent of the porous facies in the San Andres formation.

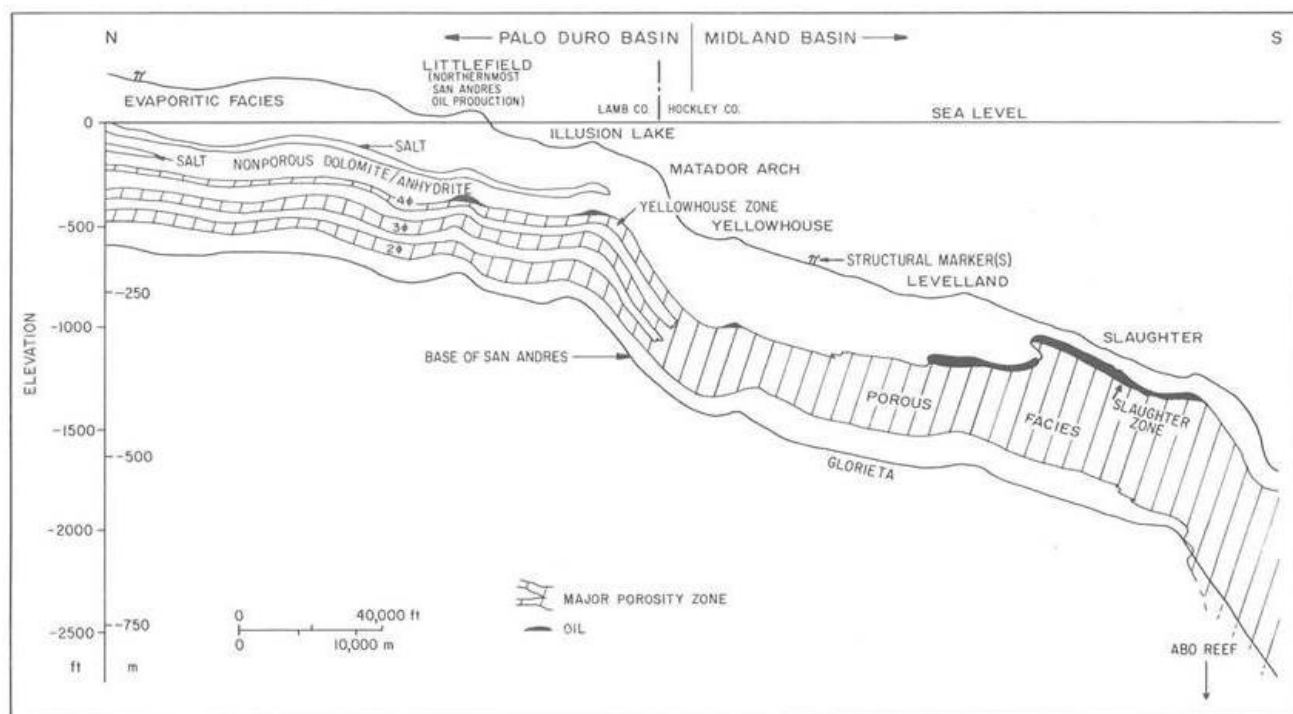


Figure 3-6 Cross section of lower San Andres Formation, Northern Shelf, showing porosity relationships.

A typical stratigraphic section for the area is shown below in Figure 3-7.

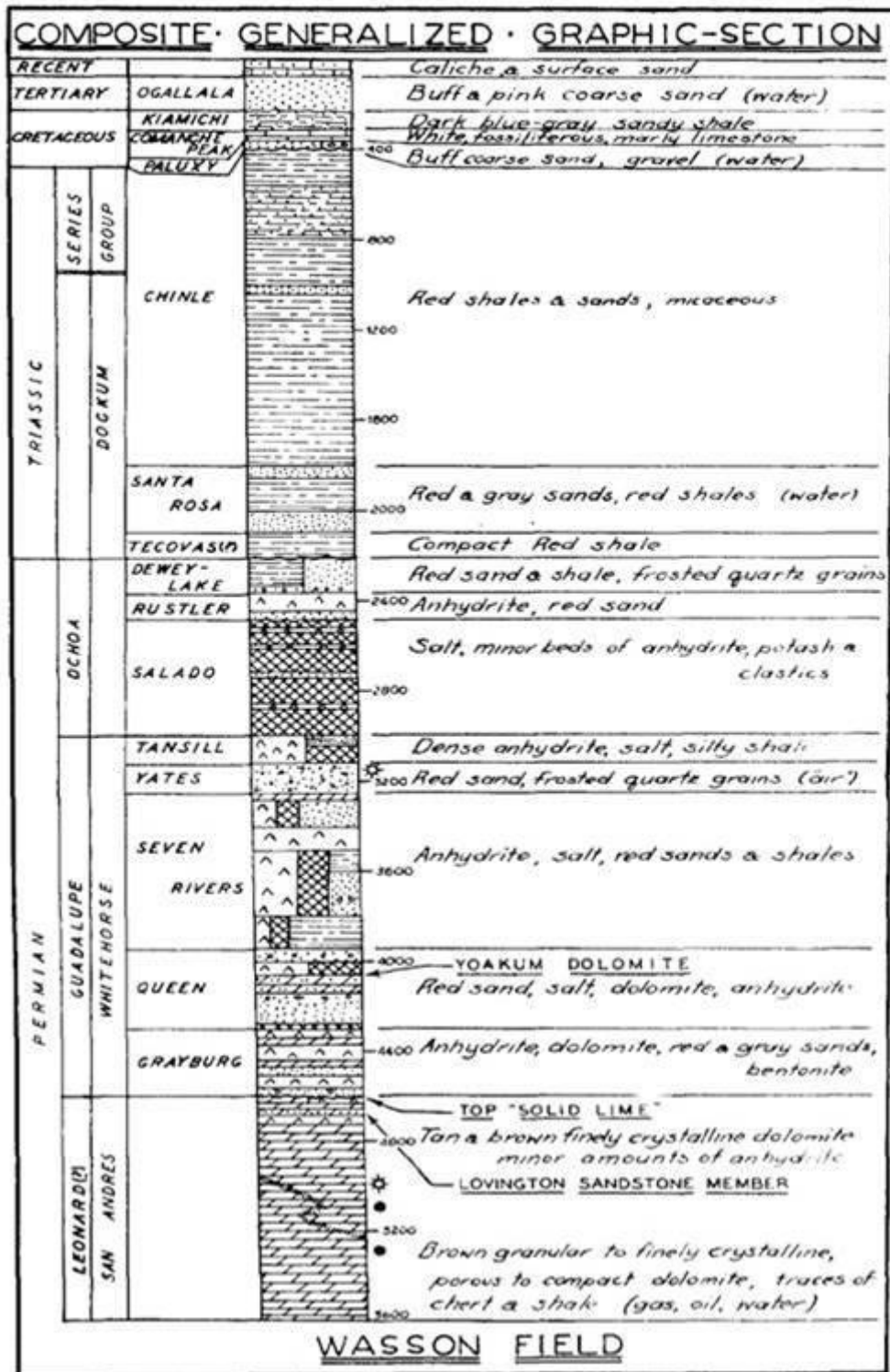


Figure 3-7 Composite generalized stratigraphic section.

The stratigraphy and facies of the Upper Permian on the Northwest Shelf and Central Basin Platform is quite uniform and serves as an ideal setting for trapping hydrocarbons and for the same reasons is an ideal setting for trapping/sequestering CO₂. Thick porous, shallow water, carbonate facies which prograded basinward over time are overlain and interfinger with tidal flat and restricted/exposed shelf facies which serve as widespread and efficient seals. The notable thing about the Upper Permian rocks described here is that there are multiple and thick intervals that should eliminate the possibility of any vertical migration of fluids or gases from the San Andres reservoir to the surface.

The first seal is the Upper San Andres which consists of dense, fine crystalline dolomite and anhydrite devoid of any porosity or permeability deposited on the tidal flats of a broad, restricted shelf. Where the porous, shallow water carbonate facies of the Lower San Andres pinch out and interfinger with these rocks a series of stratigraphic traps is formed in the northern part of the Northwest Shelf; the Levelland-Slaughter-Chaveroo-Cato San Andres fields are found in this trend. A similar porosity pinchout on the interior of the Central Basin platform controls the widespread San Andres production found on the eastern margin of the Central Basin platform. These widespread producing trends attest to sealing capacity of the Upper San Andres anhydritic dolomite facies both vertically and laterally.

Above the San Andres are a series of restricted/exposed shelf facies consisting of tight, anhydritic dolomite, anhydrite, salt, and thin sandstones of the Upper Guadalupian Grayburg, Queen, Seven Rivers, Yates and Tansill formations. The sandstones sometimes have porosity and permeability, but are often cemented by salt and non-permeable. Where permeable, they offer no chance for vertical migration of fluids or gases as they are inter-layered with impermeable salt, anhydrite, and anhydritic dolomite.

Following the Tansill we have the Ochoan, Upper Permian evaporites of the Salado and Rustler formations. The Salado is a roughly 600-700 feet thick in the Wasson/George Allen area and consists dominantly of halite with some thin beds of potash and anhydrite and a few very thin layers of red mud, silt, and fine sand. Being widespread, thick, and impermeable this formation alone should certainly stop the vertical migration of any fluids or gases from the subsurface to the surface. Even if fractured, the salt will flow and seal any open cracks. It is followed by the Rustler formation; 60 feet of dense, white anhydrite at the top overlying 30 feet of red shale interbedded with anhydrite; another capstone, on top a over 2500 feet of mostly impermeable rock.

The Permian ends with the Dewey Lake formation which consists of red gypsum cemented sandstone and red shales.

Above the Permian unconformity are the Triassic Tecovas red shale and then the Santa Rosa formation which contains fresh water bearing sandstones. This is followed by the micaceous red shales and sands of the Chinle formation. A major unconformity separates the Triassic Chinle from the overlying Cretaceous sediments. These consist of coarse sand and gravel, white marly limestone, and dark, blue-gray sandy shale.

An important aquifer, the Tertiary Ogallala formation overlies these Cretaceous sediments. It consists of coarse, sands and vari-colored gravels, all loose or poorly consolidated which are followed by Recent wind-blown sand and caliche.

3.4. Description of CO₂-EOR Project Facilities and the Injection Process

Figure 3-8 shows a simplified process flow diagram of the project facilities and equipment in the DCF. CO₂ will be delivered to the DCF via the Kinder Morgan CO₂ pipeline network. The CO₂ will be supplied by several different sources including both natural and anthropogenic CO₂ sources. Specified amounts will be drawn from an outside source pipeline based on contractual arrangements among suppliers of CO₂, purchasers of CO₂, and the pipeline operator. The Specified amounts are the amount of CO₂ required in addition to the produced gas to meet target CO₂ injection rates forecasted using the dimensionless curve approach.

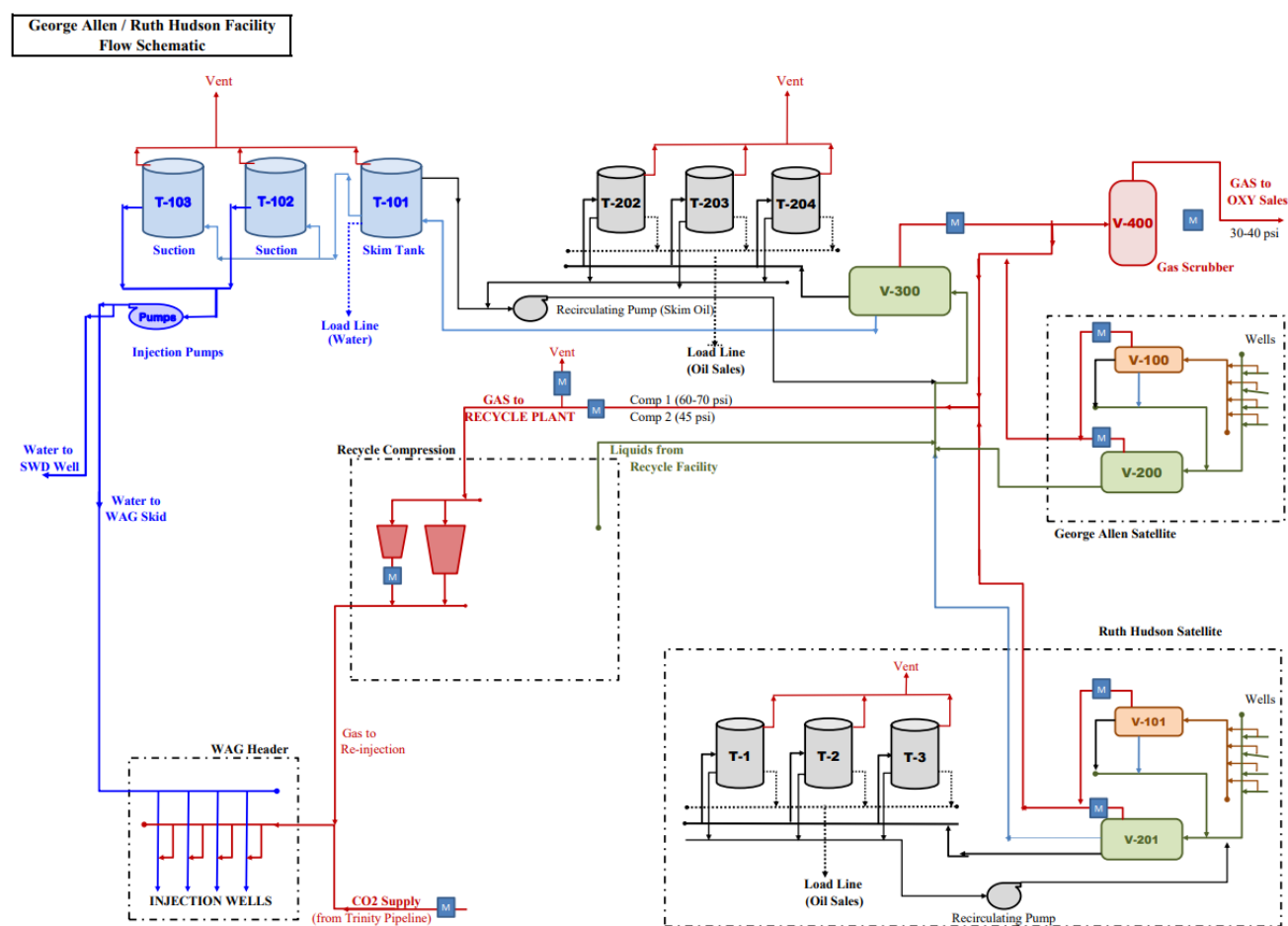


Figure 3-8 George Allen Unit/Ruth Hudson lease Process Flow Diagram

Once CO₂ enters the DCF there are three main processes involved in CO₂-EOR operations:

- i. CO₂ Distribution and Injection: The mass of CO₂ received at the DCF is metered and calculated through the Custody Transfer Meter located at the pipeline delivery point. The mass of CO₂ received is combined with recycled CO₂ / hydrocarbon gas mix from the recycle compression facility (RCF) and distributed to the WAG headers for injection into the injection wells according to the pre-programmed injection plan for each well pattern which alternates

between water and CO₂ injection. WAG headers are manually operated and can inject either CO₂ or water at various rates and injection pressures as specified in the injection plans. This is an EOR project and reservoir pressure must be maintained above minimum miscibility pressure. Therefore, injection pressure must be sufficiently high to allow injectants to enter the reservoir, but below formation parting pressure (FPP).

ii. Produced Fluids Handling: Produced fluids from the production wells are a mixture of oil, hydrocarbon gas, water, CO₂, and trace amounts of other constituents in the field including nitrogen and Hydrogen Sulfide (H₂S) as discussed in Section 7. They are gathered and sent to Satellite Test Stations (SAT) for separation into a gas/CO₂ mix and a produced fluids mix of water, oil, gas, and CO₂. The produced gas, which is composed primarily of CO₂ and minor hydrocarbons, is sent to the RCF for dehydration and recompression before reinjection into the reservoir. An operations meter at the RCF is used to determine the total volume of produced gas that is reinjected. The separated oil is sent to two separate tanks (one at GAU and one at RH) where it is then sold via truck.

iii. Water Treatment and Injection: Water is recovered for reuse and forwarded to the water injection station for reinjection or disposal.

3.4.1. Wells in the Denver City Fields

The TRRC has broad authority over oil and gas operations including primacy to implement UIC Class II wells. The rules are found in Texas Administrative Code Title 16, Part 1, Chapter 3 and are also explained in a TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual (See Appendix 12-2). TRRC rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Briefly, TRRC rules include the following requirements:

- Fluids must be constrained in the strata in which they are encountered,
- Activities cannot result in the pollution of subsurface or surface water,
- Wells must adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into other strata with oil and gas, or into subsurface and surface waters,
- Completion report for each well including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore) must be prepared,
- Operators must follow plugging procedures that require advance approval from the TRRC Director and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs; and,
- Injection well operators must identify an Area of Review (AoR), use compatible materials and equipment, test, and maintain well records.

Table 3.2 provides a well count by type and status. All these wells are in material compliance with TRRC rules.

Table 3.2 DCF Well Penetrations by Type and Status

TYPE	ACTIVE	INACTIVE	P & A	Total
PROD_OIL	16	3		19
INJ_WTR	0	1		1
INJ_WAG	8	0		8
INJ_SWD*	0	0		0
WSW**	0	0		0
P&A***			3	3
TOTAL	24	4	3	31

*INJ_SWD = Saltwater disposal wells

**WSW= Water source wells

***P&A = Plugged and Abandoned wells

As indicated in Figure 3-9, wells are distributed across the DCF. The well patterns currently undergoing CO₂ flooding are identified by black 5-spot pattern outlines and CO₂ will be injected across the entire unit over the project life.

DCF CO₂-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Reservoir pressure in the DCF is managed by maintaining an injection to withdrawal ratio (IWR) of approximately 1.0. To maintain the IWR, fluid injection and production are monitored and managed to ensure that reservoir pressure does not increase to a level that would compromise the reservoir seal or otherwise damage the integrity of the oil field.

Injection pressure is also maintained below the formation parting pressure (FPP), which is measured using step-rate tests.

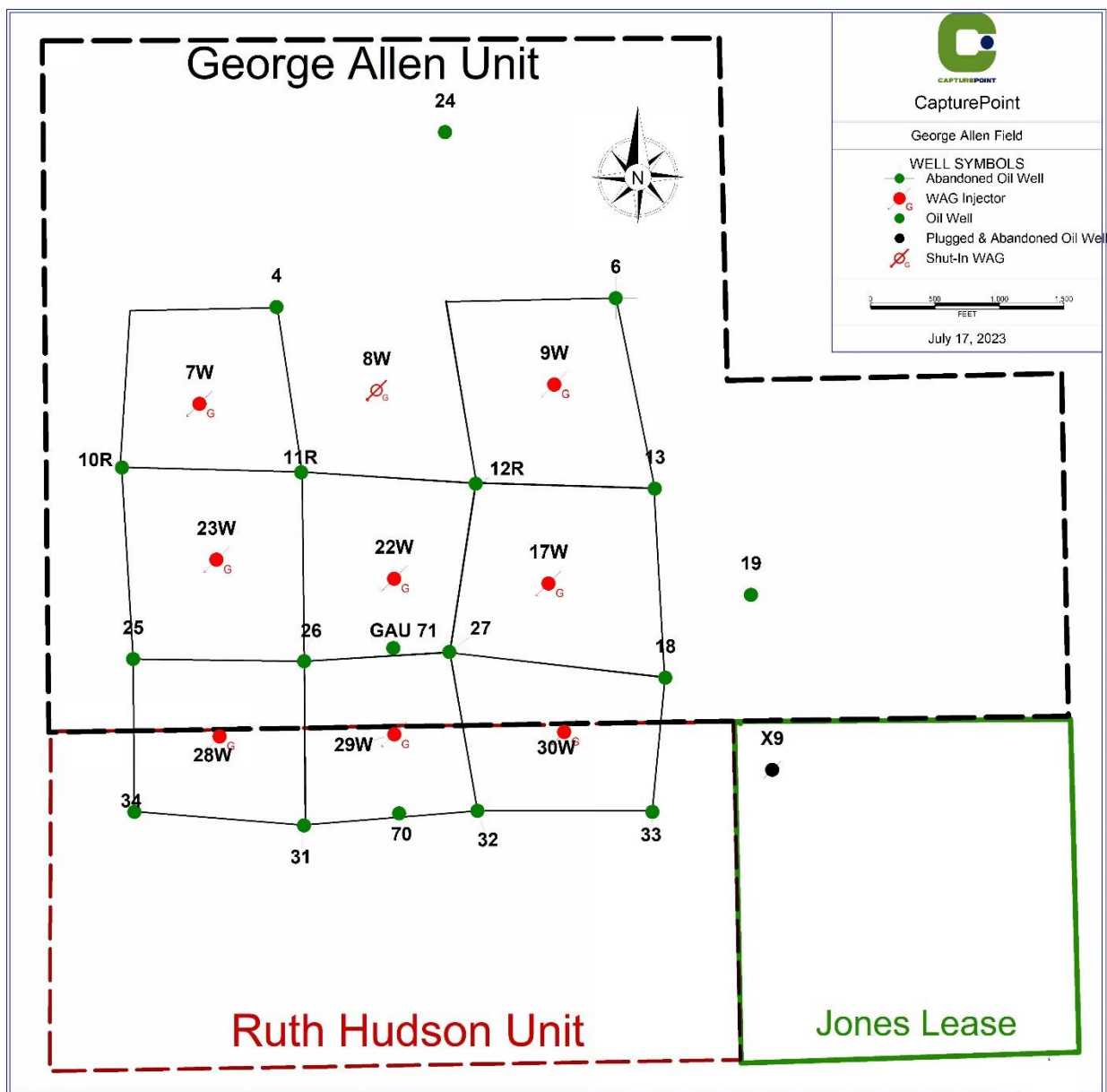


Figure 3-9 DCF Wells and Injection Patterns

3.5. Reservoir Forecasting

Dimensionless performance curves (DPCs) derived from analogous fields were used to project CO₂-EOR in the Denver City Fields. Most dimensionless curves are derived from geologic and reservoir models. In the DCF case the DPC was derived from actual field performance from an analogous field.

A dimensionless curve is a plot where everything is normalized by dividing by Hydrocarbon Pore Volume (HCPV). See Figure 3-10. The dimensioned projections of oil, CO₂ and water production, and CO₂ and water injection are made from DPCs using the original oil in place of an area of interest.

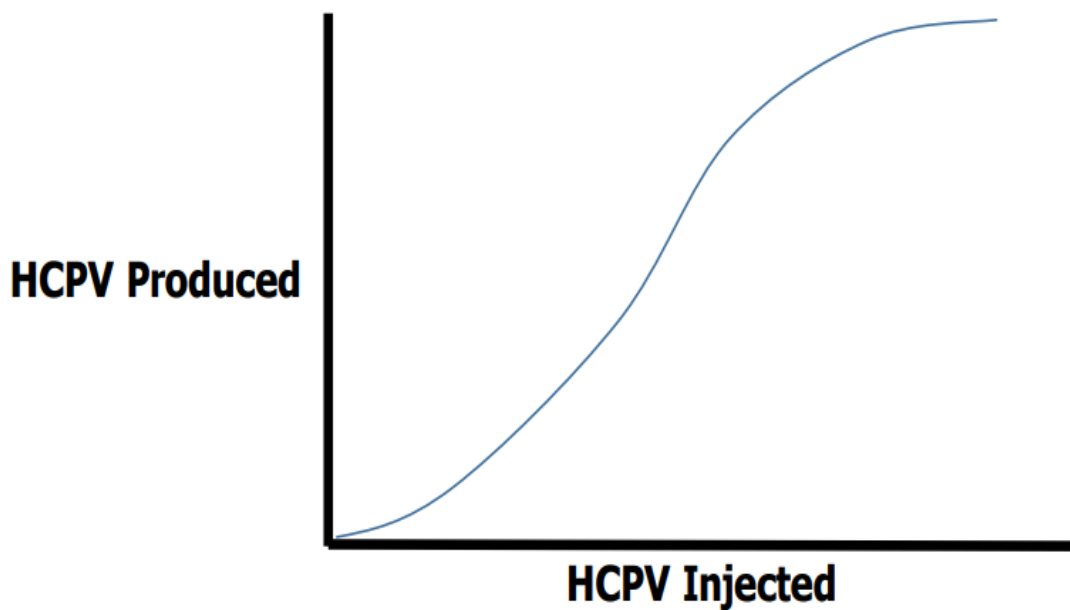


Figure 3-10 Dimensionless curve plot

The DCF DPC was calculated from the cumulative production and injection from an analogous field. The DCF DPC was used on each pattern in the DCF and then summed up to full field. This method allows you to use different start times and implement different field implementation speeds.

The DPCs are the basis for future performance prediction scenarios but are additionally a means of evaluating the reservoir process efficiencies. In a similar manner to history matching in reservoir simulation, deviations from expected performance can indicate errors in the geologic model of the pore volume, growth of the CO₂ plume laterally or vertically or metering and production allocation errors.

4. Delineation of Monitoring Area and Timeframes

4.1. Active Monitoring Area

The Active Monitoring Area (AMA) is defined by the GAU and RH boundaries. Based on our projections, CapturePoint expects the free phase CO₂ plume to remain within the George Allen Unit and Ruth Hudson boundaries for the entire length of the project and through year [t+5]. The CO₂ storage volume calculations show the CO₂ to remain within the unit boundaries in the timeframe associated with the AMA which is year 2037. The CO₂ injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO₂-EOR. Maintenance of an Injection to Withdrawal ratio of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

Figure 3-7 displays wells that have CO₂ retention on the 370 acres that have been under CO₂ injection since project initialization. The CO₂ storage volumes were forecasted (Figure 4.1) using the DPC approach. This technique indicates that the flooded acreage still has significant storage potential. The maximum CO₂ storage (254 BCF) is limited to the amount of space available by the removal of the produced hydrocarbon and water. The projection indicates that there is pore space available to store approximately 0.15 decimal fraction of HCPV amounting to 27.8 million reservoir barrels of oil (MMRB) (37.5 BCF).

The lateral extent of CO₂ in the injection zone or the CO₂ storage radius for each well was estimated by calculating a storage radius based on the forecasted CO₂ storage volume of 37.5 BCF. Figure 4-1 shows the map of the storage area outline for each pattern (dashed red line). This calculation showed 166 acres (this calculates to 18 acres per pattern) would be needed to store 37.5 BCF. This is significantly less than the 1133 acres in the DCF outline.

CO₂ injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO₂-EOR. Namely, maintenance of an Injection to Withdrawal Ratio (IWR) of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

4.2. Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined by the GAU and RH boundaries plus the required ½ mile buffer as required by 40 CFR §98.440-449 (Subpart RR). The CO₂ plume (Figure 4-1) is expected to be contained within the GAU and RH boundaries which will be actively monitored. The MMA would be the same as the AMA since the plume location is less than the unit area. 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 FR 98.448(d)(1).

4.3. Monitoring Timeframes

The primary purpose for injecting CO₂ is to produce oil that would otherwise remain trapped in the reservoir and not, as in UIC Class VI, “specifically for the purpose of geologic storage.”¹ During a Specified Period, there will be a subsidiary purpose of establishing the long-term containment of CO₂ in the DCF. The Specified Period is the timeframe that CO₂ storage will occur. In the Denver City Fields CO₂ storage will occur until 2037 at which point CO₂ injection will equal CO₂ production. Specified Period will be shorter than the period of production from the DCF.

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted with a demonstration that current monitoring and model(s) show that the cumulative mass of CO₂ reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration after the Specified Period ends based upon monitoring data.

The reservoir pressure in the DCF is collected for use in operations management. Reservoir pressure is not forecasted to change appreciably since the IWR will be maintained at approximately 1.0. Once injection ceases, reservoir pressure is predicted to stabilize within one year.

¹ EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b).

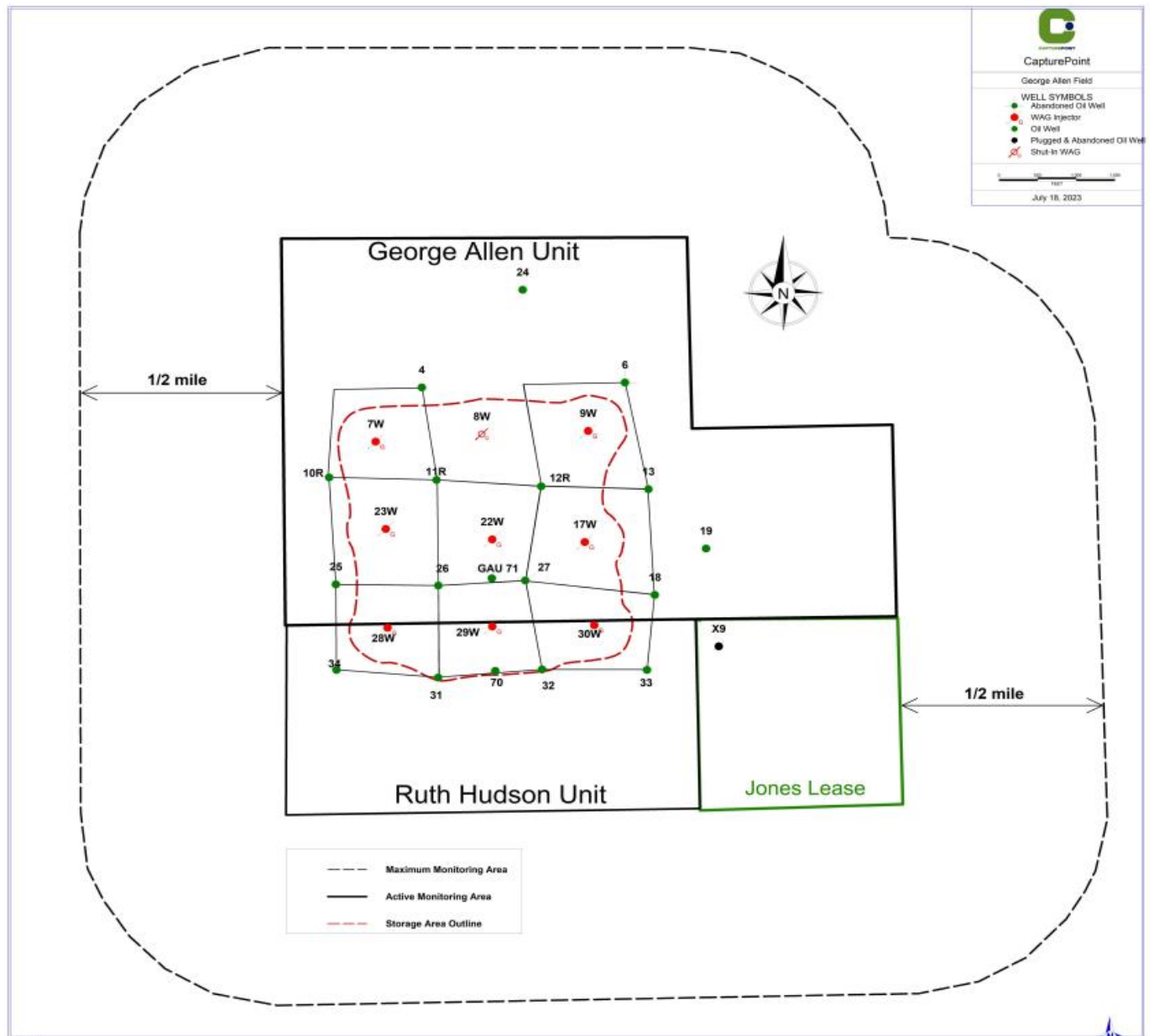


Figure 4-1 Projected CO₂ storage area

5. Evaluation of Potential Pathways for Leakage to the Surface, Leakage Detection, Verification, and Quantification

In the roughly 60 years since the DCF oil field was discovered, the reservoir has been studied extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO₂ to the surface including:

1. Existing Wellbores
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the DCF
7. Drilling Through the CO₂ Area
8. Diffuse Leakage Through the Seal
9. Leakage Detection, Verification, and Quantification

This analysis shows that leakage through wellbores and surface equipment pose the only meaningful potential leakage pathways. The monitoring program to detect and quantify leakage is based on this assessment as discussed below.

5.1. Existing Wellbores

As part of the TRRC requirement to initiate CO₂ flooding, an extensive review of all the DCF penetrations was completed to determine the need for corrective action. That analysis showed that all penetrations have either been adequately plugged and abandoned or, if in use, do not require corrective action. All wells in the DCF were constructed and are operated in compliance with TRRC rules.

As part of routine risk management, the potential risk of leakage associated with the following were identified and evaluated:

- CO₂ flood beam pumped producing wells,
- CO₂ flood Electrical Submersible Pump (ESP) producing wells; and,
- CO₂ WAG injector wells.

The risk assessment classified all risks associated with subsurface as low risk, i.e., less than 1% likelihood to occur and having a consequence that is insubstantial. The risks were classified as low risk because DCF geology is well suited to CO₂ sequestration with an extensive confining zone that is free of fractures and faults that could be potential conduits for CO₂ migration. Any risks are further mitigated because the DCF is operated in a manner that maintains, monitors, and documents the integrity of the reservoir.

The risk of well leakage is mitigated through:

- Adhering to regulatory requirements for well drilling and testing,
- Implementing best practices that CapturePoint has developed through its extensive operating experience,
- Monitoring injection/production performance, wellbores, and the surface; and,
- Maintaining surface equipment.

Continual and routine monitoring of the wellbores and site operations will be used to detect leaks or other potential well problems, as follows:

- Pressure in injection wells is monitored daily. The injection plans for each pattern are provided to field operations to govern the rate, pressure, and duration of either water or CO₂ injection. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such events occur, they are investigated and addressed. CapturePoint's experience, from over 10 years of operating this CO₂-EOR project, is that such leakage has not occurred at GAU_RH.
- Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a SAT. There is a routine well testing cycle for each SAT, with each well being tested approximately once every month. During this cycle, each production well is diverted to the well test equipment for a period sufficient to measure and sample produced fluids (generally 12-24 hours). These tests are the basis for allocating a portion of the produced fluids measured at the SAT to each production well, assessing the composition of produced fluids by location, and assessing the performance of each well. Performance data are reviewed on a routine basis to ensure that CO₂ flooding efficiency is optimized. If production is off plan, it is investigated, and any identified issues addressed. Leakage to the outside of production wells is not considered a major risk because of the reduced pressure in the casing. Further, the personal H₂S monitors are designed to detect leaked fluids around production wells during well inspections as well as various permanent H₂S monitors throughout the field at ground level.
- Field inspections are conducted on a routine basis by field personnel. Leaking CO₂ is very cold and leads to the formation of bright white clouds and ice that are easily spotted. All field personnel are trained to identify leaking CO₂ and other potential problems at wellbores and in the field. Any CO₂ leakage detected will be documented and reported and quantified.

Based on ongoing monitoring activities and review of the potential leakage risks posed by wellbores, it is concluded that the risk of CO₂ leakage through wellbores is being mitigated by detecting problems as they arise and quantifying any leakage that does occur.

If leakage did occur, the magnitude of 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.'

5.2. Faults and Fractures

After reviewing geologic, seismic, operating, and other evidence, it has been concluded that there are no known faults or fractures that transect the San Andres reservoir in the project area. As a result, there is minimal risk of leakage due to fractures or faults.

Measurements to determine FPP and reservoir pressure are routinely updated. This information is used to manage injection patterns so that the injection pressure will not exceed FPP. An IWR at or near 1 is also maintained. Both measures mitigate the potential for inducing faults or fractures. As a safeguard, WAG skids are continuously monitored.

5.3. Natural or Induced Seismicity

After reviewing the literature and actual operating experience; it is concluded that there is no direct evidence that natural seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF.

To evaluate this potential risk at the DCF, CapturePoint has reviewed the nature and location of seismic events in West Texas. Some of the recorded earthquakes in West Texas are far removed from any injection operation. These are judged to be from natural causes. Others are near oil fields or water disposal wells and are placed in the category of “quakes in close association with human enterprise.”² A review of the United States Geological Survey (USGS) database of recorded earthquakes at M1.0 or greater in the Permian Basin since 1956 indicates that none have occurred in the DCF; the closest took place in 1992 approximately 42 miles away. See Figure 5.1.

The concern about induced seismicity is that it could lead to fractures in the seal providing a pathway for CO₂ leakage to the surface. CapturePoint is not aware of any reported loss of injectant (brine water or CO₂) to the surface associated with any seismic activity. There is no direct evidence to suggest that natural seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF. If induced seismicity resulted in a pathway for material amounts of CO₂ to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would detect the migration and lead to further investigation. CapturePoint monitors the USGS earthquake monitoring Geographical Information System (GIS) site³ for seismic signals that could indicate the creation of potential leakage pathways in the DCF.

² Frohlich, Cliff (2012) “Induced or Triggered Earthquakes in Texas: Assessment of Current Knowledge and Suggestions for Future Research”, Final Technical Report, Institute for Geophysics, University of Texas at Austin, Office of Sponsored Research.

³ <https://earthquake.usgs.gov/earthquakes/map/>

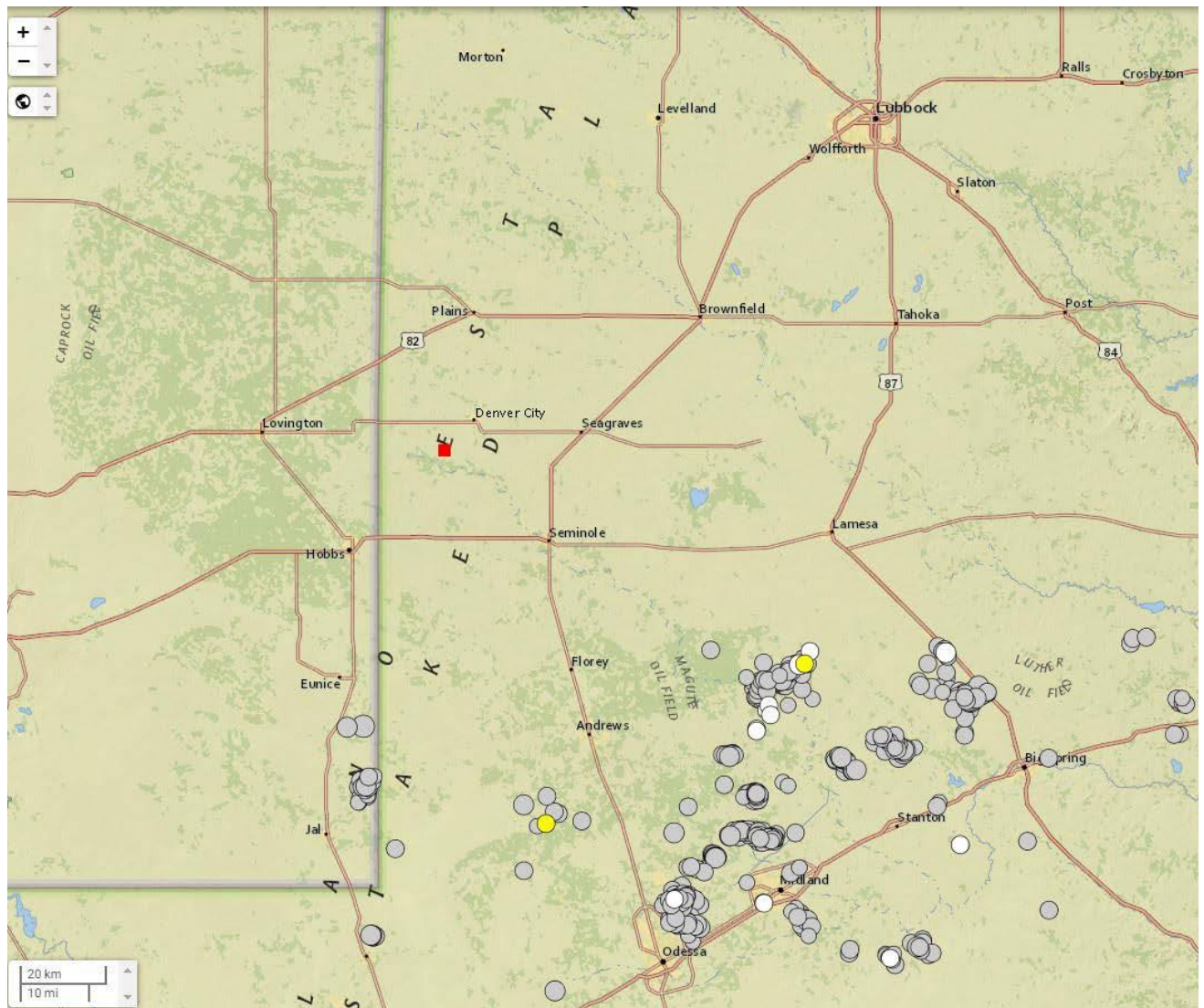


Figure 5-1 USGS earthquakes (+1.0 magnitude) for last 57 years)

5.4. Previous Operations

CO₂ flooding was initiated in the DCF in 2007. To obtain permits for CO₂ flooding, the AoR around all CO₂ injector wells was evaluated to determine if there were any unknown penetrations and to assess if corrective action was required at any wells. As indicated in Section 5.1, this evaluation reviewed the identified penetrations and determined that no additional corrective action was needed. Further, CapturePoint's standard practice for drilling new wells includes a rigorous review of nearby wells to ensure that drilling will not cause damage to or interfere with existing wells. Additionally, requirements to construct wells with materials that are designed for CO₂ injection are adhered to at the DCF. These practices ensure that there are no unknown wells within the DCF and that the risk of migration from older wells has been sufficiently mitigated. The successful experience with CO₂ flooding in the DCF demonstrates that the confining zone has not been impaired by previous operations.

5.5. Pipelines and Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO₂. CapturePoint anticipates that the use of prevailing design and construction practices and compliance with applicable laws will reduce to the maximum extent practicable the risk of unplanned leakage from surface facilities. The facilities and pipelines currently utilize and will continue to utilize materials of construction and control processes that are standard for CO₂-EOR projects in the oil and gas industry. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. Field personnel are trained to look for and report potential leaks from pipeline and surface equipment as part of their routine activities. Surface equipment leaks have a low risk of occurring based on design standards that are followed, and any leak would have insubstantial results. The magnitude of surface equipment leaks will range from .1 to 2 MT yearly and are addressed within 6-12 hours of occurring. Should leakage be detected from pipeline or surface equipment, the volume of released CO₂ will be quantified following the requirements of Subpart W of the Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP).

5.6. Lateral Migration Outside the Denver City Fields

It is highly unlikely that injected CO₂ will migrate downdip and laterally outside the DCF because of the nature of the geology and the approach used for injection. Over long periods of time, injected CO₂ will tend to rise vertically towards the Upper San Andres and continue towards the point in the DCF with the highest elevation. Second, the planned injection volumes and active fluid management during injection operations will prevent CO₂ from migrating laterally out of the structure. Finally, the total volume of fluids contained in the DCF will stay relatively constant. Based on site characterization and planned and projected operations it is estimated that the total volume of stored CO₂ will be considerably less than calculated capacity.

5.7. Drilling in the Denver City Fields

The TRRC regulates well drilling activity in Texas. Pursuant to TRRC rules, well casing shall be securely anchored in the hole to effectively control the well at all times, all usable-quality water zones shall be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flow zones, and zones with corrosive formation fluids shall be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. Where TRRC rules do not detail specific methods to achieve these objectives, operators shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology. The TRRC requires applications and approvals before a well is drilled, recompleted, or reentered. Well drilling activity at the DCF is conducted in accordance with TRRC rules. CapturePoint's visual inspection process, including routine site visits, will identify unapproved drilling activity in the DCF.

In addition, CapturePoint intends to operate the DCF for several more years and will continue to be vigilant about protecting the integrity of its assets and maximizing the potential of its resources, including oil, gas and CO₂. Consequently, the risks associated with third parties penetrating the DCF are negligible.

5.8. Diffuse Leakage Through the Seal

Diffuse leakage through the seal formed by the upper San Andres is highly unlikely. There are a number of sections above the reservoir that are impermeable and serve as reliable barriers to prevent fluids from moving upwards towards the surface. These barriers are referred to as seals because they effectively seal fluids within the formations beneath them.

Our injection pattern monitoring program assures that no breach of the seal will be created. The seal is highly impermeable. Wellbores that penetrate the seal make use of cement and steel construction that is closely regulated to ensure that no leakage takes place. Injection pressure is continuously monitored and unexplained changes in injection pressure that might indicate leakage would trigger investigation as to the cause.

5.9. Leakage Detection, Verification, and Quantification

As discussed above, the potential sources of leakage include issues, such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment (wellbores), and unique events such as induced fractures. An event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage is used. Table 5.1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, the standard response, and other applicable regulatory programs requiring similar reporting.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods for quantifying the volume of leaked CO₂ will be determined on a case-by-case basis using all metering and measurement equipment from each wellhead through the output of the tanks and recycle. In the event leakage occurs, the most appropriate methods for quantifying the volume leaked will be determined and it will be reported as required as part of the

annual Subpart RR submission.

Any volume of CO₂ detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as the frequency of inspection. Leaks will be documented, evaluated, and addressed in a timely manner.

Records of leakage events will be retained in an electronic environmental documentation and reporting system. The Field Foreman is notified for maintenance activities that cannot be addressed on the spot.

Table 5.1 Response Plan for CO₂ Loss

Risk	Monitoring Plan	Response Plan
Tubing Leak	Monitor changes in tubing and annulus pressure; MIT for injectors	Well is shut in and workover crews respond within days
Casing Leak	Routine Field inspection; Monitor changes in annulus pressure, MIT for injectors; extra attention to high risk wells	Well is shut in and workover crews respond within days
Wellhead Leak	Routine Field inspection, SCADA system monitors wellhead pressure	Well is shut in and workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations	Maintain well kill procedures
Unplanned wells drilled through San Andres	Routine Field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells.	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Reservoir pressure in WAG headers; high pressure found in new wells	Re-enter and reseal abandoned wells
Pumps, valves, etc.	Routine Field inspection, SCADA	Workover crews respond within days
Overfill beyond spill points	Reservoir pressure in WAG headers; high pressure found in new wells	Fluid management along lease lines
Leakage through induced fractures	Reservoir pressure in WAG headers; high pressure found in new wells	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Reservoir pressure in WAG headers; high pressure found in new wells	Shut in injectors near seismic event
Diffuse leakage through the seal	Monitor injection pressure for unexplained changes in injection pressure that might indicate leakage	Investigate to determine if cement and steel construction is the issue. Well is shut in and workover crews respond within days.

5.10. Summary

The structure and stratigraphy of the San Andres reservoir in the DCF is ideally suited for the injection and storage of CO₂. The stratigraphy within the CO₂ injection zones is porous, permeable, and thick, providing ample capacity for long-term CO₂ storage. The reservoir is overlain by several intervals of impermeable geologic zones that form effective seals or “caps” to fluids in the reservoir.

In summary, based on a careful assessment of the potential risk of release of CO₂ from the subsurface, it has been determined that there are no leakage pathways at the DCF that are likely to result in significant loss of CO₂ to the atmosphere. Further, given the detailed knowledge of the field and its operating protocols, it is concluded that any CO₂ leakage to the surface that could arise through either identified or unexpected leakage pathways would be detected and quantified.

6. Monitoring and Considerations for Calculating Site Specific Variables

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

6.1. For the Mass Balance Equation

6.1.1. General Monitoring Procedures

Flow rate, pressure, and gas composition data are monitored and collected from the DCF in centralized data management systems as part of ongoing operations. This data is monitored by qualified technicians who follow response and reporting protocols when the systems deliver notifications that data exceed statistically acceptable boundaries.

Metering protocols used at the DCF follow the prevailing industry standard(s) for custody transfer as currently promulgated by the American Petroleum Institute (API), the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. This approach is consistent with EPA GHGRP’s Subpart RR, section §98.444(e)(3). These meters will be maintained routinely, operated continually, and will feed data directly to the centralized data collection systems. The meters meet the industry standard for custody transfer meter accuracy and calibration frequency.

6.1.2. CO₂ Received

As indicated in Figure 3-5, the volume of received CO₂ is measured using a commercial custody transfer meter at the point at which custody of the CO₂ from the Kinder Morgan CO₂ Pipeline Delivery System is transferred to the DCF. This meter measures the flow rate continually. The transfer is a commercial transaction that is documented. CO₂ composition is governed by contract and the gas is routinely sampled. Fluid composition will be determined, at a minimum, quarterly, consistent with EPA GHGRP’s Subpart RR, section §98.447(a). All meter and composition data are documented, and records will be retained for at least three years. No CO₂ is received in containers.

6.1.3. CO₂ Injected in the Subsurface

Injected CO₂ will be calculated using the flow meter volumes at the operations meter at the outlet of the Recycle Compression Facility (RCF) and the custody transfer meter at the CO₂ off-take point from the Kinder Morgan CO₂ Pipeline Delivery System.

6.1.4. CO₂ Produced, Entrained in Products, and Recycled

The following measurements are used for the mass balance equations in Section 8:

- CO₂ produced in the gaseous stage is calculated using the volumetric flow meters at the outlet of the separation facility (Figure 3-8 vessels, V-100, V-101, V-200, V201, V300, and V400),
- CO₂ that is entrained in produced oil, as indicated in Figure 3-5, is calculated from routinely captured samples and volume is measured by the truck flow meter,
- Recycled CO₂ is calculated using the volumetric flow meter at the outlet of the RCF, which is an operations meter.

6.1.5. CO₂ Emitted by Surface Leakage

CapturePoint uses 40 CFR Part 98 Subpart W to estimate surface leaks from equipment at the DCF. Subpart W uses a factor-driven approach to estimate equipment leakage. In addition, an event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage to the surface is used. The Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet two objectives: 1) to detect problems before CO₂ leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the volumes of CO₂ leaked to the surface.

6.1.6. Monitoring for Potential Leakage from the Injection/Production Zone

In addition to the measures discussed in Section 5.9, both injection into and production from the reservoir will be monitored as a means of early identification of potential anomalies that could indicate leakage from the subsurface.

Injection plans (fluid rate, pressure, volume) are given to operations on a weekly basis. If injection pressure or rate measurements are outside the specified set points determined as part of each pattern injection plan, reservoir engineering will notify field personnel and they will investigate and resolve the problem. These excursions will be reviewed by well management personnel to determine if CO₂ leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or some other minor action is required), and there is no threat of CO₂ leakage. In the case of issues that are not readily resolved, more detailed investigation and response would be initiated, and support staff would provide

additional assistance and evaluation.

Likewise, a forecast of the rate and composition of produced fluids is developed. Each producer well is assigned to a specific SAT and is isolated during each cycle for a well production test. This data is reviewed on a periodic basis to confirm that production is at the level forecasted. If there is a significant deviation from the plan, well management personnel investigate. If the issue cannot be resolved quickly, a more detailed investigation and response would be initiated. If leakage in the flood zone were detected, an appropriate method would be used to quantify the involved volume of CO₂. This might include use of material balance equations based on known injected quantities and monitored pressures in the injection zone to estimate the volume of CO₂ involved.

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

In the event leakage from the subsurface occurred diffusely through the seals, the leaked gas would include H₂S, which would trigger the alarm on the personal monitors worn by field personnel as well as the various permanent H₂S monitors throughout the field at ground level. Such a diffuse leak from the subsurface has not occurred in the DCF. In the event such a leak was detected, personnel would determine how to address the problem. The personnel might use modeling, engineering estimates, and direct measurements to assess, address, and quantify the leakage.

6.1.7. Monitoring of Wellbores

DCF wells are monitored through daily pressure monitoring of the injection zone, monitoring of the annular pressure in wellheads, and routine maintenance and inspection.

Leaks from wellbores would be detected through the follow-up investigation of pressure anomalies, visual inspection, or the use of personal H₂S monitors and various permanent H₂S monitors throughout the field at ground level.

Anomalies in injection zone pressure may not indicate a leak, as discussed above. However, if an investigation leads to a need for further study, field personnel would inspect the equipment in question and determine the nature of the problem. If it is a simple matter, the repair would be made, and the volume of leaked CO₂ would be included in the 40 CFR Part 98 Subpart W report for the DCF. If more extensive repair were needed, the appropriate approach for quantifying leaked CO₂ using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be determined.

Anomalies in annular pressure or other issues detected during routine maintenance inspections would be treated in the same way. Field personnel would inspect the equipment in question and determine the nature of the problem. For simple matters the repair would be made at the time of inspection and the volume of leaked CO₂ would be included in the 40 CFR Part 98 Subpart W report for the DCF. If more extensive repairs were needed, the well would be shut in, a work order would be generated and the appropriate approach for quantifying leaked CO₂ using the relevant parameters

(e.g., the rate, concentration, and duration of leakage) would be determined. The work order would serve as the basis for tracking the event for Green House Gas (GHG) reporting.

Because leaking CO₂ at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a visual inspection process in the area of the DCF is employed to detect unexpected releases from wellbores. Field personnel visit the surface facilities on a routine basis. Inspections may include tank levels, equipment status, lube oil levels, pressures and flow rates in the facility, and valves. Field personnel also check that injectors are on the proper WAG schedule and observe the facility for visible CO₂ or fluid line leaks.

Finally, the data collected by the H₂S monitors, which are always worn by field personnel and are located permanently throughout the field at ground level, is used as a last method to detect leakage from wellbores. The H₂S monitor's detection limit is 10 ppm; if an H₂S alarm is triggered, the first response is to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. As noted previously, H₂S is considered a proxy for potential CO₂ leaks in the field. Thus, detected H₂S leaks will be investigated to determine and, if needed, quantify potential CO₂ leakage.

6.1.8. Other Potential Leakage at the Surface

The same visual inspection process and H₂S monitoring system will be used to detect other potential leakage at the surface as it does for leakage from wellbores. Routine visual inspections are used to detect significant loss of CO₂ to the surface. Field personnel routinely visit surface facilities to conduct a visual inspection. Inspections may include review of tank level, equipment status, lube oil levels, pressures and flow rates in the facility, valves, ensuring that injectors are on the proper WAG schedule, and also conducting a general observation of the facility for visible CO₂ or fluid line leaks. If problems are detected, field personnel would investigate, and complete any maintenance that is required. In addition to these visual inspections, the results of the personal H₂S monitors worn by field personnel and the permanent H₂S monitors throughout the field at ground level will be used as a supplement for smaller leaks that may escape visual detection.

If CO₂ leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, steps are taken to prevent further leaks.

6.1.9. CO₂ emitted from equipment leaks and vented emissions of CO₂ from surface equipment located between the injection flow meter and the injection wellhead.

CapturePoint evaluates and estimates leaks from equipment, the CO₂ content of produced oil, and vented CO₂, as required under 40 CFR Part 98 Subpart W.

6.1.10. CO₂ emitted from equipment leaks and vented emissions of CO₂ from surface equipment located between the production flow meter and the production wellhead.

CapturePoint evaluates and estimates leaks from equipment, the CO₂ content of produced oil, and vented CO₂, as required under 40 CFR Part 98 Subpart W.

6.1.11. To Demonstrate that Injected CO₂ is not Expected to Migrate to the surface

At the end of the Specified Period, injecting CO₂ for the subsidiary purpose of establishing the long-term storage of CO₂ in the DCF will cease. Sometime after the end of the Specified Period, a request to discontinue monitoring and reporting will be submitted. The request will demonstrate that the amount of CO₂ reported under 40 CFR §98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage. At that time, the request will be supported with years of data collected during the Specified Period. This demonstration will provide the information necessary for the EPA Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

- Data comparing actual performance to predicted performance (purchase, injection, production) over the monitoring period,
- An assessment of the CO₂ leakage detected, including the discussion of the estimated amount of CO₂ leaked and the distribution of emissions by leakage pathway,
- A demonstration that future operations will not release the volume of stored CO₂ to the surface,
- A demonstration that there has been no significant leakage of CO₂; and,
- An evaluation of reservoir pressure that demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

7. Determination of Baselines

Ongoing operational monitoring has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO₂ 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. The necessary system guidelines to capture the information that is relevant to identify possible CO₂ leakage will be developed. The following describes the approach to collecting this information.

7.1. Visual Inspections

As field operators conduct routine inspections and repairs, the field Foreman is notified for maintenance activities that cannot be addressed on the spot. Examples include occurrences of well workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation (the responsible party will be provided in the monitoring plan, as required under Subpart A, §98.3(g)). The Annual Subpart RR Report will include an estimate of the amount of CO₂ leaked. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

7.2. Personal H₂S Monitors

H₂S monitors are worn by all field personnel. The H₂S monitors detect concentrations of H₂S up to 500 ppm in 0.1 ppm increments and will sound an alarm if the detection limit exceeds 10 ppm. The current H₂S concentration in the produced gas is 5,709 ppm taken from the recycle compressor inlet and 205 ppm in the produced oil. If an H₂S alarm is triggered, the immediate response is to protect the safety of the personnel, and the next step is to safely investigate the source of persistent alarms. CapturePoint considers H₂S to be a proxy for potential CO₂ leaks in the field. The person responsible for MRV documentation will receive notice of all incidents where H₂S is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO₂ emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

As stated before, there are various permanent H₂S monitors throughout the field at ground level to detect H₂S and alarm if a limit is reached.

7.3. Injection Rates, Pressures and Volumes

Target injection rate and pressure for each injector are developed within the permitted limits based on the results of ongoing pattern balancing. The injection targets are submitted to field operations. Field operations flags whenever statistically significant deviations from the targeted ranges are identified. The set points are designed to be conservative, because it is preferable to have too many flags rather than too few. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO₂ leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions. The Annual Subpart RR Report will provide an estimate of CO₂ emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

7.4. Production Volumes and Compositions

A general forecast of production volumes and composition is developed which is used to periodically evaluate performance and refine current and projected injection plans and the forecast. This information is used to make operational decisions but is not recorded in an automated data system. The MRV plan implementation lead will review the data and identify those that could result in CO₂ leakage. Should such events occur, leakage volumes would be calculated following the approaches described in Sections 5 and 6. Impact to Subpart RR reporting will be addressed, if deemed necessary.

8. Determination of Sequestration Volumes Using Mass Balance Equations

To account for the potential error that would result if volume data from flow meters at each injection and production well were utilized, the data from custody transfer meters, operations meters on the main system pipelines, and at all points of separation, is used to determine injection and production volumes used in the mass balance of the system, per subpart RR requirements. This issue arises because while each meter has a small but acceptable margin of error, this error would become significant if data were taken from all the well head meters within the DCF.

The following sections describe how each element of the mass-balance equation (Equation RR- 11) will be calculated.

8.1. Mass of CO₂ Received

Equation RR-2 will be used as indicated in Subpart RR §98.443 to calculate the mass of CO₂ at the receiving custody transfer meter from the Kinder Morgan CO₂ Pipeline Delivery System. The volumetric flow at standard conditions will be multiplied by the CO₂ concentration and the density of CO₂ at standard conditions to determine mass.

$$CO_2T_r = \sum_{p=1}^4 (Q_{r,p} - S_{r,p}) * D * C_{CO_2,r,p} \quad (\text{Eq. RR-2})$$

where:

- CO₂T_r = Net annual mass of CO₂ received through flow meter r (metric tons)
- Q_{r,p} = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters)
- S_{r,p} = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into a site well in quarter p (standard cubic meters)
- D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682
- C_{CO₂,p,r} = Quarterly CO₂ concentration measurement in flow for flow meter r in quarter p (vol. percent CO₂, expressed as a decimal fraction)
- p = Quarter of the year
- r = Receiving flow meters

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

- All delivery to the DCF is used within the unit so no quarterly flow redelivered, and S_{r,p} will be zero ("0").
- Quarterly CO₂ concentration will be taken from the gas measurements.

8.2. Mass of CO₂ Injected into the Subsurface

The equation for calculating the Mass of CO₂ Injected into the Subsurface at the DCF is equal to the sum of the Mass of CO₂ Received as calculated in RR-2 of §98.443 (section 8.1 above) and the Mass of CO₂ Recycled calculated using measurements taken from the flow meter located at the output of the RCF (see Figure 3-5). As previously explained, using data at each injection well would give an inaccurate estimate of total injection volume due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

The Mass of CO₂ Recycled will be determined using equations RR-5 as follows:

$$CO_{2u} = \sum_{p=1}^4 Q_{p,u} * D * C_{CO_2,p,u} \quad (\text{Eq. RR-5})$$

where:

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

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter):
0.0018682

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

p = Quarter of the year

u = Flow meter

The total Mass of CO₂ Injected will be the sum of the Mass of CO₂ Received (RR-2) and Mass of CO₂ Recycled (modified RR-5).

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

where:

CO_{2I} = Total annual CO₂ mass injected (metric tons) through all injection wells.

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

u = Flow meter.

8.3. Mass of CO₂ Produced

The Mass of CO₂ Produced at the DCF will be calculated using the measurements from the flow meters at the inlet to RCF and from routinely captured samples and volume is measured by the truck flow meter rather than the metered data from each production well. Again, using the data at each production well would give an inaccurate estimate of total injection due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

Equation RR-8 in §98.443 will be used to calculate the Mass of CO₂ Produced from all production wells as follows:

$$CO_{2w} = \sum_{p=1}^4 Q_{p,w} * D * C_{CO_2,p,w} \quad (\text{Eq. RR-8})$$

where:

CO_{2w} = Annual CO₂ mass produced (metric tons)

$Q_{p,w}$ = Volumetric gas flow rate measurement for meter w in quarter p at standard conditions (standard cubic meters)

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter):
0.0018682

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

p = Quarter of the year

w = Inlet meter to RCF

For Equation RR-9 in §98.443 the variable X_{oil} will be measured as follows:

$$CO_{2p} = \sum_{w=1}^W CO_{2w} + X_{oil} \quad (\text{Eq. RR-9})$$

where:

CO_{2p} = Total annual CO₂ mass produced (metric tons) through all meters in the reporting year

CO_{2w} = Annual CO₂ mass produced (metric tons) through meter w in the reporting year.

X_{oil} = Mass of entrained CO₂ in oil in the reporting year measured utilizing commercial meters and electronic flow-measurement devices at each point of custody transfer. The mass of CO₂ will be calculated by multiplying the total volumetric rate by the CO₂ concentration.

8.4. Mass of CO₂ 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 CO₂ stream, for facilities that conduct CO₂-EOR operations.

CapturePoint will calculate the total annual mass of CO₂ emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 below

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

where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway

8.5. Mass of CO₂ Sequestered in Subsurface Geologic Formation

Equation RR-11 in §98.443 will be used to calculate the Mass of CO₂ Sequestered in Subsurface Geologic Formations in the Reporting Year as follows:

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

where:

CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2P} = Total annual CO₂ mass produced (metric tons) net of CO₂ entrained in oil in the reporting year

CO_{2E} = Total annual CO₂ mass emitted (metric tons) by surface leakage in the reporting year

CO_{2FI} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of this part

CO_{2FP} = Total annual CO₂ mass emitted (metric tons) from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of this part

8.6. Cumulative Mass of CO₂ Reported as Sequestered in Subsurface Geologic Formation

The total annual volumes obtained using equation RR-11 in §98.443 will be summed to arrive at the Cumulative Mass of CO₂ Sequestered in Subsurface Geologic Formations.

9. MRV Plan Implementation Schedule

This MRV plan will be implemented starting January 2024 or within 90 days of EPA approval, whichever occurs later. Other GHG reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. It is anticipated that the MRV program will be in effect during the Specified Period, during which time the DCF will be operated with the subsidiary purpose of establishing long-term containment of a measurable quantity of CO₂ in subsurface geological formations at the DCF. It is anticipated to establish that a measurable amount of CO₂ injected during the Specified Period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be prepared and a request to discontinue monitoring and reporting under this MRV plan will be submitted. See 40 C.F.R. §98.441(b)(2)(ii).

10. Quality Assurance Program

10.1. Monitoring QA/QC

The requirements of §98.444 (a)-(d) have been incorporated in the discussion of mass balance equations. These include the following provisions.

10.2. CO₂ Received and Injected

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

10.3. CO₂ Produced

- The point of measurement for the quantity of CO₂ produced from oil or other fluid production wells is a flow meter directly downstream of each separator that sends a stream of gas into a recycle or end use system.
- The produced gas stream is sampled annually downstream of the flow meter used to measure flow rate of that gas stream and measure the CO₂ concentration of the sample.
- The quarterly flow rate of the produced gas is measured at the flow meters located at the RCF inlet.

10.4. CO₂ Emissions from Equipment Leaks and Vented Emissions of CO₂

These volumes are measured in conformance with the monitoring and QA/QC requirements specified in subpart W of 40 CFR Part 98.

10.5. Flow Meter Provisions

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

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

10.6. Concentration of CO₂

CO₂ concentration is measured using an appropriate standard method. Further, all measured volumes of CO₂ have been converted to standard cubic meters at a temperature of 60°F and at an absolute pressure of 1 atmosphere, including those used in Equations RR-2, RR-5, RR-8, RR-9, RR-10, and RR-11 in Section 8.

10.7. Missing Data Procedures

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

- A quarterly flow rate of CO₂ received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.
- A quarterly CO₂ concentration of a CO₂ stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO₂ injected that is missing would be estimated using a representative quantity of CO₂ injected from the nearest previous time period at a similar injection pressure.
- For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.
- The quarterly quantity of CO₂ produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO₂ produced from the nearest previous time period.

10.8. MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters of the CO₂-

EOR operations in the DCF that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in §98.448(d).

11. Records Retention

The record retention requirements specified by §98.3(g) will be followed. In addition, the requirements in Subpart RR §98.447 will be met by maintaining the following records for at least three years:

- Quarterly records of CO₂ received at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams,
- Quarterly records of produced CO₂, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams,
- Quarterly records of injected CO₂ including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams,
- Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways,
- Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead; and,
- Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

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

12. Appendix

12.1 Well Identification Numbers

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

Well Type

- PROD_OIL refers to wells that produce oil
- INJ_WTR refers to wells that inject water
- INJ_WAG refers to wells that inject water and CO₂ Gas
- INJ_SWD refers to wells that inject water for disposal
- SWS refers to wells that supply water
- P&A refers to plugged and abandoned wells

Well Status

- ACTIVE refers to active wells
- INACTIVE refers to wells that have been completed but are not in use
- SHUT_IN refers to wells that have been temporarily idled or shut-in

Well Name	API Number	Well Type	Status
GAU #1WS	42165339890000	SWS	INACTIVE
GAU #2W	42165106400000	P&A	INACTIVE
GAU #3	42165106340000	P&A	INACTIVE
GAU #4	42165103790000	PROD_OIL	SHUT_IN
GAU #5	42165106070000	PROD_OIL	INACTIVE
GAU #6	42165106530000	P&A	INACTIVE
GAU #6R	42165367760000	PROD_OIL	INACTIVE
GAU #7W	42165339900000	INJ_WAG	ACTIVE
GAU #8W	42165339910000	INJ_WAG	SHUT_IN
GAU #9W	42165339920000	INJ_WAG	ACTIVE
GAU #10	42165106510000	P&A	INACTIVE
GAU #10R	42165367820000	PROD_OIL	ACTIVE
GAU #11	42165106060000	P&A	INACTIVE
GAU #11R	42165367490000	PROD_OIL	ACTIVE
GAU #12	42165102070000	P&A	INACTIVE
GAU #12R	42165367510000	PROD_OIL	ACTIVE
GAU #13	42165003830000	PROD_OIL	ACTIVE
GAU #14W	42165317930000	INJ_WAG	SHUT_IN
GAU #15	42165101300000	PROD_OIL	INACTIVE
GAU #16W	42165106270000	INJ_SWD	ACTIVE
GAU #17W	42165339930000	INJ_WAG	ACTIVE

Well Name	API Number	Well Type	Status
GAU #18	42165103780000	PROD_OIL	ACTIVE
GAU #19	42165106460000	PROD_OIL	SHUT_IN
GAU #20W	42165008790000	P&A	INACTIVE
GAU #22W	42165352720000	INJ_WAG	ACTIVE
GAU #23W	42165367500000	INJ_WAG	ACTIVE
GAU #24	42165106440000	PROD_OIL	INACTIVE
GAU #25	42165367550000	PROD_OIL	ACTIVE
GAU #26	42165367530000	PROD_OIL	ACTIVE
GAU #27	42165367540000	PROD_OIL	ACTIVE
GAU #71	42165384590000	PROD_OIL	ACTIVE
RH #28W	42165367610000	INJ_WAG	ACTIVE
RH #29W	42165367620000	INJ_WAG	ACTIVE
RH #30W	42165367630000	INJ_WAG	ACTIVE
RH #31	42165367660000	PROD_OIL	ACTIVE
RH #32	42165367670000	PROD_OIL	ACTIVE
RH #33	42165367520000	PROD_OIL	ACTIVE
RH #34	42165367890000	PROD_OIL	SHUT_IN
RH #70	42165384430000	PROD_OIL	ACTIVE

12.2 Regulatory References

Regulations cited in this plan:

- Texas Administrative Code Title 16 Part 1 Chapter 3 Oil & Gas Division -
[https://texreg.sos.state.tx.us/public/readtac\\$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y](https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y)
- TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual –
<https://www.rrc.texas.gov/oil-and-gas/publications-and-notices/manuals/injection-storage-manual/>

12.3 Abbreviations and Acronyms

AGA - American Gas Association

AMA - Active Monitoring Area

API - American Petroleum Institute

AoR - Area of Review

Bcf – 1 Billion Standard Cubic Feet of Gas

CO₂ - Carbon Dioxide

DCF – Denver City Fields

DPCs - Dimensionless Performance Curves

EPA - Environmental Protection Agency

EOR - Enhanced Oil Recovery
ESP - Electrical Submersible Pump
FPP - Formation Parting Pressure
GAU – George Allen Unit
GHG - Greenhouse Gas
GHGRP - Greenhouse Gas Reporting Program
GIS - Geographical Information System
GPA - Gas Processors Association
H₂S – Hydrogen Sulfide
HCPV - Hydrocarbon Pore Volume
IWR - Injection to withdrawal Ratio
MMA - Maximum Monitoring Area
MMRB – One million reservoir barrels
MRV - Monitoring, Reporting and Verification Plan
Mscf – 1,000 Standard Cubic Feet of Gas
NIST - National Institute of Standards and Technology
OWC – Oil water contact
RB - Reservoir Barrels
RH – Ruth Hudson Lease
RCF - Recycle Compression Facility
ROZ - Residual Oil Zone
SAT - Satellite Test Stations
TAC - Texas Administrative Code
TRRC - Texas Railroad Commission - Oil and Gas Division
TZ – Transition Zone
UIC - Underground Injection Control
USGS - United States Geological Survey
WAG - Water Alternating Gas

12.4 Appendix 12.4 – Conversion Factors

CapturePoint reports CO₂ 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 CO₂ mass from CO₂ 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 CO₂ 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 CO₂ of 0.002641684 lb-moles per cubic foot. Converting the CO₂ density in units of metric tonnes per cubic foot:

$$Density_{CO_2} \left(\frac{MT}{ft^3} \right) = Density_{CO_2} \left(\frac{lb - moles}{ft^3} \right) \times MW_{CO_2} \times \frac{1 MT}{2,204.62 lbs}$$

Where:

$Density_{CO_2}$ = Density of CO₂ in metric tonnes (MT) per cubic foot

$Density_{CO_2}$ = 0.002641684

MW_{CO_2} = 44.0095

$Density_{CO_2} = 5.2734 \times 10^{-5} \frac{MT}{ft^3}$ or $5.2734 \times 10^{-2} \frac{MT}{Mcf}$

The conversion factor 5.2734 x 10⁻² MT/Mcf is used to convert CO₂ volumes in standard cubic feet to CO₂ mass in metric tonnes.

Request for Additional Information: Denver City Fields
July 31, 2023

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	Please ensure that all acronyms are defined during the first use within the MRV plan. For example, “OWC” and “MMRB” are not defined within the text and “CO ₂ -EOR” is not defined when it first appears in the text.	Done. Checked to ensure all acronyms are defined during the first use within the MRV plan and cleaned up as many hyphens, bolding, quotation marks, font, and capitalization we could locate.
2.	N/A	N/A	There is a lack of consistency with punctuation, hyphens, bolding, quotation marks, spelling, and capitalization throughout the MRV plan. Examples include but are not limited to: • “Figure 3-1 DCF Historic and Forecast Injection, Production, and Storage(.).” • CO₂ vs. CO2 • Well Bores vs. Wellbores • 2,060,000 vs. 188 million • Thousands place separator usage We recommend reviewing the formatting in the MRV plan for consistency. Furthermore, we recommend doing an additional review for spelling, grammar, etc.	Done. Checked for consistency.
3.	N/A	N/A	Please review the figures included in the MRV plan to ensure that citations are consistent, all text is legible and in the same font and size, and that all legends, scale bars, and North arrows are scaled appropriately, etc. For example: • The North arrow is illegible in Figure 3-7 and Figure 4-1. • There is no Figure 3-6 in the MRV plan.	Done. Made corrections.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	N/A	N/A	We recommend adding a geologic discussion and an accompanying stratigraphic column to the MRV plan.	Added discussion and figures in Section 3.3. This caused the other sections to be renumbered.
5.	N/A	N/A	We recommend identifying the target storage formation as well as the formation(s) that will serve as the primary (and secondary) confining seal(s).	The target storage formation is stated in Section 3 and the formation that will serve as the primary and secondary confining seal is stated in Section 3.3.
6.	3.2	9	“There is more than enough pore space to sequester the planned CO₂ injection.” We suggest revising the above sentence for clarity.	Done. Now reads “There is more than enough pore space (188 million reservoir barrels (MRB) to sequester the planned CO ₂ injection (27.8 million reservoir barrels).”
7.	3.2	9	CO₂ will occupy only 15% of the total calculated storage capacity by the year 2039 based on the current project forecast. What is the significance of the year 2039 as it appears above? The plan also references a “Specified Period” several times. Is there a specific anticipated timeframe associated with the Specified Period? Please revise the MRV plan for clarity.	Done. The specified period is the time frame that CO ₂ storage will be occurring. In this field the time frame is until 2037 and not 2039. This has been corrected.
8.	3.4	15	“Specified amounts will be drawn from an outside source pipeline based on contractual arrangements among suppliers of CO₂, purchasers of CO₂, and the pipeline operator.” Please clarify and/or define “Specified amounts” in the MRV plan.	Done in Section 3.4 to read “The Specified amounts are the amount of CO ₂ required in addition to the produced gas to meet target CO ₂ injection rates forecasted using the dimensionless curve approach.’ This would be purchased CO ₂ .

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
9.	4	20	Per 40 CFR 98.449, active monitoring area is defined as the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase 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. While the MRV plan identifies the AMA, please provide further explanation of whether the AMA meets the definitions in 40 CFR 98.449. For example, please specify whether CO₂ will remain within the unit boundaries at year t with a ½ mile buffer superimposed over the extent of the plume at year t+5 as required in the above definitions. Is there a specific timeframe associated with the AMA?	The active monitoring area is defined by the GAU and RH boundaries. Based on our projections, CapturePoint expects the free phase CO₂ plume to remain within the George Allen Unit and Ruth Hudson boundaries for the entire length of the project and through year [t+5]. The CO₂ storage volume calculations show the CO₂ to remain within the unit boundaries in the timeframe associated with the AMA which is year 2037. The CO₂ injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO₂-EOR. Maintenance of an Injection to Withdrawal ratio of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.
10.	4	20	Per 40 CFR 98.449, maximum monitoring area 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. While the MRV plan identifies the MMA, please provide further explanation of whether the MMA meets the definitions in 40 CFR 98.449. Please specify whether CO₂ will remain in the unit boundaries when the CO₂ plume has stabilized as required in the above definitions. E.g., is there a specific timeframe in which the plume is expected to stabilize? What will happen to the CO₂ plume when the facility is no longer producing/injecting fluids?	"The CO₂ plume (Figure 4-1) is expected to be contained within the George Allen and Ruth Hudson boundaries which will be actively monitored. The MMA would be the same as the AMA since the plume location is less than the unit area. 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 FR 98.448(d)(1).
11.	4	15	Please clearly label the AMA and MMA in Figure 4-1.	Done.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
12.	5	23-29	In addition to listing the possible leakage pathways and their monitoring strategies, please ensure each has clear characterization of the likelihood, magnitude, and timing of leakage for each potential leakage pathway. For example, the format of such a characterization might look like: “leakage from XYZ pathway is unlikely but possible. If it did occur, it would be most likely when pressures are highest during XYZ timeframe, and the leakage could result in XYZ kgs/metric tons before being addressed...”	Added to Section 5.5 “Surface equipment leaks have a low risk of occurring based on design standards that are followed, and any leak would have insubstantial results. The magnitude of surface equipment leaks will range from .1 to 2 MT yearly and are addressed with 6-12 hours of occurring.” Added to Section 5.1 “If leakage did occur, the magnitude of leaks will range from 5 to 20 MT once every 50 years and will be addressed withing 2 to 6 months of discovery to allow for obtaining drilling permits and contractor equipment mobilization.”
13.	5.1	24	“CapturePoint’s experience, from over 10 years of operating CO₂-EOR projects, is that such leakage is very rare.” In the MRV plan, please clarify whether such leakage has happened previously, and what is meant by “rare”.	Changed wording to read “CapturePoint’s experience, from over 10 years of operating this CO₂-EOR project, is that such leakage has not occurred at GAU_RH.” Leaks would be scarce or rare.
14.	5.2	25	“...there are no known faults or fractures that transect the San Andres reservoir in the project area. As a result, there is no risk of leakage due to fractures or faults.” Although the likelihood of leakage through faults and fractures may be very low, it is not impossible (e.g., given the discussion of measures to not exceed FPP). We recommend revising this characterization.	Changed no risk to minimal risk.
15.	5.8	28	Diffuse leakage through the seal is listed as a potential leakage pathway, but it does not have a corresponding monitoring strategy in Table 5-1. For consistency, please ensure that all leakage pathways identified have a corresponding monitoring strategy.	Added to Table 5.1.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
16.	5.9	28	“Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods for quantifying the volume of leaked CO₂ will be determined on a case-by-case basis.” While the MRV plan mentions that the facility intends to quantify potential surface leakage, please provide example quantification strategies that may be applied for the surface pathways identified in the MRV plan.	Edited Section 5.9 on page 27 to read “case-by-case basis using all metering and measurement equipment from each wellhead through the output of the tanks and recycle facility.”
17.	6.1.4	31	“CO₂ produced in the gaseous stage is calculated using the volumetric flow meters at the inlet to the RCF,” Flow meters used to measure CO₂ produced must be located at the outlet of the separation facilities, not the inlet. Please clarify this section. For reference, see https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-RR#p-98.444(c)	Edited Section 6.1.4 to read “CO ₂ produced in the gaseous stage is calculated using the volumetric flow meters at the outlet of the separation facility (Figure 3-8 vessels, V-100, V-101, V-200, V201, V300, and V400),”
18.	6.1.7	32	“The H₂S monitors detection limit is 10 ppm...” The plan mentions H₂S detection as a proxy for CO₂ leakage detection. We recommend adding information about the H₂S concentration in the fluids.	The latest fluid analysis shows 5,709 ppm in the produced gas (recycle compressor inlet) and 205 ppm in the produced oil. This has been updated in Section 7.2.
19.	8	36	“To account for the potential propagation of error that would result if volume data from flow meters at each injection and production well were utilized, it is proposed to use the data from custody and operations meters on the main system pipelines to determine injection and production volumes used in the mass balance.” Please review 40 CFR 98.444 to ensure that all flow meter locations are consistent with the subpart RR requirements and revise the MRV plan as necessary.	Edited in Section 8 to read “To account for the potential error that would result if volumetric data from flow meters at each injection and production well were utilized, the data from custody transfer meters, operations meters on the main system pipelines, and at all points of separation, is used to determine injection and production volumes used in the mass balance of the system, per subpart RR requirements.”

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
20.	8.1	36	<i>“C_{CO2,r,r} = Quarterly CO₂ concentration measurement in flow for flow meter r quarter p (vol. percent CO₂, expressed as a decimal fraction)”</i> In Equation RR-2, this variable is “C_{CO2,p,r} = Quarterly CO₂ concentration measurement in flow for flow meter r quarter p (vol. percent CO₂, expressed as a decimal fraction”. Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Equation updated in Section 8.1.
21.	8.2	37	<i>“The total Mass of CO₂ Injected will be the sum of the Mass of CO₂ Received (RR-3) and Mass of CO₂ Recycled (modified RR-5).”</i> According to Subpart RR, “to aggregate injection data for all wells covered under this subpart, you must sum the mass of all CO₂ injected through all injection wells in accordance with the procedure specified in Equation RR–6 of this section.” Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Revised section 8.2 to include Eq. RR-6 and made sure equations are consistent with the text in 40 CFR 98.443.
22.	8.4	39	<i>“Equation RR-10 in §98.433 will be used to calculate and report the Mass of CO₂ emitted by Surface Leakage.”</i> This section explains that surface leakage will be summed using RR-10, but also mentioned subpart W procedures. Please note that the “surface leakage” described in RR-10 is separate from the surface equipment leaks that are calculated using subpart W procedures (see eq. RR-11). We recommend revising this section for clarity.	Section 8.4 was revised for clarity.

**CapturePoint LLC Denver City Fields
Subpart RR Monitoring, Reporting and
Verification (MRV) Plan**

May 19th, 2023

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1. Introduction

CapturePoint LLC operates a CO₂-EOR project in the Denver City Fields (DCF) located in Gaines County, Texas, approximately four miles southwest of the town of Denver City, Texas and less than two miles west of the Denver Unit of the giant Wasson San Andres Fields for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO₂) with a subsidiary or ancillary purpose of geologic sequestration of CO₂ in a subsurface geologic formation. The DCF is comprised of the George Allen Unit (GAU) and the Ruth Hudson Lease (RH). Like Wasson production is from the San Andres formation at an average depth of 5000 feet. The Monitoring, Reporting and Verification (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 CO₂ sequestered at the Denver City Fields during a specified period of injection.

2. Facility Information

2.1. Reporter Number

576482 – Denver City Fields

2.2. UIC Permit Class

The Oil and Gas Division of the Texas Railroad Commission (TRRC) regulates oil and gas activity in Texas. All wells in the DCF (including production, injection, and monitoring wells) are permitted by TRRC through Texas Administrative Code (TAC) Title 16 Chapter 3. TRRC has primacy to implement the Underground Injection Control (UIC) Class II program in the state for injection wells. All EOR injection wells in the DCF are currently classified as UIC Class II wells.

2.3. Existing Wells

Wells in the DCF are identified by name and number, API number, type, and status. The list of wells as of March 2023 is included in Section 12.1. Any changes in wells will be indicated in the annual subpart RR submission.

3. Project Description

This project takes place in the DCF, an oil field located in West Texas that was first produced more than 60 years ago. The DCF is comprised of the George Allen Unit (GAU) and the Ruth Hudson (RH) Lease. The two abut each other, produce oil and gas from the same geologic formations and structure, and are under the sole operatorship of CapturePoint LLC. The geology, facilities/equipment, and operational procedures are similar for both in the DCF. In addition, the two properties share the same CO₂ recycle and water injection facilities as well as the injection piping system for both CO₂ and water. Because of these common facilities and common reservoir, one MRV Plan is being prepared for the two properties in the DCF and any important differences between the properties will be noted in the MRV plan. CO₂ flooding was initiated in 2007 in the

GAU and in 2012 in the RH. The field is well characterized and is suitable for secure geologic storage. CapturePoint LLC uses a water alternating with gas (WAG) injection process and maintains an injection to withdrawal ratio (IWR) at or near 1.0.

3.1. Project Characteristics

The DCF was discovered in 1956 and started production in the same year. The DCF consists of one unit (GAU) and one lease (RH). The GAU began to produce in May 1956 and the waterflood was initiated in September 1989. CO₂ flooding was initiated in December 2007, in both the Main Pay and Residual Oil Zone (ROZ). The RH initiated a waterflood in March 2008 and began to produce in November 2008. CO₂ flooding was initiated in December 2012, also in the Main Pay and ROZ.

A long-term forecast for both the GAU and RH was developed using a dimensionless curve approach. Using this approach, approximately 2.0 million tonnes of stored CO₂ is forecasted over the life of the project. Figure 3-1 shows actual and projected CO₂ injection, production, and stored volumes in DCF.

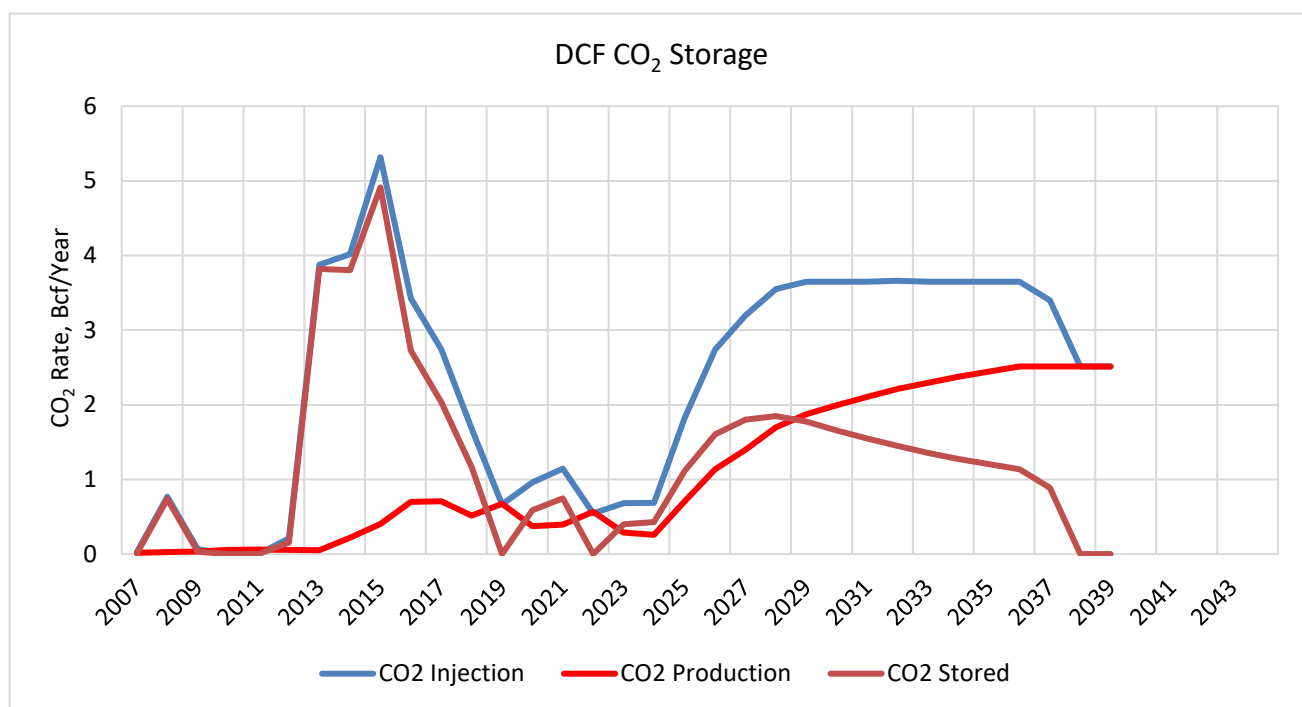


Figure 3-1 DCF Historic and Forecast CO₂ Injection, Production, and Storage

3.2. Environmental Setting

The DCF is located in the NE portion of the Central Basin Platform in West Texas (See Figure 3-2). This map also shows the location of the Denver Unit and other Wasson San Andres Units. The Denver City Fields are shown by the green dot.

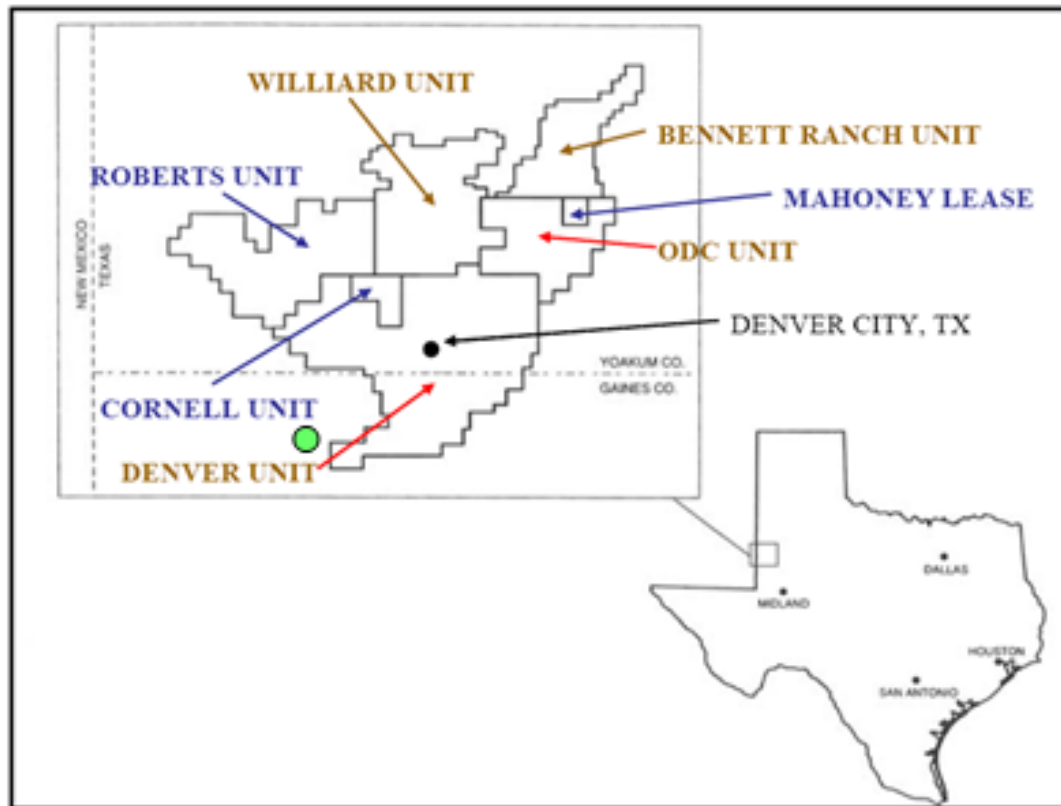


Figure 3-2 Location of Denver City Fields in West Texas

Like Wasson, the DCF produces from a San Andres dolomite reservoir at a depth of about 5000 feet. In contrast to Wasson, DCF is an insignificant oil accumulation with a thin mobile oil column trapped by a very low relief anticlinal structure as shown in figure 3-3. The Wasson field has produced over 2 billion barrels of oil to date from the San Andres while the DCF has produced 2,060,000 barrels of oil to 1-1-2022.

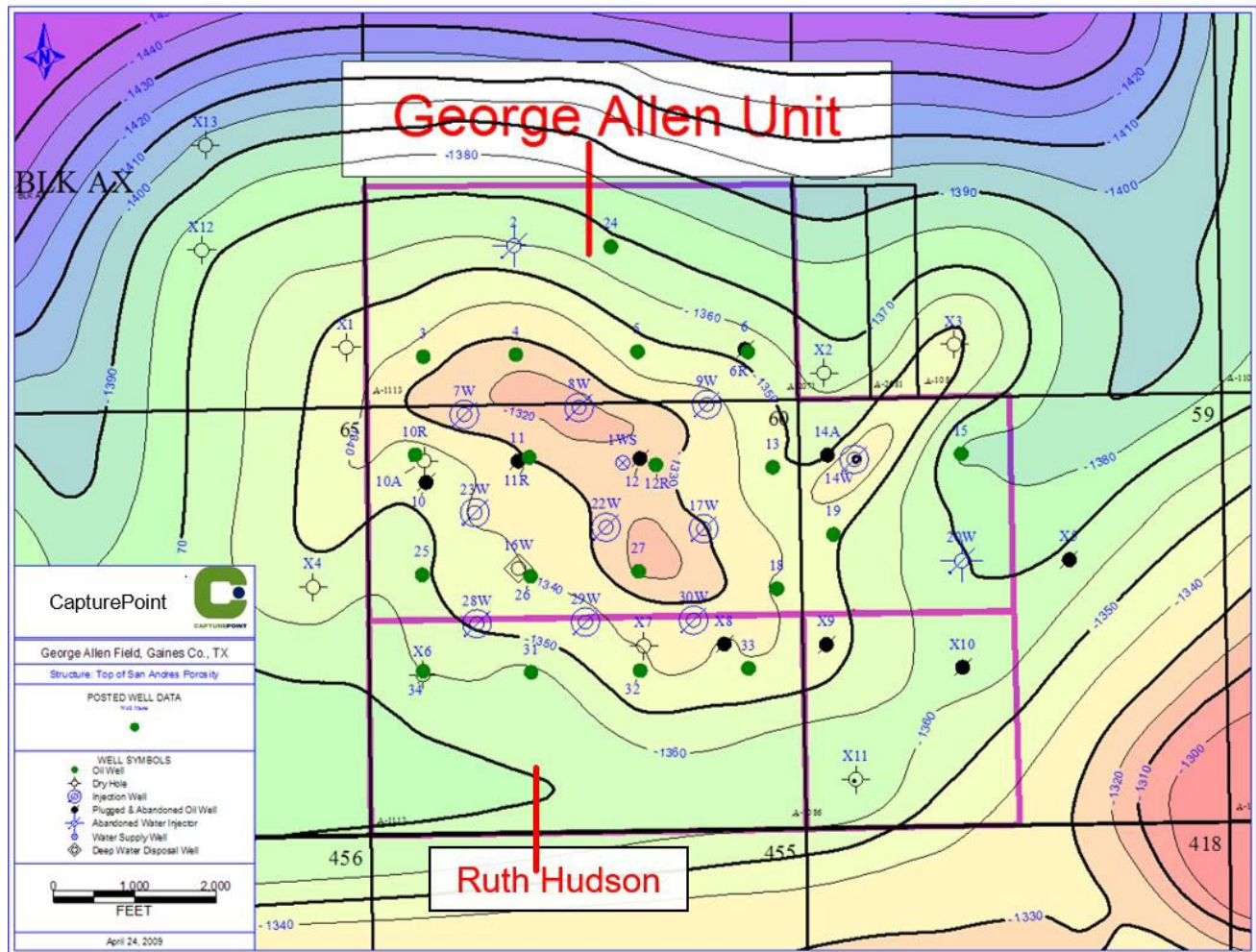


Figure 3-3 Local Area Structure on Top of San Andres

In the DCF there is a thin mobile oil column. Beneath the conventional oil column there is a thick, porous section with transition zone/residual oil (TZ/ROZ) that can only be produced via tertiary recovery methods, primarily CO₂ injection. This thick TZ/ROZ zone as found in the Wasson field gives a sizeable target for tertiary recovery (over 300 feet gross thickness).

Oil in the TZ/ROZ is currently being produced via CO₂ injection. Nine 40-acre patterns were prepared to inject CO₂ in this zone in the DCF. The presence of thick residual zones in the San Andres of the Permian Basin is widespread. Lindsay (2001), Melzer (2005), Melzer (2006), and Koperna and Kuuskraa (2006; 1&2) discuss the possible origins and the extent of residual oil zones in the Permian Basin. Brown (2001) discusses the ROZ in the area and its possible origin. The residual zone in the DCF has better porosity and permeability and is much thicker than the mobile oil zone which produced during primary and secondary (waterflood) recovery. This is often the case in residual oil zones, particularly those found in smaller fields with thinner oil columns. This gives us a large resource in which to economically sequester large volumes of CO₂, as CO₂ can both be stored and utilized for oil recovery in the extensive residual oil zones found in the San Andres in the Permian Basin.

The oil saturation profile found in the DCF/Wasson area is shown below in figure 3-4 from Koperna and Kuuskraa (2006; 2):

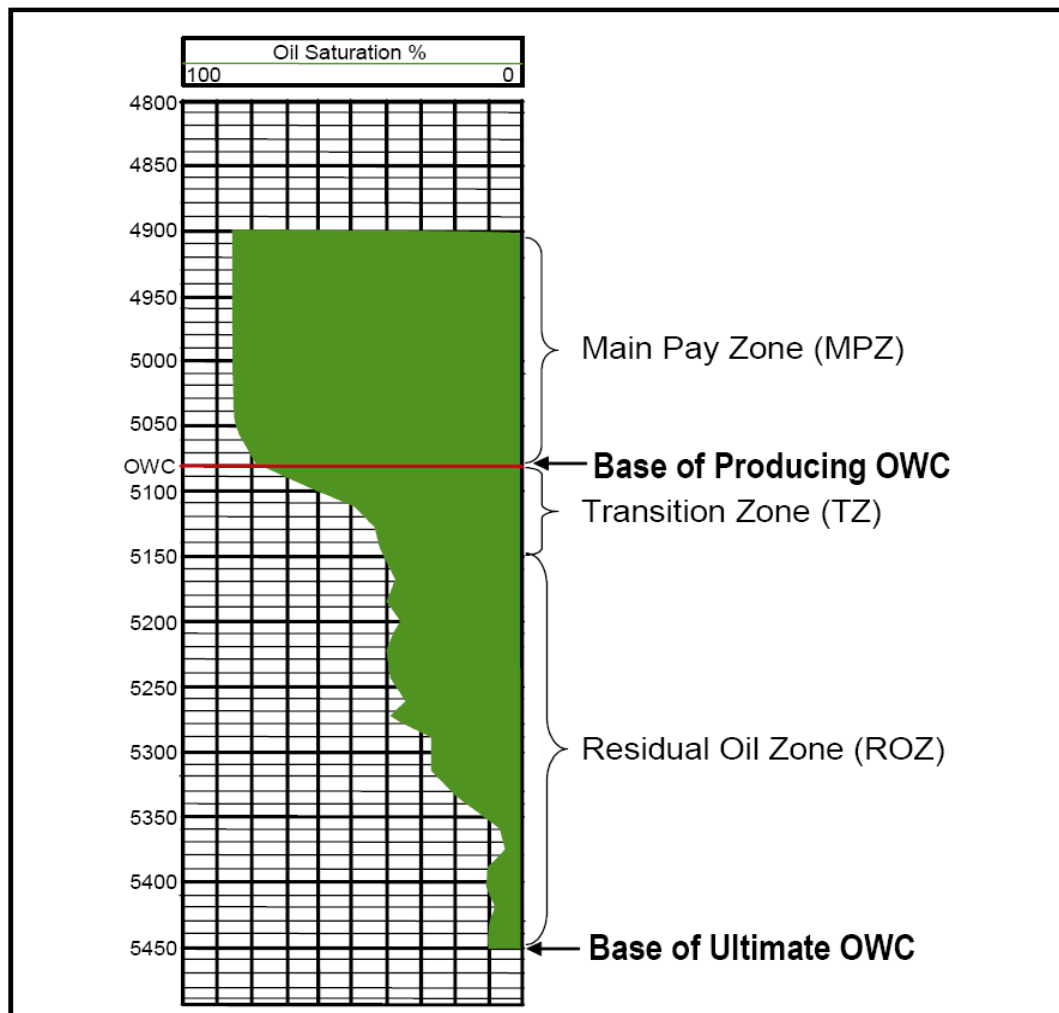


Figure 3-4 Local Area Structure on Top of San Andres

Due to hydrodynamic flow in the San Andres aquifer, a ROZ was created and is under CO₂ flood along with the Main Pay Zone in the San Andres Formation.

Once the CO₂ flood is complete and injection ceases, the remaining mobile CO₂ will rise slowly upward, driven by buoyancy forces. There is more than enough pore space to sequester the planned CO₂ injection. The amount of CO₂ injected will not exceed the reservoir's secure storage capacity and, consequently, the risk that CO₂ could migrate to other reservoirs in the Central Basin Platform is negligible. The volume of CO₂ storage is based on the estimated total pore space within the DCF. The total pore space within the DCF, from the top of the reservoir down to the base of the ROZ, is calculated to be 188 million reservoir barrels (RB). This is the volume of rock multiplied by porosity. Table 3-1 below shows the conversion of this amount of pore space into an estimated

maximum volume of approximately 254 Bcf (13.4 million tonnes) of CO₂ storage in the reservoir. CO₂ will occupy only 15% of the total calculated storage capacity by the year 2039 based on the current project forecast.

Table 3-1 Calculation of Maximum Volume of CO₂ Storage Capacity at DCF

Top of Main Pay to Bottom of Residual Oil Zone (ROZ)	
Variables	DCF Outline
Pore Volume (RB)	188,396,478
B_{CO2} (RB/Mscf)	0.407
S_{wirr}	0.35
S_{or CO2}	0.10
Max CO₂ (MCF)	254,589,835
Max CO₂ (BCF)	254

$$\text{Max CO}_2 = \text{Volume (RB)} * (1 - S_{wirr} - S_{or CO_2}) / B_{CO_2}$$

where:

Max CO₂ = the maximum amount of storage capacity

B_{CO2} = the formation volume factor for CO₂

S_{wirr} = the irreducible water saturation

S_{or CO2} = the irreducible oil saturation

Reservoir management is employed on a constant basis to obtain the maximum possible economic recovery from a reservoir based on facts, information, and knowledge. A reservoir management strategy that is used in CO₂ floods is the implementation of water curtain injectors. This will be utilized in the DCF to create a pressure barrier or “curtain” to contain the injected CO₂ to the area selected for production. Water curtain injection is an efficient method of maintaining and controlling lateral migration of fluids to assure that CO₂ does not cross structurally deficient locations. Injected fluids (CO₂) stay in the reservoir within the DCF unit boundary and do not move to adjacent areas.

Given that in DCF the confining zone has proved competent over both millions of years and in the current CO₂ flooding, and that the DCF has ample storage capacity, there is confidence that stored CO₂ will be contained securely within the reservoir.

3.3. Description of CO₂-EOR Project Facilities and the Injection Process

Figure 3-5 shows a simplified process flow diagram of the project facilities and equipment in the DCF. CO₂ will be delivered to the DCF via the Kinder Morgan CO₂ pipeline network. The CO₂ will be supplied by several different sources including both natural and anthropogenic CO₂ sources. Specified amounts will be drawn from an outside source pipeline based on contractual arrangements among suppliers of CO₂, purchasers of CO₂, and the pipeline operator.

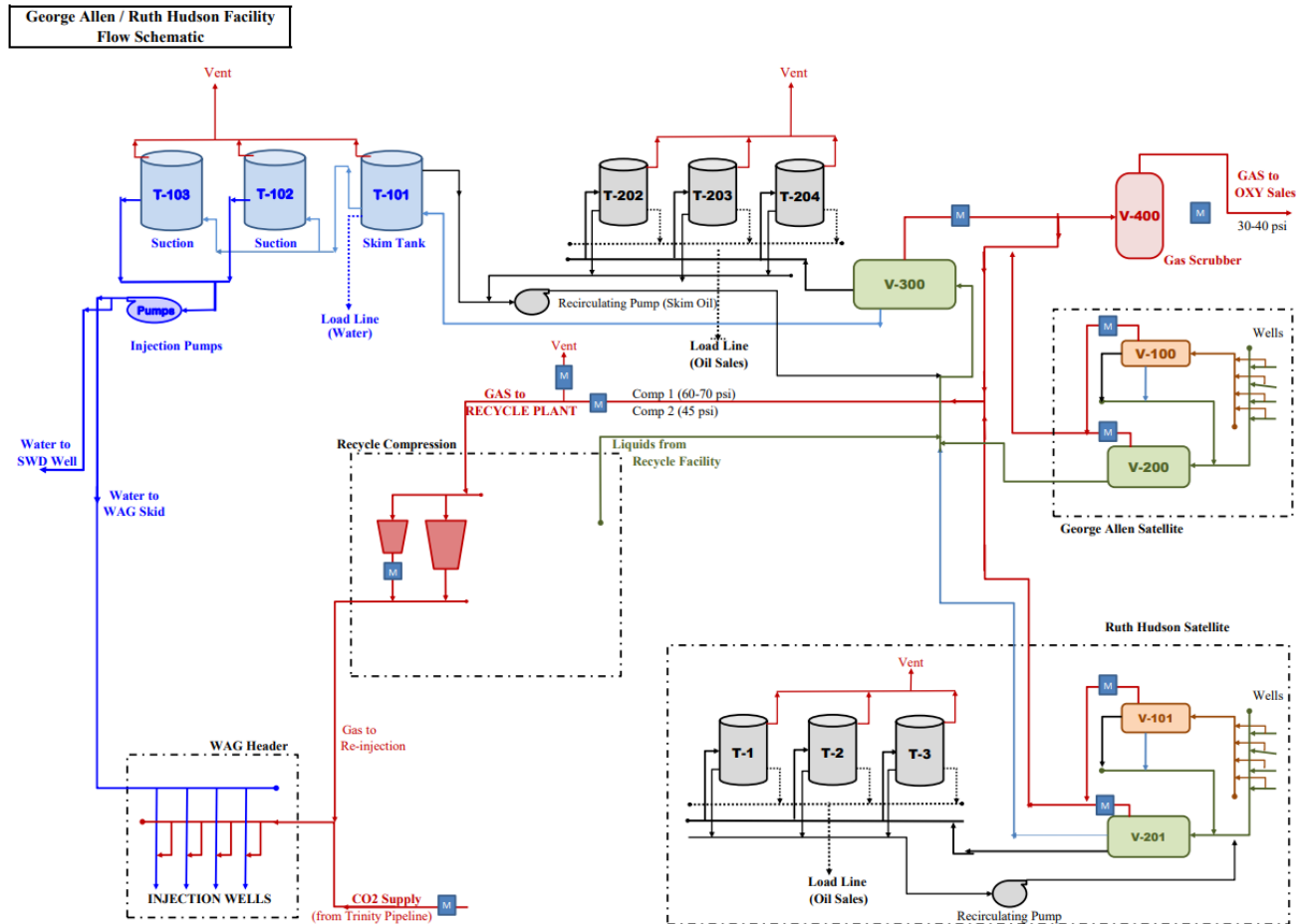


Figure 3-5 George Allen Unit/Ruth Hudson lease Process Flow Diagram

Once CO₂ enters the DCF there are three main processes involved in CO₂-EOR operations:

- i. CO₂ Distribution and Injection: The mass of CO₂ received at the DCF is metered and calculated through the Custody Transfer Meter located at the pipeline delivery point. The mass of CO₂ received is combined with recycled CO₂ / hydrocarbon gas mix from the recycle compression facility (RCF) and distributed to the WAG headers for injection into the injection wells according to the pre-programmed injection plan for each well pattern which alternates between water and CO₂ injection. WAG headers are manually operated and can inject either CO₂ or water at various rates and injection pressures as specified in the injection plans. This is an EOR project and reservoir pressure must be maintained above minimum miscibility pressure. Therefore, injection pressure must be sufficiently high to allow injectants to enter the reservoir, but below formation parting pressure (FPP).
- ii. Produced Fluids Handling: Produced fluids from the production wells are a mixture of oil, hydrocarbon gas, water, CO₂, and trace amounts of other constituents in the field including nitrogen and Hydrogen Sulfide (H₂S) as discussed in Section 7. They are gathered and sent to Satellite Test Stations (SAT) for separation into a gas/CO₂ mix and a produced fluids mix of water, oil, gas, and CO₂. The produced gas, which is composed primarily of CO₂ and minor hydrocarbons, is sent to the RCF for dehydration and recompression before reinjection into the

reservoir. An operations meter at the RCF is used to determine the total volume of produced gas that is reinjected. The separated oil is sent to two separate tanks (one at GAU and one at RH) where is then sold via truck.

iii. Water Treatment and Injection: Water is recovered for reuse and forwarded to the water injection station for reinjection or disposal.

3.3.1. Wells in the Denver City Fields

The TRRC has broad authority over oil and gas operations including primacy to implement UIC Class II wells. The rules are found in Texas Administrative Code Title 16, Part 1, Chapter 3 and are also explained in a TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual (See Appendix 12-2). TRRC rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. Briefly, TRRC rules include the following requirements:

- Fluids must be constrained in the strata in which they are encountered,
- Activities cannot result in the pollution of subsurface or surface water,
- Wells must adhere to specified casing, cementing, drilling well control, and completion requirements designed to prevent fluids from moving from the strata they are encountered into other strata with oil and gas, or into subsurface and surface waters,
- Completion report for each well including basic electric log (e.g., a density, sonic, or resistivity (except dip meter) log run over the entire wellbore) must be prepared,
- Operators must follow plugging procedures that require advance approval from the TRRC Director and allow consideration of the suitability of the cement based on the use of the well, the location and setting of plugs; and,
- Injection well operators must identify an Area of Review (AoR), use compatible materials and equipment, test, and maintain well records.

Table 3.2 provides a well count by type and status. All these wells are in material compliance with TRRC rules.

Table 3.2 DCF Well Penetrations by Type and Status

TYPE	ACTIVE	INACTIVE	P & A	Total
PROD_OIL	16	3		19
INJ_WTR	0	1		1
INJ_WAG	8	0		8
INJ_SWD*	0	0		0
WSW**	0	0		0
P&A***			3	3
TOTAL	24	4	3	31

*INJ_SWD = Saltwater disposal wells

**WSW= Water source wells

***P&A = Plugged and Abandoned wells

As indicated in Figure 3-7, wells are distributed across the DCF. The well patterns currently undergoing CO₂ flooding are identified by black 5-spot pattern outlines and CO₂ will be injected across the entire unit over the project life.

DCF CO₂-EOR operations are designed to avoid conditions which could damage the reservoir and cause a potential leakage pathway. Reservoir pressure in the DCF is managed by maintaining an injection to withdrawal ratio (IWR) of approximately 1.0. To maintain the IWR, fluid injection and production are monitored and managed to ensure that reservoir pressure does not increase to a level that would compromise the reservoir seal or otherwise damage the integrity of the oil field.

Injection pressure is also maintained below the FPP, which is measured using step-rate tests.

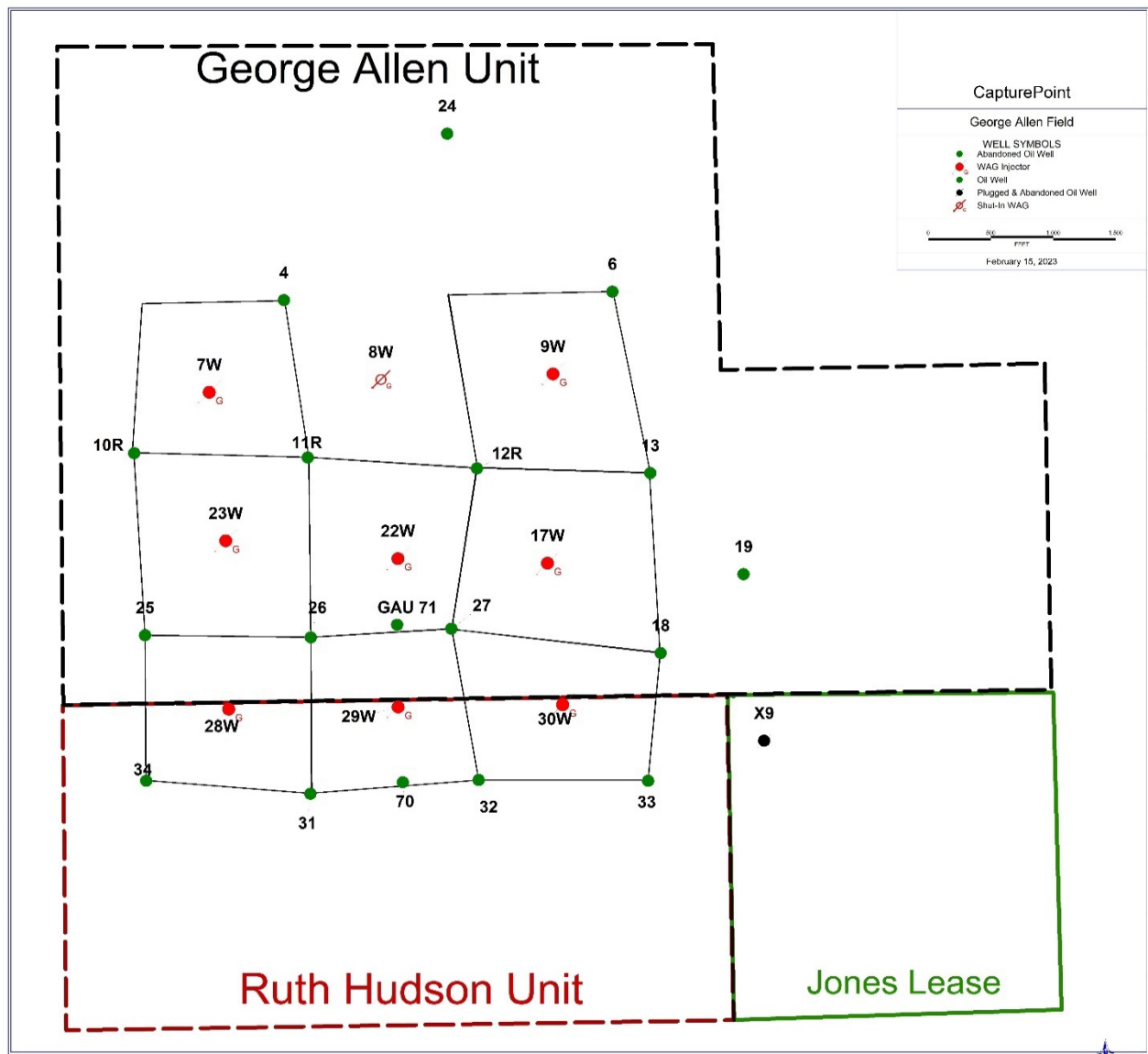


Figure 3-7 DCF Wells and Injection Patterns

3.4. Reservoir Forecasting

Dimensionless performance curves (DPCs) derived from analogous fields were used to project CO₂-EOR in the Denver City Fields. Most dimensionless curves are derived from geologic and reservoir models. In the DCF case the DPC was derived from actual field performance from an analogous field.

A dimensionless curve is a plot where everything is normalized by dividing by Hydrocarbon Pore Volume (HCPV). See Figure 3-8. The dimensioned projections of oil, CO₂ and water production, and CO₂ and water injection are made from DPCs using the original oil in place of an area of interest.

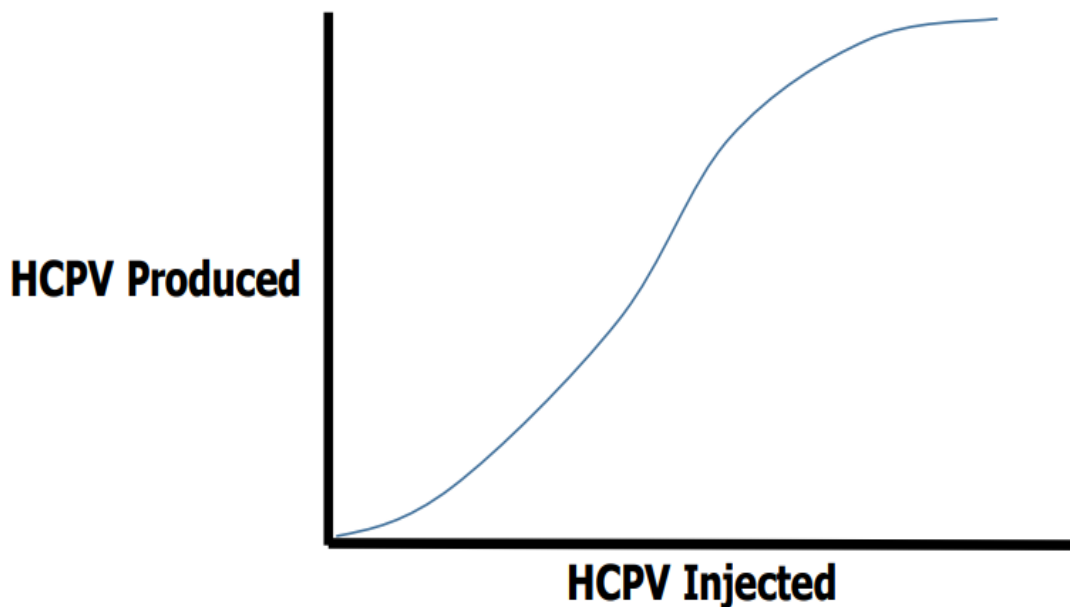


Figure 3-8 Dimensionless curve plot

The DCF DPC was calculated from the cumulative production and injection from an analogous field. The DCF DPC was used on each pattern in the DCF and then summed up to full field. This method allows you to use different start times and implement different field implementation speeds.

The DPCs are the basis for future performance prediction scenarios but are additionally a means of evaluating the reservoir process efficiencies. In a similar manner to history matching in reservoir simulation, deviations from expected performance can indicate errors in the geologic model of the pore volume, growth of the CO₂ plume laterally or vertically or metering and production allocation errors.

4. Delineation of Monitoring Area and Timeframes

4.1. Active Monitoring Area

The Active Monitoring Area (AMA) is defined by the GAU and RH boundaries.

Figure 3-7 displays wells that have CO₂ retention on the 370 acres that have been under CO₂ injection since project initialization. The CO₂ storage volumes were forecasted (Figure 4.1) using the DPC approach. This technique indicates that the flooded acreage still has significant storage potential. The maximum CO₂ storage (254 BCF) is limited to the amount of space available by the removal of the produced hydrocarbon and water. The projection indicates that there is pore space available to store approximately 0.15 decimal fraction of HCPV amounting to 27.8 MMRB (37.5 BCF).

The lateral extent of CO₂ in the injection zone or the CO₂ storage radius for each well was estimated by calculating a storage radius based on the forecasted CO₂ storage volume of 37.5 BCF. Figure 4-1 shows the map of the storage area outline for each pattern (dashed red line). This calculation showed 166 acres (this calculates to 18 acres per pattern) would be needed to store 37.5 BCF. This is significantly less than the 1133 acres in the DCF outline.

CO₂ injected into the DCF remains contained within the field because of the fluid and pressure management impacts associated with CO₂-EOR. Namely, maintenance of an Injection to Withdrawal Ratio (IWR) of 1.0 assures a stable reservoir pressure and managed production wells are used to retain fluids in the DCF.

4.2. Maximum Monitoring Area

The Maximum Monitoring Area (MMA) is defined by the GAU and RH boundaries plus the required ½ mile buffer as required by 40 CFR §98.440-449 (Subpart RR). The MMA would be the same as the AMA since the plume location is less than the unit area.

4.3. Monitoring Timeframes

The primary purpose for injecting CO₂ is to produce oil that would otherwise remain trapped in the reservoir and not, as in UIC Class VI, “specifically for the purpose of geologic storage.”¹ During a Specified Period, there will be a subsidiary purpose of establishing the long-term containment of CO₂ in the DCF. The Specified Period will be shorter than the period of production from the DCF.

At the conclusion of the Specified Period, a request for discontinuation of reporting will be submitted. This request will be submitted with a demonstration that current monitoring and model(s) show that the cumulative mass of CO₂ reported as sequestered during the Specified Period is not expected to migrate in the future in a manner likely to result in surface leakage. It is expected that it will be possible to make this demonstration after the Specified Period ends based

¹ EPA UIC Class VI rule, EPA 75 FR 77291, December 10, 2010, section 146.81(b).

upon monitoring data.

The reservoir pressure in the DCF is collected for use in operations management. Reservoir pressure is not forecasted to change appreciably since the IWR will be maintained at approximately 1.0. Once injection ceases, reservoir pressure is predicted to stabilize within one year.

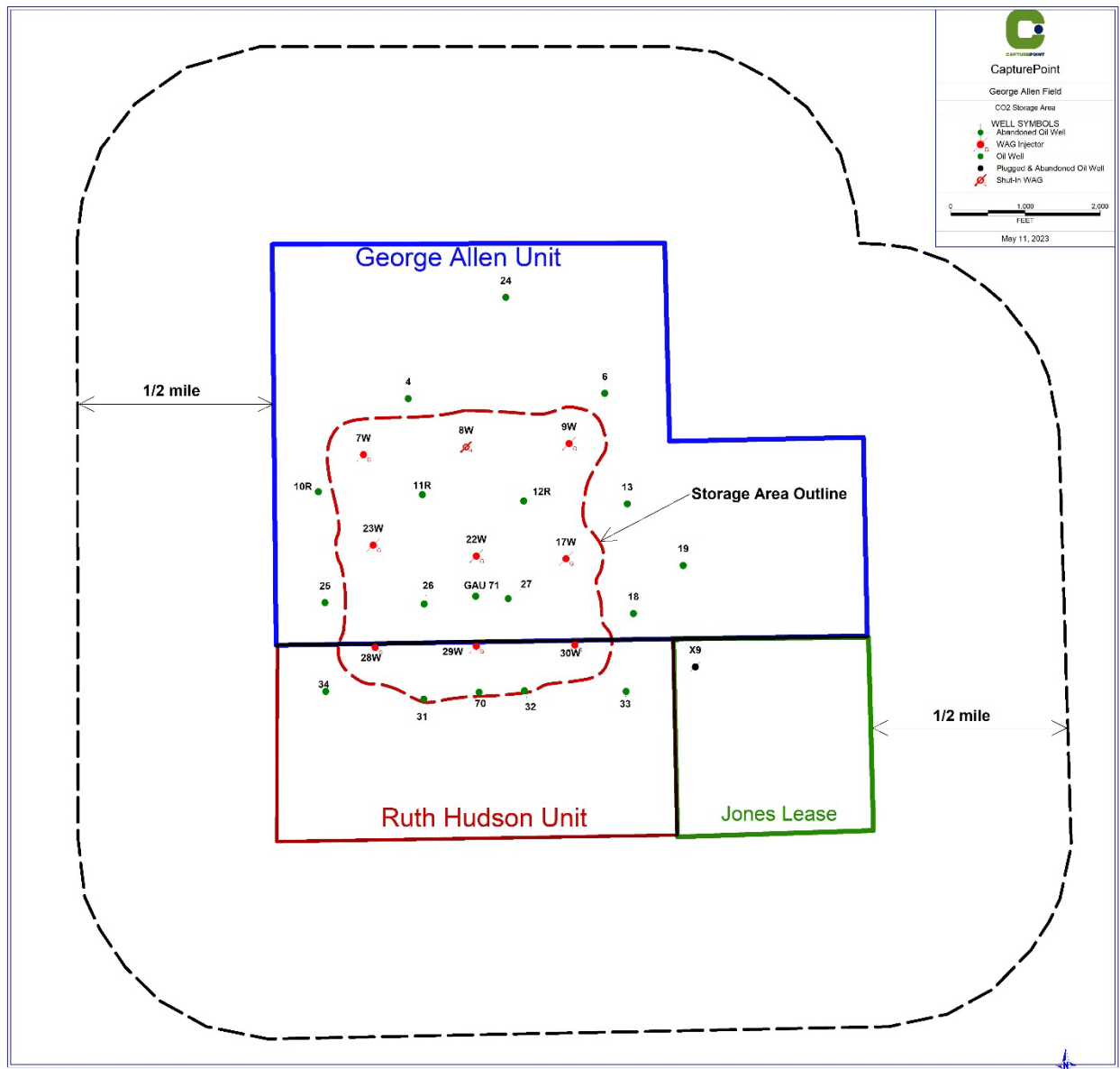


Figure 4-1 Projected CO₂ storage area

5. Evaluation of Potential Pathways for Leakage to the Surface, Leakage Detection, Verification, and Quantification

In the roughly 60 years since the DCF oil field was discovered, the reservoir has been studied extensively. Based on the knowledge gained from that experience, this section assesses the potential pathways for leakage of stored CO₂ to the surface including:

1. Existing Well Bores
2. Faults and Fractures
3. Natural and Induced Seismic Activity
4. Previous Operations
5. Pipeline/Surface Equipment
6. Lateral Migration Outside the DCF
7. Drilling Through the CO₂ Area
8. Diffuse Leakage Through the Seal
9. Leakage Detection, Verification, and Quantification

This analysis shows that leakage through wellbores and surface equipment pose the only meaningful potential leakage pathways. The monitoring program to detect and quantify leakage is based on this assessment as discussed below.

5.1. Existing Wellbores

As part of the TRRC requirement to initiate CO₂ flooding, an extensive review of all the DCF penetrations was completed to determine the need for corrective action. That analysis showed that all penetrations have either been adequately plugged and abandoned or, if in use, do not require corrective action. All wells in the DCF were constructed and are operated in compliance with TRRC rules.

As part of routine risk management, the potential risk of leakage associated with the following were identified and evaluated:

- CO₂ flood beam pumped producing wells,
- CO₂ flood Electrical Submersible Pump (ESP) producing wells; and,
- CO₂ WAG injector wells.

The risk assessment classified all risks associated with subsurface as low risk, i.e., less than 1% likelihood to occur and having a consequence that is insubstantial. The risks were classified as low risk because DCF geology is well suited to CO₂ sequestration with an extensive confining zone that is free of fractures and faults that could be potential conduits for CO₂ migration. Any risks are further mitigated because the DCF is operated in a manner that maintains, monitors, and documents the integrity of the reservoir.

The risk of well leakage is mitigated through:

- Adhering to regulatory requirements for well drilling and testing,
- Implementing best practices that CapturePoint has developed through its extensive operating experience,
- Monitoring injection/production performance, wellbores, and the surface; and,
- Maintaining surface equipment.

Continual and routine monitoring of the wellbores and site operations will be used to detect leaks or other potential well problems, as follows:

- Pressure in injection wells is monitored daily. The injection plans for each pattern are provided to field operations to govern the rate, pressure, and duration of either water or CO₂ injection. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such events occur, they are investigated and addressed. CapturePoint's experience, from over 10 years of operating CO₂-EOR projects, is that such leakage is very rare.
- Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a SAT. There is a routine well testing cycle for each SAT, with each well being tested approximately once every month. During this cycle, each production well is diverted to the well test equipment for a period sufficient to measure and sample produced fluids (generally 12-24 hours). These tests are the basis for allocating a portion of the produced fluids measured at the SAT to each production well, assessing the composition of produced fluids by location, and assessing the performance of each well. Performance data are reviewed on a routine basis to ensure that CO₂ flooding efficiency is optimized. If production is off plan, it is investigated, and any identified issues addressed. Leakage to the outside of production wells is not considered a major risk because of the reduced pressure in the casing. Further, the personal H₂S monitors are designed to detect leaked fluids around production wells during well inspections as well as various permanent H₂S monitors throughout the field at ground level.
- Field inspections are conducted on a routine basis by field personnel. Leaking CO₂ is very cold and leads to the formation of bright white clouds and ice that are easily spotted. All field personnel are trained to identify leaking CO₂ and other potential problems at wellbores and in the field. Any CO₂ leakage detected will be documented and reported and quantified.

Based on ongoing monitoring activities and review of the potential leakage risks posed by well bores, it is concluded that the risk of CO₂ leakage through well bores is being mitigated by detecting problems as they arise and quantifying any leakage that does occur.

5.2. Faults and Fractures

After reviewing geologic, seismic, operating, and other evidence, it has been concluded that there are no known faults or fractures that transect the San Andres reservoir in the project area. As a result, there is no risk of leakage due to fractures or faults.

Measurements to determine FPP and reservoir pressure are routinely updated. This information is used to manage injection patterns so that the injection pressure will not exceed FPP. An IWR at or near 1 is also maintained. Both measures mitigate the potential for inducing faults or fractures. As a safeguard, WAG skids are continuously monitored.

5.3. Natural or Induced Seismicity

After reviewing the literature and actual operating experience; it is concluded that there is no direct evidence that natural seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF.

To evaluate this potential risk at the DCF, CapturePoint has reviewed the nature and location of seismic events in West Texas. Some of the recorded earthquakes in West Texas are far removed from any injection operation. These are judged to be from natural causes. Others are near oil fields or water disposal wells and are placed in the category of “quakes in close association with human enterprise.”² A review of the United States Geological Survey (USGS) database of recorded earthquakes at M1.0 or greater in the Permian Basin since 1956 indicates that none have occurred in the DCF; the closest took place in 1992 approximately 42 miles away. See Figure 5.1.

The concern about induced seismicity is that it could lead to fractures in the seal providing a pathway for CO₂ leakage to the surface. CapturePoint is not aware of any reported loss of injectant (brine water or CO₂) to the surface associated with any seismic activity. There is no direct evidence to suggest that natural seismic activity poses a significant risk for loss of CO₂ to the surface in the Permian Basin, and specifically in the DCF. If induced seismicity resulted in a pathway for material amounts of CO₂ to migrate from the injection zone, other reservoir fluid monitoring provisions (e.g., reservoir pressure, well pressure, and pattern monitoring) would detect the migration and lead to further investigation. CapturePoint monitors the USGS earthquake monitoring Geographical Information System (GIS) site³ for seismic signals that could indicate the creation of potential leakage pathways in the DCF.

² Frohlich, Cliff (2012) “Induced or Triggered Earthquakes in Texas: Assessment of Current Knowledge and Suggestions for Future Research”, Final Technical Report, Institute for Geophysics, University of Texas at Austin, Office of Sponsored Research.

³ <https://earthquake.usgs.gov/earthquakes/map/>

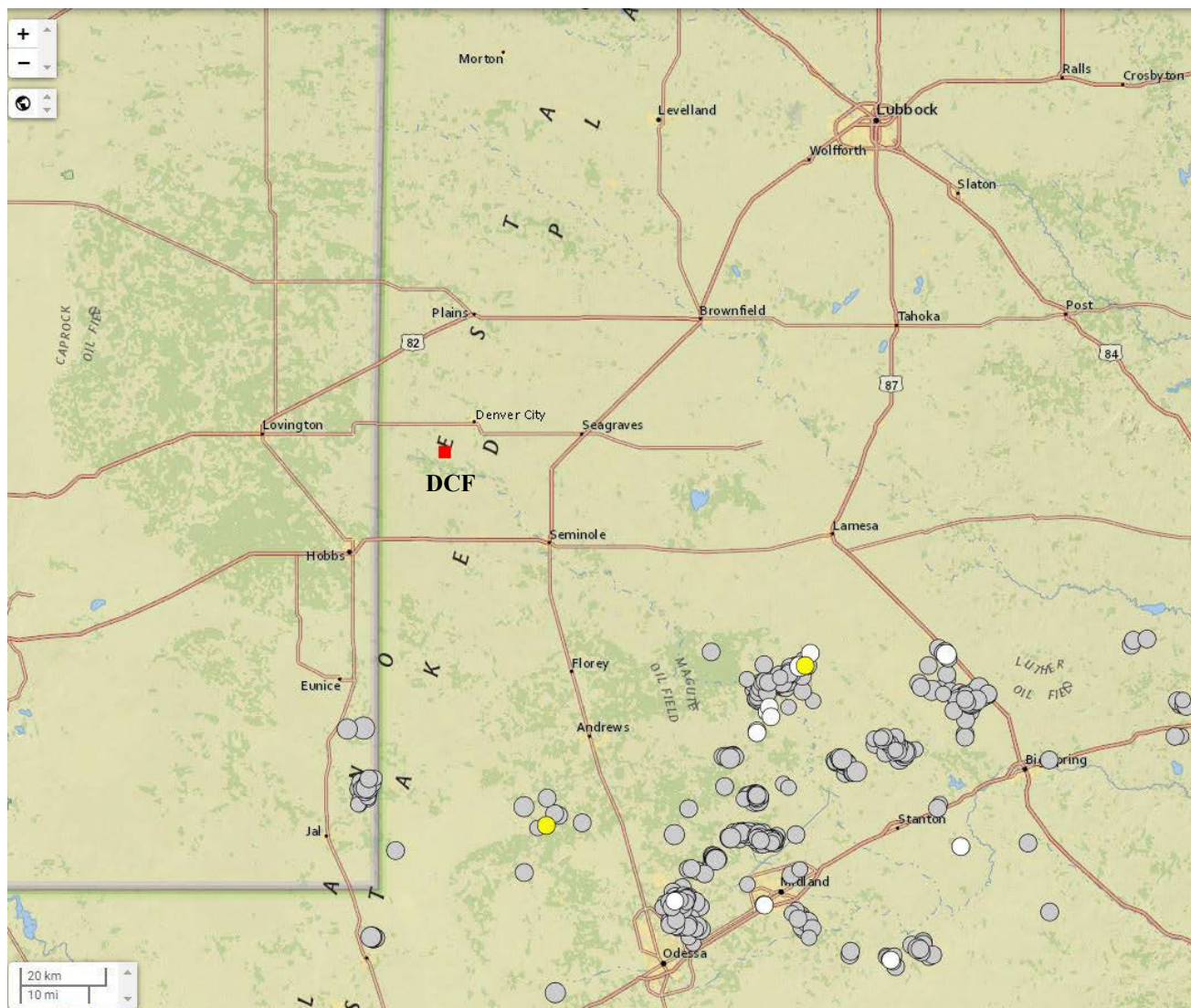


Figure 5-1 USGS earthquakes (+1.0 magnitude) for last 57 years)

5.4. Previous Operations

CO₂ flooding was initiated in the DCF in 2007. To obtain permits for CO₂ flooding, the AoR around all CO₂ injector wells was evaluated to determine if there were any unknown penetrations and to assess if corrective action was required at any wells. As indicated in Section 5.1, this evaluation reviewed the identified penetrations and determined that no additional corrective action was needed. Further, CapturePoint's standard practice for drilling new wells includes a rigorous review of nearby wells to ensure that drilling will not cause damage to or interfere with existing wells. Additionally, requirements to construct wells with materials that are designed for CO₂ injection are adhered to at the DCF. These practices ensure that there are no unknown wells within the DCF and that the risk of migration from older wells has been sufficiently mitigated. The successful experience with CO₂ flooding in the DCF demonstrates that the confining zone has not been impaired by previous operations.

5.5. Pipelines and Surface Equipment

Damage to or failure of pipelines and surface equipment can result in unplanned losses of CO₂. CapturePoint anticipates that the use of prevailing design and construction practices and compliance with applicable laws will reduce to the maximum extent practicable the risk of unplanned leakage from surface facilities. The facilities and pipelines currently utilize and will continue to utilize materials of construction and control processes that are standard for CO₂-EOR projects in the oil and gas industry. Operating and maintenance practices currently follow and will continue to follow demonstrated industry standards. Field personnel are trained to look for and report potential leaks from pipeline and surface equipment as part of their routine activities. Should leakage be detected from pipeline or surface equipment, the volume of released CO₂ will be quantified following the requirements of Subpart W of the Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP).

5.6. Lateral Migration Outside the Denver City Fields

It is highly unlikely that injected CO₂ will migrate downdip and laterally outside the DCF because of the nature of the geology and the approach used for injection. Over long periods of time, injected CO₂ will tend to rise vertically towards the Upper San Andres and continue towards the point in the DCF with the highest elevation. Second, the planned injection volumes and active fluid management during injection operations will prevent CO₂ from migrating laterally out of the structure. Finally, the total volume of fluids contained in the DCF will stay relatively constant. Based on site characterization and planned and projected operations it is estimated that the total volume of stored CO₂ will be considerably less than calculated capacity.

5.7. Drilling in the Denver City Fields

The TRRC regulates well drilling activity in Texas. Pursuant to TRRC rules, well casing shall be securely anchored in the hole to effectively control the well at all times, all usable-quality water zones shall be isolated and sealed off to effectively prevent contamination or harm, and all productive zones, potential flow zones, and zones with corrosive formation fluids shall be isolated and sealed off to prevent vertical migration of fluids, including gases, behind the casing. Where TRRC rules do not detail specific methods to achieve these objectives, operators shall make every effort to follow the intent of the section, using good engineering practices and the best currently available technology. The TRRC requires applications and approvals before a well is drilled, recompleted, or reentered. Well drilling activity at the DCF is conducted in accordance with TRRC rules. CapturePoint's visual inspection process, including routine site visits, will identify unapproved drilling activity in the DCF.

In addition, CapturePoint intends to operate the DCF for several more years and will continue to be vigilant about protecting the integrity of its assets and maximizing the potential of its resources, including oil, gas and CO₂. Consequently, the risks associated with third parties penetrating the DCF are negligible.

5.8. Diffuse Leakage Through the Seal

Diffuse leakage through the seal formed by the upper San Andres is highly unlikely. There are a number of sections above the reservoir that are impermeable and serve as reliable barriers to prevent fluids from moving upwards towards the surface. These barriers are referred to as seals because they effectively seal fluids within the formations beneath them.

Our injection pattern monitoring program assures that no breach of the seal will be created. The seal is highly impermeable. Wellbores that penetrate the seal make use of cement and steel construction that is closely regulated to ensure that no leakage takes place. Injection pressure is continuously monitored and unexplained changes in injection pressure that might indicate leakage would trigger investigation as to the cause.

5.9. Leakage Detection, Verification, and Quantification

As discussed above, the potential sources of leakage include issues, such as problems with surface equipment (pumps, valves, etc.) or subsurface equipment (well bores), and unique events such as induced fractures. An event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage is used. Table 5.1 summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, the standard response, and other applicable regulatory programs requiring similar reporting.

Given the uncertainty concerning the nature and characteristics of any leaks that may be encountered, the most appropriate methods for quantifying the volume of leaked CO₂ will be determined on a case-by-case basis. In the event leakage occurs, the most appropriate methods for quantifying the volume leaked will be determined and it will be reported as required as part of the annual Subpart RR submission.

Any volume of CO₂ detected leaking to surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, field experience, and other factors such as the frequency of inspection. Leaks will be documented, evaluated, and addressed in a timely manner.

Records of leakage events will be retained in an electronic environmental documentation and reporting system. The Field Foreman is notified for maintenance activities that cannot be addressed on the spot.

Table 5.1 Response Plan for CO₂ Loss

Risk	Monitoring Plan	Response Plan
Tubing Leak	Monitor changes in tubing and annulus pressure; MIT for injectors	Well is shut in and workover crews respond within days
Casing Leak	Routine Field inspection; Monitor changes in annulus pressure, MIT for injectors; extra attention to high risk wells	Well is shut in and workover crews respond within days
Wellhead Leak	Routine Field inspection, SCADA system monitors wellhead pressure	Well is shut in and workover crews respond within days
Loss of Bottom-hole pressure control	Blowout during well operations	Maintain well kill procedures
Unplanned wells drilled through San Andres	Routine Field inspection to prevent unapproved drilling; compliance with TRRC permitting for planned wells.	Assure compliance with TRRC regulations
Loss of seal in abandoned wells	Reservoir pressure in WAG headers; high pressure found in new wells	Re-enter and reseal abandoned wells
Pumps, valves, etc.	Routine Field inspection, SCADA	Workover crews respond within days
Overfill beyond spill points	Reservoir pressure in WAG headers; high pressure found in new wells	Fluid management along lease lines
Leakage through induced fractures	Reservoir pressure in WAG headers; high pressure found in new wells	Comply with rules for keeping pressures below parting pressure
Leakage due to seismic event	Reservoir pressure in WAG headers; high pressure found in new wells	Shut in injectors near seismic event

5.10. Summary

The structure and stratigraphy of the San Andres reservoir in the DCF is ideally suited for the injection and storage of CO₂. The stratigraphy within the CO₂ injection zones is porous, permeable, and thick, providing ample capacity for long-term CO₂ storage. The reservoir is overlain by several intervals of impermeable geologic zones that form effective seals or “caps” to fluids in the reservoir.

In summary, based on a careful assessment of the potential risk of release of CO₂ from the subsurface, it has been determined that there are no leakage pathways at the DCF that are likely to result in significant loss of CO₂ to the atmosphere. Further, given the detailed knowledge of the field and its operating protocols, it is concluded that any CO₂ leakage to the surface that could arise through either identified or unexpected leakage pathways would be detected and quantified.

6. Monitoring and Considerations for Calculating Site Specific Variables

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

6.1. For the Mass Balance Equation

6.1.1. General Monitoring Procedures

Flow rate, pressure, and gas composition data are monitored and collected from the DCF in centralized data management systems as part of ongoing operations. This data is monitored by qualified technicians who follow response and reporting protocols when the systems deliver notifications that data exceed statistically acceptable boundaries.

Metering protocols used at the DCF follow the prevailing industry standard(s) for custody transfer as currently promulgated by the American Petroleum Institute (API), the American Gas Association (AGA), and the Gas Processors Association (GPA), as appropriate. This approach is consistent with EPA GHGRP’s Subpart RR, section §98.444(e)(3). These meters will be maintained routinely, operated continually, and will feed data directly to the centralized data collection systems. The meters meet the industry standard for custody transfer meter accuracy and calibration frequency.

6.1.2. CO₂ Received

As indicated in Figure 3-5, the volume of received CO₂ is measured using a commercial custody transfer meter at the point at which custody of the CO₂ from the Kinder Morgan CO₂ Pipeline Delivery System is transferred to the DCF. This meter measures the flow rate continually. The transfer is a commercial transaction that is documented. CO₂ composition is governed by contract and the gas is routinely sampled. Fluid composition will be determined, at a minimum, quarterly, consistent with EPA GHGRP’s Subpart RR, section §98.447(a). All meter and composition data are documented, and records will be retained for at least three years. No CO₂ is received in containers.

6.1.3. CO₂ Injected in the Subsurface

Injected CO₂ will be calculated using the flow meter volumes at the operations meter at the outlet of the Recycle Compression Facility (RCF) and the custody transfer meter at the CO₂ off-take point from the Kinder Morgan CO₂ Pipeline Delivery System.

6.1.4. CO₂ Produced, Entrained in Products, and Recycled

The following measurements are used for the mass balance equations in Section 8:

- CO₂ produced in the gaseous stage is calculated using the volumetric flow meters at the inlet to the RCF,
- CO₂ that is entrained in produced oil, as indicated in Figure 3-5, is calculated from routinely captured samples and volume is measured by the truck flow meter,
- Recycled CO₂ is calculated using the volumetric flow meter at the outlet of the RCF, which is an operations meter.

6.1.5. CO₂ Emitted by Surface Leakage

CapturePoint uses 40 CFR Part 98 Subpart W to estimate surface leaks from equipment at the DCF. Subpart W uses a factor-driven approach to estimate equipment leakage. In addition, an event-driven process to assess, address, track, and if applicable quantify potential CO₂ leakage to the surface is used. The Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

The multi-layered, risk-based monitoring program for event-driven incidents has been designed to meet two objectives: 1) to detect problems before CO₂ leaks to the surface; and 2) to detect and quantify any leaks that do occur. This section discusses how this monitoring will be conducted and used to quantify the volumes of CO₂ leaked to the surface.

6.1.6. Monitoring for Potential Leakage from the Injection/Production Zone

In addition to the measures discussed in Section 5.9, both injection into and production from the reservoir will be monitored as a means of early identification of potential anomalies that could indicate leakage from the subsurface.

Injection plans (fluid rate, pressure, volume) are given to operations on a weekly basis. If injection pressure or rate measurements are outside the specified set points determined as part of each pattern injection plan, reservoir engineering will notify field personnel and they will investigate and resolve the problem. These excursions will be reviewed by well management personnel to determine if CO₂ leakage may be occurring. Excursions are not necessarily indicators of leaks; they simply indicate that injection rates and pressures are not conforming to the pattern injection plan. In many cases, problems are straightforward to fix (e.g., a meter needs to be recalibrated or some other minor action is required), and there is no threat of CO₂ leakage. In the case of issues

that are not readily resolved, more detailed investigation and response would be initiated, and support staff would provide additional assistance and evaluation.

Likewise, a forecast of the rate and composition of produced fluids is developed. Each producer well is assigned to a specific SAT and is isolated during each cycle for a well production test. This data is reviewed on a periodic basis to confirm that production is at the level forecasted. If there is a significant deviation from the plan, well management personnel investigate. If the issue cannot be resolved quickly, a more detailed investigation and response would be initiated. If leakage in the flood zone were detected, an appropriate method would be used to quantify the involved volume of CO₂. This might include use of material balance equations based on known injected quantities and monitored pressures in the injection zone to estimate the volume of CO₂ involved.

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

In the event leakage from the subsurface occurred diffusely through the seals, the leaked gas would include H₂S, which would trigger the alarm on the personal monitors worn by field personnel as well as the various permanent H₂S monitors throughout the field at ground level. Such a diffuse leak from the subsurface has not occurred in the DCF. In the event such a leak was detected, personnel would determine how to address the problem. The personnel might use modeling, engineering estimates, and direct measurements to assess, address, and quantify the leakage.

6.1.7. Monitoring of Wellbores

DCF wells are monitored through daily pressure monitoring of the injection zone, monitoring of the annular pressure in wellheads, and routine maintenance and inspection.

Leaks from wellbores would be detected through the follow-up investigation of pressure anomalies, visual inspection, or the use of personal H₂S monitors and various permanent H₂S monitors throughout the field at ground level.

Anomalies in injection zone pressure may not indicate a leak, as discussed above. However, if an investigation leads to a need for further study, field personnel would inspect the equipment in question and determine the nature of the problem. If it is a simple matter, the repair would be made, and the volume of leaked CO₂ would be included in the 40 CFR Part 98 Subpart W report for the DCF. If more extensive repair were needed, the appropriate approach for quantifying leaked CO₂ using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be determined.

Anomalies in annular pressure or other issues detected during routine maintenance inspections would be treated in the same way. Field personnel would inspect the equipment in question and determine the nature of the problem. For simple matters the repair would be made at the time of inspection and the volume of leaked CO₂ would be included in the 40 CFR Part 98 Subpart W report for the DCF. If more extensive repairs were needed, the well would be shut in, a work order

would be generated and the appropriate approach for quantifying leaked CO₂ using the relevant parameters (e.g., the rate, concentration, and duration of leakage) would be determined. The work order would serve as the basis for tracking the event for Green House Gas (GHG) reporting.

Because leaking CO₂ at the surface is very cold and leads to formation of bright white clouds and ice that are easily spotted, a visual inspection process in the area of the DCF is employed to detect unexpected releases from wellbores. Field personnel visit the surface facilities on a routine basis. Inspections may include tank levels, equipment status, lube oil levels, pressures and flow rates in the facility, and valves. Field personnel also check that injectors are on the proper WAG schedule and observe the facility for visible CO₂ or fluid line leaks.

Finally, the data collected by the H₂S monitors, which are always worn by field personnel and are located permanently throughout the field at ground level, is used as a last method to detect leakage from wellbores. The H₂S monitor's detection limit is 10 ppm; if an H₂S alarm is triggered, the first response is to protect the safety of the personnel, and the next step is to safely investigate the source of the alarm. As noted previously, H₂S is considered a proxy for potential CO₂ leaks in the field. Thus, detected H₂S leaks will be investigated to determine and, if needed, quantify potential CO₂ leakage.

6.1.8. Other Potential Leakage at the Surface

The same visual inspection process and H₂S monitoring system will be used to detect other potential leakage at the surface as it does for leakage from wellbores. Routine visual inspections are used to detect significant loss of CO₂ to the surface. Field personnel routinely visit surface facilities to conduct a visual inspection. Inspections may include review of tank level, equipment status, lube oil levels, pressures and flow rates in the facility, valves, ensuring that injectors are on the proper WAG schedule, and also conducting a general observation of the facility for visible CO₂ or fluid line leaks. If problems are detected, field personnel would investigate, and complete any maintenance that is required. In addition to these visual inspections, the results of the personal H₂S monitors worn by field personnel and the permanent H₂S monitors throughout the field at ground level will be used as a supplement for smaller leaks that may escape visual detection.

If CO₂ leakage to the surface is detected, it will be reported to surface operations personnel who will review the reports and conduct a site investigation. If maintenance is required, steps are taken to prevent further leaks.

6.1.9. CO₂ emitted from equipment leaks and vented emissions of CO₂ from surface equipment located between the injection flow meter and the injection wellhead.

CapturePoint evaluates and estimates leaks from equipment, the CO₂ content of produced oil, and vented CO₂, as required under 40 CFR Part 98 Subpart W.

6.1.10. CO₂ emitted from equipment leaks and vented emissions of CO₂ from surface equipment located between the production flow meter and the production wellhead.

CapturePoint evaluates and estimates leaks from equipment, the CO₂ content of produced oil, and vented CO₂, as required under 40 CFR Part 98 Subpart W.

6.1.11. To Demonstrate that Injected CO₂ is not Expected to Migrate to the surface

At the end of the Specified Period, injecting CO₂ for the subsidiary purpose of establishing the long-term storage of CO₂ in the DCF will cease. Sometime after the end of the Specified Period, a request to discontinue monitoring and reporting will be submitted. The request will demonstrate that the amount of CO₂ reported under 40 CFR §98.440-449 (Subpart RR) is not expected to migrate in the future in a manner likely to result in surface leakage. At that time, the request will be supported with years of data collected during the Specified Period. This demonstration will provide the information necessary for the EPA Administrator to approve the request to discontinue monitoring and reporting and may include, but is not limited to:

- Data comparing actual performance to predicted performance (purchase, injection, production) over the monitoring period,
- An assessment of the CO₂ leakage detected, including the discussion of the estimated amount of CO₂ leaked and the distribution of emissions by leakage pathway,
- A demonstration that future operations will not release the volume of stored CO₂ to the surface,
- A demonstration that there has been no significant leakage of CO₂; and,
- An evaluation of reservoir pressure that demonstrates that injected fluids are not expected to migrate in a manner to create a potential leakage pathway.

7. Determination of Baselines

Ongoing operational monitoring has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO₂ 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. The necessary system guidelines to capture the information that is relevant to identify possible CO₂ leakage will be developed. The following describes the approach to collecting this information.

7.1. Visual Inspections

As field operators conduct routine inspections and repairs, the field Foreman is notified for maintenance activities that cannot be addressed on the spot. Examples include occurrences of well

workover or repair, as well as visual identification of vapor clouds or ice formations. Each incident will be flagged for review by the person responsible for MRV documentation (the responsible party will be provided in the monitoring plan, as required under Subpart A, §98.3(g)). The Annual Subpart RR Report will include an estimate of the amount of CO₂ leaked. Records of information used to calculate emissions will be maintained on file for a minimum of three years.

7.2. Personal H₂S Monitors

H₂S monitors are worn by all field personnel. The H₂S monitors detect concentrations of H₂S up to 500 ppm in 0.1 ppm increments and will sound an alarm if the detection limit exceeds 10 ppm. If an H₂S alarm is triggered, the immediate response is to protect the safety of the personnel, and the next step is to safely investigate the source of persistent alarms. CapturePoint considers H₂S to be a proxy for potential CO₂ leaks in the field. The person responsible for MRV documentation will receive notice of all incidents where H₂S is confirmed to be present. The Annual Subpart RR Report will provide an estimate of the amount of CO₂ emitted from any such incidents. Records of information to calculate emissions will be maintained on file for a minimum of three years.

As stated before, there are various permanent H₂S monitors throughout the field at ground level to detect H₂S and alarm if a limit is reached.

7.3. Injection Rates, Pressures and Volumes

Target injection rate and pressure for each injector are developed within the permitted limits based on the results of ongoing pattern balancing. The injection targets are submitted to field operations. Field operations flags whenever statistically significant deviations from the targeted ranges are identified. The set points are designed to be conservative, because it is preferable to have too many flags rather than too few. As a result, flags can occur frequently and are often found to be insignificant. For purposes of Subpart RR reporting, flags (or excursions) will be screened to determine if they could also lead to CO₂ leakage to the surface. The person responsible for the MRV documentation will receive notice of excursions. The Annual Subpart RR Report will provide an estimate of CO₂ emissions. Records of information to calculate emissions will be maintained on file for a minimum of three years.

7.4. Production Volumes and Compositions

A general forecast of production volumes and composition is developed which is used to periodically evaluate performance and refine current and projected injection plans and the forecast. This information is used to make operational decisions but is not recorded in an automated data system. The MRV plan implementation lead will review the data and identify those that could result in CO₂ leakage. Should such events occur, leakage volumes would be calculated following the approaches described in Sections 5 and 6. Impact to Subpart RR reporting will be addressed, if deemed necessary.

8. Determination of Sequestration Volumes Using Mass Balance Equations

To account for the potential propagation of error that would result if volume data from flow meters at each injection and production well were utilized, it is proposed to use the data from custody and operations meters on the main system pipelines to determine injection and production volumes used in the mass balance. This issue arises because while each meter has a small but acceptable margin of error, this error would become significant if data were taken from all the well head meters within the DCF.

The following sections describe how each element of the mass-balance equation (Equation RR-11) will be calculated.

8.1. Mass of CO₂ Received

Equation RR-2 will be used as indicated in Subpart RR §98.443 to calculate the mass of CO₂ at the receiving custody transfer meter from the Kinder Morgan CO₂ Pipeline Delivery System. The volumetric flow at standard conditions will be multiplied by the CO₂ concentration and the density of CO₂ at standard conditions to determine mass.

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

where:

- $CO_{2T,r}$ = Net annual mass of CO₂ received through flow meter r (metric tons)
- $Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters)
- $S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into a site well in quarter p (standard cubic meters)
- D = Density of CO₂ at standard conditions (metric tons per standard cubic meter): 0.0018682
- $C_{CO_{2,r,p}}$ = Quarterly CO₂ concentration measurement in flow for flow meter r in quarter p (vol. percent CO₂, expressed as a decimal fraction)
- p = Quarter of the year
- r = Receiving flow meters

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

- All delivery to the DCF is used within the unit so no quarterly flow redelivered, and $S_{r,p}$ will be zero ("0").
- Quarterly CO₂ concentration will be taken from the gas measurements.

8.2. Mass of CO₂ Injected into the Subsurface

The equation for calculating the Mass of CO₂ Injected into the Subsurface at the DCF is equal to the sum of the Mass of CO₂ Received as calculated in RR-2 of §98.443 (section 8.1 above) and the Mass of CO₂ Recycled calculated using measurements taken from the flow meter located at the output of the RCF (see Figure 3-5). As previously explained, using data at each injection well would give an inaccurate estimate of total injection volume due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

The Mass of CO₂ Recycled will be determined using equations RR-5 as follows:

$$CO_{2u} = \sum_{p=1}^4 Q_{p,u} * D * C_{CO_2,p,u} \quad (\text{Eq. RR-5})$$

where:

CO_{2u} = Annual CO₂ mass recycled (metric tons) as measured by flow meter u

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

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter):
0.0018682

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

p = Quarter of the year

u = Flow meter

The total Mass of CO₂ Injected will be the sum of the Mass of CO₂ Received (RR-3) and Mass of CO₂ Recycled (modified RR-5).

$$CO_{2I} = CO_2 + CO_{2u}$$

8.3. Mass of CO₂ Produced

The Mass of CO₂ Produced at the DCF will be calculated using the measurements from the flow meters at the inlet to RCF and from routinely captured samples and volume is measured by the truck flow meter rather than the metered data from each production well. Again, using the data at each production well would give an inaccurate estimate of total injection due to the large number of wells and the potential for propagation of error due to allowable calibration ranges for each meter.

Equation RR-8 in §98.443 will be used to calculate the Mass of CO₂ Produced from all production wells as follows:

$$CO_{2w} = \sum_{p=1}^4 Q_{p,w} * D * C_{CO_2,p,w} \quad (\text{Eq. RR-8})$$

where:

CO_{2w} = Annual CO₂ mass produced (metric tons)

$Q_{p,w}$ = Volumetric gas flow rate measurement for meter w in quarter p at standard conditions (standard cubic meters)

D = Density of CO₂ at standard conditions (metric tons per standard cubic meter):
0.0018682

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

p = Quarter of the year

w = Inlet meter to RCF

For Equation RR-9 in §98.443 the variable X_{oil} will be measured as follows:

$$CO_{2p} = \sum_{w=1}^W CO_{2w} + X_{oil} \quad (\text{Eq. RR-9})$$

where:

CO_{2p} = Total annual CO₂ mass produced (metric tons) through all meters in the reporting year

CO_{2w} = Annual CO₂ mass produced (metric tons) through meter w in the reporting year.

X_{oil} = Mass of entrained CO₂ in oil in the reporting year measured utilizing commercial meters and electronic flow-measurement devices at each point of custody transfer. The mass of CO₂ will be calculated by multiplying the total volumetric rate by the CO₂ concentration.

8.4. Mass of CO₂ Emitted by Surface Leakage

The total annual Mass of CO₂ emitted by Surface Leakage will be calculated and reported using an approach that is tailored to specific leakage events and relies on 40 CFR Part 98 Subpart W reports of equipment leakage. CapturePoint is prepared to address the potential for leakage in a variety of settings. Estimates of the amount of CO₂ leaked to the surface will depend on several site-specific factors including measurements, engineering estimates, and emission factors, depending on the source and nature of the leakage.

The process for quantifying leakage will entail using the best engineering principles or emission factors. While it is not possible to predict in advance the types of leaks that will occur, some approaches for quantification are described in Sections 5.9 and 6. In the event leakage to the surface occurs, leakage amounts would be quantified and reported, and records that describe the methods used to estimate or measure the volume leaked as reported in the Annual Subpart RR Report would be retained. Further, the Subpart W report and results from any event-driven quantification will be reconciled to assure that surface leaks are not double counted.

Equation RR-10 in §98.433 will be used to calculate and report the Mass of CO₂ emitted by Surface Leakage:

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

where:

CO_{2E} = Total annual CO₂ mass emitted by surface leakage (metric tons) in the reporting year

CO_{2x} = Annual CO₂ mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway

8.5. Mass of CO₂ Sequestered in Subsurface Geologic Formation

Equation RR-11 in §98.443 will be used to calculate the Mass of CO₂ Sequestered in Subsurface Geologic Formations in the Reporting Year as follows:

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

where:

CO₂ = Total annual CO₂ mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year

CO_{2I} = Total annual CO₂ mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year

CO_{2P} = Total annual CO₂ mass produced (metric tons) net of CO₂ entrained in oil 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 this part

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 this part

8.6. Cumulative Mass of CO_2 Reported as Sequestered in Subsurface Geologic Formation

The total annual volumes obtained using equation RR-11 in §98.443 will be summed to arrive at the Cumulative Mass of CO_2 Sequestered in Subsurface Geologic Formations.

9. MRV Plan Implementation Schedule

This MRV plan will be implemented starting January 2024 or within 90 days of EPA approval, whichever occurs later. Other GHG reports are filed on March 31 of the year after the reporting year, and it is anticipated that the Annual Subpart RR Report will be filed at the same time. It is anticipated that the MRV program will be in effect during the Specified Period, during which time the DCF will be operated with the subsidiary purpose of establishing long-term containment of a measurable quantity of CO_2 in subsurface geological formations at the DCF. It is anticipated to establish that a measurable amount of CO_2 injected during the Specified Period will be stored in a manner not expected to migrate resulting in future surface leakage. At such time, a demonstration supporting the long-term containment determination will be prepared and a request to discontinue monitoring and reporting under this MRV plan will be submitted. See 40 C.F.R. §98.441(b)(2)(ii).

10. Quality Assurance Program

10.1. Monitoring QA/QC

The requirements of §98.444 (a)-(d) have been incorporated in the discussion of mass balance equations. These include the following provisions.

10.2. CO_2 Received and Injected

- The quarterly flow rate of CO_2 received by pipeline is measured at the receiving custody transfer meters.
- The quarterly CO_2 flow rate for recycled CO_2 is measured at the flow meter located at the RCF outlet.

10.3. CO₂ Produced

- The point of measurement for the quantity of CO₂ produced from oil or other fluid production wells is a flow meter directly downstream of each separator that sends a stream of gas into a recycle or end use system.
- The produced gas stream is sampled annually downstream of the flow meter used to measure flow rate of that gas stream and measure the CO₂ concentration of the sample.
- The quarterly flow rate of the produced gas is measured at the flow meters located at the RCF inlet.

10.4. CO₂ Emissions from Equipment Leaks and Vented Emissions of CO₂

These volumes are measured in conformance with the monitoring and QA/QC requirements specified in subpart W of 40 CFR Part 98.

10.5. Flow Meter Provisions

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

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

10.6. Concentration of CO₂

CO₂ concentration is measured using an appropriate standard method. Further, all measured volumes of CO₂ have been converted to standard cubic meters at a temperature of 60°F and at an absolute pressure of 1 atmosphere, including those used in Equations RR-2, RR-5, RR-8, RR-9, RR-10, and RR-11 in Section 8.

10.7. Missing Data Procedures

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

- A quarterly flow rate of CO₂ received that is missing would be estimated using invoices or using a representative flow rate value from the nearest previous time period.
- A quarterly CO₂ concentration of a CO₂ stream received that is missing would be estimated using invoices or using a representative concentration value from the nearest previous time period.
- A quarterly quantity of CO₂ injected that is missing would be estimated using a representative quantity of CO₂ injected from the nearest previous time period at a similar injection pressure.

- For any values associated with CO₂ emissions from equipment leaks and vented emissions of CO₂ from surface equipment at the facility that are reported in this subpart, missing data estimation procedures specified in subpart W of 40 CFR Part 98 would be followed.
- The quarterly quantity of CO₂ produced from subsurface geologic formations that is missing would be estimated using a representative quantity of CO₂ produced from the nearest previous time period.

10.8. MRV Plan Revisions

In the event there is a material change to the monitoring and/or operational parameters of the CO₂-EOR operations in the DCF that is not anticipated in this MRV plan, the MRV plan will be revised and submitted to the EPA Administrator within 180 days as required in §98.448(d).

11. Records Retention

The record retention requirements specified by §98.3(g) will be followed. In addition, the requirements in Subpart RR §98.447 will be met by maintaining the following records for at least three years:

- Quarterly records of CO₂ received at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams,
- Quarterly records of produced CO₂, including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams,
- Quarterly records of injected CO₂ including volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams,
- Annual records of information used to calculate the CO₂ emitted by surface leakage from leakage pathways,
- Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead; and,
- Annual records of information used to calculate the CO₂ emitted from equipment leaks and vented emissions of CO₂ from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

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

12. Appendix

12.1 Well Identification Numbers

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

Well Type

- PROD_OIL refers to wells that produce oil
- INJ_WTR refers to wells that inject water
- INJ_WAG refers to wells that inject water and CO₂ Gas
- INJ_SWD refers to wells that inject water for disposal
- SWS refers to wells that supply water
- P&A refers to plugged and abandoned wells

Well Status

- ACTIVE refers to active wells
- INACTIVE refers to wells that have been completed but are not in use
- SHUT_IN refers to wells that have been temporarily idled or shut-in

Well Name	API Number	Well Type	Status
GAU #1WS	42165339890000	SWS	INACTIVE
GAU #2W	42165106400000	P&A	INACTIVE
GAU #3	42165106340000	P&A	INACTIVE
GAU #4	42165103790000	PROD_OIL	SHUT_IN
GAU #5	42165106070000	PROD_OIL	INACTIVE
GAU #6	42165106530000	P&A	INACTIVE
GAU #6R	42165367760000	PROD_OIL	INACTIVE
GAU #7W	42165339900000	INJ_WAG	ACTIVE
GAU #8W	42165339910000	INJ_WAG	SHUT_IN
GAU #9W	42165339920000	INJ_WAG	ACTIVE
GAU #10	42165106510000	P&A	INACTIVE
GAU #10R	42165367820000	PROD_OIL	ACTIVE
GAU #11	42165106060000	P&A	INACTIVE
GAU #11R	42165367490000	PROD_OIL	ACTIVE
GAU #12	42165102070000	P&A	INACTIVE
GAU #12R	42165367510000	PROD_OIL	ACTIVE
GAU #13	42165003830000	PROD_OIL	ACTIVE
GAU #14W	42165317930000	INJ_WAG	SHUT_IN
GAU #15	42165101300000	PROD_OIL	INACTIVE
GAU #16W	42165106270000	INJ_SWD	ACTIVE
GAU #17W	42165339930000	INJ_WAG	ACTIVE

Well Name	API Number	Well Type	Status
GAU #18	42165103780000	PROD_OIL	ACTIVE
GAU #19	42165106460000	PROD_OIL	SHUT_IN
GAU #20W	42165008790000	P&A	INACTIVE
GAU #22W	42165352720000	INJ_WAG	ACTIVE
GAU #23W	42165367500000	INJ_WAG	ACTIVE
GAU #24	42165106440000	PROD_OIL	INACTIVE
GAU #25	42165367550000	PROD_OIL	ACTIVE
GAU #26	42165367530000	PROD_OIL	ACTIVE
GAU #27	42165367540000	PROD_OIL	ACTIVE
GAU #71	42165384590000	PROD_OIL	ACTIVE
RH #28W	42165367610000	INJ_WAG	ACTIVE
RH #29W	42165367620000	INJ_WAG	ACTIVE
RH #30W	42165367630000	INJ_WAG	ACTIVE
RH #31	42165367660000	PROD_OIL	ACTIVE
RH #32	42165367670000	PROD_OIL	ACTIVE
RH #33	42165367520000	PROD_OIL	ACTIVE
RH #34	42165367890000	PROD_OIL	SHUT_IN
RH #70	42165384430000	PROD_OIL	ACTIVE

12.2 Regulatory References

Regulations cited in this plan:

- Texas Administrative Code Title 16 Part 1 Chapter 3 Oil & Gas Division -
[https://texreg.sos.state.tx.us/public/readtac\\$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y](https://texreg.sos.state.tx.us/public/readtac$ext.ViewTAC?tac_view=4&ti=16&pt=1&ch=3&rl=Y)
- TRRC Injection/Disposal Well Permitting, Testing and Monitoring Manual –
<https://www.rrc.texas.gov/oil-and-gas/publications-and-notices/manuals/injection-storage-manual/>

12.3 Abbreviations and Acronyms

AGA - American Gas Association

AMA - Active Monitoring Area

API - American Petroleum Institute

AoR - Area of Review

Bcf – 1 Billion Standard Cubic Feet of Gas

CO₂ - Carbon Dioxide

DCF – Denver City Fields

DPCs - Dimensionless Performance Curves

EPA - Environmental Protection Agency

EOR - Enhanced Oil Recovery
ESP - Electrical Submersible Pump
FPP - Formation Parting Pressure
GAU – George Allen Unit
GHG - Greenhouse Gas
GHGRP - Greenhouse Gas Reporting Program
GIS - Geographical Information System
GPA - Gas Processors Association
H₂S – Hydrogen Sulfide
HCPV - Hydrocarbon Pore Volume
IWR - Injection to withdrawal Ratio
MMA - Maximum Monitoring Area
MRV - Monitoring, Reporting and Verification Plan
Mscf – 1,000 Standard Cubic Feet of Gas
NIST - National Institute of Standards and Technology
RB - Reservoir Barrels
RH – Ruth Hudson Lease
RCF - Recycle Compression Facility
ROZ - Residual Oil Zone
SAT - Satellite Test Stations
TAC - Texas Administrative Code
TRRC - Texas Railroad Commission - Oil and Gas Division
TZ – Transition Zone
UIC - Underground Injection Control
USGS - United States Geological Survey
WAG - Water Alternating Gas

12.4 Appendix 12.4 – Conversion Factors

CapturePoint reports CO₂ 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 CO₂ mass from CO₂ 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 CO₂ 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 CO₂ of 0.002641684 lb-moles per cubic foot. Converting the CO₂ density in units of metric tonnes per cubic foot:

$$Density_{CO_2} \left(\frac{MT}{ft^3} \right) = Density_{CO_2} \left(\frac{lb - moles}{ft^3} \right) \times MW_{CO_2} \times \frac{1 MT}{2,204.62 lbs}$$

Where:

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

Density_{CO2} = 0.002641684

MW_{CO2} = 44.0095

$$Density_{CO_2} = 5.2734 \times 10^{-5} \frac{MT}{ft^3} \text{ or } 5.2734 \times 10^{-2} \frac{MT}{Mcf}$$

The conversion factor 5.2734 x 10⁻² MT/Mcf is used to convert CO₂ volumes in standard cubic feet to CO₂ mass in metric tonnes.