Purdy-Bradley Springer Field:
Northeast Purdy Springer Unit (NEPSU) /
South East Bradley A Unit (SEBAU)

Monitoring, Reporting, and Verification (MRV) Plan

Daylight Petroleum, LLC
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Contents

Introduction

Daylight Petroleum, LLC (Daylight) operates the Northeast Purdy Springer Unit (NEPSU) / South East Bradley A Unit (SEBAU), collectively referred to as the Purdy-Bradley Springer Field, in south-central Oklahoma for the primary purpose of enhanced oil recovery (EOR) using carbon dioxide (CO_2) flooding on the behalf of PBMS Oil, LLC. As a secondary purpose, Daylight intends to establish secure geological storage (sequestration) of a measurable quantity of CO_2 in subsurface geologic formations at the Purdy-Bradley Springer Field. Daylight intends to continue CO_2-EOR operations until the end of economic life of the field, with the subsequent goal of long-term storage of CO_2 in geologic formations (sequestration).

Daylight has developed this Monitoring, Reporting, and Verification (MRV) Plan in accordance with 40 Code of Federal Regulations (CFR) 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) for the purpose of qualifying for the tax credit in Section 45Q of the Internal Revenue Code. Daylight intends to implement this MRV plan for both NEPSU and SEBAU, and upon merging of the facilities in the United States Environmental Protection Agency (USEPA) system will begin reporting under a single identification number.

This MRV Plan contains nine sections:

Section 1 – General facility information.

Section 2 – Project description. Contains details of the injection operation, including duration and volume of CO_2 to be injected; a description of the geology and hydrogeology of the Purdy-Bradley Springer Field; and a description of the injection reservoir assessment techniques.

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

Section 4 – Evaluation of potential surface leakage pathways for CO_2 in the MMA as required by 40 CFR 98.448(a)(2), Subpart RR of the GHGRP. A strategy is proposed for detecting, verifying, and quantifying any surface leakage of CO_2 as required by 40 CFR 98.448(a)(3), Subpart RR of the GHGRP. Other than wellbores and surface equipment, the risk of CO_2 leakage through identified pathways is demonstrated as minimal.

Section 5 – Strategy for monitoring to identify CO_2 surface leakage, including establishment of baselines to assess for potential leaks and the proposed monitoring process, as required by 40 CFR 98.448(a)(4), Subpart RR of the GHGRP. Monitoring will focus primarily on identifying potential leaks through wellbores and surface equipment.

Section 6 – Summary of the mass balance calculations and site-specific variables used to determine the volume of CO_2 sequestered as required by 40 CFR 98.448(a)(5), Subpart RR of the GHGRP.

Section 7 – Estimated schedule for implementation of this MRV Plan as required by 40 CFR 98.448(a)(7).

Section 8 – Quality assurance and quality control procedures to ensure data integrity.

Section 9 – Program for records retention as required by 40 CFR 98.3(g), Subpart A of the GHGRP, and 40 CFR 98.447, Subpart RR of the GRGRP.

Appendices with supplemental data are provided at the end of this document (Appendix 1 includes an attachment).

1.0. Facility

1.1. Reporter Number

Historically, the facility identifiers were 545261 for NEPSU and 545263 for SEBAU. Both units are now merged into one facility identifier (545261) under the name Northeast Purdy Springer Unit (NEPSU) / South East Bradley A Unit (SEBAU).

1.2. UIC Permit Class

The EOR wells covered by this MRV Plan are permitted and operated as Class II Underground Injection Control (UIC) wells under the jurisdiction of the Oklahoma Corporation Commission (OCC), which has primacy for administering Class II UIC regulations in the state.

1.3. UIC Injection Well Numbers

A list of all wells (including injection wells) in the NEPSU and SEBAU is provided as part of **Appendix 1**. Wells are identified by name, unique well identifier (UWI, using a 14-digit American Petroleum Institute [API] number), status, and type. The list is current as of January 2025, around the time this MRV Plan was created.

2.0. Project Description

2.1. Project Characteristics

2.1.1. Estimated Years of CO_2 Injection

CO_2 has been injected at the NEPSU since 1982 and at the SEBAU since 1997. Daylight intends to continue injecting CO_2 for the foreseeable future.

2.1.2. Estimated Volume of CO_2 Injected Over Lifetime of Project

Historical and forecasted cumulative CO_2 retention capacity is up to approximately 278 billion standard cubic feet (Bscf), or 14.7 million metric tons (MMT), from the start of CO_2 injection through March 2054.

2.2. Environmental Setting of MMA

2.2.1. Boundary of the MMA

Daylight has defined the boundary of the MMA as equivalent to the boundaries of the NEPSU and SEBAU plus a minimum of a half-mile buffer. A discussion of the methods used in delineating the MMA and the AMA is presented in **Section 3**.

2.2.2. Geology

This geologic description of the Purdy-Bradley Springer Field incorporates regional literature, field development studies, core and well log data, and the interpretations of Daylight, legacy operators, laboratories, and service companies.

Tectonic and Structural Setting

The Purdy-Bradley Springer Field is located within the Golden Trend of South-Central Oklahoma, in the southeastern embayment of the Anadarko Basin (**Figure 1**). The Anadarko Basin contains up to 40,000 feet of sedimentary rock and is a prolific hydrocarbon producer (Ball, Henry, and Frezon, 1991). This asymmetrical foreland basin is structurally deepest along its southern margin and is separated to the south and southeast from Cambrian-age crystalline rocks exposed in the Wichita Mountains (Ham et al., 1964; Perry, 1989). In updip areas, particularly around structural features that define the basin margins, sedimentary units are commonly truncated by onlap or erosion.

Structural development of the Anadarko Basin was preceded by crustal extension in the Precambrian and formation of the southern Oklahoma aulacogen, or failed rift, during the Cambrian (Perry, 1989). At the end of rifting, the aulacogen cooled and subsided, creating a trough that was filled with Cambrian through lower Mississippian sediments. The Anadarko Basin developed on the northwestern flank of this trough during the late Mississippian through Pennsylvanian as a result of the Wichita Orogeny. During the orogeny, the Wichita and Arbuckle mountains were uplifted and thrusted over the southern margin of the trough, causing renewed subsidence and creating the Anadarko Basin. Faulting and uplift associated with the Wichita-Arbuckle structural trend peaked in the early Pennsylvanian and had mostly ended by Permian time (Ball, Henry, and Frezon, 1991).

Producing structures in the Anadarko Basin range from complex combinations of folds and fault blocks to simpler, homoclinally dipping sediment wedges that form stratigraphic traps through erosion or facies change. The Golden Trend, which is bounded by the Nemaha-Pauls Valley uplifts on the east and by the Arbuckle Mountains to the south, produces hydrocarbons from Ordovician through Permian-age rocks (Swesnick, 1950). The NEPSU and SEBAU are two of numerous Pennsylvanian-age reservoirs formed by tilting and truncation. These units produce from the Cunningham Sandstone in the upper part of the Springer series, with shales of the upper Springer, Morrow, and Atoka series providing seal. Uplift of the Pauls Valley arch in late Springerean or early Morrowan time (Pennsylvanian) resulted in erosion of the southwest flank of the structure as Springer sands were tilted to the southwest, creating a stratigraphic trap below the unconformity.

Stratigraphy

A generalized basin stratigraphy applicable to the Purdy-Bradley Springer field area is shown in **Figure 2** and summarized below. Stratigraphic units are listed from oldest to youngest (adapted from Ball, Henry, and Frezon, 1991, except as noted):

- Granite wash and sandstone overlying igneous basement rocks
- Arbuckle Group (Cambrian to Ordovician) – Interior platform carbonates and tidal-flat mudstones; porous dolomite is common in the Western Anadarko basin, while tight facies are more common in the eastern basin.
- Simpson Group (Ordovician) – Erosionally truncated sandstones sealed by overlying Pennsylvanian shales
- Viola Limestone (Ordovician) – Dense limestone, locally dolomitized
- Hunton Group (Silurian-Devonian) – Fractured and dolomitized carbonates sealed and sourced by the overlying, organic-rich Woodford Shale

- Kinderhook, Osage, and Meramec Series (Mississippian) – Fractured limestones that shale out basinward; deposition followed by uplift and erosion resulting from the Wichita Orogeny
- Springer Group (Pennsylvanian – Springerean series) – Deltaic and shallow marine sands deposited during a marine regression, with potential reservoirs including feeder channels, upper-fan channels, middle-fan channels and sheet sands, and distal-fan sheet sands. The section reaches a maximum total thickness of 6,000 feet, though sands are on the order of tens to more than 100 feet thick, with dark shales comprising the remaining thickness. In the NEPSU and SEBAU, the Cunningham Sandstone in the upper Springer series is the historical and current production target.
- Dornick Hills Group (Pennsylvanian – Morrowan and Atokan series) – Mostly transgressive shales with sandstones (e.g., Primrose) deposited during brief regressions
- Deese Group (Pennsylvanian – Des Moinesian series) – Shales and sands (e.g., Osborne and Hart) derived from erosion of uplifted crystalline basement rocks, primarily forming stratigraphically trapped reservoirs
- Hoxbar Group (Pennsylvanian – Missourian series) – Shales and limestones (e.g., Hogshooter and Checkerboard)
- Pontotoc Group (Permian) – Conglomerates, sandstones, and mudstones
- Sumner Group (Permian) – Garber-Wellington interval consisting of sandstones, shales, and conglomerates
- Hennessey Formation (Permian) – Shale with red siltstones and very fine-grained sandstones; one of two bedrock units, along with the Duncan Sandstone of the El Reno Group, that are present at surface within the Purdy-Bradley Springer Field (Chang and Stanley, 2010)
- El Reno Group (Permian) – Duncan Sandstone and undifferentiated sandstone and shale, present at surface within the Purdy-Bradley Springer Field (Chang and Stanley, 2010)
- Alluvium (Holocene) – Clay, silt, sand, and gravel deposited in channels and on floodplains of modern streams (Chang and Stanley, 2010)

NEPSU Reservoir

The Lower Pennsylvanian Cunningham Sandstone, historically referred to as the Springer “A” sand, was deposited in shallow marine settings and consists of southwest-dipping, fine- to medium-grained siliceous sandstone (Cities Service Company, 1978; Fox et al., 1988). Within the reservoir are two lower zones deposited as bar sands on a shallow marine shelf and two upper zones consisting of channel sands.

The reservoir trends northwest-southeast and is approximately 9 miles long and 1-3 miles wide, comprising 15.6 square miles or ~10,000 acres (NEPSU, 1979). Reservoir and unit boundaries were established by erosional truncation of the Cunningham Sandstone and the original oil-water contact (Cities Service Company, 1978). The sands dip approximately 8 degrees to the southwest, and legacy core analysis showed the presence of “tight” layers within the clean sand reservoir (NEPSU, 1979). The reservoir is at a depth of about 8,000-9,000 feet, has an average porosity of 13% and permeability of 44 millidarcies (mD), and had an average initial water saturation of 18%.

Mineralogy is primarily quartz, with limited calcitic cements in shalier intervals and kaolinite, illite, and smectite within the clay fraction. These clay minerals are believed to remain stable under reservoir conditions.

SEBAU Reservoir

The geologic and reservoir properties of the SEBAU are similar to those of the NEPSU. In this unit the Springer strata were deposited in shallow marine tidal bar and channel settings (Oxy, 1998). Fine- and medium-grain sand with shale laminations and dominantly clay cements comprise the primary reservoir facies of the Cunningham Sandstone. A high degree of vertical and lateral facies heterogeneity is present as a result of shoreline deposition. Upper, middle, and lower flow units are recognized, truncated by faults to the south and west and stratigraphic pinch-outs and erosional surfaces to the northeast. The upper sand, usually the only productive flow unit, is 25-200 feet thick and 8,900-10,800 feet deep. Porosity averages 12.5% and permeability is 58 mD (Oxy, 1988). Permeability-porosity relationships are inconsistent in part because of reservoir heterogeneity.

Primary Seals

Reservoirs of the Springer are sandstone bodies that have lateral porosity and permeability variations and are encased in shale (Ball, Henry, and Frezon, 1991). At the Purdy-Bradley Springer Field, the Cunningham Sandstone is top-sealed by shales of the upper Springerean and Morrowan series that directly overlie the reservoir unit and by truncation against the base Atoka unconformity. The Cunningham is tilted and eroded below the unconformity. Above the unconformity, the Cunningham is sealed by shales of the lower Atokan series.

Bottom Seal

The Goddard Shale is the bottom seal for the Cunningham Sandstone and varies in thickness from 1,550 feet to 2,000 feet within the units. It is homogenous and rich in ductile swelling clays (smectite). The Goddard Shale also serves as a top seal of large overpressured zones (Mississippian and Devonian reservoirs) in the deep Anadarko basin. The high ductility, thickness, and overpressuring of this shale package make it a highly effective bottom seal for the Cunningham Sandstone.

Well Log Analysis

A reference petrophysical well log (SE Bradley A Unit O-19A) through the reservoir and overlying shales is shown in **Figure 3**. In this well, the Cunningham Sandstone is approximately 50 feet thick, with an approximate porosity range of 10-20% as estimated from the sonic (SPHI), neutron (NPHI), and density porosity (DPHI) logs. A permeability response in the sands is also observed in the deflection of the spontaneous potential (SP) log. These reservoir sands (yellow shade on the gamma ray [GR] log) are truncated just below the unconformity and are overlain by an estimated 170 feet of net shale (brown shade on GR log) within the Osborne section, providing separation and confinement from the Hart sandstones above. Within the Hart are another 110 feet of net shale, and as previously shown in **Figure 2** additional shales overlie the Hart section. Daylight's broader review of well logs in the field shows total net shale thickness above the Cunningham exceeds 1,200 feet, which is sufficient to prevent vertical migration of CO_2 and other fluids to the surface or into underground sources of drinking water (USDWs).

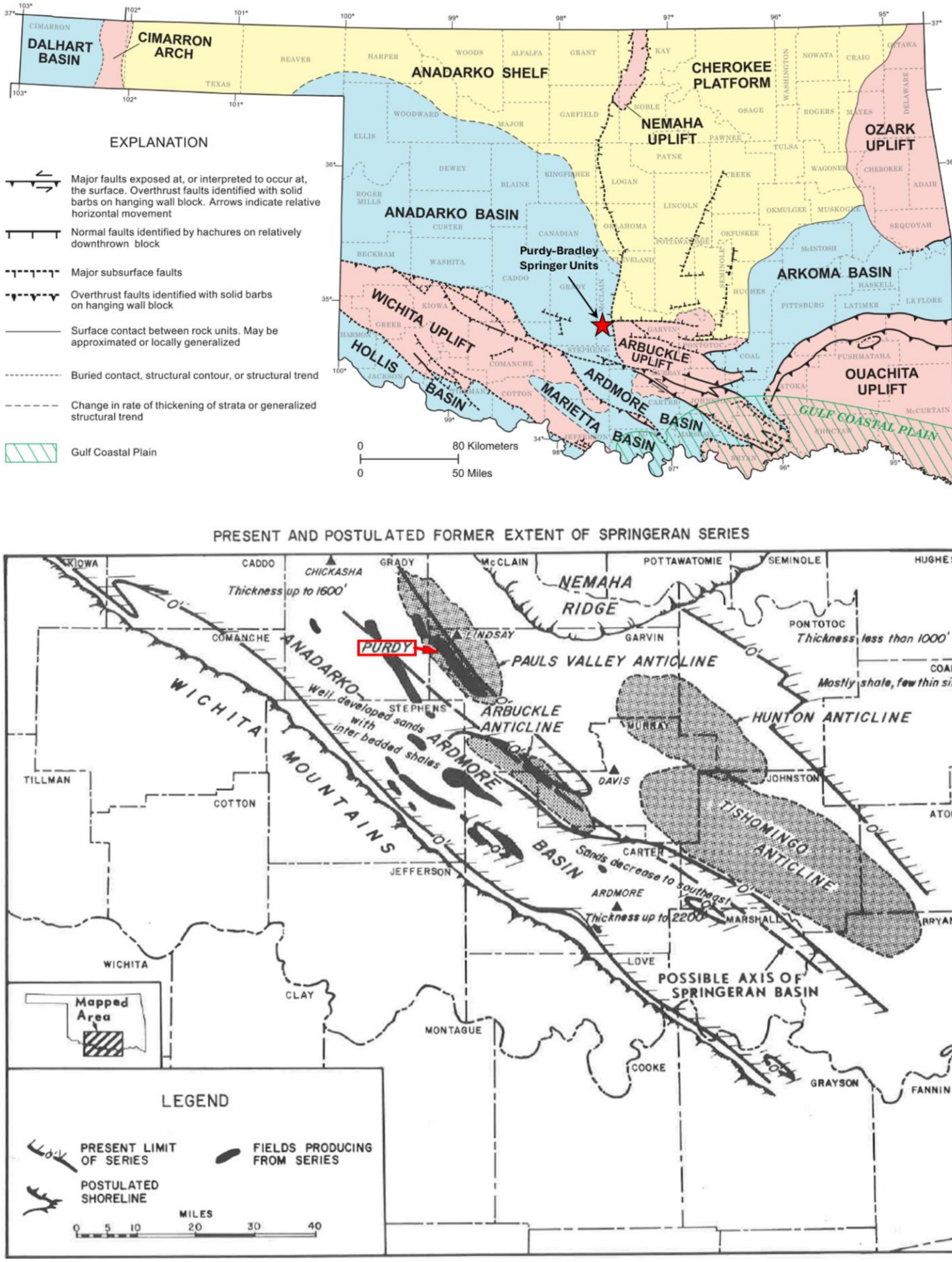


Figure 1: Top panel shows the location of the Purdy-Bradley Springer Field in the Anadarko Basin, South-Central Oklahoma, and proximity to major structural features (adapted from Johnson and Luza, 2008). Bottom panel shows the field location in relation to smaller-scale structures, the extent of the Springer series, and the locations of other Springer fields in the Anadarko-Ardmore basin trend (adapted from Cities Service Company, 1978).

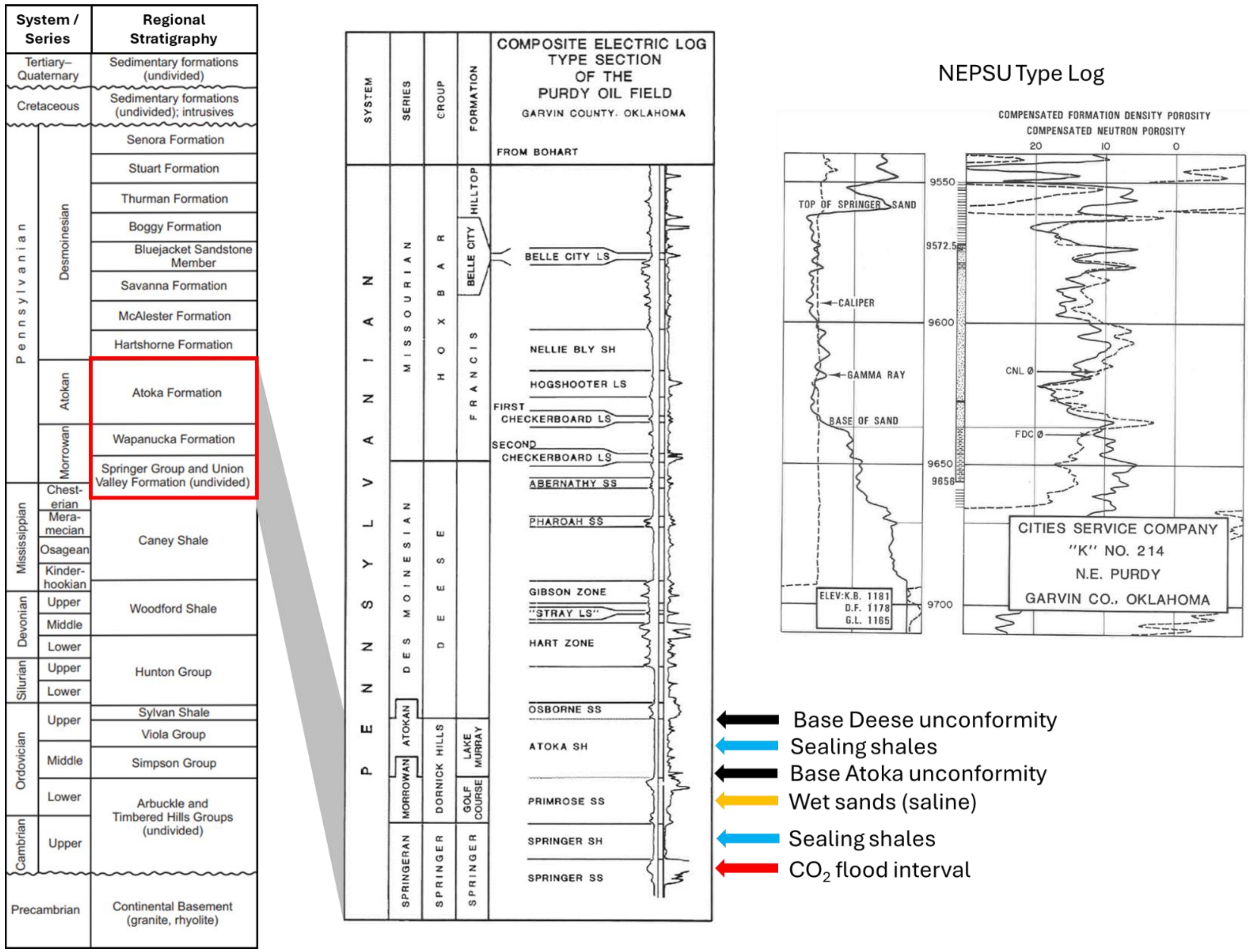


Figure 2: Regional stratigraphic column (left) shows the ages and names of sedimentary rock units in the Anadarko Basin from basement to surface. Center chart shows the type section for the Purdy-Bradley Springer Field and relation to the regional stratigraphy; colored arrows identify key units and surfaces in the Purdy-Bradley Springer Field. Note the multiple shale layers that serve as sealing units for the Springer (Cunningham Sandstone) reservoir. At right is the type log for the Northeast Purdy Springer Unit (NEPSU) reservoir, showing porosity (average ~12%) and gamma ray well log response in the Cunningham Sandstone.

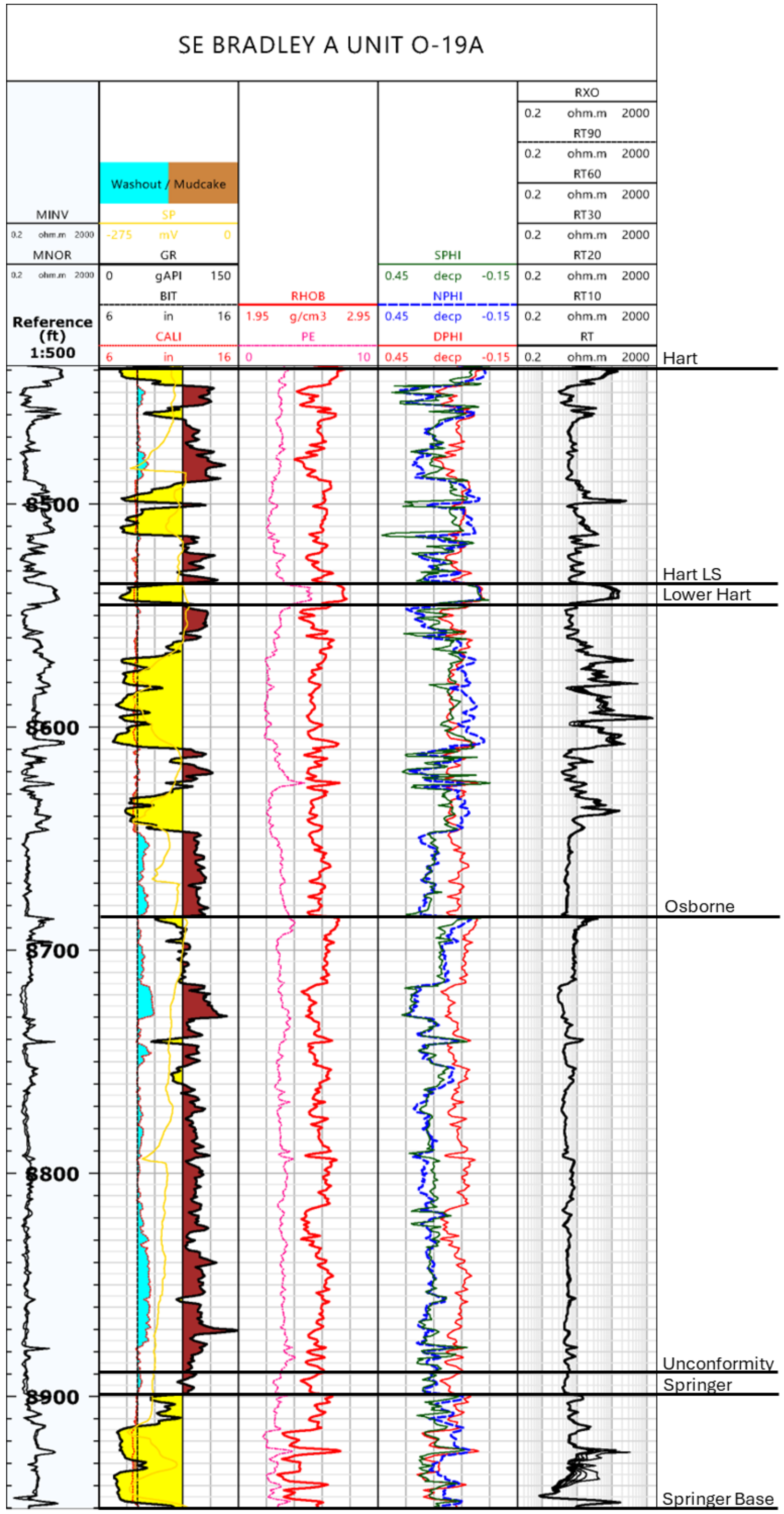


Figure 3: Type log showing the Cunningham Sandstone (at ~8,900-8,950 feet in the Springer reservoir) and overlying shales (seal). The well is located in the SE 1/4 of Section 7, T4N, R4W (API: 3504925047).

2.2.3. Hydrogeology

Groundwater flow rates in confined deep Anadarko layers are considered to be low-flow to no-flow, based on four lines of evidence presented by Nelson and Gianoutsos (2014). First, recharge of groundwater into Pennsylvanian and older strata is limited due to the presence of a low-permeability Permian cap. Second, stratigraphic pinch-outs establish a western limit of recharge. Third, highly saline formation water along the Nemaha uplift creates a west-to-east flow density barrier. Lastly, fluid movement is restricted by overpressured strata in the deep basin.

Further evidence of stratigraphic pinch-out that is more specific to the NEPSU and SEBAU is documented in internal studies developed by previous operators, including a geologic and reservoir description (Oxy, 1988) and a feasibility analysis of applying EOR methods (Cities Service Company, 1978). The SEBAU is isolated by faults to the south and west and pinched out or erosionally truncated to the northeast, while the NEPSU is bounded to the north by erosional truncation and to the southwest by a fault. Jorgensen (1993) suggested that, beginning during the Laramide Orogeny and continuing to present, the groundwater flow is west to east, driven by recharge at elevated units to the west. The NEPSU and SEBAU CO_2 injection and production operations therefore are considered unlikely to cause water to flow to the outcrops.

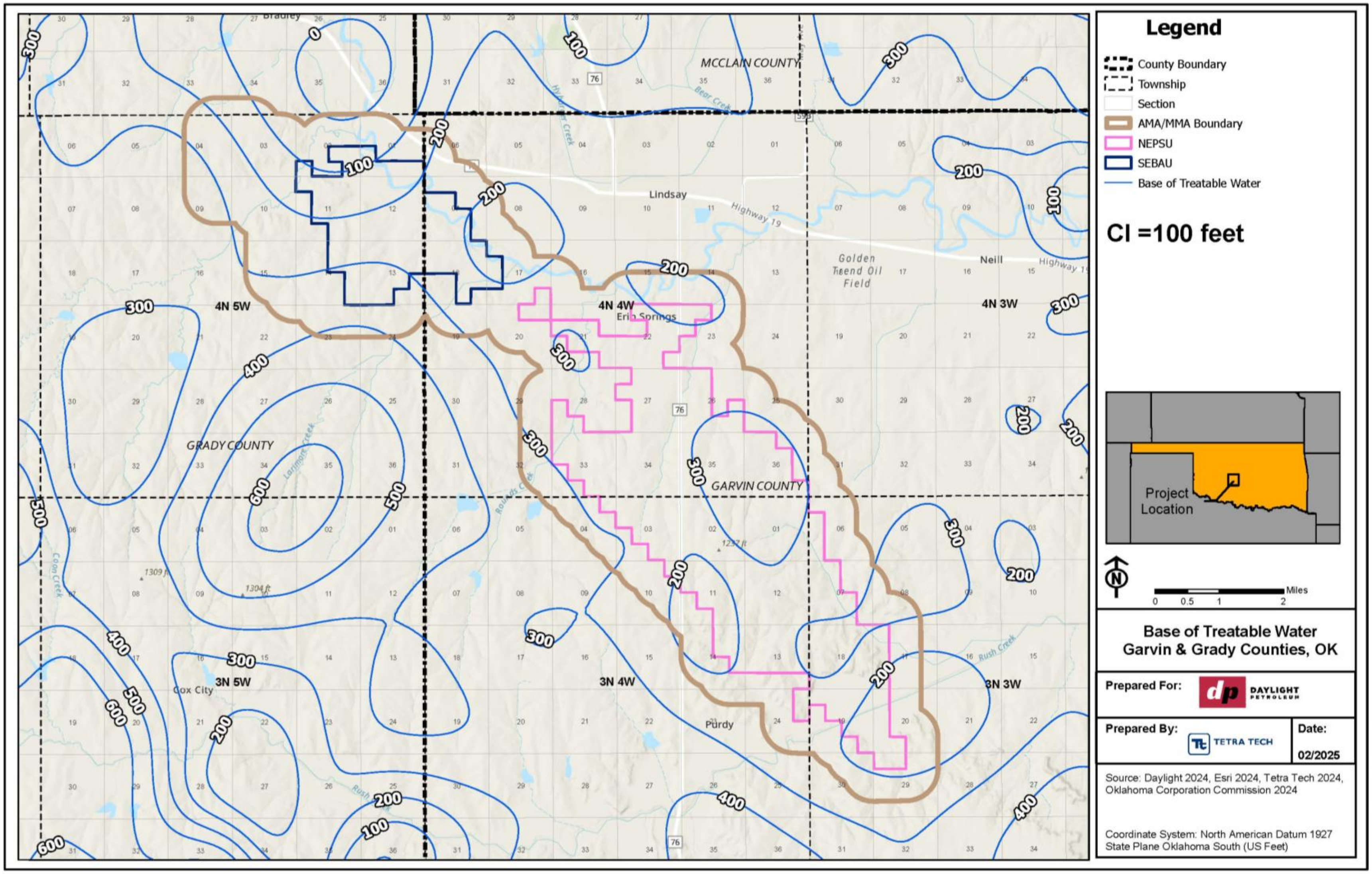
Groundwater is generally at shallow depths, with the base of treatable water approximately 100-300 feet deep (**Figure 4**). In Oklahoma, the base of treatable water is equivalent to the deepest USDW. The base of treatable water depth is relatively consistent throughout the MMA, deepening to the west and south of the MMA. The shallow base of treatable water provides upward of 8,000 feet minimum vertical separation from the Purdy-Bradley Springer Field injection interval.

2.3. Description of the CO_2 Injection Process

Figure 5 shows a simplified flow diagram of the CO_2-EOR operations within the boundaries of the NEPSU and SEBAU. Historically, a fertilizer plant in Enid, Oklahoma, has been the only source of CO_2, with CO_2 captured from the plant delivered via a Daylight-operated pipeline to the field for injection. No new CO_2 has been received since 2022, but Daylight is currently working with multiple emitters to source additional CO_2 for the EOR project. These potential sources include gas processing plants, landfills, fertilizer plants, refineries, and ethanol plants.

Currently, the CO_2-EOR operations involve three main processes. These processes are detailed in the subsections below and include:

1. **CO_2 distribution and injection.** Purchased CO_2 (when applicable) is combined with recycled CO_2 obtained from the produced gas stream and sent through the main CO_2 distribution system to various water alternating gas (WAG) injectors.
2. **Injection and production well operations.** As of January 2025, 23 injection and 36 production wells were active in the SEBAU, and 69 injection and 88 production wells were active in the NEPSU. Production is a mixture of oil, water, and CO_2 or other gases.
3. **Produced fluids handling and gas processing and compression.** Produced fluids and gases flow to satellite batteries and/or centralized tank batteries for separation. The gas phase is transported via a field gathering system to the Lindsay Gas Plant for further gas processing to dehydrate and remove natural gas liquids and hydrocarbon fuel gas. The separated CO_2 gas stream is returned to the field via a CO_2 gas distribution system for compression and injection to the producing reservoir.



Not for Construction

Figure 4: Depth (feet) to base of treatable water

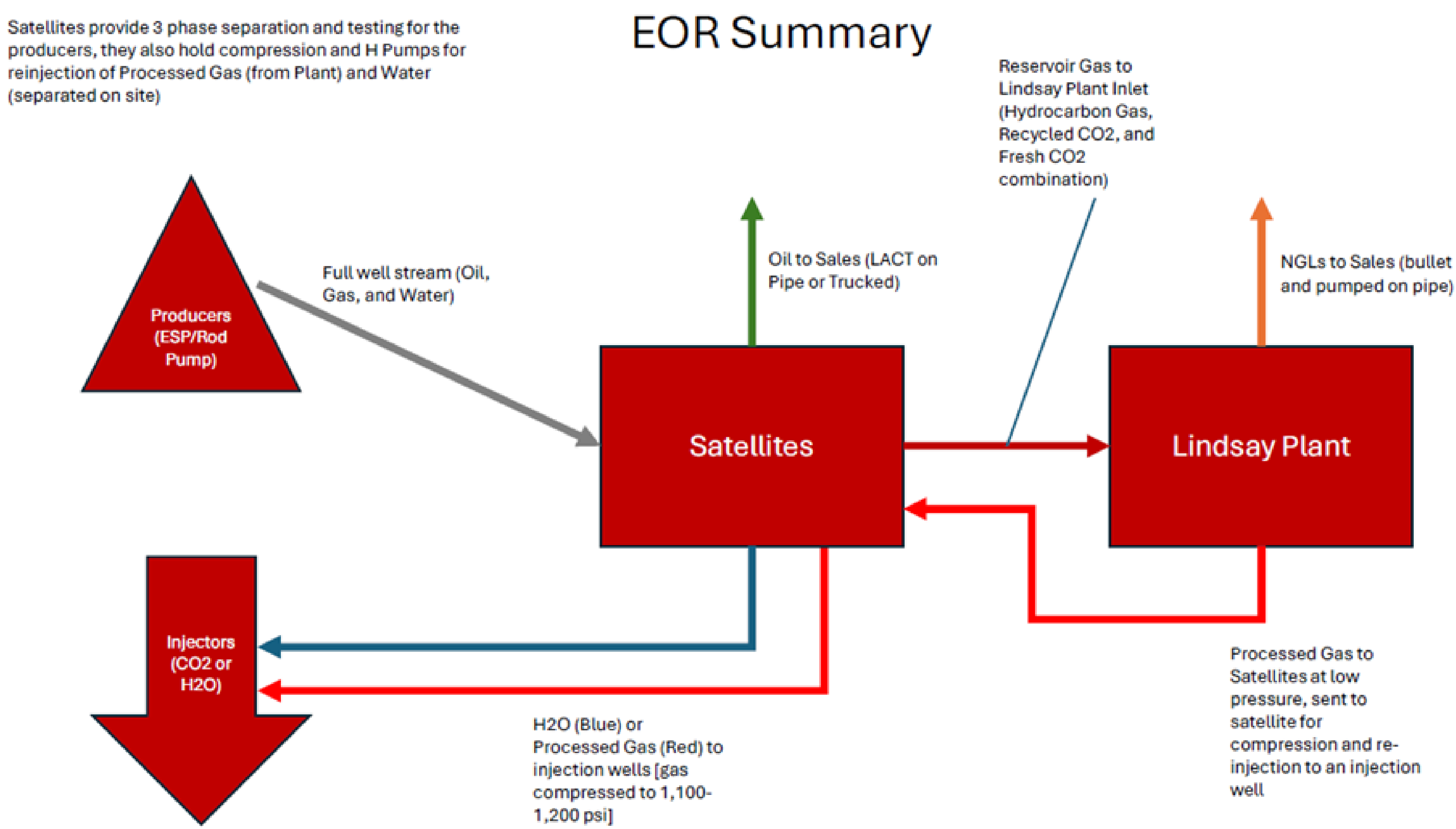


Figure 5: Simplified flow diagram of the CO_2-EOR operations within the Purdy-Bradley Springer Field

2.3.1. CO_2 Collection and Distribution

The CO_2 delivered to the NEPSU and SEBAU is supplied by one or more sources. Historically, new CO_2 delivered from the fertilizer plant was sent through an injection pipeline distribution system to CO_2 injection wells throughout the two units. Produced (recycled) CO_2 is received from Daylight's Lindsay Gas Plant, which extracts natural gas liquids (NGLs) from the produced gas stream (consisting of CO_2 and hydrocarbon gas). The produced gas stream is transported to the Lindsay plant via gathering lines. The gas compression process consists of gathering CO_2 and other produced gases, processing an NGL stream that is sold via pipeline at the plant, and sending CO_2 back out to satellites for compression and reinjection into the injection wells. The CO_2 collection and distribution process is illustrated in **Figure 6**.

Currently, CO_2 delivered to the floods for injection is received through many meters, including at the Purdy Tee delivery point, the source receipt point, the plant outlet, the recycle CO_2 source point, and at each injection well. All CO_2 that flows through the meters is sent through CO_2 injection lines to individual injection wells in the floods, in many instances through manifolds and distribution lines prior to arriving at an injection well. A flow meter at each injection well measures the injection rate of the CO_2 or water. Currently, for any given CO_2 injection well, the CO_2 injected may be sourced from the CO_2 pipeline, the Lindsay plant, or a combination of both. The ratio of CO_2 sources is expected to fluctuate over the course of time.

2.3.2. Injection and Production Well Operations

As of January 2025, 23 injection and 36 production wells were active in the SEBAU, and 69 injection and 88 production wells were active in the NEPSU. Currently, each injection well can inject CO_2, water, or both, at various rates and injection pressures, as determined by Daylight. Upon injection of CO_2 or water into the reservoir, a mixture of oil, water, CO_2 and/or other gases (collectively, produced fluids) is mobilized toward and produced at one or more production wells.

2.3.3. Produced Fluids Handling and Gas Processing and Compression

The produced fluids handling system gathers fluids from the production wells throughout various satellite batteries in the units, via gathering lines that combine, collect, and commingle the produced fluids. The mixture of produced fluids (oil, water, and gas including CO_2) flows to one of 10 satellite separation facilities or batteries and then to a centralized tank battery. Each satellite is equipped with well test equipment to measure production rates of oil, gas, and water from individual production wells.

The fluids stream is further separated into oil and water, which is recovered for reuse, re-injection, or disposal. The produced fluids handling process is illustrated in **Figure 7**. Produced oil is sold via truck or through one or more lease automatic custody transfer (LACT) units located at centralized tank batteries. The gas stream, consisting of CO_2 and other gases, is transported to the Lindsay plant via gas gathering lines throughout the fields.

The produced gas compression process (**Figure 8**) consists of gathering CO_2 and other gases produced from the floods, processing an NGL stream that is sold via pipeline at the plant, and sending CO_2 back to satellite compression for reinjection into the injection wells. The average gas mixture composition is ~82-90% CO_2, with the remaining portion comprising hydrocarbons and trace nitrogen (N_2). Future plant modifications would be intended to produce a higher-quality fuel gas stream for use on-site that would also result in a higher-quality CO_2 stream for sequestration. The CO_2 concentration is likely to change over time as CO_2-EOR operations continue and expand.

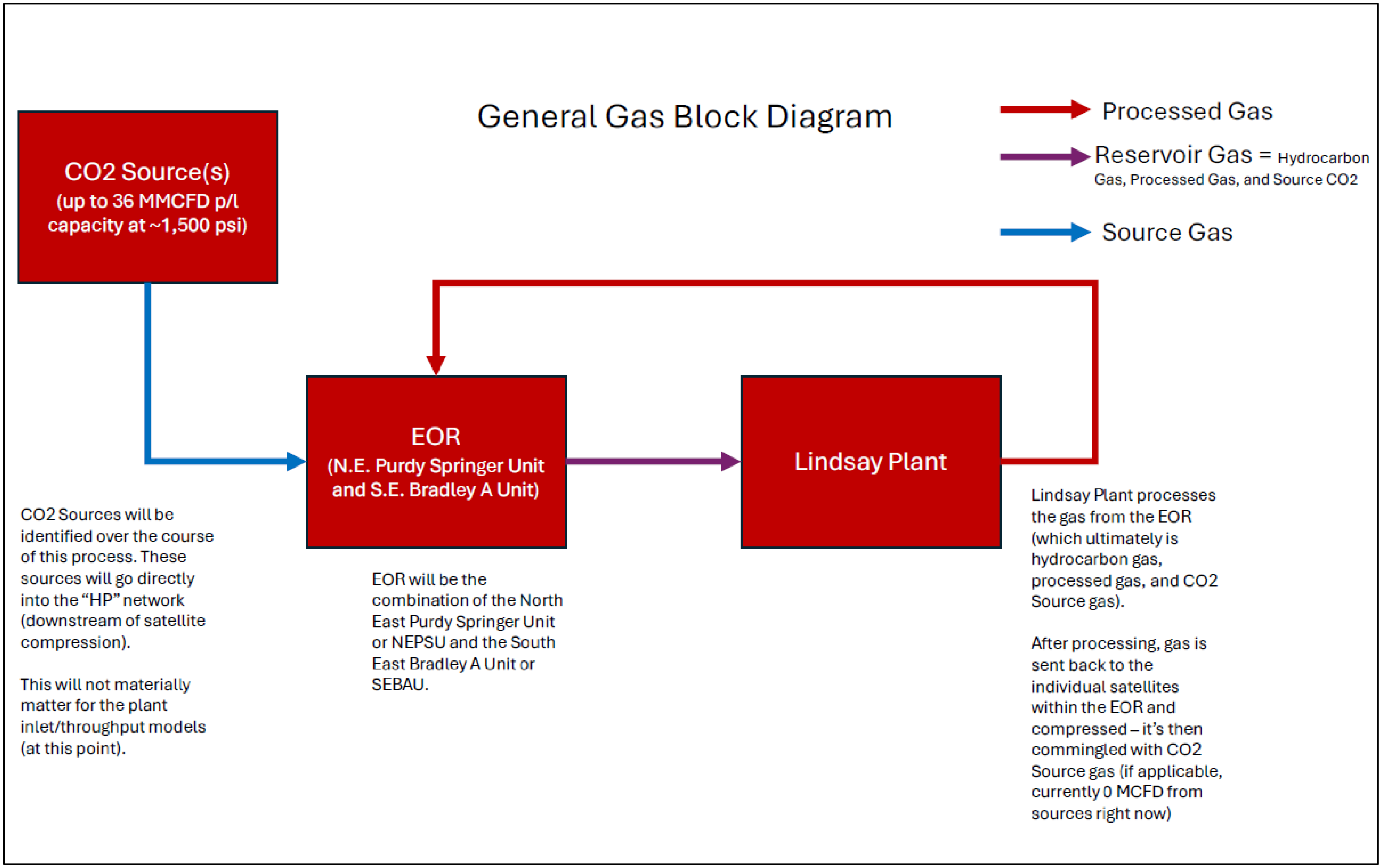


Figure 6: CO_2 collection and distribution process

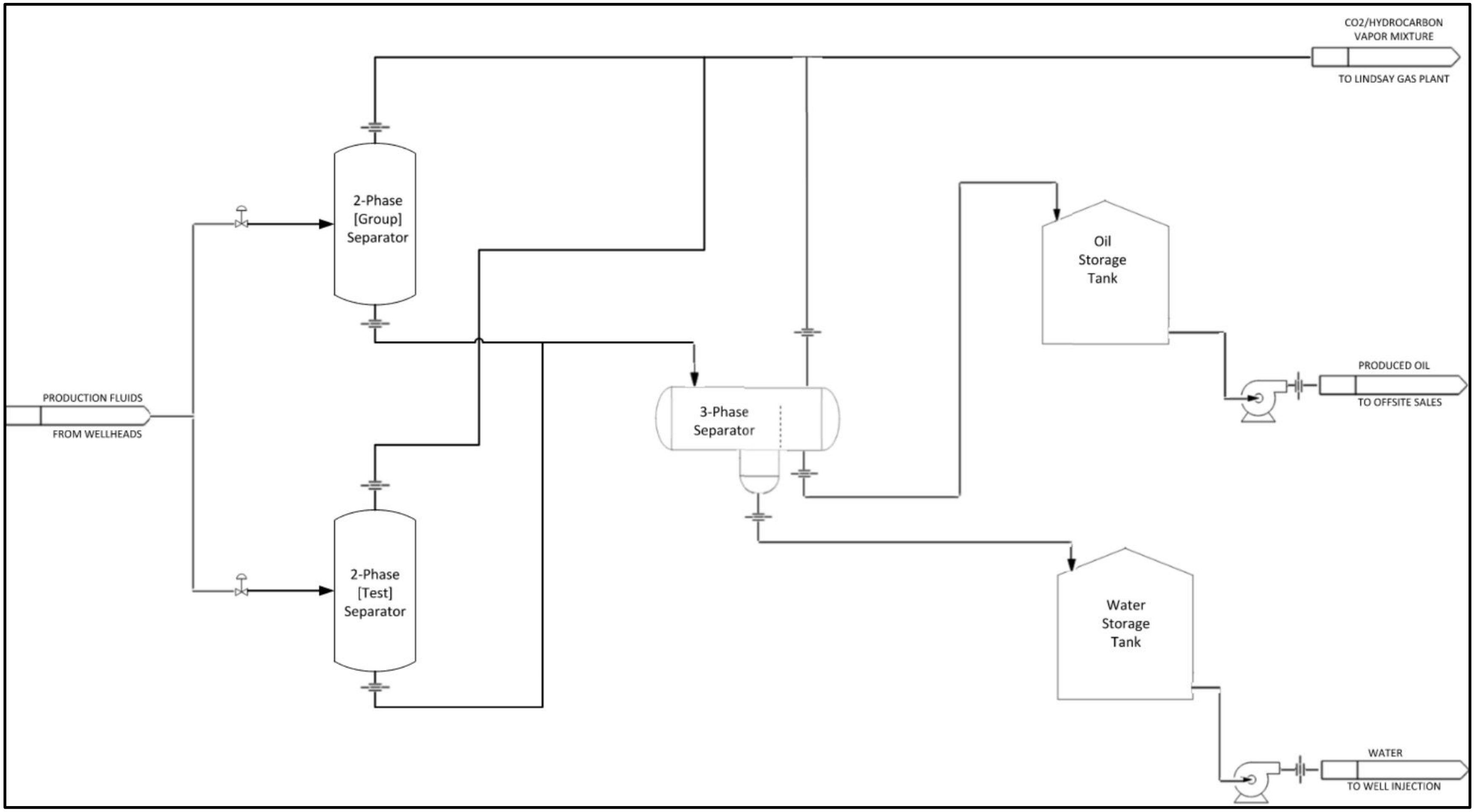


Figure 7: Simplified fluids flow diagram for a typical NEPSU satellite

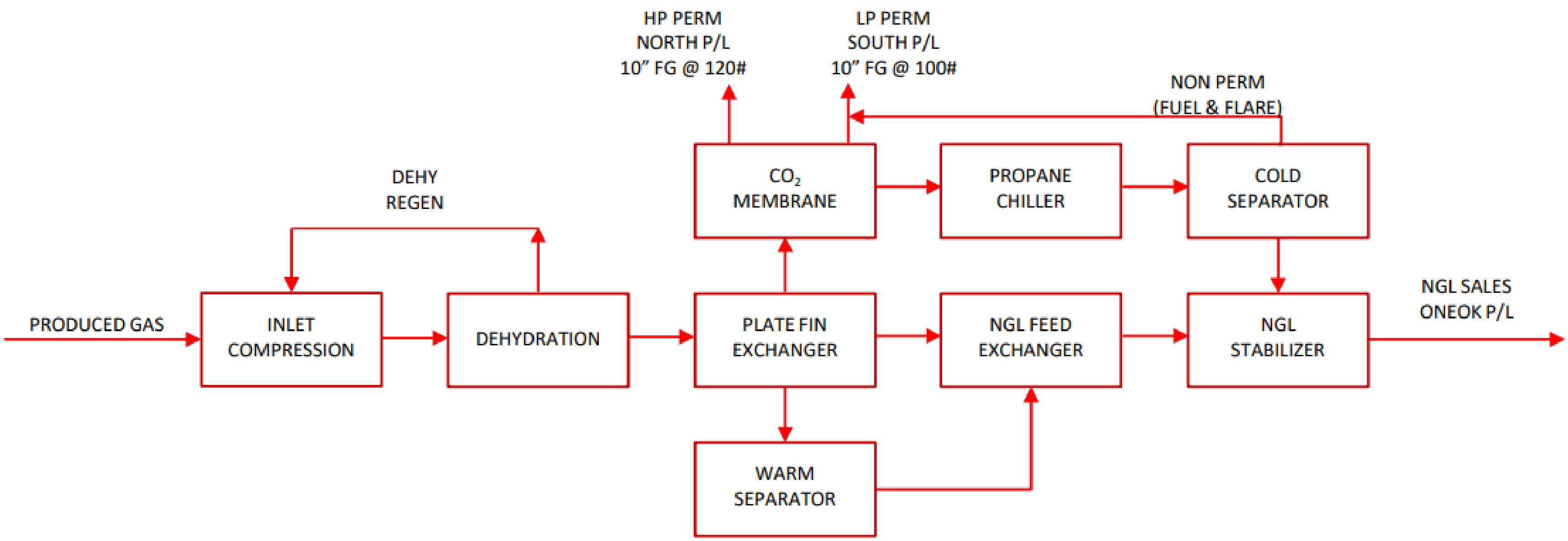


Figure 8: Process diagram for the Lindsay Gas Plant

2.3.4. Well Operations and Permitting

OCC regulations require that injection wells be completed and operated so that fluids are contained in the injection zone and that well operations do not pollute subsurface or surface waters (Oklahoma Administrative Code [OAC] §165:10-5-5 b4). Depending on the purpose of the well, regulatory requirements can impose additional standards.

CO_2 injection well permits are authorized only after approval of an application, public notice, and opportunity for a hearing. As part of the application process, Daylight establishes an Area of Review (AoR) that includes wells within the floods plus a one-quarter mile buffer. Pursuant to applicable regulations, all wells within the AoR that penetrate the injection interval are located and evaluated.

All active injection wells must undergo a periodic mechanical integrity test (MIT) per regulatory guidelines (per OAC §165:10-5-6), depending on various dates and activities associated with the well. MIT includes the use of a pressure recorder, pressure gauge, and testing of the casing-tubing annulus for a minimum amount of time at a minimum pressure, as specified in the approved well injection permit. In some instances, a radioactive tracer survey (RTS) is conducted, sometimes in combination with a pressure test, to ensure all fluids are being injected into the permitted zone.

Daylight has developed operating procedures based on its experience as a CO_2-EOR operator. Operations include developing detailed modeling at the EOR pattern level to guide injection pressures and performance expectations, leveraging Daylight's expertise in diverse disciplines to operate EOR projects based on specific site characteristics. Field personnel are trained to look for and address issues promptly and to implement corrosion prevention techniques, or to engage contracted parties for such services, to protect wellbores as needed.

Daylight's operations are designed to comply with the applicable regulations and to ensure that all fluids (including oil, water, and CO_2) remain in the units until they are produced through a Daylight-operated well. Well pressure in injection wells is monitored on a continual basis. Individual well injection is guided by a pattern-level WAG program to govern the rate, pressure, and duration of water or CO_2 injection in accordance with regulatory requirements. Pressure monitoring of the injection wells flags pressures that significantly deviate from the plan. Leakage on the inside or outside of the injection wellbore would affect pressure and be detected through this approach. If such excursions occur, they are investigated and addressed. It is the company's experience that few excursions result in fluid migration out of the intended zone and that leakage to the surface is very rare.

In addition to monitoring well pressure and injection performance, Daylight uses the experience gained over time to strategically approach well maintenance and updating. Operations staff is in the field daily monitoring the performance of the units and plant, and a call-out system exists for any disruptions when staff is away from the field. Daylight uses all the information at hand, including pattern performance and well characteristics, to determine well maintenance schedules. Production well performance is monitored using the production well test process conducted when produced fluids are gathered and sent to a satellite battery. There is a routine cycle for each satellite battery, with each well being tested approximately once every 1-2 months. During this cycle, each production well is diverted to the well test equipment for a period of time sufficient to measure and sample produced fluids (generally 24 hours). This test allows Daylight to allocate a portion of the produced fluids measured at the satellite battery to each production well, assess the composition of produced fluids by location, and assess the performance of each well.

Performance data are reviewed on a routine basis to ensure that CO_2 flooding is optimized. If production 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. Field inspections are conducted on a routine basis by field personnel. Currently, Daylight has approximately 20 personnel in the field throughout the two units. Leaking CO_2 is very cold and leads to the formation of bright white clouds or dry ice, either of which is easily spotted. All field personnel are trained to identify leaking CO_2 and other potential problems at wellbores and in the field. Any CO_2 leakage detected will be documented and reported, quantified, and addressed as described in **Section 4** and **Section 6**. Continual and routine monitoring of wellbores and site operations will be used to detect leaks. Based on these activities, Daylight will mitigate the risk of CO_2 leakage through existing wellbores by detecting problems as they arise and quantifying any leakage that does occur.

2.3.5. Number, Location, and Depth of Wells

As of January 2025, Daylight operated 23 active CO_2 injection wells and 36 active production wells in the SEBAU, and 69 active CO_2 injection wells and 88 active production wells in the NEPSU. The depth of these wells is approximately 8,200-10,800 feet (Cunningham Sandstone). These wells are listed in **Appendix 1**.

2.4. Reservoir Description

2.4.1. Reservoir Characteristics

Generalized reservoir parameters are provided in **Table 1**. These were determined from data collection, interpretation, and studies performed by historical field operators and, more recently, Daylight in support of primary, secondary, and tertiary recovery operations.

Core, well log, and operational data suggest that reservoir properties for the NEPSU and SEBAU are largely similar. Routine core analysis and flow studies conducted in the Northeast Purdy K-214 well (Ekstrand, 1979) showed an average porosity of 10% and permeability of 14.8 mD. The effect of overburden was determined to reduce porosity by 3-10% (or less than 1 porosity percent) at typical net overburden pressures (approximately 7,000 psig). Additional legacy conventional core samples have been studied from nearly 30 NEPSU wells and approximately 23 SEBAU wells. Currently accepted permeability and porosity values are generally more optimistic than those seen in the K-214 core, at 13% porosity and 44 mD permeability in the NEPSU and 12.5-14% porosity and 50-58 mD permeability in the SEBAU.

As discussed earlier, the NEPSU and SEBAU are fault-bounded stratigraphic traps, with the Cunningham Sandstone having been tilted, eroded, and covered by subsequent deposition of shales above the base Atoka unconformity. The top structure of the Springer is mapped in **Figure 9**, the net pay thickness of Springer reservoir sands is mapped in **Figure 10**, and the trapping configuration is illustrated in **Figure 11**. The Cunnigham Sandstone comprises primarily quartz framework grains and cements, with calcite cements in shaly intervals and tight streaks, significant kaolinite, and some smectite and illite (Cities Service Company, 1978). The clays are stable under reservoir conditions. Limited chemical reaction is expected from CO_2 injection given the native pH range of 5.1 to 5.4, so long as pH is maintained at 4.5-5.0 or higher. Plugging from fines migration is the primary risk to permeability and reservoir quality during flooding and production.

Initial pressure of the NEPSU reservoir was 3,050 psig at 8,200 feet, and original oil in place was approximately 225 million stock tank barrels (MMSTB) (Simlote and Withjack, 1981). Primary production began in 1951, and waterflooding for secondary recovery commenced in 1960. Cumulative production through 1977 was 79.5 million MMSTB, prompting efforts to develop a tertiary recovery program. Extensive reservoir study led to the establishment of CO_2 injection in 1982 as the most feasible tertiary method to maximize recovery (Cities Service Company, 1978).

In the SEBAU, which had ~105 MMSTB oil originally in place, primary and secondary recovery occurred from the 1950s into the 1990s. Tertiary recovery in the SEBAU began in 1997.

Operations and development throughout the history of the units have been very similar, owing in part to their immediate proximity and similar reservoir and production parameters.

Table 1: Reservoir Summary Characteristics

Parameter	Parameter by Unit	
	NEPSU	SEBAU
Unitized Area	~10,160 acres	~3,100 acres
Injection Reservoir	Cunningham Sand	Cunningham Sand
Flood Type	CO_2 and Water Alternating Gas	CO_2 and Water Alternating Gas
Depth	8,200-10,200 feet	8,900-10,800 feet
Porosity[1]	13%	12.5-14%
Permeability[2]	44 mD	50-58 mD
Temperature	148 degrees F	150 degrees F
Initial Water Saturation	18%	NA
Irreducible Water Saturation	14%	NA
Average Net Pay	40 feet	40 feet
Initial Reservoir Pressure	3,050 psi @ 8,200 feet subsea	NA
Original Oil in Place	225 MMSTB	105 MMSTB
Oil Gravity	38 degrees API	38 degrees API
Oil Viscosity	1.2 cp	1.0 cp
Minimum Miscibility Pressure	1,700-2,300 psi	1,820-2,350 psi
Water Salinity	200,000 ppm TDS	NA

[1] Range across both units = 10-22%; [2] Range across both units = 5-500 mD
Sources: Daylight internal data; Advanced Resources International, 2024; Birk, 1986; Brinlee and Brandt, 1982; Cities Service Company, 1978; Fox et al., 1988.

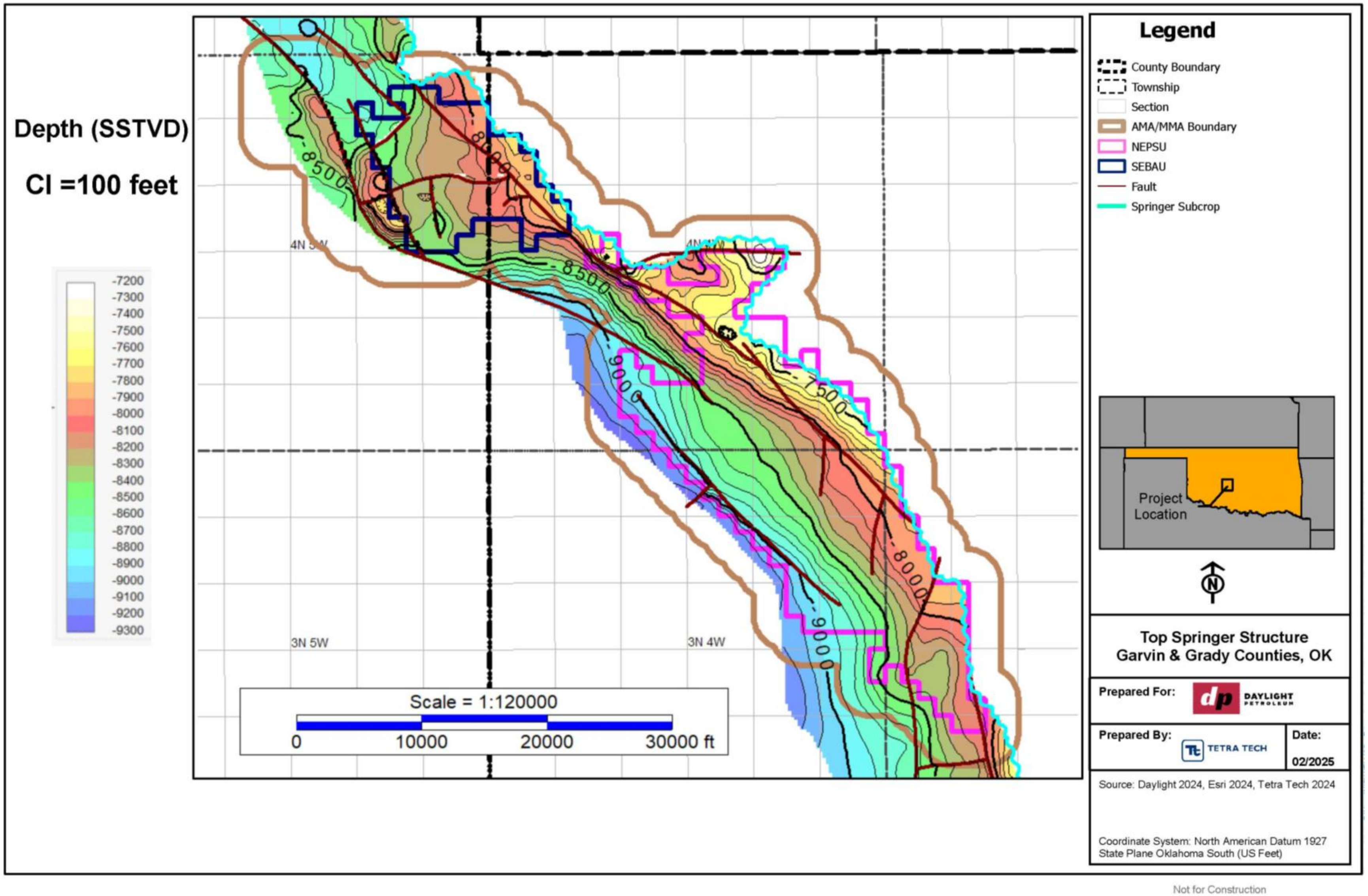
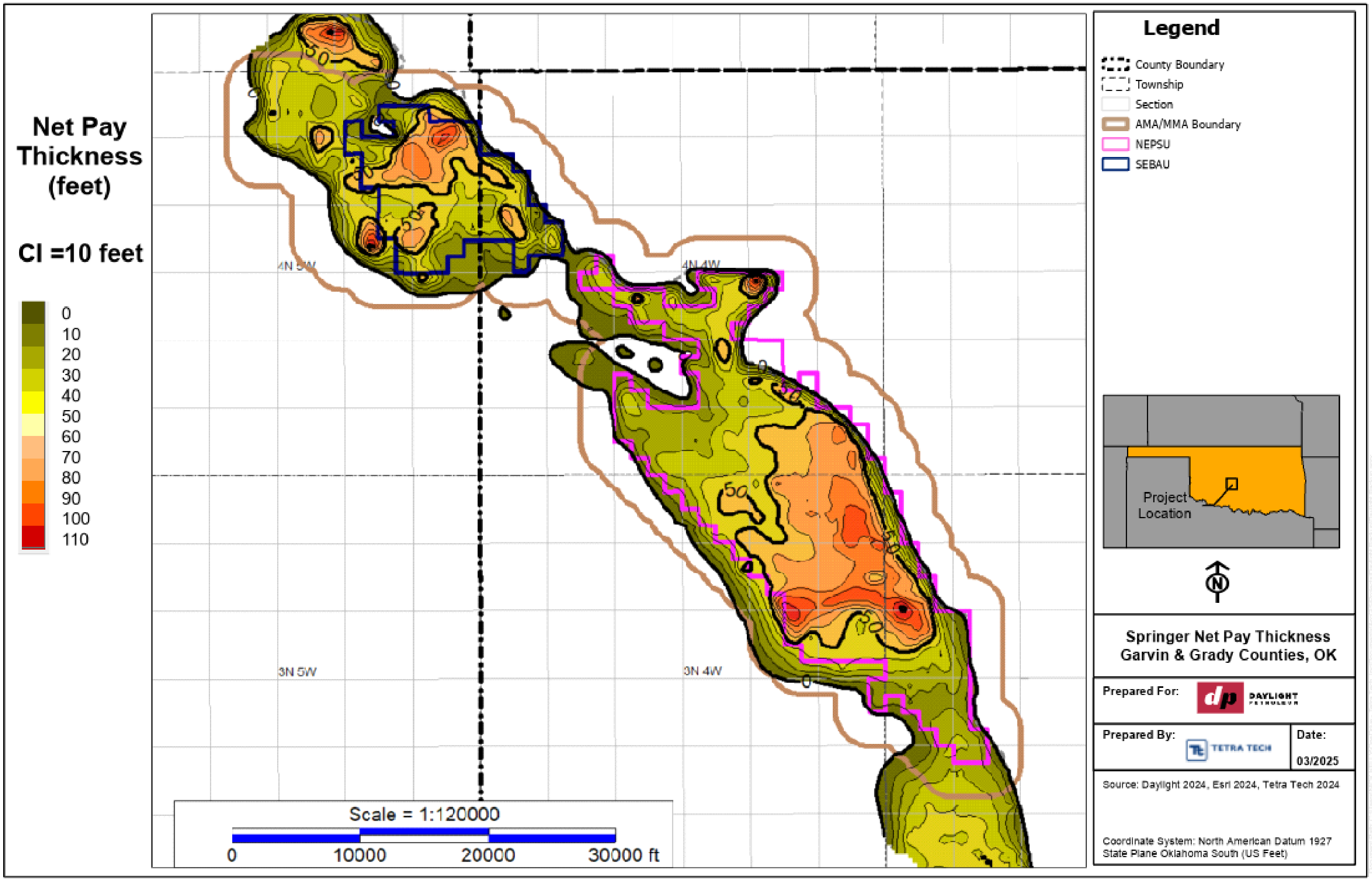


Figure 9: Top Springer structure



Not for Construction

Figure 10: Net pay thickness for the Springer reservoir sands

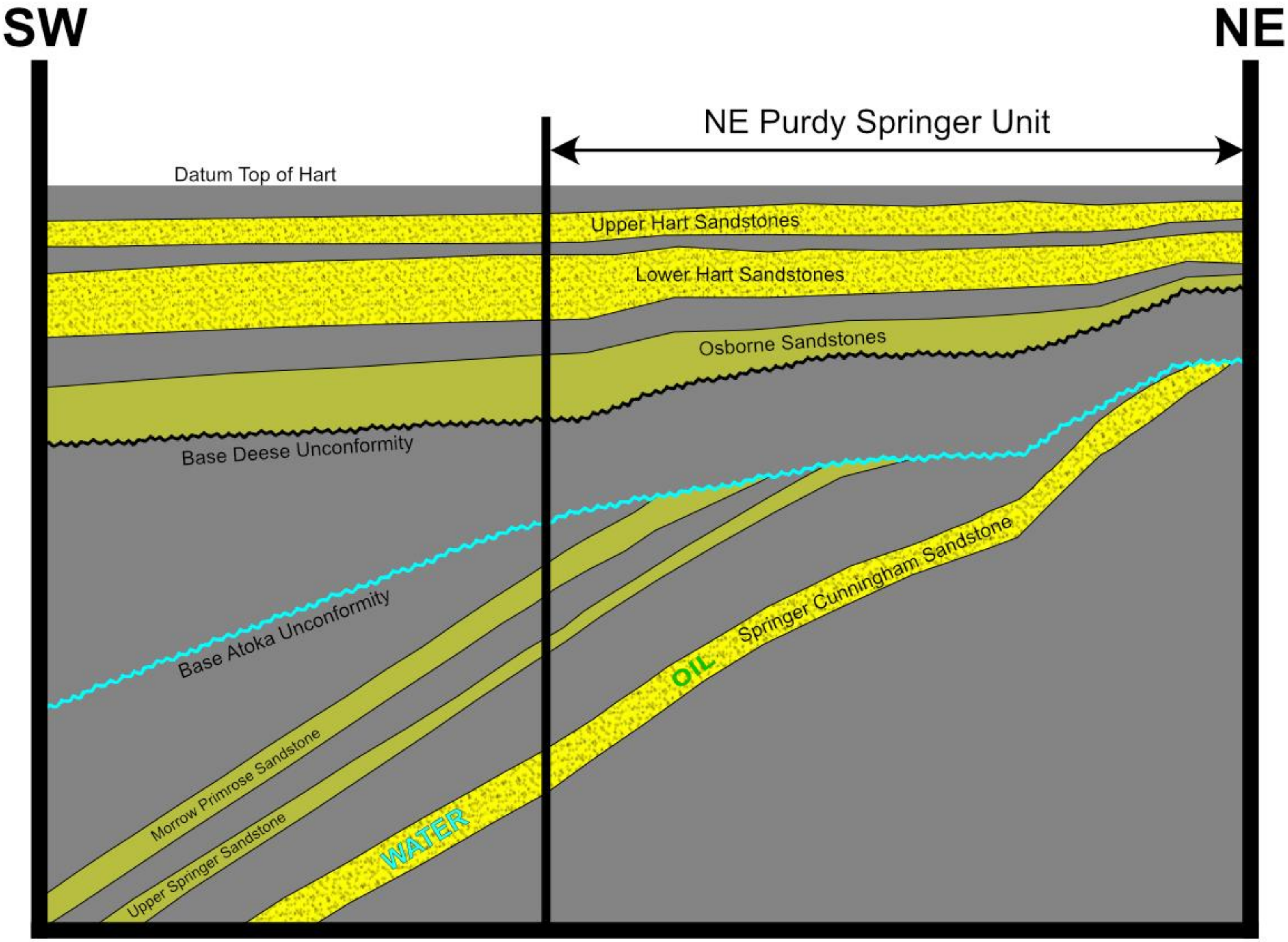


Figure 11: Schematic of the reservoir-seal stratigraphic trapping configuration

2.4.2. Reservoir Fluid Modeling

As discussed previously, NEPSU and SEBAU are operated collectively as the Purdy-Bradley Springer Field and have similar reservoir properties. Nearly all the historical reservoir data is from NEPSU, and available production data are generally combined for the two units. Therefore, the work presented in the following sections is considered to apply to the field as a whole.

A reservoir fluid model was developed based on the work of Fox et al. (1988). This article documents fluid properties for the NEPSU, and pressure, volume, and temperature (PVT) parameters were applied uniformly across the field. The minimum miscibility pressure (MMP) is calculated to be 1,750 psi. It is important to note that MMP measurements from 1979 show location dependency, with some values ranging between 2,100 psig and 2,300 psig. The tertiary flood was initiated by injection of CO_2 in September 1982, and because pressure measurements since 1982 are reported to be above 2,400 psi, flooding is expected to be miscible in most of the reservoir. Since the project involved continuous injection, a decline in pressures was not expected.

The reservoir temperature, used to create the oil PVT plots, was assumed to be 148 degrees F (Fox et al., 1988). The predicted plots and the data points from Fox et al. (1988) are compared in **Figure 12** and **Figure 13**. The gas viscosity is estimated based on a specific gravity of 8.42, calculated from the gas composition of the pre-CO_2 injection gas provided in Fox et al. (1988).

2.4.3. CO_2 Analytical Sweeping Efficiency Calculation

Accepted conventional reservoir engineering practice relies on dimensionless equations to predict the amount of oil that can be recovered through CO_2 flooding in oil reservoirs (Lee et al., 2019; Stell, 2010). The amount of oil recovered is plotted as a decimal fraction of the original oil in place, compared to the decimal fraction of the hydrocarbon pore volume (HCPV) of CO_2 injected into the reservoir, measured in reservoir barrels (rb).

To assess the enhanced oil recovery (EOR) performance, the commonly used Koval factor is applied. The Koval theory was meant to interpret the core-scale production of oil by a miscible displacement by CO_2 injection. It is calculated by multiplying the viscosity contrast effect by the heterogeneity effect. Based on core data from Daylight, the Lorenz coefficient is calculated to be 0.911, indicating a high level of heterogeneity in the reservoir (**Figure 14)**.

The Lorenz coefficient and Dykstra-Parsons are common parameters used for evaluating heterogeneity. In this study, since the Koval factor is primarily calculated using Lorenz, it was employed for the heterogeneity assessment. The Lorenz coefficient ranges from 0 for a completely homogeneous system to 1 for a completely heterogeneous system. To calculate it, the normalized cumulative permeability capacity is first plotted against the normalized cumulative volume capacity (**Figure 14**). The Lorenz coefficient is then determined by dividing the area above the straight line (Area A) by the area below the straight line (Area B).

To convert the Lorenz factor into the Koval Factor, a chart provided by Salazar and Lake (2020) was used. According to this chart, the Koval Factor is estimated to be 140 (see **Appendix 5** for additional information). With this value, the volumetric sweep efficiency can be calculated using Koval's Theory (Koval, 1963), based on the CO_2 pore volume injected. The hydrocarbon pore volume (HCPV) filled by CO_2 injected into the oil reservoir over time is shown in **Figure 15**.

By assuming 25% of the HCPV for CO_2 injection, the estimated recovery is approximately 8% (**Figure 16**). The expected sweep efficiency is relatively low due to the reservoir's heterogeneity.

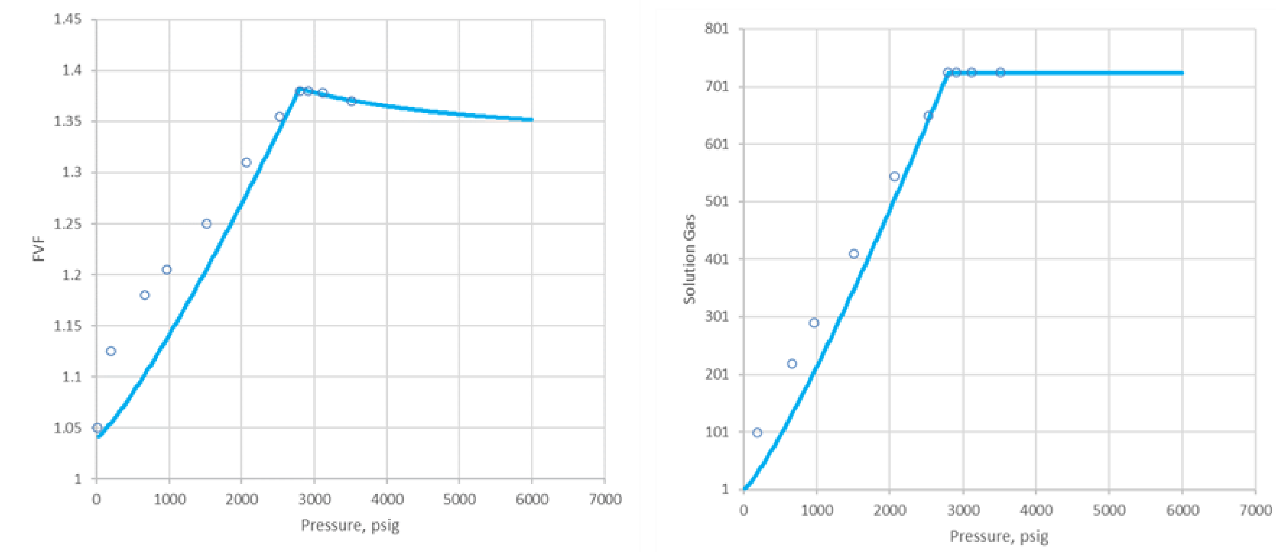


Figure 12: Oil PVT plots constructed for this modeling

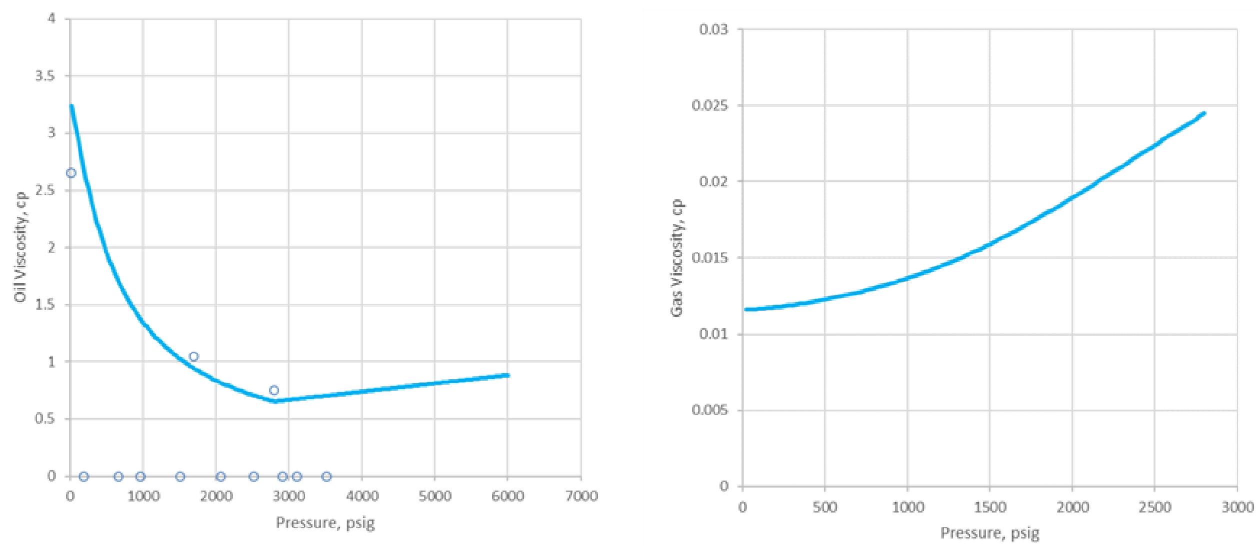


Figure 13: Oil and gas viscosity used in this modeling

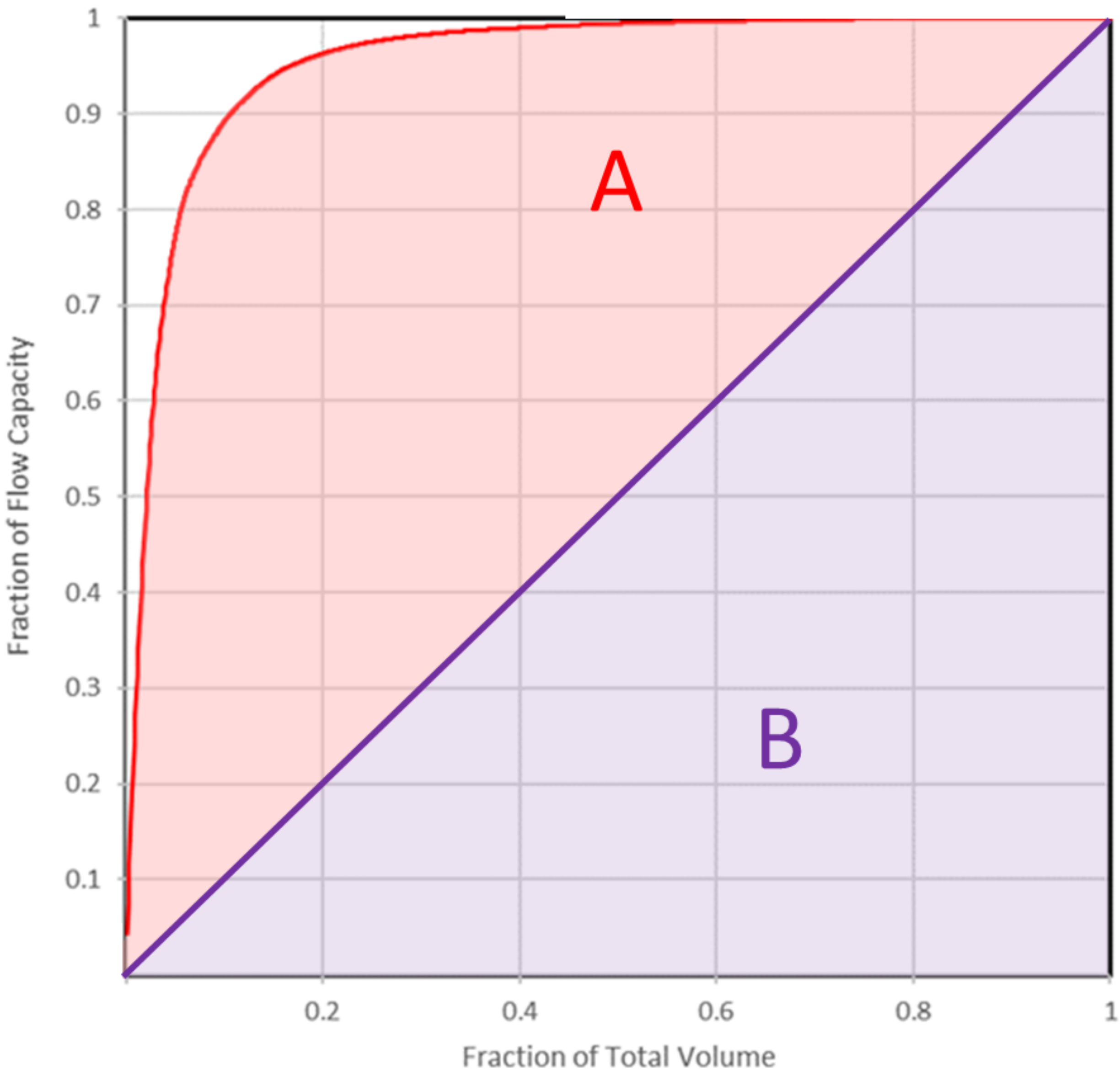


Figure 14: A Lorenz plot shows the high heterogeneity in this reservoir. The Lorenz coefficient is calculated by dividing the area above the straight line (area A) by the area under the straight line (area B).

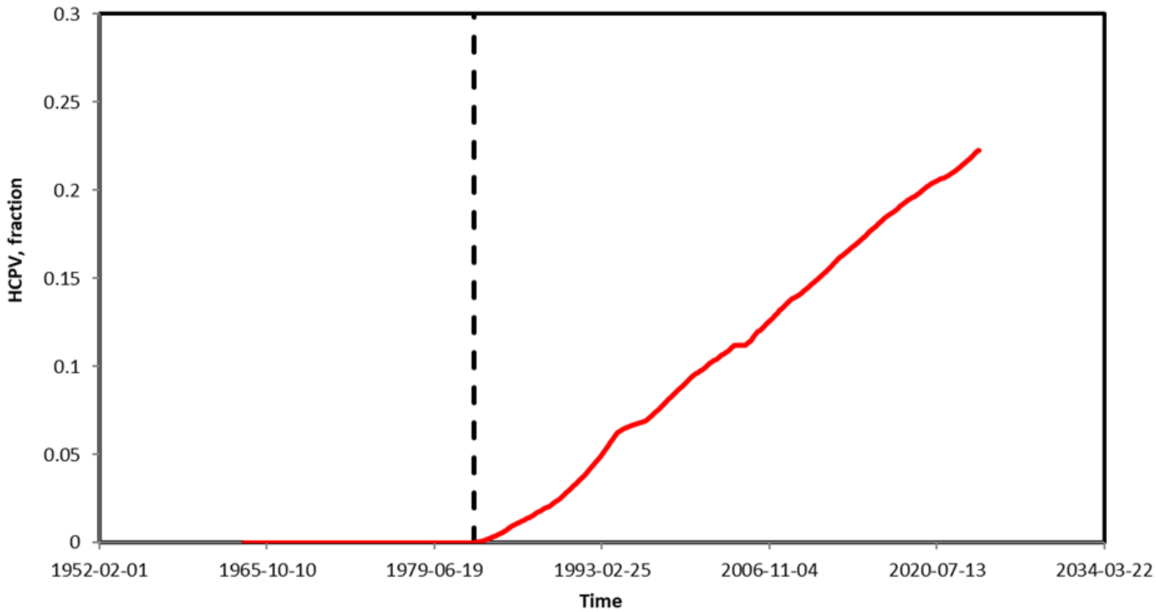


Figure 15: Hydrocarbon pore volume filled by CO_2 injection vs. time

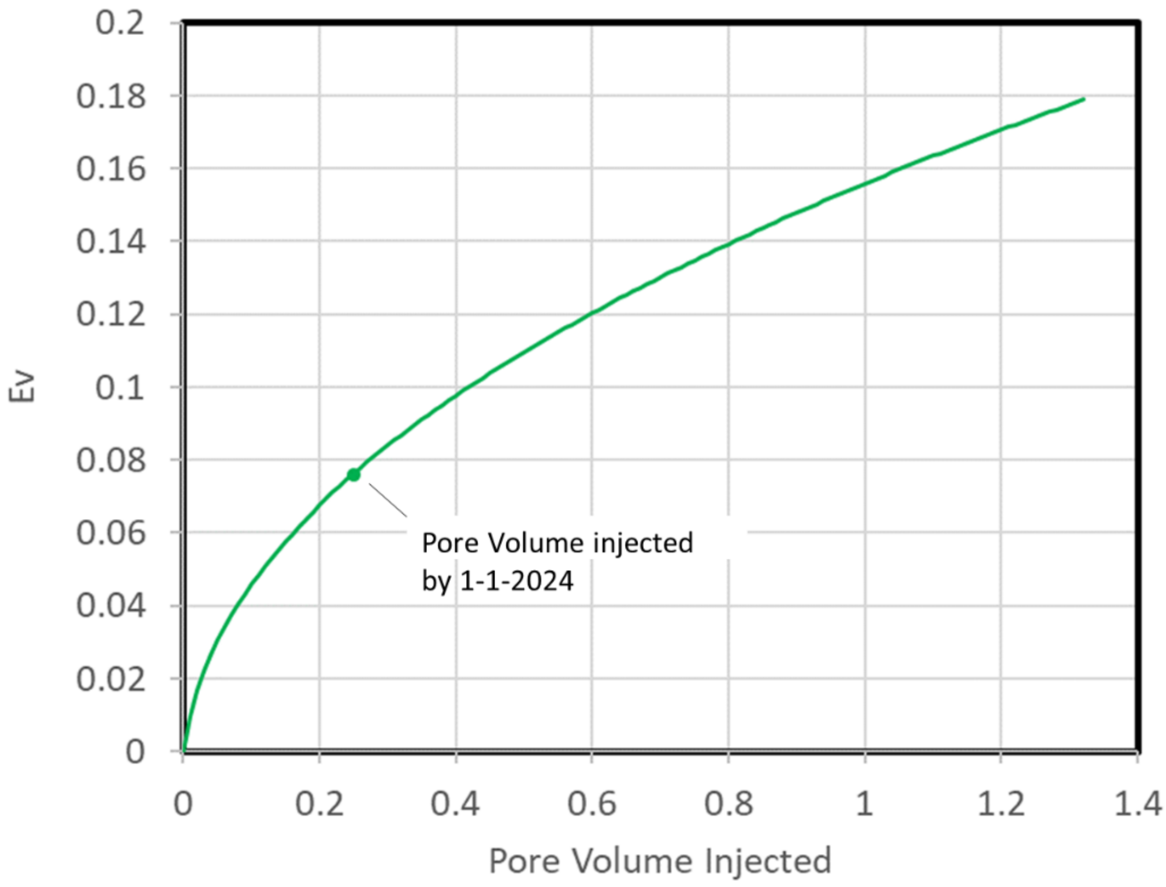


Figure 16: Recovery factor vs. CO_2 pore volume injected

2.4.4. CO_2-EOR Performance Projections

In this study, a modified Muskat model was used to calculate the pore volume available for CO_2 sequestration. This model accounts for the oil and gas PVT properties, as well as the relative permeability of the rock. A key uncertainty lies in the reservoir pressure. Actual reservoir pressure was not available and therefore was estimated using a pressure vs. time profile that offers a reasonable estimate of oil and gas production. The estimated gas saturation from the model is a critical factor, indicating the volume expected to be injectable into the reservoir. A linear pressure reduction is suggested during primary production, followed by an increase in pressure after waterflooding. Over the long term, the pressure begins to decline at a slow rate. The estimated rate is compared with actual production rates in **Figure 17**.

The primary aim of this analysis is to estimate oil production rates since September 1982, when the tertiary flood began through CO_2 injection. To determine the available volume for CO_2 storage, cumulative production rates were utilized. **Figure 18** presents a comparison of the predicted cumulative oil production with the actual cumulative oil production. As illustrated in **Figure 17** and **Figure 18**, the model demonstrates a reasonable accuracy in its predictions.

As the reservoir pressure fluctuates, both the formation volume factor (FVF) of the oil and the density of CO_2 change over time. Assuming a long-term reservoir temperature of 148 degrees F (the initial temperature of the field prior to CO_2 injection) and the current estimated pressure of 2,100 psia, the density of CO_2 is estimated to be 34.1 lbs/ft^3 (**Figure 19**). It is essential to recognize that CO_2 density is highly sensitive to pressure; for instance, a reduction in pressure to 1,800 psi would result in an approximate 20% decrease in density. Although a decline in pressure over the long term is anticipated, the last pressure measurement was used for estimating these parameters due to a lack of recent pressure measurements.

In this analysis, the dissolution of CO_2 into the oil is not considered. It is important to note that as CO_2 primarily dissolves in the oil, the capacity for this volume will diminish over time as the oil volume decreases, unless there is a subsequent increase in reservoir pressure.

Given that the oil FVF is 1.31 rb/STB at a pressure of 2,100 psi, the available volume over time is plotted in **Figure 20**. The pressure of 2,100 psi is assumed from the expectation that it has declined by a few hundred psi from the last reported value of 2,400 psi (Fox et al., 1988), and it is further assumed that the pressure will be maintained through additional CO_2 injection in the coming years. Based on the analysis, should EOR be conducted for another 30 years, the volume potentially sequestered will reach 278 Bscf by 2054. To determine the injected CO_2 volume, the CO_2 density at standard conditions is 0.117 lbs/ft^3, resulting in a gas FVF of 0.00342 rcf/scf.

It should be noted that the reported cumulative oil production at the end of 1985 was approximately 84.5 million STB (Fox et al., 1988). To account for this discrepancy, the oil production volumes have been adjusted. The gap arises due to the lack of historical data prior to the acquisition of these wells by Daylight. In **Figure 20**, this gap is referred to as the "mismatch."

Knowing the CO_2 density (34.1 lbs/ft^3), the mass of CO_2 to be stored can be calculated. It is important to note that the key assumption is that the CO_2 will only replace the oil recovered, with no additional volume considered for CO_2 dissolution. Based on this calculation, if EOR is conducted for another 30 years, the potential mass of CO_2 to be sequestered by 2054 is estimated to be approximately 278 billion Bscf, or 14.7 MMT, assuming pure CO_2 is injected (**Figure 21**).

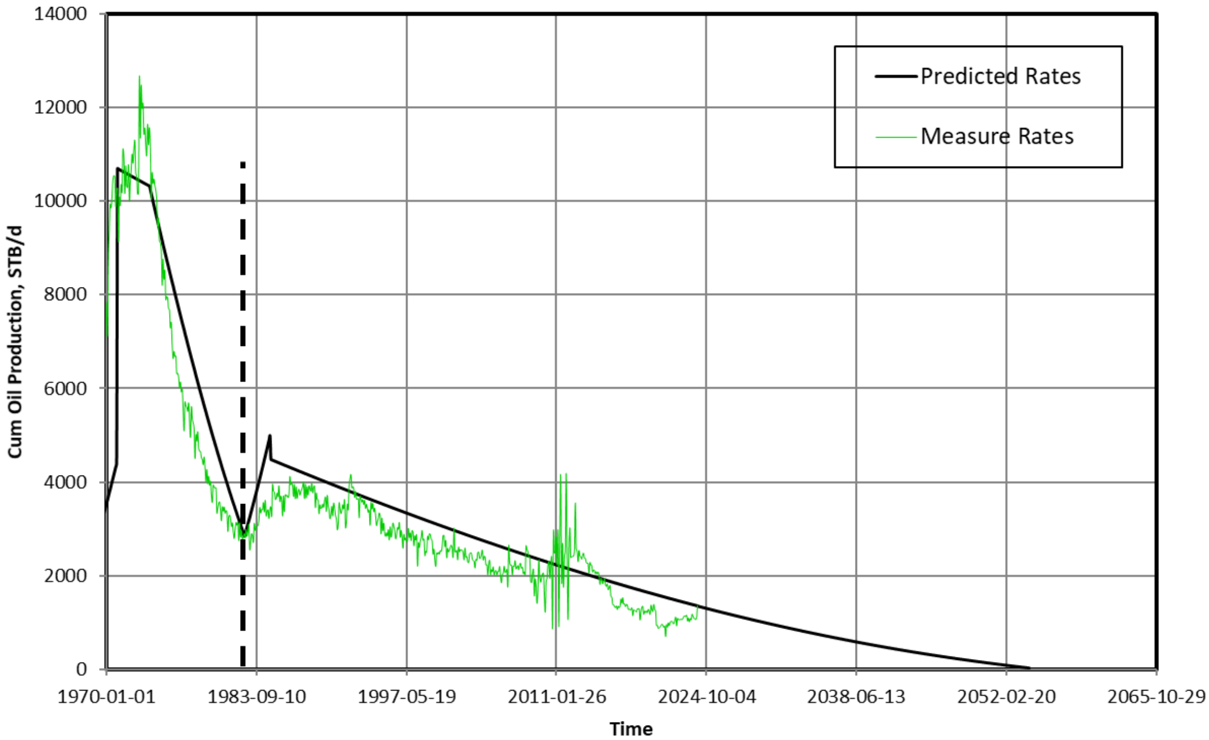


Figure 17: Oil rate-time curve comparison with actual estimations

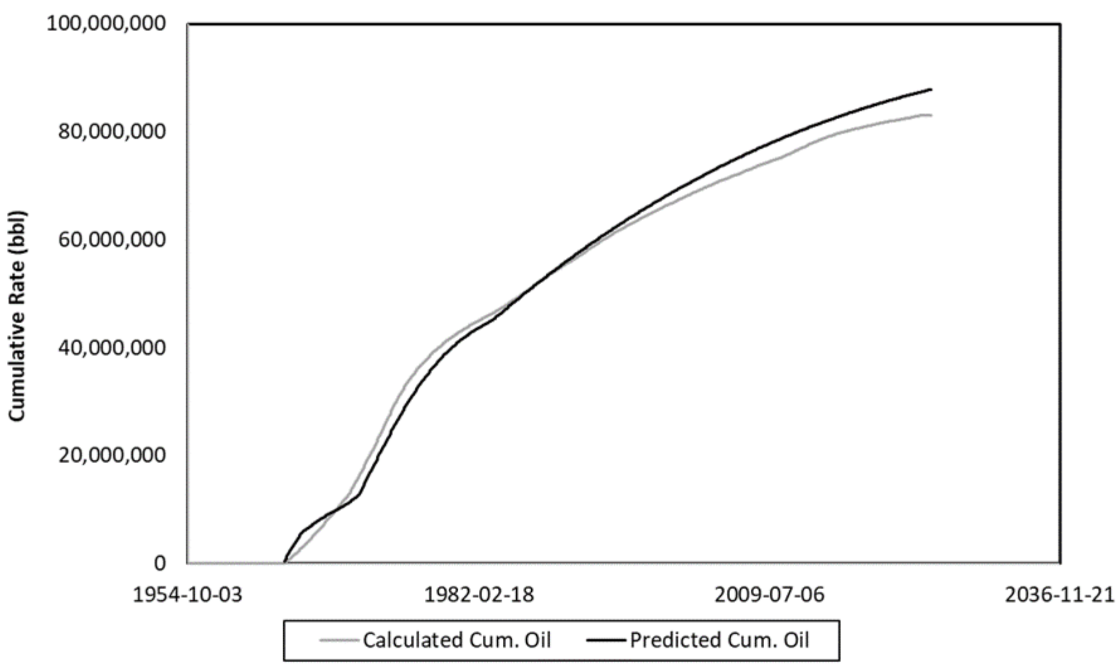


Figure 18: Comparison of the cumulative oil rates

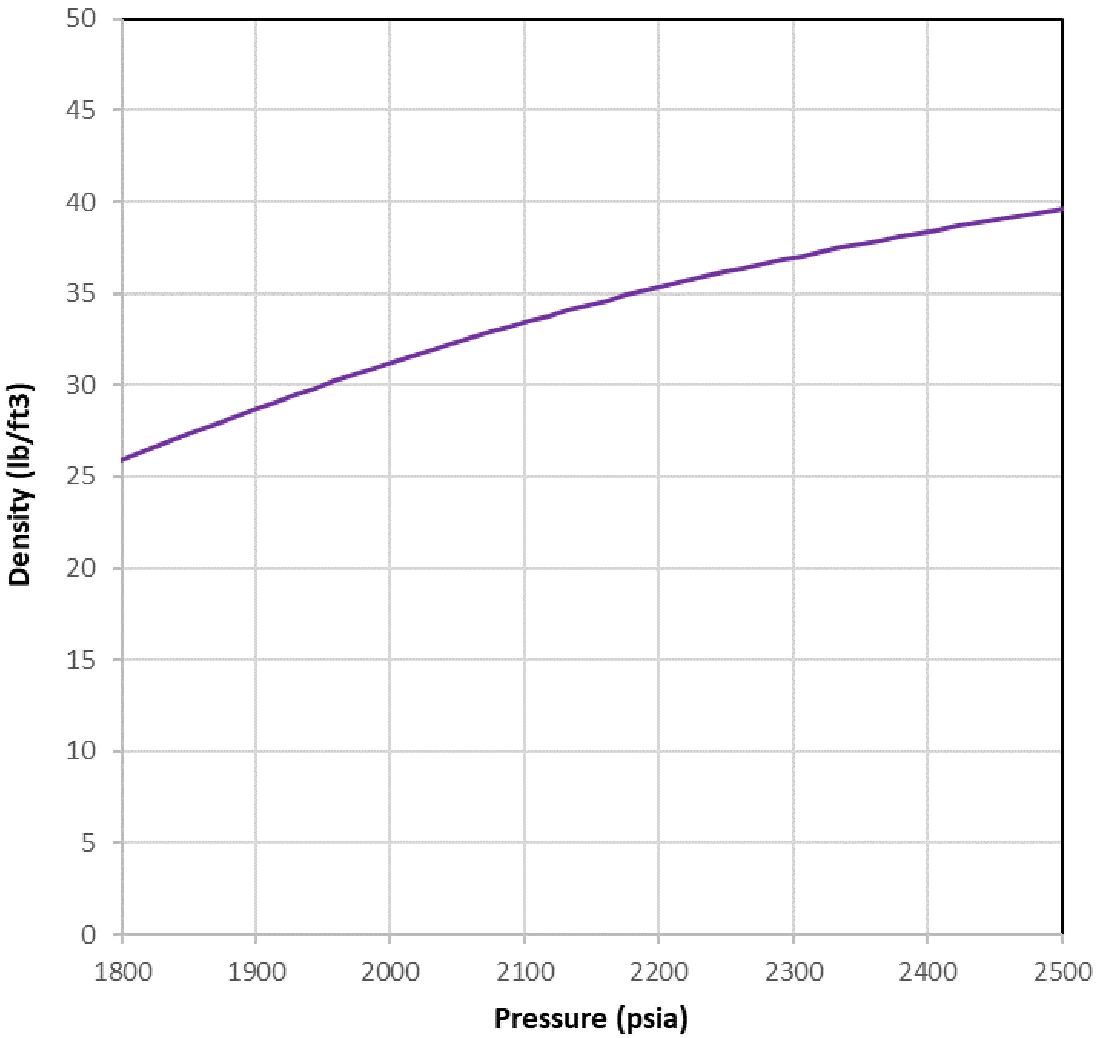


Figure 19: Variation of CO_2 density at 148 degrees F

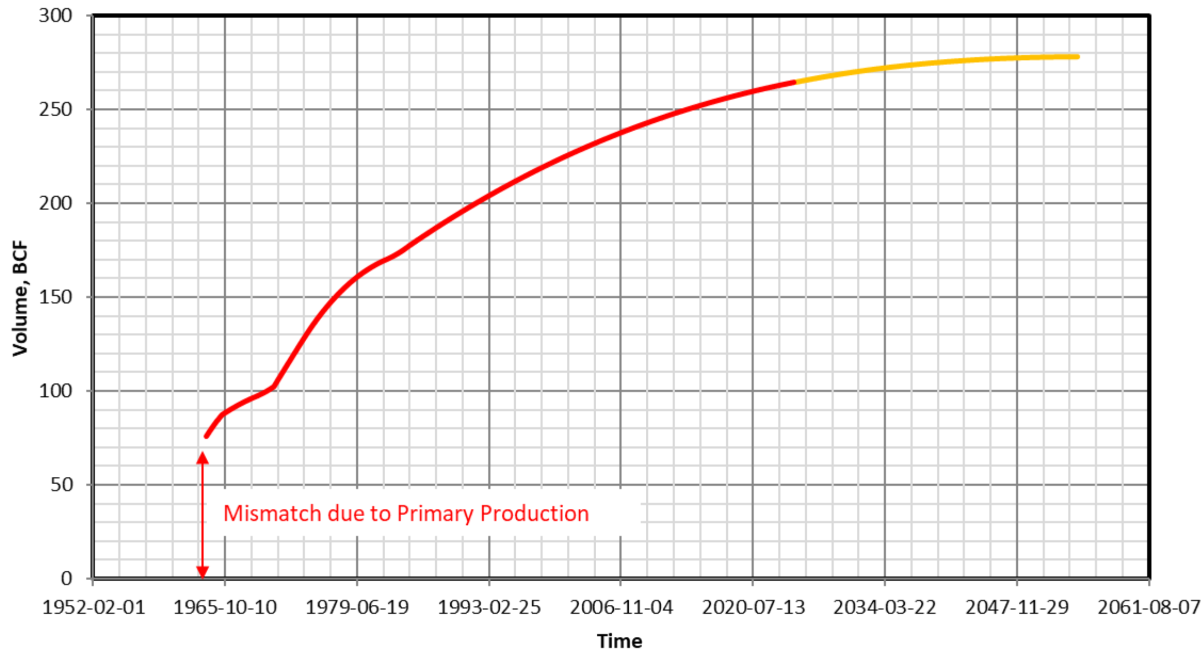


Figure 20: Predicted volume available for CO_2 injection

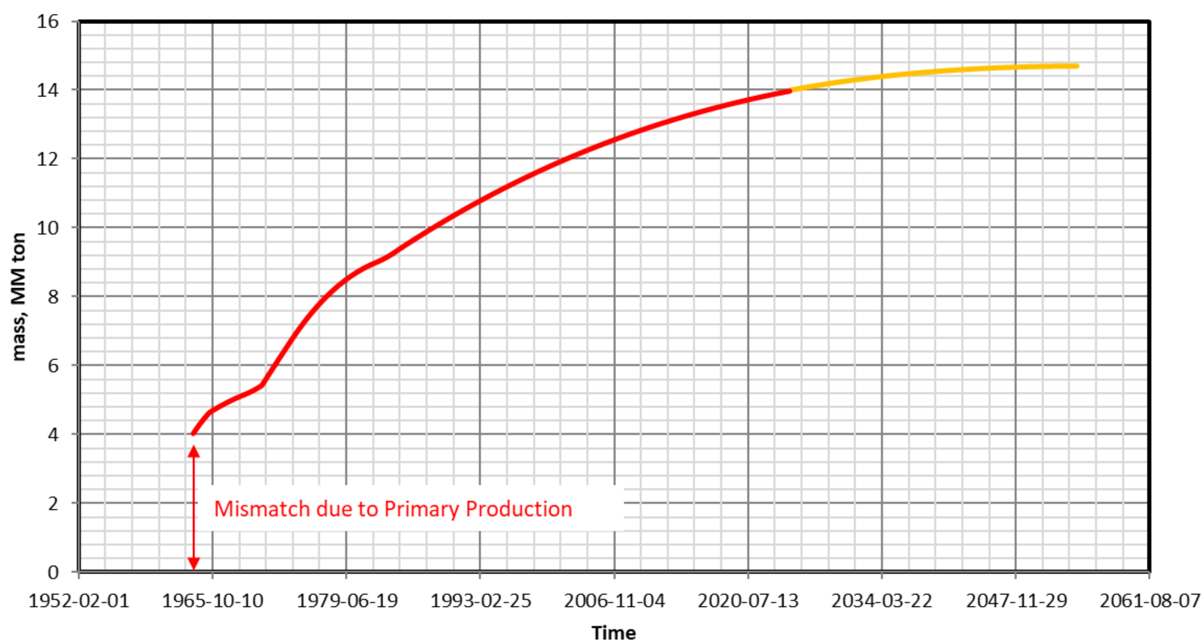


Figure 21: Predicted CO_2 storage in terms of mass

3.0. Delineation of Monitoring Area

3.1. Determination of CO_2 Storage Volumes

The estimated voidage space of 21 MMscf of CO_2 per acre of surface area, or a total of 278 Bscf CO_2, is assumed to be entirely contained within the Purdy-Bradley Springer Field (~13,200 acres).

3.2. Active Monitoring Area (AMA)

The AMA is defined by the combined boundaries of the NEPSU and SEBAU plus a buffer zone of at least one-half mile (**Figure 22**). The AMA is the area that Daylight will monitor over a specific time interval from the first year of the period (n) to the last year in the period (t). Consistent with the requirements in 40 CFR 98.449, the boundary is established by superimposing two areas:

1. The area projected to contain the free-phase CO_2 plume for the duration of the project (year t), plus an all-around buffer zone of one-half mile; and
2. The area projected to contain the free-phase CO_2 plume for at least 5 years after injection ceases (year t + 5).

Currently, Daylight's operations cover NEPSU and SEBAU in their entirety. The unit boundaries were defined during unitization based on the geologic boundaries and truncational limits of the Springer reservoir. Successful containment of free-phase CO_2 within these boundaries has been demonstrated and confirmed during 43 years of CO_2 flooding in NEPSU and 28 years of CO_2 flooding in SEBAU. Furthermore, the estimated voidage space of 278 Bscf is entirely contained within the unit boundaries and will not be exceeded by CO_2 injection volumes. Therefore, Daylight expects the free-phase CO_2 to remain within these boundaries for the duration of the project (t = Year 2054) and at least 5 years thereafter, as required for the AMA by 40 CFR 98.449.

Any additional CO_2 injection wells will be permitted under the UIC program and will be included in the annual submittal per 40 CFR 98.446(f)(13).

3.2.1. Determination of Buffer Zone

The buffer zone of a minimum of one-half mile is required by Subpart RR. No known leakage pathways extend laterally more than one-half mile.

3.3. Maximum Monitoring Area (MMA)

As defined in Subpart RR, the MMA is equal to or greater than the area expected to contain the free-phase CO_2 until the CO_2 has stabilized, plus an all-around buffer zone of at least one-half mile. The MMA is defined as equivalent to the AMA, and Daylight will continuously monitor the entire MMA for the purposes of this MRV.

The free-phase CO_2 is currently contained and will continue to be contained by the geologic limits of the Springer reservoir, which are the truncation limits of the reservoir as defined by well control obtained through the full field delineation and development of NEPSU and SEBAU since their discovery in 1951. These geologic boundaries serve as an impermeable seal as demonstrated by the initial trapping and accumulation of hydrocarbons (oil and gas cap) resulting in the formation of the field and confirmed by active monitoring of the ongoing CO_2 flood as described in **Section 4**.

After 43 years of CO_2 flooding in NEPSU and 28 years of CO_2 flooding in SEBAU, the free-phase CO_2

plume extent has spread throughout most of both units and is successfully contained by the geologic limits of the reservoir, as demonstrated by Daylight's current monitoring practices, which include production, injection, and pressure monitoring. Therefore, Daylight expects the extent of the free-phase CO_2 plume will continue to be contained by and stabilized within the geologic limits of the reservoir, since it has a proven impermeable seal and the amount of CO_2 injected will not exceed the reservoir's secure storage capacity of 278 Bscf. As such, there is no difference in the expected free-phase CO_2 plume extent between year t and year t + 5. Furthermore, the CO_2 plume extent is expected to remain stable once this facility discontinues injection operations based on historical monitoring trends.

Stabilization of the CO_2 plume will continue to be monitored and reported until the criteria outlined in **Section 4.11** have been met.

4.0. Identification and Evaluation of Leakage Pathways

Since its discovery in 1951, the unitization of the NEPSU (1959) and SEBAU (1956), and the initiation of CO_2-EOR in 1982 (NEPSU) and 1997 (SEBAU), the Purdy-Bradley Springer Field has been extensively investigated and documented. Based on this history, Daylight has identified the following potential pathways of CO_2 leakage to the surface. This section also addresses detection, verification, and quantification of leakage from each pathway.

4.1. Leakage from Surface Equipment

The surface equipment and pipelines utilize materials of construction and control processes that are standard in the oil and gas industry for CO_2-EOR projects. Ongoing field surveillance of pipelines, wellheads, and other surface equipment is conducted by personnel instructed on how to detect surface leaks and other equipment failure, thereby minimizing the potential for and impact of any leakage. Surface equipment leaks have a low risk of occurring based on design standards. In addition, under OCC rules, operators must take prompt action to eliminate leakage hazards and to conduct inspections or repairs. Operating and maintenance practices currently follow and will continue to follow industry standards. As described in **Section 6.4**, should leakage from surface equipment occur, it will be quantified according to procedures required by the GHGRP.

4.2. Leakage from Wells

As of January 2025, Daylight identified 23 active CO_2 injection wells and 36 active production wells in the SEBAU; 69 active CO_2 injection wells and 88 active production wells in the NEPSU; and approximately 886 total wellbore penetrations within the AMA. These are listed in **Appendix 1**.

Regulations governing wells in the NEPSU and SEBAU require that wells be completed and operated so that fluids are contained in the strata in which they are encountered and that well operations do not pollute subsurface and surface waters. The regulations establish the requirements with which all wells must comply, whether they are injection, production, or disposal wells. Depending on the purpose of the well, regulatory requirements can impose additional standards for evaluation of an AoR. CO_2 injection well permits are authorized only after an application, notice, and opportunity for a hearing. As part of the permit application process, Daylight evaluates an AoR that includes wells within the unit and one-quarter mile from the set of wells considered in that AoR. Pursuant to USEPA and OCC regulations, all wells within the AoR that have penetrated the injection interval are located and evaluated.

Figure 22 shows all wells in the AMA/MMA. The OCC utilizes a risk-based data management system and can only guarantee well data since 1980. The wells listed in **Appendix 1** and shown in **Figure 22** were compiled from S&P Global in an effort to provide a more complete well list.

In addition, approximately 85 shallow groundwater wells are in the AMA/MMA, per the Oklahoma Water Resources Board General Viewer. The deepest well is 360 feet, ~8,000 feet above the reservoir. Therefore, the likelihood of leakage via shallow groundwater wells is low. Daylight will test a groundwater well within the AMA on an annual basis to provide additional monitoring for potential leakage. Shallow groundwater wells are not included in **Figure 22** and **Appendix 1**.

4.2.1. Abandoned Wells

Figure 22 shows abandoned wells in the AMA/MMA. Owing to past and future AoR evaluations and a lack of historical leakage, Daylight concludes that leakage of CO_2 to the surface through abandoned wells is unlikely but cannot be ruled out. Strategies for leak detection are in place as discussed in **Section 4.8**, and the strategy to quantify any leaks is discussed in **Section 4.10**.

4.2.2. Injection Wells

Figure 22 shows the injection wells in the AMA/MMA. MIT is an essential requirement of the UIC program in demonstrating that injection wells do not act as conduits for leakage into USDWs and to the surface environment. Under OAC Title 165 Chapter 10, a pressure or monitoring test must be performed on new and existing injection wells and disposal wells. Information must be submitted on Form 1075 and witnessed by a field inspector when required. MIT and other rules documented in OAC Title 165 Chapter 10 ensure that active injection wells operate to be protective of subsurface and surface resources and the environment. Owing to past and future expectations of adhering to these rules, Daylight concludes that leakage of CO_2 to the surface through active injection wells is unlikely.

4.2.3. Production Wells

Figure 22 shows the active production wells in the AMA/MMA. As the project matures, production wells may be added and will be constructed according to the rules of the State of Oklahoma. Additionally, inactive wells may become active according to the rules of the State of Oklahoma.

During production, fluids including oil, gas, and water flow from the reservoir into the wellbore. This flow is caused by a differential pressure, where the bottom hole wellbore pressure is less than the reservoir pressure. These lower-pressure fluids are contained by the casing, tubing, wellhead, and flowline all the way to the batteries and production/separation facilities. Daylight concludes that leakage of CO_2 to the surface through production wells is unlikely.

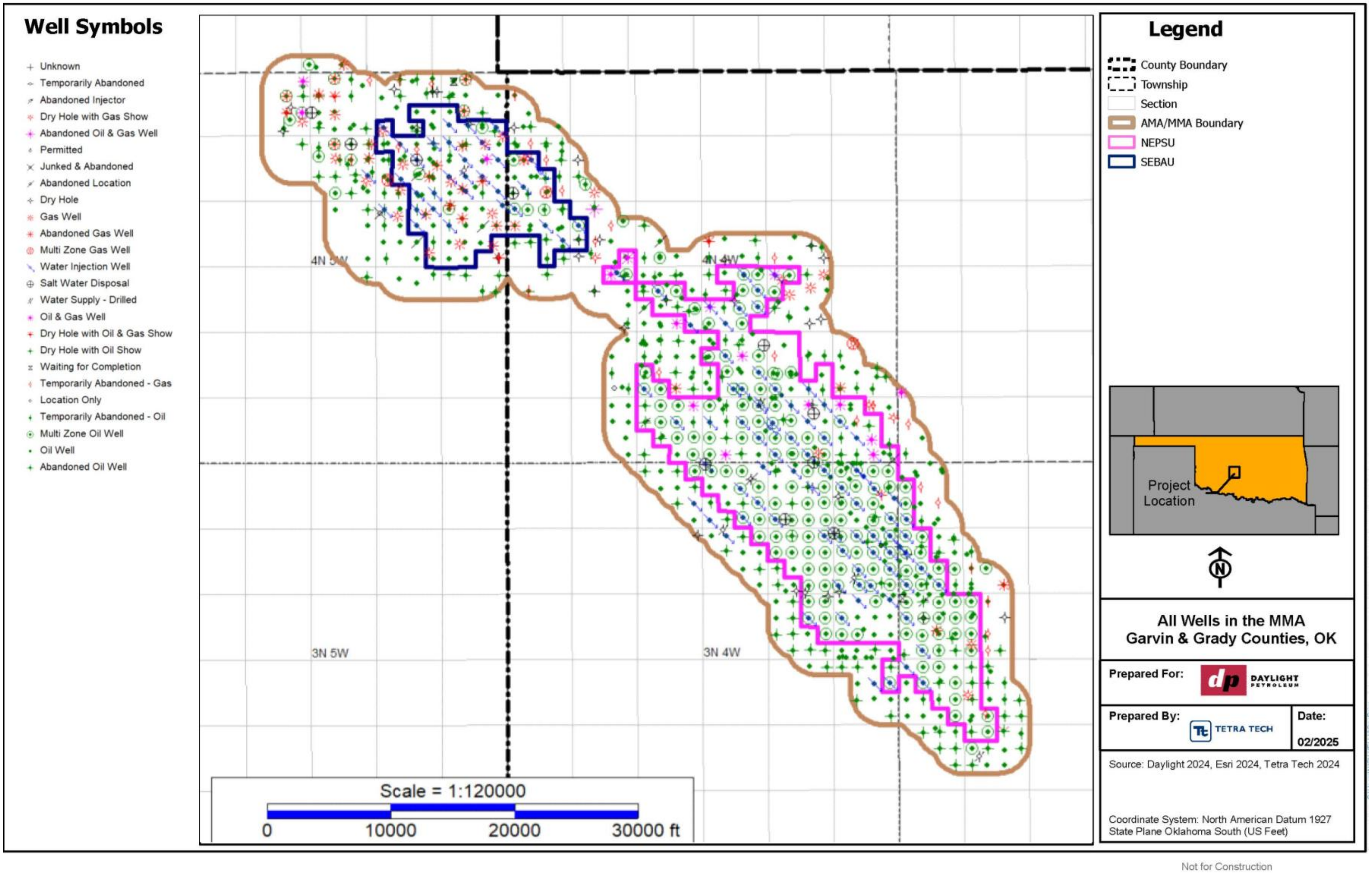


Figure 22: Location and type of all wells within the Active Monitoring Area (AMA). The Maximum Monitoring Area (MMA) is equivalent to the AMA.

4.2.4. *Inactive Wells*

Inactive wells that have been temporarily abandoned typically have a cast iron bridge plug or other isolation mechanism set above the existing perforations to isolate the reservoir from the surface. The wellhead pressures are then checked per operation schedule for any change. Given the regular monitoring of and procedures for securing inactive wells, it is unlikely that any leakage event would result in a significant magnitude or duration of CO_2 loss.

4.2.5. *New Wells*

As the project develops, new production wells and injection wells may be added to the NEPSU and SEBAU. All wells in Oklahoma oilfields, including injection and production wells, are regulated by the OCC, which has primacy to implement the Class II UIC programs. Rules govern well siting, construction, operation, maintenance, and closure for all wells in oilfields. All new wells will be constructed according to the relevant rules for the OCC which ensure protection of subsurface and surface resources and the environment. This will significantly limit any potential leakage from well pathways; however, leakage during drilling of a new well through the CO_2 flood interval cannot be ruled out.

In the event a non-operated well is drilled within the AMA, the operator would be required to follow all OCC rules and procedures in drilling the well and the potential for leakage would be similar to that of any well Daylight drills within the AMA. In addition, Daylight's visual inspection process during routine field operation will identify any unapproved drilling activity in the NEPSU and SEBAU.

4.3. Leakage from Faults, Fractures, and Bedding Plane Partings

Primary seals at the NEPSU and SEBAU have been demonstrated to be mechanically competent despite the presence of faults in and around the field (see also **Section 2.2.2**). The following lines of analysis have been used to assess this risk in the area.

4.3.1. *Presence of Hydrocarbons*

The primary evidence that leakage does not occur along faults, fractures, and bedding plane partings is the ~330 MMB of oil estimated to be originally in place in the NEPSU and SEBAU. If significant escape pathways existed, oil would have drained from the reservoir prior to the present day.

4.3.2. *Fracture Analysis*

Despite the presence of faulting in the area, conventional core samples taken from the Springer showed little evidence of fracturing (Oxy, 1988). In the event CO_2 leakage occurs through faults and fractures, it is unlikely that the leak would result in surface leakage, as these features are not known to extend from the reservoir to the surface. Daylight has strategies for leak detection in place that are discussed in **Section 4.8,** and the strategy to quantify leaks is discussed in **Section 4.10**.

4.4. Lateral Fluid Movement

The Springerean strata in Oklahoma represent primarily a deltaic to coastal island set of depositional systems that prograded toward the southeast, resulting in deposition of shales and lenticular, discontinuous coarse sandstones separated by very fine sandstone, minor conglomerates, and shale. The likelihood of extensive migration of fluid outside of the MMA is considered low.

Since CO_2 is lighter than the water and oil remaining in the reservoir, it will tend to migrate to the top of the reservoir. The producing wells create low pressure points in the field, draining water and oil while keeping some CO_2 within each discontinuous sandstone. It is estimated that the total mass of stored CO_2 will be considerably less than the calculated storage capacity and once production operations cease, very small lateral movement will occur.

4.5. Leakage through Confining/Seal System

The results of gas sampling analysis from wells producing from the Cunningham Sandstone and the shallower Hart Sandstone (i.e., the next overlying reservoir) show that CO_2 does not move vertically through the confining strata. Baseline testing of the Cunningham prior to CO_2 injection showed a 0.6% molar concentration of CO_2 (Fox et al., 1988). In October 2023, Daylight's testing of more than 50 wells producing from the Hart reservoir showed an average of 0.25% molar concentration of CO_2 in the gas stream. These results confirm that the sealing units above the Cunningham prevent upward migration of CO_2 out of the reservoir.

In the unlikely event of CO_2 leakage through the confining seal, there is a very low risk of surface leakage, since the reservoir is at depths of ~8,200-10,900 feet and is overlain by >1,200 feet of impermeable shale net thickness. As with any CO_2 leakage, Daylight has strategies for leak detection in place that are discussed in **Section 4.8** and the strategy to quantify the leak is discussed in **Section 4.10**.

4.6. Natural and Induced Seismic Activity

Figure 23 shows the locations of earthquakes with magnitudes of 2.5 or greater that have occurred within 2 miles of the MMA (data obtained from the United States Geological Survey [USGS] Earthquakes Hazard Program catalog [https://earthquake.usgs.gov/earthquakes/search/], accessed 1/30/2025). Details of these earthquakes are provided in **Table 2**. The Purdy-Bradley Springer Field is located in a seismically active region, and all but one of the mapped earthquakes occurred since the initiation of CO_2 injection in 1982. However, there is no evidence that proximal or distal earthquakes have caused a disruption in injectivity, CO_2 leakage, or damage to any of the wellbores in the Purdy-Bradley Springer Field.

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

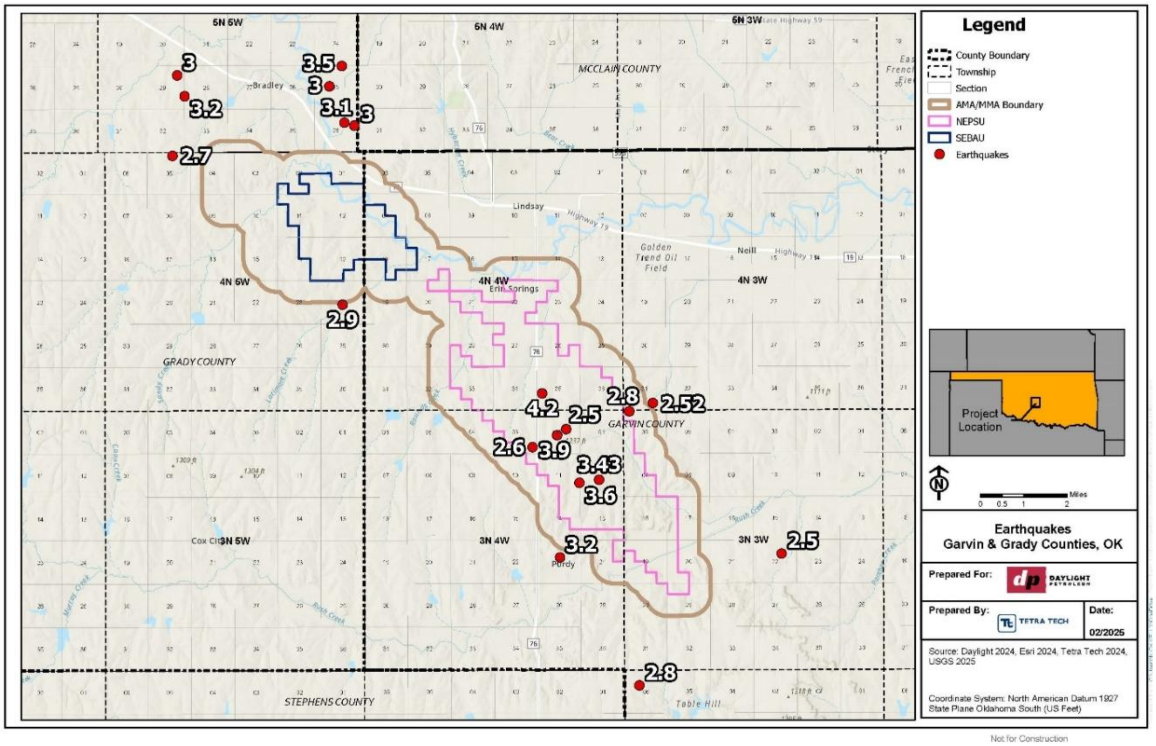


Figure 23: Earthquakes (2.5 magnitude or greater) within 2 miles of the MMA

Table 2: Details of earthquakes within the MMA

Earthquake Date	Magnitude	Location and Depth
1981-07-11	3.5	34.884°N 97.677°W – 5.0 km
1990-11-15	3.9	34.760°N 97.590°W – 5.0 km
1992-12-16	2.6	34.756°N 97.600°W – 5.0 km
1992-12-17	3.6	34.744°N 97.581°W – 5.0 km
1994-07-04	2.8	34.676°N 97.557°W – 5.0 km
1995-01-18	4.2	34.774°N 97.596°W – 5.0 km
1997-03-11	2.5	34.720°N 97.499°W – 5.0 km
1998-07-07	3.2	34.719°N 97.589°W – 5.0 km
2004-04-22	2.9	34.804°N 97.677°W – 5.0 km
2004-11-22	3.0	34.864°N 97.672°W – 5.0 km
2010-06-14	3.1	34.865°N 97.676°W – 5.0 km
2010-10-25	3.2	34.874°N 97.741°W – 5.0 km
2011-03-16	2.7	34.854°N 97.746°W – 5.0 km
2011-08-18	3.0	34.881°N 97.744°W – 5.0 km
2017-11-21	3.0	34.877°N 97.682°W – 2.4 km
2019-05-11	2.8	34.768°N 97.561°W – 5.0 km
2019-05-11	2.5	34.762°N 97.586°W – 5.0 km
2020-09-06	3.4	34.745°N 97.573°W – 7.0 km
2021-12-20	2.5	34.771°N 97.551°W – 6.5 km

4.7. Likelihood, Timing, and Magnitude of Potential Surface Leakage

Table 3 summarizes Daylight's assessment of the likelihood, timing, and magnitude of surface leakage through the potential leakage pathways identified in this section.

Table 3: Assessment of Likelihood, Magnitude, and Timing of Potential Leakage Pathways

Potential Leakage Pathway	Likelihood	Magnitude[1]	Timing
Surface Equipment	Unlikely but possible	Variable – Small or easily detected failure could result in low- to medium-magnitude CO_2 release, while a catastrophic failure could result in medium- to high-magnitude CO_2 release	During injection period
Shallow Groundwater Wells	Unlikely	Low – Monitoring should minimize any release of CO_2	During injection and post-injection periods
Other Wells	Unlikely but possible	Low – Monitoring / surveillance and well construction requirements should minimize any release of CO_2	During injection and post-injection periods
Faults, Fractures, and Bedding Plane Partings	Unlikely	Low	During injection and post-injection periods
Lateral Fluid Movement	Unlikely	Low	During injection and post-injection periods
Confining Seal / System	Unlikely	Low	During injection and post-injection periods
Natural and Induced Seismic Activity	Unlikely	Low	During injection and post-injection periods

[1] Magnitude assessed as follows:

Low – minimal risk to safety, health and environment, or USDW
Medium – moderate risk to safety, health and environment, or USDW, but easily remediated
High – extreme risk to safety, health and environment, or USDW, and difficult and/or costly to remediate.

4.8. Strategy for Detection of CO_2 Loss

Daylight intends to use the results of daily monitoring of field conditions, operational data (including automatic data systems), routine testing, and maintenance information to monitor for surface leakage and to identify and investigate deviations from expected performance that could indicate CO_2 leakage. In the event any of those results indicate a CO_2 leak may have occurred, the event will be documented and an estimate will be made of the amount of CO_2 leaked. The event and estimate will be included in the annual Subpart RR reporting. Records of each event will be kept on file for a minimum of 3 years. The methods that Daylight intends to use in this strategy include the following:

4.8.1. Data System

Daylight uses onsite management and a Supervisory Control and Data Acquisition (SCADA) system to conduct its CO_2-EOR operations. Daylight uses data from these efforts to identify and investigate variances from expected performance that could indicate CO_2 leakage. Some CO_2 meters are installed with SCADA systems that transmit data from the meters automatically into a data warehouse. Those data, as well as other operational data collected manually, are also used for operational management and controls.

4.8.2. Visual Inspections

Daylight's field personnel conduct routine weekly or daily inspections of the facilities, wells, and other equipment (such as vessels, piping, and valves). These visual inspections provide an opportunity to identify issues early and to address them proactively, which may preclude leaks from happening and/or minimize any CO_2 leakage. Any visual identification of CO_2 vapor emission or ice formation will be reported and documented, and a plan will be developed and executed to correct the issue.

4.8.3. Injection Target Rates and Pressures

Daylight manages its CO_2-EOR operations by developing and implementing target injection rates and pressures for each CO_2 injection well. These target rates and pressures are developed based on various parameters such as historic and ongoing pattern development, WAG operations, CO_2 availability, field performance, and permit conditions. Field personnel implement the WAG schedule by manually making choke adjustments at each injection well, allowing for a physical inspection of the injection well during each adjustment. Generally on a daily basis, injection rates for each CO_2 injection well are reported and compared to the target rates. Injection pressures and casing pressures are monitored on each CO_2 injection well. Injection rates or pressures falling outside of the target rates or pressures to a statistically significant degree are screened to determine whether they could lead to CO_2 leakage to the surface. If that screening or investigation identifies any indication of a CO_2 leakage to the surface in this manner, it will be reported and documented, and a plan will be developed and executed to correct the issue.

4.8.4. Production Wells

Daylight forecasts the amount of fluids (e.g. oil, water, CO_2) that is likely to be produced from each production well at the unit level in the NEPSU and SEBAU over various periods of time. Evaluation of these produced volumes, along with other data, informs operational decisions regarding management of the CO_2-EOR project and aid in identifying possible issues that may involve CO_2 leakage. These evaluations can direct engineering and/or operational personnel to investigate further. If an investigation identifies that a CO_2 leak has occurred, it will be reported and documented, and a plan will be developed and executed to correct the issue.

4.8.5. Plant and Pipeline Monitoring

Daylight currently operates the CO_2-related infrastructure used to operate the units, including the associated on-site CO_2 capture, compression, and dehydration facility. The facility includes a monitoring program that monitors the rates and pressures at the facility and on the pipeline on a continuous basis. High and low set points are established in the program, and operators at the plant, pipeline and/or the units are alerted if a parameter is outside the allowable window. If the flagged parameter is the delivery point on the pipeline, but no other parameter at the plant or pipeline is flagged, then the field personnel are alerted so that further investigation can be conducted in the field to determine if the issue poses a leak threat.

4.8.6. Well Testing

Injection wells are leak-tested via MIT as required by the USEPA or OCC. This consists of regular monitoring of the tubing-casing annular pressure and conducting a test that pressures up the well and wellhead to verify the well and wellhead can hold the appropriate amount of pressure. Sometimes, in addition to or in lieu of MIT, Daylight is required to perform a RTS to ensure that all injection fluids are going into the injection zone. Daylight personnel monitor the pressure and conduct the tests in accordance with regulations and permit requirements. In the event of a loss of mechanical integrity, the subject injection well is immediately shut in and an investigation is initiated to determine what caused the loss of mechanical integrity. If investigation of an event identifies that a CO_2 leak has occurred, it will be reported and documented, and a plan will be developed and executed to correct the issue.

4.9. Strategy for Response to CO_2 Loss

As discussed above, the potential sources of leakage include routine issues, such as problems with surface equipment (e.g., pumps, valves), wellbores or subsurface equipment, and unique and unlikely events such as induced fractures. **Table 4** summarizes some of these potential leakage scenarios, the monitoring activities designed to detect those leaks, Daylight's standard response, and other applicable regulatory programs requiring similar reporting.

The potential CO_2 losses discussed in the table are identified by type. If there is a report or indication of a CO_2 leak, such as from a visual inspection, monitor, or pressure drop, a Daylight employee or supervisor will be dispatched to investigate. Emergency shutdown systems will be utilized as necessary to isolate the leak. If the leak cannot be located without movement of equipment or other substantial work, further involvement of Daylight personnel or management will be involved to determine how the leak will be located. Once the leak is located and isolated, pressure from the system will be relieved so that further investigation of the leak area can be performed and repair work can be estimated and ultimately performed.

Table 4: Response Plan for CO_2 Loss

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

4.10. Strategy for Quantifying CO_2 Loss

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

In the event leakage occurs, Daylight will determine the most appropriate method for quantifying the volume leaked and will report the methodology used as required as part of the annual Subpart RR submission. Leakage estimating methods may potentially consist of modeling or engineering estimates based on operating conditions at the time of the leak, such as temperatures, pressures, volumes, and hole size. An example methodology would be to place a flux box or ring tent over the surface leak to measure the flow rate and gather gas samples for analysis. The volume of CO_2 in the soil can also be used with this technique. Any volume of CO_2 detected leaking to the surface will be quantified using acceptable emission factors such as those found in 40 CFR Part 98 Subpart W or engineering estimates of leak amounts based on measurements in the subsurface, Daylight's field experience, and other factors such as the frequency of inspection. Records of leakage events will be retained in Daylight's electronic documentation and reporting system, which consists of reports stored on servers, with certain details uploaded into third-party software.

4.11. Demonstration at End of Specified Period

At the end of EOR injection operations, Daylight intends to cease injecting CO_2 for the purpose of establishing long-term storage of CO_2 in the units. At that time, Daylight anticipates submitting a request to discontinue monitoring and reporting, including a demonstration that the amount of CO_2 reported under Subpart RR is not expected to migrate in the future in a manner likely to result in surface leakage. Daylight will support its request with data collected during operations as well as 1-3 years of data (or more, if needed) collected after the end of operations. Daylight expects this demonstration will provide the information necessary for the USEPA to approve the request to discontinue monitoring and reporting. This demonstration may include but is not limited to:

- An assessment of CO_2 injection data for the units, including the total volume of CO_2 injected and stored as well as actual surface injection pressures;
- An assessment of any CO_2 leakage detected, including discussion of the estimated amount of CO_2 leaked and the distribution of emissions by leakage pathway; and
- An assessment of reservoir pressure in the units that demonstrates that the reservoir pressure is stable enough to demonstrate that the injected CO_2 is not expected to migrate in a manner to create a potential leakage pathway.

5.0. Strategy for Determining CO_2 Baselines for CO_2 Monitoring

Daylight may elect to collect additional atmospheric test data using ambient air detectors or other methodologies to characterize baseline values in the units. Ongoing operational monitoring of well pressures and rates has provided data for establishing baselines and will be utilized to identify and investigate excursions from expected performance that could indicate CO_2 leakage. Data systems are used primarily for operational control and monitoring and as such are set to capture more information than is necessary for reporting in the annual Subpart RR report. Each of these is discussed in more detail below.

5.1. Site Characterization and Monitoring

As described in **Section 2.2.2** and **Section 2.4**, the Cunningham Sandstone is isolated by impermeable shale units of the upper Springer, Morrow, and/or Atoka reaching thicknesses of 150-200 feet. These units provide a suitable primary seal to prevent the migration of CO_2 out of the injection reservoir, and additional shale layers above the primary seal provide secondary confinement with a total net shale thickness >1,200 feet. As discussed in **Section 4.5**, testing of the Springer prior to CO_2 injection showed a 0.6% molar concentration of CO_2 (Fox et al., 1988). In October 2023, Daylight's testing of more than 50 wells producing from the Hart reservoir showed an average of 0.25% molar concentration of CO_2 in the gas stream. Furthermore, a review of gas sample data published in Higley (2014) shows the range of natural CO_2 concentration in the Central Anadarko Basin is 0.00-10.9 mole percent (average, 1.73 mole percent). These field- and basin-scale data will be considered in the determination of CO_2 baseline values should a potential leak be detected.

Additionally, no significant faults or fracture zones that compromise the sealing capacity of the confining shales have been identified in the Purdy-Bradley Springer Field, indicating that the most likely leakage pathway is from legacy wellbores that have been poorly completed/cemented. After ~42 years of tertiary oil recovery operations, no significant wellbore leaks are known to have occurred, and therefore Daylight concludes that wellbore leaks are unlikely to happen.

5.2. Groundwater Monitoring

Daylight obtains and tests water samples from shallow groundwater wells during the preparation of permit applications for new Class II UIC EOR injection wells. Daylight has not monitored USDW wells for CO_2 or brine contamination, as characterization of the Springer suggests that risk of groundwater contamination from CO_2 leakage from the reservoir is minimal. While groundwater contamination is unlikely to happen, any change in groundwater that is brought to the attention of Daylight will be investigated to eliminate the potential leakage pathway.

5.3. Soil CO_2 Monitoring

Daylight does not intend to collect background soil gas data. Should a possible leakage event be detected, Daylight may elect to use vapor monitoring points installed into the shallow subsurface as part of the leakage verification and quantification process.

5.4. Visual Inspection

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

5.5. Well Surveillance

Daylight adheres to the requirements of OAC Title 165 Chapter 10 governing fluid injection into productive reservoirs. Title 165 includes requirements for monitoring, reporting, and testing of Class II UIC injection wells, including an initial MIT prior to injection operations and subsequent MIT at least once every year or every 5 years, depending on the permitted injection rate. Daylight will report any mechanical failure of the surface casing or cement to the appropriate regulatory authority in full compliance with all applicable legal and regulatory requirements.

5.6. Injection Well Rates, Pressures, and Volumes

Target injection rates and pressures for each injector are developed within the permitted limits based on the results of ongoing pattern surveillance. The field operations staff monitor equipment readings and investigate any departures from the permitted limits which could have resulted in a surface CO_2 leak.

6.0. Site-Specific Considerations for Determining the Mass of CO_2 Sequestered

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

6.1. Determining Mass of CO_2 Received

Daylight has the ability to receive CO_2 at its NEPSU and SEBAU facilities via its operated pipeline from Enid, Oklahoma. Daylight also recycles CO_2 from its production wells in NEPSU and SEBAU.

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

where:

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

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

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

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

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

p = Quarter of the year

r = Receiving flow meter

6.2. Determining Mass of CO_2 Injected

Daylight injects CO_2 into the injection wells listed in **Appendix 1**.

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

where:

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

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

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

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

p = Quarter of the year

u = Flow meter

To aggregate injection data, Daylight will sum the mass of all the CO_2 injected through each injection well listed in **Appendix 1** in accordance with the procedure specified in Equation RR-6:

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

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

6.3. Determining Mass of CO_2 Produced from Oil Wells

Daylight also recycles CO_2 from its EOR production wells in the NEPSU and SEBAU. Therefore, the following equation is relevant to its operations.

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

where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w

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

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

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

p = Quarter of the year

w = Separator

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

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

where:

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

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

X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction).

w = Separator

6.4. Determining Mass of CO_2 Emitted by Surface Leakage

If needed, Daylight will reference the potential quantification methods described in **Section 4.10** to determine the total mass of CO_2 emitted by all surface leakage pathways. Daylight will calculate the total annual mass of CO_2 emitted by surface leakage using Equation RR-10:

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

where:

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

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

x = Leakage pathway

6.5. Determining Mass of CO_2 Sequestered

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

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

where:

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

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

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

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

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

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

7.0. Estimated Schedule for Implementation of MRV Plan

Daylight expects to begin implementing this MRV Plan after approval, or tentatively in 2026. Data collection for Subpart RR reporting (calculating total amount sequestered according to Equation RR-11 of this subpart) is expected to begin in 2026 after the MRV Plan is approved and a supply of fresh CO_2 is secured. As such, this data collection would begin no later than 12/31/2026 for 2027 reporting.

8.0. GHG Monitoring and Quality Assurance Program

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

8.1. GHG Monitoring

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

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

8.1.1. General

Daylight follows industry-standard metering protocols for custody transfers, such as those standards for accuracy and calibration issued by the API, the American Gas Association (AGA), and the Gas Producers Association (GPA), as appropriate. This approach is consistent with 98.444(e)(3). Meters are maintained routinely, operated continually, and will feed data directly to the centralized data collection systems. CO_2 composition is governed by contract, and the CO_2 is routinely and periodically sampled to determine average composition. These custody meters provide an accurate method of measuring mass flow.

In addition to custody transfer meters, various process control meters are used in NEPSU and SEBAU to monitor and manage in-field activities, often on a real-time basis. These operations meters provide information used to make operational decisions but are not intended to provide the same level of accuracy as the custody-transfer meters. The level of precision and accuracy for operational meters currently satisfies the requirements for reporting in existing UIC permits. Although the process control meters are accurate for operational purposes, there is some variance between most commercial meters (on the order of 1-5%), which is additive across meters. This variance is due to differences in factory settings and meter calibration, as well as the operating conditions within the field. Meter elevation, changes in temperature, fluid composition (especially in multi-component or multi-phase streams), and pressure can affect readings of these operational meters.

Measurement of CO_2 Concentration – All measurements of CO_2 concentrations of any CO_2 quantity will be conducted according to an appropriate standard method published by a consensus-based standards organization or an industry standard practice such as those established by the GPA.

Measurement of CO_2 Volume – All measurements of CO_2 volumes will be converted to the following standard industry temperature and pressure conditions for use in Equations RR-2, RR-5, and RR-8 of Subpart RR of the GHGRP: Standard cubic meters at a temperature of 60 degrees F and at an absolute pressure of 1 atmosphere. Measurement devices will be compliant with AGA and API standards and can produce and export .cfx industry-standard files for either gas or liquid meter runs.

8.1.2. CO_2 Received

Fresh CO_2 (non-recycled) is received via a pipeline running from Enid, Oklahoma, and is measured with an orifice meter (recorded with a digital transducer). Information is sent to a flow computer (Fisher/Emerson ROC800) and is configured to calculate volumes. Data is stored temporarily to be pulled by the SCADA system. Daylight will bring in new sources of CO_2 in the future according to field development and operational needs.

8.1.3. CO_2 Injected

Daily CO_2 injection is recorded by combining the totals for the recycle compressor meter and the received CO_2 meter based on what is delivered on a 24-hour basis. These data are taken from the meter daily and stored according to Daylight's data management protocols.

8.1.4. CO_2 Produced

The point of produced gas measurement is from a meter downstream of the compressors prior to being combined with purchase CO_2. The produced gas is sampled and analyzed quarterly at the plant inlet, plant tailgate (north and south) and as needed at each satellite.

8.1.5. CO_2 Emissions from Equipment Leaks and Vented Emissions of CO_2

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

As required by 98.444 (d) of Subpart RR, Daylight will assess leakage from the relevant surface equipment listed in Sections 98.233 and 98.234 of Subpart W. According to 98.233(r)(2) of Subpart W, the emissions factor listed in Table W-1A of Subpart W shall be used to estimate all streams of gases, including recycle CO_2 stream, for facilities that conduct CO_2-EOR operations. The default emission factors for production equipment are applied to the carbon capture utilization and storage (CCUS) injection operations reporting under Subpart RR.

8.1.6. *Measurement Devices*

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

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

8.2. QA/QC Procedures

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

8.3. Estimating Missing Data

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

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

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

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

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

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

8.4. Revisions to the MRV plan

Daylight will revise the MRV Plan as necessary per 40 CFR 98.448(d).

9.0. Records Retention

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

(1) A list of all units, operations, processes, and activities for which GHG emissions were calculated. The data used to calculate the GHG emissions for each unit, operation, process, and activity. These data include:
   (i) The GHG emissions calculations and methods used.
   (ii) Analytical results for the development of site-specific emissions factors, if applicable.
   (iii) The results of all required analyses.
   (iv) Any facility operating data or process information used for the GHG emission calculations.

(2) The annual GHG reports.

(3) Missing data computations. For each missing data event, Daylight will retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(4) A copy of the most recent revision of this MRV Plan.

(5) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported.

(6) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported.

(7) Quarterly records of CO_2 received, including mass flow rate of contents of container (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(8) Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(9) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(10) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

(11) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(12) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

(13) Any other records as specified for retention in this USEPA-approved MRV plan.

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Appendix 1 – List of Wells

A list of all known wells in the MMA is provided in the attached PDF spreadsheet. Information was compiled from available S&P Global (formerly IHS) data. This information may differ from records available from the online OCC Well Data Finder as well as the archived documents database for well data, which may not include certain legacy well records. To ensure all wells within the MMA are accounted for, Daylight is providing the more extensive well record data provided by S&P Global that contains 886 unique wellbores within the MMA.

Appendix 2 – References

Regulatory Citations

Oklahoma Administrative Code Title 165 Chapter 10 (https://rules.ok.gov/code)

26 CFR 1.45Q (for table of contents, see https://www.ecfr.gov/current/title-26/section-1.45Q-0)

40 CFR Part 98 Subpart A (https://www.ecfr.gov/current/title-40/part-98/subpart-A)

40 CFR Part 98 Subpart W (https://www.ecfr.gov/current/title-40/part-98/subpart-W)

40 CFR Part 98 Subpart RR (https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98/subpart-RR)

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Appendix 3 – Abbreviations and Acronyms

AGA – American Gas Association

AMA – Active Monitoring Area

ANSI – American National Standards Institute

AoR – Area of Review

API – American Petroleum Institute

ASTM – American Society for Testing and Materials

Bscf – Billion Standard Cubic Feet

CCUS – Carbon Capture, Utilization, and Storage

CFR – Code of Federal Regulations

CO_2 – Carbon Dioxide

CO_2-EOR – Carbon Dioxide Enhanced Oil Recovery

cp – Centipoise

DPHI – Density Porosity

EOR – Enhanced Oil Recovery

EOS – Equation of State

F – Fahrenheit

ft^3 – Cubic Foot

FVF – Formation Volume Factor

GERG – European Gas Research Group

GHG – Greenhouse Gas

GHGRP – Greenhouse Gas Reporting Program

GPA – Gas Producers Association

GR – Gamma Ray

HCPV – Hydrocarbon Pore Volume

lbs – Pounds

m^3 – Cubic Meter

Mcf – Thousand cubic feet

mD – Millidarcies

MIT – Mechanical Integrity Test (or Testing)

MMA – Maximum Monitoring Area

MMB – Million Barrels

MMP – Minimum Miscibility Pressure

MMscf – Million Standard Cubic Feet

MMSTB – Million Stock Tank Barrels

MMT – Million Metric Tons

MRV – Monitoring, Reporting, and Verification

MT – Metric Ton

NAESB – North American Energy Standards Board

NGL – Natural Gas Liquids

NIST – National Institute of Standards and Technology

NPHI – Neutron Porosity

OAC – Oklahoma Administrative Code

OCC – Oklahoma Corporation Commission

ppm – Parts Per Million

psi – Pounds per Square Inch

psia – Pounds per Square Inch Absolute

psig – Pounds per Square Inch Gauge

PVT – Pressure, Volume, Temperature

QA/QC – quality assurance/quality control

rb – Reservoir Barrels

RTS – Radioactive tracer survey

SPHI – Sonic Porosity

UIC – Underground Injection Control

USDW – Underground Source of Drinking Water

USEPA – United States Environmental Protection Agency

USGS – United States Geological Survey

WAG – Water Alternating Gas

Appendix 4 – Conversion Factors

Daylight reports CO_2 at standard conditions of temperature and pressure as defined in the Oklahoma Administrative Code (OAC) for Oil and Gas Conservation, Title 165 Chapter 10 as follows:

"Cubic foot of gas" means the volume of gas contained in one cubic foot (ft_3) of space at an absolute pressure of 14.65 pounds per square inch (psi) and at a temperature 60 degrees F. Conversion of volumes to conform to standard conditions shall be made in accordance with Ideal Gas Laws corrected for deviation from Boyle's Law when the pressure at point of measurement is in excess of 200 pounds per square inch gauge (psig).

To calculate CO_2 mass from CO_2 volume, USEPA 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 the density of CO_2 using the Span and Wagner equation of state (EOS) at a wide range of temperature and pressures.

At the standard conditions prescribed in the OAC, the Span and Wagner EOS gives a density of 0.0026417 lb-moles per cubic foot. Using a molecular weight for CO_2 of 44.0095, 2,204.62 lbs/MT and 35.314667 ft^3/m^3, gives a CO_2 density of 5.27346×10^{-2} MT/Mcf or 0.0018623 MT/m^3.

Note that the USEPA standard conditions of 60 degrees F and one atmosphere produce a slightly different value. The Span and Wagner EOS gives a density of 0.0026500 lb-moles per cubic foot. Using a molecular weight for CO_2 of 44.0095, 2,204.62 lbs/MT and 35.314667 ft^3 /m^3, gives a CO_2 density of 5.29003×10^{-2} MT/Mcf or 0.0018682 MT/m^3.

The conversion factor 5.27346×10^{-2} MT/Mcf is used to convert CO_2 volumes to metric tons.

Appendix 5 – Koval Factor Calculation

Based on theoretical considerations, laboratory experiments, and pilot tests, Koval (1963) suggests that in miscible flooding, viscous fingering affects the volumetric sweeping efficiency. Immiscible viscous fingering in porous media occurs when a high-viscosity fluid is displaced by an immiscible low-viscosity fluid. In such cases, the Buckley-Leverett model cannot be applied directly and requires modification. According to Koval's theory (Koval, 1963), the fraction of pore volume swept by the displacing agent, denoted as E_v, can be expressed as a function of K_v, the Koval heterogeneity factor.

If $t_D \leq 1/K_v$ then $E_v = t_D$ Equation 5-1

If $1/K_v < t_D < K_v$ then $E_v = \frac{2\sqrt{K_v t_D} - t_D - t_D}{K_v al - 1}$ Equation 5-2

If $t_D \geq K_v$ then $E_v = 1.0$ Equation 5-3

where t_D is injected pore volume.

The Koval factor combines both the viscosity contrast effect and the heterogeneity effect. In practical applications, calculating the Koval factor is a complex task. A comparison is made with the Lorenz coefficient (Salazar and Lake, 2020). In this model, **Figure A5** is used, and based on the given Lorenz coefficient, the Koval factor is calculated.

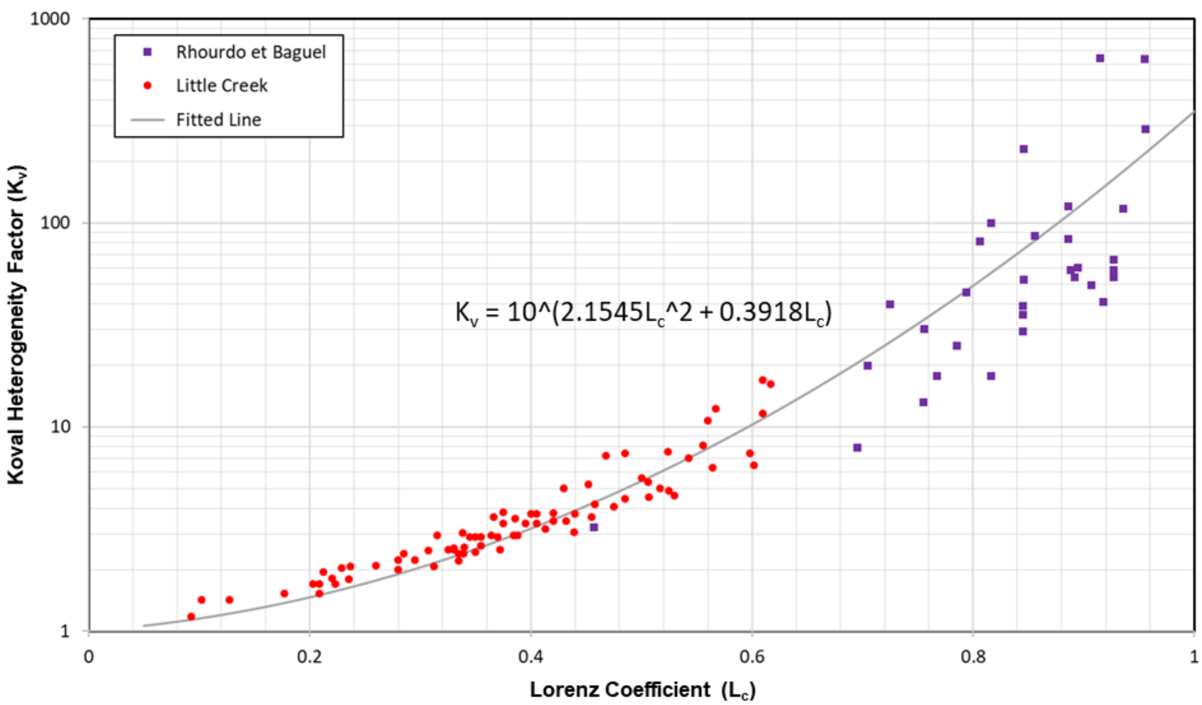

Figure A5: Comparison of the Koval factor and Lorenz coefficient.

Appendix 6 – Muskat Model Description

This appendix explains the formulation behind the Muskat Model, based on the work of Irani et al. (2021). Generally, when an analytical solution is not available, the depletion performance equations can be divided into blocks, with each block assuming constant properties. Muskat's method offers a solution that accounts for the expansion behavior of each pressure/saturation block, along with the corresponding flow equations. It also considers the expansion and liberation of gas due to pressure reduction, allowing for calculations of these effects. This method was chosen for its widespread application, simplicity, and compatibility with the available data size.

The first step involves calculating B_o, B_g, Rs, μ_o, and μ_g at pressures equal to or below the bubble point pressure.

Second, we calculate parameters α, β, and γ.

$$\alpha = \left(B_g^i\right)/\left(B_o^i\right) \times \left(R_s^{(i-1)} - R_s^i\right)/\left(P_i - P_{(i-1)}\right) \qquad \text{Equation 6-1a}$$

$$\beta = 1/\left(B_o^i\right) \times \left(B_o^i - B_o^{(i-1)}\right)/\left(P_i - P_{(i-1)}\right) \times \left(\mu_o^i\right)/\left(\mu_g^i\right) \qquad \text{Equation 6-1b}$$

$$\gamma = 1/\left(B_g^i\right) \times \left(B_g^i - B_g^{(i-1)}\right)/\left(P_i - P_{(i-1)}\right) \qquad \text{Equation 6-1c}$$

At the first iteration, oil saturation can be obtained utilizing the water saturation derived from the resistivity log.

$$S_o = 1 - S_w \qquad \text{Equation 6-2}$$

With both oil and water saturations available, the relative permeability of oil and gas can be determined. Using these relative permeability values, oil and water saturations can then be back calculated. In the next iteration, with the updated water and oil saturations, the gas saturation can be calculated, assuming a three-phase system.

$$S_g = 1 - S_w - S_o \qquad \text{Equation 6-3}$$

Now, having the saturations at previous iterations, new oil saturation can be calculated as follows:

$$\begin{aligned} S_o^i &= S_o^{(i-1)} \\ &- \left(\alpha S_o^i + \beta S_o^i \left(k_r g^i\right)/\left(k_r o^i\right) - \gamma\left(1 - S_w - S_o^i\right)\right) \\ &/ \left(1 + \left(\mu_o^i\right)/\left(\mu_g^i\right)\left(k_r g^i\right)/\left(k_r o^i\right)\right)\left(P_{(i-1)} - P_i\right) \end{aligned} \qquad \text{Equation 6-4}$$

New relative permeability values can be determined using the updated oil saturation. This process is repeated iteratively until the difference between the old and new oil saturation becomes negligible. Next, we define a given rate at day 1, where the rate on any subsequent day is calculated by multiplying the initial rate by the new mobility factor. The mobility factor is the ratio of the new oil relative permeability to the oil viscosity at the given pressure. Finally, we define the pressure change over time to match both oil production and gas production (or the produced GOR).