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

OFFICE OF
AIR AND RADIATION

July 7, 2023

Mrs. Lauren Read
BKV Corporation
1200 17th Street
Suite 2100
Denver, Colorado 80202

Re: Monitoring, Reporting and Verification (MRV) Plan for Barnett RDC Well No. 1

Dear Mrs. Read:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for Barnett RDC Well No. 1, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by Barnett RDC Well No. 1 on June 13, 2023, as the final MRV plan. The MRV Plan Approval Number is 1014524-1. This decision is effective July 12, 2023 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78.

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

Sincerely,

Julius Banks, Chief
Greenhouse Gas Reporting Branch

Technical Review of the Subpart RR MRV Plan for Barnett RDC Well No. 1

July 2023

Contents

This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) Subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted by BKV dCarbon Ventures, LLC's (dCarbon) Barnett RDC #1 Well Facility (Barnett) for its carbon dioxide (CO_2) capture and storage (CCS) project in the Fort Worth Basin near Bridgeport, Texas. Note that this evaluation pertains only to the Subpart RR MRV plan, and does not in any way replace, remove, or affect Underground Injection Control (UIC) permitting obligations. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

1 Overview of Project

Barnett indicates in Section 1 of the MRV plan that they are currently authorized to inject a total of up to 14.5 million standard cubic feet of CO_2 per day (MMscfd) into their Barnett RDC #1 well (RDC #1) under permit from the Texas Railroad Commission (TRRC). The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program. TRRC classifies the RDC #1 well as a UIC Class II well. A Class II permit was issued in accordance with Statewide Rule 9 to BKV. Barnett states that the RDC #1 well has approved W-14 injection and W-1 drilling permits with the TRRC (Permit No. 17090, UIC Number 000125478, American Petroleum Institute (API)# 42-497-38108). Barnett plans to drill the well in the first half of 2023, complete the well in mid-2023, and begin injection operations in late 2023.

According to the MRV plan, Barnett is located 4.6 miles southwest of Bridgeport, TX in Wise County, Texas near the Muenster Arch of the Fort Worth Basin. The Fort Worth basin is a flexural basin that formed in the foreland of the advancing Ouachita orogenic belt during the Late Mississippian through Pennsylvanian epochs. As illustrated in Figure 2 of the MRV plan, the Fort Worth basin is bounded to the east by the Ouachita fold and thrust belt and to the north by the Muenster Arch and Red River Arch. The Fort Worth Basin sedimentary succession begins with locally abundant Cambrian clastics in the southern section of the basin that unconformably overlies the uneven Precambrian basement. The overlying Ordovician age Ellenburger platform carbonates were deposited on a passive margin and contain thicknesses up to 4,000 feet in the Fort Worth Basin. The Ellenburger platform carbonates underwent multiple episodes of regional exposure causing dolomitization and karsting in several units of the Ellenburger. Ordovician Viola and Simpson formations overlie the Ellenburger formation and are found in the northern section of the basin near the Muenster Arch. Near the RDC #1 well, the Barnett Shale, Viola/Simpson and Ellenburger formations dip and thicken to the east toward the Muenster Arch.

Section 3 of the MRV plan describes the geologic setting around the RDC #1 well. The target CO_2 storage reservoir is the Ellenburger Group, an interval consisting of alternating limestone and dolomite lithologies. The MRV plan states that, in agreement with other sources, the Ellenburger group was divided into 8 subunits (A-G) based on vertical lithological changes. The Ellenburger subunit A is the shallowest stratigraphic subunit, while the Ellenburger subunit G is the deepest stratigraphic subunit. Barnett chose the Ellenburger subunit E as the main target storage reservoir based on its lithology, gross thickness, reservoir thickness, porosity values, and permeability values. The injection interval is at a depth of 9,350 feet to 10,250 feet below the ground level of the RDC #1 well. The Ellenburger subunit C will be used as the primary overlying confining layer. The MRV plan also states that the Barnett Shale will serve as a secondary confining unit. Barnett states that the Ellenburger subunit F serves as the lower confining zone.

According to the MRV plan, Barnett plans to inject CO_2 into the RDC #1 well for approximately 12 years plus two years of post-injection monitoring. The MRV plan states that Barnett is currently authorized to inject a total of up to 280,000 MT/yr. The MRV plan states that the UIC permit allows for CO_2 to be injected with a maximum allowable surface pressure of 4,500 pounds per square inch gauge (psig). Barnett states that they will accept captured CO_2 from the EnLink Midstream Services, LLC Bridgeport Gas Processing Plant to the RDC #1 well via an approximately 6,815-foot pipeline. The MRV plan explains that the CO_2 stream will be metered at the well site to verify the quantity of injected CO_2. The MRV plan also states that the CO_2 stream will contain 0.00002% hydrogen sulfide (H_2S).

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

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

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

The MRV plan states that the migration and size of the plume boundary was determined using Computer Modeling Group (CMG)’s General Equation of State Model (GEM). Barnett states that the model simulated CO_2 injection into the Ellenburger subunit E formation for 12 years followed by 100 years of post-injection monitoring. After doing so, the model showed that the plume will cease to migrate after 50 years post-injection. The MRV plan demonstrates that a half mile buffer was added to the plume extent after 50 years post-injection to determine the MMA. The resulting MMA has a surface area of 4.28 square miles with the greatest extent reaching 1.62 miles from the injector, as demonstrated by Figure 19 of the MRV plan. The MRV plan explains that the MMA exceeds the definition of the AMA in 40 CFR 98.449. As a result, Barnett states that the boundary of the MMA will also serve as the AMA boundary.

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

3 Identification of Potential Surface Leakage Pathways

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

- Surface Equipment
- Approved, Not Yet Drilled Wells
- Existing Wells
- Fractures and Faults
- Confining Layers
- Natural or Induced Seismicity
- Lateral Migration

Table 9 of the MRV plan (Section 6), which has been reproduced below, provides a summary of the potential leakage pathway(s) and their respective likelihoods, timings, and magnitudes.

Leakage Pathway	Likelihood	Timing	Magnitude
Potential Leakage from Surface Equipment	**Possible**	Anytime during project operations, but most likely during start-up / transition or maintenance periods	**<100 MT per event** (100 MT represents approximately 3 hours of full flow facility release)
Leakage from Approved, Not Yet Drilled Wells	**Improbable**, as there are no approved not yet drilled wells	After new wells are permitted and drilled	**<1 MT per event**
Leakage from Existing wells	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and the total depth of existing wells	When the CO_2 plume expands to the lateral locations of existing wells	**<1 MT per event** due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach an existing well combined with thickness and low porosity / permeability of upper confining zone
Potential Leakage from Fractures and Faults	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and surface or USDW that would need to be compromised and there are no mapped faults within the MMA.	Anytime during operation	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach a fault or fracture significant enough to cause leakage
Leakage Through Confining Layers	**Improbable**, as the upper confining zone is nearly 1,000' thick and very low porosity and permeability	Anytime during operations	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E and thickness/properties of upper confining zone
Leakage from Natural or Induced Seismicity	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and surface or USDW that would need to be compromised and there are no mapped faults within the MMA.	Anytime during operations	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach a fault or fracture significant enough to cause leakage
Leakage from Lateral Migration	**Improbable**, as the Ellenburger is a very thick and laterally continuous formation with the closest well penetration five miles downdip.	More likely late in life as plume expands	**<1 MT per event** due to natural dispersion of CO_2 within the Ellenburger subunit E and continuity / thickness of upper confining zone

3.1 Surface Equipment

The MRV plan explains that the surface facilities surrounding the RDC #1 well are specifically designed for injecting the CO_2 stream described previously in the MRV plan, including H_2S. The facilities minimize leakage points such as valves and flanges by following industry standards and best practices, and Barnett requires all personnel to wear gas monitors that detect H_2S. The MRV plan states that a shut-in valve is located at the RDC #1 wellhead in case of emergency, and that the compressor will also have emergency shut down switches that can be activated in case of unexpected operating conditions.

Additionally, the MRV plan states that the compressor facility, pipeline, and injection well locations will all be subject to Auditory, Visual, and Olfactory (AVO) and Forward Looking InfraRed (FLIR) leak detection per Barnett's safety and operations standards. These recurring inspections will aid in the rapid detection of any potential leaks. Any detected leaks will be analyzed to determine the amount of leaked CO_2. The MRV plan also states that leakage quantities will be included in their annual reporting form.

Table 9 of the MRV plan provides a detailed characterization of CO_2 leakage that could be expected through surface equipment. Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through surface equipment at Barnett.

3.2 Approved, Not Yet Drilled Wells

The MRV plan states that there are no active permits within the MMA. The MRV plan also states that there are multiple expired well permits within the MMA that would require re-permitting before being drilled. Barnett included details on many of the expired permit locations in Attachment B of the MRV plan.

Table 9 of the MRV plan provides a detailed characterization of CO_2 leakage that could be expected through approved, not yet drilled wells. Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through approved, but not yet drilled wells.

3.3 Existing Wells

The MRV plan states that of the 20 existing wells within the MMA, 14 have digital records available on the TRRC website (Table 6 of the MRV plan). Six of those wells have been abandoned and plugged, while eight remain active, but all 14 are shallower than the proposed disposal interval for the project. The MRV plan states that the target injection interval (which is greater than 9,350 feet) is approximately 3,000 feet deeper and separated by numerous impermeable shales from the deepest well in the MMA (API# 42-497-34419), which has a total depth of 6,334 feet. Figure 20 of the MRV plan displays the existing wells relative to the MMA. The MRV plan explains that the six remaining wells drilled within the MMA do not have digital records available on the TRRC website, but Barnett acquired paper copies of the well permit information, which can be seen in Attachment B of the MRV plan. All six wells are significantly shallower than the target Ellenburger formation according to the MRV plan. The MRV plan states that the deepest of the six wells was drilled to 6,155 feet total vertical depth (TVD), several thousand feet shallower than the Ellenburger formation.

Additionally, the MRV plan states that the wellbore design of the injection well contains three layers of steel casing, each of which runs entirely to the surface to ensure complete isolation of wellbore fluids. Each of the casing strings will be cemented to the surface and inspected with cement bond logs to ensure wellbore integrity. Finally, the MRV plan states that all injection into the well occurs through a final steel tubing string which is secured in place with a permanent packer. Barnett claims that every aspect of wellbore construction is designed to ensure that CO_2 is injected into the target formation without leakage pathways from the wellbore directly into shallower formations.

Table 9 of the MRV plan provides a detailed characterization of CO_2 leakage that could be expected through existing wells. Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through existing wells.

3.4 Fractures and Faults

The MRV plan states that several episodes of fault formation took place in the Fort Worth Basin based on 3D seismic data interpretation conducted by Barnett. It states that the oldest set of faults displaced Ordovician rocks but did not displace Mississippian rocks like the Barnett Shale. A younger set of faults that displaced Mississippian and older rocks appears to be related to the Ouachita Front collision. The MRV plan explains that these faults show displacement up into the Pennsylvanian rocks as high as the Strawn formation. The younger faults have greater displacement but are relatively sparse.

The MRV plan states that no faulting is interpreted in the MMA around the RDC #1 well based on subsurface data including 3D seismic data. It states that dynamic modeling conducted to date indicates that the CO_2 plume will not intersect any mapped faults based upon Barnett's existing 3D seismic interpretations.

The MRV plan states that karst development is present in some areas at the top of the Ellenburger, primarily where the overlying Viola and Simpson Formations were eroded. The MRV plan explains that the injection interval, the Ellenburger E, appears to be below the portion of the Upper Ellenburger affected by karst collapses. This suggests that the Ellenburger subunit C will remain a continuous seal in karst areas. It also states that there are no interpreted karst features that the CO_2 plume or pressure front intersects based on the dynamic modeling. Small karst features sit at the southern edge of the MMA but only seem to have impacted the upper 200 feet of the Ellenburger, leaving 3,000 feet of Ellenburger apparently unaffected.

The MRV plan states that even if the plume reaches the karst features on the south end of the MMA and the Ellenburger subunit C seal is not intact, the overlying and impermeable Barnett Shale, Marble Falls Limestone, and the Atoka Shales are expected to prevent migration to shallower depths.

Table 9 of the MRV plan provides a detailed characterization of CO_2 leakage that could be expected through fractures and faults. Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through fractures and faults.

3.5 Confining Layers

The MRV plan states that the Ellenburger Subunit E injection zone is bound by competent confining zones above the injection interval by Ellenburger subunit C and below the injection interval by Ellenburger subunit F. Secondary seals above the injection zone include Barnett Shale, Marble Falls Limestone, and the Atoka Shales. Ellenburger subunit F serves as the lower confining zone. Overall, there is more than 3,000 feet of impermeable rock between the injection zone and the deepest well penetrations, making vertical migration past the primary and secondary confining zones unlikely.

Table 9 of the MRV plan provides a detailed characterization of CO_2 leakage that could be expected through confining layers. Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through the confining layers.

3.6 Natural or Induced Seismicity

The MRV plan states that the RDC #1 well location is in an area of the Fort Worth Basin that is seismically inactive. It states that earthquake catalogs from both the USGS (1950-present) and TexNet (2017-present) indicate no earthquake locations within 20 miles of RDC #1 well. The closest earthquake locations are 20+ miles to the southeast in an area with larger, more regional faulting.

The MRV plan states that Barnett also plans several operational procedures to monitor injection-induced seismicity and to immediately identify any minor or major seismic events in the area. Before initiating injection into the well, Barnett will be installing both surface and bottomhole pressure gauges, so that reservoir pressure and injection pressure can be monitored. Additionally, the MRV plan states that Barnett, consistent with TRRC guidelines and permit conditions, plans to maintain bottomhole injection pressure below formation fracture pressure, and also maintain surface pressure below 0.50 pounds per square inch per foot (psi/ft) gradient when measured from the top of the injection interval. Finally, Barnett states that they plan to perform periodic pressure fall-off tests (PFOT) to determine and monitor reservoir pressure to ensure unexpected static pressure increases are not observed. The MRV plan also states that should any unexpected increase in formation pressure be detected, Barnett can perform Fault Slip Potential (FSP) analysis to evaluate the risk of induced seismicity on the closest mapped faults.

The MRV plan states that since no faults are mapped that cut from the injection interval through the sealing limestones and shales of the Pennsylvanian, and that no leakage is expected due to induced seismic activity.

Furthermore, Barnett plans to install new ground seismic monitoring arrays near the injection site that are designed to detect any seismic events in the area, natural or induced. Any seismic events detected in the area will be located in the subsurface and analyzed to determine their origin and if they may have potential impacts to the injection program or confining layers. Additionally, the TexNet seismic monitoring program will also be monitored to ensure any material seismic events in the area are investigated.

Table 9 of the MRV plan provides a detailed characterization of CO_2 leakage that could be expected through natural or induced seismicity. Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through natural or induced seismicity.

3.7 Lateral Migration

The MRV plan explains that the structural dip of the Ellenburger in the vicinity of the RDC #1 well injection site is about one degree up to the west (100 feet/mile). It states that the closest well that penetrates the Ellenburger E injection interval up dip from the injection site is more than ten miles to the west-southwest. The closest well that penetrates the injection interval down dip is to the east approximately five miles (W S Coleman #2).

The MRV plan states that the dynamic model of the CO_2 plume has the maximum extent of the plume traveling less than one mile, with the maximum distance traveled to the west. It states that given the distance to the next penetration of the injection interval is on the order of ten times the distance that the plume is expected to travel, no leakage from lateral migration is expected.

Table 9 of the MRV plan provides a detailed characterization of CO_2 leakage that could be expected through lateral migration. Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through lateral migration.

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

40 CFR 98.448(a)(3) requires that an MRV plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Section 6 of the MRV plan discusses the strategy that Barnett will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in the previous sections to meet the requirements of 40 CFR §98.448(a)(3). As the injected stream contains both H_2S and CO_2, any observation of H_2S will serve as a preliminary indicator for CO_2 leakage, and therefore the monitoring systems to detect H_2S will also suggest a leak of CO_2. Section 6 of the MRV plan also summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur. Monitoring will occur during the planned 12-year injection period, or otherwise the cessation of operations, plus a proposed two-year post-injection period.

4.1 Detection of Leakage through Surface Equipment

As described in section 6.1 of the MRV plan, any leakage of CO_2 would be quickly detected and addressed because the CO_2 compressor station, pipeline, and injection well are all designed to handle expected concentrations, temperatures, and pressures of H_2S and CO_2. It states that the facility is designed to minimize potential leakage points by following the American Society of Mechanical Engineers (ASME) standards, API standards, and other industry standards, including those pertaining to material selection. Additionally, connections at Barnett are designed to minimize corrosion and leakage points. The H_2S in the stream is easily detectable and serves as an indicator for the release of CO_2. The facility and well will be monitored for H_2S and increases in CO_2 concentration. The MRV plan reiterates that all field personnel at Barnett are required to wear H_2S monitors, which will trigger the alarm at low levels of H_2S (typically one ppm). The injection facility will be continuously monitored through automated systems that are designed to identify abnormalities in operational conditions. In addition, field personnel at Barnett conduct daily Auditory, Visual, and Olfactory (AVO) field inspections of gauges, monitors, and leak indicators. The MRV plan also states that the effectiveness of the internal and external corrosion control program is monitored through periodic inspection of the system and analysis of liquids collected from the line. These inspections, in addition to the automated systems, will allow Barnett to quickly identify and respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Finally, the MRV plan restates that if leakage were detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5).

Additionally, the MRV plan states that injection of CO_2 will be metered in three locations for redundancy and precision. The first will be at an orifice style or Coriolis meter at the interface between the Bridgeport Plant and Barnett's compression facility. The MRV plan explains that this location will meter the CO_2 in the gas phase. Once the CO_2 is compressed to supercritical, it will be transported approximately 6,815 feet via pipeline to the injection well site. The second meter, another Coriolis meter, will take measurements immediately upstream of the injection wellhead itself. The MRV plan explains that the injection stream will also be analyzed with a gas chromatograph at the well site to determine final composition. It states that the meters will each be calibrated to industry standards. Any discrepancies in CO_2 throughput between the two meters will be investigated and reconciled. Any CO_2 that is determined to have leaked or not been received at the injection wellhead will be quantified using the procedures specified in Subpart W of the GHGRP, reported as specified in 40 CFR §98.448(a)(5), and subtracted from reported injection volumes. The MRV plan also states that gas samples will be taken and analyzed per manufacturer's recommendations to confirm stream composition and calibrate or re-calibrate meters, if necessary. At a minimum, these samples will be taken quarterly.

Thus, the MRV plan provides adequate characterization of Barnett's approach to detect potential leakage through surface components as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage Through Existing and Future Wells within the Monitoring Area

Section 6.2 of the MRV plan reiterates that there are currently no existing, approved, or pending wells in the MMA that penetrate as deep as the Ellenburger injection zone. However, section 6.2 of the MRV plan states that Barnett will reverify the status and public information for all proposed and approved drilling permits within the MMA quarterly. If any wells are proposed, permitted, or drilled within the MMA, Barnett will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, the MRV plan states that Barnett will continuously monitor and collect injection volumes, pressures, temperatures, and gas composition data for the injection well. This collected data will be reviewed by qualified personnel and will follow response and reporting procedures when data are outside acceptable performance limits. Finally, Barnett will update the MRV plan if any new wells are drilled within the MMA, or if any other material change to the project occurs.

The MRV plan states that the injection well has pressure and temperature gauges monitoring the injection stream at the wellhead as well as bottomhole pressure and temperature gauges near the bottom of the tubing. The down hole gauges will monitor the inside of the tubing (injection stream) as well as the annulus. A change of pressure on the annulus would indicate the presence of a possible leak requiring remediation. The MRV plan also states that Mechanical Integrity Tests (MITs) performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated, and the leak mitigated.

The MRV plan explains that in the unlikely event that any CO_2 leaks into existing or future wells occur in the monitoring area, Barnett will work with the operator(s) of those wells and/or midstream providers to take wellhead gas samples to quantify variations or increases of CO_2 compared with historical or baseline CO_2 concentrations. Any measurable increases in CO_2 which may be confidently attributed to injection volumes from the RDC #1 well will be calculated using standard engineering procedures for estimating potential well leakage determined to be appropriate for the situation. These volumes will be documented and reported in the annual monitoring report and subtracted from reported injection volumes. Additionally, it states that Barnett will evaluate and execute any additional downhole remediations (e.g., well workovers, such as adding plugs, remedial cement jobs, etc.) that could address leakage from the injection well to the existing and future wells in the area if necessary and practical.

Thus, the MRV plan provides adequate characterization of Barnett's approach to detect potential leakage through existing and future wells within the MMA as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage Through Faults and Fractures

As described in section 6.3 of the MRV plan, no faults or fractures have been identified that would allow CO_2 to migrate vertically to zones with USDWs or to the surface. The MRV plan states that in the unlikely event that such leakage from faults or fractures occurs, Barnett will determine which standard engineering techniques for estimating potential leakage from the faults and fractures are appropriate for the situation. Barnett will report such leakage estimates and the methodology employed in the annual monitoring report.

Thus, the MRV plan provides adequate characterization of Barnett's approach to detect potential leakage through faults and fractures as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage Through Confining Layers

According to section 6.4 of the MRV plan, Barnett states that leakage through confining layers is improbable, given the number and thickness of layers between the injection zone and potable groundwater. The MRV plan states that groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple confining layers.

The MRV plan explains that in the unlikely event CO_2 leakage occurs because of leakage through the confining seal, it is unlikely that such leakage would result in surface leakage of CO_2. It states that should a leak occur, Barnett will determine which standard engineering techniques for estimating potential leakage are appropriate to estimate any leakage quantities. Barnett will report leakage quantities and identify the methodology employed in the annual monitoring report.

Thus, the MRV plan provides adequate characterization of Barnett's approach to detect potential leakage through the confining layers as required by 40 CFR 98.448(a)(3).

4.5 Detection of Leakage Through Natural or Induced Seismicity

As discussed in section 6.5 of the MRV plan, while the likelihood of a natural or induced seismicity event is extremely low, Barnett will install a seismic monitoring station in the general area of the RDC #1 well. Barnett states that this monitoring station will augment the TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, Barnett will review the injection volumes and pressures at the RDC #1 well to determine if any significant changes occurred that would indicate potential leakage. The MRV plan states that to suspect leakage due to natural or induced seismicity, the evidence would need to suggest that the earthquakes are activating faults that penetrate through the confining zones.

The MRV plan explains that in the unlikely event CO_2 leakage occurs due to natural or induced seismicity, Barnett will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation. Barnett will report such leakage estimates and the methodology employed in the annual monitoring report.

Thus, the MRV plan provides adequate characterization of Barnett's approach to detect potential leakage through natural or induced seismicity as required by 40 CFR 98.448(a)(3).

4.6 Detection of Leakage Through Lateral Migration

According to section 6.6 of the MRV plan, the distance to the closest penetration of the Ellenburger injection interval is more than ten times the expected plume radius at the end of injection. The MRV plan states that as a result, leakage through lateral migration is not expected. In addition, it states that the wells that penetrate the injection interval are saltwater disposal wells. Injection into these wells would be expected to raise the reservoir pressure locally near the well, further limiting the ability of the CO_2 to access the saltwater injector well bore.

The MRV plan states that in the unlikely event CO_2 leakage occurs due lateral migration, Barnett will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation. Barnett will report such leakage estimates and the methodology employed in the annual monitoring report.

Thus, the MRV plan provides adequate characterization of Barnett's approach to detect potential leakage through lateral migration as required by 40 CFR 98.448(a)(3).

4.7 Quantification of Leakage

The MRV plan states that Barnett plans to install a deep groundwater monitoring well in the MMA that will be used to monitor the USDW. Barnett states that this will serve as their primary monitoring and quantification strategy. Groundwater CO_2 concentrations will be analyzed volumetrically to provide a preliminary estimate of CO_2 leakage.

The MRV plan also states that any leakage that extends to the surface could be characterized and quantified through surface surveillance in the project area paired with direct pressure, volume, and temperature (PVT) measurements. Currently available (and continuously improving) atmospheric sensing technology could be used to establish a baseline of ambient CO_2 concentration in the project area and to identify any fluctuations. For diffuse leakage, Barnett states that they are working with a leading environmental services and data company which specializes in monitoring and quantifying gas leaks in various industrial settings. One such quantification method involves utilizing fixed monitoring systems to detect CO_2. Additional system capabilities also include the deployment of an unmanned aerial vehicle (UAV) which is outfitted with an industry leading high fidelity CO_2 sensor capable of measuring concentrations as little as parts per billion (ppb).

Depending on the applicability and monitoring needs, Barnett states that they will also consider other monitoring quantification methods such as the Eddy Covariance Method (ECM). This method utilizes gas fluxes and ambient meteorological conditions to detect and quantify leaks, although the ability to detect smaller leaks may be limited. Additionally, long open path tunable diode lasers could be used to measure distance averaged concentrations of CO_2 in the air, which could help quantify a leak of CO_2.

The MRV plan states that the technology and equipment to quantify CO_2 leakage are rapidly evolving and are expected to improve over time. Therefore, Barnett states that it will continue to update its leak detection and quantification plans as appropriate.

4.8 Determination of Baselines

Section 7 of the MRV plan identifies the strategies that Barnett will undertake to establish the expected baselines for monitoring CO_2 surface leakage per §98.448(a)(4). Barnett will use supervisory control and data acquisition (SCADA) monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. Daily inspections will be conducted by field personnel at the compressor facility and the injection well. These inspections will aid with identifying and addressing issues in a timely fashion to minimize the possibility of leakage. The MRV plan states that if any issues are identified, corrective actions would be taken to address such issues.

The MRV plan states that any CO_2 release would be accompanied by H_2S, and therefore the H_2S monitors at the facility would also serve as a CO_2 release warning system. It states that in addition to personal monitors described previously, Barnett will also conduct routine AVO and FLIR monitoring to detect any CO_2 leakage near the facility or well.

The MRV plan states that the mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S, which may be present unnecessary hazards for field personnel to perform a direct leak survey. Gas detectors and continuous monitoring systems would trigger an alarm upon release. Any leakage would be detected and managed as per Texas regulations and Barnett safety and operations plans. The MRV plan also states that the mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

The MRV plan states that baseline groundwater quality and properties will be determined and monitored through the installation of a groundwater monitoring well near the injection well site. It states that samples will be taken and analyzed by a third-party laboratory to establish the baseline properties of the groundwater in the area.

The MRV plan states that baseline seismicity in the area near the RDC #1 well will be determined through historical data from USGS and TexNet seismic array data. It states that this information will be augmented by additional data from Barnett's seismic monitoring array.

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

5.1 Calculation of Mass of CO_2 Received

As stated in the MRV plan, the CO_2 received for injection will be wholly injected and not mixed with any other supply of CO_2. Therefore, Barnett will use the amount of CO_2 received as the annual mass of injected CO_2. The MRV also states that any future CO_2 streams will be metered before being combined into the calculated stream.

Barnett provides an acceptable approach for calculating the mass of CO_2 received under Subpart RR.

5.2 Calculation of Mass of CO_2 Injected

The MRV plan states that Barnett will use volumetric flow metering to measure the flow of the injected CO_2 stream and will calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5 from 40 CFR Part 98, Subpart RR:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_2,p,u}$$

Where:

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

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for Flowmeter u in Quarter p (weight percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flowmeter.

Barnett provides an acceptable approach for calculating the mass of CO_2 injected under Subpart RR.

5.3 Calculation of Mass of CO_2 Produced

The MRV plan states that the injection well is not part of an enhanced oil recovery project. As a result, no CO_2 will be produced.

Barnett provides an acceptable approach for calculating the mass of CO_2 produced under Subpart RR.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

The MRV plan states that the mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which may be hazardous for field personnel to perform a direct leak survey. Although Barnett identifies surface leakage as an unlikely event, any leakage would be detected and managed as a major upset event. Should a CO_2 leakage event occur, Barnett states in their MRV plan that the mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of leak.

Barnett will calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR-10 from 40 CFR Part 98-Subpart RR:

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

CO_{2E} = Total annual CO_2 mass emitted by any 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.

Barnett provides an acceptable approach for calculating the mass of CO_2 emitted by surface leakage under Subpart RR.

5.5 Calculation of Mass of CO_2 Sequestered

As this well will not actively produce any oil or natural gas, the MRV plan states that the mass of CO_2 sequestered in the subsurface geologic formation will be calculated using Equation RR-12 as follows:

$$CO_2 = CO_{2,I} - CO_{2,E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the Barnett RDC #1 facility in the reporting year.

$CO_{2,I}$ = Total annual CO_2 mass injected (metric tons) in the Barnett RDC #1 well in the reporting year.

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

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of Part 98.

Barnett provides an acceptable approach for calculating the mass of CO_2 emitted from equipment leaks and vented emissions under Subpart RR.

6 Summary of Findings

The Subpart RR MRV plan for BKV dCarbon Ventures, LLC's Barnett RDC #1 Well Facility meets the requirements of 40 CFR 98.238. The regulatory provisions of 40 CFR 98.238(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the Barnett MRV plan.

Subpart RR MRV Plan Requirement	Barnett RDC #1 Well Facility MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 4 of the MRV plan describes the MMA and AMA. The MRV plan explains that the simulated plume area after 50 years of post-injection plus a one-half mile buffer was used to calculate the MMA. The MRV also states that the MMA far exceeds the definition of the AMA. As a result, Barnett proposes to use the MMA boundary as the AMA boundary.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.	Section 5 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: surface equipment; approved, not yet drilled wells; existing wells; faults and fractures; confining layers; natural or induced seismicity; and lateral migration. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways. Barnett determined that the probability of leakage is low.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 6 of the MRV plan describes a strategy for how the facility would detect and quantify potential CO_2 leakage to the surface should it occur, such as H_2S monitors, field inspections, groundwater sampling, and Mechanical Integrity Tests (MIT). The MRV plan states that quantification of CO_2 leakage will be calculated based on operating conditions at the time of the event.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 7 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage. Barnett will collect baseline data before injection begins. The MRV plan states that a third-party laboratory will take and analyze groundwater samples to determine a pre-injection baseline. Barnett states that historical data from the USGS and TexNet will be used to determine a baseline for seismicity near the RDC #1 well.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation.	Section 8 of the MRV plan describes Barnett's approach to determining the amount of CO_2 sequestered using the Subpart RR mass balance equations, as related to

	calculation of total annual mass emitted from equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Section 1 of the MRV plan identifies the RDC #1 Well's UIC number and permit class. According to the MRV plan, the RDC #1 has approved W-14 injection and W-1 drilling permits with the TRRC (Permit No 17090, UIC Number 000125478, API# 42-497-38108).
40 CFR 98.448(a)(7): Proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart.	Section 9 of the MRV plan states that the monitoring baseline data will be collected before injection begins. The MRV plan also states that the injection well is expected to begin operation in the second half of 2023.

Appendix A: Final MRV Plan

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan

Barnett RDC #1

Wise County, Texas

Prepared by

BKV dCarbon Ventures, LLC

Version 5.0

June 13, 2023

TABLE OF CONTENTS

1 – INTRODUCTION

BKV dCarbon Ventures, LLC (dCarbon), a subsidiary of BKV Corporation (BKV), is authorized by the Texas Railroad Commission (TRRC) to inject up to 14.5 million standard cubic feet per day (MMscfd), equivalent to approximately 280,000 metric tons per year (MT/yr), of carbon dioxide (CO_2) into the proposed Barnett RDC #1 injection well in Wise County, Texas. The permit issued by the TRRC allows injection into the Ellenburger Group formation at a depth of 9,350 feet to 10,250 feet with a maximum allowable surface pressure of 4,500 pounds per square inch gauge (psig).

dCarbon currently intends to dispose of CO_2 from the nearby Bridgeport Gas Processing Plant (Bridgeport Plant), operated by EnLink Midstream Services, LLC (EnLink), into the Barnett RDC #1 well. The project site is located approximately 4.6 miles southwest of Bridgeport, Texas, as shown in **Figure 1**.

dCarbon anticipates drilling the Barnett RDC #1 well in the first half of 2023, completing the well in mid-2023, and beginning injection operations in late 2023. The Barnett RDC #1 has approvedW-14 injection and W-1 drilling permits with the TRRC (Texas Railroad Commission) permit number 17090, UIC number 000125478, API number 42-497-38108). Additionally, copies of the approved W-1 and W-14 are included as Attachment A.

Although dCarbon intends to initiate injection with lower volumes, all calculations in this document have been performed assuming the maximum injection amount allowed by the TRRC permit (280,000 MT/yr). dCarbon plans to inject for approximately twelve years.

dCarbon submits this Monitoring, Reporting, and Verification (MRV) plan for approval by the Environmental Protection Agency (EPA) in accordance with 40 CFR § 98.440-449, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP).

dCarbon's TRRC operator number is 100589.

dCarbon's Environmental Protection Agency Identification (EPA ID) number is 110071343305.

The Barnett RDC #1 well's Greenhouse Gas Reporting Program Identification (GHGRP ID) number is 58336. All aspects of this MRV plan refer to this well and GHGRP ID number.

Figure 1. Location of the Barnett RDC # 1 Well and EnLink Midstream's Bridgeport Gas Plant.

2 – FACILITY INFORMATION

Gas Plant Facility Name:

Bridgeport Gas Processing Plant
415 Private Road 3502
Bridgeport, Texas 76426

Latitude: 33° 11.74' N
Longitude: 97° 48.22' W

EnLink's GHGRP ID number for the Bridgeport Plant is 1006373.

FRS Id: 110028052354

NAICS Code: 211130

Currently reporting under Subpart C, W, NN

Underground Injection Control (UIC) Permit Class:

The Oil and Gas Division of the TRRC regulates oil and gas activity in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program for injection wells. The TRRC has permitted the Barnett RDC #1 well as a UIC Class II well. The Class II permit was issued to dCarbon in accordance with Statewide Rule 9.

Injection Well:

Barnett RDC #1, API number 42-497-38108

UIC# 000125478

Barnett RDC #1 GHGRP ID: 58336

The Barnett RDC #1 well will be disposing of CO_2 from the Bridgeport Gas Processing Plant. All aspects of this MRV plan refer to the Barnett RDC #1 well and GHGRP 58336.

3 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection volumes and process, and the reservoir modeling performed for the proposed Barnett RDC #1 Class II injection well. dCarbon has prepared this MRV plan to support the storage of CO_2 in Wise County, Texas.

3.1 Overview of Geology

The proposed injection site lies in the western section of Wise County, where the Barnett Shale, Viola, Simpson, and Ellenburger formations dip and thicken to the east toward the Muenster Arch, as seen in the west to east cross section of **Figure 2**. Similarly, the north to south cross section shows the Ellenburger and overlying formations dipping to the north. One inference from this is that any CO_2 injected may exhibit the tendency to move updip due to buoyancy, meaning the anticipated plume movement will be westward. This is further represented in the structure contour map of the Ellenburger formation top by Pollastro[1] in **Figure 2**.

The Fort Worth Basin sedimentary succession begins with locally abundant Cambrian clastics in the southern section of the basin that unconformably overlie the uneven Precambrian basement (see **Table 1**). The overlying Ordovician age Ellenburger platform carbonates were deposited on a passive margin and contain thicknesses up to 4,000 feet in the Fort Worth Basin. The Ellenburger platform carbonates underwent multiple episodes of regional exposure causing dolomitization and karsting in several subunits of the Ellenburger. Ordovician Viola and Simpson formations overlie the Ellenburger formation and are found in the northern section of the basin near the Muenster Arch. A major erosive interval occurred during the Mississippian, eroding down to the Ordovician formations. Later deposition of the Barnett Shale unconformably overlies the Viola limestone, Simpson formation, and the Ellenburger Group.[2] Overlying the Barnett Shale is a thick section of mostly Pennsylvanian and Permian carbonates and clastics (Bend, Strawn, and Canyon Groups). **Figure 2** indicates the general regional stratigraphy. Although there are multiple storage-confining unit systems that could be evaluated for injection, the focus was on the Mississippian-Ordovician section that consists of the Barnett shale and the Ellenburger Group. The Ellenburger Group directly overlies the basement rock and is considered the main reservoir target.

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[1] Pollastro, R.M., 2007. Geologic framework of the Mississippian Barnett Shale, Barnett-Paleozoic total petroleum system, Bend Arch-Fort Worth Basin. *American Association of Petroleum Geologists Bulletin* 91 (4), pgs. 405-436. 2007.

[2] Gao, S. *et al*., 2021. Low pressure buildup with large disposal volumes of oil field water: A flow model of the Ellenburger Group, Fort Worth Basin, North Central Texas. *American Association of Petroleum Geologists Bulletin* 105 (12), pgs. 2575-2593. 2021.

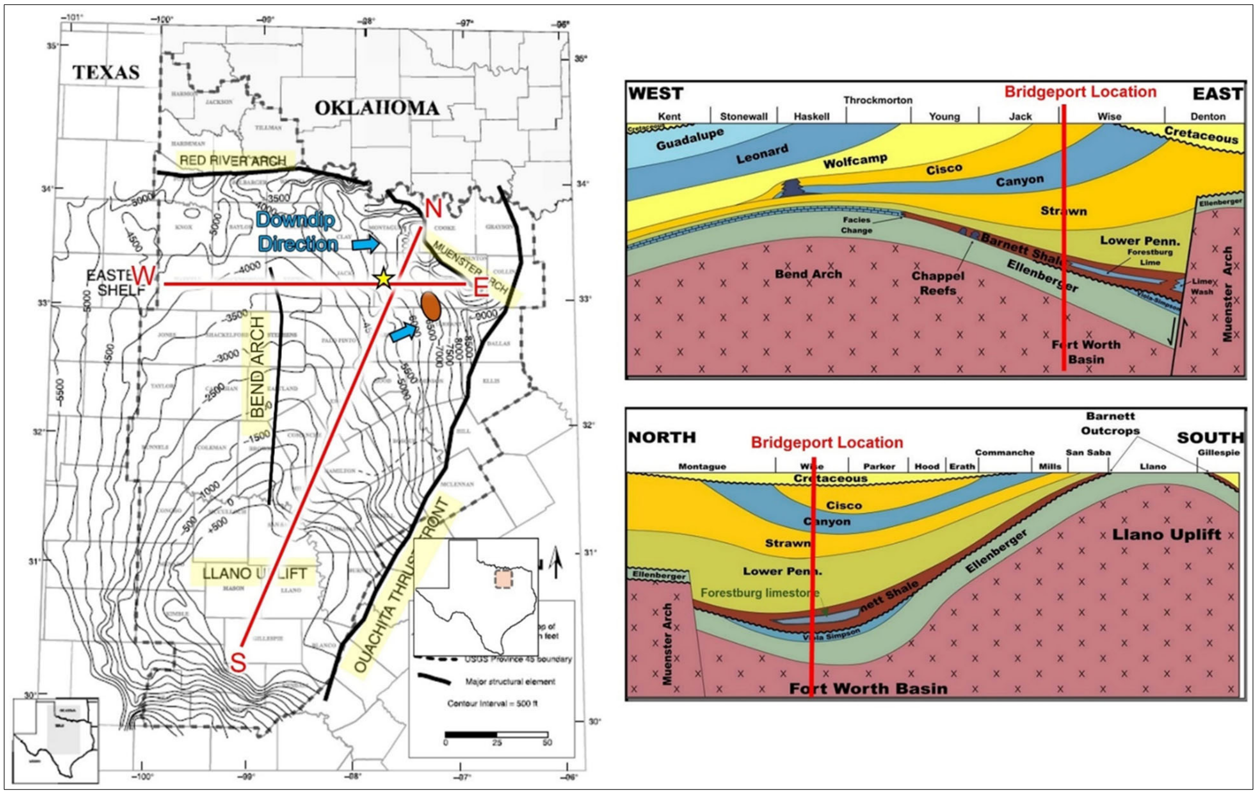

Figure 2. (*Left*) Ellenburger structural contour map modified from Jarvie *et al.*[3] showing the regional structures within and bounding the Fort Worth Basin, Ellenburger structure contours with respect to the final dCarbon area of interest (yellow star). (*Right*) Cross sections E-W and N-S show the regional dip of the sedimentary units in the Fort Worth Basin.

3.2 Bedrock Geology

3.2.1 Basin Description

The Fort Worth Basin is a flexural basin that formed in the foreland of the advancing Ouachita orogenic belt during the Late Mississippian through Pennsylvanian epochs.[4] As illustrated in **Figure 2**, the Fort Worth Basin is bounded to the east by the Ouachita fold and thrust belt and to the north by the Muenster Arch and Red River Arch. These arches are characterized by a series of high angle reverse faults. The basin is deepest to the northeast, with as much as approximately 12,000 feet of sediment infill, where the Ouachita thrust front meets the Muenster Arch and is shallowest towards the south.

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[3] Jarvie, D.M., *et al.*, 2007. Unconventional shale-gas systems: The Mississippian Barnett Shale of North Central Texas as one model for thermogenic shale-gas assessment. *American Association of Petroleum Geologists Bulletin* 91 (4), pgs. 475-499. 2007.

[4] Horne, E.A., Hennings, P.H., and Zahm, C.K., 2021. Basement structure of the Delaware basin, in The Geologic Basement of Texas: A Volume in Honor of Peter Flawn, Callahan, O.A., and Eichhubl, P. (editors), *The University of Texas at Austin, Bureau of Economic Geology Report of Investigations*, Austin, Texas. 2021.

Table 1. Regional Stratigraphy at Barnett RDC #1 Site in North Texas.

SYSTEM	SERIES	STAGE	GROUP OR FORMATION	
Cretaceous	Lower	Comanchean	Trinity Group	
Pennsylvanian	Upper	Missourian	Canyon Group	Jasper Creek Formation
	Middle	Desmonesian	Strawn Group	Willow Point Formation
				Lone Camp Formation
				Millsap Lake Formation
			Kickapoo Group	Ratville Formation
				Parks Formation
				Caddo Pool Formation
		Atokan	Bend Group	Caddo Formation
				Smithwick Shale
	Lower			Pregnant Shale
				Big Saline Formation
		Morrowan		Marble Falls Limestone
				Comyn Formation
Mississippian	Chesterian – Meramecian		Barnett	Upper Barnett Shale
				Forestberg Limestone
	Osagean			Lower Barnett Shale
Ordovician	Lower		Ellenburger Group	
Precambrian			Basement	

3.2.2 Stratigraphy

The Ellenburger Group contains alternating limestone and dolomite lithologies, consistent with regional descriptions of the Ellenburger. Vertical changes in properties throughout the Ellenburger were used to divide the unit into 8 subunits (A-G), in agreement with a similar approach demonstrated by Smye *et al.*[5] The main target storage reservoir, subunit E, was identified based on dominant lithology, gross and net reservoir thicknesses, porosity values, and permeability values. In tandem, the Ellenburger subunit B and the stratigraphic top portion of Ellenburger subunit C were identified as a potential caprock. Below this interval, there are baffles of tighter

[5] Smye, K.M., *et al.*, 2019. Stratigraphic architecture and petrophysical characterization of formations for deep disposal in the Fort Worth Basin, Texas. *Texas BEG Report: Interpretation* 7 (4), 2019.

limestone throughout Ellenburger subunits C, C2, and D that would also act as sealing units to the storage interval. Ellenburger subunit E is planned to serve as the storage zone.

Dominant lithologies were determined by comparing the photoelectric factor (PEFZ) log curve with the volume of clay (VCL), sand (VQUA), lime (VCLC), dolomite (VDOL), gas (VUGA), and free water (VUWA) curves in the North Tarrant SWD 1 (API number 42-439-31228), as well as the separation of the density and neutron porosity curves. Gross reservoir thickness was determined for each Ellenburger subunit by adding the footage from the top to the bottom of the subunit.

The W.S. Coleman #2 (API number 42-497-35807) well, approximately five miles east of the proposed Barnett RDC #1 injection well, was used to calculate reservoir zone properties for individual subunits within the Ellenburger formation since no wells currently exist at the proposed site. The North Tarrant SWD 1 well, located approximately 27 miles to the southeast was also used in well correlations because of its robust well log data across the Ellenburger Group.

Figure 3 shows the correlation of the North Tarrant SWD 1 well up to the W.S. Coleman #2. As an initial observation, subunits C and E within the Ellenburger are present and appear to be contiguous in the project area. Subunit C thickness is approximately 750 feet while subunit E thickness varies across the cross sections. It is estimated there is at least 940 feet of subunit C at the Barnett RDC #1 proposed site location with 1,250 feet of Ellenburger subunit E. The cross sections confirm regional trends in dip also apply to the area of interest, down to the north and east.

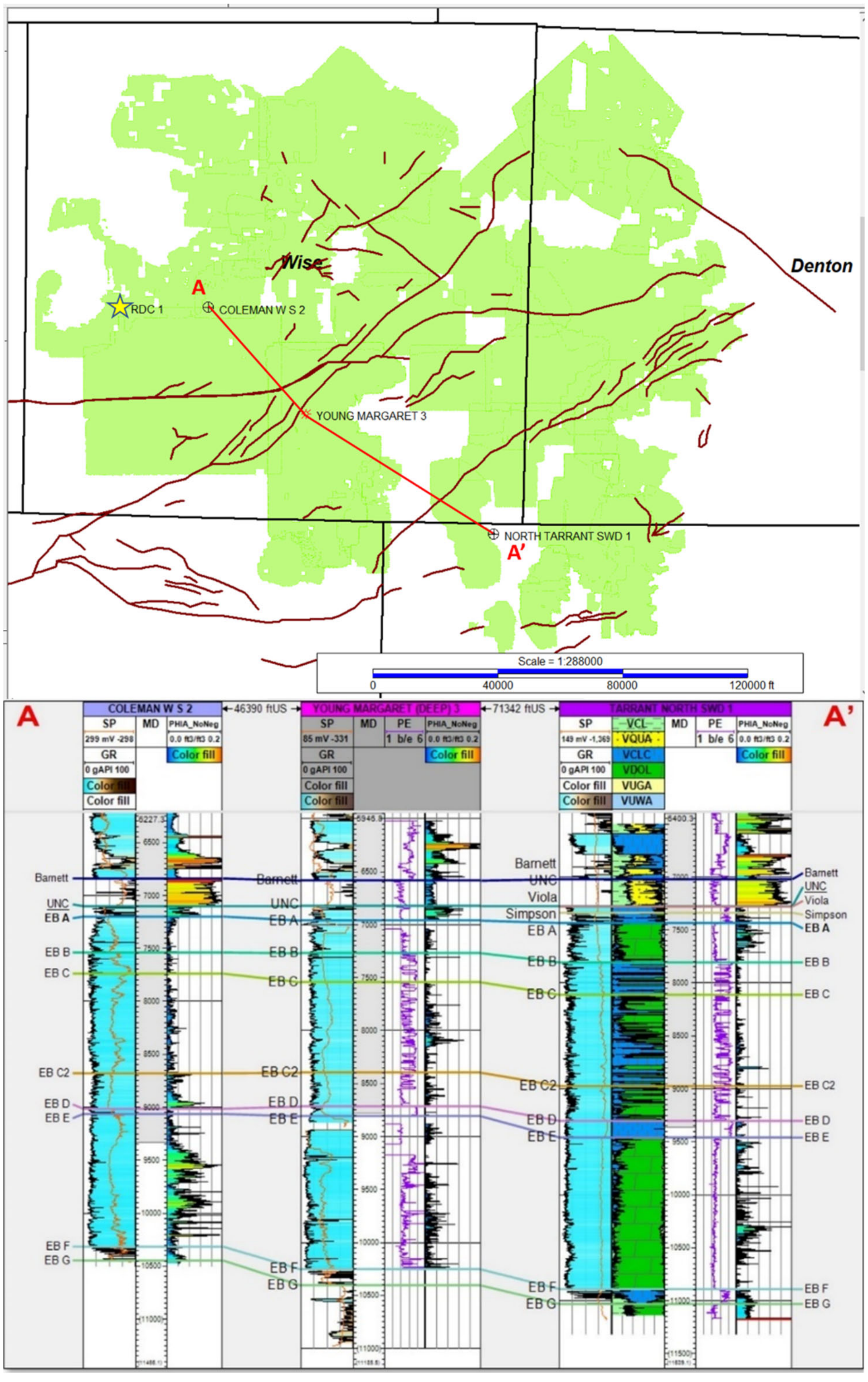

Figure 3. (*Top*) Map of Wise County with the Barnett RDC #1 (yellow star), faults (brown lines), cross section wells (black circles), dCarbon 3D seismic extent (green polygon), and a NW-SE cross section (A-A'). (*Bottom*) Cross section showing Gamma Ray (GR), Spontaneous Potential (SP), Photo Electric Factor (PE), and average porosity (PHIA) from the North Tarrant SWD 1 well to the WS Coleman 2 well. Ellenburger subunit C (EB C) is the upper confining zone and Ellenburger subunit E (EB E) is the storage zone.

3.2.3 Faulting

Faults within the Fort Worth Basin are generally northeast-trending, high-angle normal faults with most of the faults rooting into the Precambrian crystalline basement, as depicted in **Figure 4**. The mechanism for deformation that produced these faults has been attributed to flexure generated by the Ouachita orogenic belt. Deep seated faults that root into the Precambrian crystalline basement generally terminate in the base of the Pennsylvanian age strata and do not continue into the overlying Cretaceous strata, where it is present, suggesting that faults have not experienced significant movement since their formation.[4] Karsting in the region has resulted in small-scale, concentric faults that originate from the collapse of karst features predominantly within the Ellenburger Group.

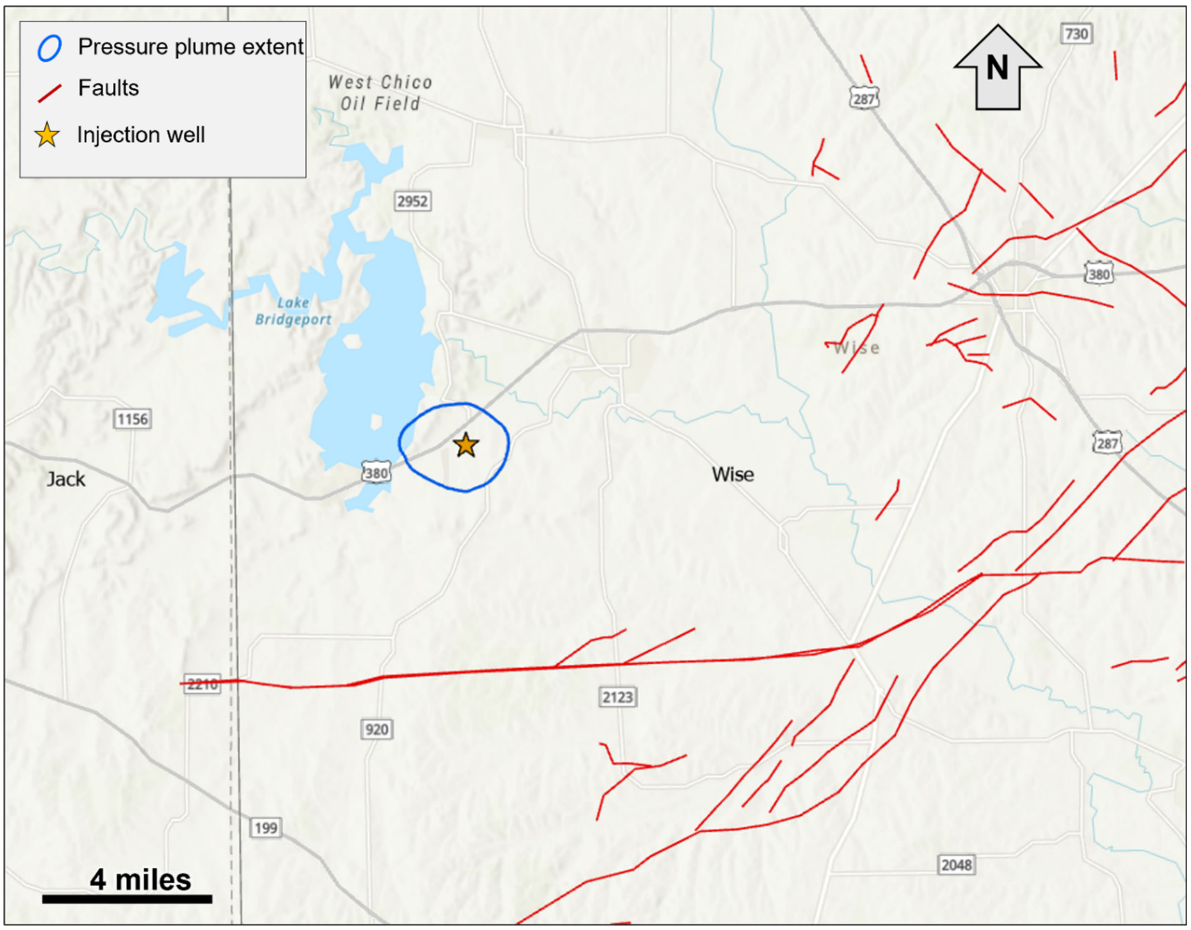

Figure 4. Mapped faults near the proposed injection well from Wood.[6]

3.3 LITHOLOGICAL AND RESERVOIR CHARACTERIZATIONS

Smye *et al.*[5] provided a detailed description of regional stratigraphy as well as petrophysical attributes of multiple units within the Ellenburger Group. Prior to understanding the petrophysical

[6] Wood, V., 2015. Reservoir Characterization and Depositional System of the Atokan Grant Sand, Fort Worth Basin, Texas. University of Arkansas Thesis, 2015.

properties of these subunits and assessing their storage reservoir or confining layer potential, it is important to understand the overall lithology. Literature suggests the Ellenburger interval is mostly composed of calcite, dolomite, quartz, and clay. The carbonate intervals are mostly clean with less than 10% clay by volume[5]. However, the top of the Ordovician section was shown to have an increased clay content (about 40% by volume). This also coincided with an increase in siliciclastic materials (quartz and clay). Porosity in clean carbonate intervals is approximately 5%, while that in siliciclastic intervals may reach 20%. The basement lithology was identified as granite wash with hematite contents ranging between 5-10% by volume. **Figure 5** shows the general stratigraphy in the area.

To better understand local stratigraphy and petrophysics, lithological characterization was focused on the red dotted area shown in **Figure 5**. The Viola Formation and Simpson Group are listed here overlying Ellenburger subunit A. However, these formations pinch out to the east of the proposed Barnett RDC #1 site, and thus, are not included in subsequent petrophysical analysis.

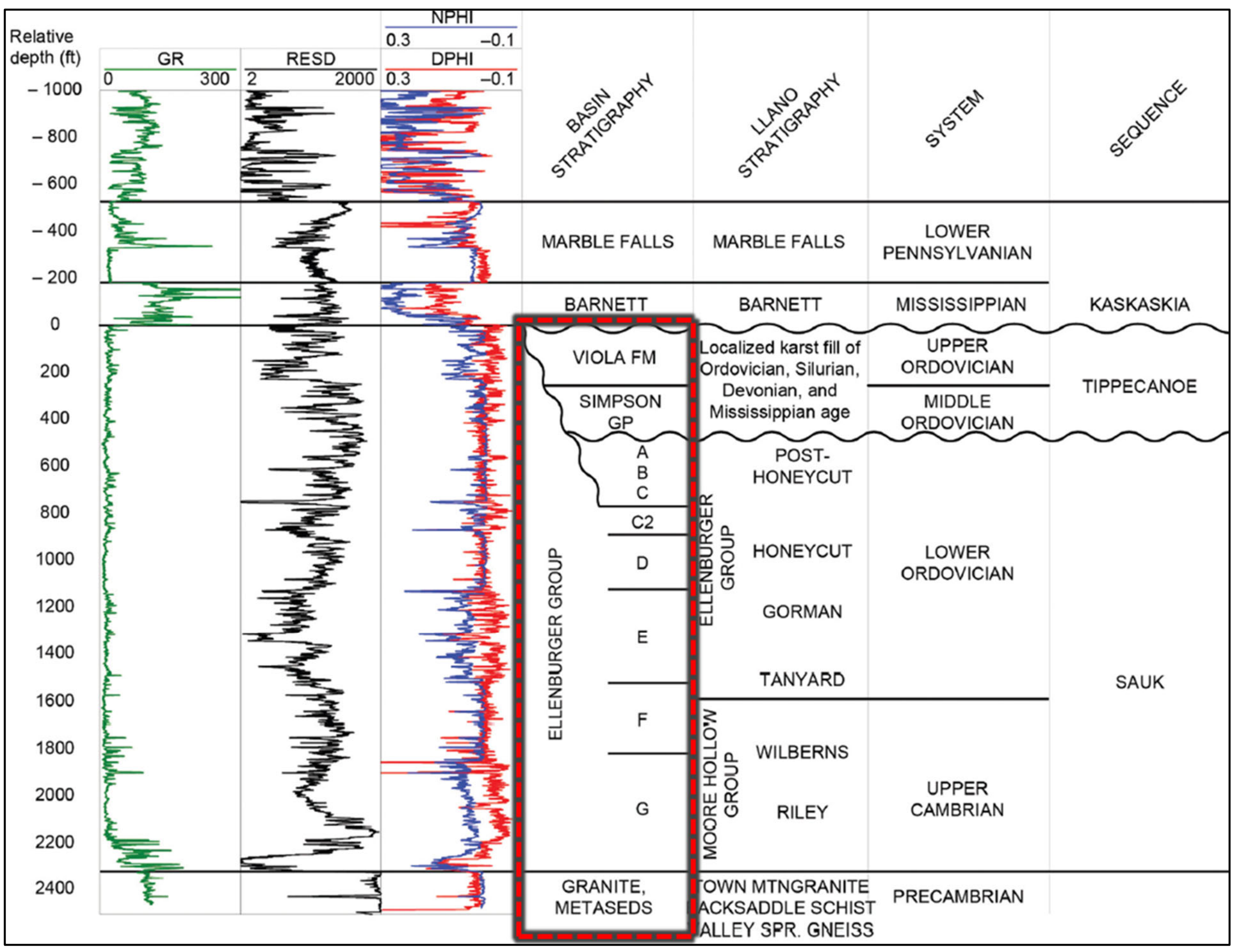

Figure 5. Regional stratigraphy at dCarbon site in North Texas (modified from Smye *et al.*[5]).

The Barnett Shale is anticipated to serve as a secondary confining interval. The Barnett Shale is a source rock and an unconventional reservoir that is extensively drilled in the Fort Worth Basin.

The porosities and permeabilities in the Barnett Shale lie in the 4-6% and 7-50 nanodarcies ranges, respectively.

Underlying the Barnett is the Ellenburger Group, which contains both the anticipated storage and confining zones. The Ellenburger could be divided into eight lithostratigraphic units starting with subunit A at the top to subunit G at the bottom which sits on top of the crystalline basement. Subunit G is composed of siliciclastic facies and is largely variable across the region. Though the porosity in subunit G is higher compared to other subunits, lateral continuity might be an issue in developing a storage project in this subunit. Consequently, subunit E will serve as the storage zone given it has approximately 4% matrix porosity. Ellenburger subunit E is a clean dolomitic reservoir zone with 49% dolomite by volume. Subunit B and subunit C were found to have lower matrix porosities compared to subunit E, which should provide vertical confinement or impediment to CO_2 movement. Ellenburger subunit A has been proven to be a reservoir zone with multiple saltwater disposal wells completed in subunit A. However, as mentioned earlier, karsting features at the top of the Ellenburger imply there is some potential for hydraulic communication between subunit A and the overlying Barnett. **Figure 6** illustrates the log response and petrophysical properties of Ellenburger subunits.

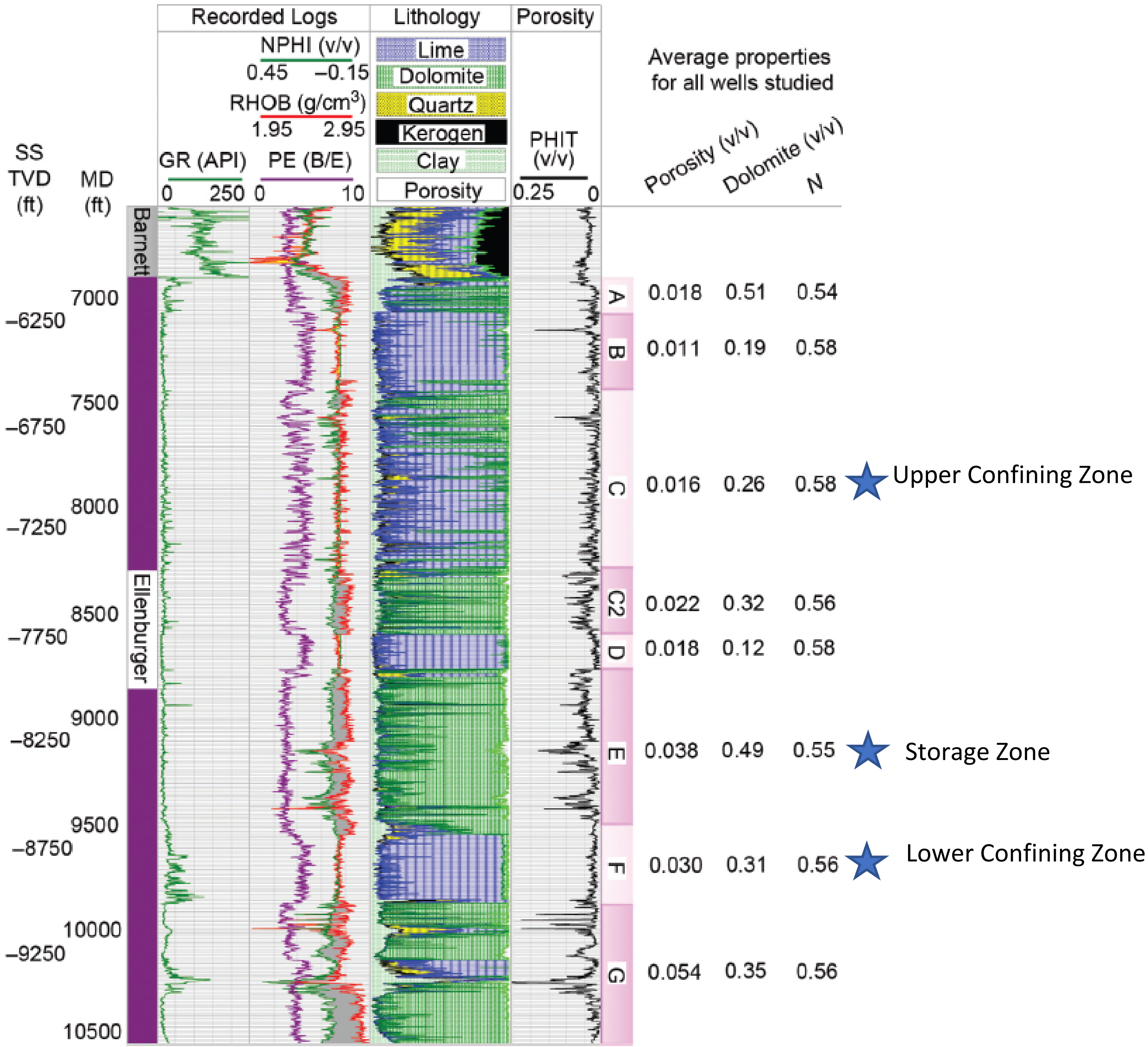

Figure 6. Properties of Ellenburger Group subunits in the project area (modified from Smye *et al.*[5]).

The W.S. Coleman #2 injection well located approximately five miles from the proposed injection site similarly contains Ellenburger subunits A through G, as shown below in **Figure 7**. Drilling at the proposed site should result in site-specific petrophysical properties like those shown here.

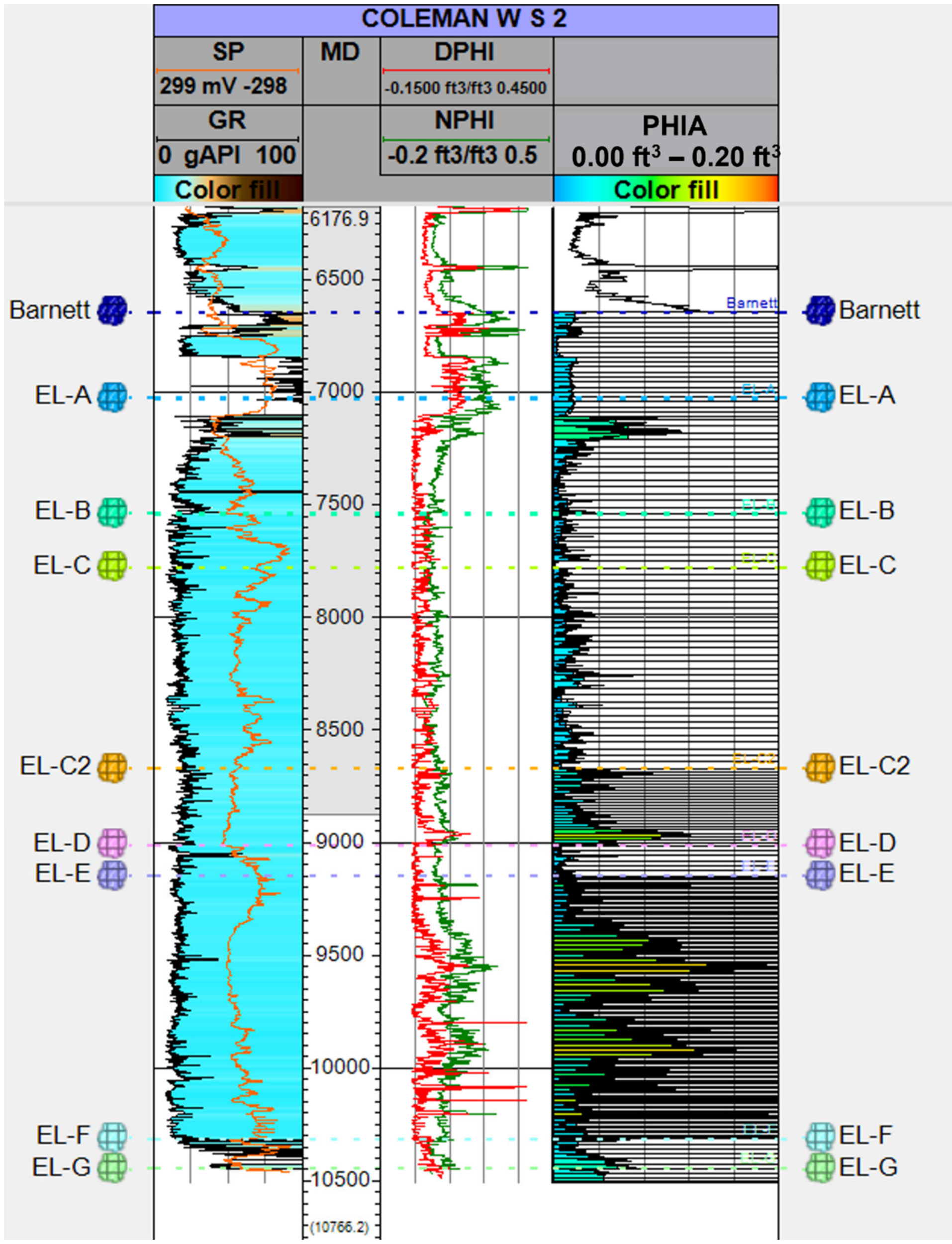

Figure 7. W.S. Coleman #2 well log interpretation; Ellenburger Group subunits A through G are denoted to the right and left of the log image.

Net reservoir thickness was determined for each subunit of the Ellenburger by summing the footage where the average porosity (PHIA) curve was greater than 2%. It is important to note that such a low matrix porosity value was chosen due to the nature of the reservoir wherein fracture porosity is a significant contributor to reservoir quality. Our understanding and evaluation of the Ellenburger suggested a low log porosity could still result in realizable CO_2 storage potential given the history of injectivity from saltwater disposal in the area (*e.g.*, North Tarrant SWD 1 and W.S. Coleman #2 wells). A net-to-gross ratio was determined for each subunit by dividing the net reservoir thickness by the gross reservoir thickness. Average porosity was calculated for each subunit of the Ellenburger by averaging the average porosity (PHIA) curve from the top to the

bottom of the subunit. These reservoir zone properties were subsequently used to derive preliminary storage resource estimates. **Table 2** lists average petrophysical properties in the Ellenburger.

Table 2. Ellenburger Group properties assessed at the project area.

Ellenburger Subunit	Dominant Lithology	Gross Reservoir Thickness (feet)	Net Reservoir Thickness (feet [>2% PHI])	Net-to-Gross Ratio	Average Reservoir Porosity (%)	
A	Dolomite	338	63	0.186	1.1	
B	Limestone	200	14	0.070	0.8	
C	Limestone	940	187	0.198	1.2	Upper Confining Zone
C2	Dolomite	335	229	0.683	3.5	
D	Limestone	49	3.5	0.072	0.6	
E	Dolomite	1252	879	0.702	5.5	Storage Zone
F	Limestone	130	88.5	0.677	3.2	Lower Confining Zone
G	Dolomite	N/A	N/A	N/A	N/A	

Permeability data in individual Ellenburger subunits was obtained from literature. As noted by Gao *et al.*,[2] regional hydrostatic pressure gradient in the Ellenburger was assumed to be 0.47 pounds per square inch (psi) per foot, while the geothermal gradient in the Fort Worth Basin was estimated at 1.4ºF per 100 feet. These parameters were used to run preliminary CO_2 storage calculations as discussed in Section 3.8.

3.4 Formation Fluid Chemistry

Through a review of chemical analyses of oil-field brines from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3, nine wells within 20 miles of the proposed injection well site were identified within the Pennsylvanian age strata, as shown in **Figure 8**. Formation fluid chemistry analyses for these wells are reported in **Table 3**.

Table 3. **Pennsylvanian formation fluid chemistry.**

	TDS (mg/L)	pH	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	86,807	6	26,000	5,494	53,392
LOW	21,926	4.4	6,291	978	13,389
HIGH	149,480	7.1	47,203	9,854	91,765

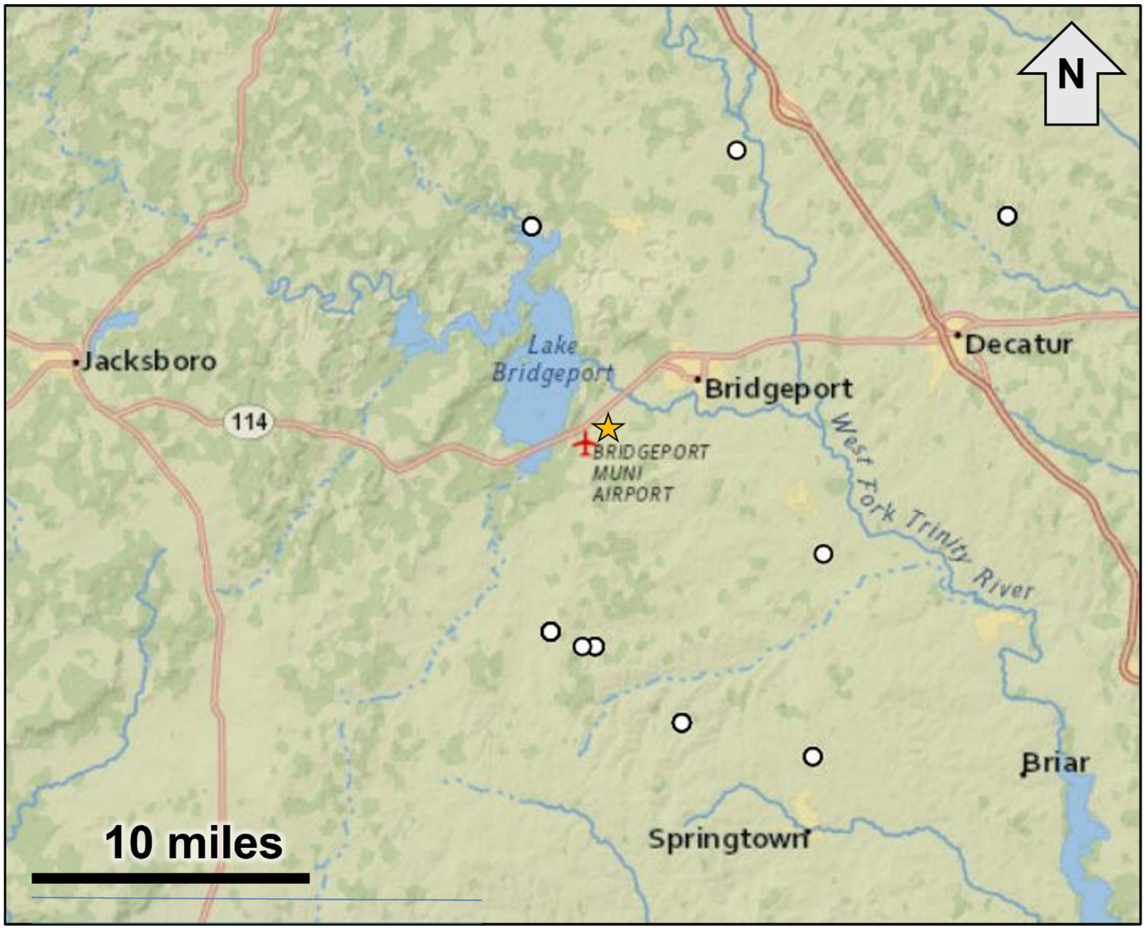

Figure 8. Map showing the location of wells used in the formation fluid chemistry analysis.

The Ellenburger Group has not been extensively drilled within the immediate area surrounding the proposed injection well and consequently formation fluid chemical analyses for the Ellenburger Group are from a basin-wide review. Based on analyses from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3, the Ellenburger fluids have greater than 194,263 parts per million (ppm) total dissolved solids (TDS) within the Fort Worth Basin. Formation fluid chemistry analyses for the Ellenburger Group Fort Worth Basin wells are reported in **Table 4**.

Table 4. Ellenburger Group formation fluid chemistry.

	TDS (mg/L)	pH	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	212,347	6	55,066	18,523	125,209
LOW	194,263	5.7	30,000	12,800	76,200
HIGH	276,388	6.6	66,482	24,750	153,071

3.5 Potential of Induced Seismicity – Ellenburger Group

An analysis of historical seismic events within a 100 square mile radius surrounding the proposed Class II well injection site shows no recorded seismic activity dating back to January 1, 1971, according to the U.S. Geological Survey (USGS) Earthquake Catalog, as illustrated in **Figure 9**. TexNet seismic activity data supports this conclusion, showing no recorded seismic events around the proposed injection well site. Fault slip potential of mapped faults within the Fort Worth Basin was assessed through a literature survey.[7] Current findings show that steeply dipping faults that strike north-northeast have the highest fault-slip potential. A Wise County saltwater disposal well has been permitted for an injection rate of 15,000 barrels per day (bpd) and is located approximately eight miles from the Barnett RDC #1 injection site. This well has been operated without any observed seismic activity.

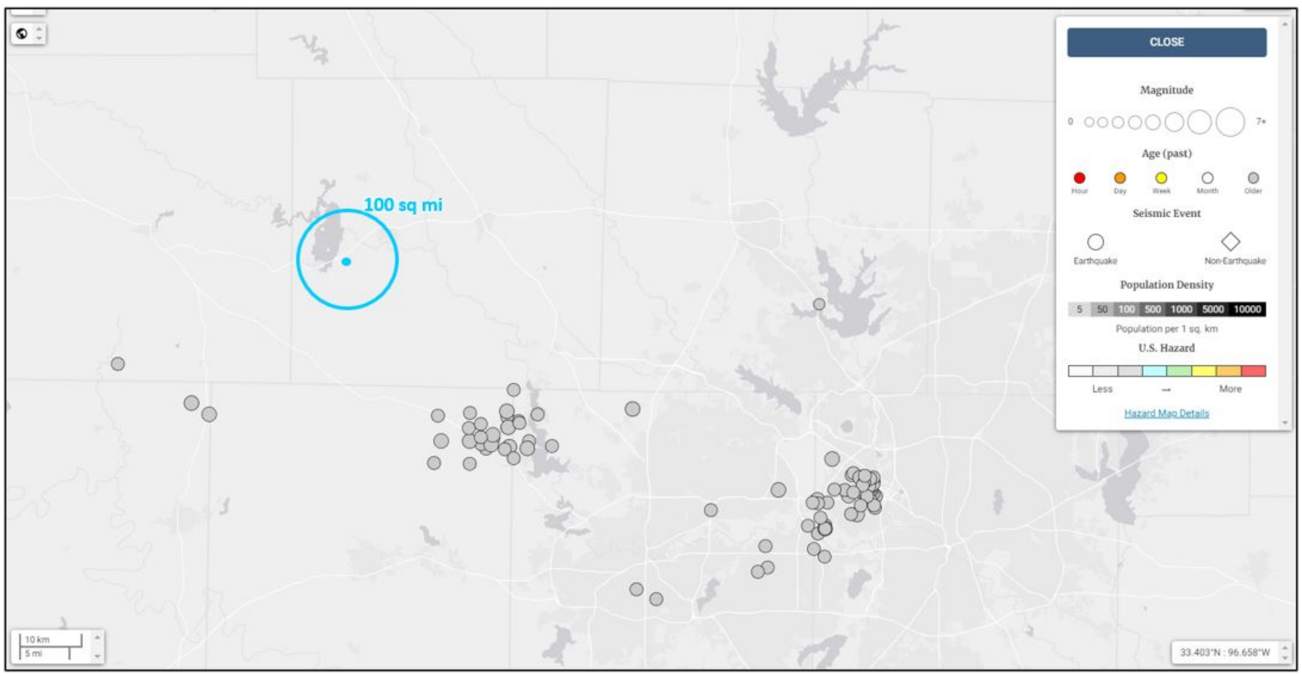

Figure 9. Screenshot from the USGS Earthquake Catalog showing no historical seismic activity in the surrounding 100 square miles to the proposed Barnett RDC #1 site.

3.6 Groundwater Hydrology in MMA

Wise County falls within the Upper Trinity Groundwater Conservation District as mapped by the Texas Water Development Board, shown in **Figure 10**. Two aquifers are within the vicinity of the proposed injection site: the Trinity Group Aquifer, a major aquifer, and the Cross Timbers Aquifer, a minor aquifer. The Lower Cretaceous Trinity Group is an important source of groundwater for a portion of Northern Texas and consequently Wise County, Texas. Lower Cretaceous strata outcrop throughout the majority of Wise County, especially to the east, but are absent at and around the

[7] Hennings, P.H., *et al*., 2019. Injection-Induced Seismicity and Fault-Slip Potential in the Fort Worth Basin, Texas. *Bulletin of the Seismological Society of America* 20 (20), 2019.

proposed injection site, as seen in **Figure 10** and **Figure 11**. Instead, strata from the Cross Timbers Aquifer outcrop on the surface at the proposed injection site. The Cross Timbers Aquifer includes four Paleozoic-age water-bearing formations including, from oldest to youngest, the Strawn, Canyon, Cisco, and Wichita Groups. The Upper Pennsylvanian Strawn Group Willow Point Formation outcrops on the surface at the proposed injection site, and rocks from the Upper Pennsylvanian Canyon Group Jasper Creek Formation outcrop 0.5 miles to the north-northwest of the proposed injection site, shown in **Figure 12**. Strawn and Canyon Group formations are primarily composed of limestones, shales, and sandstones. A stratigraphic column showing the Pennsylvanian through Cretaceous strata is included as **Figure 13**.

The Canyon Group, which outcrops at the proposed injection site, is a sequence of limestones with interstratified shales and sandstones deposited as a part of the Perrin Delta System.[8] Deposition of Canyon Group sandstones was localized within valley fill, distributary channel fill, and delta-front deposits.[9] These sandstone bodies are not laterally continuous and therefore did not constitute a regional scale major aquifer. Nearby groundwater well reports list the aquifer as Paleozoic, supporting the conclusion that freshwater in and around the well site is sourced from Pennsylvanian strata. Because the location of the well site does not fall within one of the major aquifer boundaries described by the Texas Water Development Board, describing the Total Dissolved Solids (TDS) contents of water from the Pennsylvanian Canyon Group is challenging. Consequently, this data will be collected during the drilling process. One TDS measurement from the Pennsylvanian group (formation unspecified) near the well site was recorded as 1,600 ppm.[10] Thus, freshwater wells in the area are likely drawing from localized sands within the Upper Pennsylvanian strata. The USGS's National Produced Waters Geochemical Database (NPWGD) report several TDS content measurements within the Lower Pennsylvanian Atoka/Bend formation with values ranging from 21,926 ppm to 154,593 ppm.[11] No reported TDS values from the USGS NPWGD fall below the 10,000-ppm minimum required to classify an aquifer as an Underground Source of Drinking Water (USDW). Consequently, the lowermost USDW is likely above the Lower Pennsylvanian strata at around 900 feet.

The direction of groundwater flow within Paleozoic strata is suggested to be in the west-northwest direction according to a conceptual model developed by Nicot, *et al*.[12] Recharge into the Canyon Group was estimated to occur at a rate of 0.09 inches per year by the same study. Surface-water salinity decreases downstream toward the Gulf of Mexico. Groundwater salinity increases from

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[8] Brown Jr., L.F., Cleaves II, A.W., Erxleben, A.W., 1973. Pennsylvanian depositional systems in North Central Texas, a guide for interpreting terrigenous clastic facies in a cratonic basin, *Texas Univ. Bur. Econ. Geology Guidebook*, 14 (1973), p. 132.

[9] Blandford, T.N., *et al.*, 2021. Conceptual Model Report for the Cross Timbers Aquifer. Report produced under Texas Water Development Board Contract No. 1948312322.

[10] Winslow, A.G., and Kister, L.R., 1956. Saline-Water Resources of Texas. U.S. Department of Interior Report.

[11] Blondes, M.S., *et al*., 2018. U.S. Geological Survey National Produced Waters Geochemical Database (v2.3, January 2018): U.S. Geological Survey data release, https://doi.org/10.5066/F7J964W8.

[12] Nicot, J.-P., Huang, Y., Wolaver, B.D., and Costley, R.A., 2013. Flow and Salinity Patterns in the Low-Transmissivity Upper Paleozoic Aquifer of North-Central Texas: *Gulf Coast Association of Geological Societies Journa*l (2), pgs. 53-67.

younger to older formations toward the east but there is a reversal in the Strawn Group, whose formations can be in hydraulic contact with the overlying Trinity Aquifer. The Trinity Aquifer may provide cross-formational flow to Paleozoic aquifers when they overlap, with the primary flow direction from the Trinity to the Strawn. This mixing could explain the salinity reversal observed in some parts of Texas within the Strawn Group. Locally, however, the deepest water well within two miles of the proposed injection well is 320 feet deep. This indicates that water wells in the area are drawing fresh water from localized sands within the upper several hundred feet.

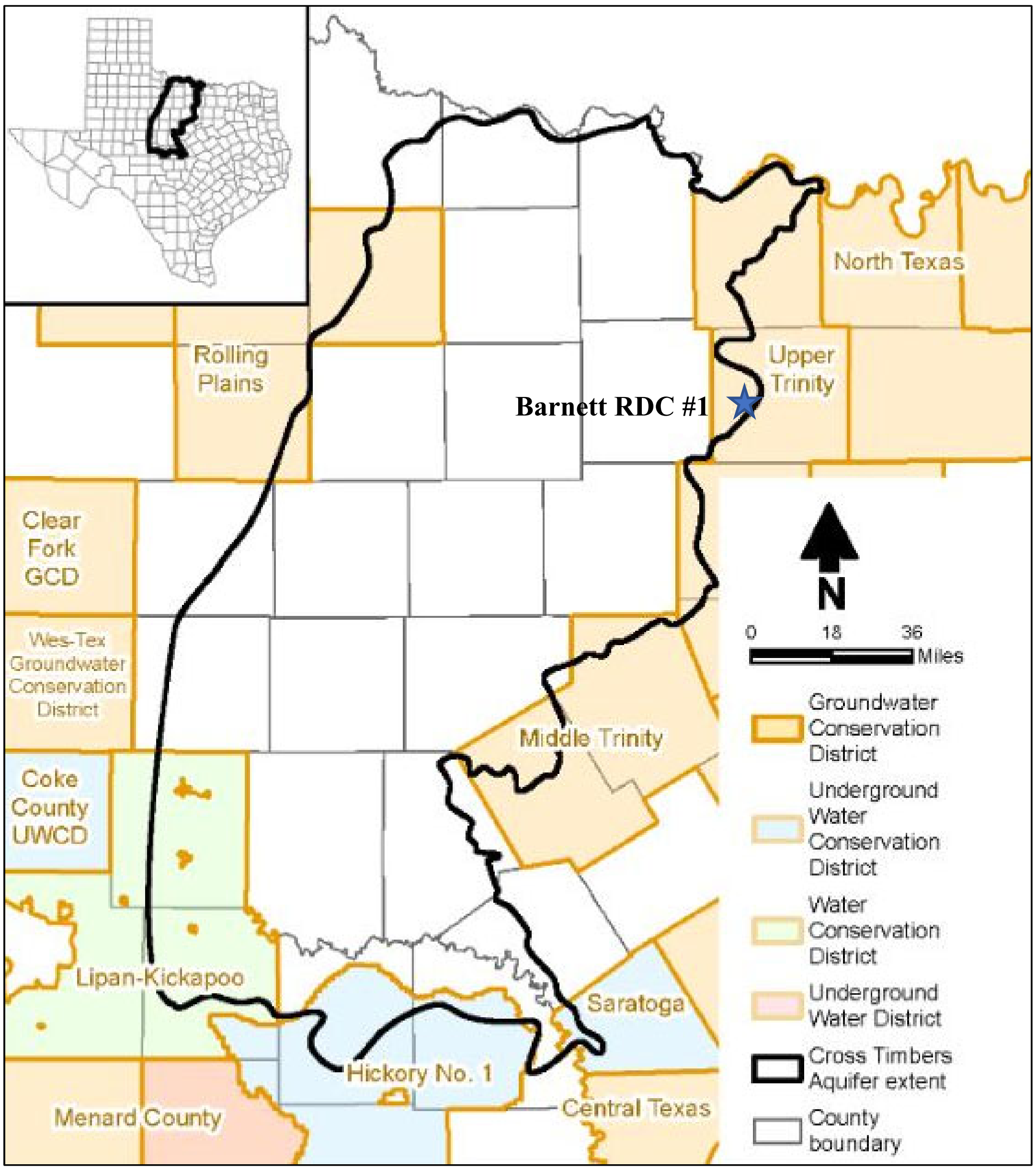

Figure 10. Map of the groundwater conservation districts and the Cross Timbers Aquifer extent within North Central Texas, from the Texas Water Development Board. The location of the proposed Barnett RDC #1 is shown with a star.

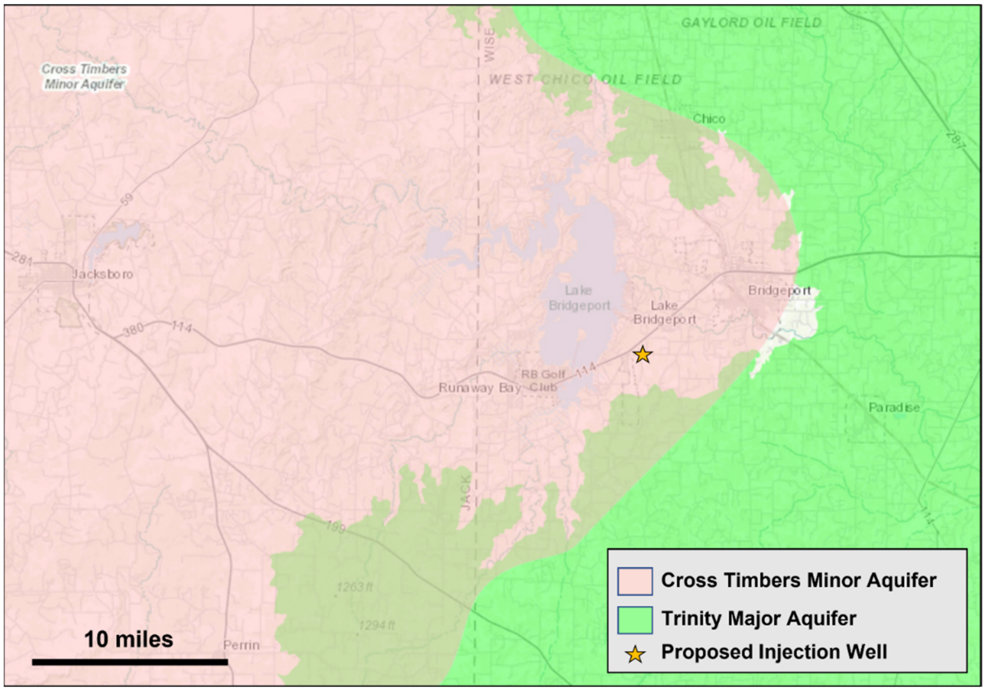

Figure 11. Location of the Cross Timbers minor aquifer and Trinity major aquifer in Texas, with the Barnett RDC #1 location labeled with a star.

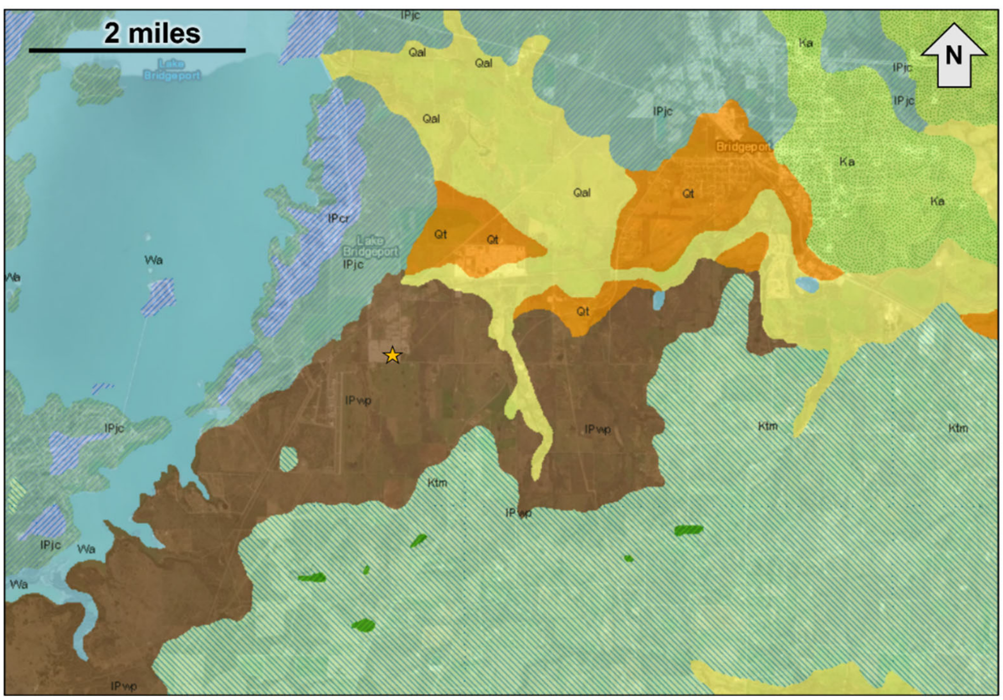

Figure 12. Geologic map of the area near the proposed injection site (yellow star). Geologic formations labeled using the state of Texas' USGS rock units codes, where: Qal = alluvium, Qt = fluviatile terrrace deposits, Wa = water, IPcr = Chico Ridge limestone, IPjc = Jasper Creek formation, IPwp = Willow Point formation, Ktm = Twin Mountains formation, and Ka = Antlers sand.

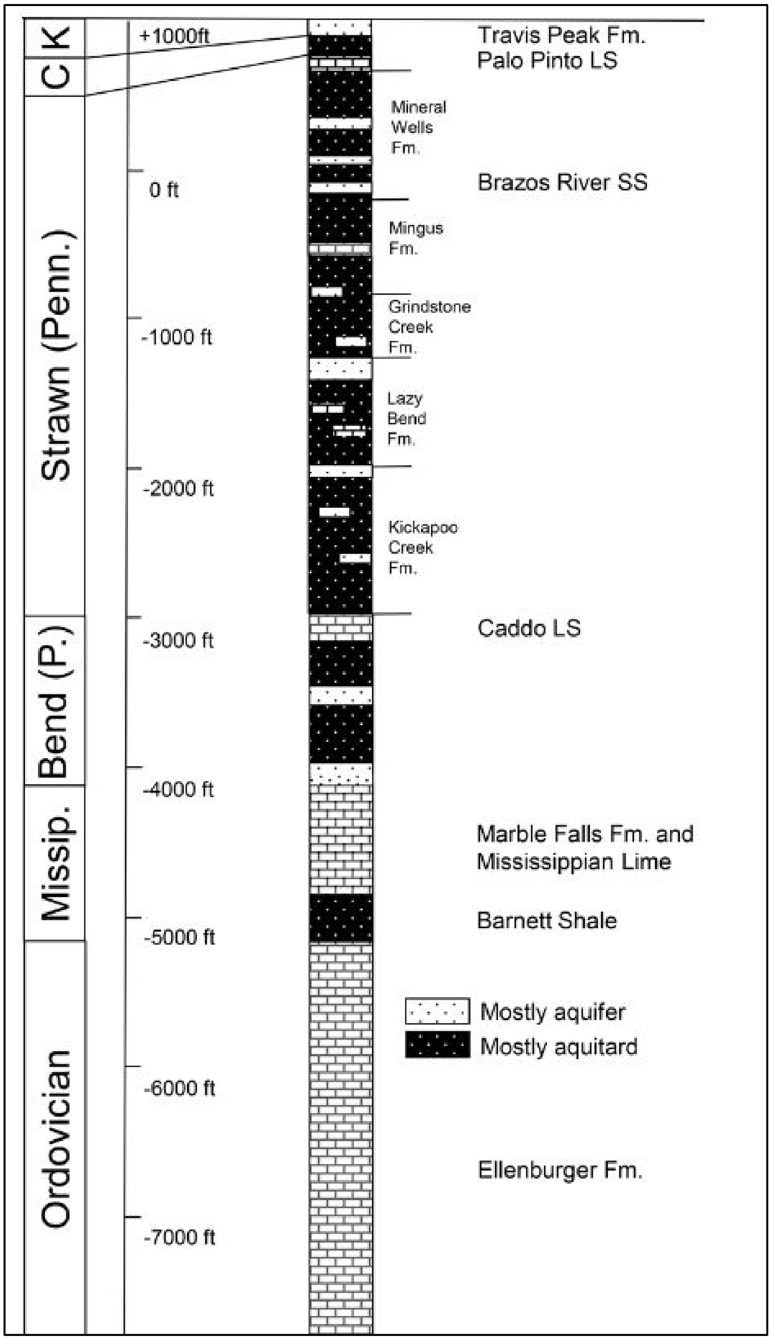

Figure 13. Stratigraphic column including aquifers and aquitards, modified from Nicot *et al.*[13]

There are 105 freshwater wells within a two-mile radius and 26 wells within a one-mile radius of the proposed injection well, according to the Texas Water Development Board Groundwater Data Viewer, shown in **Figure 14** and listed in **Table 5**.

[13] Nicot, J, *et al.*, 2011. Methane occurrences in aquifers in the Barnett Shale area with a focus on Parker County, Texas" University of Texas, 2011, https://deepblue.lib.umich.edu/bitstream/handle/2027.42/137724/gwat12508-sup-0001-supinfo.pdf?sequence=1.

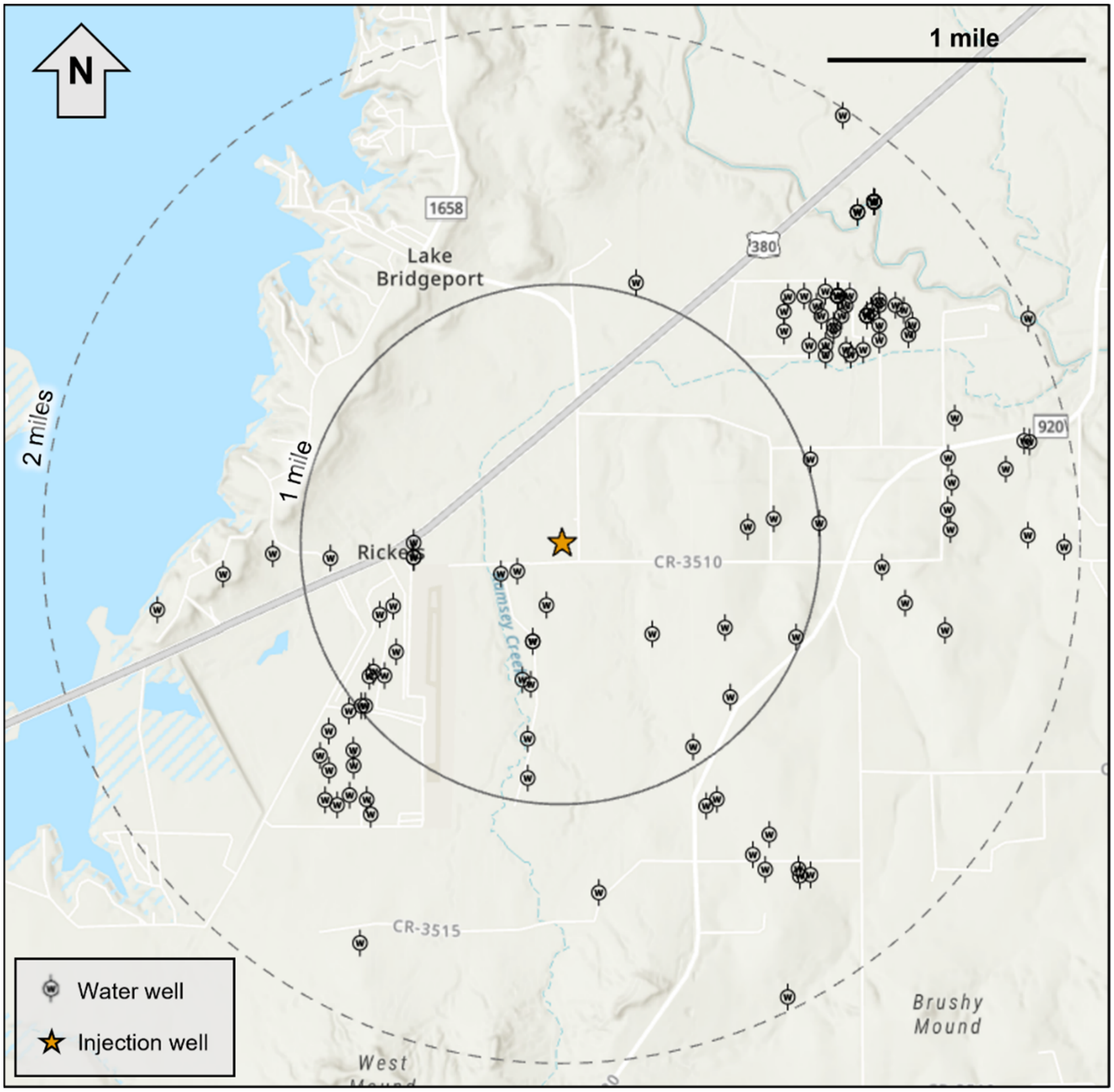

Figure 14. Water wells within one and two miles from the proposed injection site, data from the Texas Water Development Board.

Table 5. Private and state-owned groundwater wells in project area.

Private Groundwater Wells				
Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
324182	33.157501	-97.805278	180	1.97
85836	33.160834	-97.833889	180	1.74
419698	33.1635	-97.817833	160	1.37
494622	33.16434	-97.80437	140	1.59
522108	33.16439	-97.80365	140	1.61
270093	33.164723	-97.806667	200	1.50
131403	33.164723	-97.804445	110	1.57
33173	33.165556	-97.807501	280	1.42
67830	33.166667	-97.806389	100	1.39
592900	33.16871	-97.80986	155	1.16
135520	33.17	-97.8225	140	0.93
71023	33.171667	-97.811389	120	0.94
214384	33.172222	-97.8225	195	0.78
23271	33.174167	-97.833611	280	1.01
23265	33.174167	-97.833334	140	1.00
12854	33.174444	-97.808889	140	0.89
305950	33.175278	-97.822222	110	0.57
86814	33.175555	-97.822778	213	0.56
570517	33.17587	-97.83202	120	0.86
13278	33.176111	-97.832778	140	0.89
585723	33.17721	-97.83121	160	0.77
527914	33.177694	-97.822083	160	0.40
527919	33.177694	-97.822083	160	0.40
190556	33.177778	-97.804445	210	0.98
428746	33.178047	-97.81408	120	0.50
605428	33.17806	-97.79442	180	1.53
107416	33.178333	-97.809167	140	0.72
509874	33.1793	-97.83231	120	0.76
601491	33.17962	-97.79708	200	1.35
53199	33.179722	-97.847222	150	1.60
196527	33.179722	-97.821111	75	0.25
510354	33.179783	-97.831417	130	0.70
430183	33.1815	-97.824139	170	0.27
81235	33.181667	-97.842778	200	1.32
193088	33.181667	-97.823055	240	0.21
373126	33.181667	-97.798611	160	1.25
351852	33.1825	-97.835556	320	0.90
122077	33.1825	-97.83	205	0.58
143619	33.1825	-97.83	140	0.58

Private Groundwater Wells				
Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
474446	33.182659	-97.786404	180	1.95
44219	33.182778	-97.839445	230	1.13
214552	33.183334	-97.83	120	0.58
483302	33.183342	-97.78883	100	1.81
416778	33.18372	-97.79402	180	1.51
479366	33.184019	-97.807589	200	0.72
72275	33.184167	-97.802778	34	1.00
123233	33.184445	-97.805834	32	0.83
457391	33.184833	-97.794167	170	1.50
187174	33.186389	-97.793889	180	1.53
419604	33.187077	-97.790243	180	1.75
574195	33.187771	-97.794087	180	1.53
329665	33.187778	-97.803334	170	1.02
404012	33.188611	-97.788611	260	1.86
422029	33.18865	-97.78897	260	1.84
88487	33.19	-97.793611	103	1.60
72273	33.193611	-97.802223	29	1.25
72269	33.193611	-97.800556	28	1.33
62634	33.193889	-97.800834	33	1.33
72268	33.193889	-97.799722	28	1.39
62627	33.194167	-97.803334	30	1.22
62639	33.194167	-97.802223	28	1.28
219191	33.194445	-97.798611	30	1.46
219202	33.194722	-97.796667	20	1.57
123232	33.195	-97.805001	34	1.19
62632	33.195	-97.801667	33	1.34
329661	33.195278	-97.801667	145	1.35
219187	33.195278	-97.798611	30	1.49
219200	33.195278	-97.796389	24	1.60
219184	33.195556	-97.788611	30	2.01
62616	33.195834	-97.802501	35	1.33
62629	33.195834	-97.801112	35	1.40
49825	33.195834	-97.799445	27	1.47
49826	33.195834	-97.799445	27	1.47
49827	33.195834	-97.799445	27	1.47
49828	33.195834	-97.799445	27	1.47
49829	33.195834	-97.799445	32	1.47
72263	33.196111	-97.805001	30	1.24
62607	33.196111	-97.799167	31	1.50
219198	33.196111	-97.796945	27	1.60
62622	33.196389	-97.802778	38	1.35

Private Groundwater Wells				
Well Report Tracking Number	**Latitude (DD)**	**Longitude (DD)**	**Borehole Depth (feet)**	**Distance from proposed injector (mi)**
62628	33.196389	-97.800834	31	1.43
72267	33.196389	-97.798611	35	1.53
219193	33.196389	-97.7975	20	1.59
219181	33.196667	-97.798611	30	1.55
62626	33.196945	-97.804723	16	1.29
62623	33.196945	-97.803612	16	1.34
41283	33.196945	-97.801389	21	1.43
41284	33.196945	-97.801389	15	1.43
41285	33.196945	-97.801389	15	1.43
41286	33.196945	-97.801389	15	1.43
41287	33.196945	-97.801389	15	1.43
72264	33.196945	-97.800556	34	1.47
62618	33.197222	-97.802223	32	1.41
405842	33.197817	-97.814883	60	1.05
240181	33.201667	-97.800001	20	1.72
240182	33.201667	-97.800001	18	1.72
240183	33.201667	-97.800001	17.5	1.72
213490	33.202223	-97.798889	14.5	1.79
213494	33.202223	-97.798889	15	1.79
213495	33.202223	-97.798889	14	1.79
213496	33.202223	-97.798889	14.5	1.79
213499	33.202223	-97.798889	13	1.79
213500	33.202223	-97.798889	12	1.79
213502	33.202223	-97.798889	11	1.79
516919	33.20712	-97.8009	160	1.98
State Groundwater Wells				
State Well Number	**Latitude (DD)**	**Longitude (DD)**	**Borehole Depth (feet)**	**Distance from proposed injector (mi)**
1950401	33.17389	-97.83445	147	1.06
1950402	33.17278	-97.83583	146	1.17
1950408	33.16917	-97.83445	147	1.28
1950501	33.17583	-97.83306	82	0.91
1950406	33.16861	-97.83528	147	1.34
1950504	33.16806	-97.83306	147	1.29
1950404	33.17139	-97.83639	147	1.25
1950502	33.16833	-97.81056	121	1.17
1950403	33.16889	-97.83611	147	1.36
1950405	33.17083	-97.83417	147	1.19
1950407	33.17167	-97.83417	147	1.15
1950409	33.17056	-97.83583	147	1.27
1950503	33.16889	-97.83333	147	1.26

3.7 Description of CO_2 Project Facilities

dCarbon will accept CO_2 from by the Bridgeport Plant (**Figure 15**). The temperature, pressure, composition, and quantity of CO_2 will be measured and metered according to industry standards, with an orifice meter, Coriolis meter, or similar device. dCarbon will dehydrate and compress the CO_2 to a supercritical physical state at the Bridgeport site. dCarbon will then transport the CO_2 via pipeline approximately 6,815 feet to the Barnett RDC #1 injection site. Once at the well site, the CO_2 stream will again be metered to reverify quantity. The CO_2 will then be injected into the Ellenburger formation. This formation is deeper than other formations known to be productive of oil and gas in the area. A gas analysis of the CO_2 stream is shown in **Table 6**. Although this sample is expected to be representative of the composition of the gas, it is possible that the composition will vary slightly in time.

Table 6. CO_2 stream analysis for the Barnett RDC #1 site.

Name	**Normalized Weight Percent**	**Normalized Mole Percent**	**Normalized Liquid Volume Percent**
Nitrogen	0.002	0.003	0.002
Carbon Dioxide	99.358	99.054	98.646
Methane	0.105	0.287	0.286
Ethane	0.4	0.584	0.916
Propane	0.018	0.018	0.029
Isobutane	0.003	0.002	0.004
N-butane	0.008	0.006	0.011
Isopentane	0.002	0.001	0.003
N-pentane	0.002	0.001	0.003
Hexanes	0.011	0.008	0.013
Heptanes	0.011	0.002	0.011
Octanes	0.007	0.001	0.007
Nonanes	0.009	0.002	0.009
Decanes plus	0.004	0.001	0.004
BTEX	0.06	0.03	0.056
H_2S	0.00002	0.00002	0.00002
Total	100	100	100
Total Sample Properties			
Property	Value		
BTU (Gross)	16.04		
Density (lbs/gal)	12.63		
Molecular weight	43.87		
Specific gravity (Air=1)	1.5147		

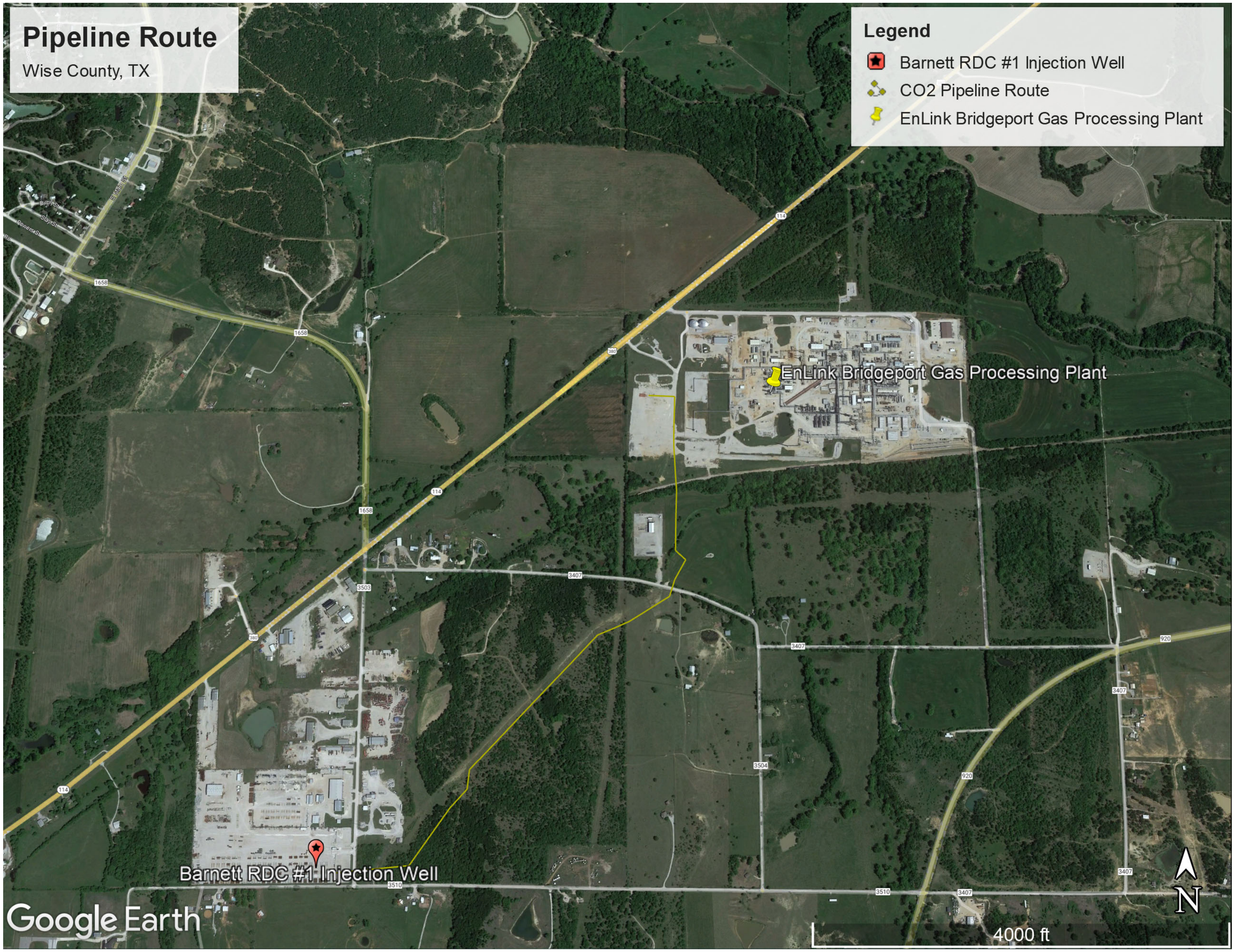

Figure 15. Proposed pipeline route.

3.8. Reservoir Characterization Modeling

A regional model encompassing nearby plugged and abandoned wells as well as saltwater disposal wells was created in Schlumberger's Petrel software. The model incorporates available well petrophysical data and generates a static earth model (SEM) for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the W.S. Coleman SWD #2 well (approximately five miles east of Barnett RDC #1, as discussed in previous sections). The reservoir is characterized by low matrix porosities as well as naturally existing fractures which are likely to contribute to fluid flow. For the current assessment, a single porosity, single permeability distribution model was deemed appropriate given the uniformity of natural fracture distribution within the Ellenburger as well as saltwater disposal rates and volumes into the Ellenburger in nearby counties. These assumptions will be examined and verified using a pressure fall-off test (PFOT) that will be conducted during the construction of the Barnett RDC #1 well. If PFOT and logging programs detect deviations from anticipated reservoir behavior, dCarbon will use the new data to update reservoir models, as well as injection forecasts and the MRV plan if appropriate.

The primary objectives of the simulation model were to:

1. Estimate the maximum areal extent of the injectate plume and its migration post injection.
2. Determine the ability of the target formation to handle the required injection rate.
3. Characterize potential interaction between the injected CO_2 and any nearby potential leakage pathways.

The CO_2 storage complex, as indicated previously, is anticipated to be confined to the Ellenburger interval. Ellenburger subunit E is modeled as the reservoir unit while Ellenburger C subunit is anticipated to provide a primary seal that impedes vertical fluid flow. The Barnett Shale is expected to serve as a secondary seal which provides an additional stratigraphic seal to the injected CO_2. The lower confining zone for the reservoir is provided by the Ellenburger F subunit. A 12-mile by 12-mile tartan grid was generated in Schlumberger's Petrel software based on well top information from nearby legacy and saltwater disposal wells. The grid was then exported to Computer Modeling Group's General Equation of State Model (CMG-GEM) simulator to account for fully implicit multiphase compositional fluid flow. This simulation was built to model other transport and mixing phenomena such as relative permeability, diffusion, advection, aqueous solubility, and buoyancy to accurately predict the plume movement. The reservoir is modeled to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 200,000 TDS, which is typical of the Ellenburger formation in the project area. The injected gas stream is assumed to be fully composed of CO_2. **Figure 16** illustrates the vertical layering with relationship to simulated CO_2 saturation profile in the model. The injection rate modeled was 280,000 MT/year for 12 years followed by 100 years of post-injection timeframe to observe post-injection movement of CO_2.

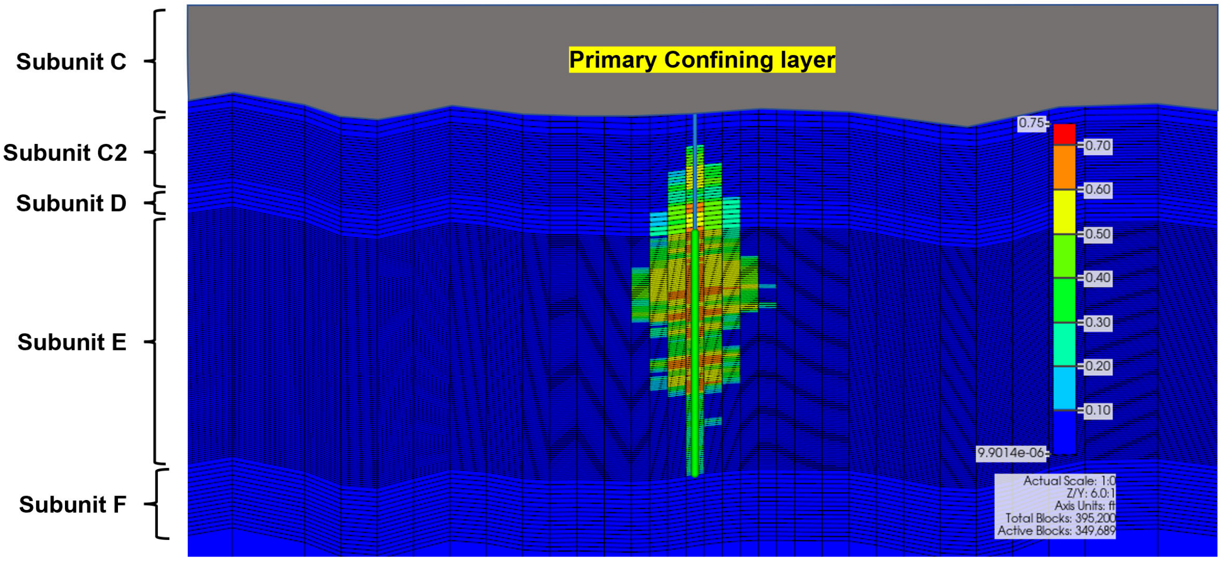

Figure 16. Vertical CO_2 saturation Profile of the CMG-GEM Model for Barnett RDC #1 Well. Color scale in Figure 16 indicates CO_2 gas saturation.

Datasets prepared for simulations were based on published literature. Specifically, the reservoir relative permeability model used in this model was sourced from literature[14] using data from the Wabamun Carbonate reservoir formation, which exhibited comparable porosities and permeabilities as the Ellenburger. The initial reservoir conditions were developed using gradients derived from literature.[2] The pressure gradient was assumed to be 0.47 psi per foot, which resulted in an estimated reservoir pressure of 4,136 psi at the top of the injection interval. The temperature gradient was assumed to be 1.5ºF per 100 feet, resulting in an estimated temperature of 201ºF at the top of the reservoir. Fracture pressures were estimated at 0.7 psi per foot. To ensure CO_2 injection does not induce fractures within the Ellenburger, injection well bottom hole pressure (BHP) was constrained to 90% of calculated fracture pressure, thereby applying a safety factor of 10%. This resulted in a maximum bottom hole injection pressure constraint of 5,524 psi. There are no active wells injecting or producing from the injection interval in the project area. Therefore, no additional wells other than injector were included in the fluid flow simulation model.

As mentioned earlier, injection was modeled at 280,000 MT/yr. The model simulated 12 years of active injection followed by 100 years without injection to determine when plume migration stops. Plume migration ceased after 50 years post-injection, which is determined to be the maximum extent of the CO_2 plume. **Figure 17** shows the CO_2 plume at the end of injection (yellow) compared to 50 years post injection (red). Injected CO_2 flows generally west, which is the regional up dip direction. However, the change in CO_2 plume area from end of injection to 50 years post-injection is minimal (approximately 29%) and the plume stops moving after 50 years.

[14] Bennion, D.B., and Bachu, S., 2007. Permeability and Relative Permeability Measurements at Reservoir Conditions for CO_2-Water Systems in Ultra Low Permeability Confining Caprocks. SPE Paper # 106995.

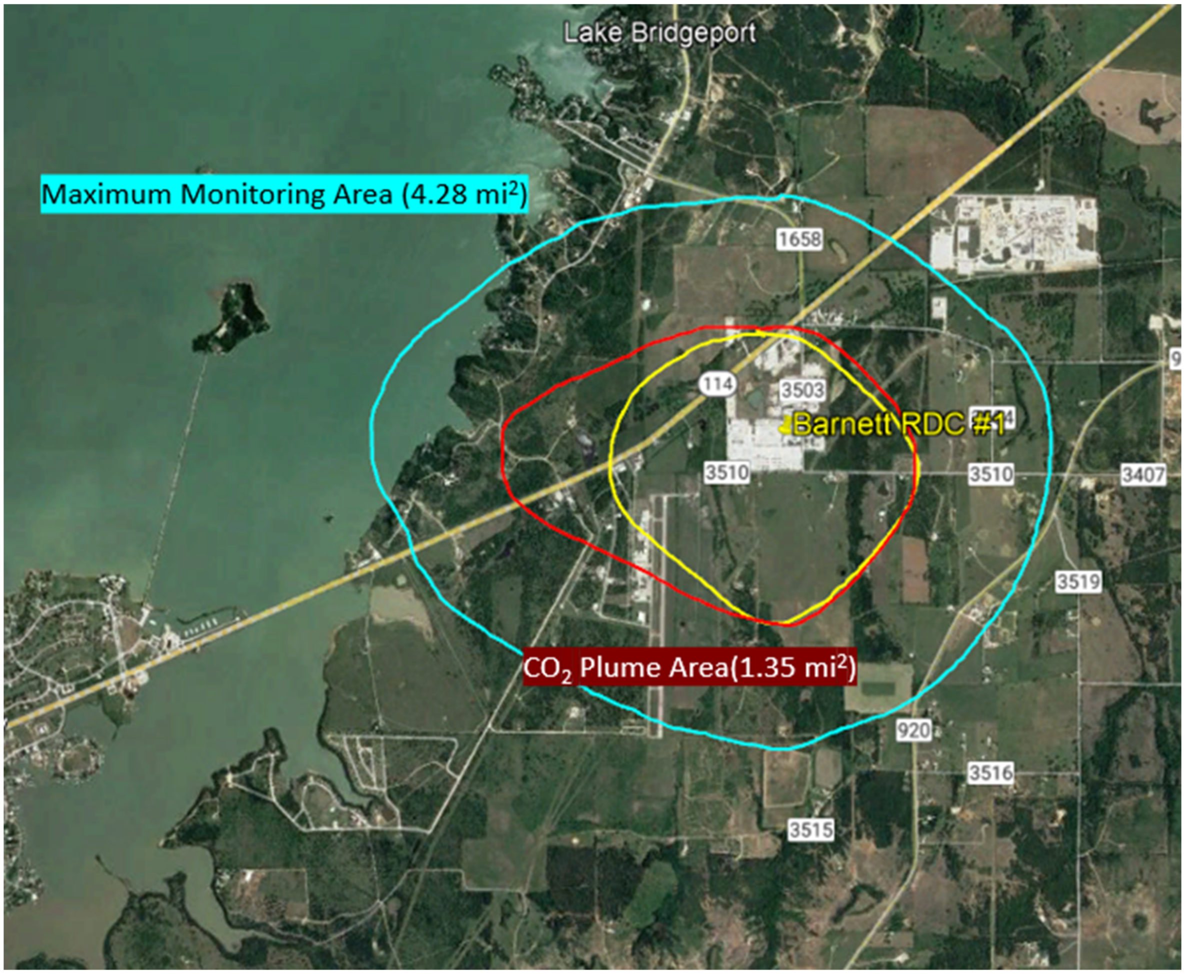

Figure 17. Simulation Results Showing CO_2 Plumes (end of injection – yellow, after 50 years of injection – red) and the Maximum Monitoring Area (blue).

Figure 18 illustrates CO_2 mass injection rate, cumulative CO_2 injection mass, and bottom hole pressure at the Barnett RDC #1 well as modeled. The bottom hole pressure remained well under the bottom hole pressure constraint. The maximum bottom hole pressure reached is 4,434 psi (1,090 psi lower than the BHP constraint), which occurs six months after the start of injection. This spike is anticipated to be a result of near wellbore effects arising from CO_2 forcing its way into the brine-filled porous media. Upon reaching a critical mass to transition from capillary driven to advection driven flow, the BHP starts to decline until the end of injection while keeping the injection rate constant. The BHP then falls until the end of injection.

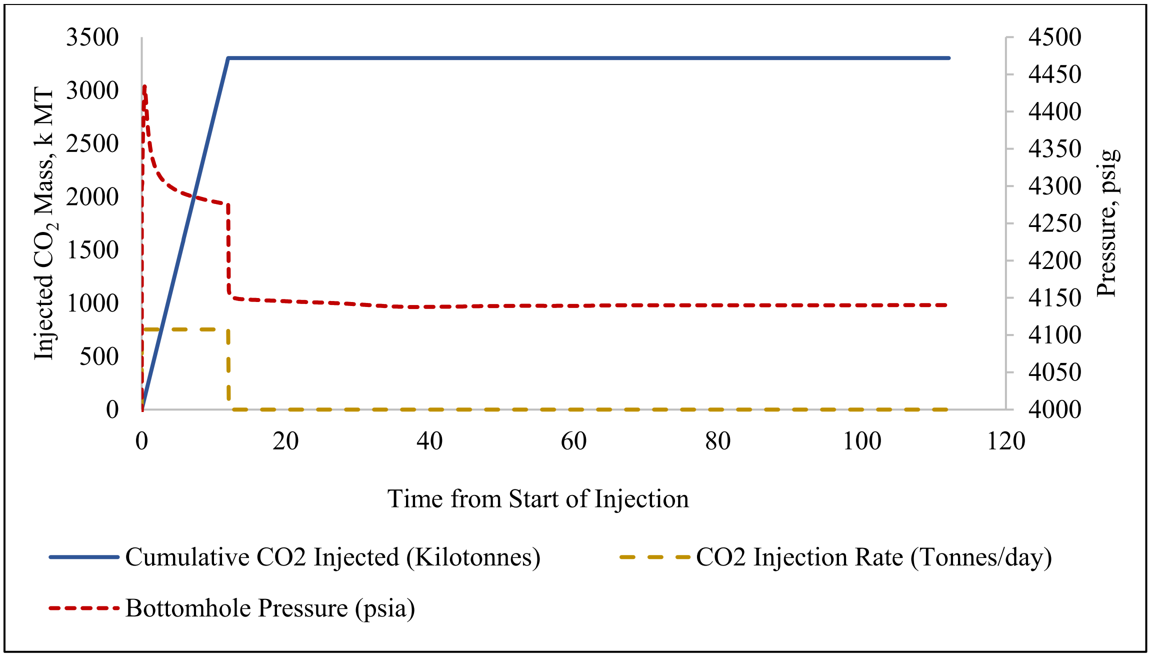

Figure 18. Modeled Injection Profile at Barnett RDC #1 Well.

4 – DELINIATION OF MONITORING AREA

4.1 Maximum Monitoring Area (MMA)

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The numerical simulation using CMG-GEM as discussed above was used to estimate the size and migration of the CO_2 plume. The model injected into the Ellenburger subunit E formation. CO_2 injection was modeled for 12 years followed by 100 years post injection. Results indicated that the plume ceased to migrate after 50 years post injection. For more information on the simulation construction and setup, please see the discussion in Section 3.8. A 5% cutoff of molar gas concentration was used to determine the boundary of the CO_2 plume. The area of the maximum monitoring area was determined to be 4.28 square miles with the greatest extent reaching 1.62 miles from the injector. **Figure 19** shows the end of injection plume (yellow), the 50-year post injection plume (red), and the maximum monitoring area using a half mile buffer (blue).

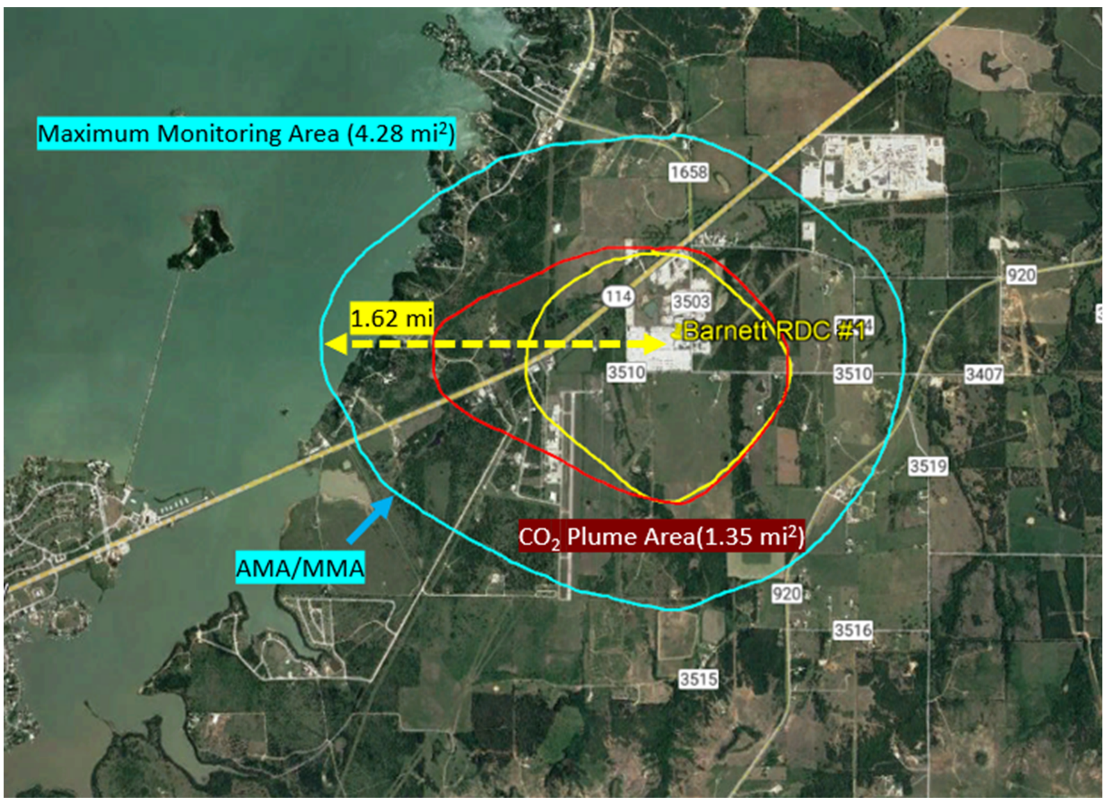

Figure 19. Maximum Monitoring Area (blue), End of Injection Plume (yellow), and 50-year Post Injection Plume (red) as Modeled at the Barnett RDC #1 Well.

4.2. Active Monitoring Area (AMA)

As discussed in Section 3, there are no structural or geological features within the project area that could cause the unintended migration of the CO_2 plume. The only potential leakage pathways that exist are well penetrations and the surface equipment. Leakage from groundwater wells, faults and

fractures, leakage through the confining layer, and seismicity events are expected to be highly improbable. That said, these leakage pathways have been considered and options to monitor them are discussed in Section 4 and Section 5. Sufficient care and consideration will be provided to monitoring these pathways, if any, and simulation models will be calibrated with new data as appropriate.

dCarbon adhered to the definition of active monitoring area (AMA) provided in 40 CFR 98.449 to delineate the AMA for this project. As noted in Section 6, dCarbon proposes to monitor the injection site from year one through year 14, which includes 12 years of injection plus two years of post-injection monitoring. As defined in 40 CFR § 98.449, the AMA must be delineated by superposition of:

(1) The area projected to contain the free phase CO_2 plume at the end of year 14, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

(2) The area projected to contain the free phase CO_2 plume at the end of year 19.

As noted in Section 4.1, dCarbon utilized the plume area after 50 years of post-injection plus a one-half mile buffer to determine the MMA, which far exceeds the definition of AMA set forth in 40 CFR § 98.449. Therefore, the AMA is proposed to have the same boundary as the MMA, which adequately covers the area that is required by 40 CFR § 98.449. **Figure 19** shows the MMA, which is the same as the AMA. **Figure 20** indicates the AMA/MMA (blue line) and currently existing water and oil and/or gas wells within this area. None of these wells were found to penetrate the Ellenburger within the project area. Water wells in the region are shallow with drilled depths up to 320 feet from surface. Additional discussion on well infrastructure within the project area can be found in later sections of this document.

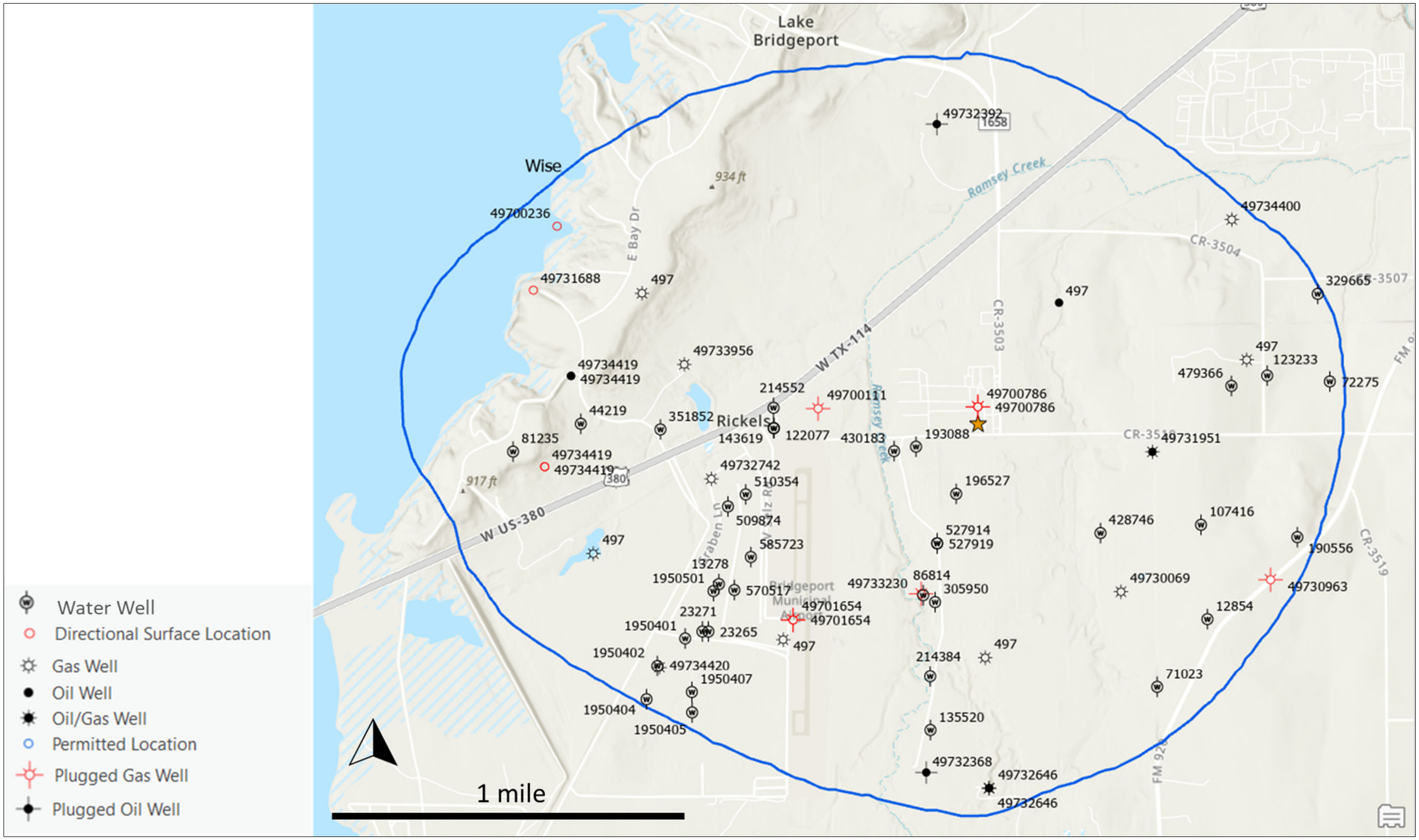

Figure 20. Maximum/Active Monitoring Area (blue) and existing wells within the project AMA/MMA. The Barnett RDC #1 is shown as a star.

5 – IDENTIFICATION AND EVALUATION OF POTENTIAL LEAKAGE PATHWAYS TO SURFACE

5.1 Potential Leakage from Surface Equipment

dCarbon's surface facilities at Bridgeport and at the injection well site are specifically designed for injecting the CO_2 stream described in **Table 6**, including H_2S. The facilities minimize leakage points such as valves and flanges by following industry standards and best practices. All BKV and dCarbon field personnel are required to wear gas monitors that detect H_2S. A shut-in valve is located at the wellhead in case of emergency. The compressor will also have emergency shut down switches that can be activated in case of unexpected operating conditions.

Additionally, the compressor facility, pipeline, and injection well locations will all be subjected to Auditory, Visual, and Olfactory (AVO) and Forward Looking InfraRed (FLIR) leak detection per BKV and dCarbon safety and operations standards. These recurring inspections, which are standard for detecting leaks and malfunctioning equipment in the gas production industry, will aid in the rapid detection of any potential leaks that may occur. As a part of these inspections, operations personnel are frequently able to repair leaks immediately by tightening valves, flanges, or similar equipment. Any leaks that are detected will be analyzed to determine the amount of CO_2 that may have leaked. These leakage quantities, if any exist, will be included in recurring reporting.

5.2 Leakage from Approved, Not Yet Drilled Wells

There are no active well permits within the MMA. However, there are multiple expired well permits within the MMA that would require re-permitting before being drilled. Details on many of the expired permit locations are included in Attachment B.

5.3 Leakage from Existing Wells

There are 20 existing wells within the MMA. Of these 20 wells, 14 have digital records available on the TRRC website, as shown in **Table 6**. Six wells have been plugged and abandoned, while eight remain active. However, all 14 of these wells are shallower than the proposed disposal interval from this project. In fact, the targeted injection interval (which is greater than 9,350 feet) is approximately 3,000 feet deeper and separated by numerous impermeable zones from the deepest existing well in the MMA (API number 42-497-34419, which has a total depth of 6,334 feet). These wells are represented relative to the project MMA in **Figure 20**. The six remaining wells that were drilled within the MMA, listed in **Table 7**, do not have digital records available on the TRRC website, but dCarbon acquired paper copies of the well permit information, and are attached herein as Attachment B. All six wells were drilled significantly shallower than the target Ellenburger formation. In fact, the deepest of the six wells was drilled to 6,155 feet true vertical depth (TVD), several thousand feet shallower than the Ellenburger formation. Note that the well labeled as D in **Table 7** below is a dual completion but single wellbore. There is one additional well that was permitted but never drilled (labeled as B in **Table 7**)

Additionally, the wellbore design of the injection well contains three layers of steel casing, each of which runs to the surface to ensure complete isolation of wellbore fluids. Each of these three casing strings will be cemented to the surface and inspected with cement bond logs to ensure wellbore integrity. Finally, all injection into the well will occur through a final steel tubing string that is secured in place with a permanent packer. All these aspects of wellbore construction are designed to ensure that all CO_2 is injected into the target formation and that there are no leakage pathways from the wellbore directly into shallower formations.

Table 6. Existing Oil & Gas wells in MMA with digital TRRC records.

API	Well Type	Latitude	Longitude	Status	Total Depth (feet)	Operator	Plug Date
49730069	Gas	33.17562	-97.8131	Open	6,128	Scout Energy Management, LLC	-
49732742	Gas	33.18044	-97.8331	Open	5,900	Eagleridge Operating, LLC	-
49733956	Gas	33.18517	-97.8344	Open	5,950	Eagleridge Operating, LLC	-
49734400	Gas	33.19088	-97.8075	Open	5,920	Eagleridge Operating, LLC	-
49734420	Gas	33.17271	-97.8357	Open	5,950	Eagleridge Operating, LLC	-
49734419	Oil	33.18474	-97.8399	Open	6,334	Merit Energy Company	-
49734419	Oil	33.18474	-97.8399	Open	6,334	Eagleridge Operating, LLC	-
49731951	Oil/Gas	33.18137	-97.8115	Open	6,125	Scout Energy Management, LLC	-
49700111	Plugged (Gas)	33.18328	-97.8278	Plugged	5,899	Mitchell Energy Corporation	4/16/1996
49700786	Plugged (Gas)	33.18328	-97.82	Plugged	5,918	Williams Petroleum Company, Inc.	2/13/2015
49701654	Plugged (Gas)	33.17462	-97.8292	Plugged	6,027	Enserch Exploration, Inc.	9/27/1996
49733230	Plugged (Gas)	33.17563	-97.8229	Plugged	5,950	Merit Energy Company	11/5/2012
49732368	Plugged (Oil)	33.16827	-97.8227	Plugged	6,000	Merit Energy Company	1/8/2001
49732392	Plugged (Oil)	33.19493	-97.8219	Plugged	5,964	Merit Energy Company	3/19/1999

Table 7. Existing Oil & Gas wells in MMA without digital TRRC records.

API	Well Type	Latitude NAD27	Longitude NAD27	Status	Total Depth (feet)	Attachment B Label	Lease / Well Name	Operator
497-01653	Gas	33.188107	-97.83638	Open	5,602	A	Craft Water BD 19-1/ DW Harrison Lease	Lone Star Production
No API	N/A	33.184969	-97.827819	Expired Permit	N/A	B	McLanahan	N/A
497-00009	Oil	33.187529	-97.815993	Open	6,200	C	HH Wharton Gas Unit 1A	A'Mell Oil Properties
497-01686	Gas	33.185100	-97.806835	Plugged	5,996	D	Kate A Stanfield 1	Lone Star Production
497-03093	Oil	33.185100	-97.806835	Plugged	5,996	D	Kate A Stanfield 1A (dual completion of 497-01686)	Lone Star Production
497-30085	Gas	33.172971	-97.819788	Open	5,389	E	CR Upham JR #2 Shilling Harold Lease	Upham Oil & Gas
497-1	Gas	33.1738	-97.829657	Plugged	6,027	F- Same as 497-01654	Craft Water Board Sampson #1	Lone Star Prod/Ensearch
497-01646	Gas	33.177438	-97.838912	Plugged	5,968	G	Craft Water Board 8-1	Lone Star Production

5.4 Potential Leakage from Fractures and Faults

Several episodes of fault formation took place in the Fort Worth Basin, based on 3D seismic data interpretation conducted by dCarbon. The oldest set of faults displaced Ordovician rocks but did not displace Mississippian rocks like the Barnett Shale. A younger set of faults displaced Mississippian and older rocks and appear to be related to the Ouachita Front collision. These faults show displacement up into the Pennsylvanian rocks as high as the Strawn. These larger, younger faults have greater displacement but are relatively sparce.

No faulting is interpreted in the MMA around the Barnett RDC #1 based on available subsurface data including 3D seismic data. Dynamic modeling conducted to date indicates that the CO_2 plume will not intersect any mapped faults, based on dCarbon's existing 3D seismic interpretations.

Karst development is present in some areas at the top of the Ellenburger, primarily where the overlying Viola and Simpson Formations were eroded. Karsting is often developed in the upper several hundred feet of an exposed carbonate (Ellenburger subunit A) where fresh water is able to

dissolve the rock (**Figure 21**). Subsequent loading of sediment can cause the roof of the cave to collapse, with overlying sediment filling the void.[15]

The injection interval, the Ellenburger subunit E appears to be below the portion of the upper Ellenburger affected by the karst collapses. This suggests that the Ellenburger subunit C will remain a continuous upper seal even in karst areas. There are no interpreted karst features that the CO_2 plume or pressure front intersects based on the dynamic modeling. Small karst features sit at the southern edge of the MMA but only seem to have impacted the upper 200 feet of the Ellenburger, leaving 3,000 feet of Ellenburger apparently unaffected (**Figure 22**).

Even if the plume reaches the karst features on the south end of the MMA and the Ellenburger subunit C upper seal is not intact, the overlying and impermeable Barnett Shale, Marble Falls Limestone, and the Atoka Shales are expected to prevent migration to shallower depths.

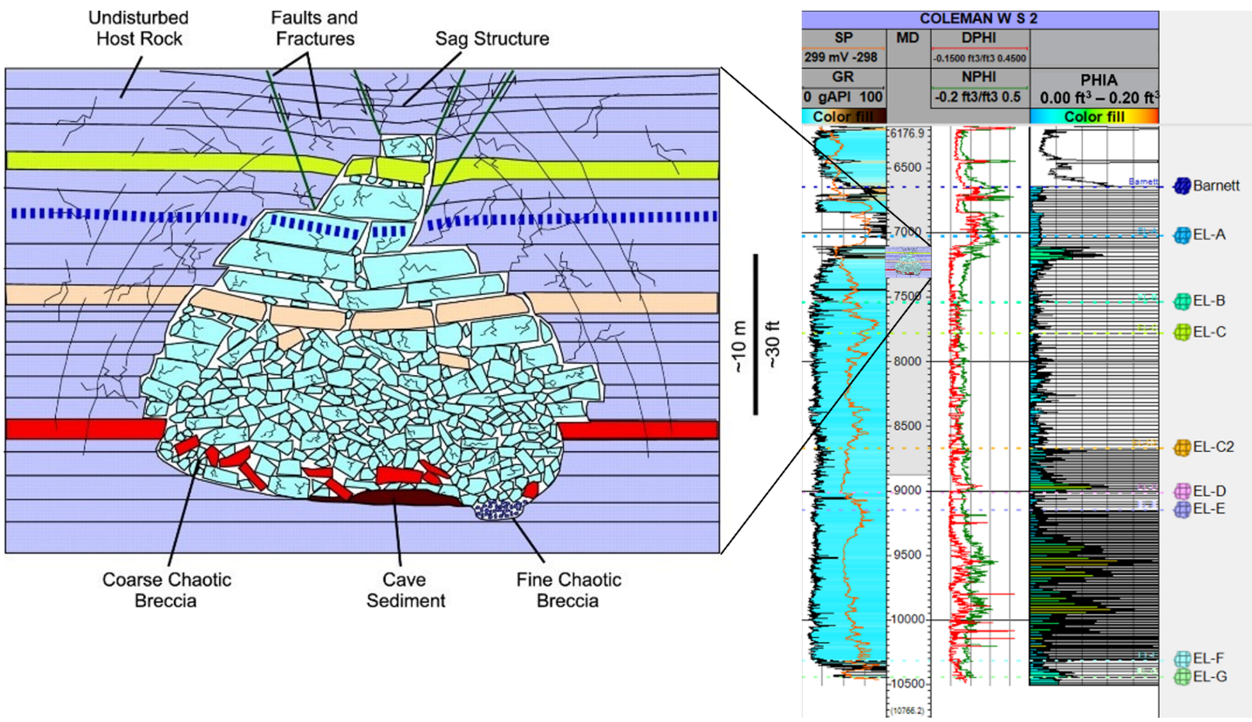

Figure 21. A schematic diagram showing the geometry and component facies of a single cave passage buried in deeper subsurface where collapse and extensive brecciation occurred (modified from Zeng *et al.*[16]). The typical scale of the karst features is shown on the right placing the feature on the W.S. Coleman #2 well log. Note that the interpreted karst features are only observed in the upper portion of the Ellenburger, above the confining unit Ellenburger subunit C.

[15] Zeng, H., 2011. Characterizing seismic bright spots in deeply buried, Ordovician Paleokarst strata, Central Tabei Uplift, Tarim Basin, Western China. *Geophysics* 76 (4), 2011.

[16] Zeng, H., *et al*., 2011. Three-dimensional seismic geomorphology and analysis of the Ordovician paleokarst drainage system in the Central Tabei Uplift, Northern Tarim Basin, Western China. *American Association of Petroleum Geologists Bulletin* 95 (12), pgs. 2061–2083. 2011.

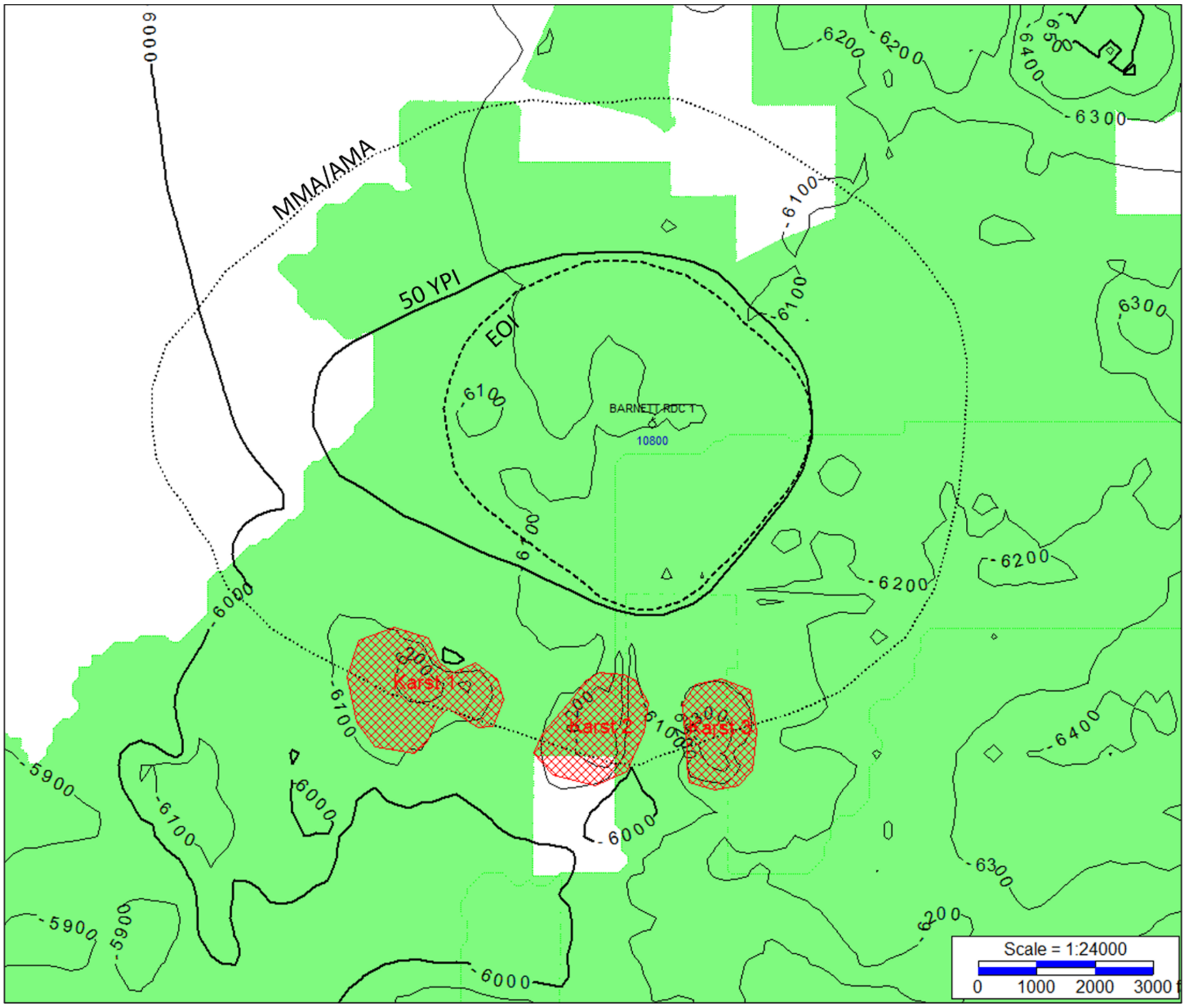

Figure 22. The Barnett RDC #1 well location with top Ellenburger structural contours (TVDSS), 3D seismic coverage (green), and mapped Ellenburger karst on the southern edges of the MMA/AMA. The CO_2 plume size at the end of injection and 50 years post-injection are also shown from Figure 19.

5.5 Leakage Through Confining Layers

The Ellenburger subunit E injection zone is bound by competent confining zones above the injection interval by the Ellenburger subunit C and below the injection interval in the Ellenburger subunit F. Secondary seals above the injection zone include the Barnett Shale, Marble Falls Limestone, and the Atoka Shales. Ellenburger subunit F serves as the lower confining zone. Overall, there is an excess of 3,000 feet of impermeable rock between the injection zone and the deepest well penetrations, making vertical migration past the primary and secondary confining zones unlikely.

5.6 Leakage from Natural or Induced Seismicity

The Barnett RDC #1 location is in an area of the Fort Worth Basin that is inactive seismically, as illustrated in Section 3.5. Earthquake catalogs from both the USGS (1950-present) and TexNet (2017-present) indicate no earthquake locations within 20 miles of the Barnett RDC #1.

The closest earthquake locations are 20+ miles to the southeast in an area of larger, regional faulting. In 2013 and 2014, a series of earthquakes were felt near the towns of Reno and Azle, Texas. The Texas Railroad Commission held hearings that investigated whether oil and gas activities near the earthquakes were responsible for the activity. The Railroad Commission was unable to determine whether oil and gas activities were responsible for the earthquake sequence.

Since no faults are mapped that cut from the injection interval through the sealing limestones and shales of the Pennsylvanian, no leakage is expected due to induced seismic activity.

However, dCarbon also plans several operational procedures to monitor injection-induced seismicity and to immediately identify any minor or major seismic events in the area. Before initiating injection into the well, dCarbon will be installing both surface and bottomhole pressure gauges, so that reservoir pressure and injection pressure can be monitored. Additionally, consistent with RRC guidelines and permit conditions, dCarbon plans to maintain bottomhole injection pressure below formation fracture pressure, and also maintain surface pressure below 0.50 psi per foot gradient when measured from the top of the injection interval. Finally, dCarbon plans to perform periodic pressure fall-off tests (PFOT) to determine and monitor reservoir pressure to ensure unexpected static pressure increases are not observed. These measures are designed to prevent induced fracturing of the formation or increase the likelihood of induced seismicity. Should any unexpected increase in formation pressure be detected, dCarbon can perform Fault Slip Potential (FSP) analysis[17] to evaluate the risk of induced seismicity on the closest mapped faults. dCarbon plans to build this model based on geologic data collected during drilling the Barnett RDC #1 well. If there is a concern related to abnormal pressures or seismicity related to operations at the well, dCarbon will shut-in the well and investigate further.

Furthermore, dCarbon plans to install new ground seismic monitoring arrays near the injection site that are designed to detect any seismic events in the area, natural or induced. Any seismic events detected in the area will be located in the subsurface and analyzed to determine their origin and if they may have potential impacts to the injection program or confining layers. Additionally, the TexNet seismic monitoring program will also be monitored to ensure any material seismic events in the area are investigated.

[17] Walsh, F.R.I., Zoback, M.D., Pais, D., Weingartern, M., and Tyrell, T. (2017). FSP 1.0: A Program for Probabilistic Estimation of Fault Slip Potential Resulting from Fluid Injection, available at: https://scits.stanford.edu/software.

5.7 LEAKAGE FROM LATERAL MIGRATION

The structural dip of the Ellenburger in the vicinity of the Barnett RDC #1 injection site is about one degree up to the west (100 feet/mile), shown in **Figure 23**. The closest well that penetrates the Ellenburger subunit E injection interval up dip from the injection site is more than ten miles to the west-southwest. The closest well that penetrates the injection interval is down dip to the east approximately five miles (W S Coleman #2).

Dynamic modeling of the CO_2 plume has the maximum extent of the plume traveling less than one mile, with the maximum distance traveled to the west. Given that the distance to the next penetration of the injection interval is on the order ten times the distance the plume is expected to travel, no leakage from lateral migration is expected.

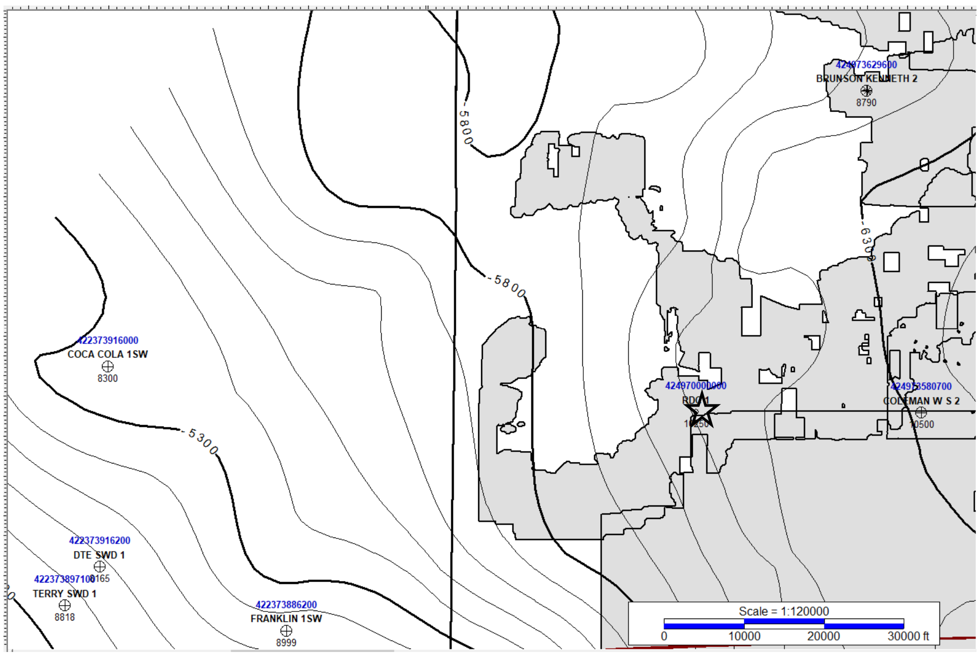

Figure 23. Top of Ordovician Unconformity (top Ellenburger) regional subsea structure in the vicinity of the Barnett RDC #1 location (star). Wells shown penetrate the injection interval. Additional wells (not shown) were used to develop the structure map. Gray areas represent areas covered by 3D seismic data.

Furthermore, dCarbon has assessed each of the previously discussed potential leakage pathways for likelihood, potential timing, and magnitude. The framework of this assessment is based upon the California Air and Resources Board's CCS Protocol Section C.2.2(d).

Table 8 describes the basis for event likelihood and **Table 9** provides the details of the leakage likelihood, timing of occurrence, and estimated magnitude of leakage for each type of leak risk.

Table 8. Risk likelihood matrix (developed based on comparable projects).

Risk Factor for Probability		Description
1	Improbable	<1% chance of occurring*
2	Unlikely	1-5% chance of occurring*
3	Possible	> 5% chance of occurring*
*During the life of the project or 100 years after project closure, whichever is shorter		

Table 9. Description of leakage likelihood, timing, and magnitude.

Leakage Pathway	Likelihood	Timing	Magnitude
Potential Leakage from Surface Equipment	**Possible**	Anytime during project operations, but most likely during start-up / transition or maintenance periods	**<100 MT per event** (100 MT represents approximately 3 hours of full flow facility release)
Leakage from Approved, Not Yet Drilled Wells	**Improbable**, as there are no approved not yet drilled wells	After new wells are permitted and drilled	**<1 MT per event**
Leakage from Existing wells	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and the total depth of existing wells	When the CO_2 plume expands to the lateral locations of existing wells	**<1 MT per event** due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach an existing well combined with thickness and low porosity / permeability of upper confining zone
Potential Leakage from Fractures and Faults	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and surface or USDW that would need to be compromised and there are no mapped faults within the MMA.	Anytime during operation	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach a fault or fracture significant enough to cause leakage
Leakage Through Confining Layers	**Improbable**, as the upper confining zone is nearly 1,000' thick and very low porosity and permeability	Anytime during operations	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E and thickness/properties of upper confining zone
Leakage from Natural or Induced Seismicity	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and surface or USDW that would need to be compromised and there are no mapped faults within the MMA.	Anytime during operations	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach a fault or fracture significant enough to cause leakage
Leakage from Lateral Migration	**Improbable**, as the Ellenburger is a very thick and laterally continuous formation with the closest well penetration five miles downdip.	More likely late in life as plume expands	**<1 MT per event** due to natural dispersion of CO_2 within the Ellenburger subunit E and continuity / thickness of upper confining zone

6 – PLAN OF ACTION FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

This section discusses the strategy that dCarbon will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in previous sections to meet the requirements of 40 CFR § 98.448(a)(3). As the injected stream contains both H_2S and CO_2, any observation of H_2S will serve as a preliminary indicator for CO_2 leakage and therefore the monitoring systems to detect H_2S will also suggest a leak of CO_2. This section summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur. Monitoring will occur during the planned 12-year injection period, or until the cessation of operations, plus a proposed two-year post-injection period.

6.1 Leakage from Surface Equipment

As the CO_2 compressor station, pipeline, and injection well are all designed to handle expected concentrations, temperatures, and pressures of H_2S and CO_2, any leakage from surface equipment will be quickly detected and addressed. The facility is designed to minimize potential leakage points by following the American Society of Mechanical Engineers (ASME) standards, American Petroleum Institute (API) standards, and other industry standards, including standards pertaining to material selection and construction. Additionally, connections are designed to minimize corrosion and leakage points. The H_2S in the stream is easily detectable and serves as an indicator for the release of CO_2. The facility and well will be monitored for H_2S and CO_2 concentration increases. This monitoring equipment will be set with a high alarm setpoint for H_2S that automatically alerts field personnel of abnormalities. Additionally, all dCarbon and BKV field personnel are required to wear H_2S monitors, which will trigger the alarm at low levels of H_2S (typically one ppm). The injection facility will be continuously monitored through automated systems that are designed to identify abnormalities in operational conditions. In addition, field personnel conduct daily AVO field inspections of gauges, monitors, and leak indicators. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system and analysis of liquids collected from the line. These inspections, in addition to the automated systems, will allow dCarbon to quickly identify and respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR § 98.448(a)(5).

Additionally, CO_2 for injection will be metered in three locations for redundancy and precision. The first will be at an orifice style or Coriolis meter at the interface between the Bridgeport Plant and dCarbon's compression facility. This location will meter the CO_2 in gas phase and is depicted in **Figure 24a** and **Figure 24b**. Once the CO_2 is compressed to supercritical, it will pass through a Coriolis meter for measurement and then be transported approximately 6,815 feet via pipeline (see **Figure 15**) to the injection well site. The CO_2 will then be measured again with a Coriolis meter at the injection well site, immediately upstream of the injection wellhead itself. The injection stream will also be analyzed with a gas chromatograph at the well site to determine final composition. The meters will each be calibrated to industry standards. Any discrepancies in CO_2

throughput between the meters will be investigated and reconciled. Any CO_2 that is determined to have leaked or not been received at the injection wellhead will be quantified using the procedures specified in subpart W of the GHGRP, reported as specified in 40 CFR § 98.448(a)(5), and subtracted from reported injection volumes. Gas samples will be taken and analyzed per manufacturer's recommendations to confirm stream composition and calibrate or re-calibrate meters, if necessary. At a minimum, these samples will be taken quarterly. Minimal variation of concentration and composition are expected but will be included in regulatory filings as appropriate.

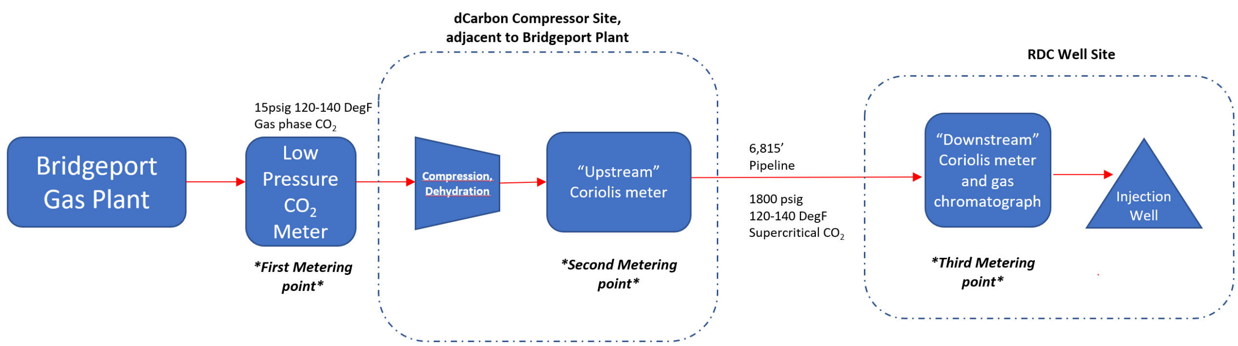

Figure 24a. Project conceptual diagram and metering locations.

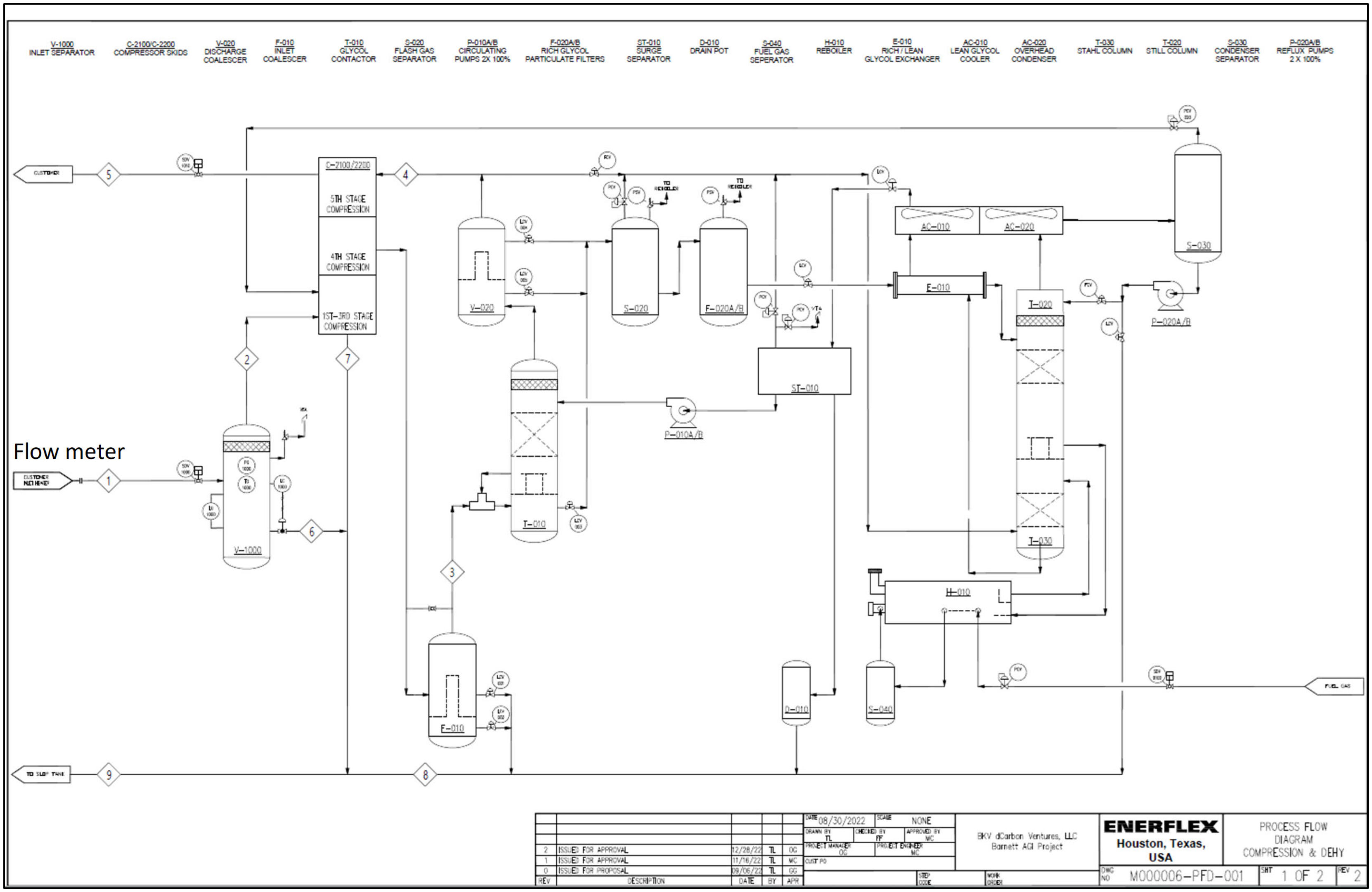

Figure 24b. Compression facility process flow diagram.

6.2 Leakage from Existing and Future Wells within the Monitoring Area

As previously discussed, there are no wells in the MMA currently existing, approved, or pending that penetrate as deep as the Ellenburger injection zone. However, dCarbon will reverify the status and public information for all proposed and approved drilling permits within the MMA quarterly. If any wells are proposed, permitted, or drilled within the MMA, BKV will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, dCarbon will continuously monitor and collect injection volumes, pressures, temperatures, and gas composition data for the injection well. This data will be reviewed by qualified personnel and will follow response and reporting procedures when data is outside acceptable performance limits. Finally, dCarbon will update the MRV plan if any new wells are drilled within the MMA, or if any other material change to the project occurs.

The injection well design has pressure and temperature gauges monitoring the injection stream at the wellhead as well as bottomhole pressure and temperature gauges near the bottom of the tubing. The downhole gauges will monitor the inside of the tubing (injection stream) as well as the annulus. A change of pressure on the annulus would indicate the presence of a possible leak requiring remediation. Mechanical Integrity Tests (MITs) performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated, and the leak mitigated.

In the unlikely event that any CO_2 leaks occur into existing or future wells in the monitoring area, dCarbon will endeavor to work with the operator(s) of those wells and/or midstream providers to take wellhead gas samples to quantify variations or increases of CO_2 compared with historical or baseline CO_2 concentrations. Any measurable increases in CO_2 which may be confidently attributed to injection volumes from the Barnett RDC #1 well will be calculated using standard engineering procedures for estimating potential well leakage determined to be appropriate for the situation. These volumes will be documented and reported in the annual monitoring report and subtracted from reported injection volumes. Additionally, dCarbon will evaluate and execute any additional downhole remediations (*e.g.*, well workovers, such as adding plugs, remedial cement jobs, etc.) that could address leakage from the injection well to the existing and future wells in the area if necessary and practical.

6.3 Leakage from Faults and Fractures

No faults or fractures have been identified that would allow CO_2 to migrate vertically to zones with USDWs or to the surface. In the unlikely event that such leakage from faults or fractures occurs, dCarbon will determine which standard engineering techniques for estimating potential leakage from the faults and fractures is appropriate for the situation to estimate any leakage from faults and fractures, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.4 Leakage through Confining Layers

Leakage through confining layers is improbable, given the number and thickness of layers between the injection zone and potable groundwater. Groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple confining layers.

In the unlikely event CO_2 leakage occurs because of leakage through the confining seal, it is also unlikely that the leak would result in surface leakage. As with any CO_2 leakage, however, should it occur, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation to estimate any leakage, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.5 Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, dCarbon plans to install a seismic monitoring array in the general area of the Barnett RDC #1 well. This monitoring array will augment the TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, dCarbon will review the injection volumes and pressures at the Barnett RDC #1 well to determine if any significant changes occurred that would indicate potential leakage. To suspect leakage due to natural or induced seismicity, the evidence would need to suggest that the earthquakes are activating faults that penetrate through the confining zones.

In the unlikely event CO_2 leakage occurs due to natural or induced seismicity, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation and report such leakage estimates and the methodology employed in the annual monitoring report.

6.6 Leakage through Lateral Migration

The distances to the closest penetration of the Ellenburger injection interval are more than ten times the expected plume radius at the end of injection. As such, leakage through lateral migration is not expected. In addition, the wells that penetrate the injection interval are saltwater disposal wells. Injection into these wells would be expected to raise the reservoir pressure locally near the well, further limiting the ability of the CO_2 to access the saltwater injector well bore.

In the unlikely event CO_2 leakage occurs due lateral migration, similar to leakage through confining layers, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.7 Quantification of Leakage

In the unlikely event that CO_2 moves vertically past the primary and secondary confining layers as described earlier in Section 6, there are several methods dCarbon may utilize to quantify leakage depending on the nature and severity of the leak. dCarbon has designed a monitoring network

suited to detect CO_2 leaks before they interact with local resources, infrastructure, or USDW. dCarbon will consider additional standard and specialized engineering methods to quantify leaks as appropriate. dCarbon's methodology to characterize, monitor, detect, and isolate leaks for quantification is described below.

As a primary monitoring and quantification strategy, dCarbon plans to install a deep groundwater monitoring well in the MMA that will be used to monitor the USDW. This well will be deeper than any active groundwater wells in the area that typically draw water from shallow drinking water zones. dCarbon also plans to periodically sample the well to monitor for chemical composition. If dCarbon notices an increase in groundwater CO_2 concentration compared to baseline measurements, the increase in concentration will be analyzed volumetrically to provide a preliminary estimate of CO_2 leakage.

Any leakage that did extend to the surface could be characterized and quantified through surface surveillance in the project area paired with direct pressure, volume, and temperature (PVT) measurements. Currently available (and continuously improving) atmospheric sensing technology could be used to establish a baseline of ambient CO_2 concentration in the project area and identify any fluctuations. Deviations from baseline concentration along with understanding of the distance from potential leak sources can then be coupled with temporally matched meteorological data to semi-quantitatively determine leak attribution and rate. Based on the size of leak, these qualified or quantified leak rates can be compared with spatiotemporally monitored PVT data to co-index or further refine leaked volumes from likely point sources.

Any diffuse leak or leak without an obvious single point source may require additional identification and quantification methods. dCarbon is working with a leading environmental services and data company that specializes in monitoring and quantifying gas leaks in various industrial settings. One such quantification method involves utilizing fixed monitoring systems to detect CO_2. Additional system capabilities also include the deployment of an unmanned aerial vehicle (UAV), which is outfitted with an industry leading high fidelity CO_2 sensor capable of measuring concentrations as little as parts per billion (ppb). The UAV mobile surveillance platform possesses the ability to be flown on a programmable and highly replicable pattern across the MMA in both X and Y axis (longitude + latitude) as well as Z axis (height). Depending on the system's ability to obtain a reliable baseline across the MMA, areal deviation in CO_2 concentration could be measured, and diffuse leak sources could potentially be identified, provided the emissions reach a sufficient threshold. dCarbon will also consider similar technologies with less spatial resolution or fidelity such as fixed wing flyovers and/or improving satellite data with UAV technology to screen for and support diffuse emissions identification and investigation.

Depending on the applicability and monitoring needs, dCarbon will also consider other monitoring quantification methods such as the Eddy Covariance Method (ECM).[18] This method utilizes gas fluxes and ambient meteorological conditions to detect and quantify leaks, although the ability to

[18] Korre, A., *et al.*, 2011. Quantification techniques for potential CO_2 leakage from geologic sites. Energy Procedia 4 (2011), pgs. 3143-3420.

detect smaller leaks may be limited.[19] Additionally, long open path tunable diode lasers could be used to measure distance averaged concentrations of CO_2 in the air, which could help quantify a leak of CO_2. This system could be paired with an array of short, closed path detectors (*e.g.*, gas chromatographs) that are typically placed around a suspected leak or leak area to monitor point-source CO_2 concentration increases and to quantify leakage. dCarbon may also evaluate other emerging technologies for quantifying CO_2 leakage such as non-dispersive infra-red (NDIR) CO_2 sensors and soil flux detectors. dCarbon may also utilize three-dimensional reservoir models that factor in faults and surface topography to predict CO_2 leakage locations, quantity, and timing. The applicability of such models in predicting and quantifying gas leaks has been tested and documented at the Leroy natural gas storage site in Wyoming, USA.[19]

As the technology and equipment to quantify CO_2 leakage is rapidly evolving and expected to improve over time, dCarbon will continue to update its leak detection and quantification plans as appropriate. If dCarbon detects a leak associated with CO_2 injection at the Barnett RDC #1 well, all methods discussed in this section will be considered in addition to emerging technologies to determine the most applicable and effective method of quantification.

[19] Chen, M., *et al.*, 2013. Analysis of fault leakage from Leroy underground natural gas storage facility, Wyoming, USA. *Hydrogeology* 21, pgs. 1429–1445. 2013.

7 – BASELINE DETERMINATIONS

This section identifies the strategies that dCarbon will undertake to establish the expected baselines for monitoring CO_2 surface leakage per § 98.448(a)(4). dCarbon will use the existing Supervisory Control and Data Acquisition (SCADA) monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. Daily inspections will be conducted by field personnel at the compressor facility and the injection well. These inspections will aid with identifying and addressing issues in a timely fashion to minimize the possibility of leakage. If any issues are identified, such as vapor clouds, ice formations, or abnormal AVO or FLIR observations, corrective actions will be taken to address such issues. As previously discussed, H_2S is present in the injection stream at a low concentration. All field personnel are required to wear personal H_2S monitors, which are set to trigger the alarm at approximately 1 ppm levels of H_2S. Any alarm would trigger an immediate response to protect personnel and verify that the equipment and monitors are working properly. If monitors are working correctly and a leak is detected, immediate actions would be taken to secure the facility.

Any leakage would be detected and managed as per Texas regulations and dCarbon's safety and operations plans. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR § 98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

Baseline groundwater quality and properties will be determined and monitored through the installation of a groundwater well near the injection well site. Samples will be taken and analyzed by a third-party laboratory to establish the baseline properties of the groundwater in the area.

Baseline seismicity in the area near the Barnett RDC #1 will be determined through the historical data from USGS and TexNet seismic array data. This information will be augmented by additional data from dCarbon's seismic monitoring array.

8 – SITE SPECIFIC CONSIDERATIONS FOR DETERMINING THE MASS OF CO_2 SEQUESTERED

This section identifies how dCarbon will calculate the mass of CO_2 injected, emitted, and sequestered. This also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, per 40 CFR § 98.448(a)(5).

8.1 MASS OF CO_2 RECEIVED

Per 40 CFR § 98.443, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR §98.444(a)(4)." 40 CFR § 98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received."

The CO_2 received by dCarbon for injection into the Barnett RDC #1 injection well is wholly injected and not mixed with any other supply and the annual mass of CO_2 injected will equal the amount received. Any future streams will be metered separately before being combined into the calculated stream.

8.2 MASS OF CO_2 INJECTED

Per 40 CFR § 98.444(b), since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Subpart RR Equation 5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

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
$C_{CO2,p,u}$	=	Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (weight percent CO_2, expressed as a decimal fraction)
p	=	Quarter of the year
u	=	Flow meter

8.3 MASS OF CO_2 PRODUCED

The injection well is not part of an enhanced oil recovery project, and therefore, no CO_2 will be produced.

8.4 Mass of CO_2 Emitted by Surface Leakage

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S, which may be hazardous for field personnel to perform a direct leak survey. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR § 98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released because of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using 40 CFR Part 98-Subpart RR Equation 10 as follows:

$$CO_{2,E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

$CO_{2,E}$	=	Total annual 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

Annual mass of CO2 emitted (in metric tons) from any equipment leaks and vented emissions of CO2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan

8.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in the subsurface geologic formations will be calculated based off from 40 CFR Part 98, Subpart RR Equation 12 , as this well will not actively produce any oil or natural gas or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2	=	Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the Barnett RDC #1 facility in the reporting year.
$CO_{2,I}$	=	Total annual CO_2 mass injected (metric tons) in the Barnett RDC #1 well in the reporting year.
$CO_{2,E}$	=	Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of Part 98.

9 – ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

The injection well is expected to begin operation in the second half of 2023. Baseline data will be collected before injection begins and the MRV plan will be implemented upon receiving EPA MRV approval.

10 – QUALITY ASSURANCE

10.1 CO_2 INJECTED

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer specifications.

10.2 CO_2 EMISSIONS FROM LEAKS AND VENTED EMISSIONS

- Gas detectors will be operated continuously, except for maintenance and calibration.
- Gas detectors will be calibrated according to manufacturer recommendations and API standards.
- Calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

10.3 MEASUREMENT DEVICES

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to the requirements in 40 CFR § 98.3(i).
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.
- Flow meter calibrations will be traceable to the National Institute of Standards and Technology (NIST).

All measured volumes of CO_2 will be converted to standard cubic feet at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1.0 atmosphere.

10.4 MISSING DATA

In accordance with 40 CFR § 98.445, dCarbon will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR § 98.

11 – RECORDS RETENTION

dCarbon will retain records as required by 40 CFR § 98.3(g). These records will be retained for at least three years and include:

- Quarterly records of the CO_2 injected.
- Volumetric flow at standard conditions.
- Volumetric flow at operating conditions.
- Operating temperature and pressure.
- Concentration of the CO_2 stream.
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate 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.

Appendix B: Submissions and Responses to Requests for Additional Information

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan

Barnett RDC #1

Wise County, Texas

Prepared by

BKV dCarbon Ventures, LLC

Version 5.0

June 13, 2023

TABLE OF CONTENTS

1 – INTRODUCTION

BKV dCarbon Ventures, LLC (dCarbon), a subsidiary of BKV Corporation (BKV), is authorized by the Texas Railroad Commission (TRRC) to inject up to 14.5 million standard cubic feet per day (MMscfd), equivalent to approximately 280,000 metric tons per year (MT/yr), of carbon dioxide (CO_2) into the proposed Barnett RDC #1 injection well in Wise County, Texas. The permit issued by the TRRC allows injection into the Ellenburger Group formation at a depth of 9,350 feet to 10,250 feet with a maximum allowable surface pressure of 4,500 pounds per square inch gauge (psig).

dCarbon currently intends to dispose of CO_2 from the nearby Bridgeport Gas Processing Plant (Bridgeport Plant), operated by EnLink Midstream Services, LLC (EnLink), into the Barnett RDC #1 well. The project site is located approximately 4.6 miles southwest of Bridgeport, Texas, as shown in **Figure 1**.

dCarbon anticipates drilling the Barnett RDC #1 well in the first half of 2023, completing the well in mid-2023, and beginning injection operations in late 2023. The Barnett RDC #1 has approvedW-14 injection and W-1 drilling permits with the TRRC (Texas Railroad Commission) permit number 17090, UIC number 000125478, API number 42-497-38108). Additionally, copies of the approved W-1 and W-14 are included as Attachment A.

Although dCarbon intends to initiate injection with lower volumes, all calculations in this document have been performed assuming the maximum injection amount allowed by the TRRC permit (280,000 MT/yr). dCarbon plans to inject for approximately twelve years.

dCarbon submits this Monitoring, Reporting, and Verification (MRV) plan for approval by the Environmental Protection Agency (EPA) in accordance with 40 CFR § 98.440-449, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP).

dCarbon's TRRC operator number is 100589.

dCarbon's Environmental Protection Agency Identification (EPA ID) number is 110071343305.

The Barnett RDC #1 well's Greenhouse Gas Reporting Program Identification (GHGRP ID) number is 58336. All aspects of this MRV plan refer to this well and GHGRP ID number.

Figure 1. Location of the Barnett RDC # 1 Well and EnLink Midstream's Bridgeport Gas Plant.

2 – FACILITY INFORMATION

Gas Plant Facility Name:

Bridgeport Gas Processing Plant
415 Private Road 3502
Bridgeport, Texas 76426

Latitude: 33° 11.74' N
Longitude: 97° 48.22' W

EnLink's GHGRP ID number for the Bridgeport Plant is 1006373.

FRS Id: 110028052354

NAICS Code: 211130

Currently reporting under Subpart C, W, NN

Underground Injection Control (UIC) Permit Class:

The Oil and Gas Division of the TRRC regulates oil and gas activity in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program for injection wells. The TRRC has permitted the Barnett RDC #1 well as a UIC Class II well. The Class II permit was issued to dCarbon in accordance with Statewide Rule 9.

Injection Well:

Barnett RDC #1, API number 42-497-38108

UIC# 000125478

Barnett RDC #1 GHGRP ID: 58336

The Barnett RDC #1 well will be disposing of CO_2 from the Bridgeport Gas Processing Plant. All aspects of this MRV plan refer to the Barnett RDC #1 well and GHGRP 58336.

3 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection volumes and process, and the reservoir modeling performed for the proposed Barnett RDC #1 Class II injection well. dCarbon has prepared this MRV plan to support the storage of CO_2 in Wise County, Texas.

3.1 Overview of Geology

The proposed injection site lies in the western section of Wise County, where the Barnett Shale, Viola, Simpson, and Ellenburger formations dip and thicken to the east toward the Muenster Arch, as seen in the west to east cross section of **Figure 2**. Similarly, the north to south cross section shows the Ellenburger and overlying formations dipping to the north. One inference from this is that any CO_2 injected may exhibit the tendency to move updip due to buoyancy, meaning the anticipated plume movement will be westward. This is further represented in the structure contour map of the Ellenburger formation top by Pollastro[1] in **Figure 2**.

The Fort Worth Basin sedimentary succession begins with locally abundant Cambrian clastics in the southern section of the basin that unconformably overlie the uneven Precambrian basement (see **Table 1**). The overlying Ordovician age Ellenburger platform carbonates were deposited on a passive margin and contain thicknesses up to 4,000 feet in the Fort Worth Basin. The Ellenburger platform carbonates underwent multiple episodes of regional exposure causing dolomitization and karsting in several subunits of the Ellenburger. Ordovician Viola and Simpson formations overlie the Ellenburger formation and are found in the northern section of the basin near the Muenster Arch. A major erosive interval occurred during the Mississippian, eroding down to the Ordovician formations. Later deposition of the Barnett Shale unconformably overlies the Viola limestone, Simpson formation, and the Ellenburger Group.[2] Overlying the Barnett Shale is a thick section of mostly Pennsylvanian and Permian carbonates and clastics (Bend, Strawn, and Canyon Groups). **Figure 2** indicates the general regional stratigraphy. Although there are multiple storage-confining unit systems that could be evaluated for injection, the focus was on the Mississippian-Ordovician section that consists of the Barnett shale and the Ellenburger Group. The Ellenburger Group directly overlies the basement rock and is considered the main reservoir target.

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[1] Pollastro, R.M., 2007. Geologic framework of the Mississippian Barnett Shale, Barnett-Paleozoic total petroleum system, Bend Arch-Fort Worth Basin. *American Association of Petroleum Geologists Bulletin* 91 (4), pgs. 405-436. 2007.

[2] Gao, S. *et al.*, 2021. Low pressure buildup with large disposal volumes of oil field water: A flow model of the Ellenburger Group, Fort Worth Basin, North Central Texas. *American Association of Petroleum Geologists Bulletin* 105 (12), pgs. 2575-2593. 2021.

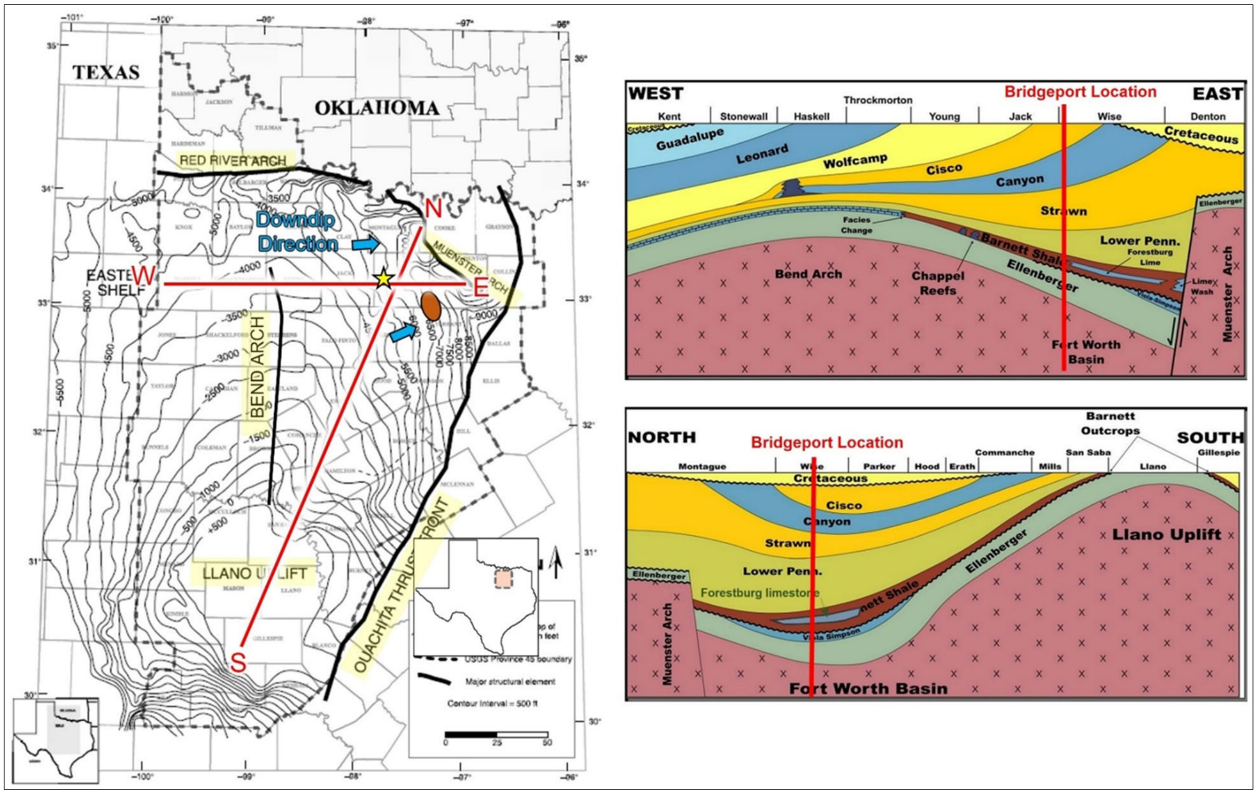

Figure 2. (*Left*) Ellenburger structural contour map modified from Jarvie *et al.*[3] showing the regional structures within and bounding the Fort Worth Basin, Ellenburger structure contours with respect to the final dCarbon area of interest (yellow star). (*Right*) Cross sections E-W and N-S show the regional dip of the sedimentary units in the Fort Worth Basin.

3.2 Bedrock Geology

3.2.1 Basin Description

The Fort Worth Basin is a flexural basin that formed in the foreland of the advancing Ouachita orogenic belt during the Late Mississippian through Pennsylvanian epochs.[4] As illustrated in **Figure 2**, the Fort Worth Basin is bounded to the east by the Ouachita fold and thrust belt and to the north by the Muenster Arch and Red River Arch. These arches are characterized by a series of high angle reverse faults. The basin is deepest to the northeast, with as much as approximately 12,000 feet of sediment infill, where the Ouachita thrust front meets the Muenster Arch and is shallowest towards the south.

[3] Jarvie, D.M., *et al.*, 2007. Unconventional shale-gas systems: The Mississippian Barnett Shale of North Central Texas as one model for thermogenic shale-gas assessment. *American Association of Petroleum Geologists Bulletin* 91 (4), pgs. 475-499. 2007.

[4] Horne, E.A., Hennings, P.H., and Zahm, C.K., 2021. Basement structure of the Delaware basin, in The Geologic Basement of Texas: A Volume in Honor of Peter Flawn, Callahan, O.A., and Eichhubl, P. (editors), *The University of Texas at Austin, Bureau of Economic Geology Report of Investigations*, Austin, Texas. 2021.

Table 1. Regional Stratigraphy at Barnett RDC #1 Site in North Texas.

<table>
<tr><th>SYSTEM</th><th>SERIES</th><th>STAGE</th><th colspan="2">GROUP OR FORMATION</th></tr>
<tr><td>Cretaceous</td><td>Lower</td><td>Comanchean</td><td colspan="2">Trinity Group</td></tr>
<tr><td rowspan="13">Pennsylvanian</td><td>Upper</td><td>Missourian</td><td>Canyon Group</td><td>Jasper Creek Formation</td></tr>
<tr><td rowspan="8">Middle</td><td rowspan="6">Desmonesian</td><td rowspan="3">Strawn Group</td><td>Willow Point Formation</td></tr>
<tr><td>Lone Camp Formation</td></tr>
<tr><td>Millsap Lake Formation</td></tr>
<tr><td rowspan="3">Kickapoo Group</td><td>Ratville Formation</td></tr>
<tr><td>Parks Formation</td></tr>
<tr><td>Caddo Pool Formation</td></tr>
<tr><td rowspan="4">Atokan</td><td rowspan="7">Bend Group</td><td>Caddo Formation</td></tr>
<tr><td>Smithwick Shale</td></tr>
<tr><td rowspan="4">Lower</td><td>Pregnant Shale</td></tr>
<tr><td>Big Saline Formation</td></tr>
<tr><td rowspan="2">Morrowan</td><td>Marble Falls Limestone</td></tr>
<tr><td rowspan="2">Comyn Formation</td></tr>
<tr><td rowspan="4">Mississippian</td><td colspan="2" rowspan="3">Chesterian – Meramecian</td></tr>
<tr><td rowspan="3">Barnett</td><td>Upper Barnett Shale</td></tr>
<tr><td>Forestberg Limestone</td></tr>
<tr><td colspan="2">Osagean</td><td>Lower Barnett Shale</td></tr>
<tr><td>Ordovician</td><td colspan="2">Lower</td><td colspan="2">Ellenburger Group</td></tr>
<tr><td>Precambrian</td><td colspan="2"></td><td colspan="2">Basement</td></tr>
</table>

3.2.2 Stratigraphy

The Ellenburger Group contains alternating limestone and dolomite lithologies, consistent with regional descriptions of the Ellenburger. Vertical changes in properties throughout the Ellenburger were used to divide the unit into 8 subunits (A-G), in agreement with a similar approach demonstrated by Smye *et al.*[5] The main target storage reservoir, subunit E, was identified based on dominant lithology, gross and net reservoir thicknesses, porosity values, and permeability values. In tandem, the Ellenburger subunit B and the stratigraphic top portion of Ellenburger subunit C were identified as a potential caprock. Below this interval, there are baffles of tighter

[5] Smye, K.M., *et al.*, 2019. Stratigraphic architecture and petrophysical characterization of formations for deep disposal in the Fort Worth Basin, Texas. *Texas BEG Report: Interpretation* 7 (4), 2019.

limestone throughout Ellenburger subunits C, C2, and D that would also act as sealing units to the storage interval. Ellenburger subunit E is planned to serve as the storage zone.

Dominant lithologies were determined by comparing the photoelectric factor (PEFZ) log curve with the volume of clay (VCL), sand (VQUA), lime (VCLC), dolomite (VDOL), gas (VUGA), and free water (VUWA) curves in the North Tarrant SWD 1 (API number 42-439-31228), as well as the separation of the density and neutron porosity curves. Gross reservoir thickness was determined for each Ellenburger subunit by adding the footage from the top to the bottom of the subunit.

The W.S. Coleman #2 (API number 42-497-35807) well, approximately five miles east of the proposed Barnett RDC #1 injection well, was used to calculate reservoir zone properties for individual subunits within the Ellenburger formation since no wells currently exist at the proposed site. The North Tarrant SWD 1 well, located approximately 27 miles to the southeast was also used in well correlations because of its robust well log data across the Ellenburger Group.

Figure 3 shows the correlation of the North Tarrant SWD 1 well up to the W.S. Coleman #2. As an initial observation, subunits C and E within the Ellenburger are present and appear to be contiguous in the project area. Subunit C thickness is approximately 750 feet while subunit E thickness varies across the cross sections. It is estimated there is at least 940 feet of subunit C at the Barnett RDC #1 proposed site location with 1,250 feet of Ellenburger subunit E. The cross sections confirm regional trends in dip also apply to the area of interest, down to the north and east.

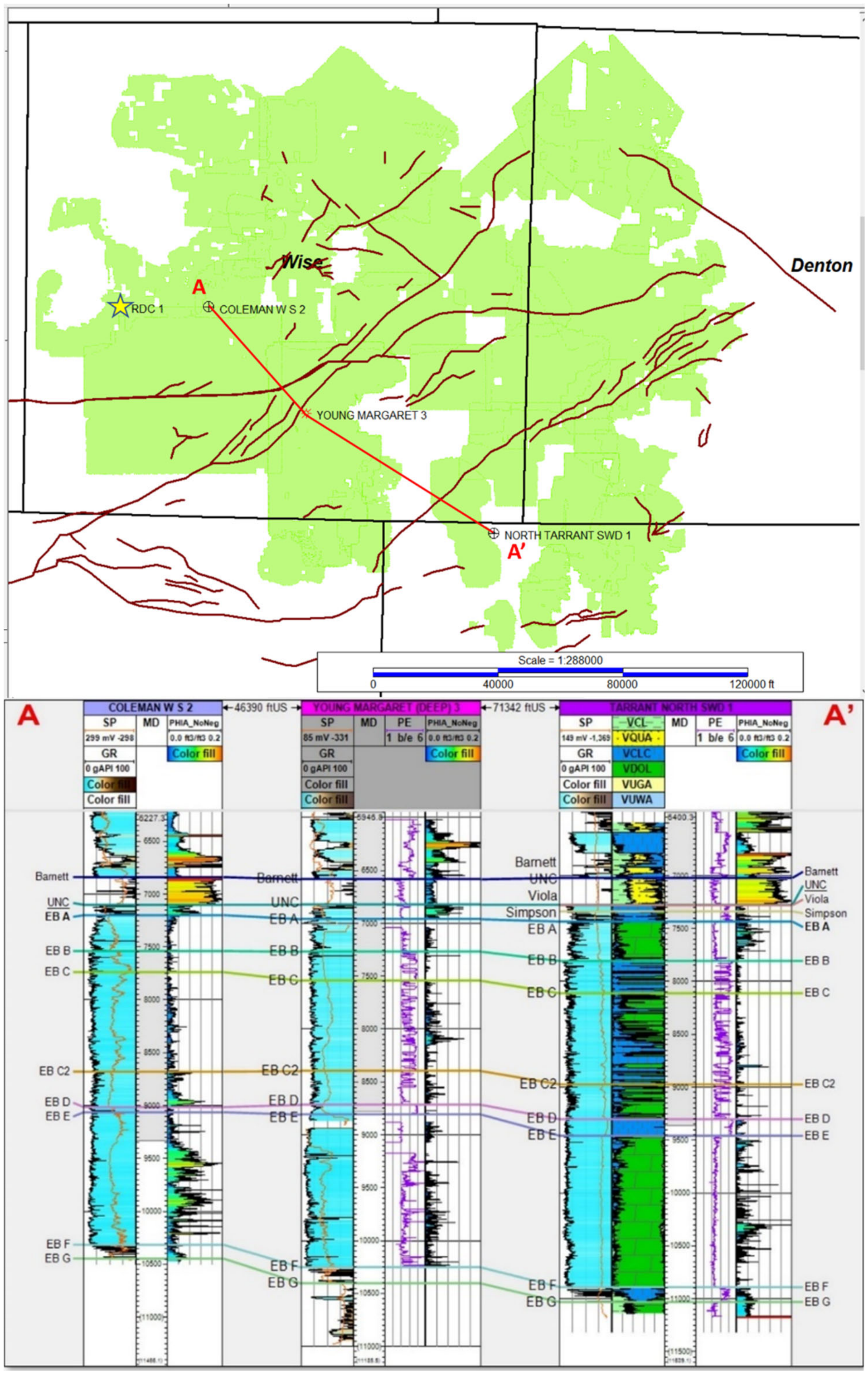

Figure 3. (***Top***) **Map of Wise County with the Barnett RDC #1 (yellow star), faults (brown lines), cross section wells (black circles), dCarbon 3D seismic extent (green polygon), and a NW-SE cross section (A-A').** (***Bottom***) **Cross section showing Gamma Ray (GR), Spontaneous Potential (SP), Photo Electric Factor (PE), and average porosity (PHIA) from the North Tarrant SWD 1 well to the WS Coleman 2 well. Ellenburger subunit C (EB C) is the upper confining zone and Ellenburger subunit E (EB E) is the storage zone.**

3.2.3 Faulting

Faults within the Fort Worth Basin are generally northeast-trending, high-angle normal faults with most of the faults rooting into the Precambrian crystalline basement, as depicted in **Figure 4**. The mechanism for deformation that produced these faults has been attributed to flexure generated by the Ouachita orogenic belt. Deep seated faults that root into the Precambrian crystalline basement generally terminate in the base of the Pennsylvanian age strata and do not continue into the overlying Cretaceous strata, where it is present, suggesting that faults have not experienced significant movement since their formation.[4] Karsting in the region has resulted in small-scale, concentric faults that originate from the collapse of karst features predominantly within the Ellenburger Group.

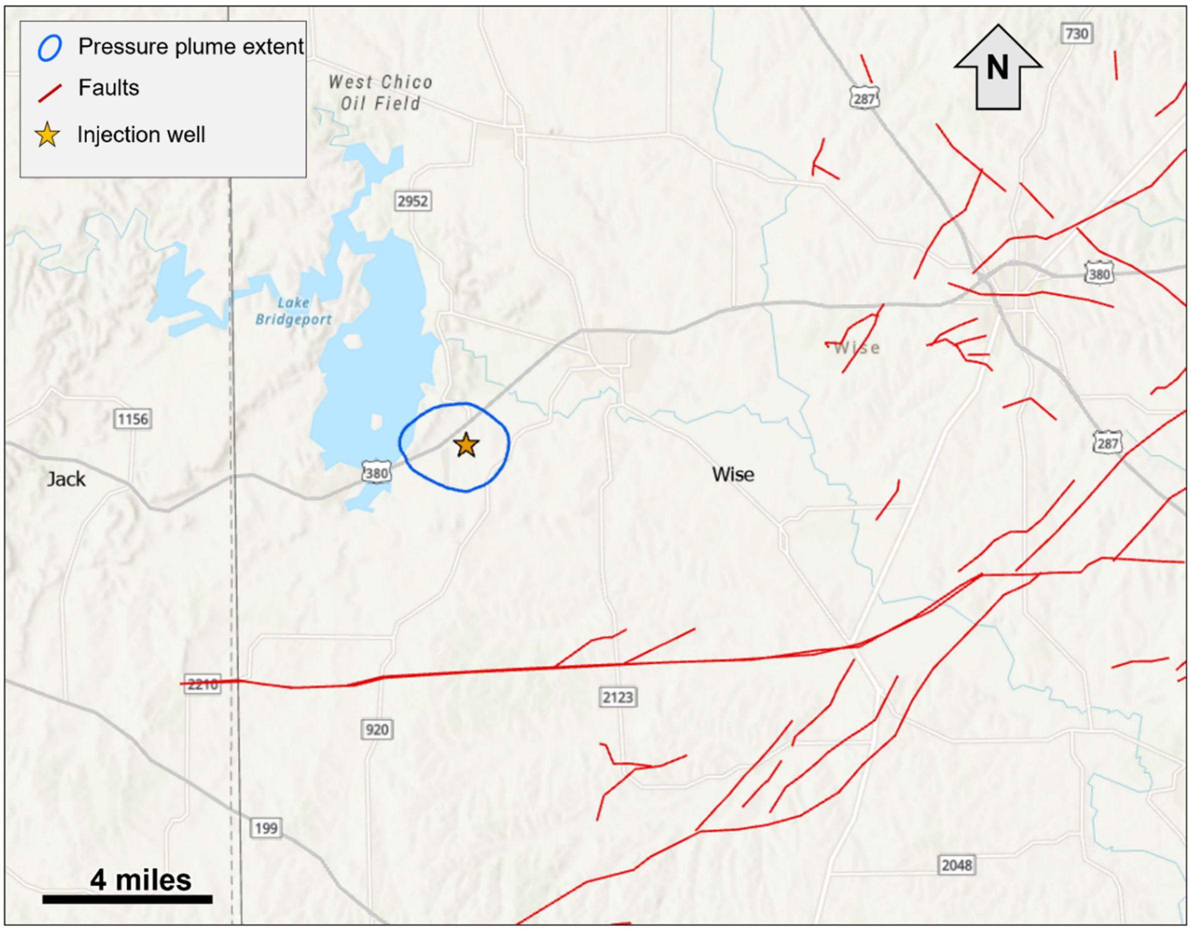

Figure 4. Mapped faults near the proposed injection well from Wood.[6]

3.3 Lithological and Reservoir Characterizations

Smye *et al.*[5] provided a detailed description of regional stratigraphy as well as petrophysical attributes of multiple units within the Ellenburger Group. Prior to understanding the petrophysical

[6] Wood, V., 2015. Reservoir Characterization and Depositional System of the Atokan Grant Sand, Fort Worth Basin, Texas. University of Arkansas Thesis, 2015.

properties of these subunits and assessing their storage reservoir or confining layer potential, it is important to understand the overall lithology. Literature suggests the Ellenburger interval is mostly composed of calcite, dolomite, quartz, and clay. The carbonate intervals are mostly clean with less than 10% clay by volume[5]. However, the top of the Ordovician section was shown to have an increased clay content (about 40% by volume). This also coincided with an increase in siliciclastic materials (quartz and clay). Porosity in clean carbonate intervals is approximately 5%, while that in siliciclastic intervals may reach 20%. The basement lithology was identified as granite wash with hematite contents ranging between 5-10% by volume. **Figure 5** shows the general stratigraphy in the area.

To better understand local stratigraphy and petrophysics, lithological characterization was focused on the red dotted area shown in **Figure 5**. The Viola Formation and Simpson Group are listed here overlying Ellenburger subunit A. However, these formations pinch out to the east of the proposed Barnett RDC #1 site, and thus, are not included in subsequent petrophysical analysis.

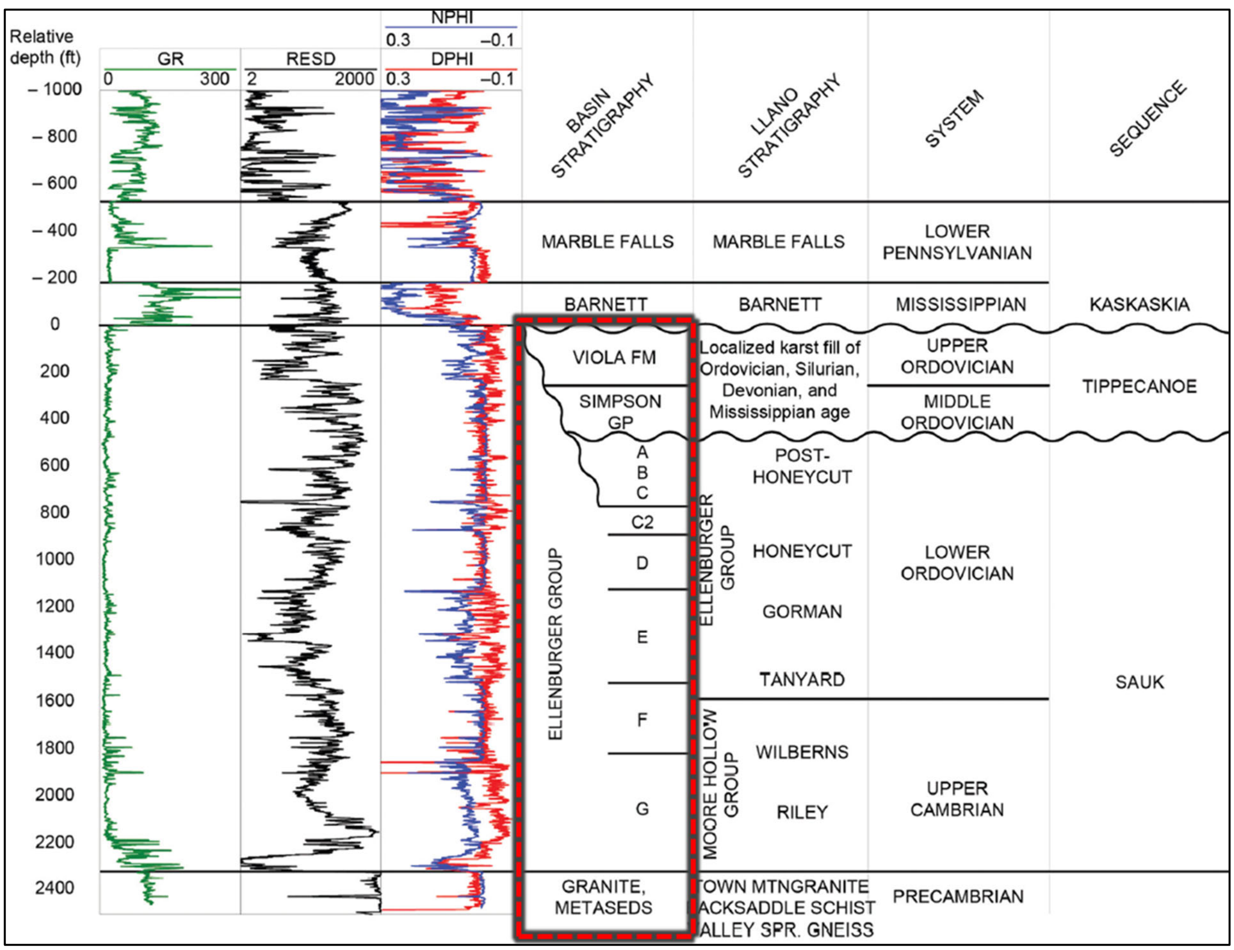

Figure 5. Regional stratigraphy at dCarbon site in North Texas (modified from Smye *et al.*[5]).

The Barnett Shale is anticipated to serve as a secondary confining interval. The Barnett Shale is a source rock and an unconventional reservoir that is extensively drilled in the Fort Worth Basin.

The porosities and permeabilities in the Barnett Shale lie in the 4-6% and 7-50 nanodarcies ranges, respectively.

Underlying the Barnett is the Ellenburger Group, which contains both the anticipated storage and confining zones. The Ellenburger could be divided into eight lithostratigraphic units starting with subunit A at the top to subunit G at the bottom which sits on top of the crystalline basement. Subunit G is composed of siliciclastic facies and is largely variable across the region. Though the porosity in subunit G is higher compared to other subunits, lateral continuity might be an issue in developing a storage project in this subunit. Consequently, subunit E will serve as the storage zone given it has approximately 4% matrix porosity. Ellenburger subunit E is a clean dolomitic reservoir zone with 49% dolomite by volume. Subunit B and subunit C were found to have lower matrix porosities compared to subunit E, which should provide vertical confinement or impediment to CO_2 movement. Ellenburger subunit A has been proven to be a reservoir zone with multiple saltwater disposal wells completed in subunit A. However, as mentioned earlier, karsting features at the top of the Ellenburger imply there is some potential for hydraulic communication between subunit A and the overlying Barnett. **Figure 6** illustrates the log response and petrophysical properties of Ellenburger subunits.

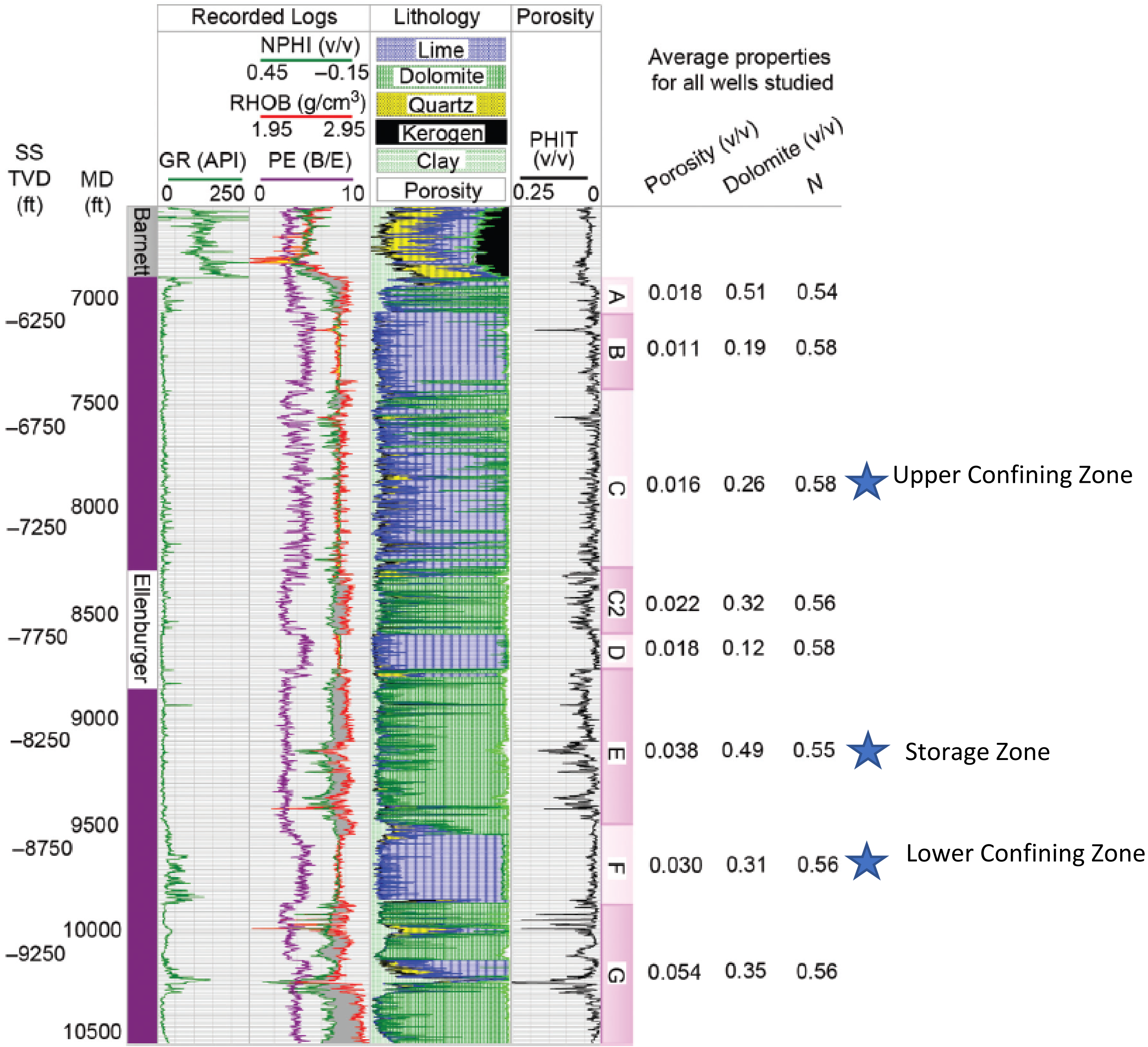

Figure 6. Properties of Ellenburger Group subunits in the project area (modified from Smye *et al.*[5]).

The W.S. Coleman #2 injection well located approximately five miles from the proposed injection site similarly contains Ellenburger subunits A through G, as shown below in **Figure 7**. Drilling at the proposed site should result in site-specific petrophysical properties like those shown here.

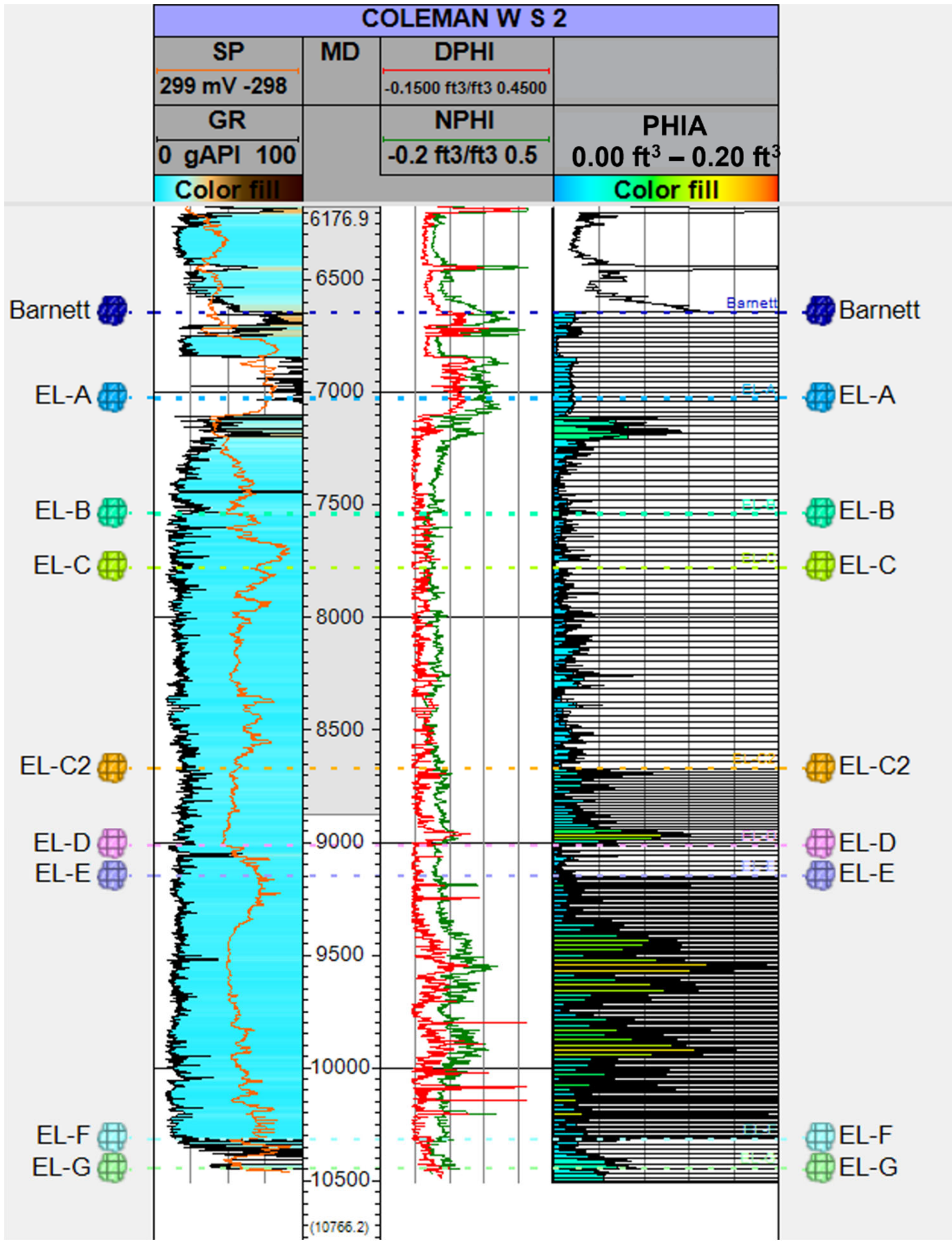

Figure 7. W.S. Coleman #2 well log interpretation; Ellenburger Group subunits A through G are denoted to the right and left of the log image.

Net reservoir thickness was determined for each subunit of the Ellenburger by summing the footage where the average porosity (PHIA) curve was greater than 2%. It is important to note that such a low matrix porosity value was chosen due to the nature of the reservoir wherein fracture porosity is a significant contributor to reservoir quality. Our understanding and evaluation of the Ellenburger suggested a low log porosity could still result in realizable CO_2 storage potential given the history of injectivity from saltwater disposal in the area (*e.g.*, North Tarrant SWD 1 and W.S. Coleman #2 wells). A net-to-gross ratio was determined for each subunit by dividing the net reservoir thickness by the gross reservoir thickness. Average porosity was calculated for each subunit of the Ellenburger by averaging the average porosity (PHIA) curve from the top to the

bottom of the subunit. These reservoir zone properties were subsequently used to derive preliminary storage resource estimates. **Table 2** lists average petrophysical properties in the Ellenburger.

Table 2. Ellenburger Group properties assessed at the project area.

Ellenburger Subunit	Dominant Lithology	Gross Reservoir Thickness (feet)	Net Reservoir Thickness (feet [>2% PHI])	Net-to-Gross Ratio	Average Reservoir Porosity (%)	
A	Dolomite	338	63	0.186	1.1	
B	Limestone	200	14	0.070	0.8	
C	Limestone	940	187	0.198	1.2	Upper Confining Zone
C2	Dolomite	335	229	0.683	3.5	
D	Limestone	49	3.5	0.072	0.6	
E	Dolomite	1252	879	0.702	5.5	Storage Zone
F	Limestone	130	88.5	0.677	3.2	Lower Confining Zone
G	Dolomite	N/A	N/A	N/A	N/A	

Permeability data in individual Ellenburger subunits was obtained from literature. As noted by Gao *et al.*,[2] regional hydrostatic pressure gradient in the Ellenburger was assumed to be 0.47 pounds per square inch (psi) per foot, while the geothermal gradient in the Fort Worth Basin was estimated at 1.4ºF per 100 feet. These parameters were used to run preliminary CO_2 storage calculations as discussed in Section 3.8.

3.4 Formation Fluid Chemistry

Through a review of chemical analyses of oil-field brines from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3, nine wells within 20 miles of the proposed injection well site were identified within the Pennsylvanian age strata, as shown in **Figure 8**. Formation fluid chemistry analyses for these wells are reported in **Table 3**.

Table 3. Pennsylvanian formation fluid chemistry.

	TDS (mg/L)	pH	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	86,807	6	26,000	5,494	53,392
LOW	21,926	4.4	6,291	978	13,389
HIGH	149,480	7.1	47,203	9,854	91,765

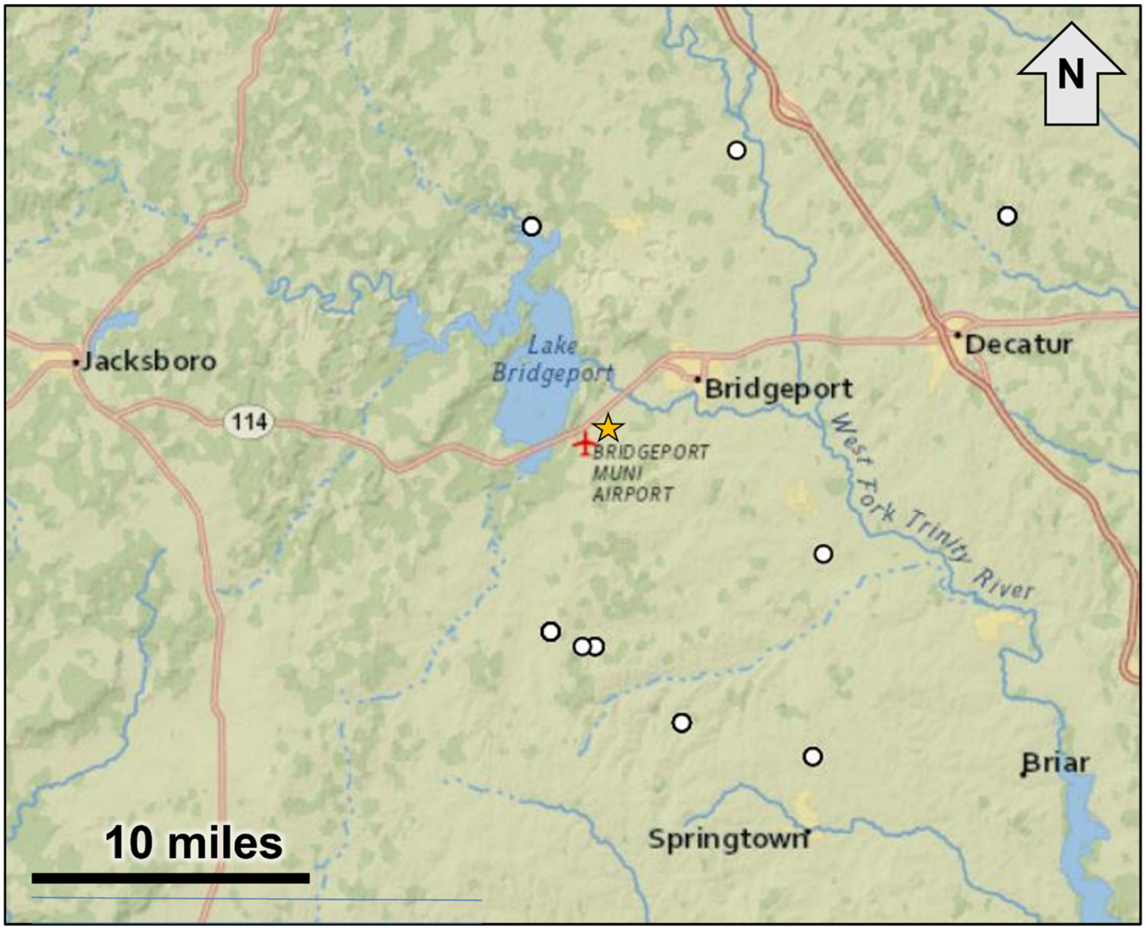

Figure 8. Map showing the location of wells used in the formation fluid chemistry analysis.

The Ellenburger Group has not been extensively drilled within the immediate area surrounding the proposed injection well and consequently formation fluid chemical analyses for the Ellenburger Group are from a basin-wide review. Based on analyses from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3, the Ellenburger fluids have greater than 194,263 parts per million (ppm) total dissolved solids (TDS) within the Fort Worth Basin. Formation fluid chemistry analyses for the Ellenburger Group Fort Worth Basin wells are reported in **Table 4**.

Table 4. Ellenburger Group formation fluid chemistry.

	TDS (mg/L)	pH	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	212,347	6	55,066	18,523	125,209
LOW	194,263	5.7	30,000	12,800	76,200
HIGH	276,388	6.6	66,482	24,750	153,071

3.5 POTENTIAL OF INDUCED SEISMICITY – ELLENBURGER GROUP

An analysis of historical seismic events within a 100 square mile radius surrounding the proposed Class II well injection site shows no recorded seismic activity dating back to January 1, 1971, according to the U.S. Geological Survey (USGS) Earthquake Catalog, as illustrated in **Figure 9**. TexNet seismic activity data supports this conclusion, showing no recorded seismic events around the proposed injection well site. Fault slip potential of mapped faults within the Fort Worth Basin was assessed through a literature survey.[7] Current findings show that steeply dipping faults that strike north-northeast have the highest fault-slip potential. A Wise County saltwater disposal well has been permitted for an injection rate of 15,000 barrels per day (bpd) and is located approximately eight miles from the Barnett RDC #1 injection site. This well has been operated without any observed seismic activity.

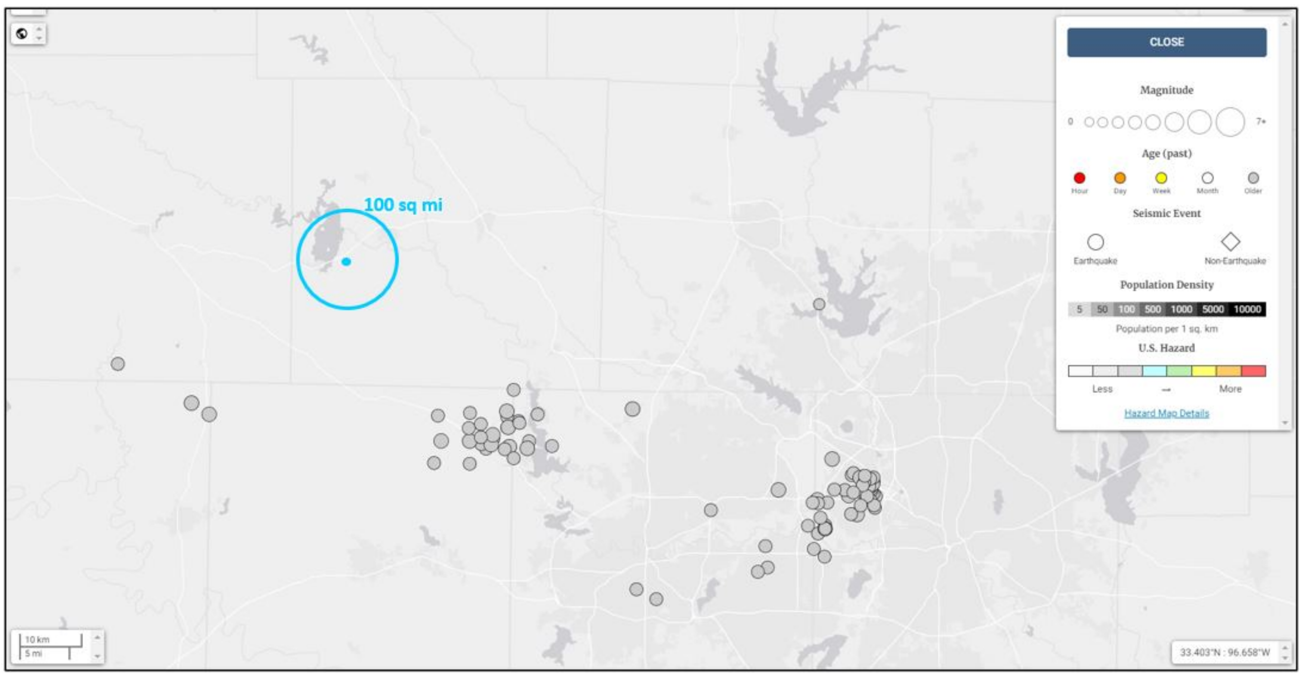

Figure 9. Screenshot from the USGS Earthquake Catalog showing no historical seismic activity in the surrounding 100 square miles to the proposed Barnett RDC #1 site.

3.6 GROUNDWATER HYDROLOGY IN MMA

Wise County falls within the Upper Trinity Groundwater Conservation District as mapped by the Texas Water Development Board, shown in **Figure 10**. Two aquifers are within the vicinity of the proposed injection site: the Trinity Group Aquifer, a major aquifer, and the Cross Timbers Aquifer, a minor aquifer. The Lower Cretaceous Trinity Group is an important source of groundwater for a portion of Northern Texas and consequently Wise County, Texas. Lower Cretaceous strata outcrop throughout the majority of Wise County, especially to the east, but are absent at and around the

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[7] Hennings, P.H., *et al*., 2019. Injection-Induced Seismicity and Fault-Slip Potential in the Fort Worth Basin, Texas. *Bulletin of the Seismological Society of America* 20 (20), 2019.

proposed injection site, as seen in **Figure 10** and **Figure 11**. Instead, strata from the Cross Timbers Aquifer outcrop on the surface at the proposed injection site. The Cross Timbers Aquifer includes four Paleozoic-age water-bearing formations including, from oldest to youngest, the Strawn, Canyon, Cisco, and Wichita Groups. The Upper Pennsylvanian Strawn Group Willow Point Formation outcrops on the surface at the proposed injection site, and rocks from the Upper Pennsylvanian Canyon Group Jasper Creek Formation outcrop 0.5 miles to the north-northwest of the proposed injection site, shown in **Figure 12**. Strawn and Canyon Group formations are primarily composed of limestones, shales, and sandstones. A stratigraphic column showing the Pennsylvanian through Cretaceous strata is included as **Figure 13**.

The Canyon Group, which outcrops at the proposed injection site, is a sequence of limestones with interstratified shales and sandstones deposited as a part of the Perrin Delta System.[8] Deposition of Canyon Group sandstones was localized within valley fill, distributary channel fill, and delta-front deposits.[9] These sandstone bodies are not laterally continuous and therefore did not constitute a regional scale major aquifer. Nearby groundwater well reports list the aquifer as Paleozoic, supporting the conclusion that freshwater in and around the well site is sourced from Pennsylvanian strata. Because the location of the well site does not fall within one of the major aquifer boundaries described by the Texas Water Development Board, describing the Total Dissolved Solids (TDS) contents of water from the Pennsylvanian Canyon Group is challenging. Consequently, this data will be collected during the drilling process. One TDS measurement from the Pennsylvanian group (formation unspecified) near the well site was recorded as 1,600 ppm.[10] Thus, freshwater wells in the area are likely drawing from localized sands within the Upper Pennsylvanian strata. The USGS's National Produced Waters Geochemical Database (NPWGD) report several TDS content measurements within the Lower Pennsylvanian Atoka/Bend formation with values ranging from 21,926 ppm to 154,593 ppm.[11] No reported TDS values from the USGS NPWGD fall below the 10,000-ppm minimum required to classify an aquifer as an Underground Source of Drinking Water (USDW). Consequently, the lowermost USDW is likely above the Lower Pennsylvanian strata at around 900 feet.

The direction of groundwater flow within Paleozoic strata is suggested to be in the west-northwest direction according to a conceptual model developed by Nicot, *et al*.[12] Recharge into the Canyon Group was estimated to occur at a rate of 0.09 inches per year by the same study. Surface-water salinity decreases downstream toward the Gulf of Mexico. Groundwater salinity increases from

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[8] Brown Jr., L.F., Cleaves II, A.W., Erxleben, A.W., 1973. Pennsylvanian depositional systems in North Central Texas, a guide for interpreting terrigenous clastic facies in a cratonic basin, *Texas Univ. Bur. Econ. Geology Guidebook*, 14 (1973), p. 132.

[9] Blandford, T.N., *et al.*, 2021. Conceptual Model Report for the Cross Timbers Aquifer. Report produced under Texas Water Development Board Contract No. 1948312322.

[10] Winslow, A.G., and Kister, L.R., 1956. Saline-Water Resources of Texas. U.S. Department of Interior Report.

[11] Blondes, M.S., *et al.*, 2018. U.S. Geological Survey National Produced Waters Geochemical Database (v2.3, January 2018): U.S. Geological Survey data release, https://doi.org/10.5066/F7J964W8.

[12] Nicot, J.-P., Huang, Y., Wolaver, B.D., and Costley, R.A., 2013. Flow and Salinity Patterns in the Low-Transmissivity Upper Paleozoic Aquifer of North-Central Texas: *Gulf Coast Association of Geological Societies Journa*l (2), pgs. 53-67.

younger to older formations toward the east but there is a reversal in the Strawn Group, whose formations can be in hydraulic contact with the overlying Trinity Aquifer. The Trinity Aquifer may provide cross-formational flow to Paleozoic aquifers when they overlap, with the primary flow direction from the Trinity to the Strawn. This mixing could explain the salinity reversal observed in some parts of Texas within the Strawn Group. Locally, however, the deepest water well within two miles of the proposed injection well is 320 feet deep. This indicates that water wells in the area are drawing fresh water from localized sands within the upper several hundred feet.

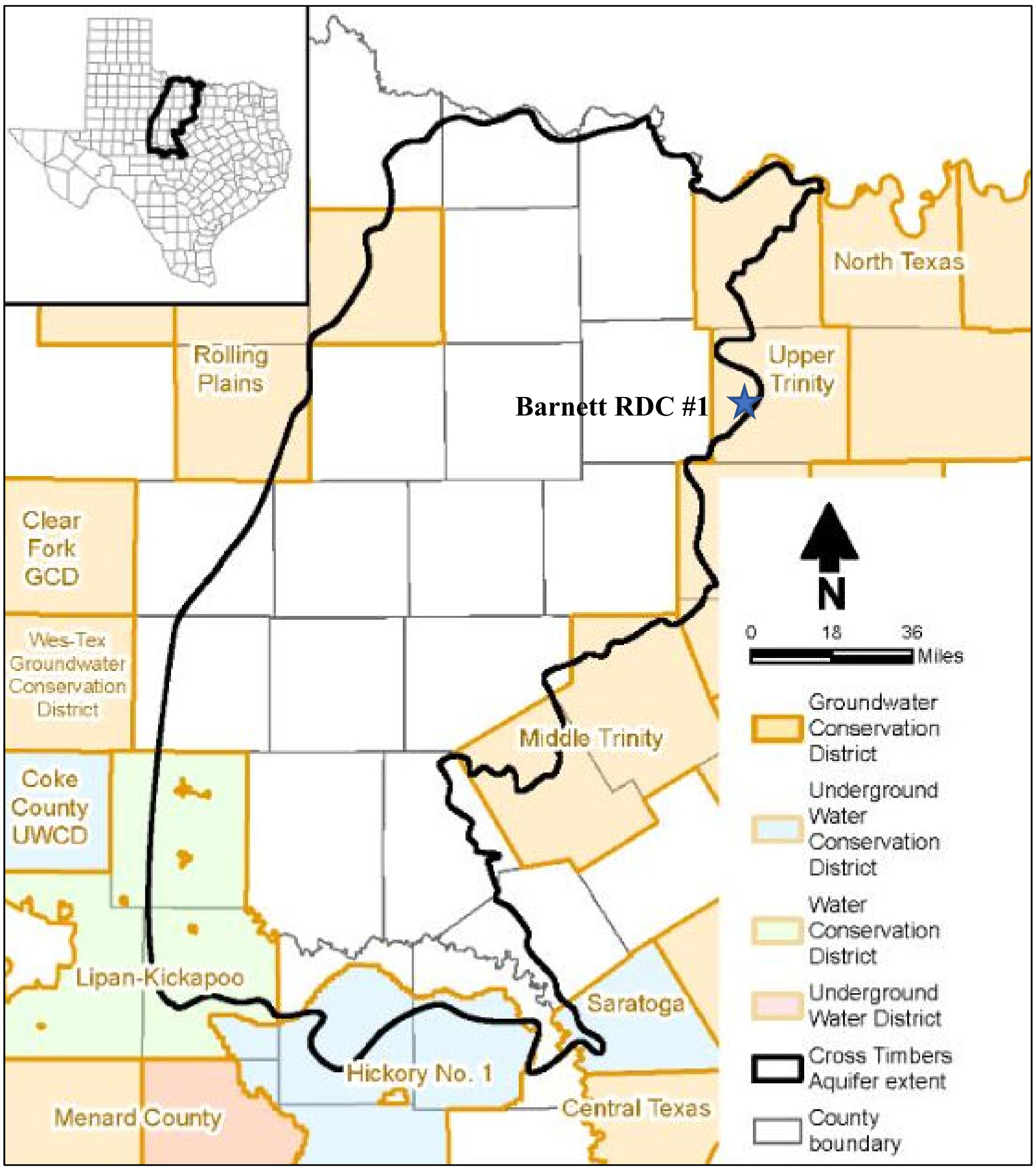

Figure 10. Map of the groundwater conservation districts and the Cross Timbers Aquifer extent within North Central Texas, from the Texas Water Development Board. The location of the proposed Barnett RDC #1 is shown with a star.

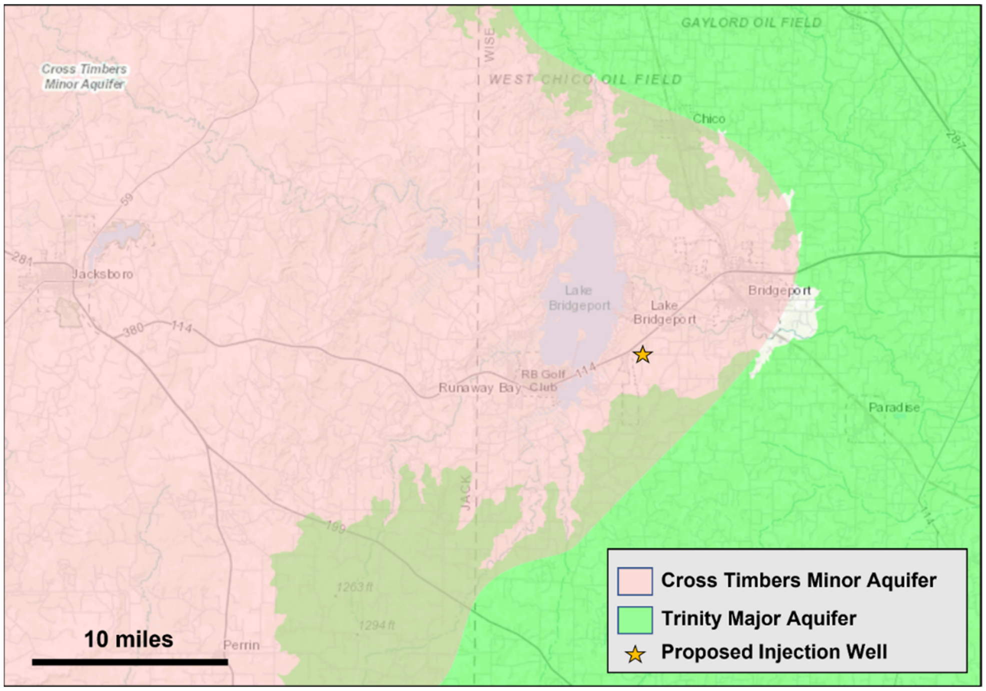

Figure 11. Location of the Cross Timbers minor aquifer and Trinity major aquifer in Texas, with the Barnett RDC #1 location labeled with a star.

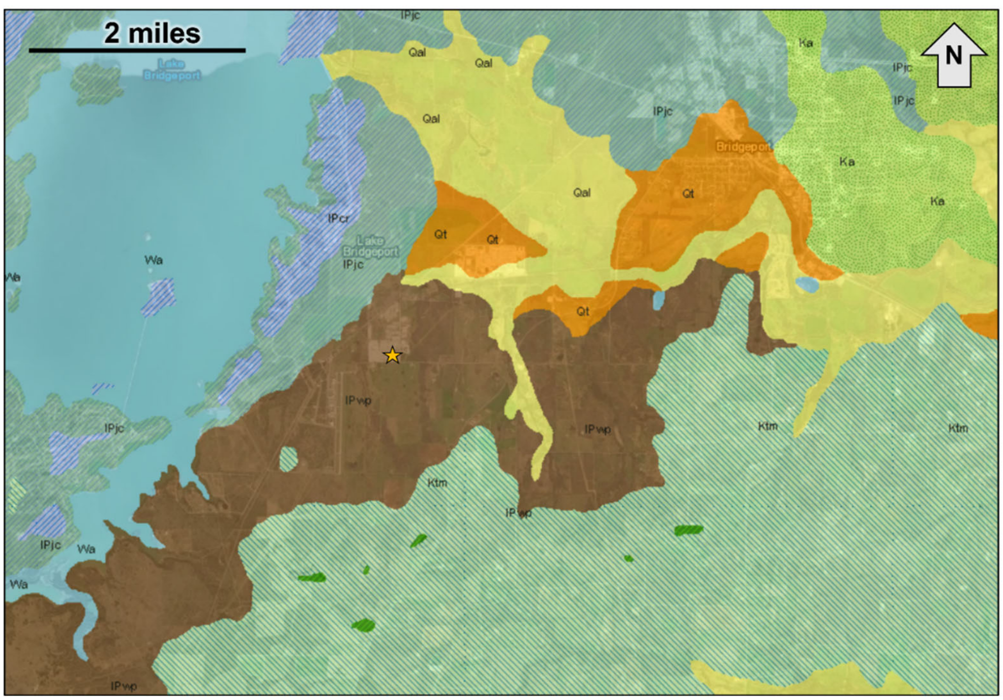

Figure 12. Geologic map of the area near the proposed injection site (yellow star). Geologic formations labeled using the state of Texas' USGS rock units codes, where: Qal = alluvium, Qt = fluviatile terrrace deposits, Wa = water, IPcr = Chico Ridge limestone, IPjc = Jasper Creek formation, IPwp = Willow Point formation, Ktm = Twin Mountains formation, and Ka = Antlers sand.

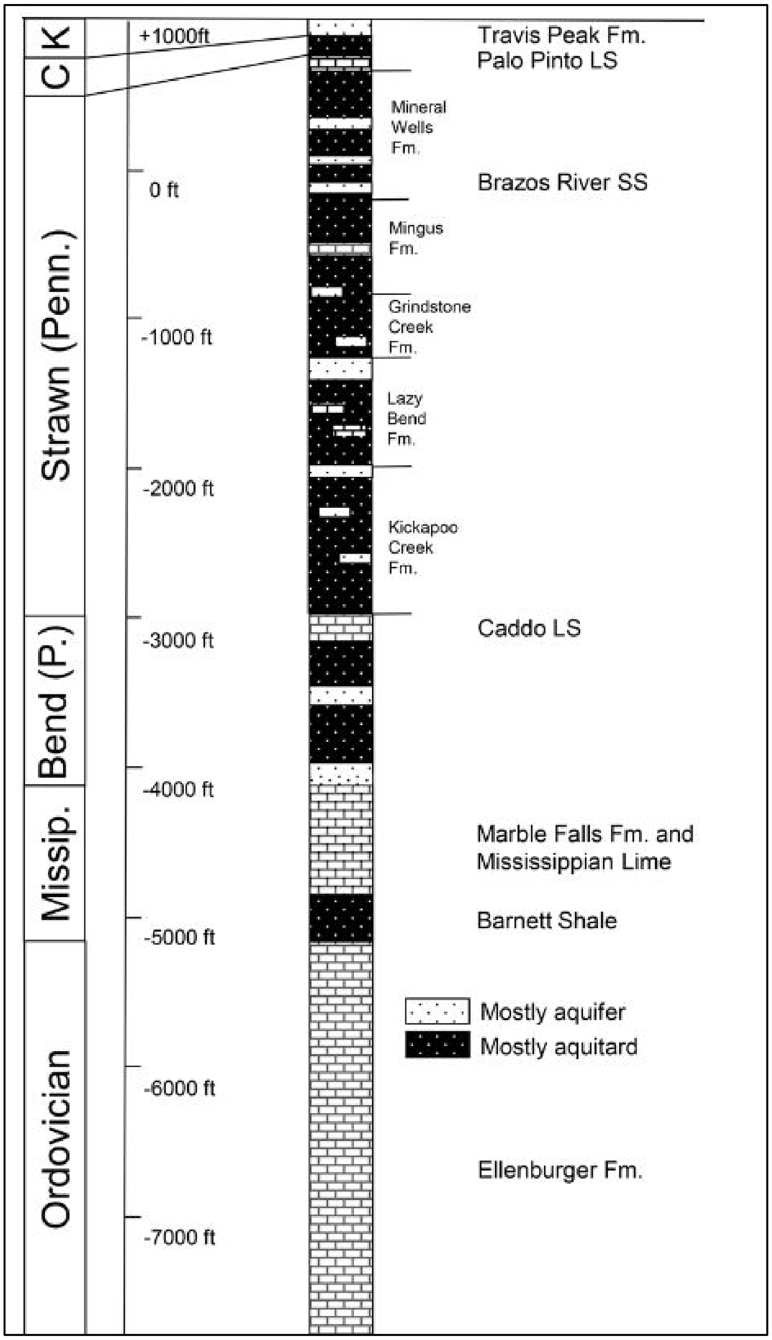

Figure 13. Stratigraphic column including aquifers and aquitards, modified from Nicot *et al*.[13]

There are 105 freshwater wells within a two-mile radius and 26 wells within a one-mile radius of the proposed injection well, according to the Texas Water Development Board Groundwater Data Viewer, shown in **Figure 14** and listed in **Table 5**.

[13] Nicot, J, *et al*., 2011. Methane occurrences in aquifers in the Barnett Shale area with a focus on Parker County, Texas" University of Texas, 2011, https://deepblue.lib.umich.edu/bitstream/handle/2027.42/137724/gwat12508-sup-0001-supinfo.pdf?sequence=1.

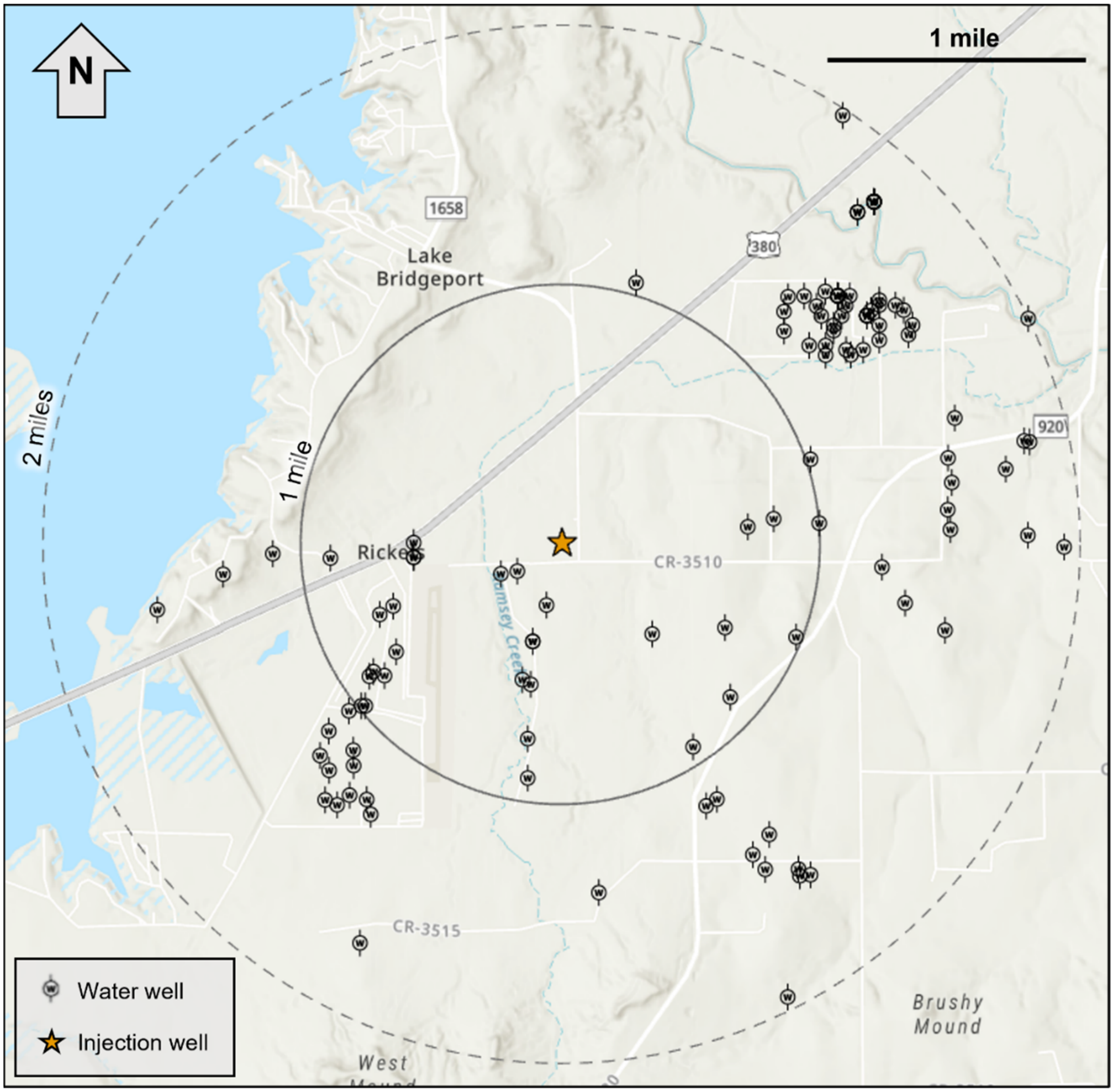

Figure 14. Water wells within one and two miles from the proposed injection site, data from the Texas Water Development Board.

Table 5. Private and state-owned groundwater wells in project area.

Private Groundwater Wells				
Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
324182	33.157501	-97.805278	180	1.97
85836	33.160834	-97.833889	180	1.74
419698	33.1635	-97.817833	160	1.37
494622	33.16434	-97.80437	140	1.59
522108	33.16439	-97.80365	140	1.61
270093	33.164723	-97.806667	200	1.50
131403	33.164723	-97.804445	110	1.57
33173	33.165556	-97.807501	280	1.42
67830	33.166667	-97.806389	100	1.39
592900	33.16871	-97.80986	155	1.16
135520	33.17	-97.8225	140	0.93
71023	33.171667	-97.811389	120	0.94
214384	33.172222	-97.8225	195	0.78
23271	33.174167	-97.833611	280	1.01
23265	33.174167	-97.833334	140	1.00
12854	33.174444	-97.808889	140	0.89
305950	33.175278	-97.822222	110	0.57
86814	33.175555	-97.822778	213	0.56
570517	33.17587	-97.83202	120	0.86
13278	33.176111	-97.832778	140	0.89
585723	33.17721	-97.83121	160	0.77
527914	33.177694	-97.822083	160	0.40
527919	33.177694	-97.822083	160	0.40
190556	33.177778	-97.804445	210	0.98
428746	33.178047	-97.81408	120	0.50
605428	33.17806	-97.79442	180	1.53
107416	33.178333	-97.809167	140	0.72
509874	33.1793	-97.83231	120	0.76
601491	33.17962	-97.79708	200	1.35
53199	33.179722	-97.847222	150	1.60
196527	33.179722	-97.821111	75	0.25
510354	33.179783	-97.831417	130	0.70
430183	33.1815	-97.824139	170	0.27
81235	33.181667	-97.842778	200	1.32
193088	33.181667	-97.823055	240	0.21
373126	33.181667	-97.798611	160	1.25
351852	33.1825	-97.835556	320	0.90
122077	33.1825	-97.83	205	0.58
143619	33.1825	-97.83	140	0.58

Private Groundwater Wells				
Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
474446	33.182659	-97.786404	180	1.95
44219	33.182778	-97.839445	230	1.13
214552	33.183334	-97.83	120	0.58
483302	33.183342	-97.78883	100	1.81
416778	33.18372	-97.79402	180	1.51
479366	33.184019	-97.807589	200	0.72
72275	33.184167	-97.802778	34	1.00
123233	33.184445	-97.805834	32	0.83
457391	33.184833	-97.794167	170	1.50
187174	33.186389	-97.793889	180	1.53
419604	33.187077	-97.790243	180	1.75
574195	33.187771	-97.794087	180	1.53
329665	33.187778	-97.803334	170	1.02
404012	33.188611	-97.788611	260	1.86
422029	33.18865	-97.78897	260	1.84
88487	33.19	-97.793611	103	1.60
72273	33.193611	-97.802223	29	1.25
72269	33.193611	-97.800556	28	1.33
62634	33.193889	-97.800834	33	1.33
72268	33.193889	-97.799722	28	1.39
62627	33.194167	-97.803334	30	1.22
62639	33.194167	-97.802223	28	1.28
219191	33.194445	-97.798611	30	1.46
219202	33.194722	-97.796667	20	1.57
123232	33.195	-97.805001	34	1.19
62632	33.195	-97.801667	33	1.34
329661	33.195278	-97.801667	145	1.35
219187	33.195278	-97.798611	30	1.49
219200	33.195278	-97.796389	24	1.60
219184	33.195556	-97.788611	30	2.01
62616	33.195834	-97.802501	35	1.33
62629	33.195834	-97.801112	35	1.40
49825	33.195834	-97.799445	27	1.47
49826	33.195834	-97.799445	27	1.47
49827	33.195834	-97.799445	27	1.47
49828	33.195834	-97.799445	27	1.47
49829	33.195834	-97.799445	32	1.47
72263	33.196111	-97.805001	30	1.24
62607	33.196111	-97.799167	31	1.50
219198	33.196111	-97.796945	27	1.60
62622	33.196389	-97.802778	38	1.35

Private Groundwater Wells				
Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
62628	33.196389	-97.800834	31	1.43
72267	33.196389	-97.798611	35	1.53
219193	33.196389	-97.7975	20	1.59
219181	33.196667	-97.798611	30	1.55
62626	33.196945	-97.804723	16	1.29
62623	33.196945	-97.803612	16	1.34
41283	33.196945	-97.801389	21	1.43
41284	33.196945	-97.801389	15	1.43
41285	33.196945	-97.801389	15	1.43
41286	33.196945	-97.801389	15	1.43
41287	33.196945	-97.801389	15	1.43
72264	33.196945	-97.800556	34	1.47
62618	33.197222	-97.802223	32	1.41
405842	33.197817	-97.814883	60	1.05
240181	33.201667	-97.800001	20	1.72
240182	33.201667	-97.800001	18	1.72
240183	33.201667	-97.800001	17.5	1.72
213490	33.202223	-97.798889	14.5	1.79
213494	33.202223	-97.798889	15	1.79
213495	33.202223	-97.798889	14	1.79
213496	33.202223	-97.798889	14.5	1.79
213499	33.202223	-97.798889	13	1.79
213500	33.202223	-97.798889	12	1.79
213502	33.202223	-97.798889	11	1.79
516919	33.20712	-97.8009	160	1.98
State Groundwater Wells				
State Well Number	**Latitude (DD)**	**Longitude (DD)**	**Borehole Depth (feet)**	**Distance from proposed injector (mi)**
1950401	33.17389	-97.83445	147	1.06
1950402	33.17278	-97.83583	146	1.17
1950408	33.16917	-97.83445	147	1.28
1950501	33.17583	-97.83306	82	0.91
1950406	33.16861	-97.83528	147	1.34
1950504	33.16806	-97.83306	147	1.29
1950404	33.17139	-97.83639	147	1.25
1950502	33.16833	-97.81056	121	1.17
1950403	33.16889	-97.83611	147	1.36
1950405	33.17083	-97.83417	147	1.19
1950407	33.17167	-97.83417	147	1.15
1950409	33.17056	-97.83583	147	1.27
1950503	33.16889	-97.83333	147	1.26

3.7 DESCRIPTION OF CO_2 PROJECT FACILITIES

dCarbon will accept CO_2 from by the Bridgeport Plant (**Figure 15**). The temperature, pressure, composition, and quantity of CO_2 will be measured and metered according to industry standards, with an orifice meter, Coriolis meter, or similar device. dCarbon will dehydrate and compress the CO_2 to a supercritical physical state at the Bridgeport site. dCarbon will then transport the CO_2 via pipeline approximately 6,815 feet to the Barnett RDC #1 injection site. Once at the well site, the CO_2 stream will again be metered to reverify quantity. The CO_2 will then be injected into the Ellenburger formation. This formation is deeper than other formations known to be productive of oil and gas in the area. A gas analysis of the CO_2 stream is shown in **Table 6**. Although this sample is expected to be representative of the composition of the gas, it is possible that the composition will vary slightly in time.

Table 6. CO_2 stream analysis for the Barnett RDC #1 site.

Name	**Normalized Weight Percent**	**Normalized Mole Percent**	**Normalized Liquid Volume Percent**
Nitrogen	0.002	0.003	0.002
Carbon Dioxide	99.358	99.054	98.646
Methane	0.105	0.287	0.286
Ethane	0.4	0.584	0.916
Propane	0.018	0.018	0.029
Isobutane	0.003	0.002	0.004
N-butane	0.008	0.006	0.011
Isopentane	0.002	0.001	0.003
N-pentane	0.002	0.001	0.003
Hexanes	0.011	0.008	0.013
Heptanes	0.011	0.002	0.011
Octanes	0.007	0.001	0.007
Nonanes	0.009	0.002	0.009
Decanes plus	0.004	0.001	0.004
BTEX	0.06	0.03	0.056
H_2S	0.00002	0.00002	0.00002
Total	100	100	100
Total Sample Properties			
Property	Value		
BTU (Gross)	16.04		
Density (lbs/gal)	12.63		
Molecular weight	43.87		
Specific gravity (Air=1)	1.5147		

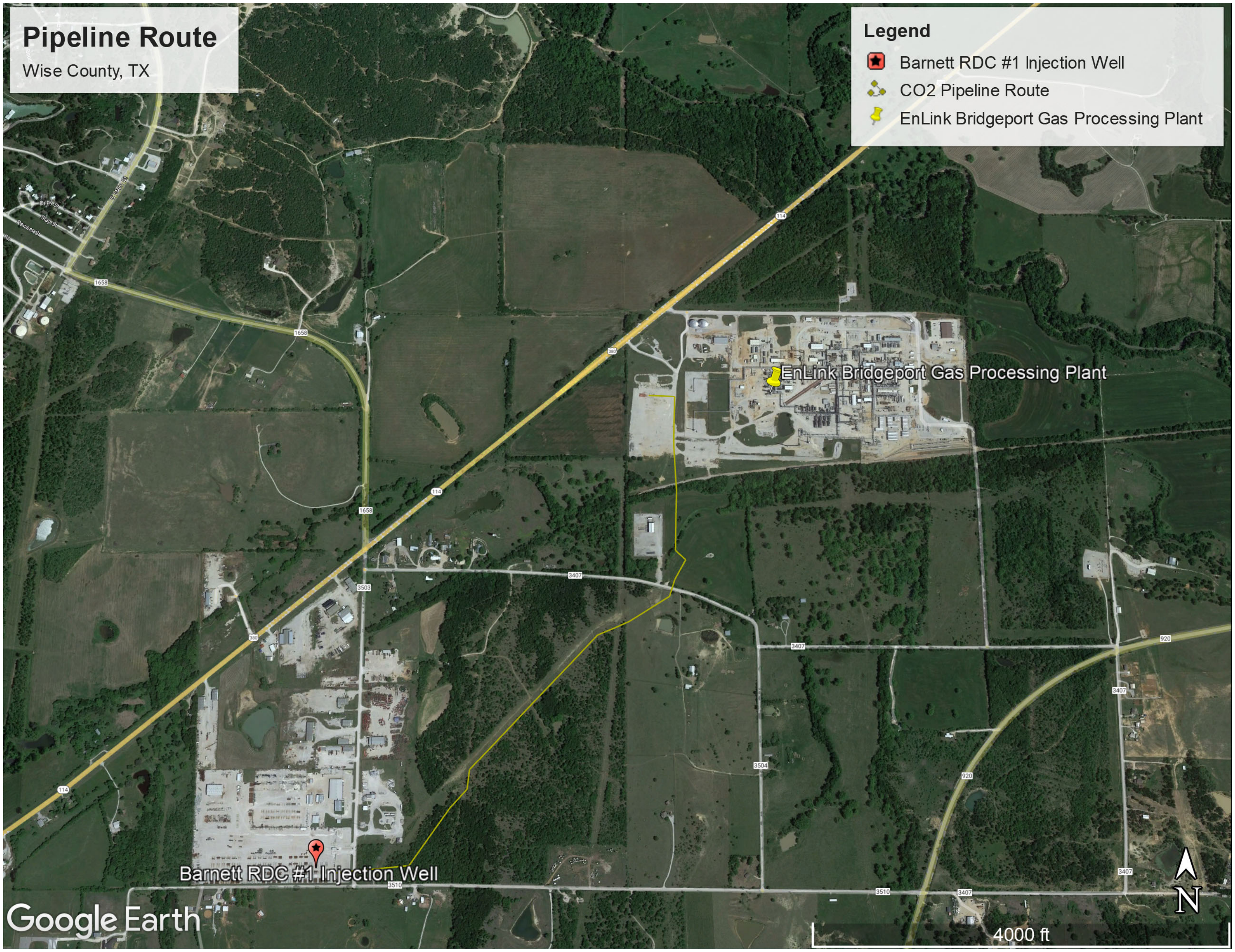

Figure 15. Proposed pipeline route.

3.8. Reservoir Characterization Modeling

A regional model encompassing nearby plugged and abandoned wells as well as saltwater disposal wells was created in Schlumberger's Petrel software. The model incorporates available well petrophysical data and generates a static earth model (SEM) for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the W.S. Coleman SWD #2 well (approximately five miles east of Barnett RDC #1, as discussed in previous sections). The reservoir is characterized by low matrix porosities as well as naturally existing fractures which are likely to contribute to fluid flow. For the current assessment, a single porosity, single permeability distribution model was deemed appropriate given the uniformity of natural fracture distribution within the Ellenburger as well as saltwater disposal rates and volumes into the Ellenburger in nearby counties. These assumptions will be examined and verified using a pressure fall-off test (PFOT) that will be conducted during the construction of the Barnett RDC #1 well. If PFOT and logging programs detect deviations from anticipated reservoir behavior, dCarbon will use the new data to update reservoir models, as well as injection forecasts and the MRV plan if appropriate.

The primary objectives of the simulation model were to:

1. Estimate the maximum areal extent of the injectate plume and its migration post injection.
2. Determine the ability of the target formation to handle the required injection rate.
3. Characterize potential interaction between the injected CO_2 and any nearby potential leakage pathways.

The CO_2 storage complex, as indicated previously, is anticipated to be confined to the Ellenburger interval. Ellenburger subunit E is modeled as the reservoir unit while Ellenburger C subunit is anticipated to provide a primary seal that impedes vertical fluid flow. The Barnett Shale is expected to serve as a secondary seal which provides an additional stratigraphic seal to the injected CO_2. The lower confining zone for the reservoir is provided by the Ellenburger F subunit. A 12-mile by 12-mile tartan grid was generated in Schlumberger's Petrel software based on well top information from nearby legacy and saltwater disposal wells. The grid was then exported to Computer Modeling Group's General Equation of State Model (CMG-GEM) simulator to account for fully implicit multiphase compositional fluid flow. This simulation was built to model other transport and mixing phenomena such as relative permeability, diffusion, advection, aqueous solubility, and buoyancy to accurately predict the plume movement. The reservoir is modeled to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 200,000 TDS, which is typical of the Ellenburger formation in the project area. The injected gas stream is assumed to be fully composed of CO_2. **Figure 16** illustrates the vertical layering with relationship to simulated CO_2 saturation profile in the model. The injection rate modeled was 280,000 MT/year for 12 years followed by 100 years of post-injection timeframe to observe post-injection movement of CO_2.

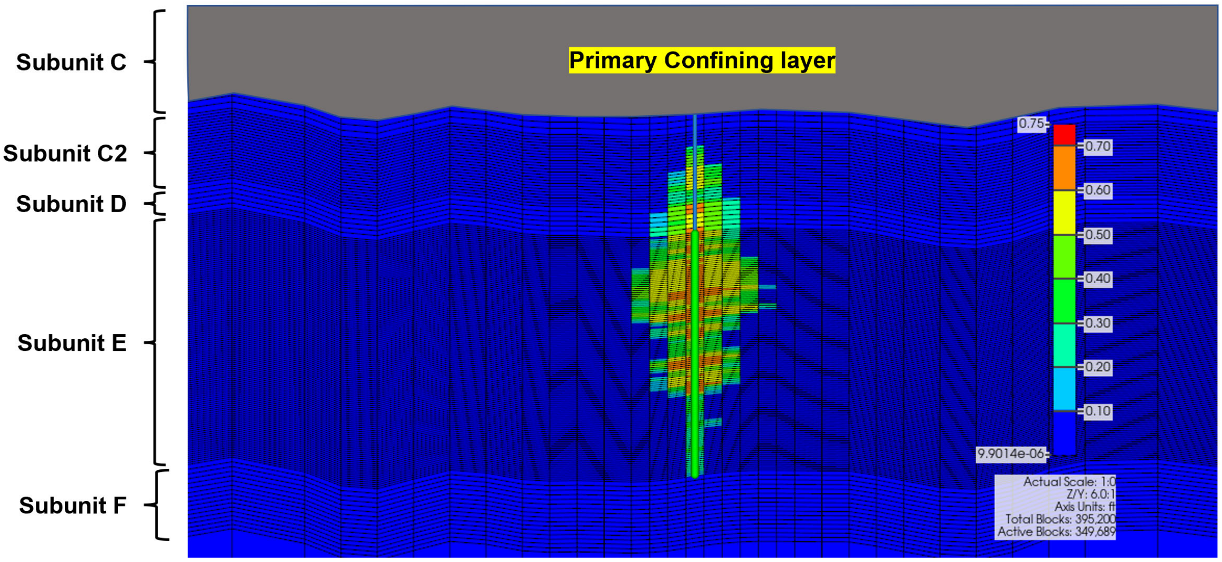

Figure 16. Vertical CO_2 saturation Profile of the CMG-GEM Model for Barnett RDC #1 Well. Color scale in Figure 16 indicates CO_2 gas saturation.

Datasets prepared for simulations were based on published literature. Specifically, the reservoir relative permeability model used in this model was sourced from literature[14] using data from the Wabamun Carbonate reservoir formation, which exhibited comparable porosities and permeabilities as the Ellenburger. The initial reservoir conditions were developed using gradients derived from literature.[2] The pressure gradient was assumed to be 0.47 psi per foot, which resulted in an estimated reservoir pressure of 4,136 psi at the top of the injection interval. The temperature gradient was assumed to be 1.5°F per 100 feet, resulting in an estimated temperature of 201°F at the top of the reservoir. Fracture pressures were estimated at 0.7 psi per foot. To ensure CO_2 injection does not induce fractures within the Ellenburger, injection well bottom hole pressure (BHP) was constrained to 90% of calculated fracture pressure, thereby applying a safety factor of 10%. This resulted in a maximum bottom hole injection pressure constraint of 5,524 psi. There are no active wells injecting or producing from the injection interval in the project area. Therefore, no additional wells other than injector were included in the fluid flow simulation model.

As mentioned earlier, injection was modeled at 280,000 MT/yr. The model simulated 12 years of active injection followed by 100 years without injection to determine when plume migration stops. Plume migration ceased after 50 years post-injection, which is determined to be the maximum extent of the CO_2 plume. **Figure 17** shows the CO_2 plume at the end of injection (yellow) compared to 50 years post injection (red). Injected CO_2 flows generally west, which is the regional up dip direction. However, the change in CO_2 plume area from end of injection to 50 years post-injection is minimal (approximately 29%) and the plume stops moving after 50 years.

[14] Bennion, D.B., and Bachu, S., 2007. Permeability and Relative Permeability Measurements at Reservoir Conditions for CO_2-Water Systems in Ultra Low Permeability Confining Caprocks. SPE Paper # 106995.

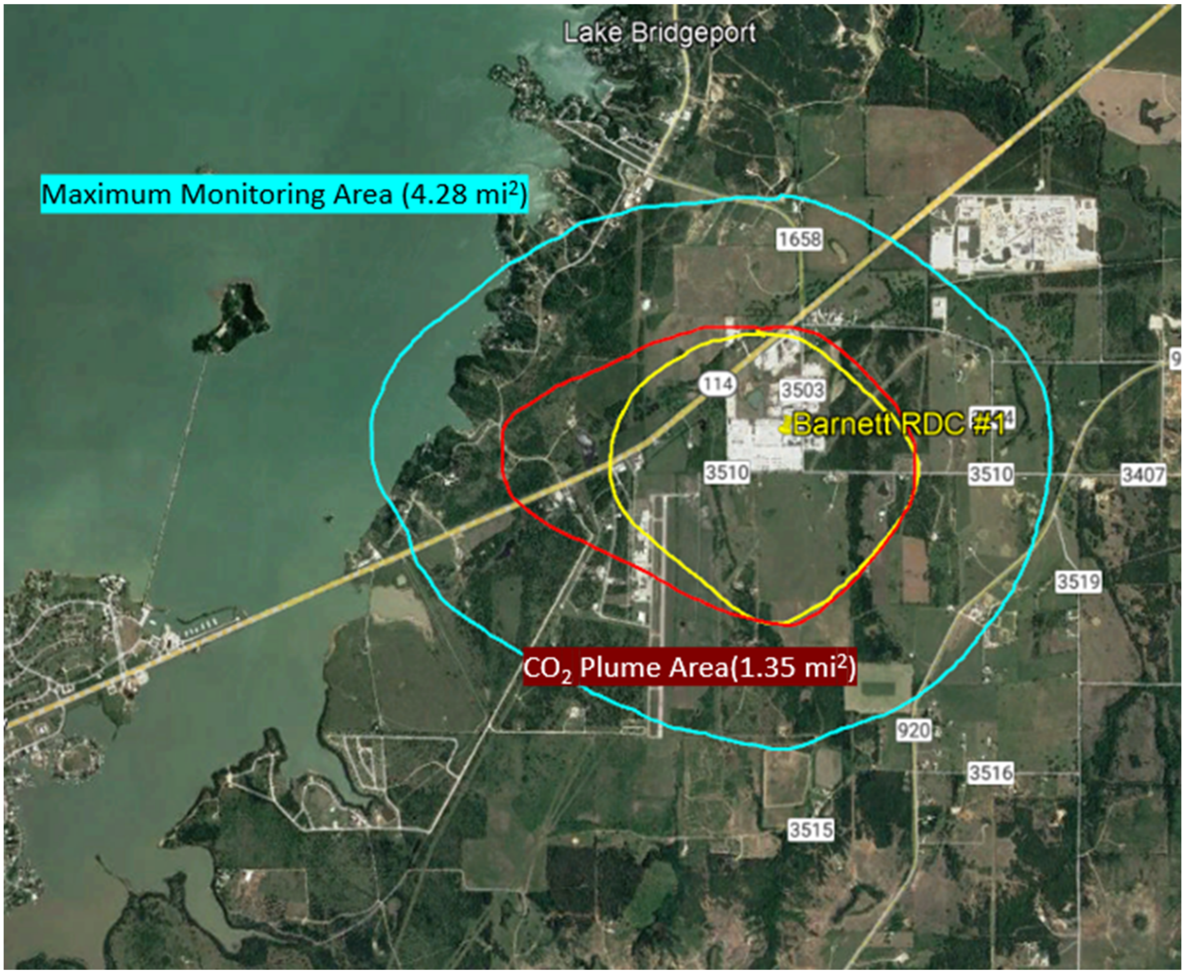

Figure 17. Simulation Results Showing CO_2 Plumes (end of injection – yellow, after 50 years of injection – red) and the Maximum Monitoring Area (blue).

Figure 18 illustrates CO_2 mass injection rate, cumulative CO_2 injection mass, and bottom hole pressure at the Barnett RDC #1 well as modeled. The bottom hole pressure remained well under the bottom hole pressure constraint. The maximum bottom hole pressure reached is 4,434 psi (1,090 psi lower than the BHP constraint), which occurs six months after the start of injection. This spike is anticipated to be a result of near wellbore effects arising from CO_2 forcing its way into the brine-filled porous media. Upon reaching a critical mass to transition from capillary driven to advection driven flow, the BHP starts to decline until the end of injection while keeping the injection rate constant. The BHP then falls until the end of injection.

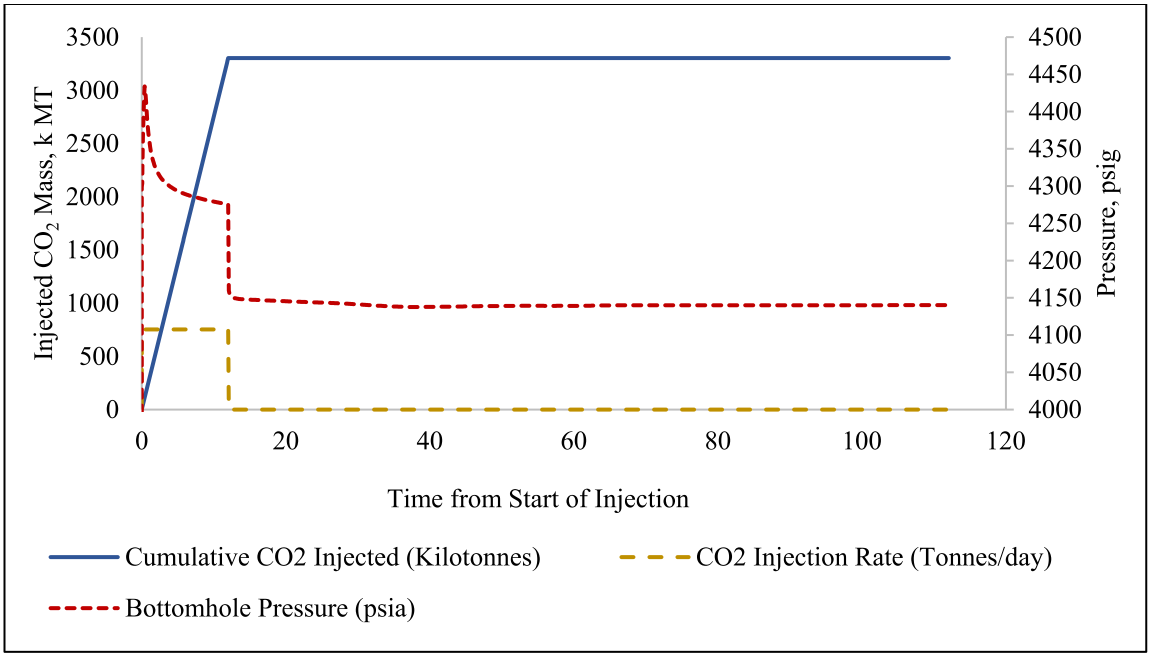

Figure 18. Modeled Injection Profile at Barnett RDC #1 Well.

4 – DELINIATION OF MONITORING AREA

4.1 Maximum Monitoring Area (MMA)

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The numerical simulation using CMG-GEM as discussed above was used to estimate the size and migration of the CO_2 plume. The model injected into the Ellenburger subunit E formation. CO_2 injection was modeled for 12 years followed by 100 years post injection. Results indicated that the plume ceased to migrate after 50 years post injection. For more information on the simulation construction and setup, please see the discussion in Section 3.8. A 5% cutoff of molar gas concentration was used to determine the boundary of the CO_2 plume. The area of the maximum monitoring area was determined to be 4.28 square miles with the greatest extent reaching 1.62 miles from the injector. **Figure 19** shows the end of injection plume (yellow), the 50-year post injection plume (red), and the maximum monitoring area using a half mile buffer (blue).

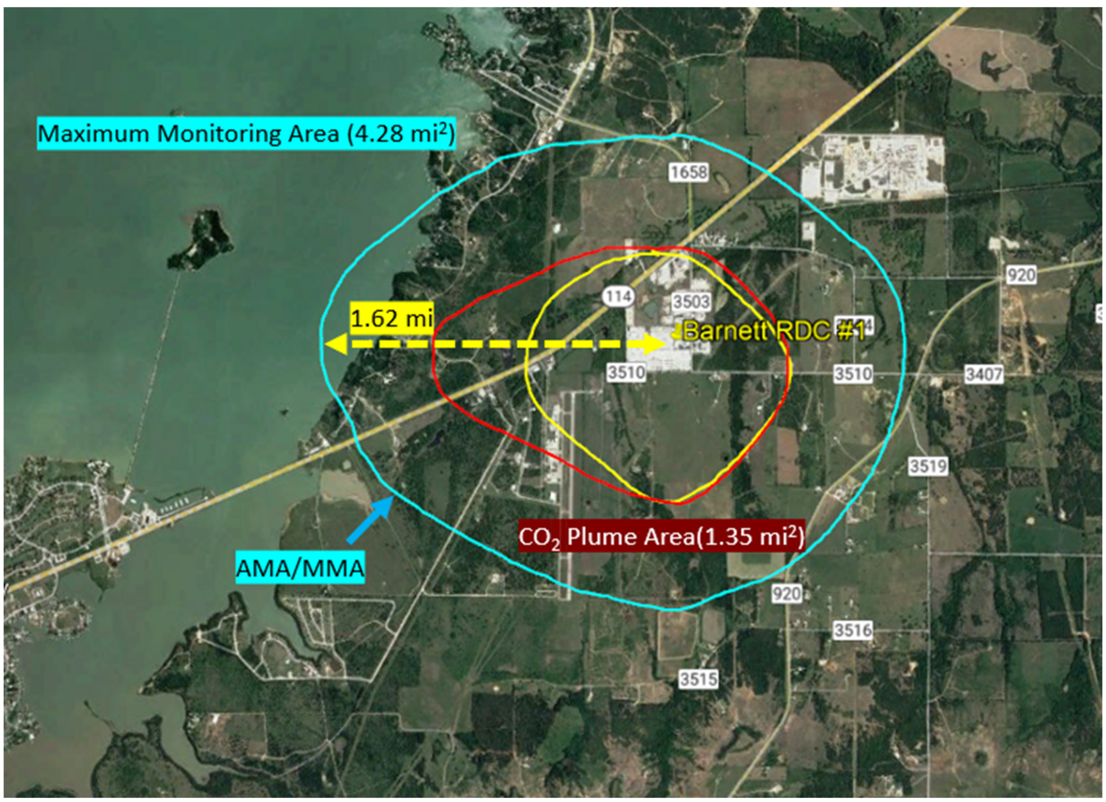

Figure 19. Maximum Monitoring Area (blue), End of Injection Plume (yellow), and 50-year Post Injection Plume (red) as Modeled at the Barnett RDC #1 Well.

4.2. Active Monitoring Area (AMA)

As discussed in Section 3, there are no structural or geological features within the project area that could cause the unintended migration of the CO_2 plume. The only potential leakage pathways that exist are well penetrations and the surface equipment. Leakage from groundwater wells, faults and

fractures, leakage through the confining layer, and seismicity events are expected to be highly improbable. That said, these leakage pathways have been considered and options to monitor them are discussed in Section 4 and Section 5. Sufficient care and consideration will be provided to monitoring these pathways, if any, and simulation models will be calibrated with new data as appropriate.

dCarbon adhered to the definition of active monitoring area (AMA) provided in 40 CFR 98.449 to delineate the AMA for this project. As noted in Section 6, dCarbon proposes to monitor the injection site from year one through year 14, which includes 12 years of injection plus two years of post-injection monitoring. As defined in 40 CFR § 98.449, the AMA must be delineated by superposition of:

(1) The area projected to contain the free phase CO_2 plume at the end of year 14, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

(2) The area projected to contain the free phase CO_2 plume at the end of year 19.

As noted in Section 4.1, dCarbon utilized the plume area after 50 years of post-injection plus a one-half mile buffer to determine the MMA, which far exceeds the definition of AMA set forth in 40 CFR § 98.449. Therefore, the AMA is proposed to have the same boundary as the MMA, which adequately covers the area that is required by 40 CFR § 98.449. **Figure 19** shows the MMA, which is the same as the AMA. **Figure 20** indicates the AMA/MMA (blue line) and currently existing water and oil and/or gas wells within this area. None of these wells were found to penetrate the Ellenburger within the project area. Water wells in the region are shallow with drilled depths up to 320 feet from surface. Additional discussion on well infrastructure within the project area can be found in later sections of this document.

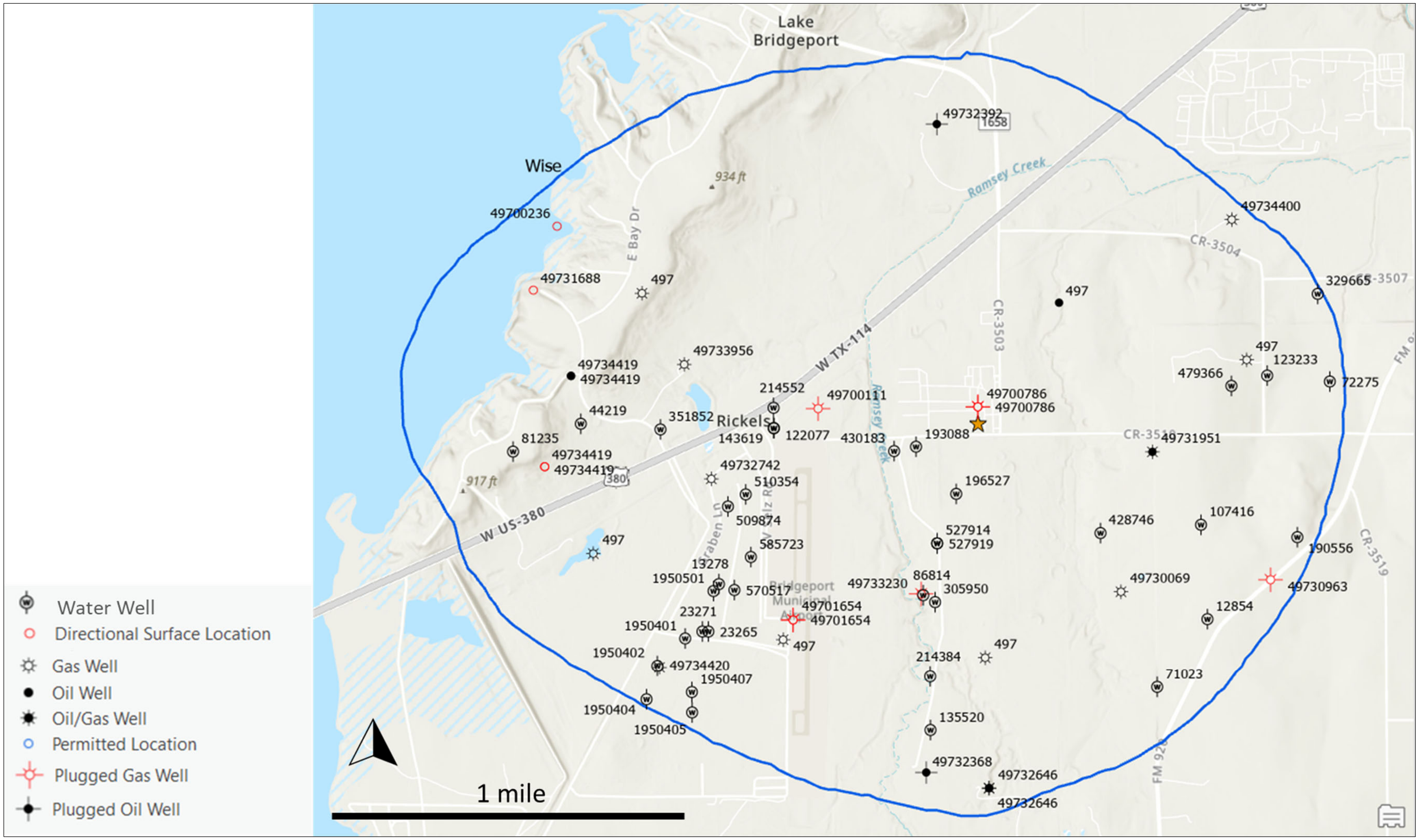

Figure 20. Maximum/Active Monitoring Area (blue) and existing wells within the project AMA/MMA. The Barnett RDC #1 is shown as a star.

5 – IDENTIFICATION AND EVALUATION OF POTENTIAL LEAKAGE PATHWAYS TO SURFACE

5.1 Potential Leakage from Surface Equipment

dCarbon's surface facilities at Bridgeport and at the injection well site are specifically designed for injecting the CO_2 stream described in **Table 6**, including H_2S. The facilities minimize leakage points such as valves and flanges by following industry standards and best practices. All BKV and dCarbon field personnel are required to wear gas monitors that detect H_2S. A shut-in valve is located at the wellhead in case of emergency. The compressor will also have emergency shut down switches that can be activated in case of unexpected operating conditions.

Additionally, the compressor facility, pipeline, and injection well locations will all be subjected to Auditory, Visual, and Olfactory (AVO) and Forward Looking InfraRed (FLIR) leak detection per BKV and dCarbon safety and operations standards. These recurring inspections, which are standard for detecting leaks and malfunctioning equipment in the gas production industry, will aid in the rapid detection of any potential leaks that may occur. As a part of these inspections, operations personnel are frequently able to repair leaks immediately by tightening valves, flanges, or similar equipment. Any leaks that are detected will be analyzed to determine the amount of CO_2 that may have leaked. These leakage quantities, if any exist, will be included in recurring reporting.

5.2 Leakage from Approved, Not Yet Drilled Wells

There are no active well permits within the MMA. However, there are multiple expired well permits within the MMA that would require re-permitting before being drilled. Details on many of the expired permit locations are included in Attachment B.

5.3 Leakage from Existing Wells

There are 20 existing wells within the MMA. Of these 20 wells, 14 have digital records available on the TRRC website, as shown in **Table 6**. Six wells have been plugged and abandoned, while eight remain active. However, all 14 of these wells are shallower than the proposed disposal interval from this project. In fact, the targeted injection interval (which is greater than 9,350 feet) is approximately 3,000 feet deeper and separated by numerous impermeable zones from the deepest existing well in the MMA (API number 42-497-34419, which has a total depth of 6,334 feet). These wells are represented relative to the project MMA in **Figure 20**. The six remaining wells that were drilled within the MMA, listed in **Table 7**, do not have digital records available on the TRRC website, but dCarbon acquired paper copies of the well permit information, and are attached herein as Attachment B. All six wells were drilled significantly shallower than the target Ellenburger formation. In fact, the deepest of the six wells was drilled to 6,155 feet true vertical depth (TVD), several thousand feet shallower than the Ellenburger formation. Note that the well labeled as D in **Table 7** below is a dual completion but single wellbore. There is one additional well that was permitted but never drilled (labeled as B in **Table 7**)

Additionally, the wellbore design of the injection well contains three layers of steel casing, each of which runs to the surface to ensure complete isolation of wellbore fluids. Each of these three casing strings will be cemented to the surface and inspected with cement bond logs to ensure wellbore integrity. Finally, all injection into the well will occur through a final steel tubing string that is secured in place with a permanent packer. All these aspects of wellbore construction are designed to ensure that all CO_2 is injected into the target formation and that there are no leakage pathways from the wellbore directly into shallower formations.

Table 6. Existing Oil & Gas wells in MMA with digital TRRC records.

API	Well Type	Latitude	Longitude	Status	Total Depth (feet)	Operator	Plug Date
49730069	Gas	33.17562	-97.8131	Open	6,128	Scout Energy Management, LLC	-
49732742	Gas	33.18044	-97.8331	Open	5,900	Eagleridge Operating, LLC	-
49733956	Gas	33.18517	-97.8344	Open	5,950	Eagleridge Operating, LLC	-
49734400	Gas	33.19088	-97.8075	Open	5,920	Eagleridge Operating, LLC	-
49734420	Gas	33.17271	-97.8357	Open	5,950	Eagleridge Operating, LLC	-
49734419	Oil	33.18474	-97.8399	Open	6,334	Merit Energy Company	-
49734419	Oil	33.18474	-97.8399	Open	6,334	Eagleridge Operating, LLC	-
49731951	Oil/Gas	33.18137	-97.8115	Open	6,125	Scout Energy Management, LLC	-
49700111	Plugged (Gas)	33.18328	-97.8278	Plugged	5,899	Mitchell Energy Corporation	4/16/1996
49700786	Plugged (Gas)	33.18328	-97.82	Plugged	5,918	Williams Petroleum Company, Inc.	2/13/2015
49701654	Plugged (Gas)	33.17462	-97.8292	Plugged	6,027	Enserch Exploration, Inc.	9/27/1996
49733230	Plugged (Gas)	33.17563	-97.8229	Plugged	5,950	Merit Energy Company	11/5/2012
49732368	Plugged (Oil)	33.16827	-97.8227	Plugged	6,000	Merit Energy Company	1/8/2001
49732392	Plugged (Oil)	33.19493	-97.8219	Plugged	5,964	Merit Energy Company	3/19/1999

Table 7. Existing Oil & Gas wells in MMA without digital TRRC records.

API	Well Type	Latitude NAD27	Longitude NAD27	Status	Total Depth (feet)	Attachment B Label	Lease / Well Name	Operator
497-01653	Gas	33.188107	-97.83638	Open	5,602	A	Craft Water BD 19-1/ DW Harrison Lease	Lone Star Production
No API	N/A	33.184969	-97.827819	Expired Permit	N/A	B	McLanahan	N/A
497-00009	Oil	33.187529	-97.815993	Open	6,200	C	HH Wharton Gas Unit 1A	A'Mell Oil Properties
497-01686	Gas	33.185100	-97.806835	Plugged	5,996	D	Kate A Stanfield 1	Lone Star Production
497-03093	Oil	33.185100	-97.806835	Plugged	5,996	D	Kate A Stanfield 1A (dual completion of 497-01686)	Lone Star Production
497-30085	Gas	33.172971	-97.819788	Open	5,389	E	CR Upham JR #2 Shilling Harold Lease	Upham Oil & Gas
497-1	Gas	33.1738	-97.829657	Plugged	6,027	F- Same as 497-01654	Craft Water Board Sampson #1	Lone Star Prod/Ensearch
497-01646	Gas	33.177438	-97.838912	Plugged	5,968	G	Craft Water Board 8-1	Lone Star Production

5.4 Potential Leakage from Fractures and Faults

Several episodes of fault formation took place in the Fort Worth Basin, based on 3D seismic data interpretation conducted by dCarbon. The oldest set of faults displaced Ordovician rocks but did not displace Mississippian rocks like the Barnett Shale. A younger set of faults displaced Mississippian and older rocks and appear to be related to the Ouachita Front collision. These faults show displacement up into the Pennsylvanian rocks as high as the Strawn. These larger, younger faults have greater displacement but are relatively sparce.

No faulting is interpreted in the MMA around the Barnett RDC #1 based on available subsurface data including 3D seismic data. Dynamic modeling conducted to date indicates that the CO_2 plume will not intersect any mapped faults, based on dCarbon's existing 3D seismic interpretations.

Karst development is present in some areas at the top of the Ellenburger, primarily where the overlying Viola and Simpson Formations were eroded. Karsting is often developed in the upper several hundred feet of an exposed carbonate (Ellenburger subunit A) where fresh water is able to

dissolve the rock (**Figure 21**). Subsequent loading of sediment can cause the roof of the cave to collapse, with overlying sediment filling the void.[15]

The injection interval, the Ellenburger subunit E appears to be below the portion of the upper Ellenburger affected by the karst collapses. This suggests that the Ellenburger subunit C will remain a continuous upper seal even in karst areas. There are no interpreted karst features that the CO_2 plume or pressure front intersects based on the dynamic modeling. Small karst features sit at the southern edge of the MMA but only seem to have impacted the upper 200 feet of the Ellenburger, leaving 3,000 feet of Ellenburger apparently unaffected (**Figure 22**).

Even if the plume reaches the karst features on the south end of the MMA and the Ellenburger subunit C upper seal is not intact, the overlying and impermeable Barnett Shale, Marble Falls Limestone, and the Atoka Shales are expected to prevent migration to shallower depths.

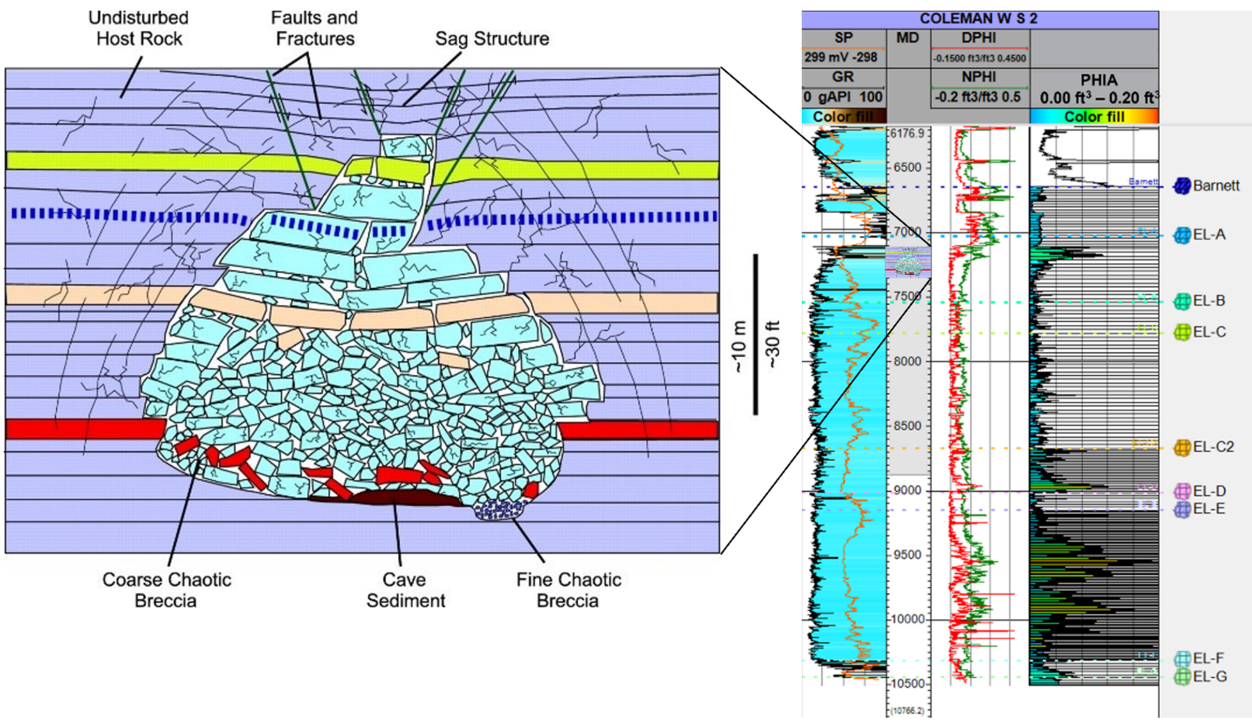

Figure 21. A schematic diagram showing the geometry and component facies of a single cave passage buried in deeper subsurface where collapse and extensive brecciation occurred (modified from Zeng *et al.*[16]). The typical scale of the karst features is shown on the right placing the feature on the W.S. Coleman #2 well log. Note that the interpreted karst features are only observed in the upper portion of the Ellenburger, above the confining unit Ellenburger subunit C.

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[15] Zeng, H., 2011. Characterizing seismic bright spots in deeply buried, Ordovician Paleokarst strata, Central Tabei Uplift, Tarim Basin, Western China. *Geophysics* 76 (4), 2011.

[16] Zeng, H., *et al*., 2011. Three-dimensional seismic geomorphology and analysis of the Ordovician paleokarst drainage system in the Central Tabei Uplift, Northern Tarim Basin, Western China. *American Association of Petroleum Geologists Bulletin* 95 (12), pgs. 2061–2083. 2011.

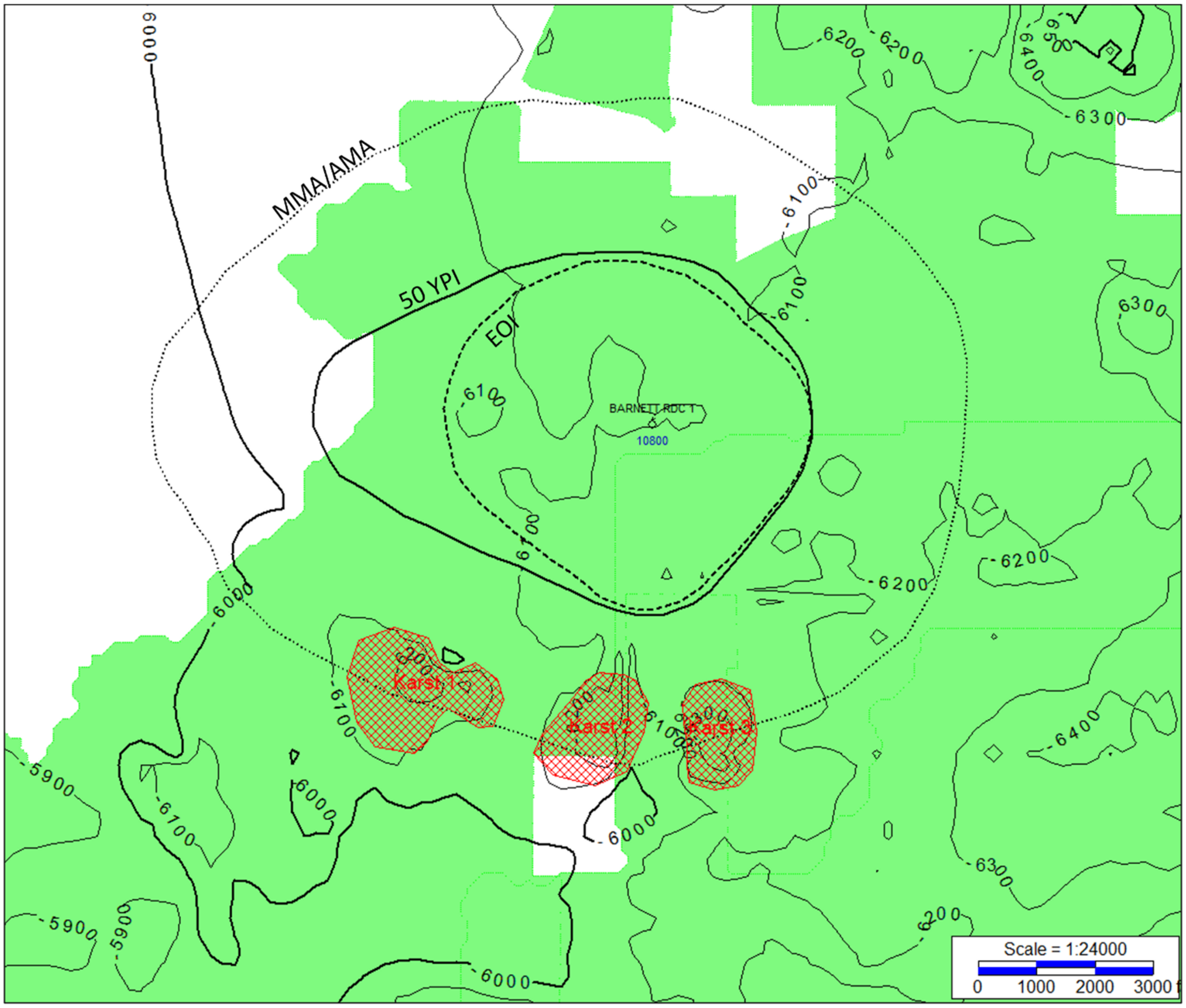

Figure 22. The Barnett RDC #1 well location with top Ellenburger structural contours (TVDSS), 3D seismic coverage (green), and mapped Ellenburger karst on the southern edges of the MMA/AMA. The CO_2 plume size at the end of injection and 50 years post-injection are also shown from Figure 19.

5.5 Leakage Through Confining Layers

The Ellenburger subunit E injection zone is bound by competent confining zones above the injection interval by the Ellenburger subunit C and below the injection interval in the Ellenburger subunit F. Secondary seals above the injection zone include the Barnett Shale, Marble Falls Limestone, and the Atoka Shales. Ellenburger subunit F serves as the lower confining zone. Overall, there is an excess of 3,000 feet of impermeable rock between the injection zone and the deepest well penetrations, making vertical migration past the primary and secondary confining zones unlikely.

5.6 Leakage from Natural or Induced Seismicity

The Barnett RDC #1 location is in an area of the Fort Worth Basin that is inactive seismically, as illustrated in Section 3.5. Earthquake catalogs from both the USGS (1950-present) and TexNet (2017-present) indicate no earthquake locations within 20 miles of the Barnett RDC #1.

The closest earthquake locations are 20+ miles to the southeast in an area of larger, regional faulting. In 2013 and 2014, a series of earthquakes were felt near the towns of Reno and Azle, Texas. The Texas Railroad Commission held hearings that investigated whether oil and gas activities near the earthquakes were responsible for the activity. The Railroad Commission was unable to determine whether oil and gas activities were responsible for the earthquake sequence.

Since no faults are mapped that cut from the injection interval through the sealing limestones and shales of the Pennsylvanian, no leakage is expected due to induced seismic activity.

However, dCarbon also plans several operational procedures to monitor injection-induced seismicity and to immediately identify any minor or major seismic events in the area. Before initiating injection into the well, dCarbon will be installing both surface and bottomhole pressure gauges, so that reservoir pressure and injection pressure can be monitored. Additionally, consistent with RRC guidelines and permit conditions, dCarbon plans to maintain bottomhole injection pressure below formation fracture pressure, and also maintain surface pressure below 0.50 psi per foot gradient when measured from the top of the injection interval. Finally, dCarbon plans to perform periodic pressure fall-off tests (PFOT) to determine and monitor reservoir pressure to ensure unexpected static pressure increases are not observed. These measures are designed to prevent induced fracturing of the formation or increase the likelihood of induced seismicity. Should any unexpected increase in formation pressure be detected, dCarbon can perform Fault Slip Potential (FSP) analysis[17] to evaluate the risk of induced seismicity on the closest mapped faults. dCarbon plans to build this model based on geologic data collected during drilling the Barnett RDC #1 well. If there is a concern related to abnormal pressures or seismicity related to operations at the well, dCarbon will shut-in the well and investigate further.

Furthermore, dCarbon plans to install new ground seismic monitoring arrays near the injection site that are designed to detect any seismic events in the area, natural or induced. Any seismic events detected in the area will be located in the subsurface and analyzed to determine their origin and if they may have potential impacts to the injection program or confining layers. Additionally, the TexNet seismic monitoring program will also be monitored to ensure any material seismic events in the area are investigated.

[17] Walsh, F.R.I., Zoback, M.D., Pais, D., Weingartern, M., and Tyrell, T. (2017). FSP 1.0: A Program for Probabilistic Estimation of Fault Slip Potential Resulting from Fluid Injection, available at: https://scits.stanford.edu/software.

5.7 LEAKAGE FROM LATERAL MIGRATION

The structural dip of the Ellenburger in the vicinity of the Barnett RDC #1 injection site is about one degree up to the west (100 feet/mile), shown in **Figure 23**. The closest well that penetrates the Ellenburger subunit E injection interval up dip from the injection site is more than ten miles to the west-southwest. The closest well that penetrates the injection interval is down dip to the east approximately five miles (W S Coleman #2).

Dynamic modeling of the CO_2 plume has the maximum extent of the plume traveling less than one mile, with the maximum distance traveled to the west. Given that the distance to the next penetration of the injection interval is on the order ten times the distance the plume is expected to travel, no leakage from lateral migration is expected.

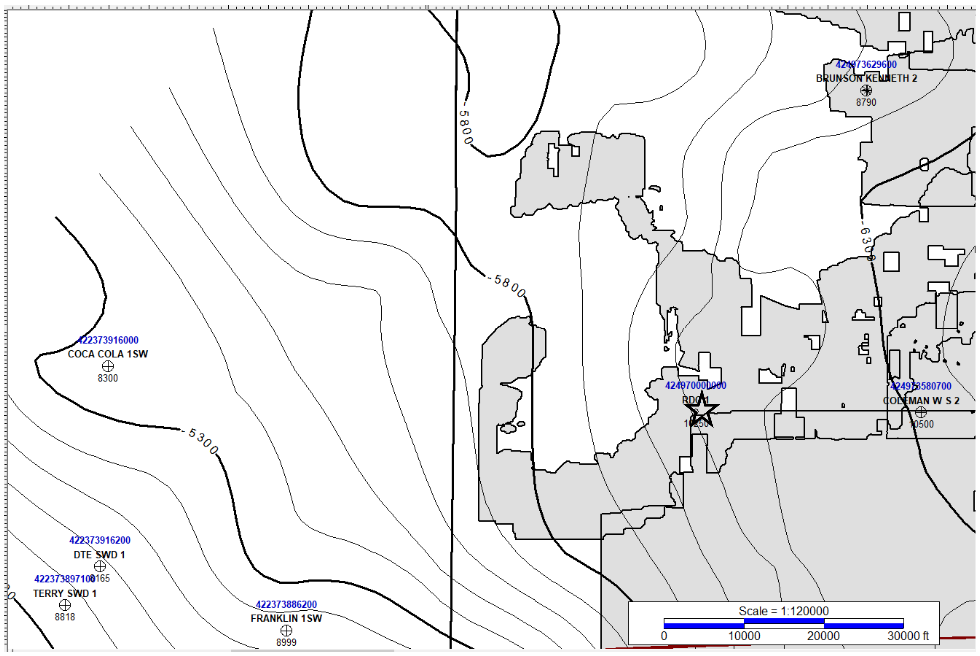

Figure 23. Top of Ordovician Unconformity (top Ellenburger) regional subsea structure in the vicinity of the Barnett RDC #1 location (star). Wells shown penetrate the injection interval. Additional wells (not shown) were used to develop the structure map. Gray areas represent areas covered by 3D seismic data.

Furthermore, dCarbon has assessed each of the previously discussed potential leakage pathways for likelihood, potential timing, and magnitude. The framework of this assessment is based upon the California Air and Resources Board's CCS Protocol Section C.2.2(d).

Table 8 describes the basis for event likelihood and **Table 9** provides the details of the leakage likelihood, timing of occurrence, and estimated magnitude of leakage for each type of leak risk.

Table 8. Risk likelihood matrix (developed based on comparable projects).

Risk Factor for Probability		Description
1	Improbable	<1% chance of occurring*
2	Unlikely	1-5% chance of occurring*
3	Possible	> 5% chance of occurring*
*During the life of the project or 100 years after project closure, whichever is shorter		

Table 9. Description of leakage likelihood, timing, and magnitude.

Leakage Pathway	Likelihood	Timing	Magnitude
Potential Leakage from Surface Equipment	**Possible**	Anytime during project operations, but most likely during start-up / transition or maintenance periods	**<100 MT per event** (100 MT represents approximately 3 hours of full flow facility release)
Leakage from Approved, Not Yet Drilled Wells	**Improbable**, as there are no approved not yet drilled wells	After new wells are permitted and drilled	**<1 MT per event**
Leakage from Existing wells	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and the total depth of existing wells	When the CO_2 plume expands to the lateral locations of existing wells	**<1 MT per event** due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach an existing well combined with thickness and low porosity / permeability of upper confining zone
Potential Leakage from Fractures and Faults	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and surface or USDW that would need to be compromised and there are no mapped faults within the MMA.	Anytime during operation	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach a fault or fracture significant enough to cause leakage
Leakage Through Confining Layers	**Improbable**, as the upper confining zone is nearly 1,000' thick and very low porosity and permeability	Anytime during operations	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E and thickness/properties of upper confining zone
Leakage from Natural or Induced Seismicity	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and surface or USDW that would need to be compromised and there are no mapped faults within the MMA.	Anytime during operations	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach a fault or fracture significant enough to cause leakage
Leakage from Lateral Migration	**Improbable**, as the Ellenburger is a very thick and laterally continuous formation with the closest well penetration five miles downdip.	More likely late in life as plume expands	**<1 MT per event** due to natural dispersion of CO_2 within the Ellenburger subunit E and continuity / thickness of upper confining zone

6 – PLAN OF ACTION FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

This section discusses the strategy that dCarbon will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in previous sections to meet the requirements of 40 CFR § 98.448(a)(3). As the injected stream contains both H_2S and CO_2, any observation of H_2S will serve as a preliminary indicator for CO_2 leakage and therefore the monitoring systems to detect H_2S will also suggest a leak of CO_2. This section summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur. Monitoring will occur during the planned 12-year injection period, or until the cessation of operations, plus a proposed two-year post-injection period.

6.1 Leakage from Surface Equipment

As the CO_2 compressor station, pipeline, and injection well are all designed to handle expected concentrations, temperatures, and pressures of H_2S and CO_2, any leakage from surface equipment will be quickly detected and addressed. The facility is designed to minimize potential leakage points by following the American Society of Mechanical Engineers (ASME) standards, American Petroleum Institute (API) standards, and other industry standards, including standards pertaining to material selection and construction. Additionally, connections are designed to minimize corrosion and leakage points. The H_2S in the stream is easily detectable and serves as an indicator for the release of CO_2. The facility and well will be monitored for H_2S and CO_2 concentration increases. This monitoring equipment will be set with a high alarm setpoint for H_2S that automatically alerts field personnel of abnormalities. Additionally, all dCarbon and BKV field personnel are required to wear H_2S monitors, which will trigger the alarm at low levels of H_2S (typically one ppm). The injection facility will be continuously monitored through automated systems that are designed to identify abnormalities in operational conditions. In addition, field personnel conduct daily AVO field inspections of gauges, monitors, and leak indicators. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system and analysis of liquids collected from the line. These inspections, in addition to the automated systems, will allow dCarbon to quickly identify and respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR § 98.448(a)(5).

Additionally, CO_2 for injection will be metered in three locations for redundancy and precision. The first will be at an orifice style or Coriolis meter at the interface between the Bridgeport Plant and dCarbon's compression facility. This location will meter the CO_2 in gas phase and is depicted in **Figure 24a** and **Figure 24b**. Once the CO_2 is compressed to supercritical, it will pass through a Coriolis meter for measurement and then be transported approximately 6,815 feet via pipeline (see **Figure 15**) to the injection well site. The CO_2 will then be measured again with a Coriolis meter at the injection well site, immediately upstream of the injection wellhead itself. The injection stream will also be analyzed with a gas chromatograph at the well site to determine final composition. The meters will each be calibrated to industry standards. Any discrepancies in CO_2

throughput between the meters will be investigated and reconciled. Any CO_2 that is determined to have leaked or not been received at the injection wellhead will be quantified using the procedures specified in subpart W of the GHGRP, reported as specified in 40 CFR § 98.448(a)(5), and subtracted from reported injection volumes. Gas samples will be taken and analyzed per manufacturer's recommendations to confirm stream composition and calibrate or re-calibrate meters, if necessary. At a minimum, these samples will be taken quarterly. Minimal variation of concentration and composition are expected but will be included in regulatory filings as appropriate.

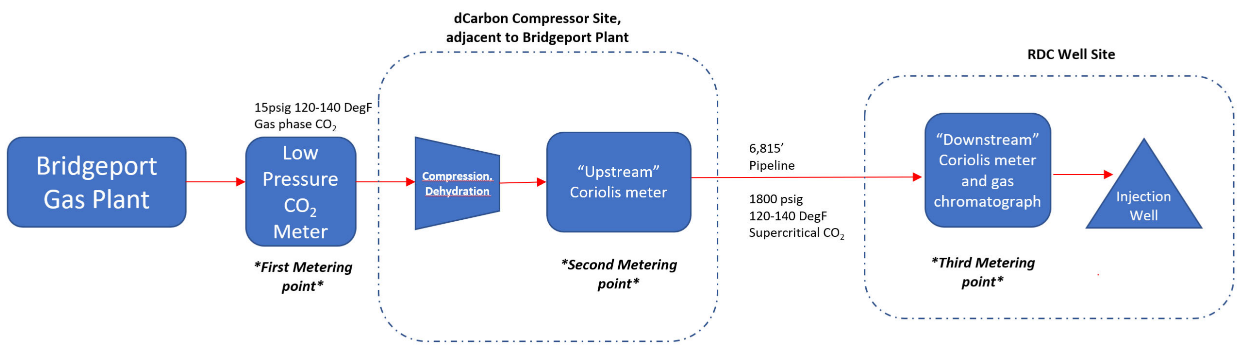

Figure 24a. Project conceptual diagram and metering locations.

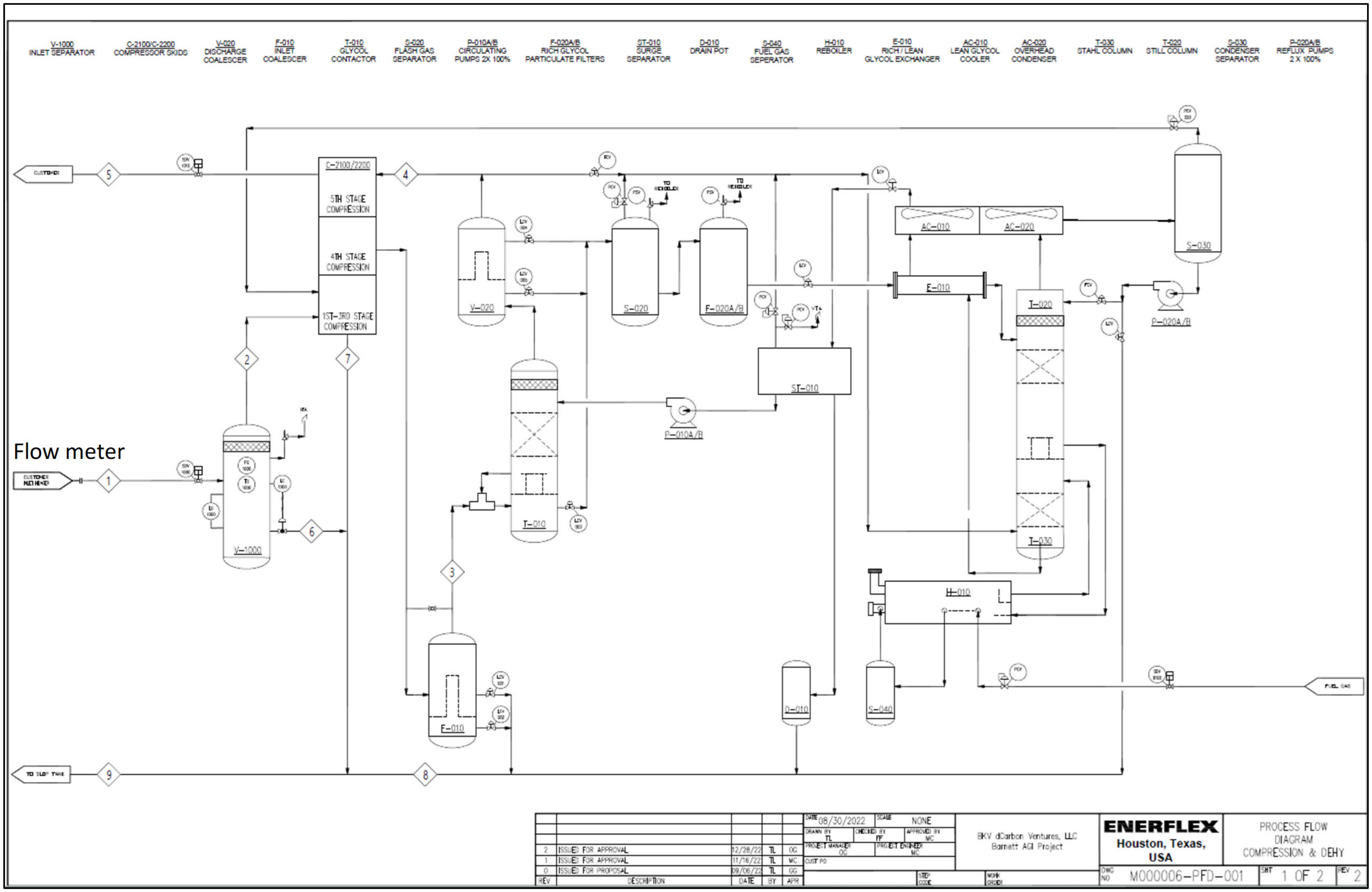

Figure 24b. Compression facility process flow diagram.

6.2 Leakage from Existing and Future Wells within the Monitoring Area

As previously discussed, there are no wells in the MMA currently existing, approved, or pending that penetrate as deep as the Ellenburger injection zone. However, dCarbon will reverify the status and public information for all proposed and approved drilling permits within the MMA quarterly. If any wells are proposed, permitted, or drilled within the MMA, BKV will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, dCarbon will continuously monitor and collect injection volumes, pressures, temperatures, and gas composition data for the injection well. This data will be reviewed by qualified personnel and will follow response and reporting procedures when data is outside acceptable performance limits. Finally, dCarbon will update the MRV plan if any new wells are drilled within the MMA, or if any other material change to the project occurs.

The injection well design has pressure and temperature gauges monitoring the injection stream at the wellhead as well as bottomhole pressure and temperature gauges near the bottom of the tubing. The downhole gauges will monitor the inside of the tubing (injection stream) as well as the annulus. A change of pressure on the annulus would indicate the presence of a possible leak requiring remediation. Mechanical Integrity Tests (MITs) performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated, and the leak mitigated.

In the unlikely event that any CO_2 leaks occur into existing or future wells in the monitoring area, dCarbon will endeavor to work with the operator(s) of those wells and/or midstream providers to take wellhead gas samples to quantify variations or increases of CO_2 compared with historical or baseline CO_2 concentrations. Any measurable increases in CO_2 which may be confidently attributed to injection volumes from the Barnett RDC #1 well will be calculated using standard engineering procedures for estimating potential well leakage determined to be appropriate for the situation. These volumes will be documented and reported in the annual monitoring report and subtracted from reported injection volumes. Additionally, dCarbon will evaluate and execute any additional downhole remediations (*e.g.*, well workovers, such as adding plugs, remedial cement jobs, etc.) that could address leakage from the injection well to the existing and future wells in the area if necessary and practical.

6.3 Leakage from Faults and Fractures

No faults or fractures have been identified that would allow CO_2 to migrate vertically to zones with USDWs or to the surface. In the unlikely event that such leakage from faults or fractures occurs, dCarbon will determine which standard engineering techniques for estimating potential leakage from the faults and fractures is appropriate for the situation to estimate any leakage from faults and fractures, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.4 Leakage through Confining Layers

Leakage through confining layers is improbable, given the number and thickness of layers between the injection zone and potable groundwater. Groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple confining layers.

In the unlikely event CO_2 leakage occurs because of leakage through the confining seal, it is also unlikely that the leak would result in surface leakage. As with any CO_2 leakage, however, should it occur, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation to estimate any leakage, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.5 Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, dCarbon plans to install a seismic monitoring array in the general area of the Barnett RDC #1 well. This monitoring array will augment the TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, dCarbon will review the injection volumes and pressures at the Barnett RDC #1 well to determine if any significant changes occurred that would indicate potential leakage. To suspect leakage due to natural or induced seismicity, the evidence would need to suggest that the earthquakes are activating faults that penetrate through the confining zones.

In the unlikely event CO_2 leakage occurs due to natural or induced seismicity, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation and report such leakage estimates and the methodology employed in the annual monitoring report.

6.6 Leakage through Lateral Migration

The distances to the closest penetration of the Ellenburger injection interval are more than ten times the expected plume radius at the end of injection. As such, leakage through lateral migration is not expected. In addition, the wells that penetrate the injection interval are saltwater disposal wells. Injection into these wells would be expected to raise the reservoir pressure locally near the well, further limiting the ability of the CO_2 to access the saltwater injector well bore.

In the unlikely event CO_2 leakage occurs due lateral migration, similar to leakage through confining layers, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.7 Quantification of Leakage

In the unlikely event that CO_2 moves vertically past the primary and secondary confining layers as described earlier in Section 6, there are several methods dCarbon may utilize to quantify leakage depending on the nature and severity of the leak. dCarbon has designed a monitoring network

suited to detect CO_2 leaks before they interact with local resources, infrastructure, or USDW. dCarbon will consider additional standard and specialized engineering methods to quantify leaks as appropriate. dCarbon's methodology to characterize, monitor, detect, and isolate leaks for quantification is described below.

As a primary monitoring and quantification strategy, dCarbon plans to install a deep groundwater monitoring well in the MMA that will be used to monitor the USDW. This well will be deeper than any active groundwater wells in the area that typically draw water from shallow drinking water zones. dCarbon also plans to periodically sample the well to monitor for chemical composition. If dCarbon notices an increase in groundwater CO_2 concentration compared to baseline measurements, the increase in concentration will be analyzed volumetrically to provide a preliminary estimate of CO_2 leakage.

Any leakage that did extend to the surface could be characterized and quantified through surface surveillance in the project area paired with direct pressure, volume, and temperature (PVT) measurements. Currently available (and continuously improving) atmospheric sensing technology could be used to establish a baseline of ambient CO_2 concentration in the project area and identify any fluctuations. Deviations from baseline concentration along with understanding of the distance from potential leak sources can then be coupled with temporally matched meteorological data to semi-quantitatively determine leak attribution and rate. Based on the size of leak, these qualified or quantified leak rates can be compared with spatiotemporally monitored PVT data to co-index or further refine leaked volumes from likely point sources.

Any diffuse leak or leak without an obvious single point source may require additional identification and quantification methods. dCarbon is working with a leading environmental services and data company that specializes in monitoring and quantifying gas leaks in various industrial settings. One such quantification method involves utilizing fixed monitoring systems to detect CO_2. Additional system capabilities also include the deployment of an unmanned aerial vehicle (UAV), which is outfitted with an industry leading high fidelity CO_2 sensor capable of measuring concentrations as little as parts per billion (ppb). The UAV mobile surveillance platform possesses the ability to be flown on a programmable and highly replicable pattern across the MMA in both X and Y axis (longitude + latitude) as well as Z axis (height). Depending on the system's ability to obtain a reliable baseline across the MMA, areal deviation in CO_2 concentration could be measured, and diffuse leak sources could potentially be identified, provided the emissions reach a sufficient threshold. dCarbon will also consider similar technologies with less spatial resolution or fidelity such as fixed wing flyovers and/or improving satellite data with UAV technology to screen for and support diffuse emissions identification and investigation.

Depending on the applicability and monitoring needs, dCarbon will also consider other monitoring quantification methods such as the Eddy Covariance Method (ECM).[18] This method utilizes gas fluxes and ambient meteorological conditions to detect and quantify leaks, although the ability to

[18] Korre, A., *et al.*, 2011. Quantification techniques for potential CO_2 leakage from geologic sites. Energy Procedia 4 (2011), pgs. 3143-3420.

detect smaller leaks may be limited.[19] Additionally, long open path tunable diode lasers could be used to measure distance averaged concentrations of CO_2 in the air, which could help quantify a leak of CO_2. This system could be paired with an array of short, closed path detectors (*e.g.*, gas chromatographs) that are typically placed around a suspected leak or leak area to monitor point-source CO_2 concentration increases and to quantify leakage. dCarbon may also evaluate other emerging technologies for quantifying CO_2 leakage such as non-dispersive infra-red (NDIR) CO_2 sensors and soil flux detectors. dCarbon may also utilize three-dimensional reservoir models that factor in faults and surface topography to predict CO_2 leakage locations, quantity, and timing. The applicability of such models in predicting and quantifying gas leaks has been tested and documented at the Leroy natural gas storage site in Wyoming, USA.[19]

As the technology and equipment to quantify CO_2 leakage is rapidly evolving and expected to improve over time, dCarbon will continue to update its leak detection and quantification plans as appropriate. If dCarbon detects a leak associated with CO_2 injection at the Barnett RDC #1 well, all methods discussed in this section will be considered in addition to emerging technologies to determine the most applicable and effective method of quantification.

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[19] Chen, M., *et al.*, 2013. Analysis of fault leakage from Leroy underground natural gas storage facility, Wyoming, USA. *Hydrogeology* 21, pgs. 1429–1445. 2013.

7 – BASELINE DETERMINATIONS

This section identifies the strategies that dCarbon will undertake to establish the expected baselines for monitoring CO_2 surface leakage per § 98.448(a)(4). dCarbon will use the existing Supervisory Control and Data Acquisition (SCADA) monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. Daily inspections will be conducted by field personnel at the compressor facility and the injection well. These inspections will aid with identifying and addressing issues in a timely fashion to minimize the possibility of leakage. If any issues are identified, such as vapor clouds, ice formations, or abnormal AVO or FLIR observations, corrective actions will be taken to address such issues. As previously discussed, H_2S is present in the injection stream at a low concentration. All field personnel are required to wear personal H_2S monitors, which are set to trigger the alarm at approximately 1 ppm levels of H_2S. Any alarm would trigger an immediate response to protect personnel and verify that the equipment and monitors are working properly. If monitors are working correctly and a leak is detected, immediate actions would be taken to secure the facility.

Any leakage would be detected and managed as per Texas regulations and dCarbon's safety and operations plans. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR § 98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

Baseline groundwater quality and properties will be determined and monitored through the installation of a groundwater well near the injection well site. Samples will be taken and analyzed by a third-party laboratory to establish the baseline properties of the groundwater in the area.

Baseline seismicity in the area near the Barnett RDC #1 will be determined through the historical data from USGS and TexNet seismic array data. This information will be augmented by additional data from dCarbon's seismic monitoring array.

8 – SITE SPECIFIC CONSIDERATIONS FOR DETERMINING THE MASS OF CO_2 SEQUESTERED

This section identifies how dCarbon will calculate the mass of CO_2 injected, emitted, and sequestered. This also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, per 40 CFR § 98.448(a)(5).

8.1 MASS OF CO_2 RECEIVED

Per 40 CFR § 98.443, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR §98.444(a)(4)." 40 CFR § 98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received."

The CO_2 received by dCarbon for injection into the Barnett RDC #1 injection well is wholly injected and not mixed with any other supply and the annual mass of CO_2 injected will equal the amount received. Any future streams will be metered separately before being combined into the calculated stream.

8.2 MASS OF CO_2 INJECTED

Per 40 CFR § 98.444(b), since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Subpart RR Equation 5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

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
$C_{CO2,p,u}$	=	Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (weight percent CO_2, expressed as a decimal fraction)
p	=	Quarter of the year
u	=	Flow meter

8.3 MASS OF CO_2 PRODUCED

The injection well is not part of an enhanced oil recovery project, and therefore, no CO_2 will be produced.

8.4 Mass of CO_2 Emitted by Surface Leakage

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S, which may be hazardous for field personnel to perform a direct leak survey. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR § 98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released because of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using 40 CFR Part 98-Subpart RR Equation 10 as follows:

$$CO_{2,E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

$CO_{2,E}$	=	Total annual 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

Annual mass of CO2 emitted (in metric tons) from any equipment leaks and vented emissions of CO2 from equipment located on the surface between the flowmeter used to measure injection quantity and injection wellhead will comply with the calculation and quality assurance/quality control requirement proposed in Part 98, Subpart W and will be reconciled with the annual data collected through the monitoring plan

8.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in the subsurface geologic formations will be calculated based off from 40 CFR Part 98, Subpart RR Equation 12 , as this well will not actively produce any oil or natural gas or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2	=	Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the Barnett RDC #1 facility in the reporting year.
$CO_{2,I}$	=	Total annual CO_2 mass injected (metric tons) in the Barnett RDC #1 well in the reporting year.
$CO_{2,E}$	=	Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI}	=	Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in Subpart W of Part 98.

9 – ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

The injection well is expected to begin operation in the second half of 2023. Baseline data will be collected before injection begins and the MRV plan will be implemented upon receiving EPA MRV approval.

10 – QUALITY ASSURANCE

10.1 CO_2 INJECTED

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer specifications.

10.2 CO_2 EMISSIONS FROM LEAKS AND VENTED EMISSIONS

- Gas detectors will be operated continuously, except for maintenance and calibration.
- Gas detectors will be calibrated according to manufacturer recommendations and API standards.
- Calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

10.3 MEASUREMENT DEVICES

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to the requirements in 40 CFR § 98.3(i).
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.
- Flow meter calibrations will be traceable to the National Institute of Standards and Technology (NIST).

All measured volumes of CO_2 will be converted to standard cubic feet at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1.0 atmosphere.

10.4 MISSING DATA

In accordance with 40 CFR § 98.445, dCarbon will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR § 98.

11 – RECORDS RETENTION

dCarbon will retain records as required by 40 CFR § 98.3(g). These records will be retained for at least three years and include:

- Quarterly records of the CO_2 injected.
- Volumetric flow at standard conditions.
- Volumetric flow at operating conditions.
- Operating temperature and pressure.
- Concentration of the CO_2 stream.
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate 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.

Request for Additional Information: Barnett RDC Well No. 1
June 12, 2023

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	8.2	51	"Qp,u = Quarterly volumetric flow rate measurement for flow meter u in quarter p (metric tons per quarter)" In equation RR-5, this variable is "$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter)." Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Replaced the phrase … "Qp,u = Quarterly volumetric flow rate measurement for flow meter u in quarter p (metric tons per quarter)" With… "Qp,u = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter)" to match RR-5.
2.	8.5	52	"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 and the Barnett RDC #1 injection wellhead." In equation RR-12, this variable is "CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of this part." Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	Replaced the phrase… "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 and the Barnett RDC #1 injection wellhead." With … "CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of this subpart RR."

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan

Barnett RDC #1

Wise County, Texas

Prepared by

BKV dCarbon Ventures, LLC

Version 4.0

May 9, 2023

TABLE OF CONTENTS

1 – INTRODUCTION

BKV dCarbon Ventures, LLC (dCarbon), a subsidiary of BKV Corporation (BKV), is authorized by the Texas Railroad Commission (TRRC) to inject up to 14.5 million standard cubic feet per day (MMscfd), equivalent to approximately 280,000 metric tons per year (MT/yr), of carbon dioxide (CO_2) into the proposed Barnett RDC #1 injection well in Wise County, Texas. The permit issued by the TRRC allows injection into the Ellenburger Group formation at a depth of 9,350 feet to 10,250 feet with a maximum allowable surface pressure of 4,500 pounds per square inch gauge (psig).

dCarbon currently intends to dispose of CO_2 from the nearby Bridgeport Gas Processing Plant (Bridgeport Plant), operated by EnLink Midstream Services, LLC (EnLink), into the Barnett RDC #1 well. The project site is located approximately 4.6 miles southwest of Bridgeport, Texas, as shown in **Figure 1**.

dCarbon anticipates drilling the Barnett RDC #1 well in the first half of 2023, completing the well in mid-2023, and beginning injection operations in late 2023. The Barnett RDC #1 has approvedW-14 injection and W-1 drilling permits with the TRRC (Texas Railroad Commission) permit number 17090, UIC number 000125478, API number 42-497-38108). Additionally, copies of the approved W-1 and W-14 are included as Attachment A.

Although dCarbon intends to initiate injection with lower volumes, all calculations in this document have been performed assuming the maximum injection amount allowed by the TRRC permit (280,000 MT/yr). dCarbon plans to inject for approximately twelve years.

dCarbon submits this Monitoring, Reporting, and Verification (MRV) plan for approval by the Environmental Protection Agency (EPA) in accordance with 40 CFR § 98.440-449, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP).

dCarbon’s TRRC operator number is 100589.

dCarbon’s Environmental Protection Agency Identification (EPA ID) number is 110071343305.

The Barnett RDC #1 well’s Greenhouse Gas Reporting Program Identification (GHGRP ID) number is 58336. All aspects of this MRV plan refer to this well and GHGRP ID number.

Figure 1. Location of the Barnett RDC # 1 Well and EnLink Midstream's Bridgeport Gas Plant.

2 – FACILITY INFORMATION

Gas Plant Facility Name:

Bridgeport Gas Processing Plant
415 Private Road 3502
Bridgeport, Texas 76426

Latitude: 33° 11.74' N
Longitude: 97° 48.22' W

EnLink's GHGRP ID number for the Bridgeport Plant is 1006373.

FRS Id: 110028052354

NAICS Code: 211130

Currently reporting under Subpart C, W, NN

Underground Injection Control (UIC) Permit Class:

The Oil and Gas Division of the TRRC regulates oil and gas activity in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program for injection wells. The TRRC has permitted the Barnett RDC #1 well as a UIC Class II well. The Class II permit was issued to dCarbon in accordance with Statewide Rule 9.

Injection Well:

Barnett RDC #1, API number 42-497-38108

UIC# 000125478

Barnett RDC #1 GHGRP ID: 58336

The Barnett RDC #1 well will be disposing of CO_2 from the Bridgeport Gas Processing Plant. All aspects of this MRV plan refer to the Barnett RDC #1 well and GHGRP 58336.

3 – PROJECT DESCRIPTION

This Project Description discusses the geologic setting, planned injection volumes and process, and the reservoir modeling performed for the proposed Barnett RDC #1 Class II injection well. dCarbon has prepared this MRV plan to support the storage of CO_2 in Wise County, Texas.

3.1 Overview of Geology

The proposed injection site lies in the western section of Wise County, where the Barnett Shale, Viola, Simpson, and Ellenburger formations dip and thicken to the east toward the Muenster Arch, as seen in the west to east cross section of **Figure 2**. Similarly, the north to south cross section shows the Ellenburger and overlying formations dipping to the north. One inference from this is that any CO_2 injected may exhibit the tendency to move updip due to buoyancy, meaning the anticipated plume movement will be westward. This is further represented in the structure contour map of the Ellenburger formation top by Pollastro[1] in **Figure 2**.

The Fort Worth Basin sedimentary succession begins with locally abundant Cambrian clastics in the southern section of the basin that unconformably overlie the uneven Precambrian basement (see **Table 1**). The overlying Ordovician age Ellenburger platform carbonates were deposited on a passive margin and contain thicknesses up to 4,000 feet in the Fort Worth Basin. The Ellenburger platform carbonates underwent multiple episodes of regional exposure causing dolomitization and karsting in several subunits of the Ellenburger. Ordovician Viola and Simpson formations overlie the Ellenburger formation and are found in the northern section of the basin near the Muenster Arch. A major erosive interval occurred during the Mississippian, eroding down to the Ordovician formations. Later deposition of the Barnett Shale unconformably overlies the Viola limestone, Simpson formation, and the Ellenburger Group.[2] Overlying the Barnett Shale is a thick section of mostly Pennsylvanian and Permian carbonates and clastics (Bend, Strawn, and Canyon Groups). **Figure 2** indicates the general regional stratigraphy. Although there are multiple storage-confining unit systems that could be evaluated for injection, the focus was on the Mississippian-Ordovician section that consists of the Barnett shale and the Ellenburger Group. The Ellenburger Group directly overlies the basement rock and is considered the main reservoir target.

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[1] Pollastro, R.M., 2007. Geologic framework of the Mississippian Barnett Shale, Barnett-Paleozoic total petroleum system, Bend Arch-Fort Worth Basin. *American Association of Petroleum Geologists Bulletin* 91 (4), pgs. 405-436. 2007.

[2] Gao, S. *et al*., 2021. Low pressure buildup with large disposal volumes of oil field water: A flow model of the Ellenburger Group, Fort Worth Basin, North Central Texas. *American Association of Petroleum Geologists Bulletin* 105 (12), pgs. 2575-2593. 2021.

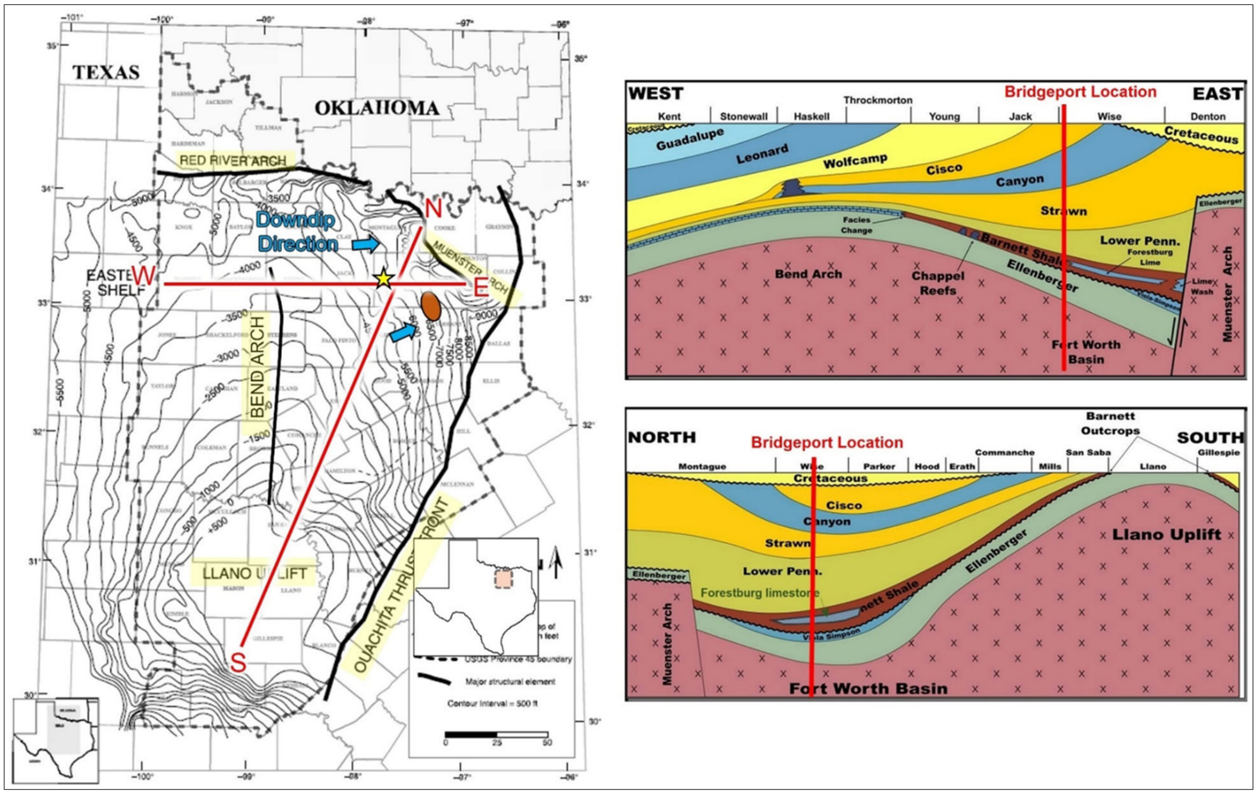

Figure 2. (*Left*) Ellenburger structural contour map modified from Jarvie *et al.*[3] showing the regional structures within and bounding the Fort Worth Basin, Ellenburger structure contours with respect to the final dCarbon area of interest (yellow star). (*Right*) Cross sections E-W and N-S show the regional dip of the sedimentary units in the Fort Worth Basin.

3.2 Bedrock Geology

3.2.1 Basin Description

The Fort Worth Basin is a flexural basin that formed in the foreland of the advancing Ouachita orogenic belt during the Late Mississippian through Pennsylvanian epochs.[4] As illustrated in **Figure 2**, the Fort Worth Basin is bounded to the east by the Ouachita fold and thrust belt and to the north by the Muenster Arch and Red River Arch. These arches are characterized by a series of high angle reverse faults. The basin is deepest to the northeast, with as much as approximately 12,000 feet of sediment infill, where the Ouachita thrust front meets the Muenster Arch and is shallowest towards the south.

[3] Jarvie, D.M., *et al.*, 2007. Unconventional shale-gas systems: The Mississippian Barnett Shale of North Central Texas as one model for thermogenic shale-gas assessment. *American Association of Petroleum Geologists Bulletin* 91 (4), pgs. 475-499. 2007.

[4] Horne, E.A., Hennings, P.H., and Zahm, C.K., 2021. Basement structure of the Delaware basin, in The Geologic Basement of Texas: A Volume in Honor of Peter Flawn, Callahan, O.A., and Eichhubl, P. (editors), *The University of Texas at Austin, Bureau of Economic Geology Report of Investigations*, Austin, Texas. 2021.

Table 1. Regional Stratigraphy at Barnett RDC #1 Site in North Texas.

<table>
<tr><th>SYSTEM</th><th>SERIES</th><th>STAGE</th><th colspan="2">GROUP OR FORMATION</th></tr>
<tr><td>Cretaceous</td><td>Lower</td><td>Comanchean</td><td colspan="2">Trinity Group</td></tr>
<tr><td rowspan="13">Pennsylvanian</td><td>Upper</td><td>Missourian</td><td>Canyon Group</td><td>Jasper Creek Formation</td></tr>
<tr><td rowspan="8">Middle</td><td rowspan="6">Desmonesian</td><td rowspan="3">Strawn Group</td><td>Willow Point Formation</td></tr>
<tr><td>Lone Camp Formation</td></tr>
<tr><td>Millsap Lake Formation</td></tr>
<tr><td rowspan="3">Kickapoo Group</td><td>Ratville Formation</td></tr>
<tr><td>Parks Formation</td></tr>
<tr><td>Caddo Pool Formation</td></tr>
<tr><td rowspan="4">Atokan</td><td rowspan="7">Bend Group</td><td>Caddo Formation</td></tr>
<tr><td>Smithwick Shale</td></tr>
<tr><td rowspan="4">Lower</td><td>Pregnant Shale</td></tr>
<tr><td>Big Saline Formation</td></tr>
<tr><td rowspan="2">Morrowan</td><td>Marble Falls Limestone</td></tr>
<tr><td rowspan="2">Comyn Formation</td></tr>
<tr><td rowspan="4">Mississippian</td><td colspan="2" rowspan="3">Chesterian – Meramecian</td></tr>
<tr><td rowspan="3">Barnett</td><td>Upper Barnett Shale</td></tr>
<tr><td>Forestberg Limestone</td></tr>
<tr><td colspan="2">Osagean</td><td>Lower Barnett Shale</td></tr>
<tr><td>Ordovician</td><td colspan="2">Lower</td><td colspan="2">Ellenburger Group</td></tr>
<tr><td>Precambrian</td><td colspan="2"></td><td colspan="2">Basement</td></tr>
</table>

3.2.2 Stratigraphy

The Ellenburger Group contains alternating limestone and dolomite lithologies, consistent with regional descriptions of the Ellenburger. Vertical changes in properties throughout the Ellenburger were used to divide the unit into 8 subunits (A-G), in agreement with a similar approach demonstrated by Smye *et al.*[5] The main target storage reservoir, subunit E, was identified based on dominant lithology, gross and net reservoir thicknesses, porosity values, and permeability values. In tandem, the Ellenburger subunit B and the stratigraphic top portion of Ellenburger subunit C were identified as a potential caprock. Below this interval, there are baffles of tighter

[5] Smye, K.M., *et al.*, 2019. Stratigraphic architecture and petrophysical characterization of formations for deep disposal in the Fort Worth Basin, Texas. *Texas BEG Report: Interpretation* 7 (4), 2019.

limestone throughout Ellenburger subunits C, C2, and D that would also act as sealing units to the storage interval. Ellenburger subunit E is planned to serve as the storage zone.

Dominant lithologies were determined by comparing the photoelectric factor (PEFZ) log curve with the volume of clay (VCL), sand (VQUA), lime (VCLC), dolomite (VDOL), gas (VUGA), and free water (VUWA) curves in the North Tarrant SWD 1 (API number 42-439-31228), as well as the separation of the density and neutron porosity curves. Gross reservoir thickness was determined for each Ellenburger subunit by adding the footage from the top to the bottom of the subunit.

The W.S. Coleman #2 (API number 42-497-35807) well, approximately five miles east of the proposed Barnett RDC #1 injection well, was used to calculate reservoir zone properties for individual subunits within the Ellenburger formation since no wells currently exist at the proposed site. The North Tarrant SWD 1 well, located approximately 27 miles to the southeast was also used in well correlations because of its robust well log data across the Ellenburger Group.

Figure 3 shows the correlation of the North Tarrant SWD 1 well up to the W.S. Coleman #2. As an initial observation, subunits C and E within the Ellenburger are present and appear to be contiguous in the project area. Subunit C thickness is approximately 750 feet while subunit E thickness varies across the cross sections. It is estimated there is at least 940 feet of subunit C at the Barnett RDC #1 proposed site location with 1,250 feet of Ellenburger subunit E. The cross sections confirm regional trends in dip also apply to the area of interest, down to the north and east.

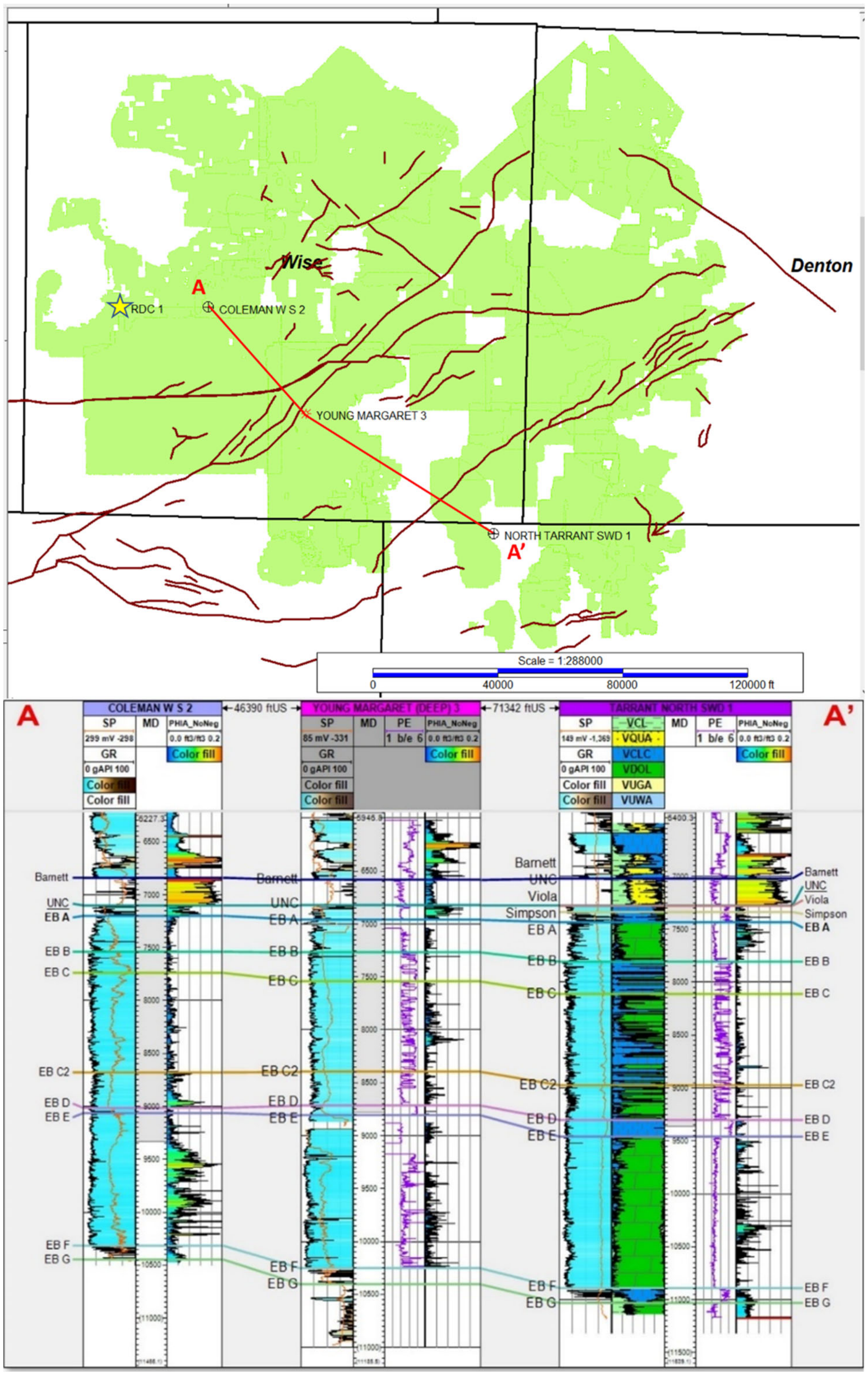

Figure 3. (*Top*) **Map of Wise County with the Barnett RDC #1 (yellow star), faults (brown lines), cross section wells (black circles), dCarbon 3D seismic extent (green polygon), and a NW-SE cross section (A-A'). (*Bottom*) Cross section showing Gamma Ray (GR), Spontaneous Potential (SP), Photo Electric Factor (PE), and average porosity (PHIA) from the North Tarrant SWD 1 well to the WS Coleman 2 well. Ellenburger subunit C (EB C) is the upper confining zone and Ellenburger subunit E (EB E) is the storage zone.**

3.2.3 Faulting

Faults within the Fort Worth Basin are generally northeast-trending, high-angle normal faults with most of the faults rooting into the Precambrian crystalline basement, as depicted in **Figure 4**. The mechanism for deformation that produced these faults has been attributed to flexure generated by the Ouachita orogenic belt. Deep seated faults that root into the Precambrian crystalline basement generally terminate in the base of the Pennsylvanian age strata and do not continue into the overlying Cretaceous strata, where it is present, suggesting that faults have not experienced significant movement since their formation.[4] Karsting in the region has resulted in small-scale, concentric faults that originate from the collapse of karst features predominantly within the Ellenburger Group.

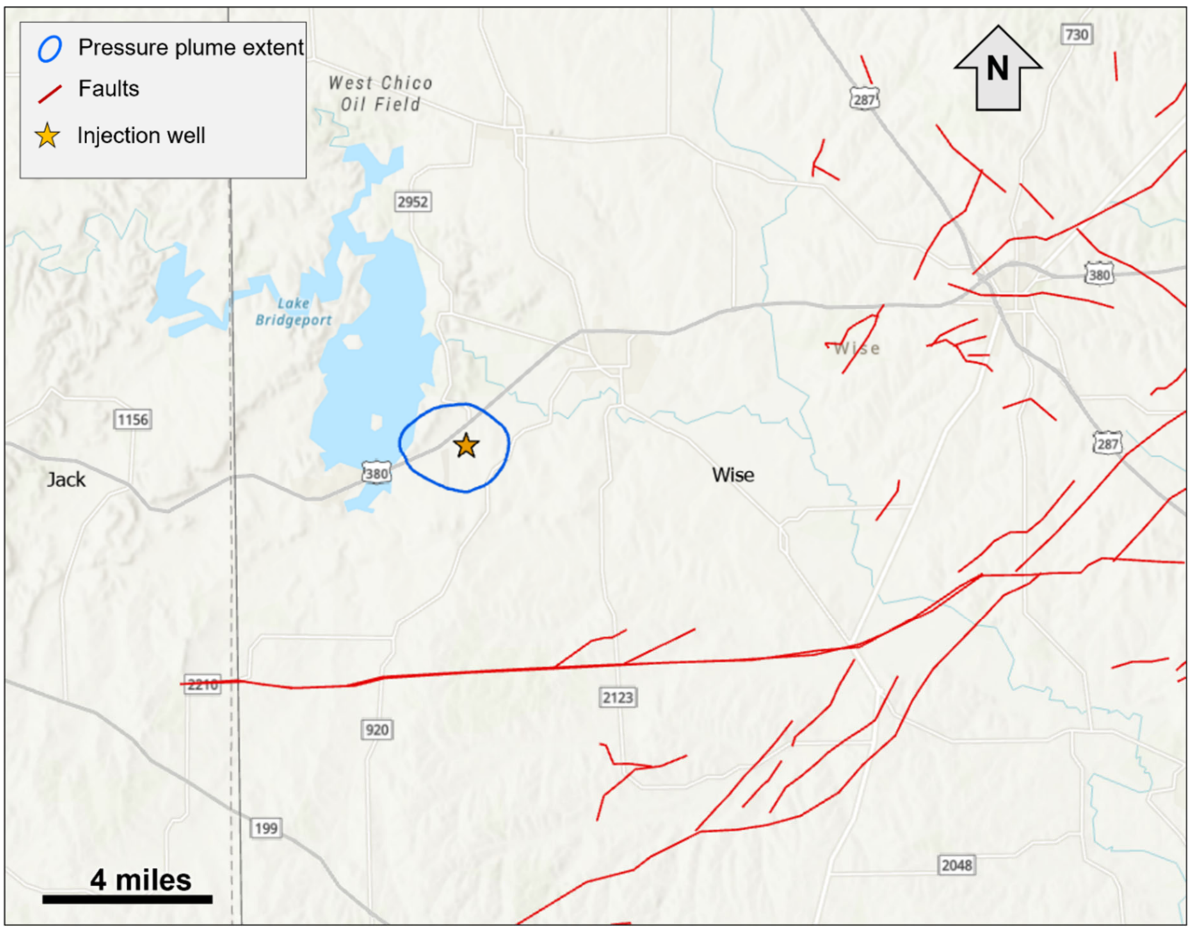

Figure 4. Mapped faults near the proposed injection well from Wood.[6]

3.3 LITHOLOGICAL AND RESERVOIR CHARACTERIZATIONS

Smye *et al.*[5] provided a detailed description of regional stratigraphy as well as petrophysical attributes of multiple units within the Ellenburger Group. Prior to understanding the petrophysical

[6] Wood, V., 2015. Reservoir Characterization and Depositional System of the Atokan Grant Sand, Fort Worth Basin, Texas. University of Arkansas Thesis, 2015.

properties of these subunits and assessing their storage reservoir or confining layer potential, it is important to understand the overall lithology. Literature suggests the Ellenburger interval is mostly composed of calcite, dolomite, quartz, and clay. The carbonate intervals are mostly clean with less than 10% clay by volume[5]. However, the top of the Ordovician section was shown to have an increased clay content (about 40% by volume). This also coincided with an increase in siliciclastic materials (quartz and clay). Porosity in clean carbonate intervals is approximately 5%, while that in siliciclastic intervals may reach 20%. The basement lithology was identified as granite wash with hematite contents ranging between 5-10% by volume. **Figure 5** shows the general stratigraphy in the area.

To better understand local stratigraphy and petrophysics, lithological characterization was focused on the red dotted area shown in **Figure 5**. The Viola Formation and Simpson Group are listed here overlying Ellenburger subunit A. However, these formations pinch out to the east of the proposed Barnett RDC #1 site, and thus, are not included in subsequent petrophysical analysis.

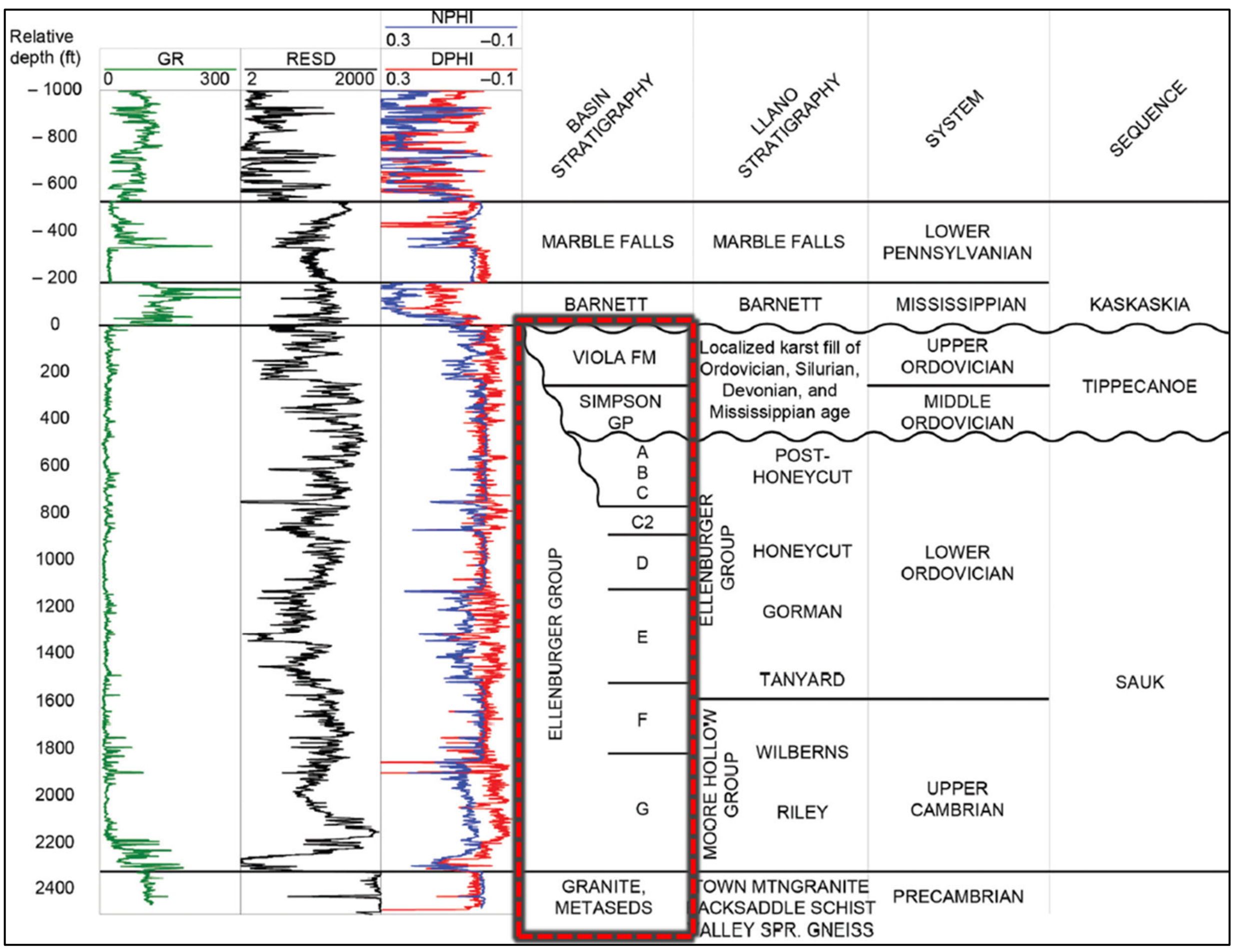

Figure 5. Regional stratigraphy at dCarbon site in North Texas (modified from Smye *et al.*[5]).

The Barnett Shale is anticipated to serve as a secondary confining interval. The Barnett Shale is a source rock and an unconventional reservoir that is extensively drilled in the Fort Worth Basin.

The porosities and permeabilities in the Barnett Shale lie in the 4-6% and 7-50 nanodarcies ranges, respectively.

Underlying the Barnett is the Ellenburger Group, which contains both the anticipated storage and confining zones. The Ellenburger could be divided into eight lithostratigraphic units starting with subunit A at the top to subunit G at the bottom which sits on top of the crystalline basement. Subunit G is composed of siliciclastic facies and is largely variable across the region. Though the porosity in subunit G is higher compared to other subunits, lateral continuity might be an issue in developing a storage project in this subunit. Consequently, subunit E will serve as the storage zone given it has approximately 4% matrix porosity. Ellenburger subunit E is a clean dolomitic reservoir zone with 49% dolomite by volume. Subunit B and subunit C were found to have lower matrix porosities compared to subunit E, which should provide vertical confinement or impediment to CO_2 movement. Ellenburger subunit A has been proven to be a reservoir zone with multiple saltwater disposal wells completed in subunit A. However, as mentioned earlier, karsting features at the top of the Ellenburger imply there is some potential for hydraulic communication between subunit A and the overlying Barnett. **Figure 6** illustrates the log response and petrophysical properties of Ellenburger subunits.

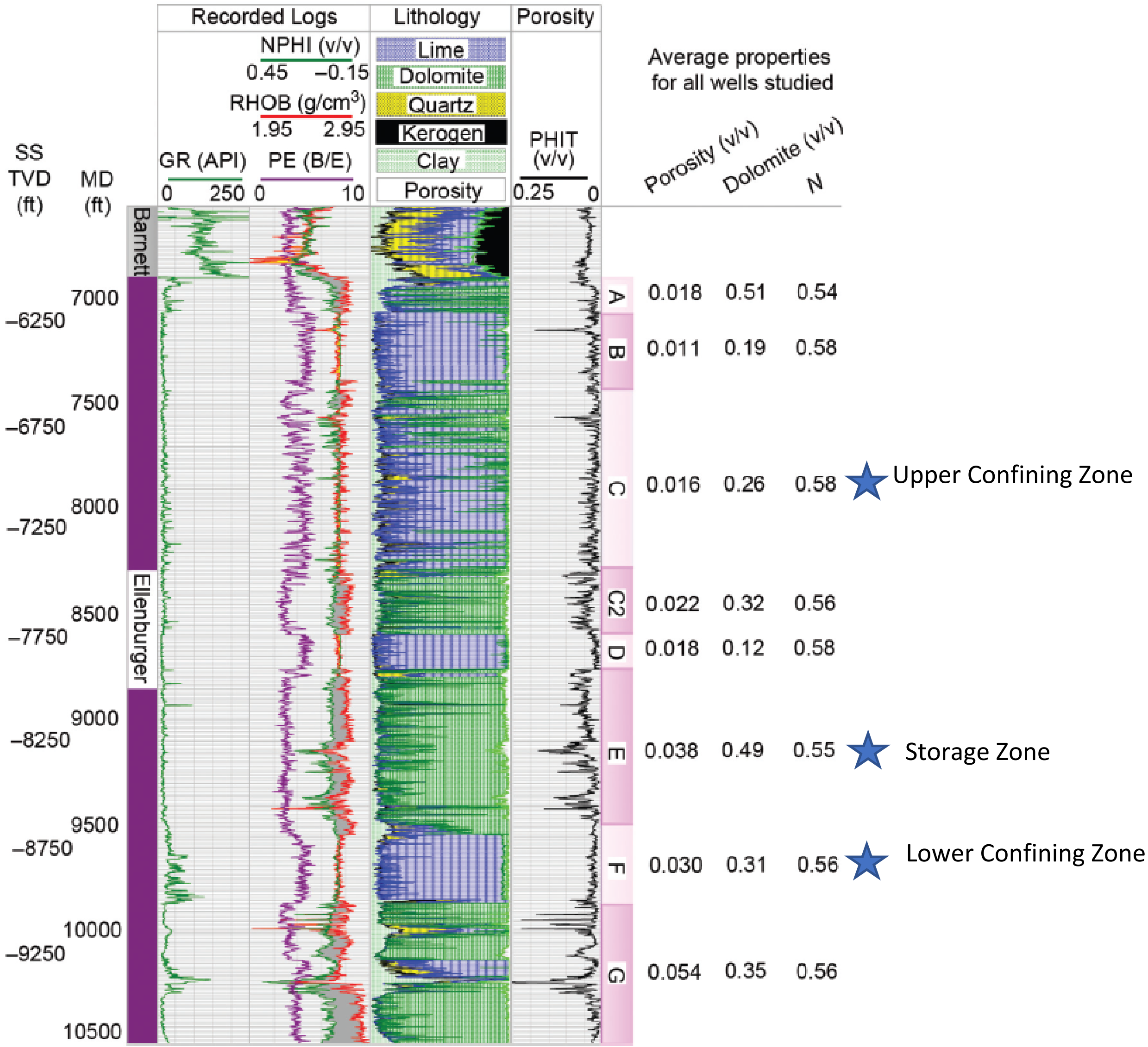

Figure 6. Properties of Ellenburger Group subunits in the project area (modified from Smye *et al.*[5]).

The W.S. Coleman #2 injection well located approximately five miles from the proposed injection site similarly contains Ellenburger subunits A through G, as shown below in **Figure 7**. Drilling at the proposed site should result in site-specific petrophysical properties like those shown here.

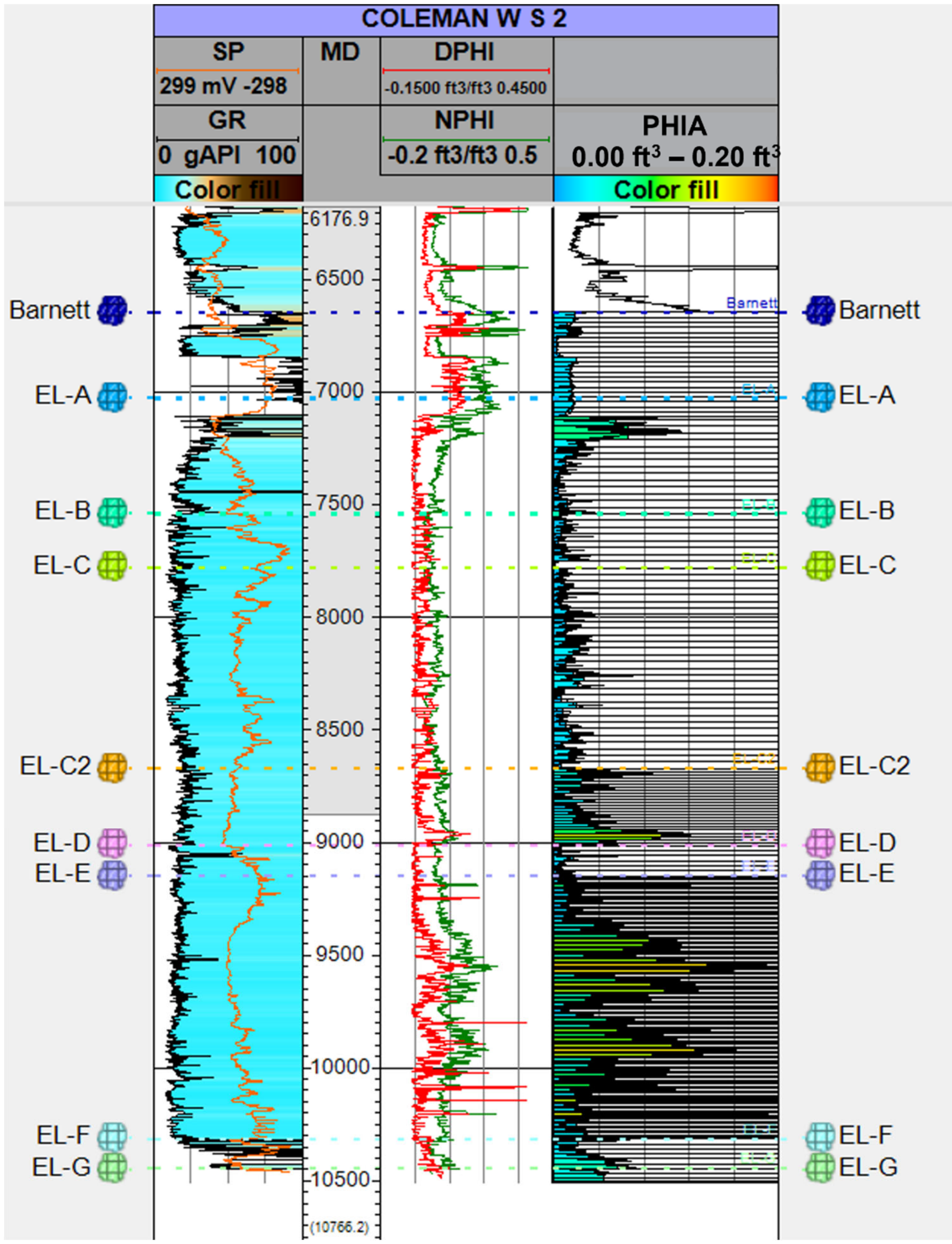

Figure 7. W.S. Coleman #2 well log interpretation; Ellenburger Group subunits A through G are denoted to the right and left of the log image.

Net reservoir thickness was determined for each subunit of the Ellenburger by summing the footage where the average porosity (PHIA) curve was greater than 2%. It is important to note that such a low matrix porosity value was chosen due to the nature of the reservoir wherein fracture porosity is a significant contributor to reservoir quality. Our understanding and evaluation of the Ellenburger suggested a low log porosity could still result in realizable CO_2 storage potential given the history of injectivity from saltwater disposal in the area (*e.g.*, North Tarrant SWD 1 and W.S. Coleman #2 wells). A net-to-gross ratio was determined for each subunit by dividing the net reservoir thickness by the gross reservoir thickness. Average porosity was calculated for each subunit of the Ellenburger by averaging the average porosity (PHIA) curve from the top to the

bottom of the subunit. These reservoir zone properties were subsequently used to derive preliminary storage resource estimates. **Table 2** lists average petrophysical properties in the Ellenburger.

Table 2. Ellenburger Group properties assessed at the project area.

Ellenburger Subunit	Dominant Lithology	Gross Reservoir Thickness (feet)	Net Reservoir Thickness (feet [>2% PHI])	Net-to-Gross Ratio	Average Reservoir Porosity (%)	
A	Dolomite	338	63	0.186	1.1	
B	Limestone	200	14	0.070	0.8	
C	Limestone	940	187	0.198	1.2	Upper Confining Zone
C2	Dolomite	335	229	0.683	3.5	
D	Limestone	49	3.5	0.072	0.6	
E	Dolomite	1252	879	0.702	5.5	Storage Zone
F	Limestone	130	88.5	0.677	3.2	Lower Confining Zone
G	Dolomite	N/A	N/A	N/A	N/A	

Permeability data in individual Ellenburger subunits was obtained from literature. As noted by Gao *et al.*,[2] regional hydrostatic pressure gradient in the Ellenburger was assumed to be 0.47 pounds per square inch (psi) per foot, while the geothermal gradient in the Fort Worth Basin was estimated at 1.4°F per 100 feet. These parameters were used to run preliminary CO_2 storage calculations as discussed in Section 3.8.

3.4 Formation Fluid Chemistry

Through a review of chemical analyses of oil-field brines from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3, nine wells within 20 miles of the proposed injection well site were identified within the Pennsylvanian age strata, as shown in **Figure 8**. Formation fluid chemistry analyses for these wells are reported in **Table 3**.

Table 3. Pennsylvanian formation fluid chemistry.

	TDS (mg/L)	pH	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	86,807	6	26,000	5,494	53,392
LOW	21,926	4.4	6,291	978	13,389
HIGH	149,480	7.1	47,203	9,854	91,765

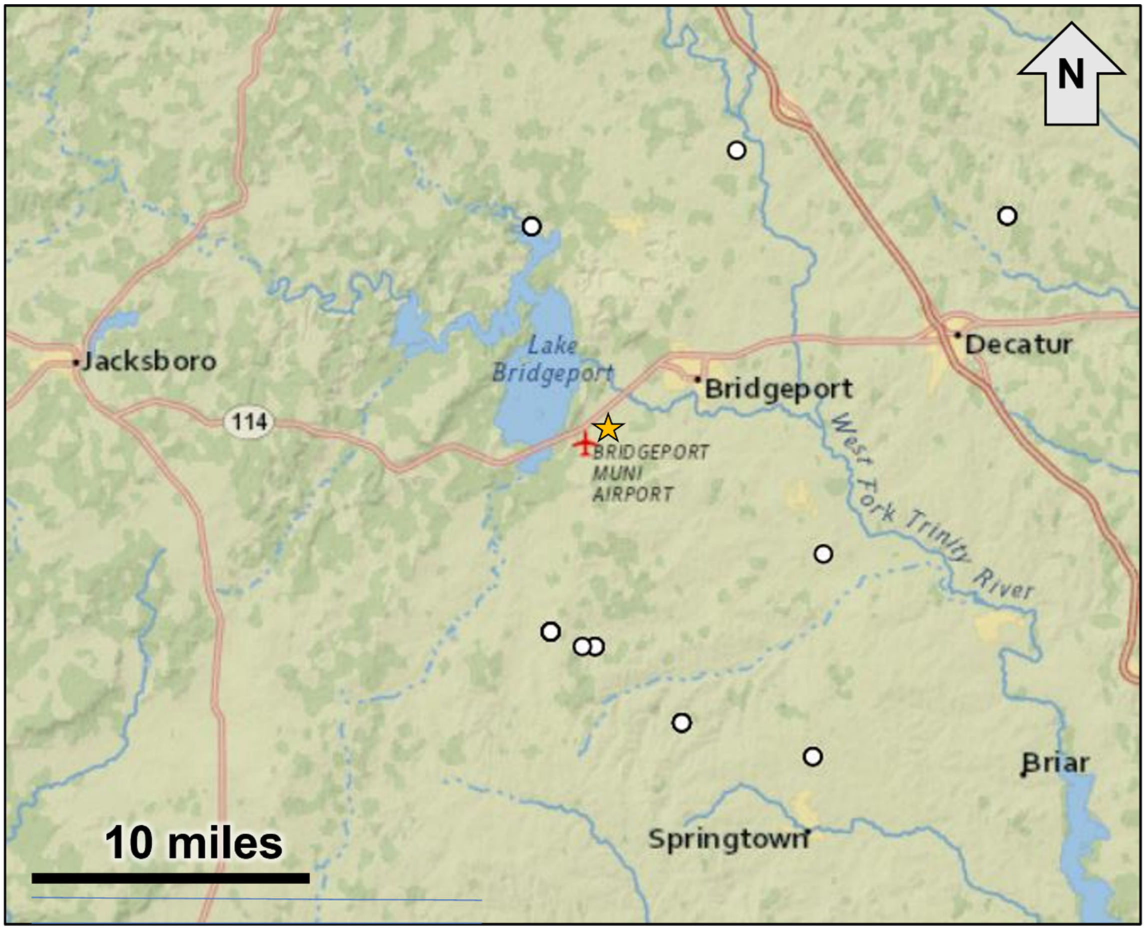

Figure 8. Map showing the location of wells used in the formation fluid chemistry analysis.

The Ellenburger Group has not been extensively drilled within the immediate area surrounding the proposed injection well and consequently formation fluid chemical analyses for the Ellenburger Group are from a basin-wide review. Based on analyses from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3, the Ellenburger fluids have greater than 194,263 parts per million (ppm) total dissolved solids (TDS) within the Fort Worth Basin. Formation fluid chemistry analyses for the Ellenburger Group Fort Worth Basin wells are reported in **Table 4**.

Table 4. Ellenburger Group formation fluid chemistry.

	TDS (mg/L)	pH	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	212,347	6	55,066	18,523	125,209
LOW	194,263	5.7	30,000	12,800	76,200
HIGH	276,388	6.6	66,482	24,750	153,071

3.5 Potential of Induced Seismicity – Ellenburger Group

An analysis of historical seismic events within a 100 square mile radius surrounding the proposed Class II well injection site shows no recorded seismic activity dating back to January 1, 1971, according to the U.S. Geological Survey (USGS) Earthquake Catalog, as illustrated in **Figure 9**. TexNet seismic activity data supports this conclusion, showing no recorded seismic events around the proposed injection well site. Fault slip potential of mapped faults within the Fort Worth Basin was assessed through a literature survey.[7] Current findings show that steeply dipping faults that strike north-northeast have the highest fault-slip potential. A Wise County saltwater disposal well has been permitted for an injection rate of 15,000 barrels per day (bpd) and is located approximately eight miles from the Barnett RDC #1 injection site. This well has been operated without any observed seismic activity.

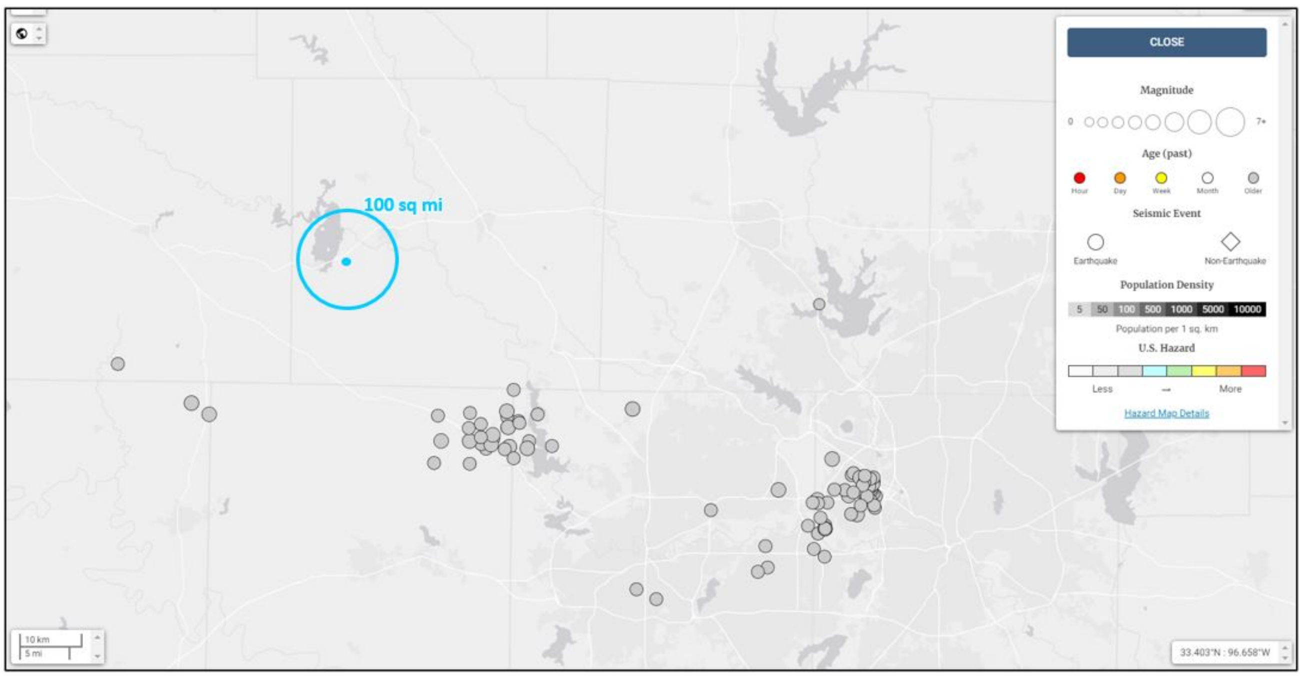

Figure 9. Screenshot from the USGS Earthquake Catalog showing no historical seismic activity in the surrounding 100 square miles to the proposed Barnett RDC #1 site.

3.6 Groundwater Hydrology in MMA

Wise County falls within the Upper Trinity Groundwater Conservation District as mapped by the Texas Water Development Board, shown in **Figure 10**. Two aquifers are within the vicinity of the proposed injection site: the Trinity Group Aquifer, a major aquifer, and the Cross Timbers Aquifer, a minor aquifer. The Lower Cretaceous Trinity Group is an important source of groundwater for a portion of Northern Texas and consequently Wise County, Texas. Lower Cretaceous strata outcrop throughout the majority of Wise County, especially to the east, but are absent at and around the

[7] Hennings, P.H., *et al*., 2019. Injection-Induced Seismicity and Fault-Slip Potential in the Fort Worth Basin, Texas. *Bulletin of the Seismological Society of America* 20 (20), 2019.

proposed injection site, as seen in **Figure 10** and **Figure 11**. Instead, strata from the Cross Timbers Aquifer outcrop on the surface at the proposed injection site. The Cross Timbers Aquifer includes four Paleozoic-age water-bearing formations including, from oldest to youngest, the Strawn, Canyon, Cisco, and Wichita Groups. The Upper Pennsylvanian Strawn Group Willow Point Formation outcrops on the surface at the proposed injection site, and rocks from the Upper Pennsylvanian Canyon Group Jasper Creek Formation outcrop 0.5 miles to the north-northwest of the proposed injection site, shown in **Figure 12**. Strawn and Canyon Group formations are primarily composed of limestones, shales, and sandstones. A stratigraphic column showing the Pennsylvanian through Cretaceous strata is included as **Figure 13**.

The Canyon Group, which outcrops at the proposed injection site, is a sequence of limestones with interstratified shales and sandstones deposited as a part of the Perrin Delta System.[8] Deposition of Canyon Group sandstones was localized within valley fill, distributary channel fill, and delta-front deposits.[9] These sandstone bodies are not laterally continuous and therefore did not constitute a regional scale major aquifer. Nearby groundwater well reports list the aquifer as Paleozoic, supporting the conclusion that freshwater in and around the well site is sourced from Pennsylvanian strata. Because the location of the well site does not fall within one of the major aquifer boundaries described by the Texas Water Development Board, describing the Total Dissolved Solids (TDS) contents of water from the Pennsylvanian Canyon Group is challenging. Consequently, this data will be collected during the drilling process. One TDS measurement from the Pennsylvanian group (formation unspecified) near the well site was recorded as 1,600 ppm.[10] Thus, freshwater wells in the area are likely drawing from localized sands within the Upper Pennsylvanian strata. The USGS's National Produced Waters Geochemical Database (NPWGD) report several TDS content measurements within the Lower Pennsylvanian Atoka/Bend formation with values ranging from 21,926 ppm to 154,593 ppm.[11] No reported TDS values from the USGS NPWGD fall below the 10,000-ppm minimum required to classify an aquifer as an Underground Source of Drinking Water (USDW). Consequently, the lowermost USDW is likely above the Lower Pennsylvanian strata at around 900 feet.

The direction of groundwater flow within Paleozoic strata is suggested to be in the west-northwest direction according to a conceptual model developed by Nicot, *et al*.[12] Recharge into the Canyon Group was estimated to occur at a rate of 0.09 inches per year by the same study. Surface-water salinity decreases downstream toward the Gulf of Mexico. Groundwater salinity increases from

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[8] Brown Jr., L.F., Cleaves II, A.W., Erxleben, A.W., 1973. Pennsylvanian depositional systems in North Central Texas, a guide for interpreting terrigenous clastic facies in a cratonic basin, *Texas Univ. Bur. Econ. Geology Guidebook*, 14 (1973), p. 132.

[9] Blandford, T.N., *et al.*, 2021. Conceptual Model Report for the Cross Timbers Aquifer. Report produced under Texas Water Development Board Contract No. 1948312322.

[10] Winslow, A.G., and Kister, L.R., 1956. Saline-Water Resources of Texas. U.S. Department of Interior Report.

[11] Blondes, M.S., *et al*., 2018. U.S. Geological Survey National Produced Waters Geochemical Database (v2.3, January 2018): U.S. Geological Survey data release, https://doi.org/10.5066/F7J964W8.

[12] Nicot, J.-P., Huang, Y., Wolaver, B.D., and Costley, R.A., 2013. Flow and Salinity Patterns in the Low-Transmissivity Upper Paleozoic Aquifer of North-Central Texas: *Gulf Coast Association of Geological Societies Journa*l (2), pgs. 53-67.

younger to older formations toward the east but there is a reversal in the Strawn Group, whose formations can be in hydraulic contact with the overlying Trinity Aquifer. The Trinity Aquifer may provide cross-formational flow to Paleozoic aquifers when they overlap, with the primary flow direction from the Trinity to the Strawn. This mixing could explain the salinity reversal observed in some parts of Texas within the Strawn Group. Locally, however, the deepest water well within two miles of the proposed injection well is 320 feet deep. This indicates that water wells in the area are drawing fresh water from localized sands within the upper several hundred feet.

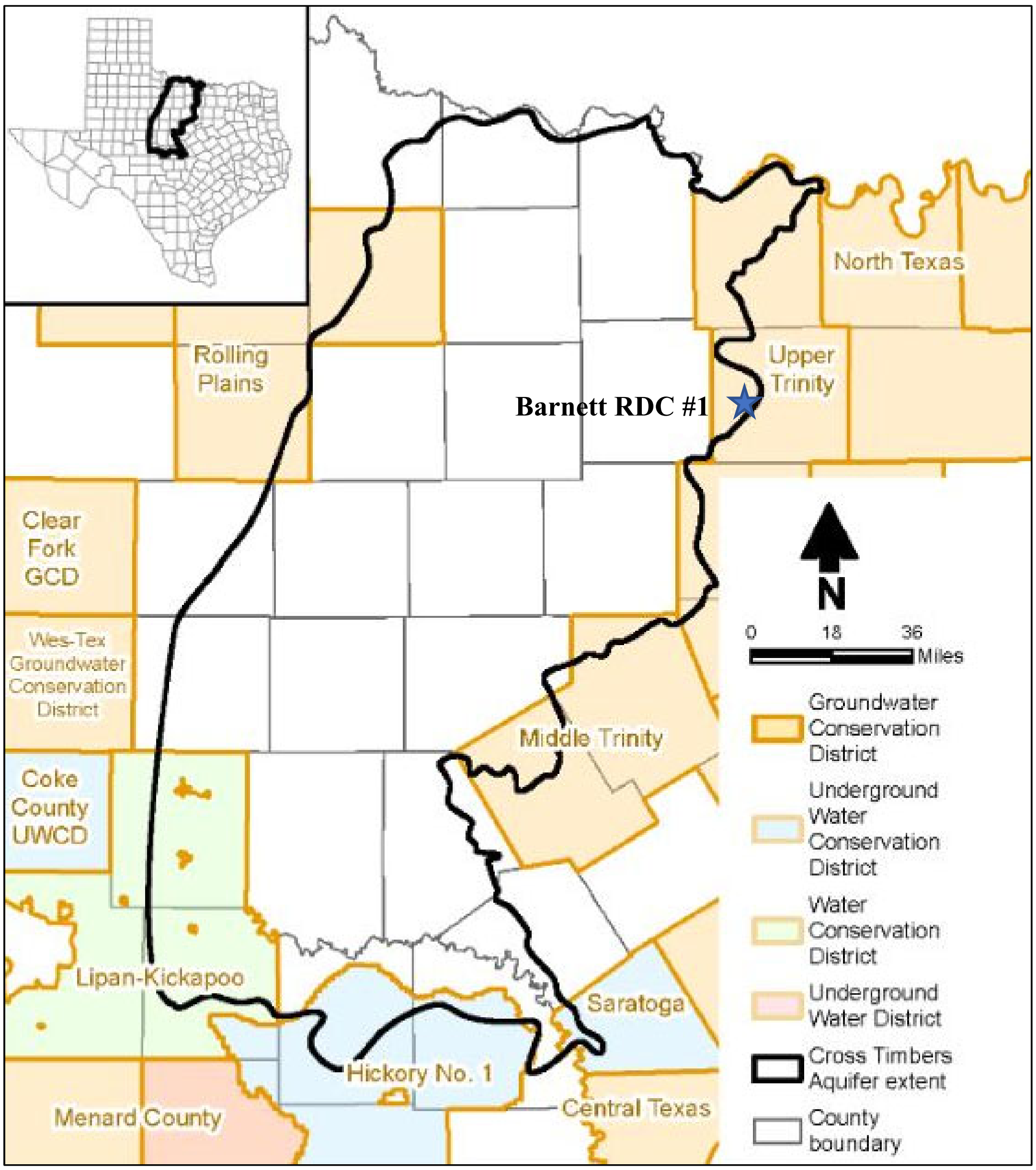

Figure 10. Map of the groundwater conservation districts and the Cross Timbers Aquifer extent within North Central Texas, from the Texas Water Development Board. The location of the proposed Barnett RDC #1 is shown with a star.

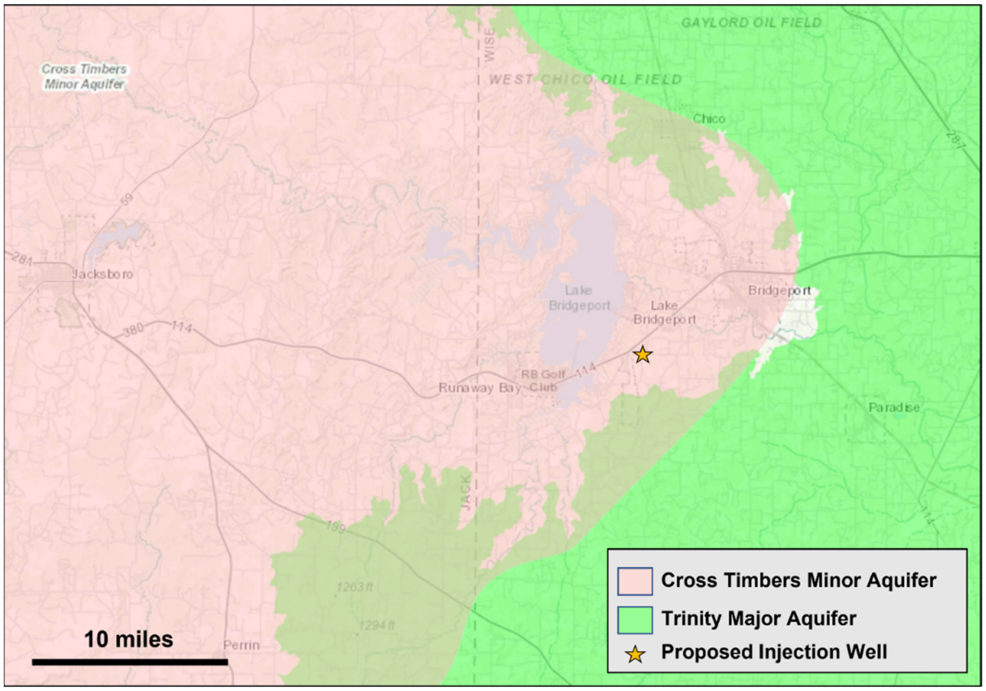

Figure 11. Location of the Cross Timbers minor aquifer and Trinity major aquifer in Texas, with the Barnett RDC #1 location labeled with a star.

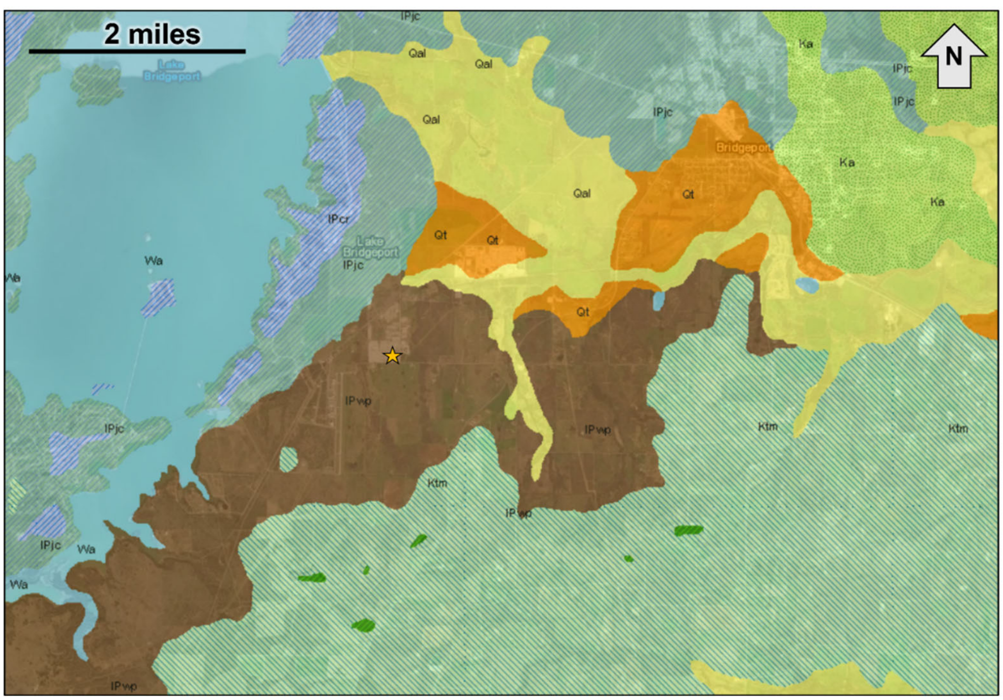

Figure 12. Geologic map of the area near the proposed injection site (yellow star). Geologic formations labeled using the state of Texas' USGS rock units codes, where: Qal = alluvium, Qt = fluviatile terrrace deposits, Wa = water, IPcr = Chico Ridge limestone, IPjc = Jasper Creek formation, IPwp = Willow Point formation, Ktm = Twin Mountains formation, and Ka = Antlers sand.

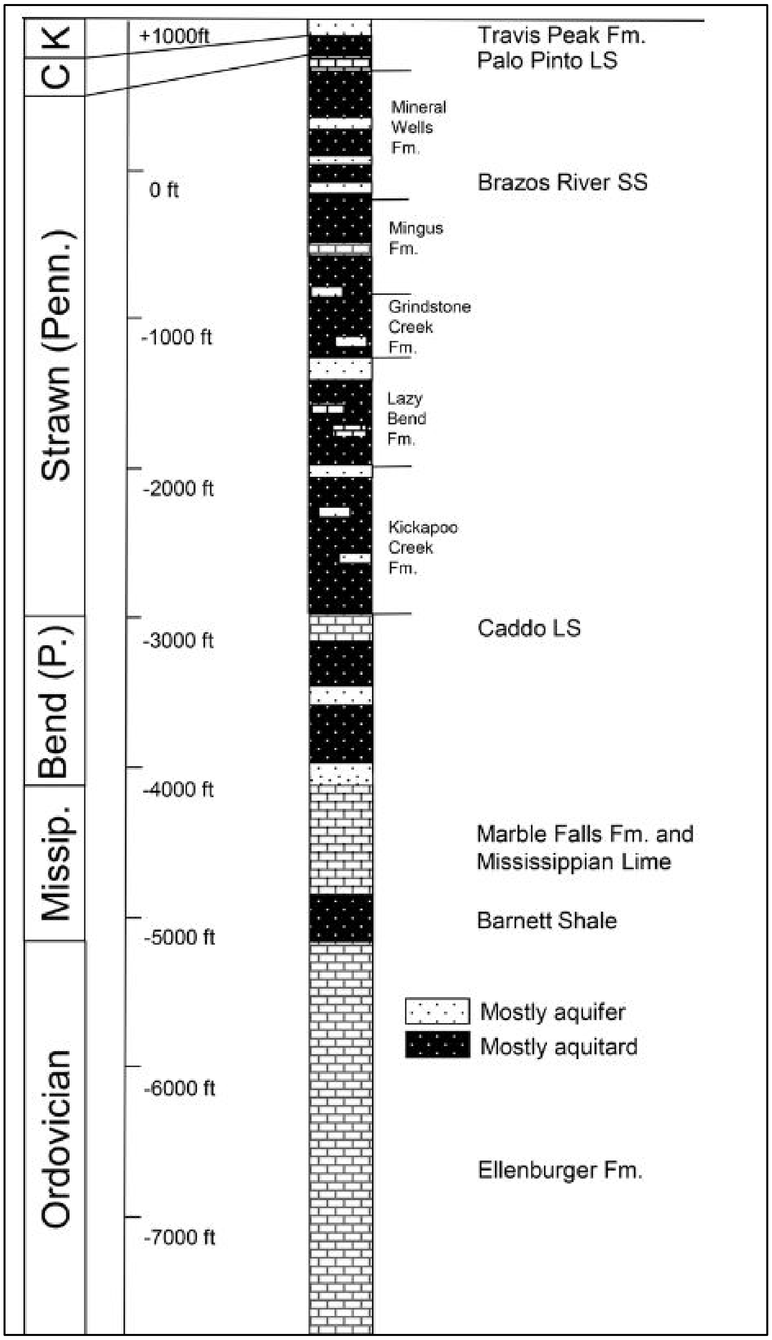

Figure 13. Stratigraphic column including aquifers and aquitards, modified from Nicot *et al*.[13]

There are 105 freshwater wells within a two-mile radius and 26 wells within a one-mile radius of the proposed injection well, according to the Texas Water Development Board Groundwater Data Viewer, shown in **Figure 14** and listed in **Table 5**.

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13 Nicot, J, *et al*., 2011. Methane occurrences in aquifers in the Barnett Shale area with a focus on Parker County, Texas" University of Texas, 2011, https://deepblue.lib.umich.edu/bitstream/handle/2027.42/137724/gwat12508-sup-0001-supinfo.pdf?sequence=1.

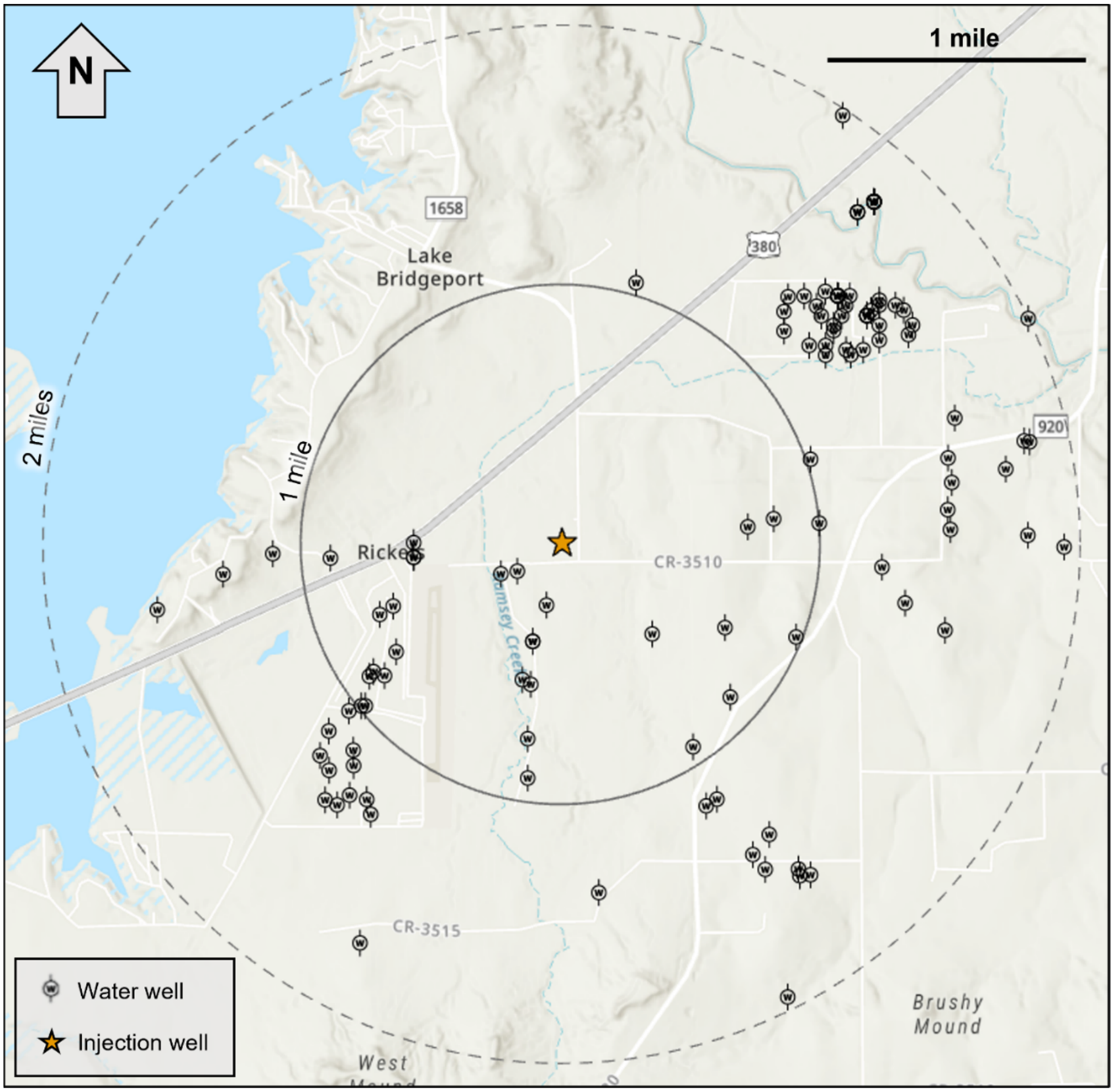

Figure 14. Water wells within one and two miles from the proposed injection site, data from the Texas Water Development Board.

Table 5. Private and state-owned groundwater wells in project area.

Private Groundwater Wells				
Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
324182	33.157501	-97.805278	180	1.97
85836	33.160834	-97.833889	180	1.74
419698	33.1635	-97.817833	160	1.37
494622	33.16434	-97.80437	140	1.59
522108	33.16439	-97.80365	140	1.61
270093	33.164723	-97.806667	200	1.50
131403	33.164723	-97.804445	110	1.57
33173	33.165556	-97.807501	280	1.42
67830	33.166667	-97.806389	100	1.39
592900	33.16871	-97.80986	155	1.16
135520	33.17	-97.8225	140	0.93
71023	33.171667	-97.811389	120	0.94
214384	33.172222	-97.8225	195	0.78
23271	33.174167	-97.833611	280	1.01
23265	33.174167	-97.833334	140	1.00
12854	33.174444	-97.808889	140	0.89
305950	33.175278	-97.822222	110	0.57
86814	33.175555	-97.822778	213	0.56
570517	33.17587	-97.83202	120	0.86
13278	33.176111	-97.832778	140	0.89
585723	33.17721	-97.83121	160	0.77
527914	33.177694	-97.822083	160	0.40
527919	33.177694	-97.822083	160	0.40
190556	33.177778	-97.804445	210	0.98
428746	33.178047	-97.81408	120	0.50
605428	33.17806	-97.79442	180	1.53
107416	33.178333	-97.809167	140	0.72
509874	33.1793	-97.83231	120	0.76
601491	33.17962	-97.79708	200	1.35
53199	33.179722	-97.847222	150	1.60
196527	33.179722	-97.821111	75	0.25
510354	33.179783	-97.831417	130	0.70
430183	33.1815	-97.824139	170	0.27
81235	33.181667	-97.842778	200	1.32
193088	33.181667	-97.823055	240	0.21
373126	33.181667	-97.798611	160	1.25
351852	33.1825	-97.835556	320	0.90
122077	33.1825	-97.83	205	0.58
143619	33.1825	-97.83	140	0.58

Private Groundwater Wells				
Well Report Tracking Number	**Latitude (DD)**	**Longitude (DD)**	**Borehole Depth (feet)**	**Distance from proposed injector (mi)**
474446	33.182659	-97.786404	180	1.95
44219	33.182778	-97.839445	230	1.13
214552	33.183334	-97.83	120	0.58
483302	33.183342	-97.78883	100	1.81
416778	33.18372	-97.79402	180	1.51
479366	33.184019	-97.807589	200	0.72
72275	33.184167	-97.802778	34	1.00
123233	33.184445	-97.805834	32	0.83
457391	33.184833	-97.794167	170	1.50
187174	33.186389	-97.793889	180	1.53
419604	33.187077	-97.790243	180	1.75
574195	33.187771	-97.794087	180	1.53
329665	33.187778	-97.803334	170	1.02
404012	33.188611	-97.788611	260	1.86
422029	33.18865	-97.78897	260	1.84
88487	33.19	-97.793611	103	1.60
72273	33.193611	-97.802223	29	1.25
72269	33.193611	-97.800556	28	1.33
62634	33.193889	-97.800834	33	1.33
72268	33.193889	-97.799722	28	1.39
62627	33.194167	-97.803334	30	1.22
62639	33.194167	-97.802223	28	1.28
219191	33.194445	-97.798611	30	1.46
219202	33.194722	-97.796667	20	1.57
123232	33.195	-97.805001	34	1.19
62632	33.195	-97.801667	33	1.34
329661	33.195278	-97.801667	145	1.35
219187	33.195278	-97.798611	30	1.49
219200	33.195278	-97.796389	24	1.60
219184	33.195556	-97.788611	30	2.01
62616	33.195834	-97.802501	35	1.33
62629	33.195834	-97.801112	35	1.40
49825	33.195834	-97.799445	27	1.47
49826	33.195834	-97.799445	27	1.47
49827	33.195834	-97.799445	27	1.47
49828	33.195834	-97.799445	27	1.47
49829	33.195834	-97.799445	32	1.47
72263	33.196111	-97.805001	30	1.24
62607	33.196111	-97.799167	31	1.50
219198	33.196111	-97.796945	27	1.60
62622	33.196389	-97.802778	38	1.35

Private Groundwater Wells				
Well Report Tracking Number	**Latitude (DD)**	**Longitude (DD)**	**Borehole Depth (feet)**	**Distance from proposed injector (mi)**
62628	33.196389	-97.800834	31	1.43
72267	33.196389	-97.798611	35	1.53
219193	33.196389	-97.7975	20	1.59
219181	33.196667	-97.798611	30	1.55
62626	33.196945	-97.804723	16	1.29
62623	33.196945	-97.803612	16	1.34
41283	33.196945	-97.801389	21	1.43
41284	33.196945	-97.801389	15	1.43
41285	33.196945	-97.801389	15	1.43
41286	33.196945	-97.801389	15	1.43
41287	33.196945	-97.801389	15	1.43
72264	33.196945	-97.800556	34	1.47
62618	33.197222	-97.802223	32	1.41
405842	33.197817	-97.814883	60	1.05
240181	33.201667	-97.800001	20	1.72
240182	33.201667	-97.800001	18	1.72
240183	33.201667	-97.800001	17.5	1.72
213490	33.202223	-97.798889	14.5	1.79
213494	33.202223	-97.798889	15	1.79
213495	33.202223	-97.798889	14	1.79
213496	33.202223	-97.798889	14.5	1.79
213499	33.202223	-97.798889	13	1.79
213500	33.202223	-97.798889	12	1.79
213502	33.202223	-97.798889	11	1.79
516919	33.20712	-97.8009	160	1.98
State Groundwater Wells				
State Well Number	**Latitude (DD)**	**Longitude (DD)**	**Borehole Depth (feet)**	**Distance from proposed injector (mi)**
1950401	33.17389	-97.83445	147	1.06
1950402	33.17278	-97.83583	146	1.17
1950408	33.16917	-97.83445	147	1.28
1950501	33.17583	-97.83306	82	0.91
1950406	33.16861	-97.83528	147	1.34
1950504	33.16806	-97.83306	147	1.29
1950404	33.17139	-97.83639	147	1.25
1950502	33.16833	-97.81056	121	1.17
1950403	33.16889	-97.83611	147	1.36
1950405	33.17083	-97.83417	147	1.19
1950407	33.17167	-97.83417	147	1.15
1950409	33.17056	-97.83583	147	1.27
1950503	33.16889	-97.83333	147	1.26

3.7 Description of CO_2 Project Facilities

dCarbon will accept CO_2 from by the Bridgeport Plant (**Figure 15**). The temperature, pressure, composition, and quantity of CO_2 will be measured and metered according to industry standards, with an orifice meter, Coriolis meter, or similar device. dCarbon will dehydrate and compress the CO_2 to a supercritical physical state at the Bridgeport site. dCarbon will then transport the CO_2 via pipeline approximately 6,815 feet to the Barnett RDC #1 injection site. Once at the well site, the CO_2 stream will again be metered to reverify quantity. The CO_2 will then be injected into the Ellenburger formation. This formation is deeper than other formations known to be productive of oil and gas in the area. A gas analysis of the CO_2 stream is shown in **Table 6**. Although this sample is expected to be representative of the composition of the gas, it is possible that the composition will vary slightly in time.

Table 6. CO_2 stream analysis for the Barnett RDC #1 site.

Name	**Normalized Weight Percent**	**Normalized Mole Percent**	**Normalized Liquid Volume Percent**
Nitrogen	0.002	0.003	0.002
Carbon Dioxide	99.358	99.054	98.646
Methane	0.105	0.287	0.286
Ethane	0.4	0.584	0.916
Propane	0.018	0.018	0.029
Isobutane	0.003	0.002	0.004
N-butane	0.008	0.006	0.011
Isopentane	0.002	0.001	0.003
N-pentane	0.002	0.001	0.003
Hexanes	0.011	0.008	0.013
Heptanes	0.011	0.002	0.011
Octanes	0.007	0.001	0.007
Nonanes	0.009	0.002	0.009
Decanes plus	0.004	0.001	0.004
BTEX	0.06	0.03	0.056
H_2S	0.00002	0.00002	0.00002
Total	100	100	100
Total Sample Properties			
Property	Value		
BTU (Gross)	16.04		
Density (lbs/gal)	12.63		
Molecular weight	43.87		
Specific gravity (Air=1)	1.5147		

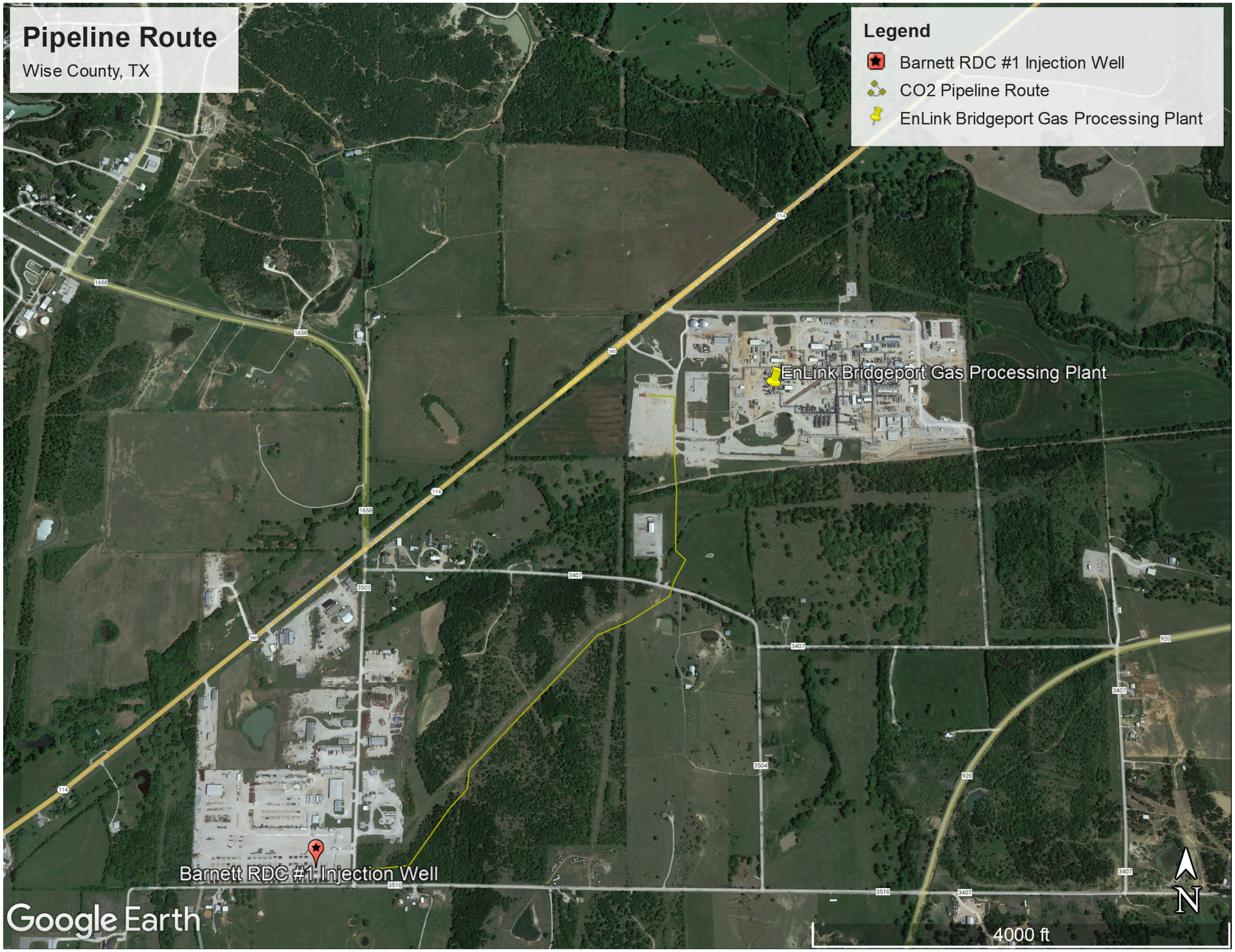

Figure 15. Proposed pipeline route.

3.8. Reservoir Characterization Modeling

A regional model encompassing nearby plugged and abandoned wells as well as saltwater disposal wells was created in Schlumberger's Petrel software. The model incorporates available well petrophysical data and generates a static earth model (SEM) for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the W.S. Coleman SWD #2 well (approximately five miles east of Barnett RDC #1, as discussed in previous sections). The reservoir is characterized by low matrix porosities as well as naturally existing fractures which are likely to contribute to fluid flow. For the current assessment, a single porosity, single permeability distribution model was deemed appropriate given the uniformity of natural fracture distribution within the Ellenburger as well as saltwater disposal rates and volumes into the Ellenburger in nearby counties. These assumptions will be examined and verified using a pressure fall-off test (PFOT) that will be conducted during the construction of the Barnett RDC #1 well. If PFOT and logging programs detect deviations from anticipated reservoir behavior, dCarbon will use the new data to update reservoir models, as well as injection forecasts and the MRV plan if appropriate.

The primary objectives of the simulation model were to:

1. Estimate the maximum areal extent of the injectate plume and its migration post injection.
2. Determine the ability of the target formation to handle the required injection rate.
3. Characterize potential interaction between the injected CO_2 and any nearby potential leakage pathways.

The CO_2 storage complex, as indicated previously, is anticipated to be confined to the Ellenburger interval. Ellenburger subunit E is modeled as the reservoir unit while Ellenburger C subunit is anticipated to provide a primary seal that impedes vertical fluid flow. The Barnett Shale is expected to serve as a secondary seal which provides an additional stratigraphic seal to the injected CO_2. The lower confining zone for the reservoir is provided by the Ellenburger F subunit. A 12-mile by 12-mile tartan grid was generated in Schlumberger's Petrel software based on well top information from nearby legacy and saltwater disposal wells. The grid was then exported to Computer Modeling Group's General Equation of State Model (CMG-GEM) simulator to account for fully implicit multiphase compositional fluid flow. This simulation was built to model other transport and mixing phenomena such as relative permeability, diffusion, advection, aqueous solubility, and buoyancy to accurately predict the plume movement. The reservoir is modeled to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 200,000 TDS, which is typical of the Ellenburger formation in the project area. The injected gas stream is assumed to be fully composed of CO_2. **Figure 16** illustrates the vertical layering with relationship to simulated CO_2 saturation profile in the model. The injection rate modeled was 280,000 MT/year for 12 years followed by 100 years of post-injection timeframe to observe post-injection movement of CO_2.

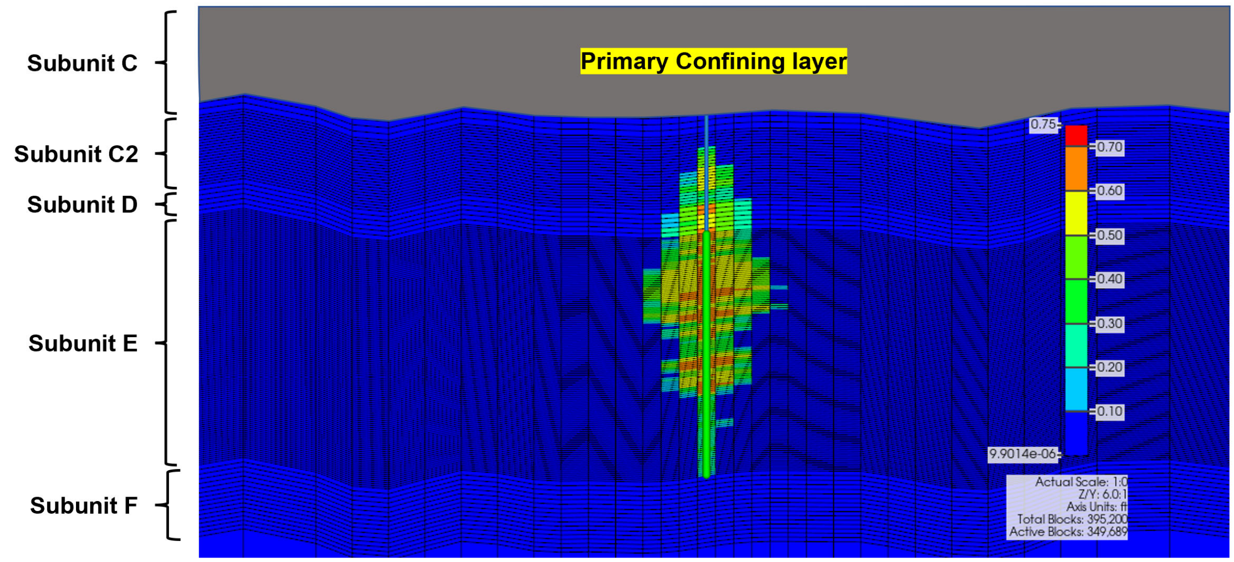

Figure 16. Vertical CO_2 saturation Profile of the CMG-GEM Model for Barnett RDC #1 Well. Color scale in Figure 16 indicates CO_2 gas saturation.

Datasets prepared for simulations were based on published literature. Specifically, the reservoir relative permeability model used in this model was sourced from literature[14] using data from the Wabamun Carbonate reservoir formation, which exhibited comparable porosities and permeabilities as the Ellenburger. The initial reservoir conditions were developed using gradients derived from literature.[2] The pressure gradient was assumed to be 0.47 psi per foot, which resulted in an estimated reservoir pressure of 4,136 psi at the top of the injection interval. The temperature gradient was assumed to be 1.5°F per 100 feet, resulting in an estimated temperature of 201°F at the top of the reservoir. Fracture pressures were estimated at 0.7 psi per foot. To ensure CO_2 injection does not induce fractures within the Ellenburger, injection well bottom hole pressure (BHP) was constrained to 90% of calculated fracture pressure, thereby applying a safety factor of 10%. This resulted in a maximum bottom hole injection pressure constraint of 5,524 psi. There are no active wells injecting or producing from the injection interval in the project area. Therefore, no additional wells other than injector were included in the fluid flow simulation model.

As mentioned earlier, injection was modeled at 280,000 MT/yr. The model simulated 12 years of active injection followed by 100 years without injection to determine when plume migration stops. Plume migration ceased after 50 years post-injection, which is determined to be the maximum extent of the CO_2 plume. **Figure 17** shows the CO_2 plume at the end of injection (yellow) compared to 50 years post injection (red). Injected CO_2 flows generally west, which is the regional up dip direction. However, the change in CO_2 plume area from end of injection to 50 years post-injection is minimal (approximately 29%) and the plume stops moving after 50 years.

[14] Bennion, D.B., and Bachu, S., 2007. Permeability and Relative Permeability Measurements at Reservoir Conditions for CO_2-Water Systems in Ultra Low Permeability Confining Caprocks. SPE Paper # 106995.

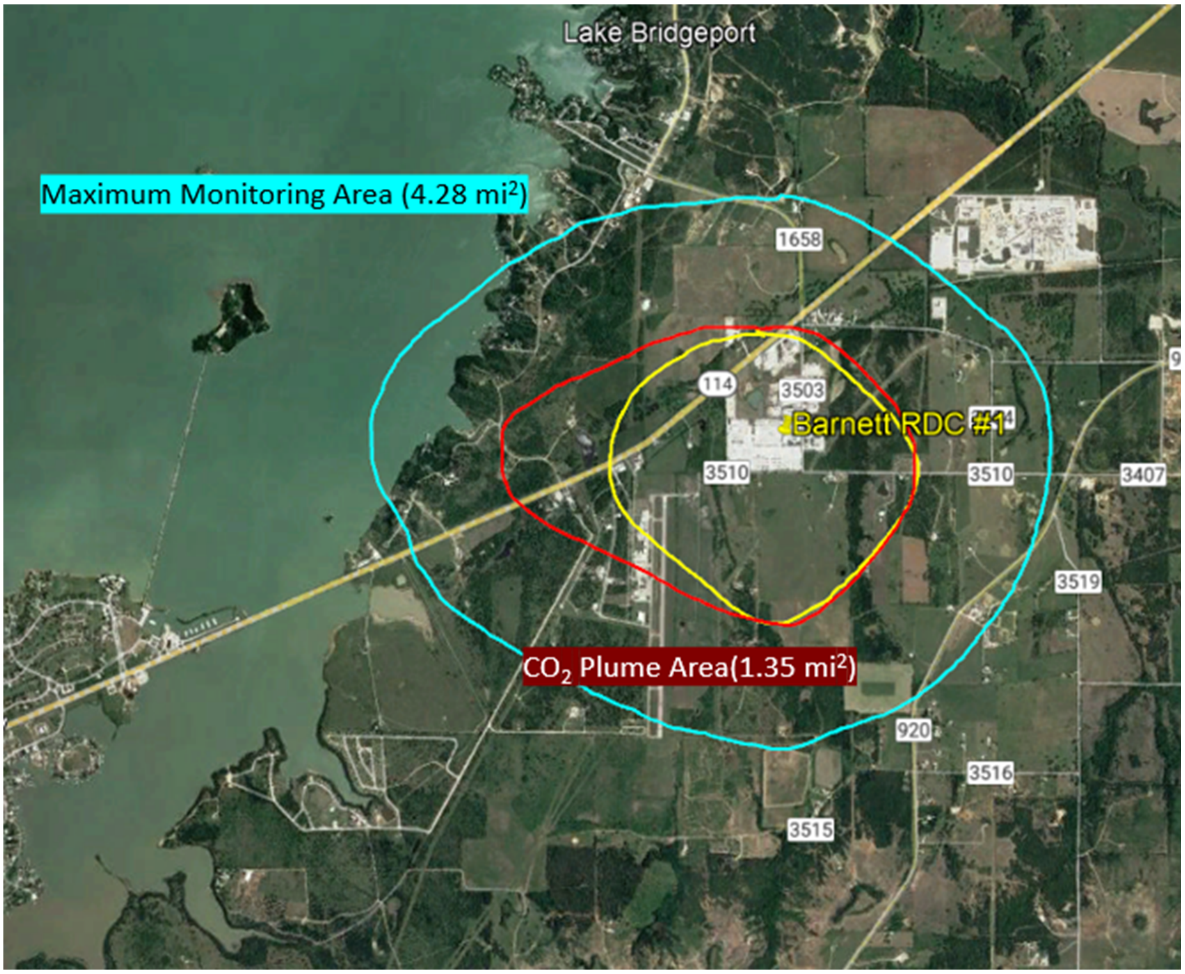

Figure 17. Simulation Results Showing CO_2 Plumes (end of injection – yellow, after 50 years of injection – red) and the Maximum Monitoring Area (blue).

Figure 18 illustrates CO_2 mass injection rate, cumulative CO_2 injection mass, and bottom hole pressure at the Barnett RDC #1 well as modeled. The bottom hole pressure remained well under the bottom hole pressure constraint. The maximum bottom hole pressure reached is 4,434 psi (1,090 psi lower than the BHP constraint), which occurs six months after the start of injection. This spike is anticipated to be a result of near wellbore effects arising from CO_2 forcing its way into the brine-filled porous media. Upon reaching a critical mass to transition from capillary driven to advection driven flow, the BHP starts to decline until the end of injection while keeping the injection rate constant. The BHP then falls until the end of injection.

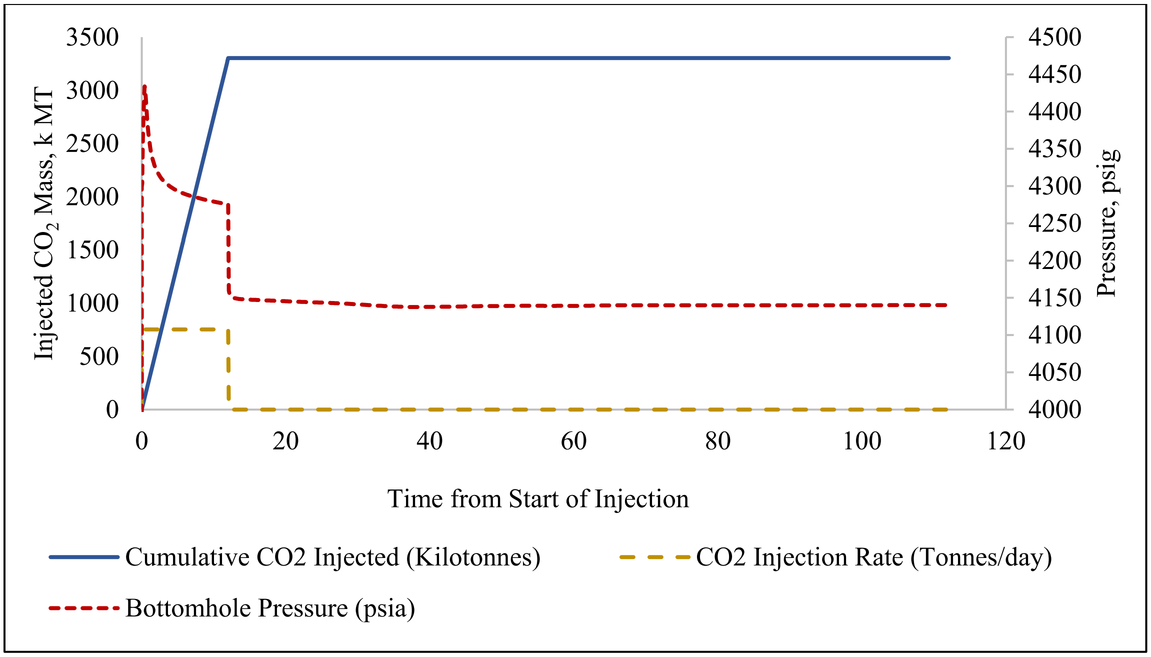

Figure 18. Modeled Injection Profile at Barnett RDC #1 Well.

4 – DELINIATION OF MONITORING AREA

4.1 Maximum Monitoring Area (MMA)

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The numerical simulation using CMG-GEM as discussed above was used to estimate the size and migration of the CO_2 plume. The model injected into the Ellenburger subunit E formation. CO_2 injection was modeled for 12 years followed by 100 years post injection. Results indicated that the plume ceased to migrate after 50 years post injection. For more information on the simulation construction and setup, please see the discussion in Section 3.8. A 5% cutoff of molar gas concentration was used to determine the boundary of the CO_2 plume. The area of the maximum monitoring area was determined to be 4.28 square miles with the greatest extent reaching 1.62 miles from the injector. **Figure 19** shows the end of injection plume (yellow), the 50-year post injection plume (red), and the maximum monitoring area using a half mile buffer (blue).

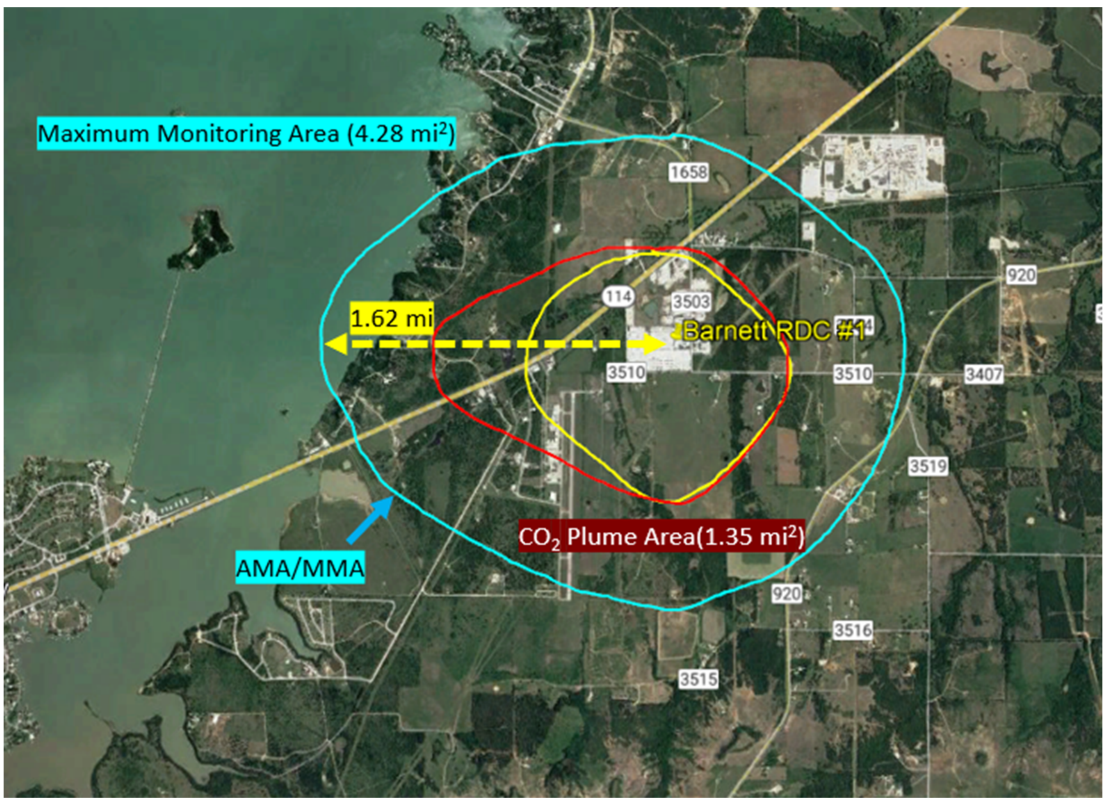

Figure 19. Maximum Monitoring Area (blue), End of Injection Plume (yellow), and 50-year Post Injection Plume (red) as Modeled at the Barnett RDC #1 Well.

4.2. Active Monitoring Area (AMA)

As discussed in Section 3, there are no structural or geological features within the project area that could cause the unintended migration of the CO_2 plume. The only potential leakage pathways that exist are well penetrations and the surface equipment. Leakage from groundwater wells, faults and

fractures, leakage through the confining layer, and seismicity events are expected to be highly improbable. That said, these leakage pathways have been considered and options to monitor them are discussed in Section 4 and Section 5. Sufficient care and consideration will be provided to monitoring these pathways, if any, and simulation models will be calibrated with new data as appropriate.

dCarbon adhered to the definition of active monitoring area (AMA) provided in 40 CFR 98.449 to delineate the AMA for this project. As noted in Section 6, dCarbon proposes to monitor the injection site from year one through year 14, which includes 12 years of injection plus two years of post-injection monitoring. As defined in 40 CFR § 98.449, the AMA must be delineated by superposition of:

(1) The area projected to contain the free phase CO_2 plume at the end of year 14, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

(2) The area projected to contain the free phase CO_2 plume at the end of year 19.

As noted in Section 4.1, dCarbon utilized the plume area after 50 years of post-injection plus a one-half mile buffer to determine the MMA, which far exceeds the definition of AMA set forth in 40 CFR § 98.449. Therefore, the AMA is proposed to have the same boundary as the MMA, which adequately covers the area that is required by 40 CFR § 98.449. **Figure 19** shows the MMA, which is the same as the AMA. **Figure 20** indicates the AMA/MMA (blue line) and currently existing water and oil and/or gas wells within this area. None of these wells were found to penetrate the Ellenburger within the project area. Water wells in the region are shallow with drilled depths up to 320 feet from surface. Additional discussion on well infrastructure within the project area can be found in later sections of this document.

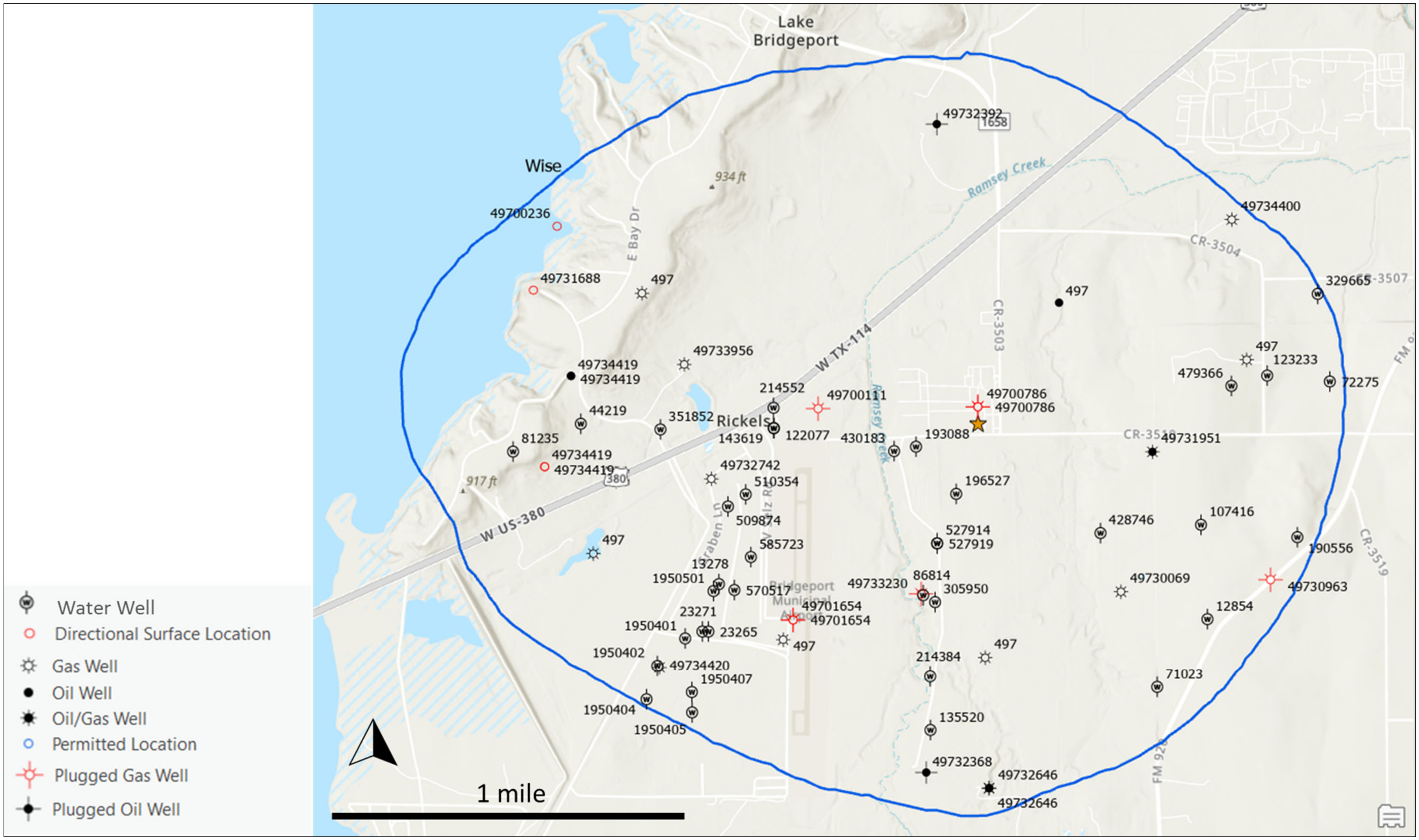

Figure 20. Maximum/Active Monitoring Area (blue) and existing wells within the project AMA/MMA. The Barnett RDC #1 is shown as a star.

5 – IDENTIFICATION AND EVALUATION OF POTENTIAL LEAKAGE PATHWAYS TO SURFACE

5.1 Potential Leakage from Surface Equipment

dCarbon's surface facilities at Bridgeport and at the injection well site are specifically designed for injecting the CO_2 stream described in **Table 6**, including H_2S. The facilities minimize leakage points such as valves and flanges by following industry standards and best practices. All BKV and dCarbon field personnel are required to wear gas monitors that detect H_2S. A shut-in valve is located at the wellhead in case of emergency. The compressor will also have emergency shut down switches that can be activated in case of unexpected operating conditions.

Additionally, the compressor facility, pipeline, and injection well locations will all be subjected to Auditory, Visual, and Olfactory (AVO) and Forward Looking InfraRed (FLIR) leak detection per BKV and dCarbon safety and operations standards. These recurring inspections, which are standard for detecting leaks and malfunctioning equipment in the gas production industry, will aid in the rapid detection of any potential leaks that may occur. As a part of these inspections, operations personnel are frequently able to repair leaks immediately by tightening valves, flanges, or similar equipment. Any leaks that are detected will be analyzed to determine the amount of CO_2 that may have leaked. These leakage quantities, if any exist, will be included in recurring reporting.

5.2 Leakage from Approved, Not Yet Drilled Wells

There are no active well permits within the MMA. However, there are multiple expired well permits within the MMA that would require re-permitting before being drilled. Details on many of the expired permit locations are included in Attachment B.

5.3 Leakage from Existing Wells

There are 20 existing wells within the MMA. Of these 20 wells, 14 have digital records available on the TRRC website, as shown in **Table 6**. Six wells have been plugged and abandoned, while eight remain active. However, all 14 of these wells are shallower than the proposed disposal interval from this project. In fact, the targeted injection interval (which is greater than 9,350 feet) is approximately 3,000 feet deeper and separated by numerous impermeable zones from the deepest existing well in the MMA (API number 42-497-34419, which has a total depth of 6,334 feet). These wells are represented relative to the project MMA in **Figure 20**. The six remaining wells that were drilled within the MMA, listed in **Table 7**, do not have digital records available on the TRRC website, but dCarbon acquired paper copies of the well permit information, and are attached herein as Attachment B. All six wells were drilled significantly shallower than the target Ellenburger formation. In fact, the deepest of the six wells was drilled to 6,155 feet true vertical depth (TVD), several thousand feet shallower than the Ellenburger formation. Note that the well labeled as D in **Table 7** below is a dual completion but single wellbore. There is one additional well that was permitted but never drilled (labeled as B in **Table 7**)

Additionally, the wellbore design of the injection well contains three layers of steel casing, each of which runs to the surface to ensure complete isolation of wellbore fluids. Each of these three casing strings will be cemented to the surface and inspected with cement bond logs to ensure wellbore integrity. Finally, all injection into the well will occur through a final steel tubing string that is secured in place with a permanent packer. All these aspects of wellbore construction are designed to ensure that all CO_2 is injected into the target formation and that there are no leakage pathways from the wellbore directly into shallower formations.

Table 6. Existing Oil & Gas wells in MMA with digital TRRC records.

API	Well Type	Latitude	Longitude	Status	Total Depth (feet)	Operator	Plug Date
49730069	Gas	33.17562	-97.8131	Open	6,128	Scout Energy Management, LLC	-
49732742	Gas	33.18044	-97.8331	Open	5,900	Eagleridge Operating, LLC	-
49733956	Gas	33.18517	-97.8344	Open	5,950	Eagleridge Operating, LLC	-
49734400	Gas	33.19088	-97.8075	Open	5,920	Eagleridge Operating, LLC	-
49734420	Gas	33.17271	-97.8357	Open	5,950	Eagleridge Operating, LLC	-
49734419	Oil	33.18474	-97.8399	Open	6,334	Merit Energy Company	-
49734419	Oil	33.18474	-97.8399	Open	6,334	Eagleridge Operating, LLC	-
49731951	Oil/Gas	33.18137	-97.8115	Open	6,125	Scout Energy Management, LLC	-
49700111	Plugged (Gas)	33.18328	-97.8278	Plugged	5,899	Mitchell Energy Corporation	4/16/1996
49700786	Plugged (Gas)	33.18328	-97.82	Plugged	5,918	Williams Petroleum Company, Inc.	2/13/2015
49701654	Plugged (Gas)	33.17462	-97.8292	Plugged	6,027	Enserch Exploration, Inc.	9/27/1996
49733230	Plugged (Gas)	33.17563	-97.8229	Plugged	5,950	Merit Energy Company	11/5/2012
49732368	Plugged (Oil)	33.16827	-97.8227	Plugged	6,000	Merit Energy Company	1/8/2001
49732392	Plugged (Oil)	33.19493	-97.8219	Plugged	5,964	Merit Energy Company	3/19/1999

Table 7. Existing Oil & Gas wells in MMA without digital TRRC records.

API	Well Type	Latitude NAD27	Longitude NAD27	Status	Total Depth (feet)	Attachment B Label	Lease / Well Name	Operator
497-01653	Gas	33.188107	-97.83638	Open	5,602	A	Craft Water BD 19-1/ DW Harrison Lease	Lone Star Production
No API	N/A	33.184969	-97.827819	Expired Permit	N/A	B	McLanahan	N/A
497-00009	Oil	33.187529	-97.815993	Open	6,200	C	HH Wharton Gas Unit 1A	A'Mell Oil Properties
497-01686	Gas	33.185100	-97.806835	Plugged	5,996	D	Kate A Stanfield 1	Lone Star Production
497-03093	Oil	33.185100	-97.806835	Plugged	5,996	D	Kate A Stanfield 1A (dual completion of 497-01686)	Lone Star Production
497-30085	Gas	33.172971	-97.819788	Open	5,389	E	CR Upham JR #2 Shilling Harold Lease	Upham Oil & Gas
497-1	Gas	33.1738	-97.829657	Plugged	6,027	F- Same as 497-01654	Craft Water Board Sampson #1	Lone Star Prod/Ensearch
497-01646	Gas	33.177438	-97.838912	Plugged	5,968	G	Craft Water Board 8-1	Lone Star Production

5.4 Potential Leakage from Fractures and Faults

Several episodes of fault formation took place in the Fort Worth Basin, based on 3D seismic data interpretation conducted by dCarbon. The oldest set of faults displaced Ordovician rocks but did not displace Mississippian rocks like the Barnett Shale. A younger set of faults displaced Mississippian and older rocks and appear to be related to the Ouachita Front collision. These faults show displacement up into the Pennsylvanian rocks as high as the Strawn. These larger, younger faults have greater displacement but are relatively sparce.

No faulting is interpreted in the MMA around the Barnett RDC #1 based on available subsurface data including 3D seismic data. Dynamic modeling conducted to date indicates that the CO_2 plume will not intersect any mapped faults, based on dCarbon's existing 3D seismic interpretations.

Karst development is present in some areas at the top of the Ellenburger, primarily where the overlying Viola and Simpson Formations were eroded. Karsting is often developed in the upper several hundred feet of an exposed carbonate (Ellenburger subunit A) where fresh water is able to

dissolve the rock (**Figure 21**). Subsequent loading of sediment can cause the roof of the cave to collapse, with overlying sediment filling the void.[15]

The injection interval, the Ellenburger subunit E appears to be below the portion of the upper Ellenburger affected by the karst collapses. This suggests that the Ellenburger subunit C will remain a continuous upper seal even in karst areas. There are no interpreted karst features that the CO_2 plume or pressure front intersects based on the dynamic modeling. Small karst features sit at the southern edge of the MMA but only seem to have impacted the upper 200 feet of the Ellenburger, leaving 3,000 feet of Ellenburger apparently unaffected (**Figure 22**).

Even if the plume reaches the karst features on the south end of the MMA and the Ellenburger subunit C upper seal is not intact, the overlying and impermeable Barnett Shale, Marble Falls Limestone, and the Atoka Shales are expected to prevent migration to shallower depths.

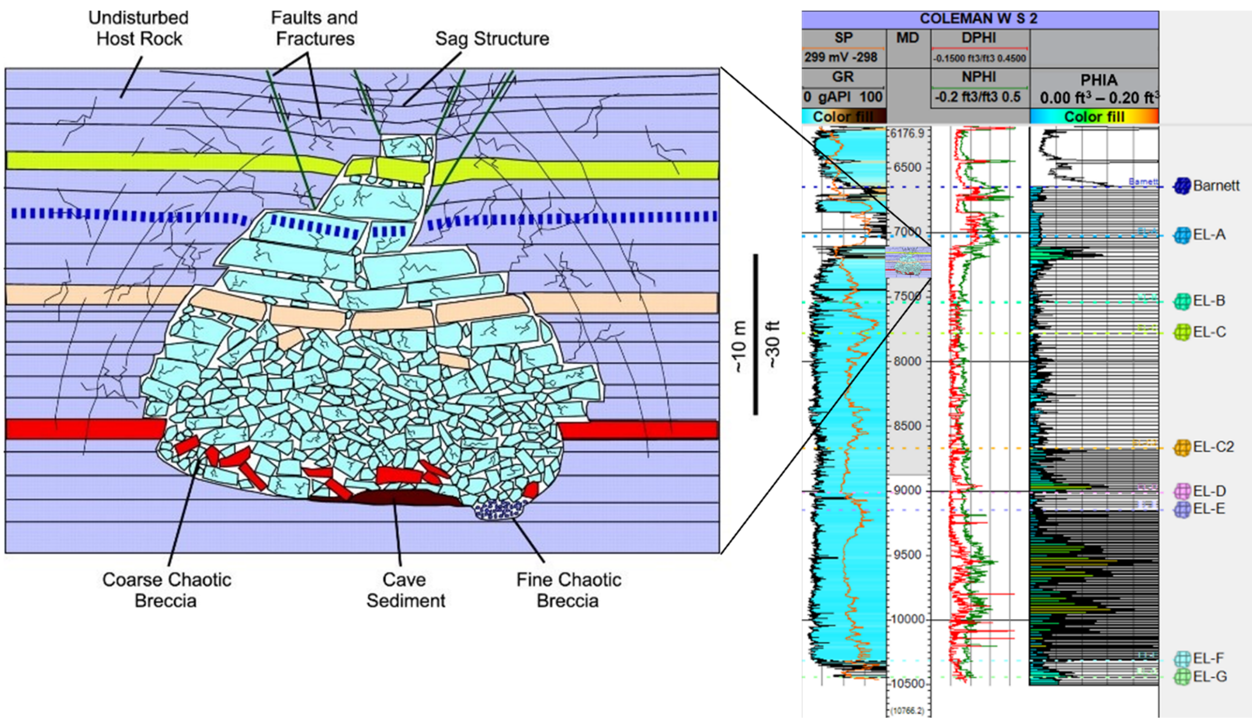

Figure 21. A schematic diagram showing the geometry and component facies of a single cave passage buried in deeper subsurface where collapse and extensive brecciation occurred (modified from Zeng *et al.*[16]). The typical scale of the karst features is shown on the right placing the feature on the W.S. Coleman #2 well log. Note that the interpreted karst features are only observed in the upper portion of the Ellenburger, above the confining unit Ellenburger subunit C.

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[15] Zeng, H., 2011. Characterizing seismic bright spots in deeply buried, Ordovician Paleokarst strata, Central Tabei Uplift, Tarim Basin, Western China. *Geophysics* 76 (4), 2011.

[16] Zeng, H., *et al*., 2011. Three-dimensional seismic geomorphology and analysis of the Ordovician paleokarst drainage system in the Central Tabei Uplift, Northern Tarim Basin, Western China. *American Association of Petroleum Geologists Bulletin* 95 (12), pgs. 2061–2083. 2011.

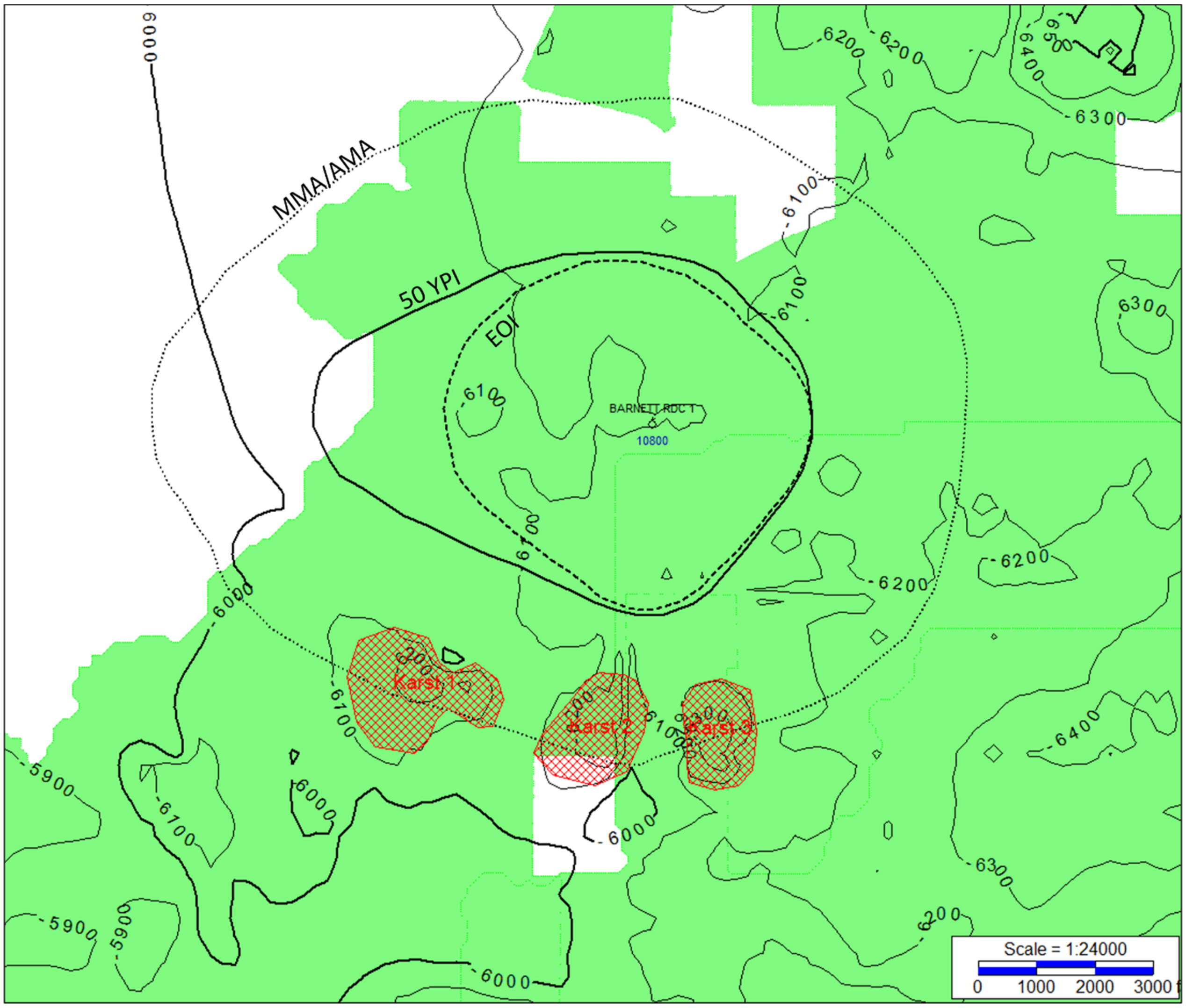


Figure 22. The Barnett RDC #1 well location with top Ellenburger structural contours (TVDSS), 3D seismic coverage (green), and mapped Ellenburger karst on the southern edges of the MMA/AMA. The CO_2 plume size at the end of injection and 50 years post-injection are also shown from Figure 19.

5.5 Leakage Through Confining Layers

The Ellenburger subunit E injection zone is bound by competent confining zones above the injection interval by the Ellenburger subunit C and below the injection interval in the Ellenburger subunit F. Secondary seals above the injection zone include the Barnett Shale, Marble Falls Limestone, and the Atoka Shales. Ellenburger subunit F serves as the lower confining zone. Overall, there is an excess of 3,000 feet of impermeable rock between the injection zone and the deepest well penetrations, making vertical migration past the primary and secondary confining zones unlikely.

5.6 Leakage from Natural or Induced Seismicity

The Barnett RDC #1 location is in an area of the Fort Worth Basin that is inactive seismically, as illustrated in Section 3.5. Earthquake catalogs from both the USGS (1950-present) and TexNet (2017-present) indicate no earthquake locations within 20 miles of the Barnett RDC #1.

The closest earthquake locations are 20+ miles to the southeast in an area of larger, regional faulting. In 2013 and 2014, a series of earthquakes were felt near the towns of Reno and Azle, Texas. The Texas Railroad Commission held hearings that investigated whether oil and gas activities near the earthquakes were responsible for the activity. The Railroad Commission was unable to determine whether oil and gas activities were responsible for the earthquake sequence.

Since no faults are mapped that cut from the injection interval through the sealing limestones and shales of the Pennsylvanian, no leakage is expected due to induced seismic activity.

However, dCarbon also plans several operational procedures to monitor injection-induced seismicity and to immediately identify any minor or major seismic events in the area. Before initiating injection into the well, dCarbon will be installing both surface and bottomhole pressure gauges, so that reservoir pressure and injection pressure can be monitored. Additionally, consistent with RRC guidelines and permit conditions, dCarbon plans to maintain bottomhole injection pressure below formation fracture pressure, and also maintain surface pressure below 0.50 psi per foot gradient when measured from the top of the injection interval. Finally, dCarbon plans to perform periodic pressure fall-off tests (PFOT) to determine and monitor reservoir pressure to ensure unexpected static pressure increases are not observed. These measures are designed to prevent induced fracturing of the formation or increase the likelihood of induced seismicity. Should any unexpected increase in formation pressure be detected, dCarbon can perform Fault Slip Potential (FSP) analysis[17] to evaluate the risk of induced seismicity on the closest mapped faults. dCarbon plans to build this model based on geologic data collected during drilling the Barnett RDC #1 well. If there is a concern related to abnormal pressures or seismicity related to operations at the well, dCarbon will shut-in the well and investigate further.

Furthermore, dCarbon plans to install new ground seismic monitoring arrays near the injection site that are designed to detect any seismic events in the area, natural or induced. Any seismic events detected in the area will be located in the subsurface and analyzed to determine their origin and if they may have potential impacts to the injection program or confining layers. Additionally, the TexNet seismic monitoring program will also be monitored to ensure any material seismic events in the area are investigated.

[17] Walsh, F.R.I., Zoback, M.D., Pais, D., Weingartern, M., and Tyrell, T. (2017). FSP 1.0: A Program for Probabilistic Estimation of Fault Slip Potential Resulting from Fluid Injection, available at: https://scits.stanford.edu/software.

5.7 Leakage from Lateral Migration

The structural dip of the Ellenburger in the vicinity of the Barnett RDC #1 injection site is about one degree up to the west (100 feet/mile), shown in **Figure 23**. The closest well that penetrates the Ellenburger subunit E injection interval up dip from the injection site is more than ten miles to the west-southwest. The closest well that penetrates the injection interval is down dip to the east approximately five miles (W S Coleman #2).

Dynamic modeling of the CO_2 plume has the maximum extent of the plume traveling less than one mile, with the maximum distance traveled to the west. Given that the distance to the next penetration of the injection interval is on the order ten times the distance the plume is expected to travel, no leakage from lateral migration is expected.

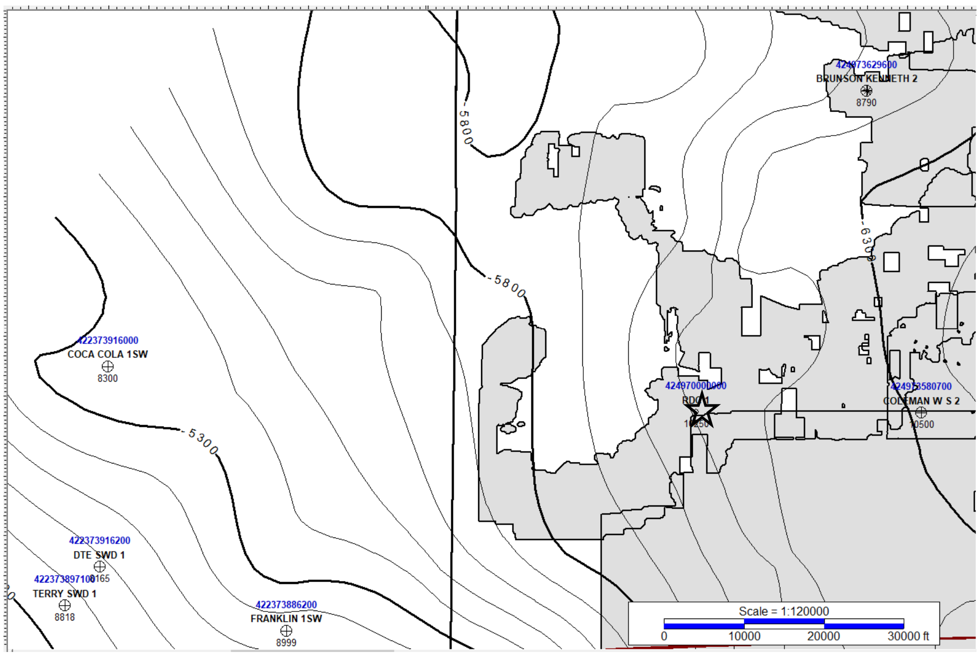


Figure 23. Top of Ordovician Unconformity (top Ellenburger) regional subsea structure in the vicinity of the Barnett RDC #1 location (star). Wells shown penetrate the injection interval. Additional wells (not shown) were used to develop the structure map. Gray areas represent areas covered by 3D seismic data.

Furthermore, dCarbon has assessed each of the previously discussed potential leakage pathways for likelihood, potential timing, and magnitude. The framework of this assessment is based upon the California Air and Resources Board's CCS Protocol Section C.2.2(d).

Table 8 describes the basis for event likelihood and **Table 9** provides the details of the leakage likelihood, timing of occurrence, and estimated magnitude of leakage for each type of leak risk.

Table 8. Risk likelihood matrix (developed based on comparable projects).

Risk Factor for Probability		Description
1	Improbable	<1% chance of occurring*
2	Unlikely	1-5% chance of occurring*
3	Possible	> 5% chance of occurring*
*During the life of the project or 100 years after project closure, whichever is shorter		

Table 9. Description of leakage likelihood, timing, and magnitude.

Leakage Pathway	Likelihood	Timing	Magnitude
Potential Leakage from Surface Equipment	**Possible**	Anytime during project operations, but most likely during start-up / transition or maintenance periods	**<100 MT per event** (100 MT represents approximately 3 hours of full flow facility release)
Leakage from Approved, Not Yet Drilled Wells	**Improbable**, as there are no approved not yet drilled wells	After new wells are permitted and drilled	**<1 MT per event**
Leakage from Existing wells	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and the total depth of existing wells	When the CO_2 plume expands to the lateral locations of existing wells	**<1 MT per event** due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach an existing well combined with thickness and low porosity / permeability of upper confining zone
Potential Leakage from Fractures and Faults	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and surface or USDW that would need to be compromised and there are no mapped faults within the MMA.	Anytime during operation	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach a fault or fracture significant enough to cause leakage
Leakage Through Confining Layers	**Improbable**, as the upper confining zone is nearly 1,000' thick and very low porosity and permeability	Anytime during operations	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E and thickness/properties of upper confining zone
Leakage from Natural or Induced Seismicity	**Improbable**, as there are several thousand feet of impermeable rock between the injection zone and surface or USDW that would need to be compromised and there are no mapped faults within the MMA.	Anytime during operations	**<100 MT per event**, due to natural dispersion of CO_2 within the Ellenburger subunit E before it would laterally reach a fault or fracture significant enough to cause leakage
Leakage from Lateral Migration	**Improbable**, as the Ellenburger is a very thick and laterally continuous formation with the closest well penetration five miles downdip.	More likely late in life as plume expands	**<1 MT per event** due to natural dispersion of CO_2 within the Ellenburger subunit E and continuity / thickness of upper confining zone

6 – PLAN OF ACTION FOR DETECTING AND QUANTIFYING SURFACE LEAKAGE OF CO_2

This section discusses the strategy that dCarbon will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in previous sections to meet the requirements of 40 CFR § 98.448(a)(3). As the injected stream contains both H_2S and CO_2, any observation of H_2S will serve as a preliminary indicator for CO_2 leakage and therefore the monitoring systems to detect H_2S will also suggest a leak of CO_2. This section summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur. Monitoring will occur during the planned 12-year injection period, or until the cessation of operations, plus a proposed two-year post-injection period.

6.1 Leakage from Surface Equipment

As the CO_2 compressor station, pipeline, and injection well are all designed to handle expected concentrations, temperatures, and pressures of H_2S and CO_2, any leakage from surface equipment will be quickly detected and addressed. The facility is designed to minimize potential leakage points by following the American Society of Mechanical Engineers (ASME) standards, American Petroleum Institute (API) standards, and other industry standards, including standards pertaining to material selection and construction. Additionally, connections are designed to minimize corrosion and leakage points. The H_2S in the stream is easily detectable and serves as an indicator for the release of CO_2. The facility and well will be monitored for H_2S and CO_2 concentration increases. This monitoring equipment will be set with a high alarm setpoint for H_2S that automatically alerts field personnel of abnormalities. Additionally, all dCarbon and BKV field personnel are required to wear H_2S monitors, which will trigger the alarm at low levels of H_2S (typically one ppm). The injection facility will be continuously monitored through automated systems that are designed to identify abnormalities in operational conditions. In addition, field personnel conduct daily AVO field inspections of gauges, monitors, and leak indicators. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system and analysis of liquids collected from the line. These inspections, in addition to the automated systems, will allow dCarbon to quickly identify and respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR § 98.448(a)(5).

Additionally, CO_2 for injection will be metered in three locations for redundancy and precision. The first will be at an orifice style or Coriolis meter at the interface between the Bridgeport Plant and dCarbon's compression facility. This location will meter the CO_2 in gas phase and is depicted in **Figure 24a** and **Figure 24b**. Once the CO_2 is compressed to supercritical, it will pass through a Coriolis meter for measurement and then be transported approximately 6,815 feet via pipeline (see **Figure 15**) to the injection well site. The CO_2 will then be measured again with a Coriolis meter at the injection well site, immediately upstream of the injection wellhead itself. The injection stream will also be analyzed with a gas chromatograph at the well site to determine final composition. The meters will each be calibrated to industry standards. Any discrepancies in CO_2

throughput between the meters will be investigated and reconciled. Any CO_2 that is determined to have leaked or not been received at the injection wellhead will be quantified using the procedures specified in subpart W of the GHGRP, reported as specified in 40 CFR § 98.448(a)(5), and subtracted from reported injection volumes. Gas samples will be taken and analyzed per manufacturer's recommendations to confirm stream composition and calibrate or re-calibrate meters, if necessary. At a minimum, these samples will be taken quarterly. Minimal variation of concentration and composition are expected but will be included in regulatory filings as appropriate.

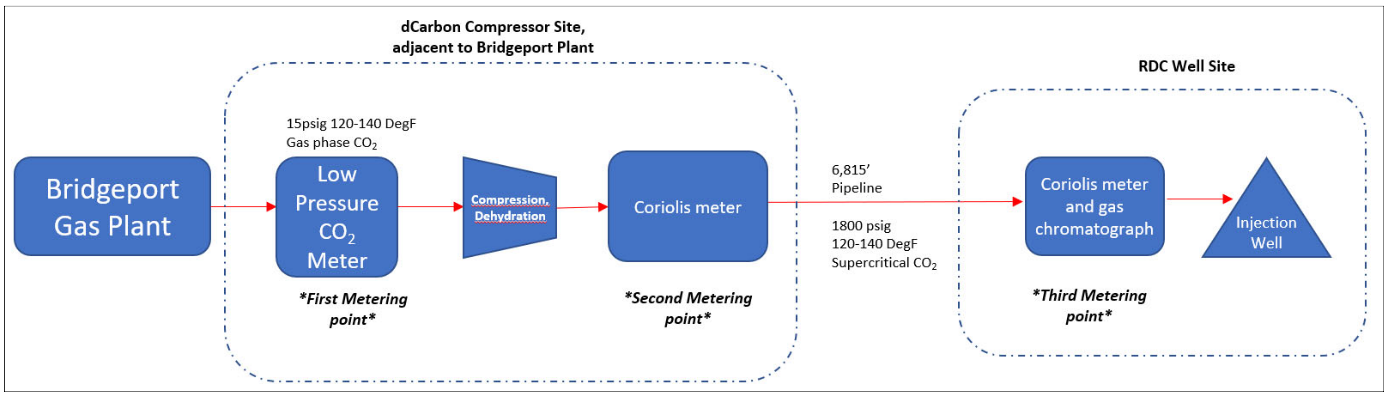


Figure 24a. Project conceptual diagram and metering locations.

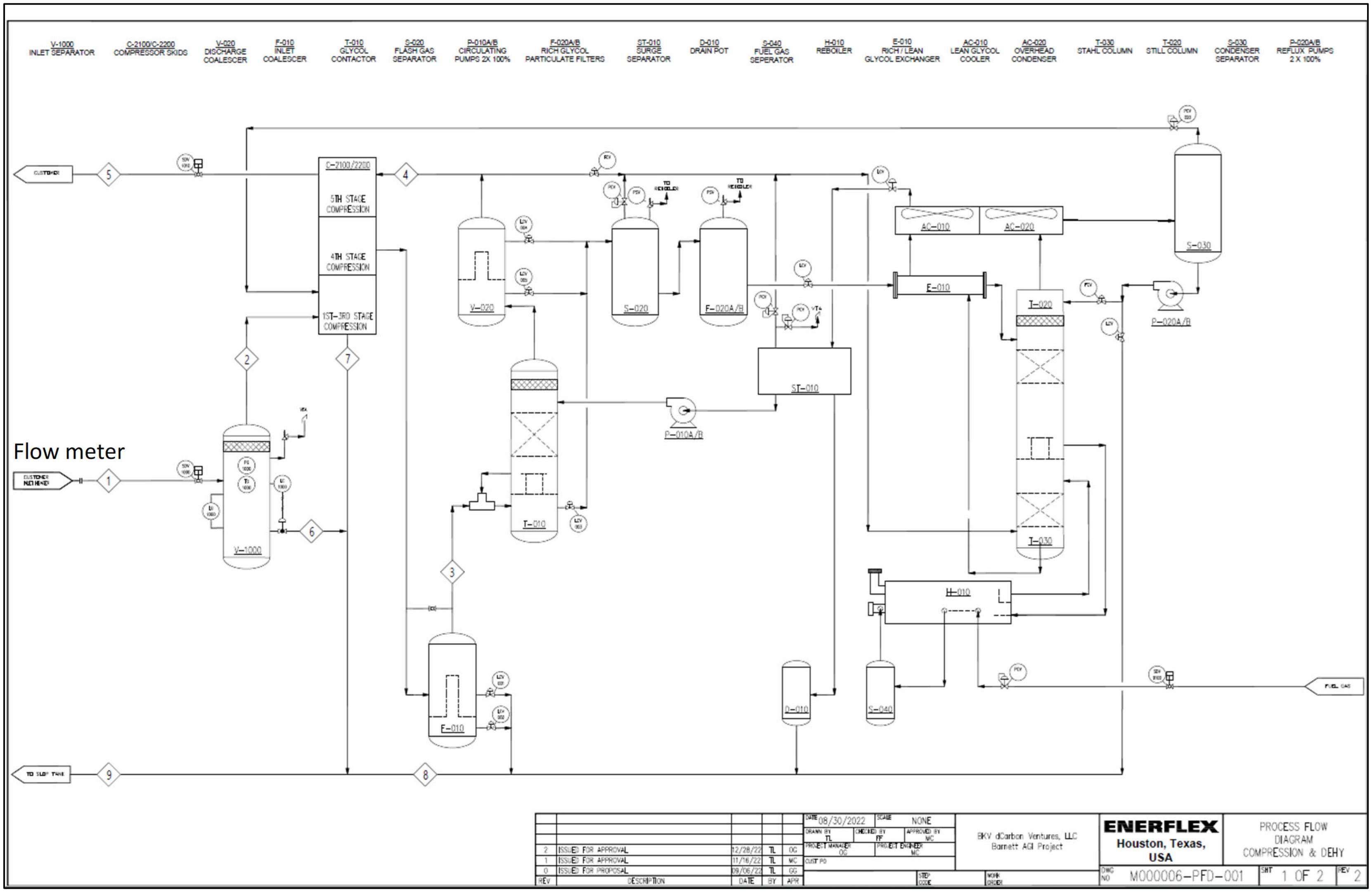


Figure 24b. Compression facility process flow diagram.

6.2 Leakage from Existing and Future Wells within the Monitoring Area

As previously discussed, there are no wells in the MMA currently existing, approved, or pending that penetrate as deep as the Ellenburger injection zone. However, dCarbon will reverify the status and public information for all proposed and approved drilling permits within the MMA quarterly. If any wells are proposed, permitted, or drilled within the MMA, BKV will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, dCarbon will continuously monitor and collect injection volumes, pressures, temperatures, and gas composition data for the injection well. This data will be reviewed by qualified personnel and will follow response and reporting procedures when data is outside acceptable performance limits. Finally, dCarbon will update the MRV plan if any new wells are drilled within the MMA, or if any other material change to the project occurs.

The injection well design has pressure and temperature gauges monitoring the injection stream at the wellhead as well as bottomhole pressure and temperature gauges near the bottom of the tubing. The downhole gauges will monitor the inside of the tubing (injection stream) as well as the annulus. A change of pressure on the annulus would indicate the presence of a possible leak requiring remediation. Mechanical Integrity Tests (MITs) performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated, and the leak mitigated.

In the unlikely event that any CO_2 leaks occur into existing or future wells in the monitoring area, dCarbon will endeavor to work with the operator(s) of those wells and/or midstream providers to take wellhead gas samples to quantify variations or increases of CO_2 compared with historical or baseline CO_2 concentrations. Any measurable increases in CO_2 which may be confidently attributed to injection volumes from the Barnett RDC #1 well will be calculated using standard engineering procedures for estimating potential well leakage determined to be appropriate for the situation. These volumes will be documented and reported in the annual monitoring report and subtracted from reported injection volumes. Additionally, dCarbon will evaluate and execute any additional downhole remediations (*e.g.*, well workovers, such as adding plugs, remedial cement jobs, etc.) that could address leakage from the injection well to the existing and future wells in the area if necessary and practical.

6.3 Leakage from Faults and Fractures

No faults or fractures have been identified that would allow CO_2 to migrate vertically to zones with USDWs or to the surface. In the unlikely event that such leakage from faults or fractures occurs, dCarbon will determine which standard engineering techniques for estimating potential leakage from the faults and fractures is appropriate for the situation to estimate any leakage from faults and fractures, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.4 Leakage through Confining Layers

Leakage through confining layers is improbable, given the number and thickness of layers between the injection zone and potable groundwater. Groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple confining layers.

In the unlikely event CO_2 leakage occurs because of leakage through the confining seal, it is also unlikely that the leak would result in surface leakage. As with any CO_2 leakage, however, should it occur, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation to estimate any leakage, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.5 Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, dCarbon plans to install a seismic monitoring array in the general area of the Barnett RDC #1 well. This monitoring array will augment the TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, dCarbon will review the injection volumes and pressures at the Barnett RDC #1 well to determine if any significant changes occurred that would indicate potential leakage. To suspect leakage due to natural or induced seismicity, the evidence would need to suggest that the earthquakes are activating faults that penetrate through the confining zones.

In the unlikely event CO_2 leakage occurs due to natural or induced seismicity, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation and report such leakage estimates and the methodology employed in the annual monitoring report.

6.6 Leakage through Lateral Migration

The distances to the closest penetration of the Ellenburger injection interval are more than ten times the expected plume radius at the end of injection. As such, leakage through lateral migration is not expected. In addition, the wells that penetrate the injection interval are saltwater disposal wells. Injection into these wells would be expected to raise the reservoir pressure locally near the well, further limiting the ability of the CO_2 to access the saltwater injector well bore.

In the unlikely event CO_2 leakage occurs due lateral migration, similar to leakage through confining layers, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.7 Quantification of Leakage

In the unlikely event that CO_2 moves vertically past the primary and secondary confining layers as described earlier in Section 6, there are several methods dCarbon may utilize to quantify leakage depending on the nature and severity of the leak. dCarbon has designed a monitoring network

suited to detect CO_2 leaks before they interact with local resources, infrastructure, or USDW. dCarbon will consider additional standard and specialized engineering methods to quantify leaks as appropriate. dCarbon's methodology to characterize, monitor, detect, and isolate leaks for quantification is described below.

As a primary monitoring and quantification strategy, dCarbon plans to install a deep groundwater monitoring well in the MMA that will be used to monitor the USDW. This well will be deeper than any active groundwater wells in the area that typically draw water from shallow drinking water zones. dCarbon also plans to periodically sample the well to monitor for chemical composition. If dCarbon notices an increase in groundwater CO_2 concentration compared to baseline measurements, the increase in concentration will be analyzed volumetrically to provide a preliminary estimate of CO_2 leakage.

Any leakage that did extend to the surface could be characterized and quantified through surface surveillance in the project area paired with direct pressure, volume, and temperature (PVT) measurements. Currently available (and continuously improving) atmospheric sensing technology could be used to establish a baseline of ambient CO_2 concentration in the project area and identify any fluctuations. Deviations from baseline concentration along with understanding of the distance from potential leak sources can then be coupled with temporally matched meteorological data to semi-quantitatively determine leak attribution and rate. Based on the size of leak, these qualified or quantified leak rates can be compared with spatiotemporally monitored PVT data to co-index or further refine leaked volumes from likely point sources.

Any diffuse leak or leak without an obvious single point source may require additional identification and quantification methods. dCarbon is working with a leading environmental services and data company that specializes in monitoring and quantifying gas leaks in various industrial settings. One such quantification method involves utilizing fixed monitoring systems to detect CO_2. Additional system capabilities also include the deployment of an unmanned aerial vehicle (UAV), which is outfitted with an industry leading high fidelity CO_2 sensor capable of measuring concentrations as little as parts per billion (ppb). The UAV mobile surveillance platform possesses the ability to be flown on a programmable and highly replicable pattern across the MMA in both X and Y axis (longitude + latitude) as well as Z axis (height). Depending on the system's ability to obtain a reliable baseline across the MMA, areal deviation in CO_2 concentration could be measured, and diffuse leak sources could potentially be identified, provided the emissions reach a sufficient threshold. dCarbon will also consider similar technologies with less spatial resolution or fidelity such as fixed wing flyovers and/or improving satellite data with UAV technology to screen for and support diffuse emissions identification and investigation.

Depending on the applicability and monitoring needs, dCarbon will also consider other monitoring quantification methods such as the Eddy Covariance Method (ECM).[18] This method utilizes gas fluxes and ambient meteorological conditions to detect and quantify leaks, although the ability to

[18] Korre, A., *et al.*, 2011. Quantification techniques for potential CO_2 leakage from geologic sites. Energy Procedia 4 (2011), pgs. 3143-3420.

detect smaller leaks may be limited.[19] Additionally, long open path tunable diode lasers could be used to measure distance averaged concentrations of CO_2 in the air, which could help quantify a leak of CO_2. This system could be paired with an array of short, closed path detectors (*e.g.*, gas chromatographs) that are typically placed around a suspected leak or leak area to monitor point-source CO_2 concentration increases and to quantify leakage. dCarbon may also evaluate other emerging technologies for quantifying CO_2 leakage such as non-dispersive infra-red (NDIR) CO_2 sensors and soil flux detectors. dCarbon may also utilize three-dimensional reservoir models that factor in faults and surface topography to predict CO_2 leakage locations, quantity, and timing. The applicability of such models in predicting and quantifying gas leaks has been tested and documented at the Leroy natural gas storage site in Wyoming, USA.[19]

As the technology and equipment to quantify CO_2 leakage is rapidly evolving and expected to improve over time, dCarbon will continue to update its leak detection and quantification plans as appropriate. If dCarbon detects a leak associated with CO_2 injection at the Barnett RDC #1 well, all methods discussed in this section will be considered in addition to emerging technologies to determine the most applicable and effective method of quantification.

[19] Chen, M., *et al.*, 2013. Analysis of fault leakage from Leroy underground natural gas storage facility, Wyoming, USA. *Hydrogeology* 21, pgs. 1429–1445. 2013.

7 – BASELINE DETERMINATIONS

This section identifies the strategies that dCarbon will undertake to establish the expected baselines for monitoring CO_2 surface leakage per § 98.448(a)(4). dCarbon will use the existing Supervisory Control and Data Acquisition (SCADA) monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. Daily inspections will be conducted by field personnel at the compressor facility and the injection well. These inspections will aid with identifying and addressing issues in a timely fashion to minimize the possibility of leakage. If any issues are identified, such as vapor clouds, ice formations, or abnormal AVO or FLIR observations, corrective actions will be taken to address such issues. As previously discussed, H_2S is present in the injection stream at a low concentration. All field personnel are required to wear personal H_2S monitors, which are set to trigger the alarm at approximately 1 ppm levels of H_2S. Any alarm would trigger an immediate response to protect personnel and verify that the equipment and monitors are working properly. If monitors are working correctly and a leak is detected, immediate actions would be taken to secure the facility.

Any leakage would be detected and managed as per Texas regulations and dCarbon's safety and operations plans. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR § 98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

Baseline groundwater quality and properties will be determined and monitored through the installation of a groundwater well near the injection well site. Samples will be taken and analyzed by a third-party laboratory to establish the baseline properties of the groundwater in the area.

Baseline seismicity in the area near the Barnett RDC #1 will be determined through the historical data from USGS and TexNet seismic array data. This information will be augmented by additional data from dCarbon's seismic monitoring array.

8 – SITE SPECIFIC CONSIDERATIONS FOR DETERMINING THE MASS OF CO_2 SEQUESTERED

This section identifies how dCarbon will calculate the mass of CO_2 injected, emitted, and sequestered. This also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, per 40 CFR § 98.448(a)(5).

8.1 Mass of CO_2 Received

Per 40 CFR § 98.443, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR §98.444(a)(4)." 40 CFR § 98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received."

The CO_2 received by dCarbon for injection into the Barnett RDC #1 injection well is wholly injected and not mixed with any other supply and the annual mass of CO_2 injected will equal the amount received. Any future streams will be metered separately before being combined into the calculated stream.

8.2 Mass of CO_2 Injected

Per 40 CFR § 98.444(b), since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

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 (metric tons per quarter)
D	=	Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682
$C_{CO2,p,u}$	=	Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (weight percent CO_2, expressed as a decimal fraction)
p	=	Quarter of the year
u	=	Flow meter

8.3 Mass of CO_2 Produced

The injection well is not part of an enhanced oil recovery project, and therefore, no CO_2 will be produced.

8.4 MASS OF CO_2 EMITTED BY SURFACE LEAKAGE

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S, which may be hazardous for field personnel to perform a direct leak survey. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR § 98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released because of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

$$CO_{2,E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

$CO_{2,E}$	=	Total annual mass emitted by surface leakage (metric tons) in the reporting year
$CO_{2,x}$	=	Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year
X	=	Leakage pathway

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

8.5 MASS OF CO_2 SEQUESTERED

The mass of CO_2 sequestered in the subsurface geologic formations will be calculated based off Equation RR-12, as this well will not actively produce any oil or natural gas or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2	=	Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the Barnett RDC #1 facility in the reporting year.
$CO_{2,I}$	=	Total annual CO_2 mass injected (metric tons) in the Barnett RDC #1 well in the reporting year.
$CO_{2,E}$	=	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 and the Barnett RDC #1 injection wellhead.

9 – ESTIMATED SCHEDULE FOR IMPLEMENTATION OF MRV PLAN

The injection well is expected to begin operation in the second half of 2023. Baseline data will be collected before injection begins and the MRV plan will be implemented upon receiving EPA approval.

10 – QUALITY ASSURANCE

10.1 CO_2 INJECTED

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer specifications.

10.2 CO_2 EMISSIONS FROM LEAKS AND VENTED EMISSIONS

- Gas detectors will be operated continuously, except for maintenance and calibration.
- Gas detectors will be calibrated according to manufacturer recommendations and API standards.
- Calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

10.3 MEASUREMENT DEVICES

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to the requirements in 40 CFR § 98.3(i).
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.
- Flow meter calibrations will be traceable to the National Institute of Standards and Technology (NIST).

All measured volumes of CO_2 will be converted to standard cubic feet at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1.0 atmosphere.

10.4 MISSING DATA

In accordance with 40 CFR § 98.445, dCarbon will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

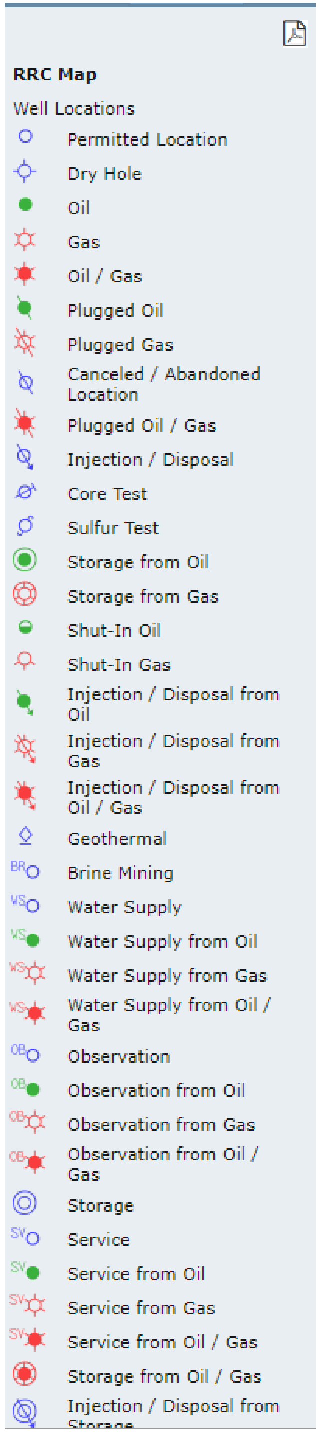
- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR § 98.

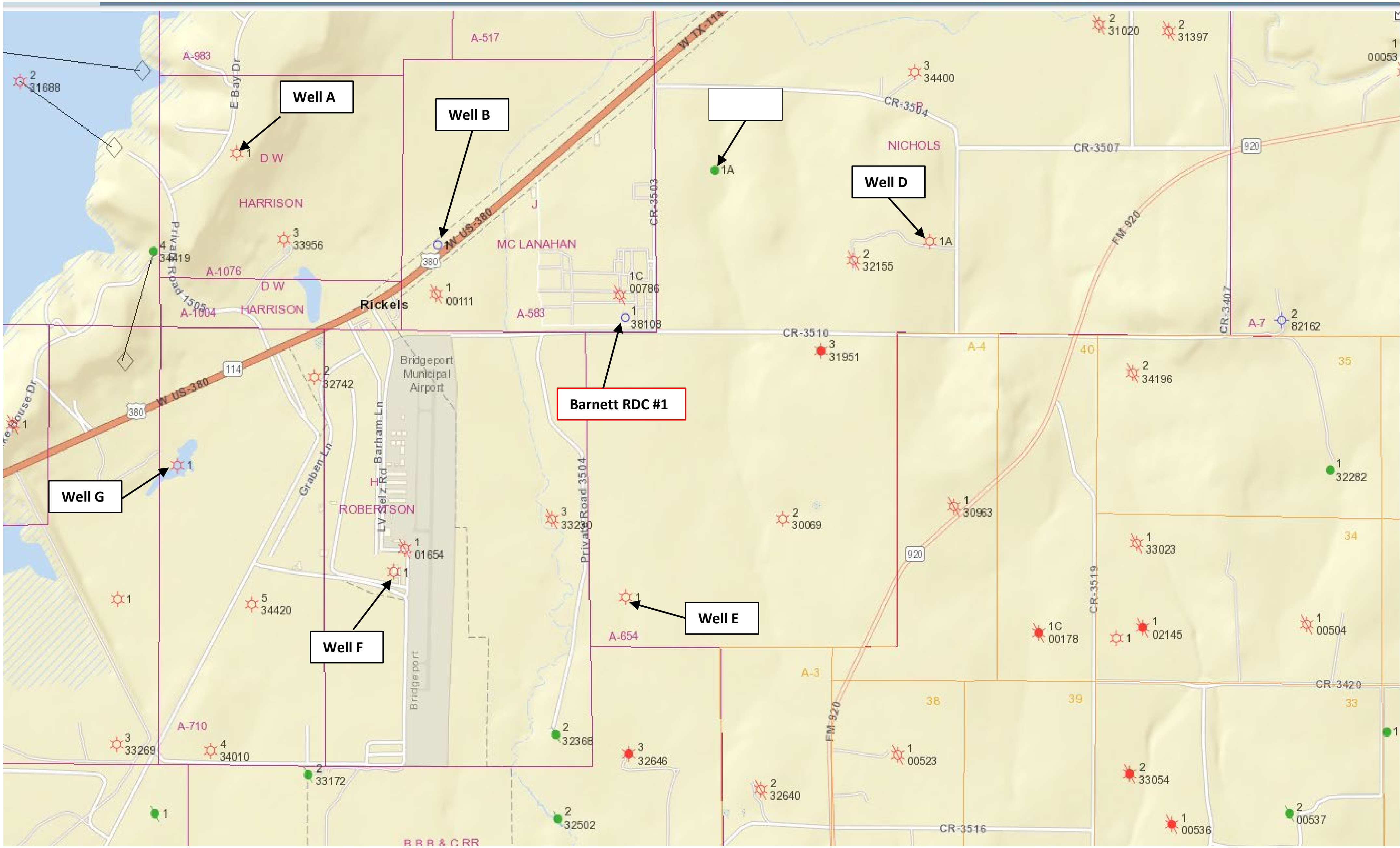
11 – RECORDS RETENTION

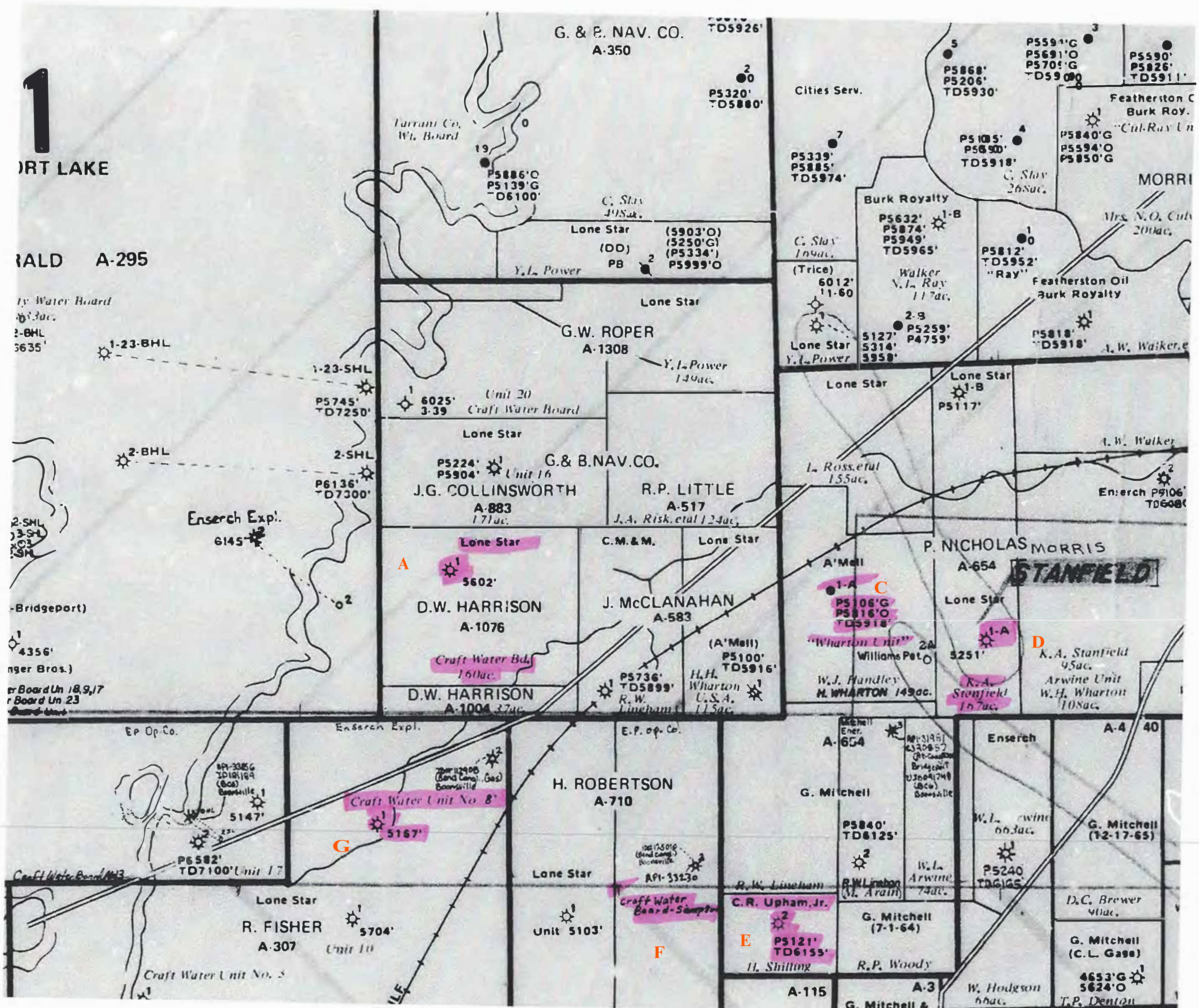
dCarbon will retain records as required by 40 CFR § 98.3(g). These records will be retained for at least three years and include:

- Quarterly records of the CO_2 injected.
- Volumetric flow at standard conditions.
- Volumetric flow at operating conditions.
- Operating temperature and pressure.
- Concentration of the CO_2 stream.
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate 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.

Attachment B: TRRC wells <u>without</u> Digital Records (From Commission Hardcopy Maps)






G. & B. NAV. CO.
A-350
Cities Serv.
Featherston C
Burk Roy.
MORRI
G.W. ROPER
A-1308
Lone Star
Unit 20
Craft Water Board
G.& B.NAV.CO.
J.G. COLLINSWORTH
A-883
R.P. LITTLE
A-517
Burk Royalty
Featherston Oil
Burk Royalty
Enserch Expl.
D.W. HARRISON
A-1076
Craft Water Bd.
D.W. HARRISON
A-1004
J. McCLANAHAN
A-583
P. NICHOLAS
A-654
MORRIS
STANFIELD
"Wharton Unit"
Williams Pet.
K.A. Stanfield
H. ROBERTSON
A-710
R. FISHER
A-307
Craft Water Unit No. 8
Craft Water Board-Sampson
C.R. Upham,Jr.
G. Mitchell
Enserch
A
B
C
D
E
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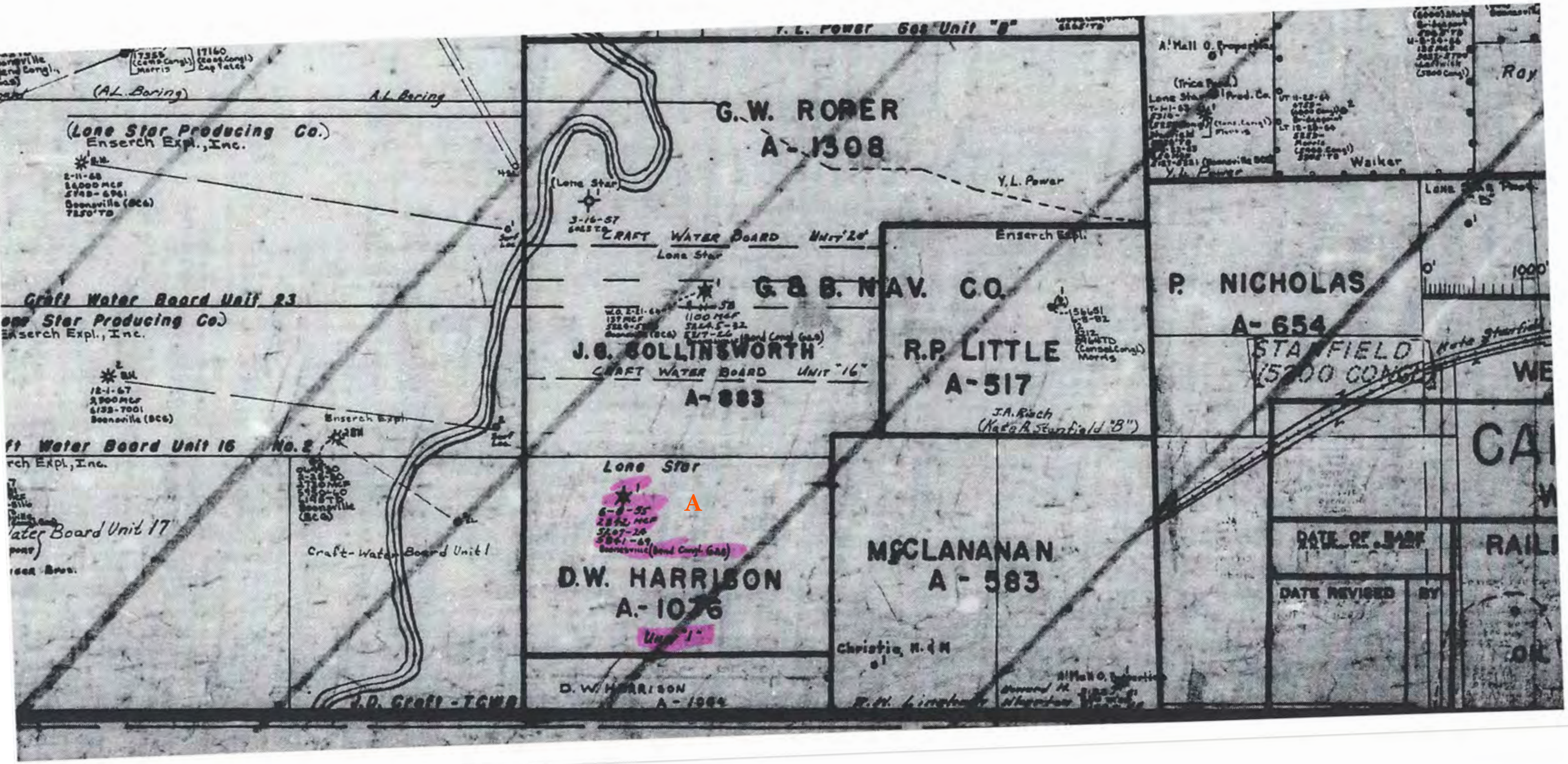
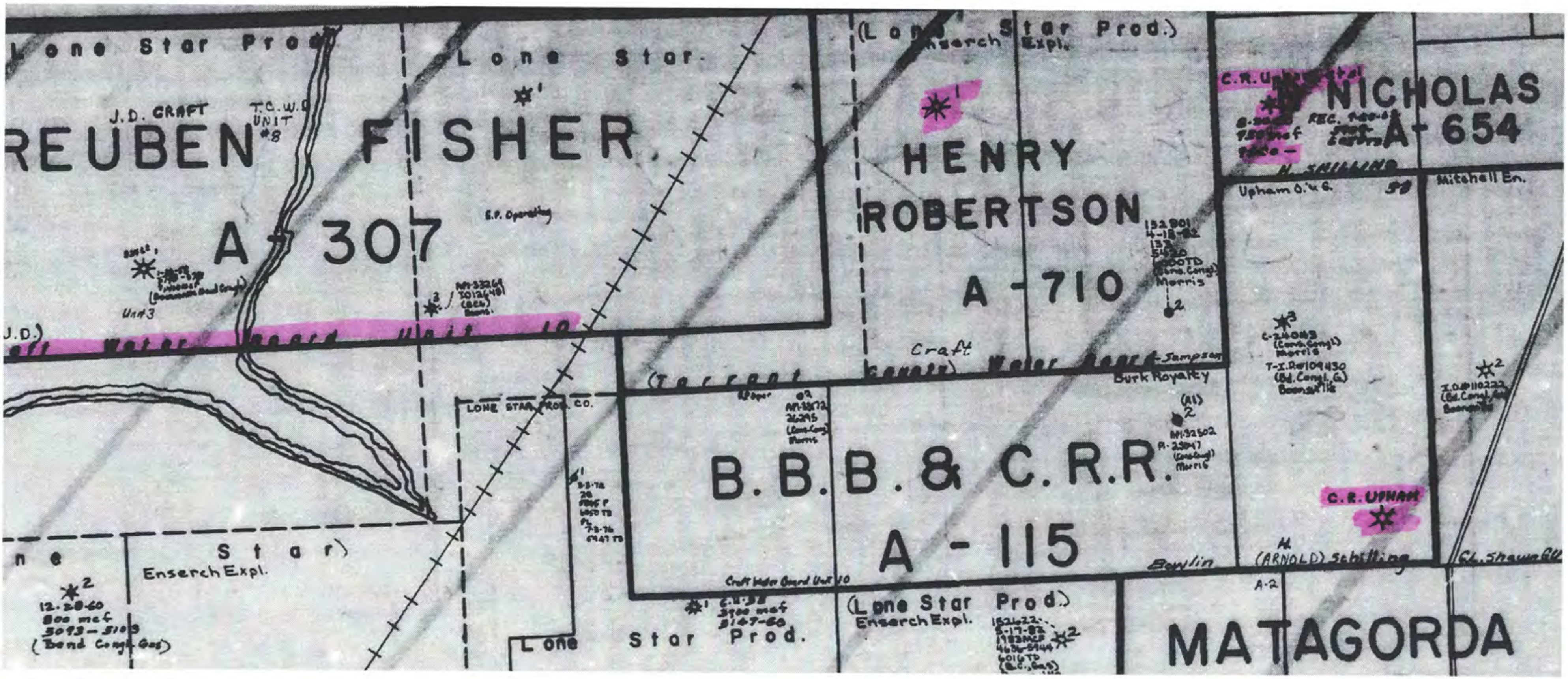
A-295
ORT LAKE
-Bridgeport)



Y. L. Power Gas Unit "B"
(A.L. Boring)
A.L. Boring
(Lone Star Producing Co.)
Enserch Expl., Inc.
G.W. ROPER
A-1308
Y. L. Power
Lone Star
3-16-57
CRAFT WATER BOARD UNIT "20"
Lone Star
G & B. NAV. CO.
J.G. COLLINSWORTH
CRAFT WATER BOARD UNIT "16"
A-883
Craft Water Board Unit 23
Lone Star Producing Co.)
Enserch Expl., Inc.
Enserch Expl.
R.P. LITTLE
A-517
J.A. Risch
(Kate R. Stanfield "B")
P. NICHOLAS
A-654
STANFIELD
(5200 CONGL)
Kate Stanfield
Craft Water Board Unit 16 No. 2
Enserch Expl., Inc.
Water Board Unit 17
Craft-Water Board Unit 1
Lone Star
6-8-55
A
D.W. HARRISON
A-1076
Unit "1"
McCLANANAN
A-583
Christie, H. & M.
D. W. HARRISON
A-1064
J.D. Craft - TCWB
A. Mall O. Properties
Walker
Roy
1000'
DATE OF BASE
DATE REVISED
BY
RAIL



Lone Star Prod.
Lone Star.
REUBEN FISHER
A-307
J.D. CRAFT
T.C.W.D UNIT #8
Unit 3
Water Board Unit 10
HENRY ROBERTSON
A-710
(Lone Star Prod.)
Enserch Expl.
Craft
(Tarrant County) Water Board
Sampson
Burk Royalty
NICHOLAS
A-654
C.R. UPHAM
Upham O. & G.
Mitchell En.
LONE STAR PROD. CO.
B.B.B. & C.R.R.
A-115
(ARNOLD) Schilling
Bowlin
CL Shawn
Star)
Enserch Expl.
12-28-60
(Bend Congl. Gas)
Craft Water Board Unit 10
(Lone Star Prod.)
Enserch Expl.
Lone Star Prod.
MATAGORDA
A-2

44447

C

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No.

Operator A'Mell Oil Properties Address 1201 Elm St., Dallas, Texas

County Wise Survey J. McClanahan Block No. A-583 Sec. No.

Lease Name H. H. Wharton Well No. 1 Elevation 795 GL (Above Sea Level)

Name of Field in which well is located Booneville Conglomerate Gas

Form 1 (Notice of Intention to Drill) Was Filed in Name of A'Mell Oil Properties

Is this a NEW WELL? Yes DEEPENING? - or a WORK-OVER? -

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

(Work-Over) (Drilling) Commenced April 27, 19 61 (Work-Over) (Drilling) Completed May 15, 19 61

Correspondence regarding this well should be sent to: Name A'Mell Oil Properties Address 1201 Elm St., Dallas, Texas

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
8-5/8"	153	77	-	-	153	77	
2-7/8"	5204	00	-	-	5204	00	

Initial Production of Gas—Volume 250 MCF 24 hrs. Pressure 500 lbs. per square inch

Initial Production of Oil: Barrels 5 of Frac per day

Initial Production of Distillate: Barrels Trace

Is this an OIL well? No , a GAS well? Yes , or a Dry HOLE?

DESCRIPTION OF PROPERTY
NORTH

WEST

EAST

SOUTH

RECEIVED
SEP 18 1961
Railroad Commission of Texas
OIL & GAS DIVISION
WICHITA FALLS, TEXAS

GENERAL REMARKS

LTR BD OF WATER EN R
DATED April 19, 1961
RECOMMENDS 150 FT.
See letter attached

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

C

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM
Shale w/sd & lm stks	0	30
Lime	30	37
Shale & Shells	37	45
Lime & Shale	45	72
Shale & Lime	72	130
Lime	130	136
Lime & Shale	136	173
Shale & Lime	173	220
Lime & Shale	220	258
Shale w/lm stks	258	328
Water Sand	328	346
Shale, sd & lm stks	346	890
Shale & lm	890	925
Shale & lm w/sdy stks	925	1067
Lime	1067	1117
Shale w/lmy stks	1117	1165
Sand & Shaley sd	1165	1196
Shale w/lm & sd stks	1196	1477
Shale	1477	1500
Shaley sd	1500	1570
Shale & sd stks	1570	1620
Hard sd	1620	1646
Shaley sd	1646	1896
Shale & sdy shale	1896	2087
Shale w/sd & lm stks	2087	2269
Shale w/sd & lm sh stks	2269	2408
Shale w/sd & lm stks	2408	2429
Shale & chalkey lm	2429	2533
Shale & lm stks	2533	2655
Lime & Shale	2655	2658
Shale w/lm stks	2658	2767
Shale & lm	2767	2804
Shale w/lm & sd stks	2804	2995
Shale & lm	2995	3020
Lmy shale & lm shells	3020	3035
Lime w/specks flo. (no odor)	3035	3052
Shale & lm	3052	3062
Shale	3062	3121
Shale & lm stks	3121	3230
Shale & lm	3230	3336
Shale w/lm stks	3336	3506
Lime	3506	3520
Shale & lm shale	3520	3658
Shale w/lm stks	3658	3840
Lime	3840	3849
Lime	3849	3861

REMARKS		
Shale & Sdy shale	3861	3964
Shale w/lm stks	3964	4020
Shale & sdy sh w/lm	4020	4299
Shale w/lm & sh stks	4299	4544
Lime (Caddo)	4544	4591
Shale & lm	4591	4645
Shale w/lm & sd stks	4645	4731
Shale & lm	4731	4848
Shale & lm shale	4848	5069
Shale	5069	5085
Shale, cong shale & conglomerate	5085	5138
Shale w/cong stks	5138	5159
Shale & lm shale	5159	5202
Shale & lm stks	5202	5220
Hard tight cong.	5220	5232
Shale & cong	5232	5240
Hard tight cong	5240	5241
Shale w/cong stks	5241	5350
Shale & Cong sh stks	5350	5400
Shale & lm shale	5400	5440
Shale & cong stks	5440	5533
Hard tight cong	5533	5540
Broken tight cong	5540	5548
Shale w/cong stks	5548	5557
Shele w/tight congstks	5557	[illegible]
Shale	5672	[illegible]
Limey shale	5733	5749
Shale w/tight cong stks	5749	5828
Shale & cong	5828	5841
Cong w/very faint flor	5841	5860
Shale w/cong stks	5860 TD	5916

Method of shutting off water No water Is water completely shut off? Yes

Amount of water with oil NONE per cent

I, A. W. Amell

being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

A W Amell

Representative of Company.

Subscribed and sworn to before me this 22nd day of June, 1961

[signature]

Notary Public

Dallas County, Texas

RECEIVED
APR 24 1961
Railroad Commission of Texas
OIL & GAS DIVISION
AUSTIN, TEXAS

44447

M

C

Application to Drill, Deepen or Plug Back.

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 1
Rev. 4/60

STATE WHETHER THIS IS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK Drill

SHALL BE FILED IN DUPLICATE ~~(IN TRIPLICATE IF RULE 37)~~ WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED
DATA FURNISHED ON THIS FORM AND ANY ATTACHMENT HERETO MUST BE CLEARLY LEGIBLE.
ANY ILLEGIBLE FORM WILL BE RETURNED WITHOUT COMMISSION ACTION.
(Black Ink or Black Typewriter Ribbon Preferable)

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, fo this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines. Also show the nearest wells on all sides of this location and the distance from the proposed location to those wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equaling 1000 feet; if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THIS PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line 467 feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease - feet.

IS THE ACREAGE ON WHICH THIS WELL IS TO BE LOCATED, PRESENTLY ASSIGNED TO ANOTHER WELL IN ANY RESERVOIR FOR WHICH THIS PERMIT IS REQUESTED? No

Date April 18, 1961

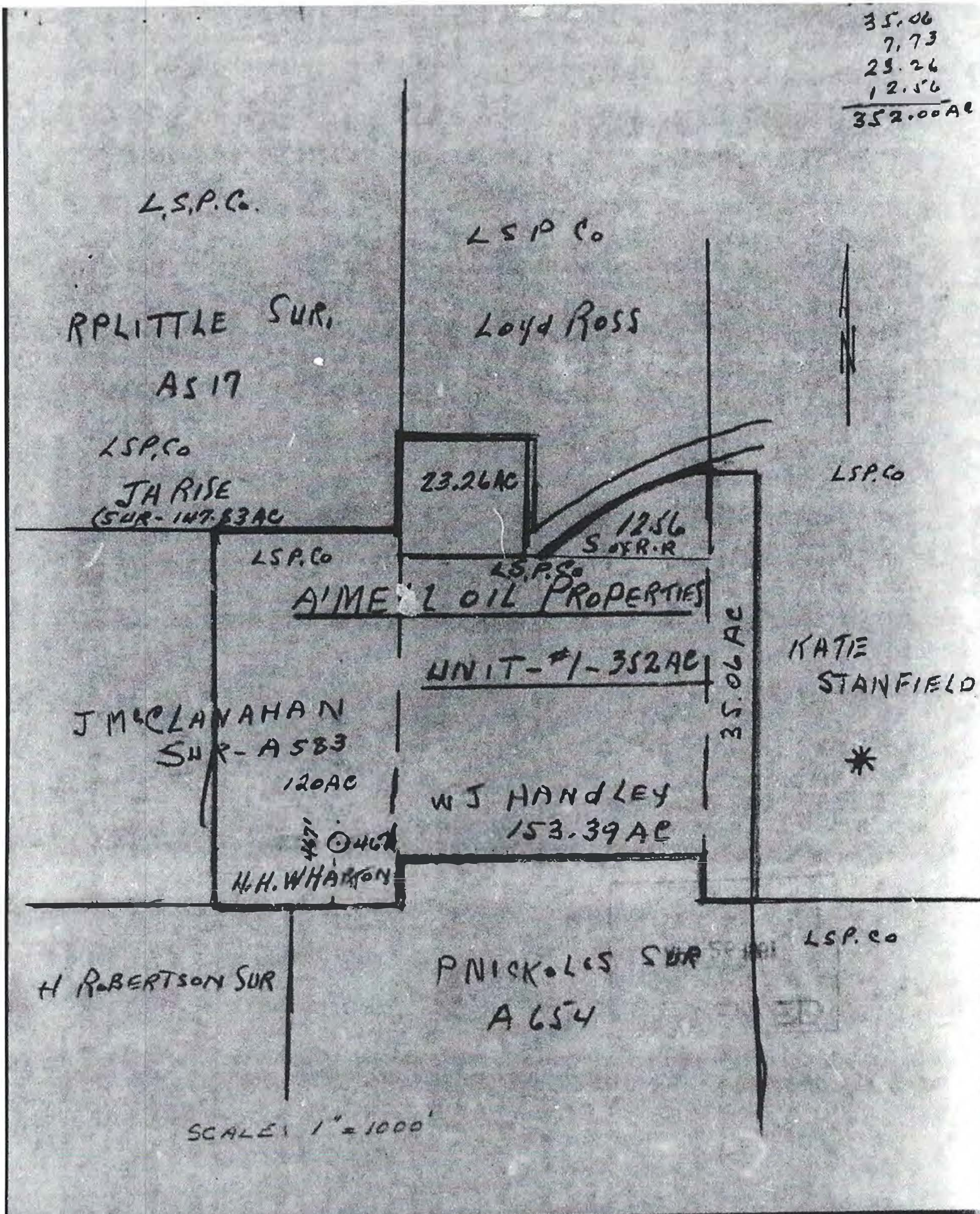
Name of company or operator
Name A'Mell Oil Properties
Address 1201 Elm Street,
City Dallas 2, Texas

Description of farm or lease:
Name of Lease Howard H. Wharton
Number of Acres 332 Well No. 1
Number of wells on lease None
Elevation ______ (Ft. above sea level) Section No. ______ Block No. ______
Survey J. McClanahan - A 583
Zone or Reservoir Conglomerate
To be Located in Boonesville(Bend Congl. Gas)
(If Wildcat state above, also state Distance and Direction from nearest Survey Lines.)
Wise County
4 Miles Northwest direction from
Bridgeport, Texas nearest post office or town.
Rotary or Cable Tools Rotary
Date work will start drilling on permit
Depth to which you propose to drill 6200 feet.
Date work will start deepening

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?
Name
Address

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE



35.06
7.73
23.26
12.56
352.00AC
L.S.P.Co.
LSP Co
RPLITTLE SUR.
AS17
Loyd Ross
LSP.Co
JA RISE
SUR-147.83AC
23.26AC
12.56
S of R.R
LSP.Co
LSP.Co
L.S.P.Co
A'ME 'L OIL PROPERTIES
UNIT-#1-352AC
35.06AC
KATIE
STANFIELD
J McCLANAHAN
SUR-A583
120AC
WJ HANdLEY
153.39AC
N.H.WHARTON
LSP.co
H RoBERTSON SUR
PNICKoLES SUR
A654
SCALE: 1"=1000'

1

9

D

D

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No. ....

Operator LONE STAR PRODUCING COMPANY Address 301 S. Harwood, Dallas, Texas

County Wise Survey Phillips-Nicholas Block No. (A-654) Sec. No. ....

Lease Name Kate Ann Stanfield "A" Well No. 1-C Elevation 810 (Above Sea Level)

Name of Field in which well is located Boonsville (Bend Conglomerate Gas)

Form 1 (Notice of Intention to Drill) Was Filed in Name of Lone Star Producing Company

Is this a NEW WELL? Yes XXXXXXXXX - - - XXXXXXXXX - - -

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

XXXXXXX (Drilling) Commenced 11-17 1959 XXXXXXX (Drilling) Completed 12-9- 1959

Correspondence regarding this well should be sent to: Name A. L. Poynor Lone Star Prod. Co. Address Box 767, Jacksboro, Tex.

Has an allowable been assigned to this well? .... No.

SIZE	PUT IN WELL Ft.	In.	PULLED OUT Ft.	In.	LEFT IN WELL Ft.	In.	PACKERS AND SHOES
9-5/8	324				324		
5½	5400				5400		HOMCO DV Tool @ 3238' packer shoe at 5394'
2-3/8	5217				5217		HOMCO Type "C" Pkr. @ 5217

Initial Production of Gas—Volume 1916 MCF 24 hrs. Pressure 200 lbs. per square inch

Initial Production of Oil: Barrels 23 bbls. (frac oil)

Initial Production of Distillate: Barrels ....

Is this an OIL well? ...., a GAS well? Yes ...., or a Dry HOLE? ....

DESCRIPTION OF PROPERTY
NORTH

See Form 1 filed Oct.1,1959

WEST

EAST

SOUTH

RECEIVED
JAN 28 1960
Railroad Commission of Texas
OIL & GAS DIVISION
WICHITA FALLS, TEXAS

GENERAL REMARKS

This well is dually completed as an oil & gas well. A HOMCO Type "C" permanent packer set @ 5217' to separate the upper zone gas & the lower zone oil. Well is completed w/1 string of 2-3/8" OD tbg. & 2-Garrett Oil Tool circulating sleeves. Lower sleeve is below Type "C" & Upper sleeve above packer.

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

D

FORMA[redacted]D

Show All Formations, Especially All [redacted]aracter and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS	
Sh W/Sd & Lm Stks.	0	110	Sh W/Lm & Sd Stks	3160
Sd & Lime		165	Shale W/Sdy Stks.	3214
Sh & Sd Stks.		222	Lime	3230
Lime		280	Shale-Lime & Sdy	3306
Sh & Sdy Sh		354	Shale-Sd Stks.	3410
Sh & Sd Stks		433	Sand - Lime	3440
Sh W/Lm & Sd		450	Shale & Sand	3487
Shale		550	Limey Sand & Shale	3505
Sh & Sd Stks		815	Sh - Lmy & sdy.	3544
Sh, Lm & Sd		950	Lime	3555
Sh & Lm		1082	Shale-Sdy-Lime Stks.	3838
Lime		1034	Shale	3875
Sand		1205	Lime	3893
Sh, Sd & Lime Stks		1340	Shale & Sandy Shale	3933
Limey Sh		1380	Limey Sand & Shale	3955
Shale		1560	Limey Sand	3975
Sh W/Sdy Lm		1580	Shale & Sand	3999
Sh - Sdy Shale		1655	Shale-Sand & Lime Stks.	4076
Sh - Sand & Lm		1700	Shale W/Sdy Stks.	4197
Sh & Sdy Sh		1798	Shale	4549
Sand -- No Shows		1835	Shale W/Lime Stks.	4601
Shale & Sd Stks		1865	Shale & Chalky Lime	4606
Lm, Sd & Sh		1929	Lime & Shale	4622
Sh, Lm & Sd		2118	Lime	4639
Sh & Sd Stks		2247	Shale & Limey Shale	4666
Sand		2259	Lime	4672
Sh W/Sand		2410	Lime & Shale	4864
Lm, Sh W/Sd Stks.		2558	Shale	4927
Lime & Shale		2600	Shale & Lime	5216
Lime		2619	Shale	5224
Sh & Sd Lm		2632	Lime	5239
Sh & Lm		2673	Shale	5246
Lime, Sh & Sand		2695	Shale & Lime	5276
Sand & Shale		2724	Congl. (Show)	5276
Shale		2765	Congl. & Lime	5294
Lim - Shale		2847	Shale-Lime & Congl. Stks.	5306
Sh W/Lm & Sd		2863	Shale & Lime	5397
Sh & Sdy Sh		2890	Lime	5422
Sh - Lm & Sd.		2932	Shale & Lime	5503
Sand & Shale		2948	Lime	5513
Sh & Sdy - Lm		3008	Shale-Lime	5518
Sh - Sdy Stks.		3030	Shale	5550
Sd & Shale		3053	Shale & Limey Shale	5598
Sand (Show)		3062	Lime & Shale	5609
Lime		3077	Limey Shale & Lime	5640
Shale		3095	Shale	5651
Sand & Shale		3130	Limy, Shale & Lime	5662

Railroad Commission of Texas
OIL & GAS DIVISION
AUSTIN, TEXAS
JAN 29 1960

Method of shutting off water Cement & Csg. Is water completely shut off? Yes

Amount of water with oil per cent

I, E. L. Smith, Jr. being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

E. L. Smith, Jr.
Representative of Company.

Subscribed and sworn to before me this 19 day of January, 1960

Lorene Stanfield
Notary Public
Jack County, Texas.

D

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Shale	5662	5668	
Sh - Lm Sh		5754	
Lime		5778	
Shale & Lime		5783	
Limey Shale & Lime		5806	
Lime		5825	
Shale & Lime		5883	
Lime-Shly. Congl.		5918	
Lime & Congl. Stks.		5930	
Lime & Limey Shale		5964	
Lime		5972	
Shale & Limey Shale		5996	
TOTAL DEPTH			

Method of shutting off water .... Is water completely shut off? ....

Amount of water with oil .... per cent ....

I, ...

being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

....

Representative of Company.

Subscribed and sworn to before me this .... day of ...., 19 ....

....

Notary Public

.... County, Texas.

52007

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No. ....

D

Operator Lone Star Producing Co. Address 301 S. Harwood St. Dallas, Texas

County Wise Survey Phillip Nicholas (A-654) Block No. .... Sec. No. ....

Lease Name Kate Ann Stanfield "A" Well No. 1-T Elevation 810 (Above Sea Level)

Name of Field in which well is located Boonsville (5085 Atoka Conglo) [redacted]

Form 1 (Notice of Intention to Drill) Was Filed in Name of Lone Star Producing Co.

Is this a NEW WELL? Yes DEEPENING? .... or a WORK-OVER? ....

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

([redacted]) (Drilling) Commenced 11-17, 1959 [redacted] (Drilling) Completed 12-9, 1959

Correspondence regarding this well should be sent to: Name Mr. A. L. Poynor Address Box 767-Jacksboro, Texas

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
9-5/8	324				324		
5½	5400				5400		HOWCO DV tool @ 3238 packer shoe @ 5394'
2-3/8"	5217				5217		HOWCO Type "C" pkr. @ 5217

Initial Production of Gas—Volume 292 MCF 24 hrs. Pressure 1100 lbs. per square inch

Initial Production of Oil: Barrels 60

Initial Production of Distillate: Barrels ....

Is this an OIL well? Yes, a GAS well? ...., or a Dry HOLE? ....

DESCRIPTION OF PROPERTY

NORTH

See Form 1 filed Oct. 1, 1959

WEST

RECEIVED
JAN 28 1960
Railroad Commission of Texas

EAST

SOUTH

GENERAL REMARKS

This well is dually completed as an oil & gas well. A HOWCO Type "C" permanent packer set @ 5217' to separate the upper zone gas & the lower zone oil. Well os completed w/1 string of 2-3/8" OD tbg. & 2-Garrett Oil Tool circulating sleeves. Lower sleeve is below Type "C" packer & upper sleeve is above packer.

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED.

52007

Please refer to File No..................

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

RECEIVED
OCT 2 1959
Railroad Commission of Texas
Oil & Gas Division
Wichita Fall, Texas

APPLICATION TO DRILL, DEEPEN OR PLUG BACK

IS THIS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK.......DRILL.........

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, to scale, of this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines. Also show the nearest wells on all sides of this location and the distance from the proposed location to these wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equalling 1000 feet; if less than 2 acres use scale of one inch equalling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THAT PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line...467...............feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease.....—....feet.

Date....October 1............. 19..59...

Name of company or operator

Name.......Lone Star Producing Company.........

Address....301 S. Harwood Street.................

City......Dallas, Texas......................

Description of farm or lease:

Name of Lease...Kate Ann Stanfield "A".........

Number of Acres..211.66......Well No....1......

Number of wells on lease..none..................

Survey Phillip Nicholas (A-654)

Elevation....810..............Feet
(Above sea level)

Section No...................Block No...............

Located in...Wildcat..........................Field

(If Wildcat state above)

.....Wise...................................County

......3.............Miles.....SW.....direction from

.....Bridgeport.........nearest postoffice or town.

Rotary or Cable Tools...Rotary...................

Date work will start drilling.....on permit........

Depth to which you propose to drill...6,000....feet.

Date work will start deepening.......................

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?

Name..

Address.......................................

OK
Dr.

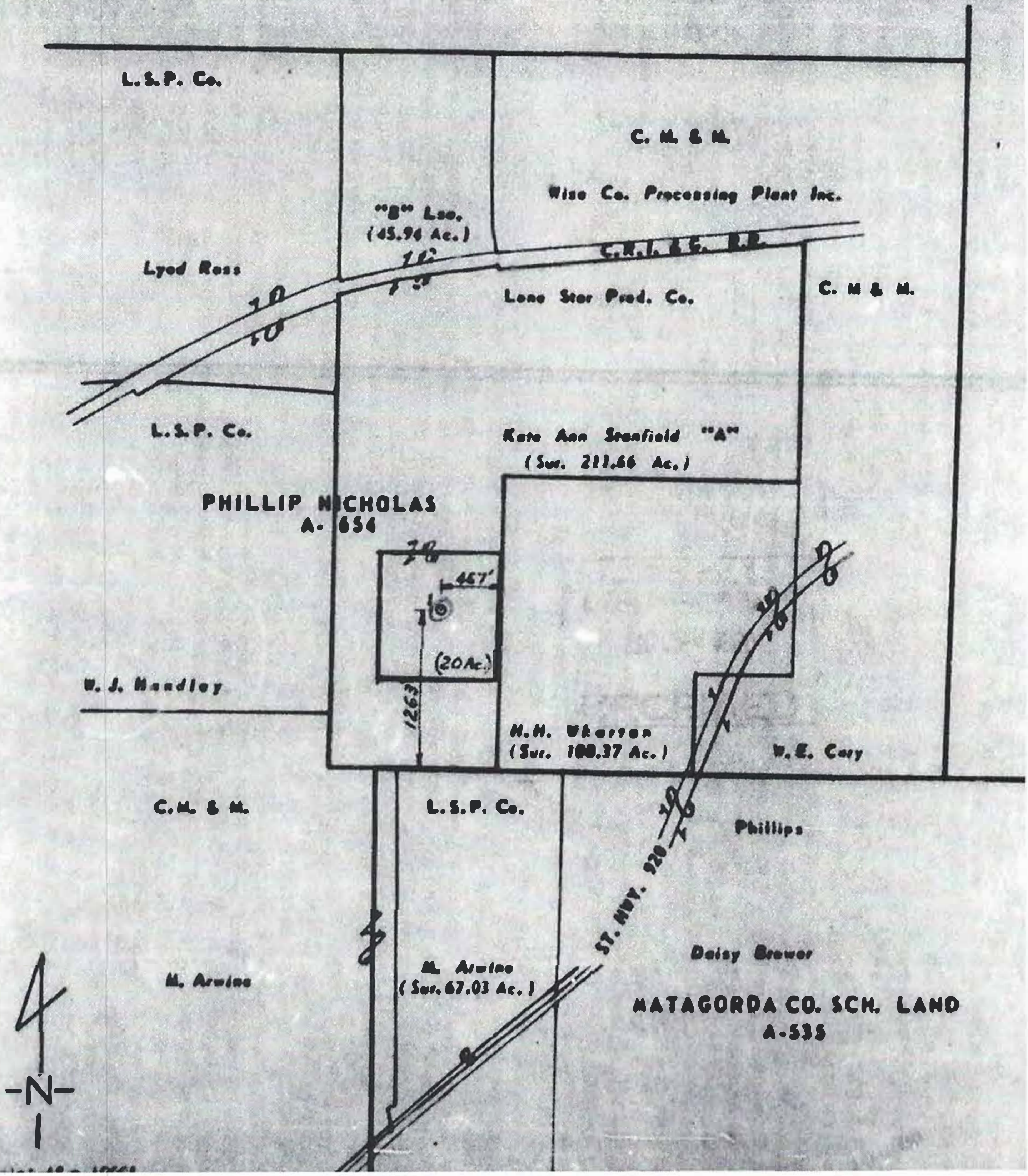
NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

Subscribed and sworn before me this the 29th day of Sept. 1959 A.D.

Notary Public, Dallas County, Texas

D



0 0 0 0 2 2 3 1 9 5 1

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

AUG 12 1971

E

Form G-1

RRC District

GAS WELL BACK PRESSURE TEST
COMPLETION OR RECOMPLETION REPORT AND LOG

RRC Identification Number: D. 51093

1. FIELD NAME: Boonsville (BCG)
2. LEASE NAME: Harold Shilling
Well Number: 2

OPERATOR: Upham Oil & Gas Company

LTR TEX W

10. County: Wise

ADDRESS: P. O. Box 940, Mineral Wells, Texas 76067

DATED 5-10-71

11. Purpose of Test: Initial Potential X; Retest; Reclass

5. If Operator has changed within last 90 Days — Give former Operator

RECOMM. NL 300

LOCATION (Section, Block, and Survey): P. Nicholas Survey A-654

12. Pipe Line Connection: Not connected

13. If Workover, give former Field (with Reservoir)

14. Completion Date: 7/30/71

List of Offset Operators Notified and Date of Notification

16. Type of Electric or other Log Run: Induct-Elec. & Sonic

Section I — GAS MEASUREMENT DATA

Date of Test: 8/2/71

Gas Measurement Method (Check One): Orifice Meter; Positive Choke; Orifice Vent Meter; Pitot Tube; Critical flow Prover X

Gas produced during test: 277 MCF

Run No.	Line Size	Orifice or Ch. ke Size	24 Hr. Coeff. Orif. or Choke	Static P_m or Choke Press.	Diff. h_w	Flow Temp. °F	Temp. Factor F_{tf}	Gravity Factor F_g	Compress. Factor F_{pv}	Volume MCF/DAY
1	2.00	1.125	28.9803	31		56	1.0039	.9258	1.004	838
2	2.00	.625	8.5694	86		60	1.0000	.9258	1.011	690
3	2.00	.625	8.5694	74		63	0.9971	.9258	1.011	591
4	2.00	.625	8.5694	62		65	0.9952	.9258	1.011	495

Section II — FIELD DATA AND PRESSURE CALCULATIONS

Gravity Dry Gas	Gravity Liquid Hydrocarbon	Gas-Liquid Hydro Ratio	Gravity of Mixture	Avg. Shut-In Temp.	Bottom Hole Temp.
.700	60 Deg. API	105,000 CF/Bbl	G_{mix} .724	103 °F	132°F @ 6155 (Depth)

$D_{eff}^{8/3}$; GL

C = 1178 ÷ $(D_{eff})^{8/3}$; GL/c

Run No.	Time of Run Min.	Choke Size	Wellhead Press. P_w PSIA	Wellhead Flow Temp. °F	P_w^2 (Thousands)	R	R^2 (Thousands)	P_f	P_w/P_f
Shut-In	72 hrs.		1325	74					
1	5 hrs.	20/64	615	80					
2	2 hrs.	16/64	725	80					
3	1 hr.	12/64	770	80					
4	1 hr.	10/64	787	80					

Run No.	F	K	S		E^{ks}	P_f and P_s	P_f^2 and P_s^2	$P_f^2 - P_s^2$
Shut-In		.1240	1.297		1.175	1557	2424	
1		.1235	1.228		1.164	716	513	1911
2		.1235	1.237		1.166	845	714	1710
3		.1235	1.243		1.167	899	808	1616
4		.1235	1.243		1.167	918	843	1581

Angle of Slope: θ = 45; n = 1.000

Absolute Open Flow: 1,060 MCF/DAY

OPEN FLOW TEST:

Shut-In Press. ____ Psig
Time Shut-In ____ Hrs.
Producing Through

In. H₂O Time	Reading	In. Hg Time	Reading	Psig

REPRESENTATIVE OF COMPANY MAKING TEST

REPRESENTATIVE OF RAILROAD COMMISSION

CERTIFICATE:

I declare under penalties prescribed in Article 6036c, R.C.S., that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete to the best of my knowledge.

REPRESENTATIVE OF COMPANY

Geologist — TITLE

8/10/71 — DATE

497 30085

E

DATA ON WELL COMPLETION AND LOG (Not Required on Retest)

Type of Completion: New Well X | Deepening | Plug Back | Other

Date Permit Issued: May 11, 1971

Name of Operator: Upham Oil & Gas Company

Number of Producing Wells on this Lease: One

Total Number of Acres in this Lease: 245.27

Commenced: June 15,1971 | Completed: July 1, 1971

Distance to Nearest Well, Same Lease & Reservoir: None

Location: 467 Feet From North Line and 934 Feet From West Line of The Harold Shilling Lease

Was Directional Survey Made: Yes X

Elevation: 833 GL & 842' RKB

Top of Pay: 5121 | Total Depth: 6155 | P.B. Depth: 5389

Recommendation of Texas Water Development Board X

Well Multiple Completion: No X

Intervals Drilled By: Rotary Tools Surf.-T.D.

Name of Drilling Contractor: Bearden Drilling Company

Is Cementing Affidavit Attached: No X

CASING RECORD (Report All Strings Set in Well)

Casing Size	Weight LB FT.	Depth Set	Hole Size	Cementing Record	Amount Pulled
8-5/8	20# & 24#	331	12-1/4"	250 sx Reg. w/2% C.C.	None
5-1/2	15.5#	5418.61	7-7/8"	175 sx Pozmix w/4% Gel.	None

LINER RECORD

Size	Top	Bottom	Sacks Cement	Screen
None				

TUBING RECORD

Size	Depth Set	Packer Set
2-3/8	5258	None

Producing Interval (this completion) Indicate Depth of Perforations or Open Hole

From	To
5121	5129
5194	5202
5211	5217
5238	5252

ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

Depth Interval	Amount and Kind of Material Used
5121-5252	1,000 gallons acid and fractured with 10,000 gallons treated salt water and 20,000 pounds of sand. (10/40)

FORMATION RECORD (LIST DEPTHS OF PRINCIPAL GEOLOGICAL MARKERS AND FORMATION TOPS)

Formations	Depth	Formations	Depth
Water Sand	1065 - 11180	Lime (Caddo)	Top 4556
"	Top 11770	Conglomerate (Atoka)	Top 5118
"	Top 1238	Lime (Marble Falls)	Top 6074
Lime	Top 2558		
"	Top 2916		
" (M-1)	Top 3840		

REMARKS

9:06:44 Tuesday, October 25, 2022

```
DISTRICT> 09        GAS WELL DATA INQUIRY - PAGE 1      SCHEDULE  > 11 / 22
FIELD    > BOONSVILLE (BEND CONGL., GAS)     # 10574 520 TYPE FIELD> CAPACITY
OPERATOR> UPHAM OIL & GAS COMPANY            # 878925   DRILL PMT >
LEASE    > SHILLING, HAROLD                             API #     > 497 30085
COUNTY   > WISE            RRCID 051043 WELL #     2     ALLOW EFF > 11/01/2022
TYPE WELL> PRODUCING                                    TOP ALLOW >
OFFSHORE>    BAYS/EST    STATE    DS>     0       0     CYCL ALLOW>
OP LACK>
OTHER  >
SCHED REM >
TOT LEASE ACRES>            COMMINGLING                     CAPABILITY          4
"@" AMOUNT> 999999999   DATE> MM/YYYY   HIGH DLY AVG> 999999999   DATE> MM/YYYY
SPEC ALLOW >         100  CODE> ADMINISTRATIVE
G-10 TEST  >  07/14/2022 TYPE >  R LAST UTIL>           G-1 TEST >    08/02/1971
DELIV      >           4  DELIV LTR EFFEC>              G-1 POTE    > NOT REQ.
DELIV CODE >              CAL DEL POTE    >             TEMPERATURE>
WH PRESS CD>              SIWH>      90   BHP CD>                BHP >       100
GAS GRAV   >   .758       COND GRAV  >  60.0            GOR        >     270
ACRES-FT   >              ACRES      >        85.2700   G1 TEST GAS>
SUPP ISSUED>  10/17/2022   SUPP REMARKS  >

GO TO RRCID <         > ENTER=PG2 PF1=HELP          PF3=DRL PMT PF4=RESTART
PF5=NEXT WELL PF6=FLD PF7=PROR SCH PF8=P4 PF9=LDGR PF10=G-10 PF11=RMKS PF12=G-1
```

E

RAILROAD COMM[illegible] TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

9 (F)

File No.

Operator Lone Star Producing Co. Address Jacksboro, Texas

County Wise Survey Henry Robertson (A-710) Block No. ... No.

Lease Name Kraft-Water Board Simpson Unit 1 Well No. 1 Elevation 835' (Above Sea Level)

Name of Field in which well is located Boonsville (Bend Congl. Gas) Field

Form 1 (Notice of Intention to Drill) Was Filed in Name of Lone Star Producing Co.

Drilling Commenced 10-5, 19 57 Drilling Completed 10-20 19 57

Is this a NEW WELL? Yes , DEEPENING? or a WORK-OVER?

Correspondence regarding this well should be sent to: Name Lone Star Producing Co. Address Box 1047- Jacksboro, Texas

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
9-5/8"	315'	0.4					HOWCO guide shoe
5½"	5621						HOWCO guide shoe

Initial Production of Gas—Volume 3,120 MCF 24 hrs. Pressure TBG-500# Sep- 200# lbs. per square inch

Initial Production of Oil: Barrels 30 bbls. frac oil 3hr.

Initial Production of Distillate: Barrels

Is this an OIL well? , a GAS well? Yes , or a Dry HOLE?

DESCRIPTION OF PROPERTY

NORTH

See Form 1 filed August 20, 1957

WEST

EAST

SOUTH

RECEIVED
FEB 13 1958
Railroad Commission of Texas
Oil & Gas Division
Wichita Falls, Texas

GENERAL REMARKS

9-5/8" csg. cemented w/250 sks

5½" csg. cemented w/201 sks

Perforated 5103-5110, 5112-5120 (Schl)

w/4 dyno jets per foot. (60 holes)

Acidized w/500 gal MCA

Fractured w/10,000 gal oil and

10,000# sand.

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

R

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Shale & lime	0	100	
Sand & shale	100	150	
Sh w/lm stks	150	290	
sh & sd stks.	290	360	
sh w/lm & sh stks.	360	646	
sh w/lm & sd stks.	646	1322	
sh w/sd stks.	1322	1550	
sh w/sdy lm stks.	1550	2370	
shale	2370	2536	
sh w/sdy lm stks.	2536	2638	
Lime	2638	2659	
sh w/sd & lm stks.	2659	3495	
sh w/lime shells	3495	3571	
sh w/lime stks.	3571	4000	
sh & sand	4000	4015	No jeep - no odor
sh w/ sd & lm stks.	4015	4550	
Lime	4550	4560	
Lime	4560	4575	Jeep & odor
Lime & shale	4575	4594	
sh & lime congl	4594	4610	
sh & lime stks.	4610	4967	
sh lm & congl	4967	4981	
sh , lm & congl	4981	5100	
sh lm & congl	5100	5174	
Sd & congl stks.	5174	5198	
shaley congl	5198	5207	
sh & congl	5207	5230	Jeep & odor
sh w/lime stks.	5230	5683	
sh & congl stks.	5683	5711	
sh & lime stks.	5711	5790	
sh & sdy congl	5790	5823	
Lime congl	5823	5862	
sh sd & shy congl	5862	5942	
sh & congl stks.	5942	6027	

RECEIVED FEB 17 1958 OIL & GAS DIVISION AUSTIN, TEXAS

RECEIVED APR 22 1958

Method of shutting off water .... Is water completely shut off? ....

Amount of water with oil ....

I, T. R. Pledger being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

T. R. Pledger
Representative of Company.

Subscribed and sworn to before me this 10th day of February, 1958

Larene Stanfield
Notary Public
Jack County, Texas.

9:27:27 Tuesday, October 25, 2022

*** OIL AND GAS DIVISION *** INQUIRY
PLUGGING DATA

TYPE/WELL(O/G/D/S): G API NUMBER: 497 016 54
DIST: 09 LEASE/ID: 132120 WELL #: 1
FIELD NAME: BOONSVILLE (CADDO LIME)
LEASE NAME: CRAFT WATER BOARD SAMPSON
OPER NAME: ENSERCH EXPLORATION, INC
DRILL PERM ISSUED: 07 / 21 / 1989 PERMIT #: 36 291 SFPC:
DRILL COMPLETED: 04 / 09 / 1989 WELL PLUGGED: 09 / 27 / 1996
DATE W-3 FILED: 02 / 10 / 1997 TOTAL DEPTH: 6 02
DIST W3 APPR DATE: MM / DD / YYYY
WAS THIS A MULTIPLE COMPLETION? N WELL WAS CONVERTED TO FRESH WATER USE? N

F

	PLUG 1	PLUG 2	PLUG 3	PLUG 4	PLUG 5	PLUG 6	PLUG 7	PLUG 8
BOTT DEP:	5120	456 8	598	385	13			
SACK CEM:	25	25	25	6 0	5			
CALC TOP:	4900	4348	498	265	3			
TOP/PLUG:	0	0	0	0	0			
TYPE CEM:	C	C	C	C	C			

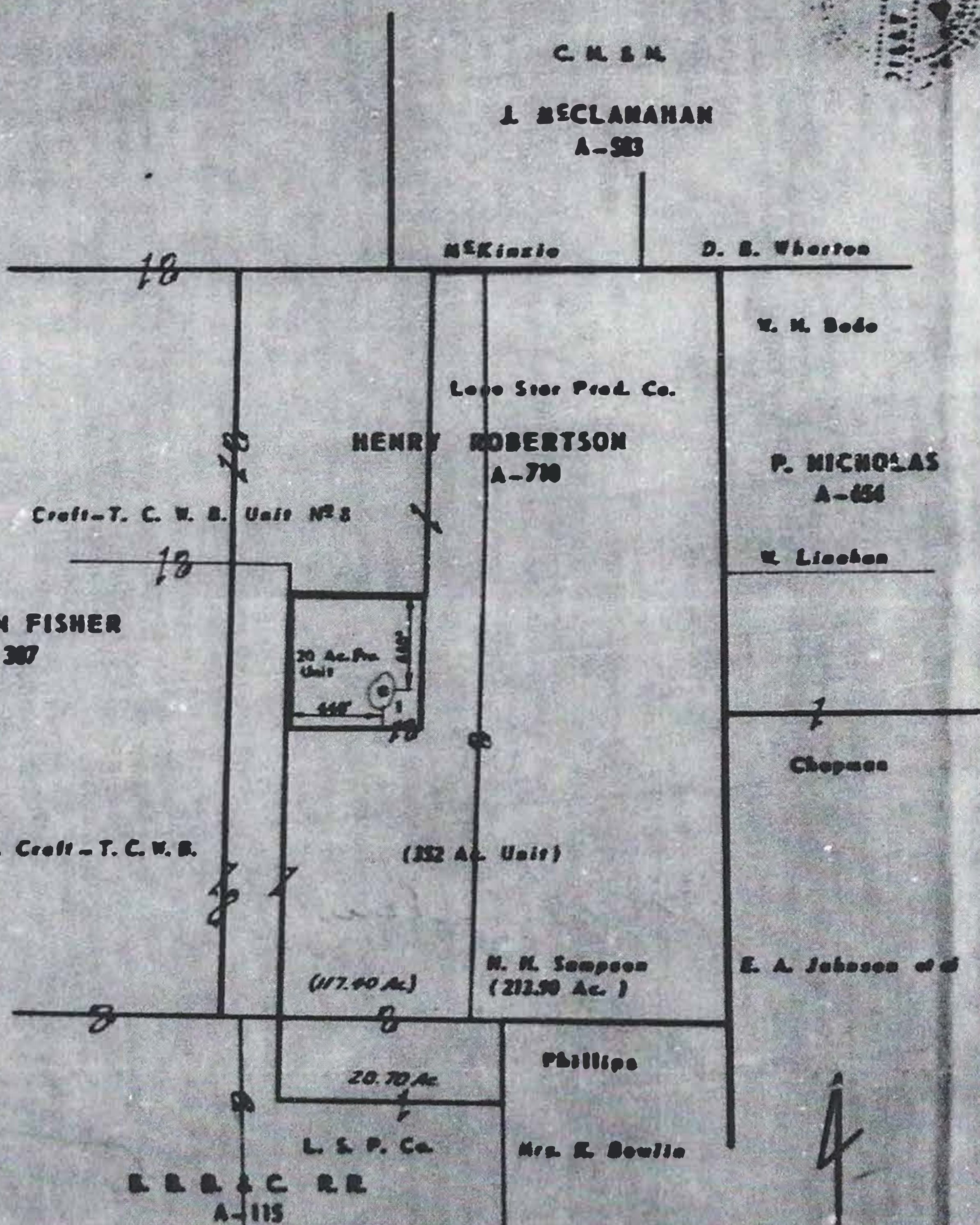
*
* SCREEN OPTIONS: 17=PLUG CAS/TUB/PERFS, 18=WATER/LOGS/REMARKS *
* SELECT OPTION: __ (01=RETURN TO MENU, 00=HELP AND OTHER OPTIONS) *
DEPRESS ENTER TO SEE PLUG CASING/TUBING/PERFS

I, BILLY M. SASSE, being duly sworn on oath, state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

Billy M. Sasse
Registered Public Surveyer

Subscribed and sworn before me this the 13th day of August 1957 A. D.

Geraldyne Knox
Notary Public, [illegible] County, Texas



G

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No. ____________

Operator: Lone Star Producing Co. Address: 301 S. Harwood St.- Dallas, Texas

County: Wise Survey: Nelson Fisher (A-307) Block No. ______ Sec. No. ______

Lease Name: Craft-Wtr. Bd Unit 30 Well No. 1 Elevation: [illegible] (Above Sea Level)

Name of Field in which well is located: Boonsville (Bend Congl. Gas)

Form 1 (Notice of Intention to Drill) Was Filed in Name of: Lone Star Prod. Co.- Craft-Wtr. Bd Unit 30 #1

Drilling Commenced 11-17, 19 57 Drilling Completed 12-11, 19 57

Is this a NEW WELL? Yes, DEEPENING? ______ or a WORK-OVER? ______

Correspondence regarding this well should be sent to: Name Lone Star Prod. Co. Address Box 767-Jacksboro, Tex.

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
9-5/8" OD	332				332		1-HOWCO guide shoe
7" OD	5860				5860		1-Baker guide shoe & 1 Baker Auto Flex flow collar
2-3/8" OD	5774				5774		1-Guiberson KV-30 w/holddown

Initial Production of Gas—Volume 4,475 MCF 24 hrs. Pressure 583 lbs. per square inch

Initial Production of Oil: Barrels ______

Initial Production of Distillate: Barrels 38.2

Is this an OIL well? No, a GAS well? Yes, or a Dry HOLE? No

DESCRIPTION OF PROPERTY
NORTH

See form 1 filed October 30th, 1957

WEST

EAST

SOUTH

GENERAL REMARKS

None

RECEIVED
MAR 26 1958
Railroad Commission of Texas
Oil & Gas Division
Wichita Falls, Texas

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS		
sh w/lime stks	0	617	sh & hrd sdy lm stks	4600	4624
Sh, sd & lm stks.	617	765	shale	4624	4633
sh & lime	765	821	sd (jcep & light odor)	4633	4646
sd & sh	821	851	sh & lm stks	4646	4695
sh & sd & lm stks	851	1065	sh w/sd & lime	4695	4836
lime	1065	1072	sh & lm stks	4836	4966
sh & lime	1072	1119	shale	4966	5038
sh & sd	1119	1142	cong. w/nice jcep & odor	5038	5071
sh & lm stks	1142	1184	sh & congl stks	5071	5084
sd & sh	1184	1212	shale	5084	5098
sh w/sd & lime	1212	1900	hd sd & lime	5098	5107
lm & shale	1900	1936	sh & lm stks	5107	5144
shale	1936	2032	sh & congl	5144	5148
sh w/sd & lime	2032	2070	congl (needer - jcep)	5148	5155
lime	2070	2082	sh & congl stks	5155	5265
sh w/sd & lm stks	2082	2350	sh & lm stks	5265	5290
sh & lime	2350	2436	sh & congl	5290	5293
shale	2436	2509	congl (no show)	5293	5303
lime	2509	2530	sh w/congl stks	5303	5425
sh & lime	2530	2613	sh & lm stks	5425	5504
lime & sd	2613	2664	sh & congl	5504	5604
sd & lime	2664	2676	sh & cong	5604	5697
sh-sd- lime	2676	2701	congl (no show)	5697	5728
sh & sd	2701	2765	sh & congl stks.	5728	5923
sh & lime	2765	2820	sh & lime	5923	5934
sd & sh	2820	2882	sh & sdy lime cherty	5934	5958
sh & lm stks	2882	2933	sh & lime	5958	5965
lime	2933	2943	T.D.		
sh & lime	2943	2972			
lime	2972	2984			
sh & lime	2984	3004			
lime & sd	3004	3016			
shale	3016	3144			
sh w/sd & lime	3144	3199			
sh & sd	3199	3327			
shale	3327	3340			
sdy shale	3340	3356			
sh & sd, & lime stks	3356	3361			
sh & lime stks	3361	3497			
lime	3497	3505			
sh & lm stks	3505	3680			
sh & sd stks	3680	3783			
shale	3783	3844			
sh & sd	3844	4000			
shale	4000	4503			
lime (no show or odor)	4503	4567			
sh & lime	4567	4600			

Method of shutting off water 268 sks cement Is water completely shut off? Yes

Amount of water with oil None per cent

I, L.J. Helms being first duly sworn on oath state that I have knowledge of the facts and matters herein stated and that the same are true and correct.

L.J. Helms

Representative of Company.

Subscribed and sworn to before me this 23rd day of March 1959

Notary Public
Jack County, Texas

52007

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No.

Operator Lone Star Producing Co. Address 301 S. Harwood St.-Dallas, Texas

County Wise Survey Reben Fisher A-307 Block No. Sec. No.

Lease Name Craft-Water Board Unit 10 Well No. 1 Elevation 834 (Above Sea Level)

Name of Field in which well is located Boonsville (Bend Congl. Gas)

Form 1 (Notice of Intention to Drill) Was Filed in Name of Lone Star Producing Co.

Is this a NEW WELL? DEEPENING? or a WORK-OVER? Yes

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

(Work-Over) Commenced 10-8 19 60 (Work-Over) Completed 10-24 19 60

Correspondence regarding this well should be sent to: Name Mr. A.L. Poyner Address Box 767-Jacksboro, Texas

Has an allowable been assigned to this well?... Yes

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
9-5/8"	332				332		1-HOWCO guide shoe
7"	5860				5860		1-Baker guide shoe & 1-Baker Auto Flux Flow Collar
2-3/8"	5705				5705		Culberson KVT-30

Initial Production of Gas—Volume 1,734 MCF 24 hrs. Pressure 640 lbs. per square inch

Initial Production of Oil: Barrels 19.35 (Frac Oil)

Initial Production of Distillate: Barrels

Is this an OIL well? , a GAS well? Yes , or a Dry HOLE?

DESCRIPTION OF PROPERTY

NORTH

WEST

EAST

See Form 1 filed Oct. 30, 1957

SOUTH

GENERAL REMARKS

RECEIVED
[illegible]
NOV 28 1960
OIL & GAS DIVISION

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

G

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS		
shw/lm stks	0	617	sh & hd sdy lm stks.	4600	4624
sh,sd & lm stks	617	765	shale	4624	4633
sh & lime	765	821	sd(jeep & lgt odor)	4633	4646
sd & sh	821	851	sh & lm stks	4646	4695
sh & sd lm stks	851	1065	sh w/sd & lm	4695	4836
lime	1065	1072	sh & lm stks	4836	4966
sh & lm	1072	1110	shale	4966	5038
sh & sd	1110	1142	congl.w/nice jeep & odor	5038	5071
sh & lm stks	1142	1184	sh & congl stsk	5071	5084
sd & sh	1184	1212	shale	5084	5098
sh w/sd & lime	1212	1900	hd sd & lime	5098	5107
lm & sh	1900	1936	sh & lm stks	5107	5144
sh	1936	2032	sh & congl.	5144	5148
sh w/sd & lm	2032	2070	congl(no odor -jeep)	5148	5155
lime	2070	2082	sh& congl stks	5155	5265
sh w/sd & lm stks	2082	2350	sh & lm stks	5265	5290
sh & lime	2350	2416	sh & congl.	5290	5293
shale	2416	2509	congl(no show)	5293	5303
lime	2509	2530	sh w/congl stks	5303	5425
sh & lime	2530	2613	sh & lm stks	5425	5504
lm & sd	2613	2664	sh & congl	5504	5684
sh & lime	2664	2676	sh & congl	[illegible]	[illegible]
sh-sd lime	2675	2701	congl (no show)	[illegible]	5728
sh & sd	2701	2765	sh & congl(Stks)	5728	5923
sh & lime	2765	2820	sh & lime	5923	5934
sd & sh	2820	2882	sh & sdy lm cherty	5934	5958
sh & lm stks	2882	2933	sh & lm	5958	5965
lime	2933	2943	T.D.		
sh & lm	2943	2972			
lime	2972	2984			
sh & lm	2984	3004			
lm & sd	3004	3046			
sh	3046	3144			
sh w/sd & lm	3144	3199			
sh & sd	3199	3327			
shale	3327	3340			
sdy sh	3340	3356			
sh & sd, & lm stks	3356	3461			
sh & lm stks	3461	3497			
lime	3497	3505			
sh & lm stks	3505	3689			
sh & sd stks	3689	3783			
shale	3783	3944			
sh & sd	3944	4000			
shale	4000	4503			
lm ([illegible]	4503	4547			
sh & lm	4547	4600			

Method of shutting off water Cement & casing Is water completely shut off? Yes

Amount of water ~~with oil~~ None per cent

I, E. L. Smith, Jr. being [illegible] that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

E. L. Smith, Jr.
Representative of Company.

Subscribed and sworn to before me this 25th day of November, 1960

Lorene Stanfield
Notary Public
Jack County, Texas.

52007

Please refer to File No..............

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 1

M

RECEIVED
NOV 6 1957
Railroad Commission of Texas
Oil and Gas Division
Wichita Fall, Texas

APPLICATION TO DRILL, DEEPEN OR PLUG BACK

IS THIS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK....Drill........?

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, of this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines. Also show the nearest wells on all sides of of this location and the distance from the proposed location to those wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equaling 1000 feet; if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THIS PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line.....800............feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease.....—...feet.

Date...October 30,..........., 19..57...

Name of company or operator

Name....Lone Star Producing Company..........

Address.301 South Harwood Street..............

City....Dallas, Texas..........................

Description of farm or lease:

Name of Lease.Craft-Water Board Unit No. 10..

Number of Acres..352..........Well No.....1.......

Number of wells on lease.......None.............

Survey.Ruben Fisher (A-307)

Elevation......834..............Feet (ABOVE SEA LEVEL)

Section No...................Block No.............

Located in.........Wildcat.................Field

(If Wildcat state above)

...........Wise.........................County

..7-1/2............Miles....N.....direction from

...Boonsville........nearest postoffice or town.

Rotary or Cable Tools.........rotary............

Date work will start drilling...on permit........

Depth to which you propose to drill..6,000...feet.

Date work will start deepening.....................

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?

Name...

Address..

833-933 20 ac.

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

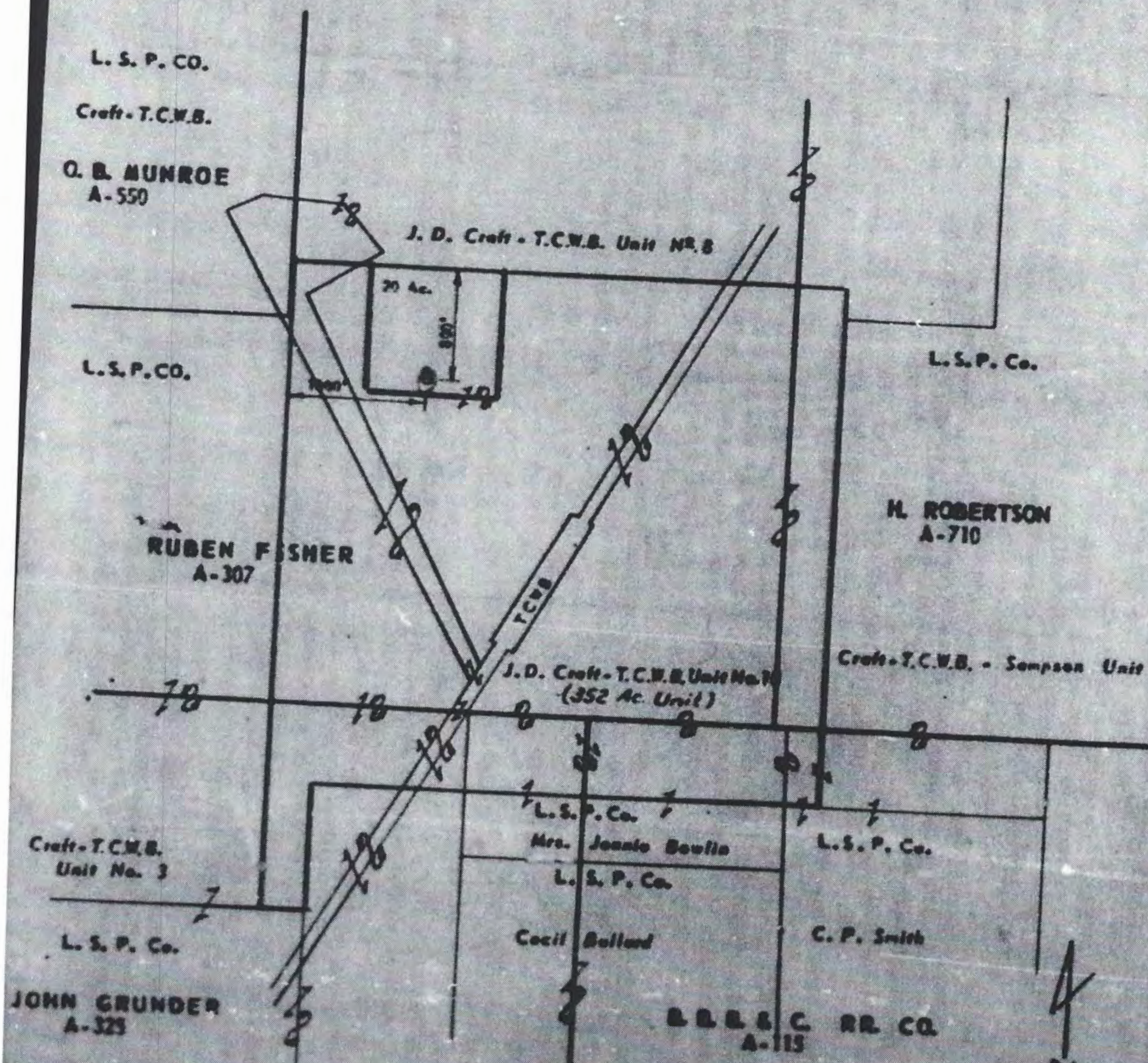
DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

NOV 13 1957

Billy M. [illegible]
Registered Public Surveyor

Subscribed and sworn before me this the 28th day of Oct. 1957 A. D.

Geraldine Knox
Notary Public, Dallas County, Texas



RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 17090

BKV BARNETT, LLC
1209 CR 1304
BRIDGEPORT, TX 76426

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated July 06, 2022, for the permitted interval(s) of the ELLENBURGER formation(s) and subject to the following terms and special conditions:

BARNETT RDC (00000) LEASE
NEWARK, EAST (BARNETT SHALE) FIELD
WISE COUNTY, DISTRICT 09

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
1	49700000	000125478	Carbon Dioxide (CO_2)	9,350	10,250		14,500		4,500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	49700000	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.** **2. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.** **3. Cement Bond Log (CBL):** **(A) A CBL must be run on the injection string casing. If the CBL does not verify adequate confinement of the injection/disposal interval, the operator must perform a remedial cement squeeze on the casing to achieve adequate confinement immediately above this interval. Adequate confinement is considered to be: annular height of 600 feet of cement based on cement volume calculations; or 250 feet of cement verified by a temperature survey conducted at the time of cementing; or 100 feet of cement verified by a cement bond log that shows the cement is well bonded to the pipe and formation (80% bond or higher) with no indication of channeling.** **(B) The operator must notify and receive approval from the RRC district office prior to performing any remedial cementing work. All cementing work must be appropriately reported on a completion report pursuant to Statewide Rule 16(b). Any CBL run on the well must be submitted. Please use the RRC Digital Well Log submission system to submit the CBL. A copy of any Forms W-15 must also be included with the next Form H-5 for this well.** **4. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.** **5. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.** **6. The operator must notify the Injection-Storage Permits Unit (UIC) and District Office of any event that may have jeopardized the mechanical and/or hydraulic integrity of any segment of the processing, injection, or storage components of the permitted facility.** **7. NOTE: Per operator email dated on July 05, 2022, the CO2 will be from the Bridgeport Processing Plant operated by Enlink Midstream.** **8. An annual annulus pressure test must be performed, and the test results submitted in accordance with the instructions of Form H-5.** **9. The tubing-casing annulus pressure must be monitored at least weekly and reported annually on Form H-10 to the Commission's Austin Offices.**

Note: This document will only be distributed electronically.

		10. Bottomhole Pressure (BHP) Test: 5 Year Lifetime **(A) Operator shall perform an initial static BHP test to quantify reservoir pressure prior to injection into the permitted formation(s).** **(B) Operator shall conduct a BHP test at least once every five (5) years from the date of the test in (A) above and provide the Commission an opportunity to witness the test as stated in (D) below. The analysis of the BHP test shall be provided under the supervision, seal, and signature of a registered professional engineer in Texas. The test analysis shall be filed with the Injection-Storage Permits Unit (UIC) within 30 days of completion of the BHP test.** **(C) Measurement for the BHP test shall be performed via wireline tool(s), or other Commission approved bottom hole pressure measurement technique.** **(D) Operator must notify the District Office 48 hours in advance of the test in order to provide opportunity for the RRC field inspector to witness the test. Operator shall provide raw data from the test to UIC within 48 hours of completing the test.** **11. NOTE: Per operator email dated on July 05, 2022, the CO2 will be from the Bridgeport Processing Plant operated by Enlink Midstream.** **12. 8/26/2022 4. Fluid migration and pressure monitoring report:** **The operator must submit a report of monitoring data, including but not limited to pressure and temperature data, used to determine fluid migration from the disposal well and pressure increases in the reservoir. The report must include, at a minimum, all monitoring data recorded since the last report (or since data recording began for the first report) through the date 30 days before the MIT is due and a summary analysis of the data. The summary analysis must include data trends and anomalies and any likely explanation for those trends or anomalies, for example, any significant operational events. The operator must submit the report with the Mechanical Integrity Test (MIT) filing to the Disposal/Injection Well Pressure Test (H-5) online system.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer.
   b. beginning any work over or remedial operation.
   c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500

Note: This document will only be distributed electronically.

psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON September 08, 2022.

Scott Rosenquist

(for)

Sean Avitt, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

Request for Additional Information: Barnett RDC Well No. 1
April 28, 2023

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	NA	NA	The MRV plan refers to both “dCarbon” and “BKV” throughout the text. Are these the same entity? If so, we recommend referring to one of these consistently throughout the MRV plan.	Corrected and clarified.
2.	NA	NA	In the previous RFAI, we recommended ensuring that references and footnotes are used consistently throughout the MRV plan. While improvements have been made in this submission, we recommend checking the MRV plan once more for inconsistencies in the referencing system. For example: • The footnote references are in different citation styles. • Sometimes both in-text citations and footnote references are used in conjunction. • Footnote numbers are inconsistently located before or after the punctuation. • (Horne *et al.* 2021) on page 12 compared with the use of footnotes on page 12.	We have attempted to correct all instances of inconsistent references and formatting. Please let us know if there is a preferred format or if any particular references are unclear.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	NA	NA	We recommend checking the MRV plan once more for consistency with hyphens, bolding, quotations marks, capitalization, and spacing throughout the MRV plan. Examples include but are not limited to: CO2 vs CO_2 Paragraph spacing on page 19 Table vs. **Table** **Figure** vs. Figure Ellenburger "E" vs. Ellenburger subunit E Furthermore, we recommend doing an additional review of the entire plan for spelling, grammar, etc. Please also review important figures to ensure the text is large enough to be legible.	We have gone through extensive additional review on this item. Please let us know where any errors remain, if any, so that we can address in a timely fashion.
4.	NA	NA	The MRV plan includes location information and identifying numbers for the Bridgeport Gas Processing Facility, which is the source of CO2 for injection. However, such information is not included for the subpart RR sequestration facility to which this MRV plan applies (Barnett RDC Well No. 1). Please clarify which of this information applies to the sequestration facility and at a minimum include the GHGRP ID number for that facility, which is different from the ID number for the Bridgeport facility.	We have added the number and clarified on pages 1 and 3.
5.	3.3	12-17	Section 3.3 in the MRV plan explains that the Ellenburger subunit F is the lower confining unit. However, section 5.5 states: "Ellenburger subunit F also serves as a secondary lower confining layer." Please ensure that the MRV plan is consistent with the confining units.	We have addressed this lack of clarity and consistency.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
6.	5	37-43	In the MRV plan, please ensure that each leakage pathway identified in section 5 has a characterization of likelihood, timing, and magnitude for potential leakage (not just a description the facility's construction and how leakage would be monitored/detected). For example, which of the leakage pathways would have the highest likelihood for leakage, and what would be the anticipated magnitude and timing of such leakage? Which pathways would have the lowest likelihood of leakage?	Discussion and quantification of likelihood, timing, and magnitude has been added in
7.	5.6	42	"dCarbon Ventures can perform Fault Slip Potential (FSP) analysis to evaluate the risk of induced seismicity on the closest mapped faults and determined that the risk of induced seismicity in minimal." The above sentence is unclear on what is planned to be performed vs. what might be considered in the future. Please clarify.	Sentence has been clarified.

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan

Barnett RDC #1

Wise County, Texas

Prepared by

BKV dCarbon Ventures, LLC

Version 3.0

March 22, 2023

Table of Contents

Section 1 – Introduction

BKV dCarbon Ventures, LLC ("dCarbon") is currently authorized to inject a total of up to 14.5 million standard cubic feet per day (MMscfd), which is equivalent to approximately 280,000 metric tons per year (MT/yr), of Carbon Dioxide (CO_2) in the Barnett RDC #1 well by the Texas Railroad Commission (TRRC). The permit allows injection into the Ellenburger formation at a depth of 9,350 feet to 10,250 feet with a maximum allowable surface pressure of 4,500 pounds per square inch gauge (psig).

The well site is located approximately 4.6 miles southwest of Bridgeport, TX in Wise County (**Figure 1**).

The Barnett RDC #1 has approved W-14 injection and W-1 drilling permits with the TRRC (Permit No 17090, UIC Number 000125478, API# 42-497-38108). Additionally, dCarbon plans to drill the well in the first half of 2023, complete the well in mid-2023 and begin injection operations in late 2023. A copy of the approved W-1 and W-14 are included as Attachment A. Although, dCarbon currently plans to initially inject approximately 180,000 MT/yr CO_2 into the well, all calculations in this document have been performed with the maximum injection amount allowed on the TRRC permit (280,000 MT/yr). dCarbon plans to inject for approximately 12 years.

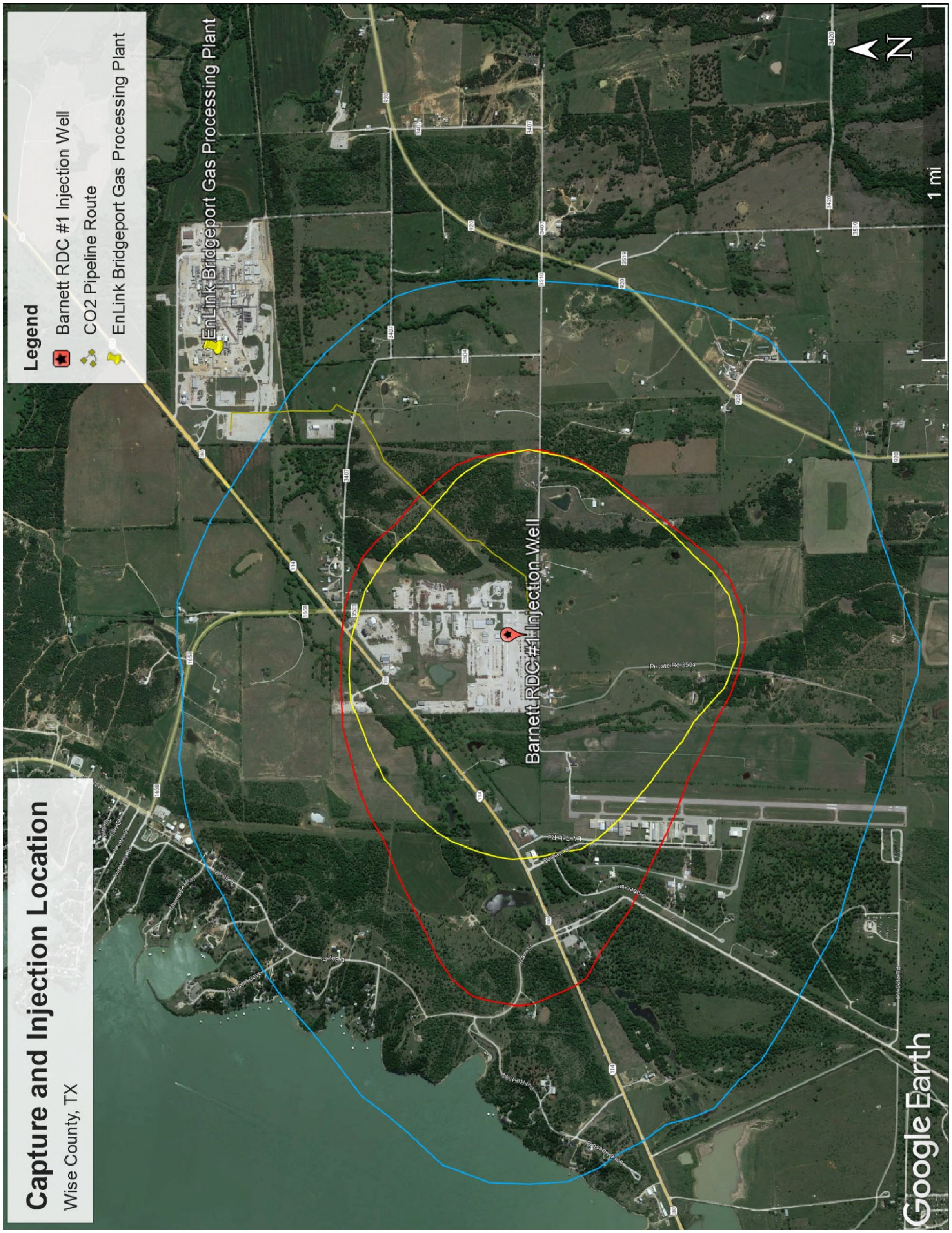
dCarbon is submitting this Monitoring, Reporting, and Verification ("MRV") plan to the EPA for approval under 40 CFR §98.440(a), Subpart RR, of the Greenhouse Gas Reporting Program ("GHGRP").

BKV dCarbon Ventures TRRC operator number is 100589

BKV dCarbon Ventures' EPA number is 110071343305

EnLink's Bridgeport Processing Plant's GHGRP is 1006373

Figure 1. Location of the Barnett RDC # 1 well and Bridgeport Gas Processing Plant; Maximum Monitoring Area (blue), End of Injection Plume (yellow), and 50-year Post Injection Plume (red) as Modeled at the Barnett RDC #1 Well.



Section 2 – Facility Information

Gas Plant Facility Name: BRIDGEPORT GAS PROCESSING PLANT

415 PRIVATE RD, 3502

BRIDGEPORT, TX, 76426

Latitude: 33° 11.74' N

Longitude: 97° 48.22' W

GHGRP Id: 1006373

FRS Id: 110028052354

NAICS Code: 211130

Currently reporting under Subpart C, W, NN

Underground Injection Control (UIC) Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control ("UIC") Class II program. TRRC classifies the Barnett RDC #1 well as a UIC Class II well. The Class II permit was issued in accordance with Statewide Rule 9.

UIC Well Identification Number

Barnett RDC #1, API 42-497-38108, UIC# 000125478

The Bridgeport Gas Processing Plant operated by EnLink Midstream is current emitting CO_2. The Barnett RDC #1 well will be disposing of CO2 from the Bridgeport Gas Processing Plant.

Section 3 – Project Description

This Project Description discusses the geologic setting, planned injection volumes and process, and the reservoir modeling performed for the proposed Barnett RDC #1 Class II injection well. dCarbon has prepared this MRV plan to support the storage of CO_2 from gas processing facilities in Wise County, Texas.

3.1. Overview of Geology

The proposed injection site lies in western Wise County, where the Barnett Shale, Viola/Simpson, and Ellenburger formations dip and thicken to the east toward the Muenster Arch as seen in the west to east cross section of **Figure 2**. Similarly, the north to south cross section shows the Ellenburger and overlying formations dipping to the north. One inference from this is that any CO_2 injected may exhibit the tendency to move up dip due to buoyancy, meaning the anticipated plume movement will be westward. This is further represented in the structure contour map of the Ellenburger formation top by Polastro[1] in **Figure 2**.

The Fort Worth Basin sedimentary succession begins with locally abundant Cambrian clastics in the southern section of the basin that unconformably overly the uneven Precambrian basement. The overlying Ordovician age Ellenburger platform carbonates were deposited on a passive margin and contain thicknesses up to 4,000 feet in the Fort Worth Basin. The Ellenburger platform carbonates underwent multiple episodes of regional exposure causing dolomitization and karsting in several units of the Ellenburger. Ordovician Viola and Simpson formations overly the Ellenburger formation and are found in the northern section of the basin near the Muenster Arch. A major erosive interval occurred during the Mississippian, eroding down to the Ordovician formations. Later deposition of the Barnett Shale unconformably overlies the Viola limestone, Simpson formation, and the Ellenburger group[2]. Overlying the Barnett Shale is a thick section of mostly Pennsylvanian and Permian carbonates and clastics (Bend, Strawn, and Canyon Groups). **Figure 2** indicates the general regional stratigraphy. While there are multiple storage-confining unit systems that could be evaluated for injection, the focus was on Mississippian-Ordovician section that consists of the Barnett shale and the Ellenburger group. The Ellenburger group directly overlies the basement rock and is considered the main reservoir target.

[1] Pollastro, R.M., 2007. Geologic framework of the Mississippian Barnett Shale, Barnett-Paleozoic total petroleum system, Bend Arch-Fort Worth Basin. *American Association of Petroleum Geologists Bulletin* 91 (4), pgs 405-436.
[2] Gao, S. *et al*., 2021. Low pressure buildup with large disposal volumes of oil field water: A flow model of the Ellenburger Group, Fort Worth Basin, northcentral Texas. AAPG Bulletin Vol 105 Number 12, 2021, pgs 2575-2593.

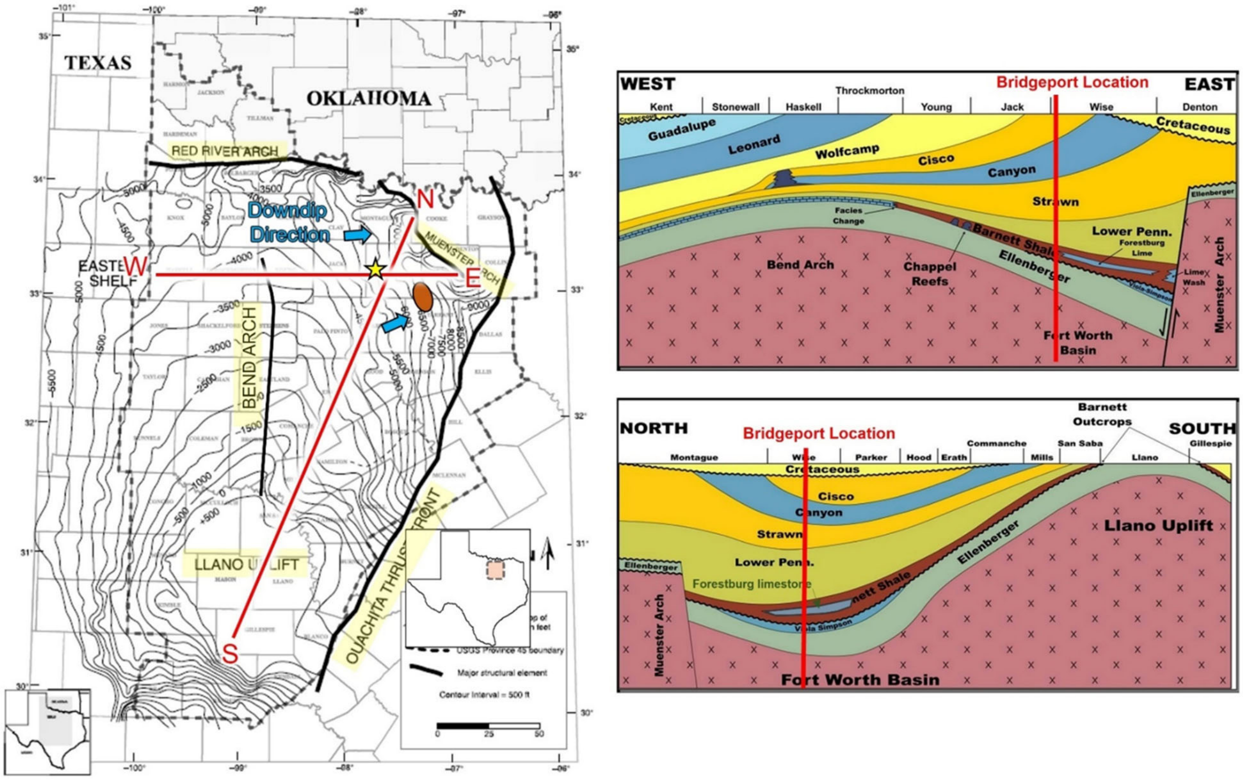


Figure 2. (Left) Ellenburger structural contour map modified from Jarvie *et al.*[3] showing the regional structures within and bounding the Fort Worth Basin, Ellenburger structure contours with respect to the final BKV area of interest (yellow star). (Right) Cross sections E-W and N-S show the regional dip of the sedimentary units in the Fort Worth Basin.

3.2. Bedrock Geology

3.2.1. Basin Description

The Fort Worth basin is a flexural basin that formed in the foreland of the advancing Ouachita orogenic belt during the Late Mississippian through Pennsylvanian epochs[4]. As illustrated in **Figure 2**, the Fort Worth Basin is bounded to the east by the Ouachita fold and thrust belt and to the north by the Muenster Arch and Red River Arch. These arches are characterized by a series of high angle reverse faults. The basin is deepest to the northeast, with as much as ~12,000 feet of sediment infill, where the Ouachita thrust front meets the Muenster Arch and is shallowest towards the south.

[3] Jarvie, D.M., *et al.*, 2007. Unconventional shale-gas systems: The Mississippian Barnett Shale of north-central Texas as one model for thermogenic shale-gas assessment. AAPG Bulletin Volume 91 Number 4, 2007, pgs 475-499

[4] Horne E. A. Hennings P. H., and Zahm C. K., 2021. Basement structure of the Delaware basin, in The Geologic Basement of Texas: A Volume in Honor of Peter Flawn , Callahan O. A., and Eichhubl P. (Editors), The University of Texas at Austin, Bureau of Economic Geology Report of Investigations, Austin, Texas.

Table 1. Regional stratigraphy at Barnett RDC #1 site in north Texas.

System	*Series*	*Stage*	*Group or Formation*	
Cretaceous	Lower	Comanchean	Trinity Group	
Pennsylvanian	Upper	Missourian	Canyon Group	Jasper Creek Formation
	Middle	Desmonesian	Strawn Group	Willow Point Formation
				Lone Camp Formation
				Millsap Lake Formation
			Kickapoo Group	Ratville Formation
				Parks Formation
				Caddo Pool Formation
		Atokan	Bend Group	Caddo Formation
				Smithwick Shale
	Lower			Pregnant Shale
				Big Saline Formation
		Morrowan		Marble Falls Limestone
				Comyn Formation
Mississippian	Chesterian – Meramecian			
			Barnett	Upper Barnett Shale
				Forestberg Limestone
	Osagean			Lower Barnett Shale
Ordovician	Lower		Ellenburger Group	
Precambrian			Basement	

3.2.2 Stratigraphy

The Ellenburger contains alternating limestone and dolomite lithologies, consistent with regional descriptions of the Ellenburger. Vertical changes in properties throughout the Ellenburger were used to divide the unit into 8 subunits (A-G), in agreement with a similar approach demonstrated by Smye *et al.*[5]. The main target storage reservoir, subunit E, was identified based on dominant lithology, gross and net reservoir thicknesses, porosity values, and permeability values. In tandem, the Ellenburger subunit B and the stratigraphic top portion of Ellenburger subunit C were identified as a potential storage caprock. Below this interval, there are baffles of tighter limestone throughout Ellenburger subunits C, C2, and D that would also act as sealing units to the storage reservoir.

[5] Smye, K.M., *et al.*, 2019. Stratigraphic architecture and petrophysical characterization of formations for deep disposal in the Fort Worth Basin, Texas. Texas BEG Report *Interpretation* Vol 7 Number 4, 2019.

Dominant lithologies were determined by comparing the photoelectric factor (PEFZ) log curve with the volume of clay (VCL), sand (VQUA), lime (VCLC), dolomite (VDOL), gas (VUGA), and free water (VUWA) curves in the Tarrant well, as well as the separation of the density and neutron porosity curves. Gross reservoir thickness was determined for each Ellenburger subunit by adding the footage from the top to the bottom of the formation.

The W.S. Coleman #2 (API 42-497-35807) well, approximately 5 miles east of the proposed Barnett RDC #1 injection well, was used to calculate reservoir zone properties for individual subunits within the Ellenburger formation since currently no wells exist at the proposed site. The North Tarrant SWD 1 (42-439-31228) well, located approximately 27 miles to the southeast was also used in well correlations because of its robust well log data across the Ellenburger Group.

Figure 3 shows the correlation of the North Tarrant SWD 1 well up to the W.S. Coleman #2. As an initial observation, subunits C and E within the Ellenburger are present and appear to be contiguous in the project area. Subunit C thickness is approximately 750 feet while subunit E thickness varies across the cross sections. It is estimated there is at least 940 feet of subunit C at the Barnett RDC #1 proposed site location with 1,250 feet of Ellenburger subunit E. The cross sections confirm regional trends in dip also apply to the area of interest wherein the reservoir unit slightly dips down to the north and east.

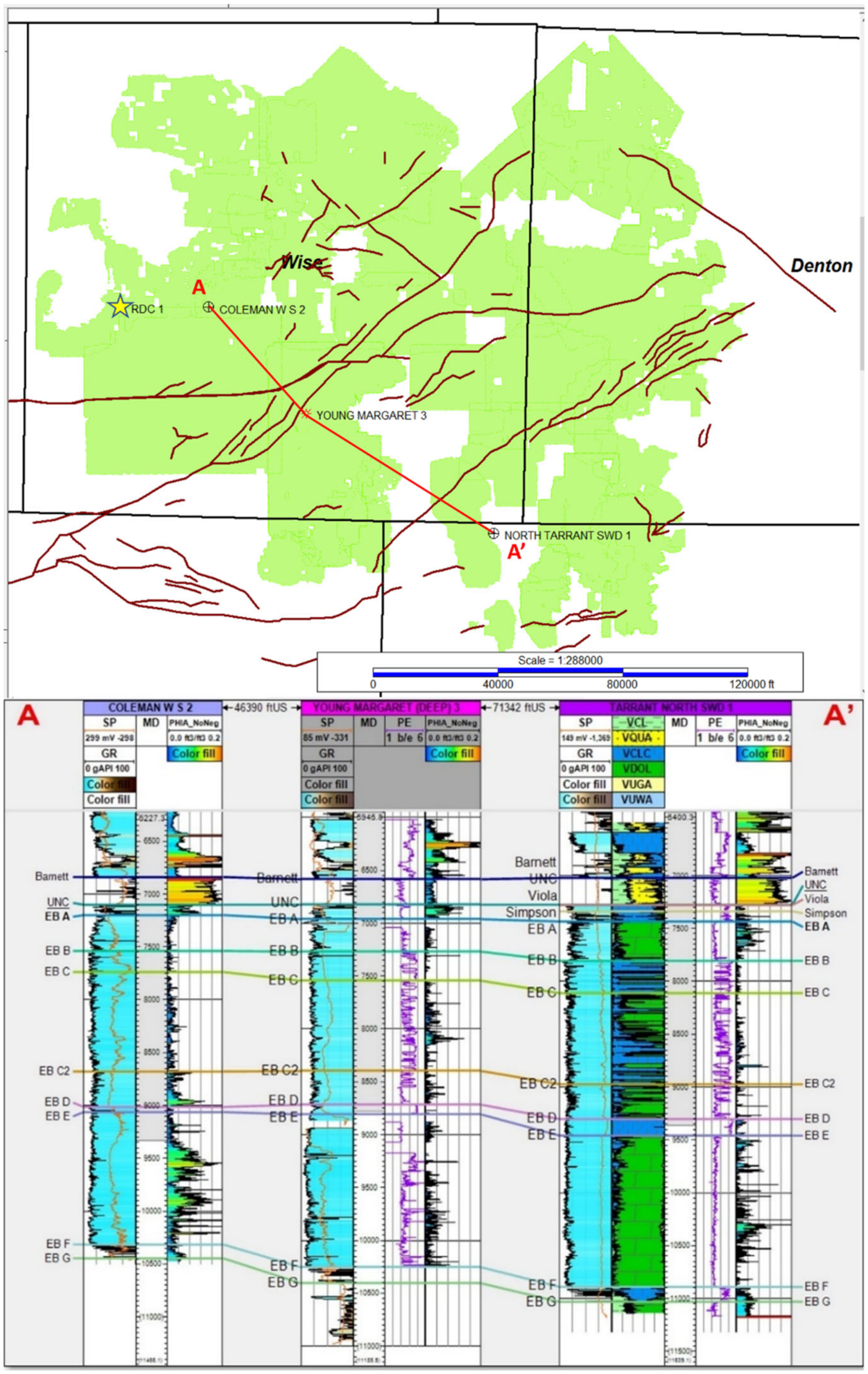


Figure 3. (Top) Map of Wise County with the Barnett RDC #1 (yellow star), faults (brown lines), cross section wells (black circles), BKV 3D seismic extent (green polygon), and a NW-SE cross section (A-A’). (Bottom) Cross section showing Gamma Ray (GR), Spontaneous Potential (SP), Photo Electric Factor (PE), and average porosity (PHIA) from the North Tarrant SWD well to the WS Coleman 2 well. Ellenburger subunit C (EB C) is the primary caprock and Ellenburger subunit E (EB E) is the primary reservoir unit.

3.2.3 Faulting

Faults within the Fort Worth Basin are generally northeast-trending, high-angle normal faults where most of the faults root into the Precambrian crystalline basement (**Figure 4**). The mechanism for deformation that produced these faults has been attributed to flexure generated by the Ouachita orogenic belt. Deep seated faults that root into the Precambrian crystalline basement generally terminate in the Pennsylvanian age strata and do not continue into the overlying Cretaceous strata, where it is present, suggesting that faults have not experienced significant movement since their formation (Horne *et al*. 2021). Karsting in the region has resulted in small-scale, concentric faults that originate from the collapse of karst features predominantly within the Ellenburger group.

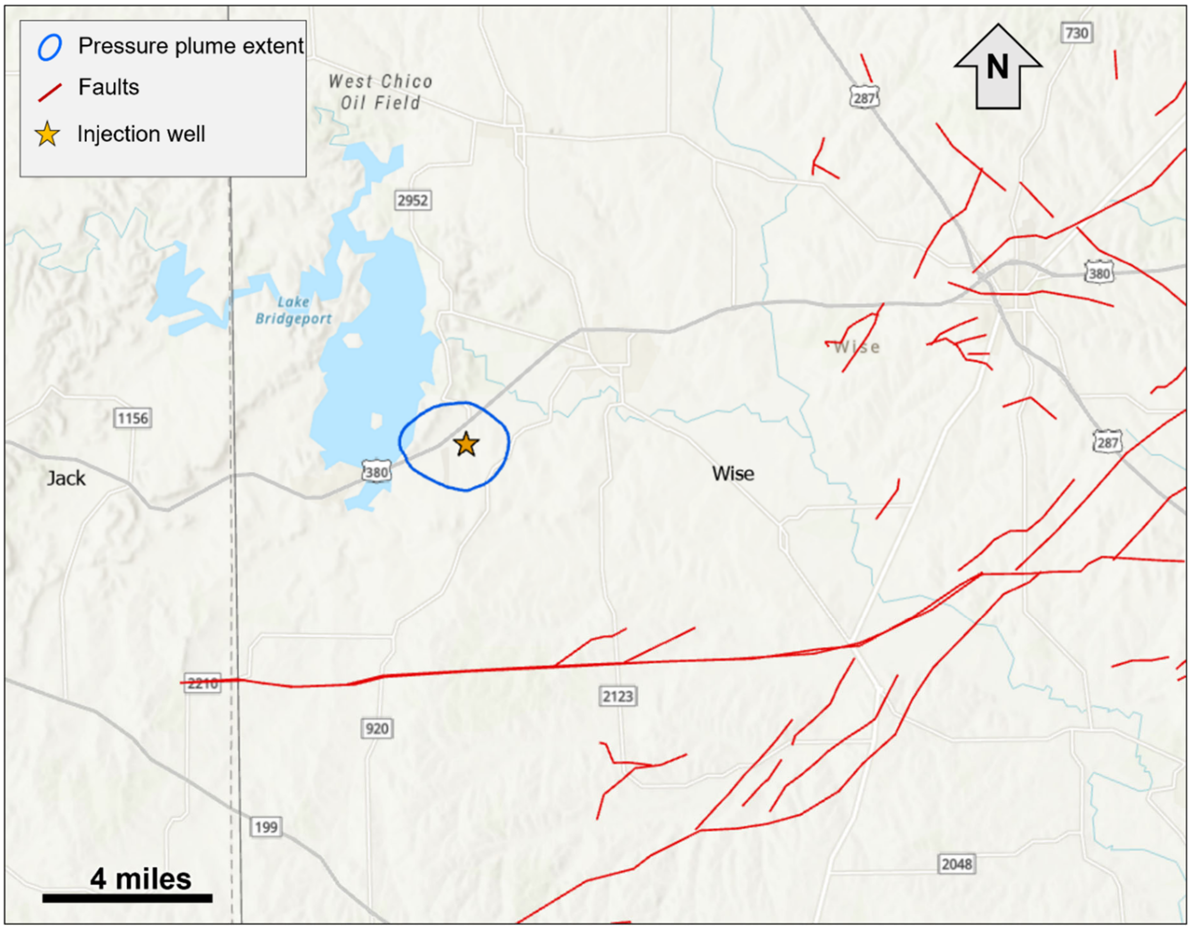


Figure 4. Mapped faults near the proposed injection well from Wood [6].

3.3 Lithological and Reservoir Characterizations

Smye *et al.*[5] provided a detailed description of regional stratigraphy as well as petrophysical attributes of multiple units within the Ellenburger group. Prior to understanding the petrophysical properties of these subunits and assessing their storage reservoir or confining layer potential, it is

[6] Wood, V., 2015. Reservoir Characterization and Depositional System of the Atokan Grant Sand, Fort Worth Basin, Texas. University of Arkansas Thesis, 2015.

important to understand the overall lithology. Literature suggests the Ellenburger interval is mostly composed of calcite, dolomite, quartz, and clay. The carbonate intervals are mostly clean with less than 10% clay by volume[5]. However, the top of the Ordovician section was shown to have an increased clay content (about 40% by volume). This also coincided with an increase in siliciclastic materials (quartz and clay). Porosity in clean carbonate intervals is approximately 5% while that in siliciclastic intervals may reach 20%. The basement lithology was identified as granite wash with hematite contents ranging between 5-10% by volume. **Figure 5** shows the general stratigraphy in the area of interest[5].

Lithological characterization was focused specifically on the red dotted area shown in **Figure 5** in order to better understand local stratigraphy and petrophysics. The Viola Formation and Simpson Group are listed here overlying the Ellenburger subunit A; however these formations pinch out to the east of the proposed Barnett RDC #1 site and are thus not included in subsequent petrophysical analysis.

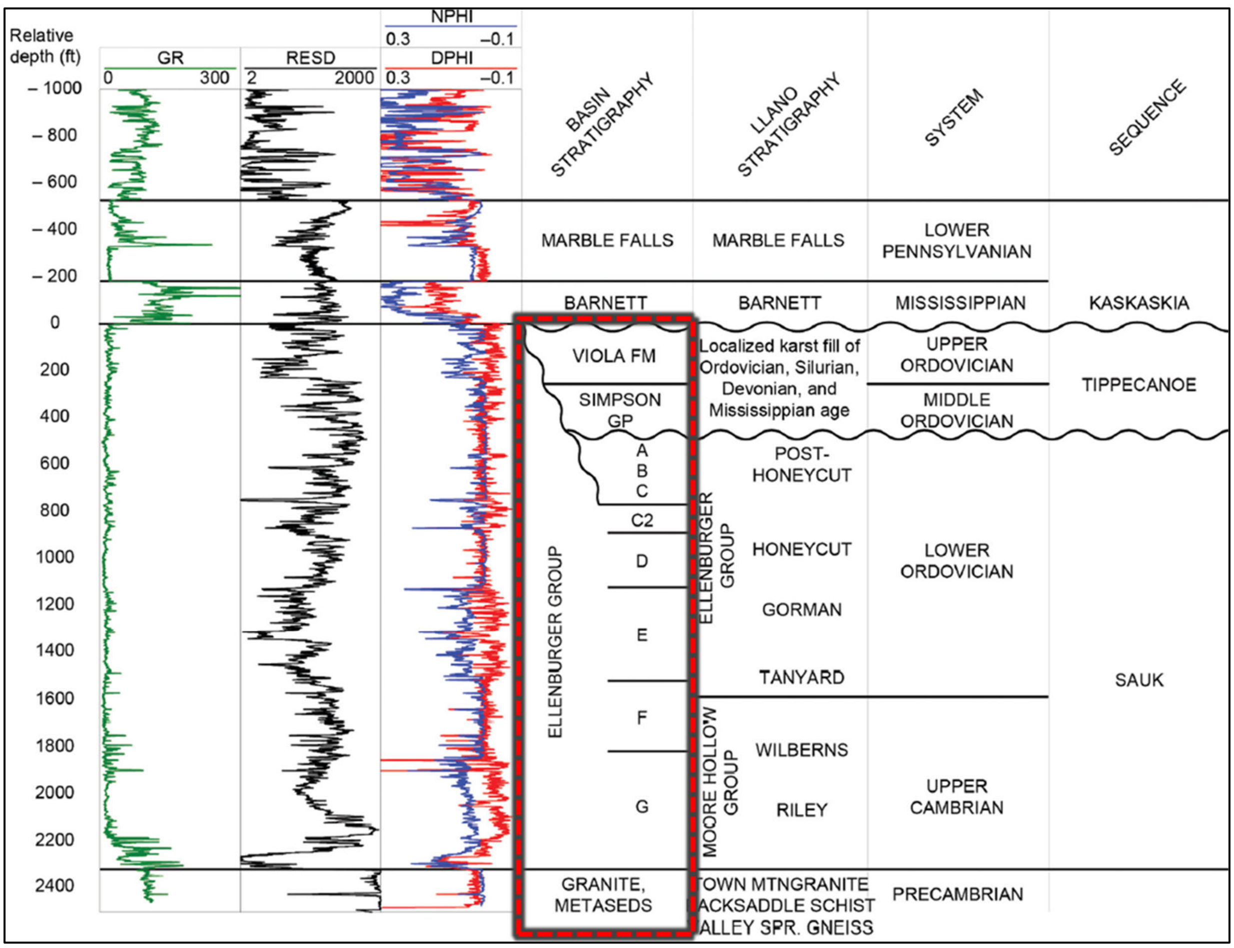


Figure 5. Regional stratigraphy at BKV site in North Texas (modified from Smye *et al.*[5]).

The Barnett Shale is anticipated to serve as a secondary confining layer. The Barnett Shale is a source rock and an unconventional reservoir which is extensively drilled in the Fort Worth Basin.

However, there are no Barnett Shale wells in the MMA of the Barnett RDC #1. The porosities and permeabilities in the Barnett Shale lie in the 4-6% and 7-50 nanodarcies ranges, respectively.

Underlying the Barnett is the Ellenburger Group, which is the anticipated injection interval. The Ellenburger could be divided into eight lithostratigraphic units starting with subunit A at the top to subunit G at the bottom which sits on top of the crystalline basement. Subunit G is composed of siliciclastic facies and is largely variable across the region. Though the porosity in subunit G is higher compared to other subunits, lateral continuity might be an issue in developing a storage project in this unit. Consequently, subunit E will serve as a potential reservoir given it has ~ 4% matrix porosity. Ellenburger subunit E is a clean dolomitic reservoir zone with 49% dolomite by volume. Subunit B and subunit C were found to have lower matrix porosities compared to subunit E, which implies these subunits could provide vertical confinement or impediment to CO_2 movement. Ellenburger subunit A has been proven to be a reservoir zone with multiple saltwater disposal wells completed in subunit A. However, as mentioned earlier, karsting features at the top of the Ellenburger imply there is some potential for hydraulic communication between subunit A and the overlying Barnett. **Figure 6** illustrates the log response and petrophysical properties of Ellenburger subunits.

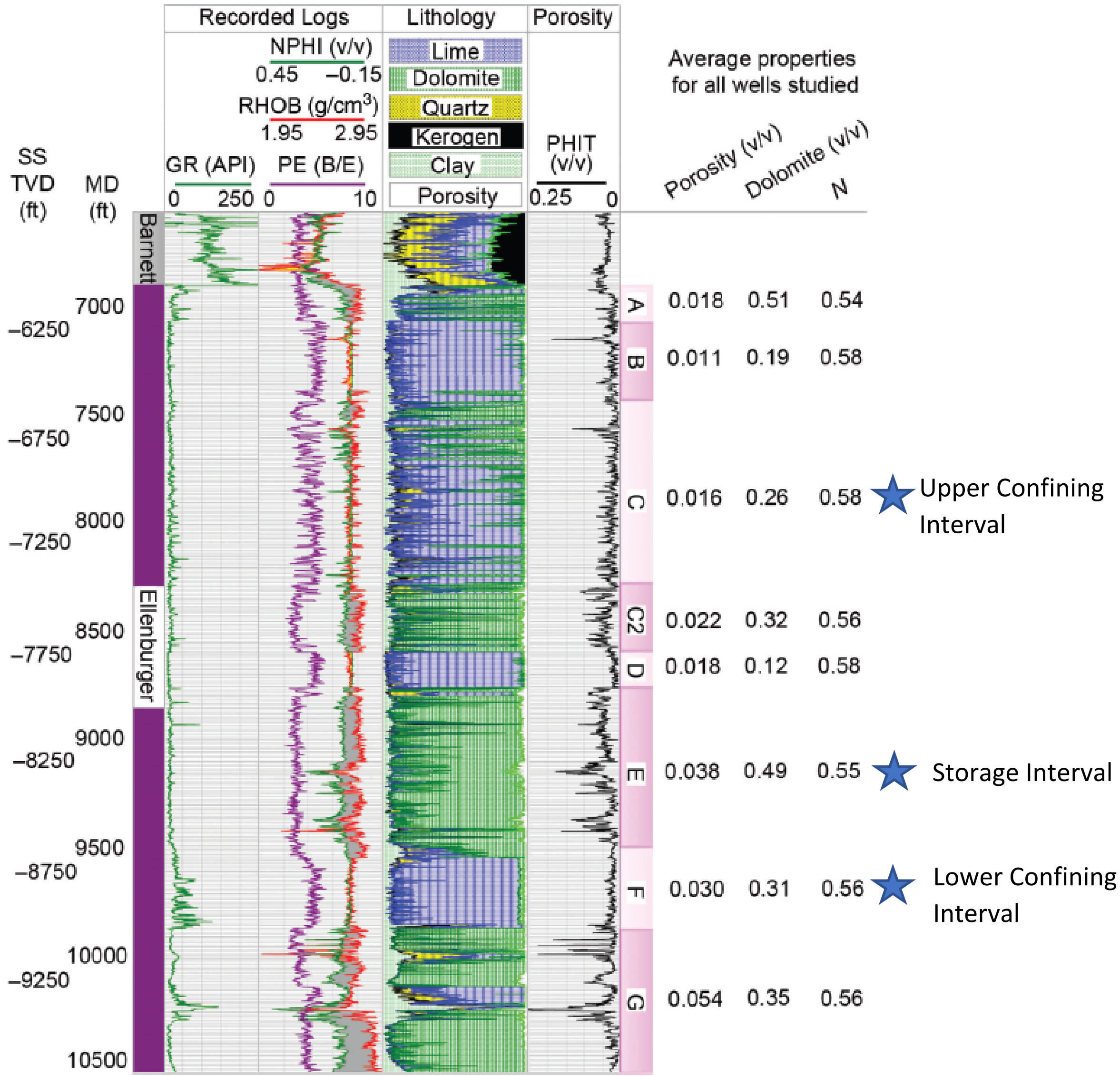


Figure 6. Properties of Ellenburger subunits in the project area (modified from Smye *et al.*[5]).

The W.S. Coleman #2 injection well located ~ 5 miles from the proposed injection site similarly contains Ellenburger subunits A through G, as shown below in **Figure 7**. Drilling at the proposed site will result in site specific petrophysical properties like those shown here.

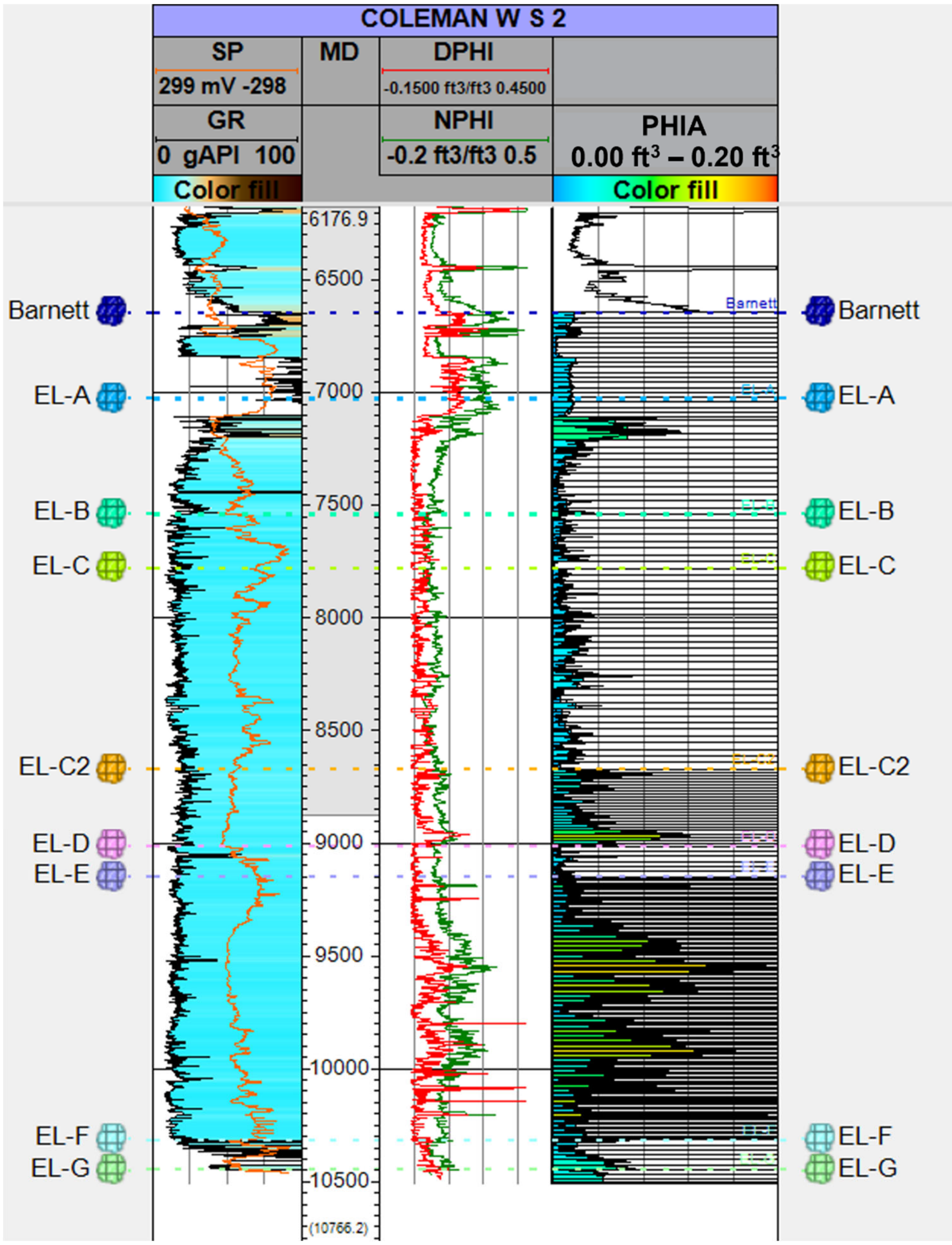


Figure 7. W.S. Coleman #2 well log interpretation; Ellenburger Group subunits A through G are denoted to the right and left of the log image.

Net reservoir thickness was determined for each subunit of the Ellenburger by summing the footage where the average porosity (PHIA) curve was greater than 2%. It is important to note that such a low matrix porosity value was chosen due to the nature of the reservoir wherein fracture porosity is a significant contributor to reservoir quality. Our understanding and evaluation of the Ellenburger suggested a low log porosity could still result in realizable CO_2 storage potential given the history of injectivity from saltwater disposal in the area (e.g. North Tarrant SWD 1 and W.S. Coleman #2 wells). A net-to-gross ratio was determined for each subunit by dividing the net reservoir thickness by the gross reservoir thickness. Average net reservoir porosity was calculated for each subunit of the Ellenburger by averaging the net reservoir average porosity (PHIA) curve from the top to the bottom of the subunit. These reservoir zone properties were subsequently used to derive preliminary storage resource estimates. **Table 2** lists average petrophysical properties in the Ellenburger.

Table 2. Ellenburger properties assessed at the area of interest.

Ellenburger Subunit	***Dominant Lithology***	***Gross Reservoir Thickness (feet)***	***Net Reservoir Thickness (feet [>2% PHI])***	***Net-to-Gross Ratio***	***Average Reservoir Porosity (%)***	
A	Dolomite	338	63	0.186	1.1	
B	Limestone	200	14	0.070	0.8	
C	Limestone	940	187	0.198	1.2	Upper Confining Zone
C2	Dolomite	335	229	0.683	3.5	
D	Limestone	49	3.5	0.072	0.6	
E	Dolomite	1252	879	0.702	5.5	Storage Interval
F	Limestone	130	88.5	0.677	3.2	Lower Confining Zone
G	Dolomite	NA	NA	NA	NA	

Permeability data in individual Ellenburger subunits was obtained from literature[2]. As noted by Gao *et al.*[2], regional hydrostatic pressure gradient in the Ellenburger was assumed to be 0.47 psi/foot while the geothermal gradient in the Fort Worth Basin was estimated at 1.4ºF/100 feet. These parameters were used to run preliminary CO_2 storage calculations as discussed in the Section 3.8.

3.4 Formation Fluid Chemistry

Nine wells were identified through a review of chemical analyses of oil-field brines from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3 within the Pennsylvanian age strata that are located within 20 miles of the proposed injection well site as shown in **Figure 8**. Formation fluid chemistry analyses for these wells is reported in **Table 3**.

Table 3. **Pennsylvanian formation fluid chemistry.**

	TDS (mg/L)	***pH***	***Na (ppm)***	***Ca (ppm)***	***Cl (ppm)***
AVG	86,807	6	26,000	5,494	53,392
LOW	21,926	4.4	6,291	978	13,389
HIGH	149,480	7.1	47,203	9,854	91,765

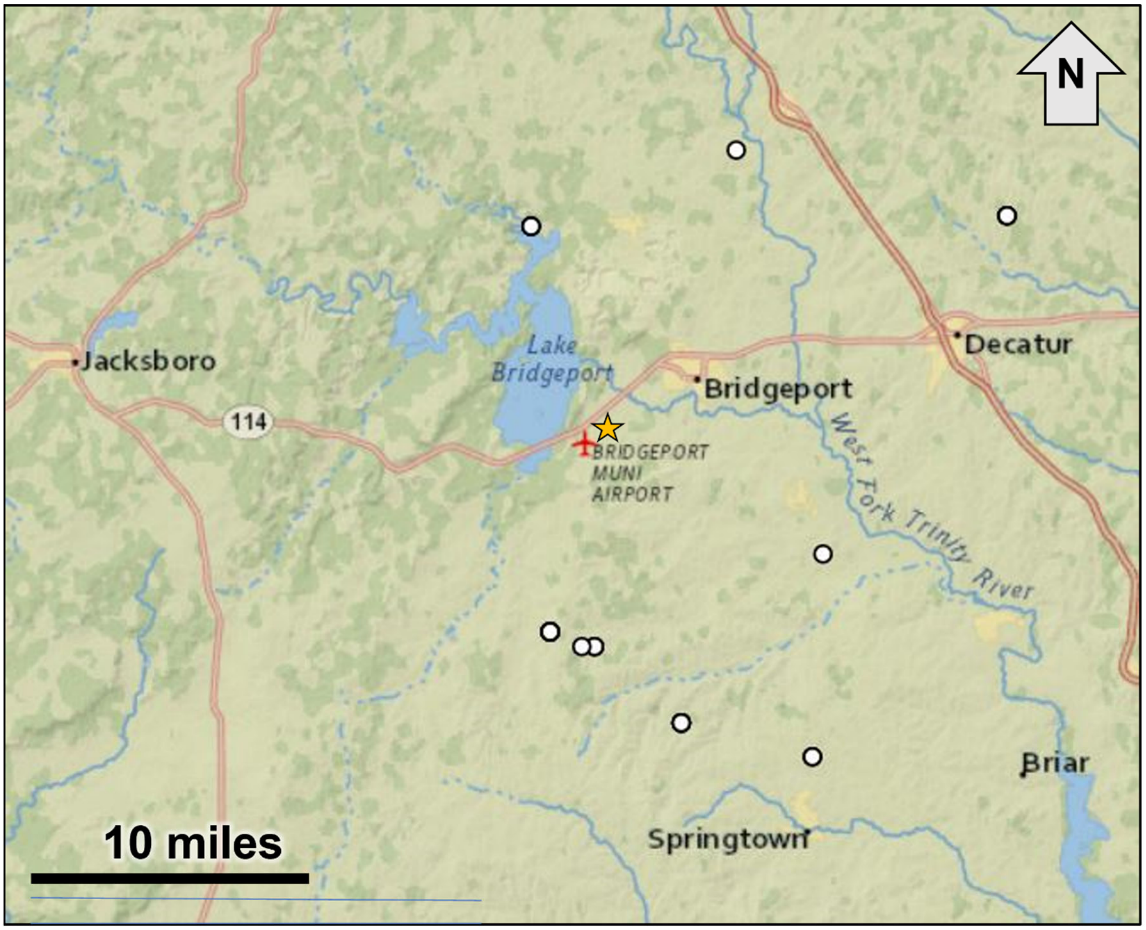


Figure 8. Map showing the location of wells used in the formation fluid chemistry analysis.

The Ellenburger Group has not been extensively drilled within the immediate area surrounding the proposed injection well and consequently formation fluid chemical analysis for the Group are from a basin-wide review. Based on analyses from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3, the Ellenburger fluids have greater than 194,263 parts per million (ppm) total dissolved solids (TDS) within the Fort Worth Basin. Formation fluid chemistry analyses for the Ellenburger Group Fort Worth Basin wells are reported in **Table 4**.

Table 4. Ellenburger Group formation fluid chemistry.

	TDS (mg/L)	*pH*	*Na (ppm)*	*Ca (ppm)*	*Cl (ppm)*
AVG	212,347	6	55,066	18,523	125,209
LOW	194,263	5.7	30,000	12,800	76,200
HIGH	276,388	6.6	66,482	24,750	153,071

3.5 Potential of Induced Seismicity – Ellenburger

An analysis of historical seismic events within a 100 square mile (5.64-mile radius) surrounding the proposed Class II

well injection site shows no recorded seismic activity dating back to January 1, 1971, according to the U. S. Geological Survey (USGS) Earthquake Catalog (**Figure 9**). TexNet seismic activity data supports this conclusion, showing no recorded seismic events around the proposed injection well site. Fault slip potential of mapped faults within the Fort Worth Basin was assessed through a literature survey[7]. Current findings show that steeply dipping faults that strike north-northeast have the highest fault-slip potential. An injection rate of up to 15,000 bpd has been permitted for a disposal well in Wise County, approximately 8 miles from the proposed injection site, and has been operated without any observed seismic activity.

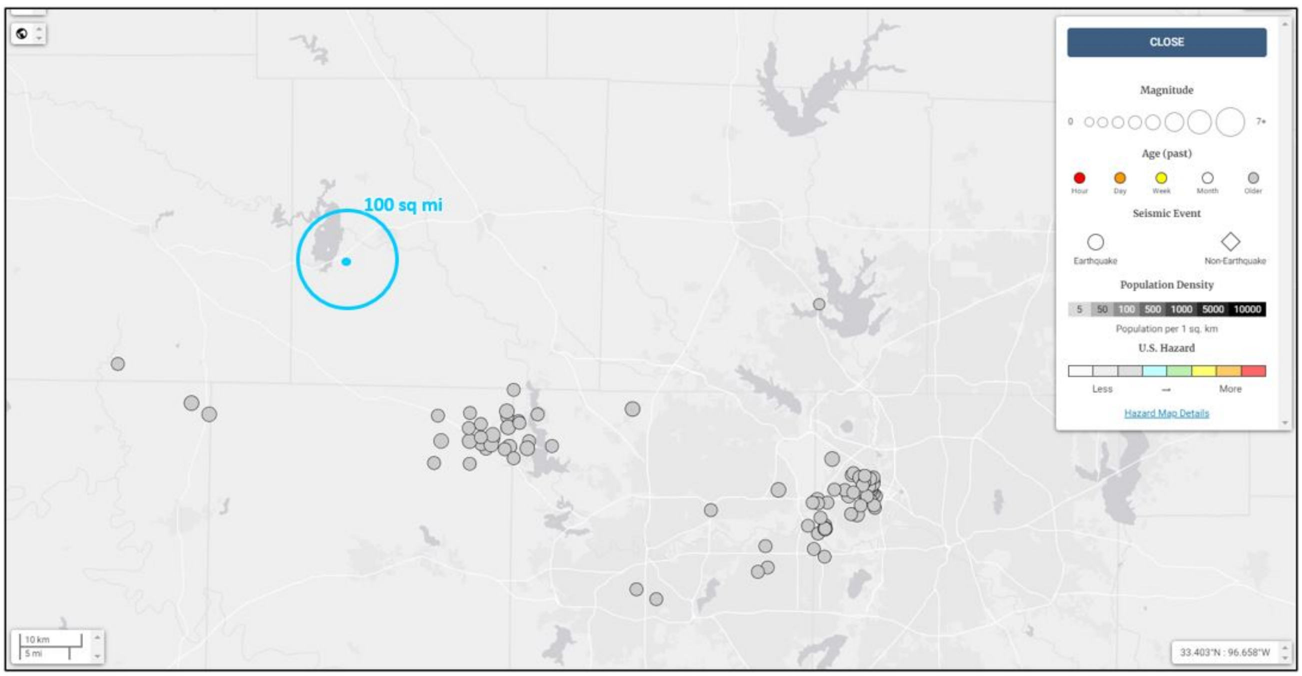


Figure 9. Screenshot from the USGS Earthquake Catalog showing no historical seismic activity in the surrounding 100 square miles to the proposed Bridgeport site.

3.6. Groundwater Hydrology in MMA

Wise County falls within the Upper Trinity Groundwater Conservation District as mapped by the Texas Water Development Board (**Figure 10**). Two aquifers are within the vicinity of the proposed injection site: the Trinity Group Aquifer, a major aquifer, and the Cross Timbers Aquifer, a minor aquifer. The Lower Cretaceous Trinity Group is an important source of groundwater for a portion of northern Texas and consequently Wise County, Texas. Lower Cretaceous strata outcrop throughout the majority of Wise County, especially to the east, but are absent at and around the

[7] Hennings, P.H., *et al*., 2019. Injection-Induced Seismicity and Fault-Slip Potential in the Fort Worth Basin, Texas. *Bulletin of the Seismological Society Of America* Vol 20 Number 20, 2019.

proposed injection site (**Figure 10** and **Figure 11**). Instead, strata from the Cross Timbers Aquifer outcrop on the surface at the proposed injection site. The Cross Timbers Aquifer includes four Paleozoic-age water-bearing formations including, from oldest to youngest, the Strawn, Canyon, Cisco, and Wichita Groups. The Upper Pennsylvanian Strawn Group Willow Point Formation outcrops on the surface at the proposed injection site, and rocks from the Upper Pennsylvanian Canyon Group Jasper Creek Formation outcrop 0.5 miles to the north-northwest of the proposed injection site (**Figure 12**). Strawn and Canyon Group formations are primarily composed of limestones, shales, and sandstones. A stratigraphic column showing the Pennsylvanian through Cretaceous strata is included as **Figure 13**.

The Canyon Group, which outcrops at the proposed injection site, is a sequence of limestones with interstratified shales and sandstones deposited as a part of the Perrin Delta System[8]. Deposition of Canyon Group sandstones was localized within valley fill, distributary channel fill, and delta-front deposits[9]. These sandstone bodies are not laterally continuous and therefore did not constitute a regional scale major aquifer. Nearby groundwater well reports list the aquifer as Paleozoic, supporting the conclusion that freshwater in and around the well site is sourced from Pennsylvanian strata. Because the location of the well site does not fall within one of the major aquifer boundaries described by the Texas Water Development Board, describing the Total Dissolved Solids (TDS) contents of water from the Pennsylvanian Canyon Group is challenging. Consequently, this data will be collected during the drilling process. One TDS measurement from the Pennsylvanian group (formation unspecified) near the well site was recorded as 1,600 ppm[10]. Thus, freshwater wells in the area are likely drawing from localized sands within the Upper Pennsylvanian strata. The USGS's National Produced Waters Geochemical Database (NPWGD) report several TDS content measurements within the Lower Pennsylvanian Atoka/Bend formation with values ranging from 21,926 ppm to 154,593 ppm[11]. No reported TDS values from the USGS NPWGD fall below the 10,000-ppm minimum required to classify an aquifer as an Underground Source of Drinking Water (USDW). Consequently, the lowermost USDW is likely above the Lower Pennsylvanian strata at around 900 feet.

The direction of groundwater flow within Paleozoic strata is suggested to be in the west-northwest direction according to a conceptual model developed by Nicot, *et al*. 2011[12]. Recharge into the Canyon Group was estimated to occur at a rate of 0.09 inches/year by the same study. Surface-water salinity decreases downstream toward the Gulf of Mexico. Groundwater salinity increases from younger to older formations toward the east but there is a reversal in the Strawn Group, whose formations can be in hydraulic contact with the overlying Trinity aquifer. The Trinity Aquifer may

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[8] Brown Jr., L.F., Cleaves II, A.W., Erxleben, A.W., 1973. Pennsylvanian depositional systems in North Central Texas, a guide for interpreting terrigenous clastic facies in a cratonic basin Texas Univ. Bur. Econ. Geology Guidebook, 14 (1973), p. 132

[9] Blandford, T.N., *et al.*, 2021. Conceptual Model Report for the Cross Timbers Aquifer. Report produced under Texas Water Development Board Contract No. 1948312322.

[10] Winslow, A.G., and Kister, L.R., 1956. Saline-Water Resources of Texas. U.S. Department of Interior Report.

[11] Blondes, M.S., *et al*., 2018. U.S. Geological Survey National Produced Waters Geochemical Database (ver. 2.3, January 2018): U.S. Geological Survey data release, https://doi.org/10.5066/F7J964W8.

[12] Nicot, J.-P., Huang, Y., Wolaver, B.D., and Costley, R.A., 2013. Flow and Salinity Patterns in the Low-Transmissivity Upper Paleozoic Aquifer of North-Central Texas: Gulf Coast Association of Geological Societies Journal, v. 2, p. 53-67.

provide cross-formational flow to Paleozoic aquifers when they overlap with the primary flow direction from the Trinity to the Strawn. This mixing could explain the salinity reversal observed in some parts of Texas within the Strawn Group. Locally, however, the deepest water well within 2 miles of the proposed injector well is 320 feet deep. This indicates that water wells in the area are drawing fresh water from localized sands within the upper several hundred feet.

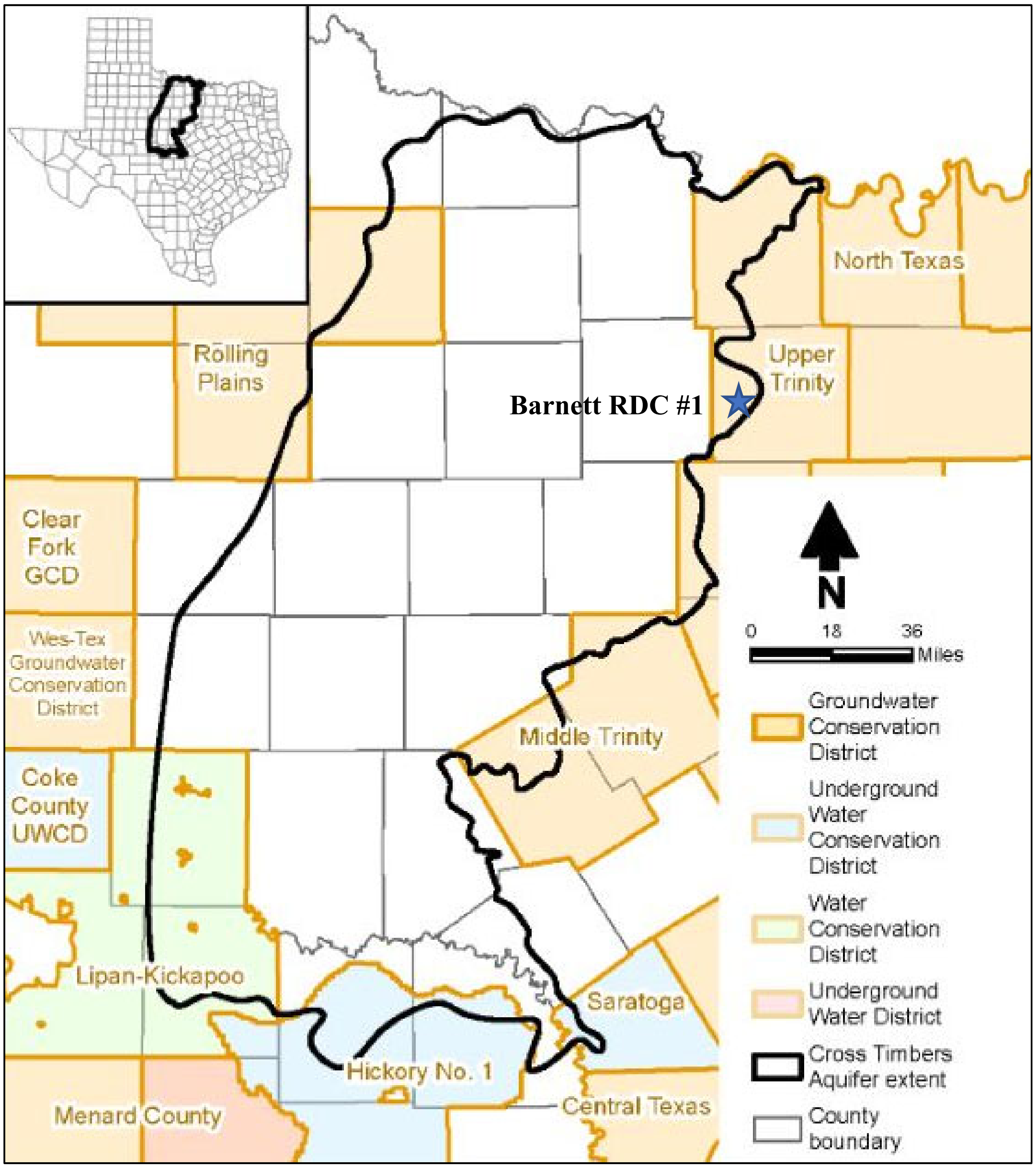

Figure 10. Map of the groundwater conservation districts and the Cross Timbers Aquifer extent within north-central Texas, from the Texas Water Development Board. Location of the proposed Barnett RDC #1, is shown with a star.

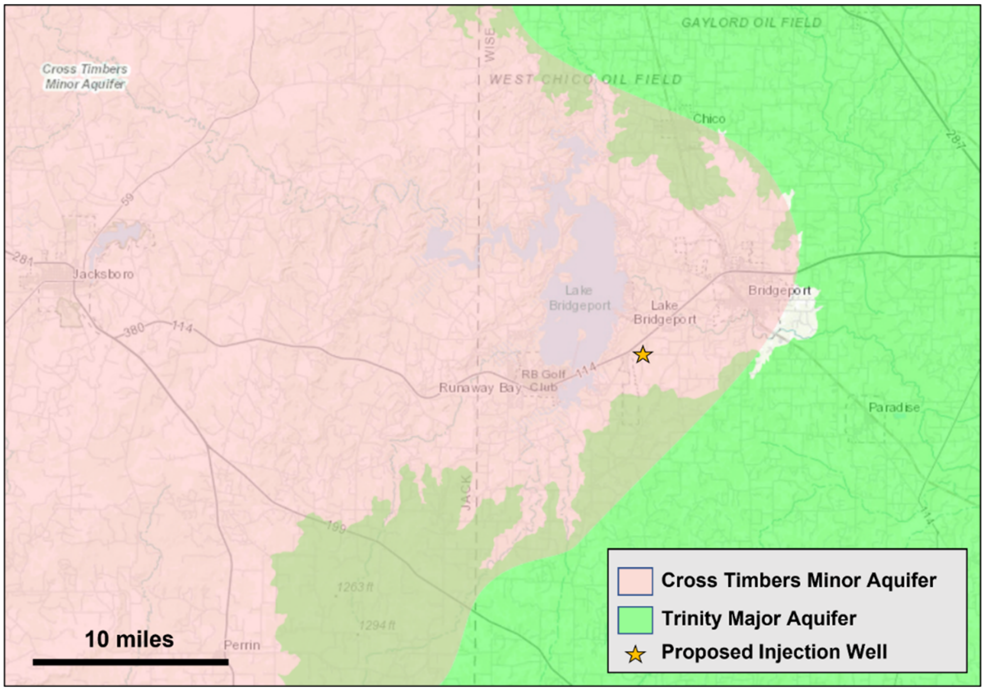

Figure 11. Location of the Cross Timbers minor aquifer and Trinity major aquifer in Texas, with well location labeled.

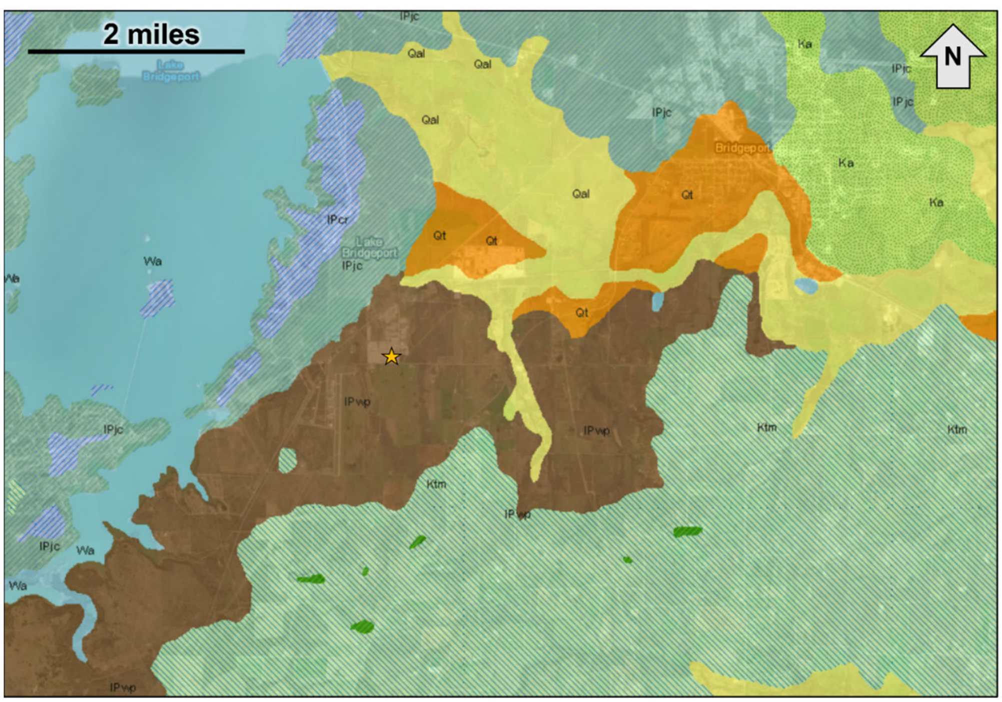

Figure 12. Geologic map of the area near the proposed injection site (yellow star). Geologic formations labeled using the state of Texas' USGS rock units codes, where: Qal = alluvium, Qt = fluviatile terrace deposits, Wa = water, IPcr = Chico Ridge limestone, IPjc = Jasper Creek formation, IPwp = Willow Point formation, Ktm = Twin Mountains formation, and Ka = Antlers sand.

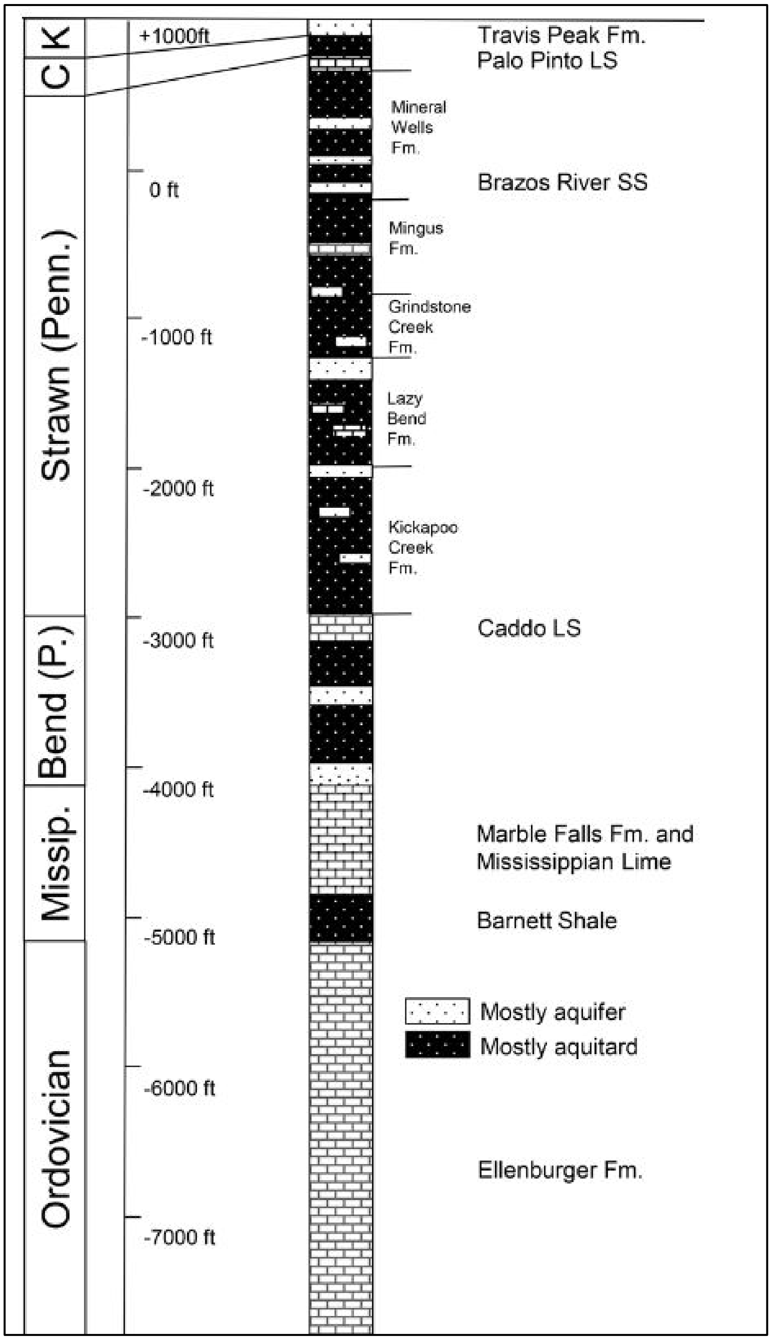

Figure 13. Stratigraphic column including aquifers and aquitards, modified from Nicot *et al.* 2011[14].

There are 105 freshwater wells within a 2-mile radius and 26 wells within a 1-mile radius of the proposed injection well, according to the Texas Water Development Board Groundwater Data Viewer shown in **Figure 14** and listed in **Table 5**.

[14] Nicot, J, *et al*., 2011. Methane occurrences in aquifers in the Barnett Shale area with a focus on Parker County, Texas" University of Texas, 2011, "https://deepblue.lib.umich.edu/bitstream/handle/2027.42/137724/gwat12508-sup-0001-supinfo.pdf?sequence=1

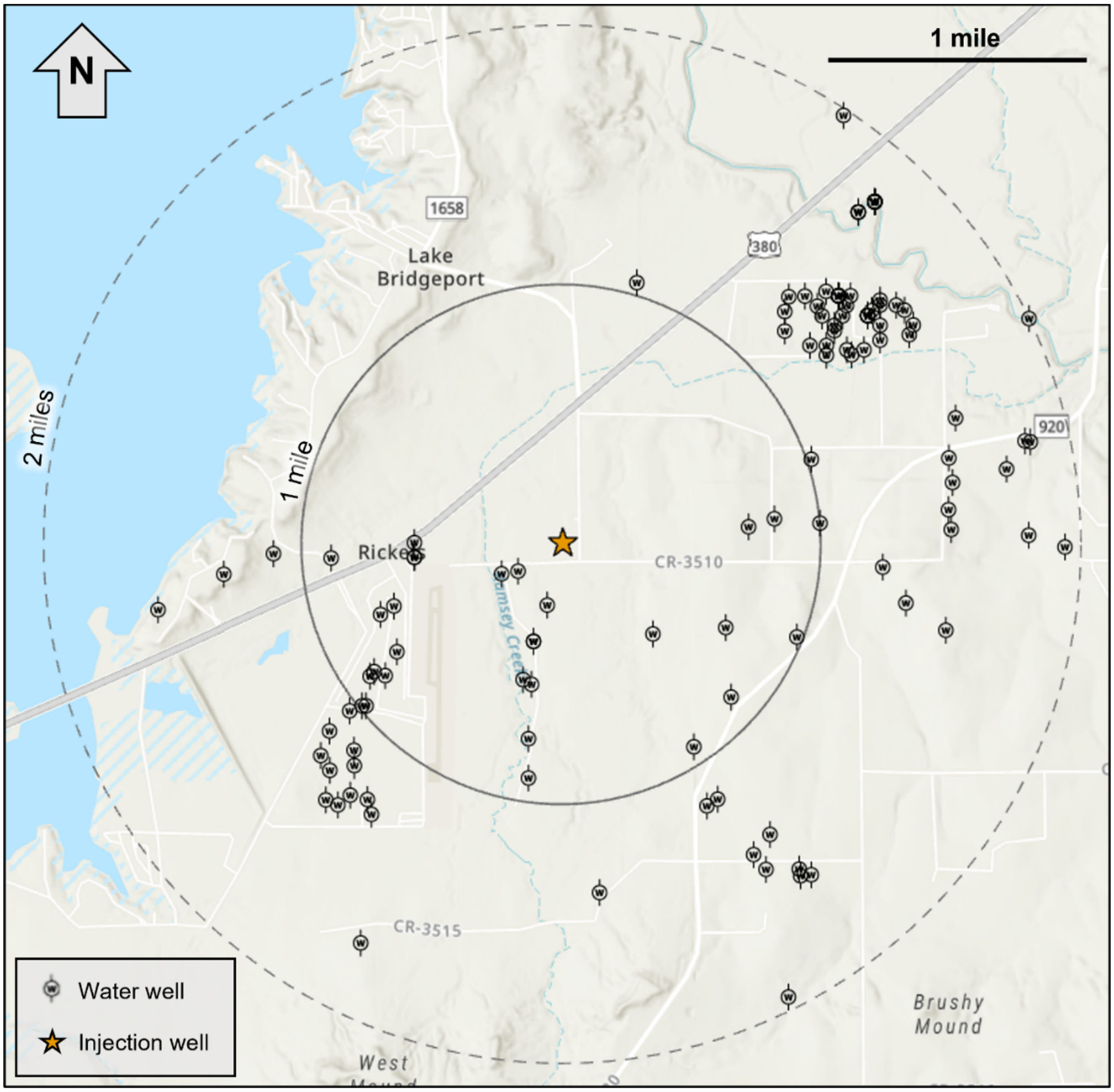

Figure 14. Water wells within 1 and 2 miles from the proposed injection site, data from the Texas Water Development Board.

Table 5. Private and state owned groundwater wells in project area.

Well Report Tracking Number	*Latitude (DD)*	*Longitude (DD)*	*Borehole Depth (feet)*	*Distance from proposed injector (mi)*
324182	33.157501	-97.805278	180	1.97
85836	33.160834	-97.833889	180	1.74
419698	33.1635	-97.817833	160	1.37
494622	33.16434	-97.80437	140	1.59
522108	33.16439	-97.80365	140	1.61
270093	33.164723	-97.806667	200	1.50
131403	33.164723	-97.804445	110	1.57
33173	33.165556	-97.807501	280	1.42
67830	33.166667	-97.806389	100	1.39
592900	33.16871	-97.80986	155	1.16
135520	33.17	-97.8225	140	0.93
71023	33.171667	-97.811389	120	0.94
214384	33.172222	-97.8225	195	0.78
23271	33.174167	-97.833611	280	1.01
23265	33.174167	-97.833334	140	1.00
12854	33.174444	-97.808889	140	0.89
305950	33.175278	-97.822222	110	0.57
86814	33.175555	-97.822778	213	0.56
570517	33.17587	-97.83202	120	0.86
13278	33.176111	-97.832778	140	0.89
585723	33.17721	-97.83121	160	0.77
527914	33.177694	-97.822083	160	0.40
527919	33.177694	-97.822083	160	0.40
190556	33.177778	-97.804445	210	0.98
428746	33.178047	-97.81408	120	0.50
605428	33.17806	-97.79442	180	1.53
107416	33.178333	-97.809167	140	0.72
509874	33.1793	-97.83231	120	0.76
601491	33.17962	-97.79708	200	1.35
53199	33.179722	-97.847222	150	1.60
196527	33.179722	-97.821111	75	0.25
510354	33.179783	-97.831417	130	0.70
430183	33.1815	-97.824139	170	0.27
81235	33.181667	-97.842778	200	1.32
193088	33.181667	-97.823055	240	0.21
373126	33.181667	-97.798611	160	1.25
351852	33.1825	-97.835556	320	0.90
122077	33.1825	-97.83	205	0.58
143619	33.1825	-97.83	140	0.58

Well Report Tracking Number	***Latitude (DD)***	***Longitude (DD)***	***Borehole Depth (feet)***	***Distance from proposed injector (mi)***
474446	33.182659	-97.786404	180	1.95
44219	33.182778	-97.839445	230	1.13
214552	33.183334	-97.83	120	0.58
483302	33.183342	-97.78883	100	1.81
416778	33.18372	-97.79402	180	1.51
479366	33.184019	-97.807589	200	0.72
72275	33.184167	-97.802778	34	1.00
123233	33.184445	-97.805834	32	0.83
457391	33.184833	-97.794167	170	1.50
187174	33.186389	-97.793889	180	1.53
419604	33.187077	-97.790243	180	1.75
574195	33.187771	-97.794087	180	1.53
329665	33.187778	-97.803334	170	1.02
404012	33.188611	-97.788611	260	1.86
422029	33.18865	-97.78897	260	1.84
88487	33.19	-97.793611	103	1.60
72273	33.193611	-97.802223	29	1.25
72269	33.193611	-97.800556	28	1.33
62634	33.193889	-97.800834	33	1.33
72268	33.193889	-97.799722	28	1.39
62627	33.194167	-97.803334	30	1.22
62639	33.194167	-97.802223	28	1.28
219191	33.194445	-97.798611	30	1.46
219202	33.194722	-97.796667	20	1.57
123232	33.195	-97.805001	34	1.19
62632	33.195	-97.801667	33	1.34
329661	33.195278	-97.801667	145	1.35
219187	33.195278	-97.798611	30	1.49
219200	33.195278	-97.796389	24	1.60
219184	33.195556	-97.788611	30	2.01
62616	33.195834	-97.802501	35	1.33
62629	33.195834	-97.801112	35	1.40
49825	33.195834	-97.799445	27	1.47
49826	33.195834	-97.799445	27	1.47
49827	33.195834	-97.799445	27	1.47
49828	33.195834	-97.799445	27	1.47
49829	33.195834	-97.799445	32	1.47
72263	33.196111	-97.805001	30	1.24
62607	33.196111	-97.799167	31	1.50
219198	33.196111	-97.796945	27	1.60
62622	33.196389	-97.802778	38	1.35

Well Report Tracking Number	*Latitude (DD)*	*Longitude (DD)*	*Borehole Depth (feet)*	*Distance from proposed injector (mi)*
62628	33.196389	-97.800834	31	1.43
72267	33.196389	-97.798611	35	1.53
219193	33.196389	-97.7975	20	1.59
219181	33.196667	-97.798611	30	1.55
62626	33.196945	-97.804723	16	1.29
62623	33.196945	-97.803612	16	1.34
41283	33.196945	-97.801389	21	1.43
41284	33.196945	-97.801389	15	1.43
41285	33.196945	-97.801389	15	1.43
41286	33.196945	-97.801389	15	1.43
41287	33.196945	-97.801389	15	1.43
72264	33.196945	-97.800556	34	1.47
62618	33.197222	-97.802223	32	1.41
405842	33.197817	-97.814883	60	1.05
240181	33.201667	-97.800001	20	1.72
240182	33.201667	-97.800001	18	1.72
240183	33.201667	-97.800001	17.5	1.72
213490	33.202223	-97.798889	14.5	1.79
213494	33.202223	-97.798889	15	1.79
213495	33.202223	-97.798889	14	1.79
213496	33.202223	-97.798889	14.5	1.79
213499	33.202223	-97.798889	13	1.79
213500	33.202223	-97.798889	12	1.79
213502	33.202223	-97.798889	11	1.79
516919	33.20712	-97.8009	160	1.98
		State Groundwater Wells		
State Well Number	*Latitude (DD)*	*Longitude (DD)*	*Borehole Depth (feet)*	*Distance from proposed injector (mi)*
1950401	33.17389	-97.83445	147	1.06
1950402	33.17278	-97.83583	146	1.17
1950408	33.16917	-97.83445	147	1.28
1950501	33.17583	-97.83306	82	0.91
1950406	33.16861	-97.83528	147	1.34
1950504	33.16806	-97.83306	147	1.29
1950404	33.17139	-97.83639	147	1.25
1950502	33.16833	-97.81056	121	1.17
1950403	33.16889	-97.83611	147	1.36
1950405	33.17083	-97.83417	147	1.19
1950407	33.17167	-97.83417	147	1.15
1950409	33.17056	-97.83583	147	1.27
1950503	33.16889	-97.83333	147	1.26

3.7. Description of CO_2 Project Facilities

EnLink Midstream has contracted to deliver CO_2 from its Bridgeport Gas Processing Plant to dCarbon. The temperature, pressure, composition, and quantity of CO_2 will be measured and metered according to industry standards, with an orifice meter, Coriolis meter, or similar device. dCarbon will dehydrate and compress the CO_2 to a supercritical physical state at the Bridgeport site. dCarbon Ventures will then transport the CO_2 via pipeline approximately 6,815 feet to the Barnett RDC #1 injection site. Once at the well site, the CO_2 stream will again be metered to reverify quantity. The CO_2 will then be injected into the Ellenburger formation. This formation is deeper than other formations known to be productive of oil and gas in the area. A gas analysis of the CO_2 stream is shown in **Table 6**. Although this sample is expected to be representative of the composition of the gas, it is possible that the composition will vary slightly in time as the field development and processing environment change.

Table 6. CO_2 stream analysis for the Barnett RDC #1 site.

Name	*Normalized Weight Percent*	*Normalized Mole Percent*	*Normalized Liquid Volume Percent*
Nitrogen	0.002	0.003	0.002
Carbon Dioxide	99.358	99.054	98.646
Methane	0.105	0.287	0.286
Ethane	0.4	0.584	0.916
Propane	0.018	0.018	0.029
Isobutane	0.003	0.002	0.004
N-butane	0.008	0.006	0.011
Isopentane	0.002	0.001	0.003
N-pentane	0.002	0.001	0.003
Hexanes	0.011	0.008	0.013
Heptanes	0.011	0.002	0.011
Octanes	0.007	0.001	0.007
Nonanes	0.009	0.002	0.009
Decanes plus	0.004	0.001	0.004
BTEX	0.06	0.03	0.056
H2S	0.00002	0.00002	0.00002
Total	100	100	100
Total Sample Properties			
Property	Value		
BTU (Gross)	16.04		
Density (lbs/gal)	12.63		
Molecular weight	43.87		
Specific gravity (Air=1)	1.5147		

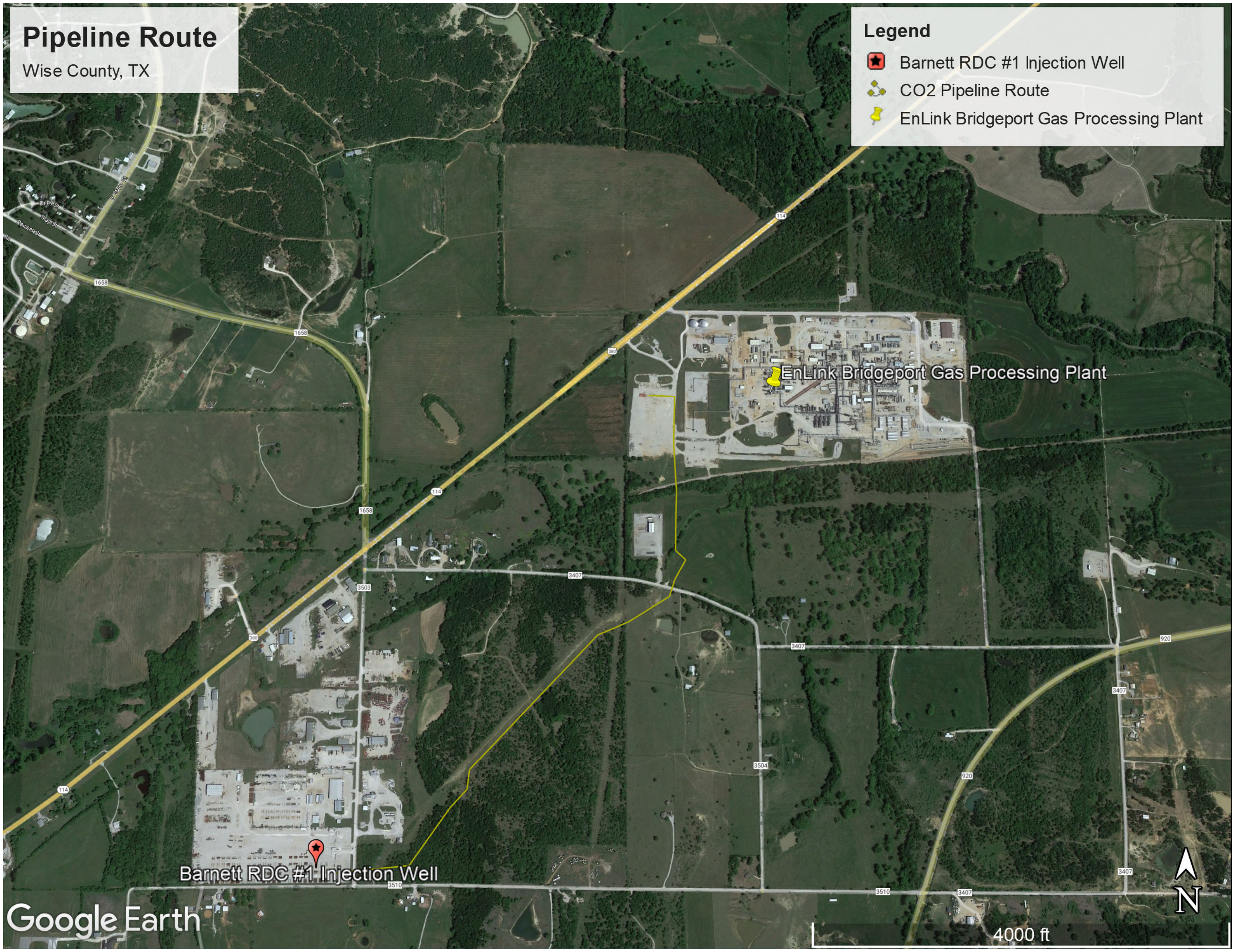

Figure 15. Proposed pipeline route.

3.8. Reservoir Characterization Modeling

A regional modeling encompassing nearby plugged and abandoned wells as well as saltwater disposal wells was created in Schlumberger's Petrel; the model incorporates available well petrophysical data and generate a static earth model (SEM) for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the W.S. Coleman SWD #2 well (~ 5 miles east of Barnett RDC #1) as discussed in previous sections. The reservoir is characterized by low matrix porosities as well as naturally existing fractures which likely contribute to fluid flow. For the current assessment, a single porosity, single permeability distribution model was deemed appropriate given the uniformity of natural fracture distribution within the Ellenburger as well as saltwater disposal rates/volumes into the Ellenburger in nearby counties. These assumptions will be examined and verified using a pressure fall-off test (PFOT) that will be conducted during the construction of the RDC #1 well. If PFOT and logging programs detect deviations from anticipated reservoir behavior, dCarbon will use the new data to update reservoir models as well as injection forecasts and MRV plan if appropriate.

The primary objectives of the simulation model were to:

1. Estimate the maximum areal extent of the injectate plume and its migration post injection.
2. Determine the ability of the target formation to handle the required injection rate.
3. Characterize potential interaction between the injected CO_2 and any nearby potential leakage pathways.

The CO_2 storage complex, as indicated previously, is anticipated to be confined to the Ellenburger interval. Ellenburger 'E' is modeled as the reservoir unit while Ellenburger 'C' unit is anticipated to provide a primary seal that impedes vertical fluid flow. The Barnett shale is expected to serve as a secondary seal which provides an additional stratigraphic seal to the injected CO_2. The basal seal for the reservoir is provided by the Ellenburger F zone. A 12-mile by 12-mile tartan grid was generated in Schlumberger's Petrel based on well top information from nearby legacy and saltwater disposal wells. The grid was then exported to Computer Modeling Group (CMG)'s General Equation of State Model (GEM) simulator to account for fully implicit multiphase compositional fluid flow. This simulation was built to model other transport and mixing phenomena such as relative permeability, diffusion, advection, aqueous solubility, and buoyancy to accurately predict the plume movement. The reservoir is modeled to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 200,000 TDS which is typical of the Ellenburger formation in the project area. The injected gas stream is assumed to be fully composed of CO_2. **Figure 16** illustrates the vertical layering with relationship to simulated CO_2 saturation profile in the model. The injection rate modeled was 280,000 MT/year for 12 years followed by 100 years of post-injection timeframe to observe post-injection movement of CO_2.

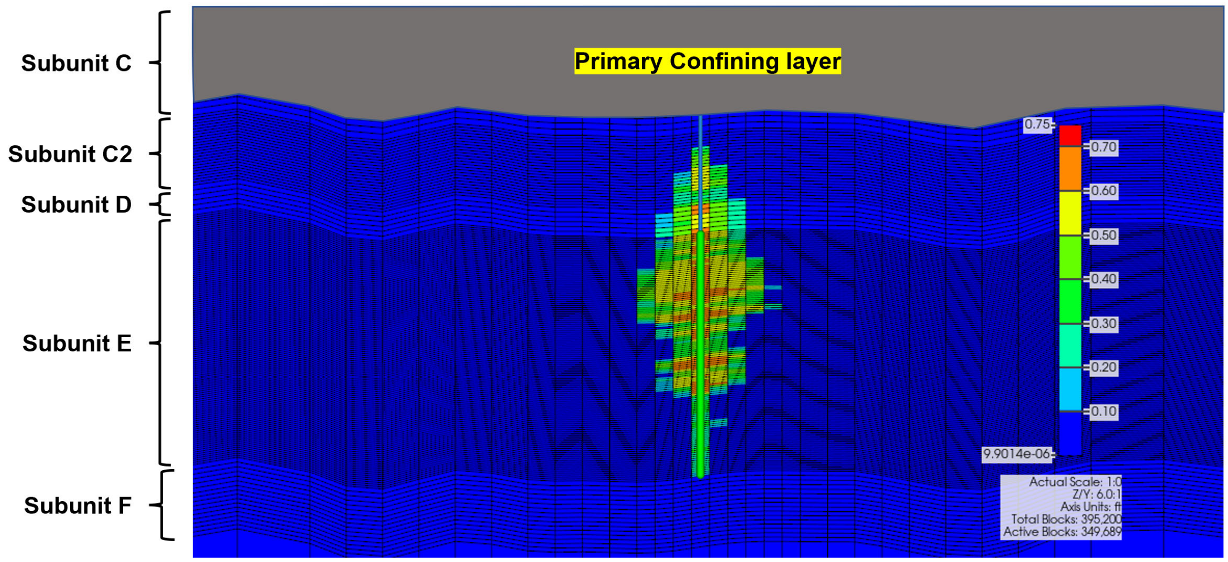

Figure 16. Vertical CO_2 saturation Profile of the CMG-GEM Model for Barnett RDC #1 Well. Color scale in the figure indicates CO_2 gas saturation.

Datasets prepared for simulations were based on published literature. Specifically, the reservoir relative permeability model used in this model were sourced from literature[15] using data from the Wabamun Carbonate reservoir formation which exhibited comparable porosities and permeabilities as the Ellenburger. The initial reservoir conditions were developed using gradients derived from literature[2]. The pressure gradient was assumed to be 0.47 psi/foot which resulted in an estimated reservoir pressure of 4,136 psi at the top of the injection interval. The temperature gradient was assumed to be 1.5°F/100 feet, resulting in an estimated temperature of 201°F at the top of the reservoir. Fracture pressures were estimated at 0.7 psi/foot. To ensure CO_2 injection does not induce fractures within the Ellenburger, injection well bottom hole pressure (BHP) was constrained to 90% of calculated fracture pressure, thereby applying a safety factor of 10%. This resulted in a maximum bottom hole injection pressure constraint of 5,524 psi. There are no active wells injecting or producing from the injection interval in the project area. Therefore, no additional wells other than injector were included in the fluid flow simulation model.

As mentioned earlier, injection was modeled at 280,000 MT/yr. The model simulated 12 years of active injection followed by 100 years without injection to determine when plume migration stops. Plume migration ceased after 50 years post-injection, which is determined to be the maximum extent of the CO_2 plume. **Figure 16** shows the CO_2 plume at the end of injection (yellow) compared to 50 years post injection (red). Injected CO_2 flows due west which is the regional up dip direction. However, the change in CO_2 plume area from end of injection to 50 years post-injection is minimal (~29%) and the plume stops moving after 50 years.

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[15] Bennion, D.B., and Bachu, S., 2007. Permeability and Relative Permeability Measurements at Reservoir Conditions for CO_2-Water Systems in Ultra Low Permeability Confining Caprocks. SPE Paper # 106995 presented at the SPE Europec/EAGE Annual Conference

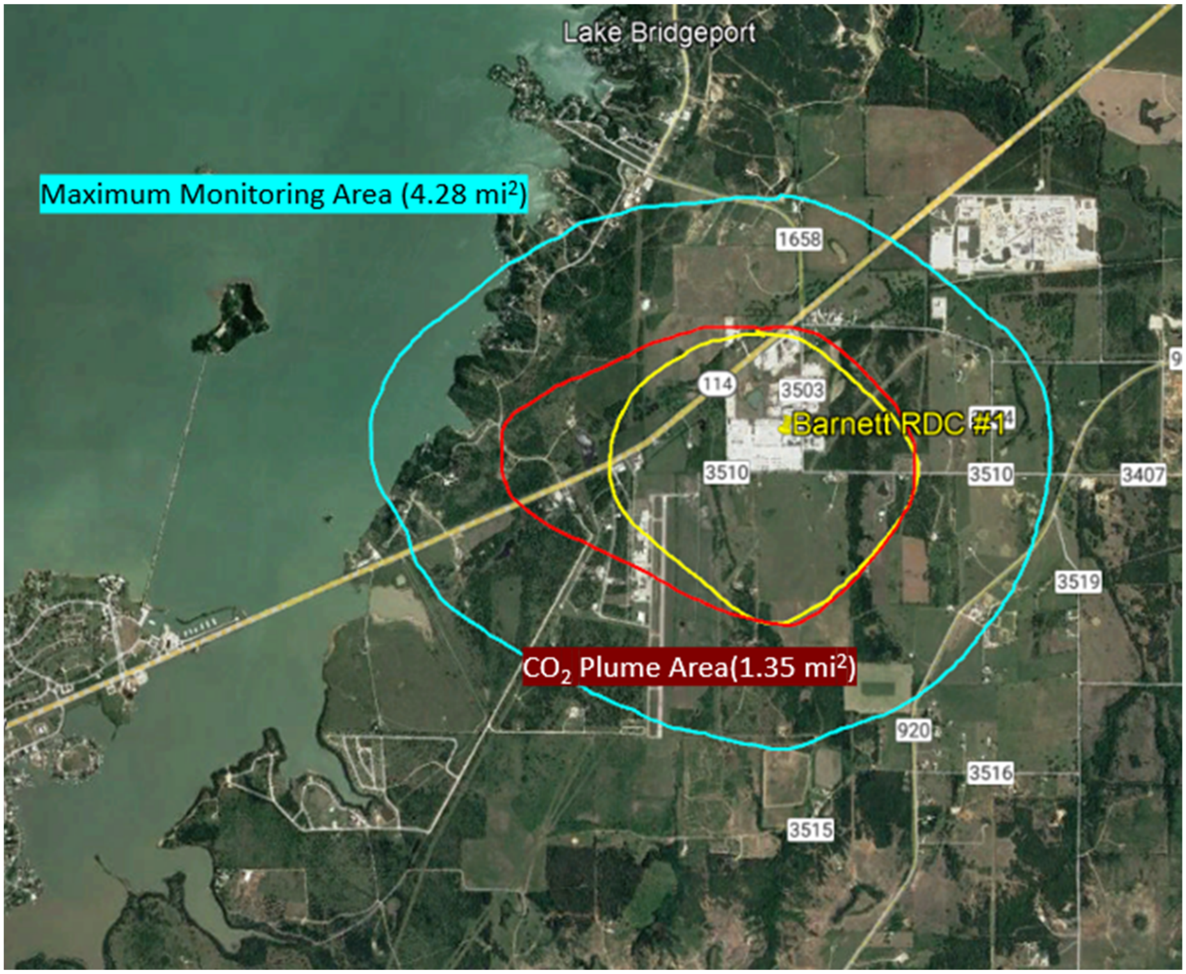

Figure 17. Simulation Results Showing CO_2 Plumes (end of injection – yellow, after 50 years of injection – red) and the Maximum Monitoring Area (blue).

Figure 18 illustrates CO_2 mass injection rate, cumulative CO_2 injection mass, and bottom hole pressure at the Barnett RDC #1 well as modeled. The bottom hole pressure remained well under the bottom hole pressure constraint. The maximum bottom hole pressure reached is 4,434 psi (1,090 psi lower than the BHP constraint) which occurs 6 months after the injection started. This spike is anticipated to be a result of near wellbore effects arising from CO_2 forcing its way into the brine-filled porous media. Upon reaching a critical mass to transition from capillary driven to advection driven flow, the BHP starts to decline until the end of injection while keeping the injection rate constant. The BHP then falls until the end of injection.

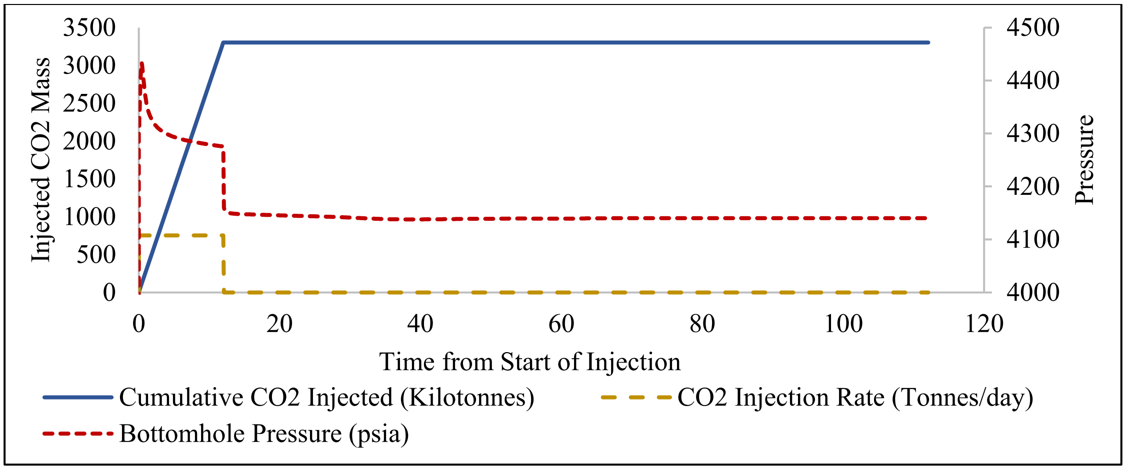

Figure 18. Modeled Injection Profile at Barnett RDC #1 Well.

Section 4 – Delineation of Monitoring Area

4.1. Maximum Monitoring Area (MMA)

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The numerical simulation using CMG-GEM as discussed above was used to estimate the size and migration of the CO_2 plume. The model injected into the Ellenburger E formation. CO_2 injection was modeled for 12 years followed by 100 years post injection. Results indicated that the plume ceased to migrate after 50 years post injection. For more information on the simulation construction and setup, please see the discussion in Section 3.8. A 5% cutoff of molar gas concentration was used to determine the boundary of the CO_2 plume. The area of the maximum monitoring area was determined to be 4.28 square miles with the greatest extent reaching 1.62 miles from the injector. **Figure 19** shows the end of injection plume (yellow), the 50-year post injection plume (red), and the maximum monitoring area using a half mile buffer (blue).

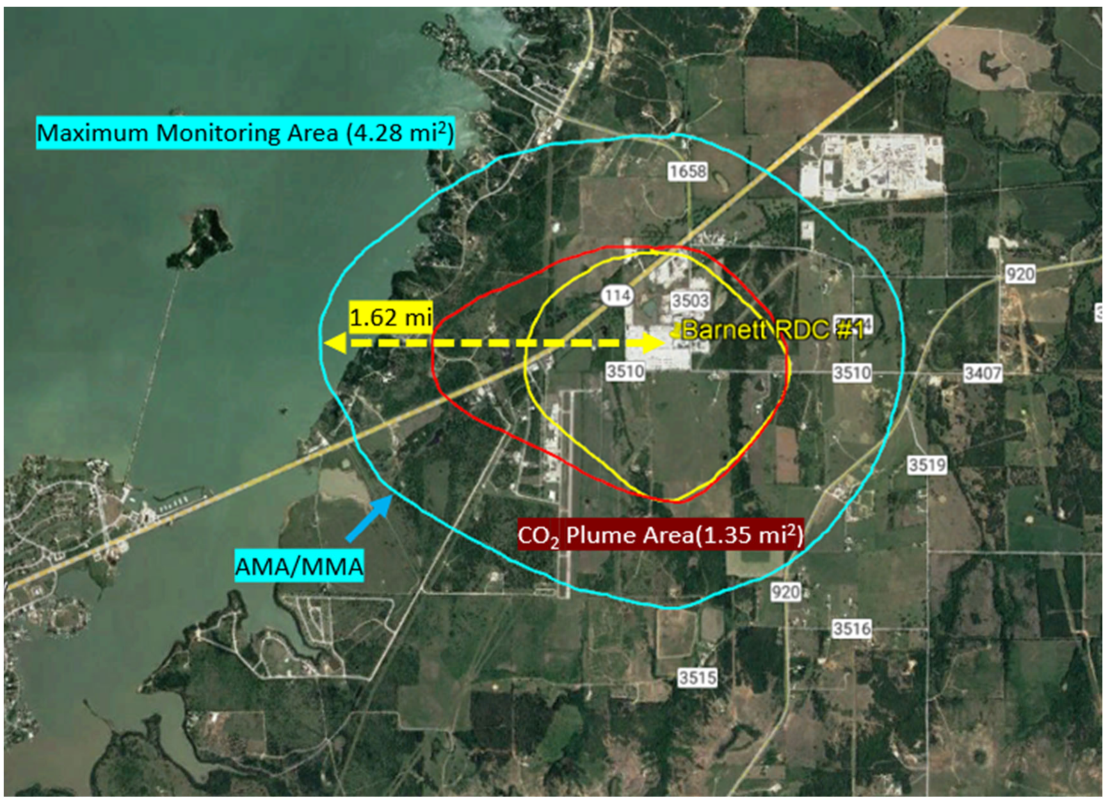

Figure 19. Maximum Monitoring Area (blue), End of Injection Plume (yellow), and 50-year Post Injection Plume (red) as Modeled at the Barnett RDC #1 Well.

Section 4.2. Active Monitoring Area (AMA)

As discussed in Chapter 3, there are no structural/geological features within the project area that could cause the unintended migration of the CO_2 plume. The only potential leakage pathways that exist are well penetrations and the surface equipment. Leakage from groundwater wells, faults and

fractures, leakage through the confining layer, and seismicity events are expected to be highly improbable. That said, these leakage pathways have been considered and options to monitor them are discussed in Section 4 and Section 5. Sufficient care and consideration will be provided to monitoring these pathways, if any, and simulation models will be calibrated with new data as appropriate.

BKV adhered to the definition of AMA provided in 40 CFR 98.449 to delineate the AMA. As noted in Section 6, BKV proposes to monitor the injection site from year one through year 14 which includes 12 years of injection plus two years of post-injection monitoring. As defined in 40 CFR 98.449, the AMA must be delineated by superposition of

(1) The area projected to contain the free phase CO_2 plume at the end of year 14, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

(2) The area projected to contain the free phase CO_2 plume at the end of year 19.

As noted in Section 4.1, BKV utilized the plume area after 50 years of post-injection plus a one-half mile buffer to determine the MMA, which far exceeds the definition of AMA set forth in 40 CFR 98.449. Therefore, the AMA is proposed to have the same boundary as the MMA, which adequately covers the area that is required by 40 CFR 98.449. **Figure 19** shows the MMA which is the same as the AMA. **Figure 20** indicates the AMA/MMA (blue line) and currently existing water and oil/gas wells within this area. None of these wells were found to penetrate the Ellenburger within the project area. Water wells in the region are shallow with drilled depths up to 300 feet from surface. Additional discussion on well infrastructure within the project area can be found in later sections of this document.

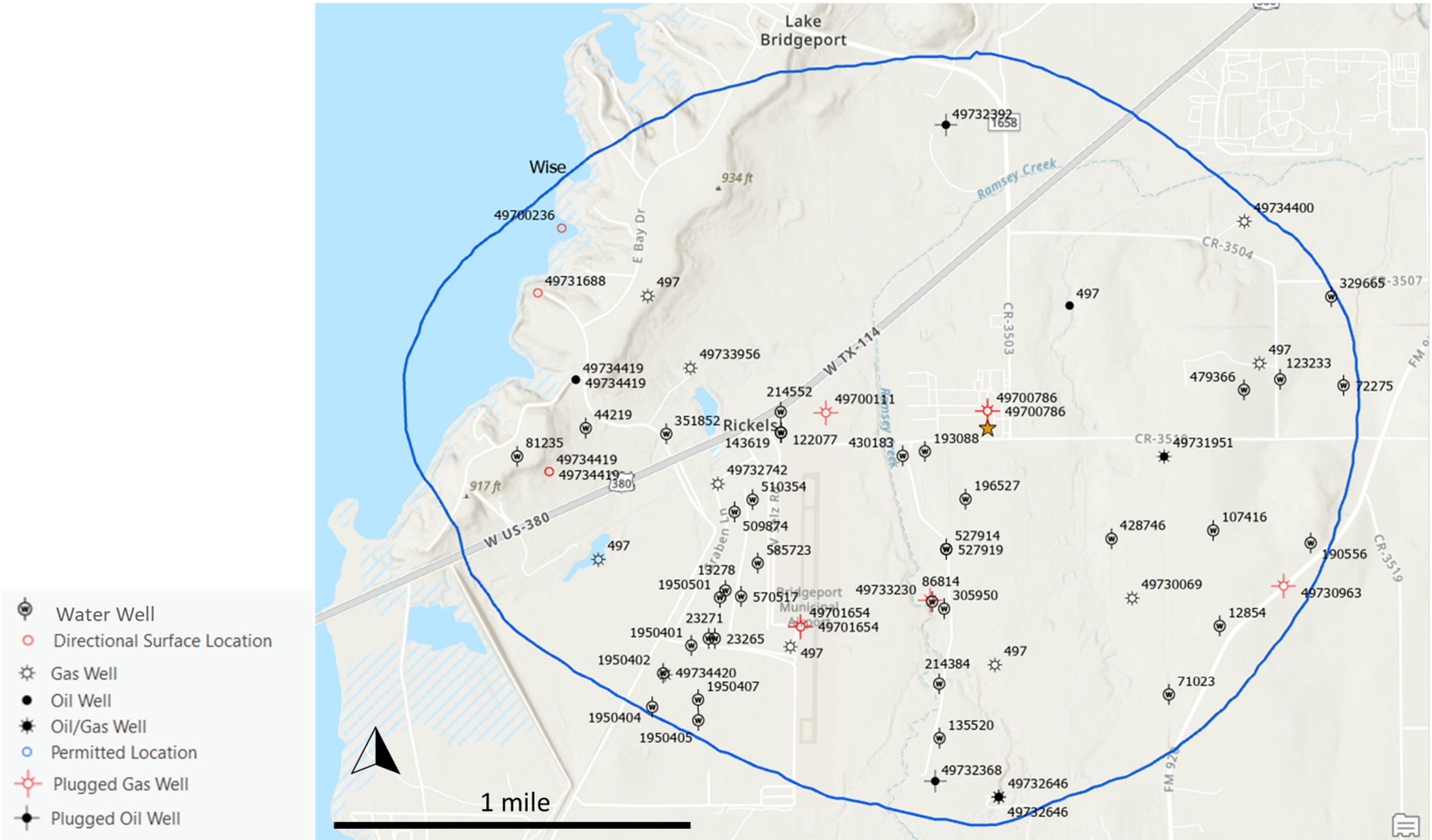

Figure 20. Maximum/Active Monitoring Area (blue) and existing wells within the project AMA/MMA.

Section 5 – Identification and Evaluation of Potential Leakage Pathways to Surface

5.1. Potential Leakage from Surface Equipment

dCarbon's surface facilities at Bridgeport and at the injection well site are specifically designed for injecting the CO_2 stream described above, including 20-30 ppm H_2S, and therefore minimize leakage points such as valves and flanges following industry standards and best practices. All BKV and dCarbon field personal are required to wear gas monitors which detect H_2S. A shut-in valve is located at the wellhead in case of emergency. The compressor will also have an emergency shut down switch which can be activated in case of unexpected operating conditions.

Additionally, the compressor facility, pipeline, and injection well locations will all be subjected to Auditory, Visual, and Olfactory ("AVO") and Forward Looking InfraRed (FLIR) leak detection per BKV and dCarbon safety and operations standards. These recurring inspections, which are standard for detecting leaks and malfunctioning equipment in the gas production industry, will aid in the rapid detection of any potential leaks which may occur. As a part of these inspections, operations personnel are frequently able to repair leaks immediately by tightening valves, flanges, or similar equipment. Any leaks that are detected will be analyzed to determine that amount of CO_2 which may have leaked. These quantities, if any exist, will be included in recurring reporting.

5.2. Leakage from Approved, Not Yet Drilled Wells

There are no active well permits within the MMA. There are multiple expired well permits within the MMA which would require re-permitting before being drilled. Details on many of the expired permit locations are included in Attachment B.

5.3. Leakage from Existing Wells

There are 20 existing wells within the MMA. Of these 20 wells, 14 have digital records available on the TRRC website (**Table 6**), and, six wells have been plugged and abandoned, while eight remain active. However, all 14 of these wells are shallower than the proposed disposal interval from this project. In fact, the targeted injection interval (> 9,350 feet) is approximately 3,000 feet deeper and separated by numerous impermeable shales from the deepest existing well in the MMA (API 42-497-34419 which has a total depth of 6,334 feet). These wells are represented relative to the project MMA in **Figure 20**. The six remaining wells which were drilled within the MMA (Table 7) do not have digital records available on the TRRC website, but dCarbon acquired paper copies of the well permit information, attached herein as Attachment B. All six wells were drilled significantly shallower than the target Ellenburger formation. In fact, the deepest of the six wells was drilled to 6,155 feet TVD, several thousand feet shallower than the Ellenburger formation.

Additionally, the wellbore design of the injection well contains three layers of steel casing, each of which runs entirely to the surface to ensure complete isolation of wellbore fluids. Each of these three casing strings will be cemented entirely to the surface and inspected with cement bond logs to ensure wellbore integrity. Finally, all injection into the well will occur through a final steel tubing string which is secured in place with a permanent packer. All these aspects of wellbore construction are designed to ensure that all CO_2 is injected into the target formation and that there are no leakage pathways from the wellbore directly into shallower formations.

Table 6. Existing Oil & Gas wells in MMA with digital TRRC records.

API	*Well Type*	*Latitude*	*Longitude*	*Status*	*Total Depth (feet)*	*Operator*	*Plug Date*
49730069	Gas	33.17562	-97.8131	Open	6,128	Scout Energy Management, LLC	-
49732742	Gas	33.18044	-97.8331	Open	5,900	Eagleridge Operating, LLC	-
49733956	Gas	33.18517	-97.8344	Open	5,950	Eagleridge Operating, LLC	-
49734400	Gas	33.19088	-97.8075	Open	5,920	Eagleridge Operating, LLC	-
49734420	Gas	33.17271	-97.8357	Open	5,950	Eagleridge Operating, LLC	-
49734419	Oil	33.18474	-97.8399	Open	6,334	Merit Energy Company	-
49734419	Oil	33.18474	-97.8399	Open	6,334	Eagleridge Operating, LLC	-
49731951	Oil/Gas	33.18137	-97.8115	Open	6,125	Scout Energy Management, LLC	-
49700111	Plugged (Gas)	33.18328	-97.8278	Plugged	5,899	Mitchell Energy Corporation	4/16/1996
49700786	Plugged (Gas)	33.18328	-97.82	Plugged	5,918	Williams Petroleum Company, Inc.	2/13/2015
49701654	Plugged (Gas)	33.17462	-97.8292	Plugged	6,028	Enserch Exploration, Inc.	9/27/1996
49733230	Plugged (Gas)	33.17563	-97.8229	Plugged	5,950	Merit Energy Company	11/5/2012
49732368	Plugged (Oil)	33.16827	-97.8227	Plugged	6,000	Merit Energy Company	1/8/2001
49732392	Plugged (Oil)	33.19493	-97.8219	Plugged	5,964	Merit Energy Company	3/19/1999

Table 7. Existing Oil & Gas wells in MMA without digital TRRC records.

API	*Well Type*	*Latitude*	*Longitude*	*Status*	*Total Depth (feet)*	*Att. B Label*	*Operator*
497-1	Gas	33.177438	-97.838912	Plugged	5,965	G	Lone Star Production
497-1	Gas	33.1738	-97.829657	Plugged	6,027	F	Lone Star Production
497-1A	Gas	33.1851	-97.806835	Plugged	5,996	D	Lone Star Production
497-1	Gas	33.188107	-97.83638	Plugged	5,602	A	A'Mell Oil Properties
497-1	Gas	33.172971	-97.819788	Plugged	6,155	E	Upham Oil & Gas
497-1	Oil	33.187529	-97.815993	Plugged	6,028	C	Enserch Exploration

5.4. Potential Leakage from Fractures and Faults

Several episodes of fault formation took place in the Fort Worth Basin, based on 3D seismic data interpretation conducted by dCarbon. The oldest set of faults displaced Ordovician rocks but did not displace Mississippian rocks like the Barnett Shale. A younger set of faults displaced Mississippian and older rocks and appear to be related to the Ouachita Front collision. These faults show displacement up into the Pennsylvanian rocks as high as the Strawn. These larger, younger faults have larger displacement but are relatively sparce.

No faulting is interpreted in the MMA around the Barnett RDC #1 based on available subsurface data including 3D seismic data. Dynamic modeling conducted to date indicates that the CO_2 plume will not intersect any mapped faults, based on dCarbon's existing 3D seismic interpretations.

Karst development is present in some areas at the top of the Ellenburger, primarily where the overlying Viola and Simpson Formations were eroded. The karst formation is often developed in the upper several hundred feet of an exposed carbonate (Ellenburger subunit A) where fresh water is able to dissolve the rock. Subsequent loading of sediment can cause the roof of the cave to collapse, with overlying sediment filling the void[17].

The injection interval, the Ellenburger "E", appears to be below the portion of the upper Ellenburger affected by the karst collapses. This suggests that the Ellenburger "C" will remain a continuous upper seal even in karst areas. There are no interpreted karst features that the CO_2 plume or pressure front intersects based on the dynamic modeling. Small karst features sit at the southern edge of the MMA but only seem to have impacted the upper 200 feet of the Ellenburger, leaving 3,000 feet of Ellenburger apparently unaffected.

Even if the plume reaches the karst features on the south end of the MMA and the Ellenburger "C" upper seal is not intact, the overlying and impermeable Barnett Shale, Marble Falls Limestone, and the Atoka Shales are expected to prevent migration to shallower depths.

[17] Zeng, H, 2011. Characterizing seismic bright spots in deeply buried, Ordovician Paleokarst strata, Central Tabei uplift, Tarim Basin, Western China. *Geophysics* Vol 76 Number 4, 2011.

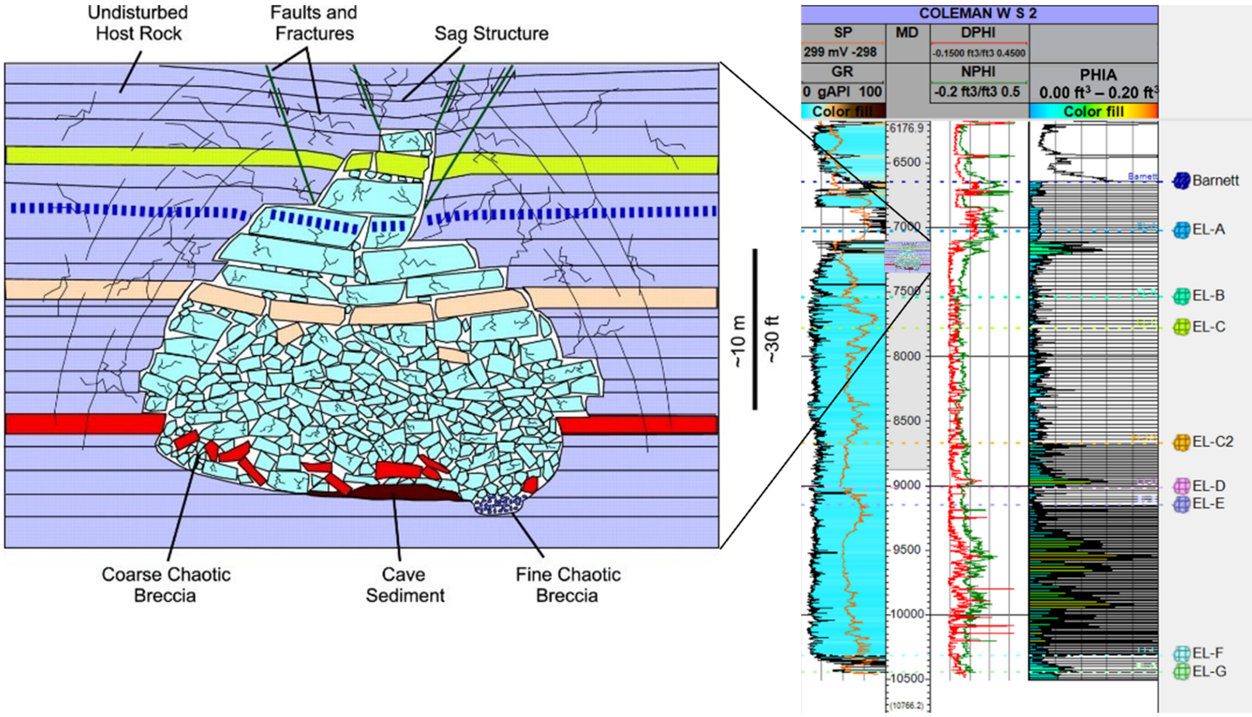

Figure 21. A schematic diagram showing the geometry and component facies of a single cave passage buried in deeper subsurface where collapse and extensive brecciation occurred (modified from Zeng *et al.*,[18]). The typical scale of the karst features is shown on the right placing the feature on the W.S. Coleman #2 well log. Note that the interpreted karst features are only observed in the upper portion of the Ellenburger, above the confining unit Ellenburger subunit C.

[18] Zeng, H., *et al*., 2011. Three-dimensional seismic geomorphology and analysis of the Ordovician paleokarst drainage system in the central Tabei Uplift, northern Tarim Basin, western China. AAPG Bulletin (2011) 95 (12), pgs 2061–2083.

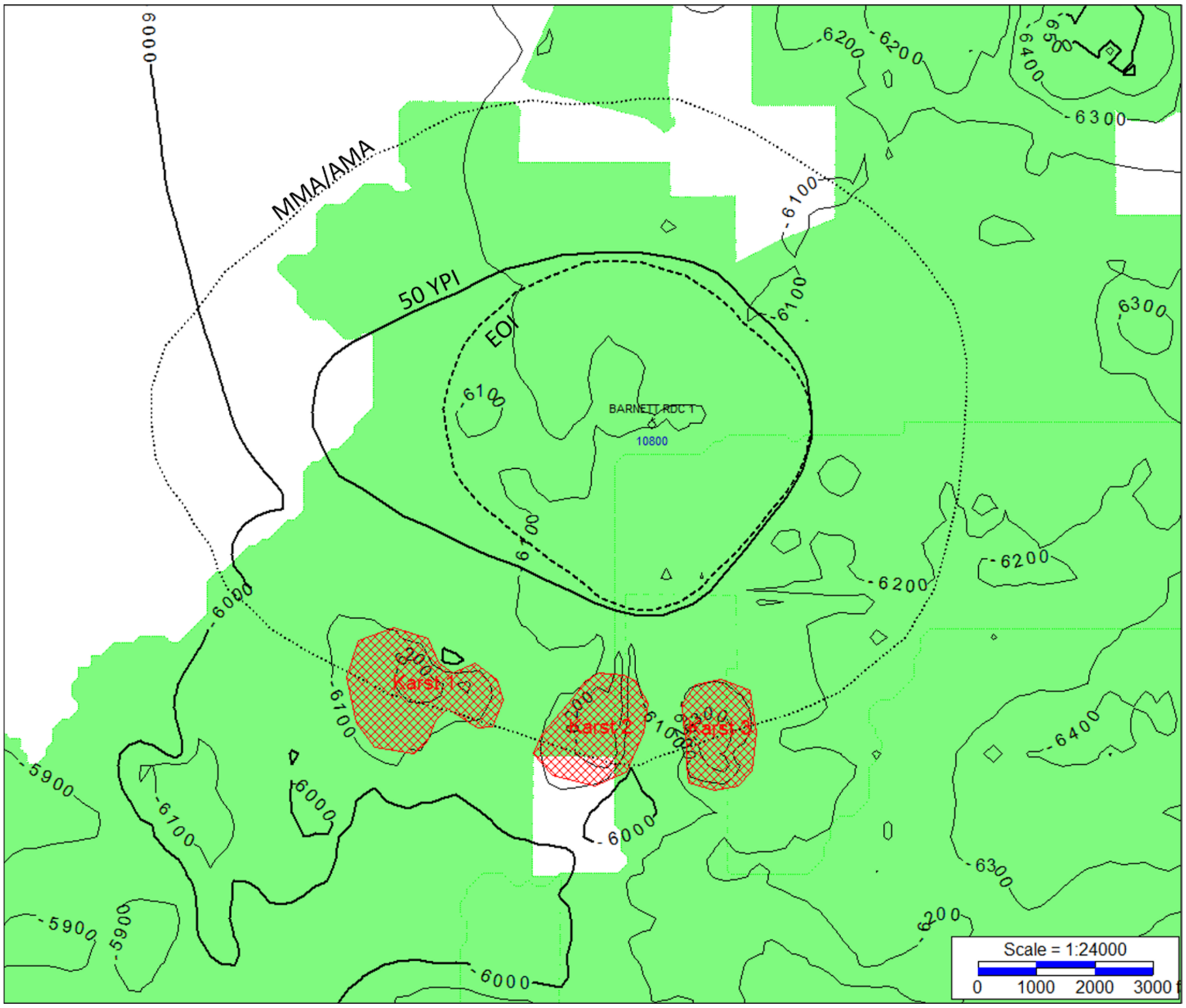

Figure 22. RDC 1 well location with top Ellenburger structural contours (TVDSS), 3D seismic coverage (green), and. mapped Ellenburger karst on the southern edges of the MMA/AMA. The CO_2 plume size at the end of injection and 50 years post-injection are also shown from Figure 19.

5.5 Leakage Through Confining Layers

The Ellenburger subunit E injection zone is bound competent confining zones above in the Ellenburger subunit C and below the injection interval in the Ellenburger subunit F zones.. Secondary seals above the Ellenburger subunit C include the Ellenburger subunit A, subunit B, Barnett Shale, Marble Falls Limestone, and the Atoka Shales. Ellenburger subunit F also serves as a secondary lower confining layer. Overall, there is in excess of 2,000 feet of impermeable rock between the injection zone and the deepest well penetrations, making vertical migration past the primary and secondary confining units unlikely.

5.6 Leakage from Natural or Induced Seismicity

The Barnett RDC #1 location is in an area of the Fort Worth Basin that is inactive seismically, as illustrated in Section 3.5. Earthquake catalogs from both the USGS (1950-present) and TexNet (2017-present) indicate no earthquake locations within 20 miles of the Barnett RDC #1.

The closest earthquake locations are 20+ miles to the southeast in an area of larger, regional faulting. In 2013 and 2014, a series of earthquakes were felt near the towns of Reno and Azle, Texas. The Texas Railroad Commission held hearings that investigated whether oil and gas activities near the earthquakes were responsible for the activity. The Railroad Commission was unable to determine whether oil and gas activities were responsible for the earthquake sequence.

Since no faults are mapped that cut from the injection interval through the sealing limestones and shales of the Pennsylvanian, no leakage is expected due to induced seismic activity.

However, dCarbon also plans several operational procedures to monitor injection-induced seismicity and to immediately identify any minor or major seismic events in the area. Before initiating injection into the well, dCarbon will be installing both surface and bottomhole pressure gauges, so that reservoir pressure and injection pressure can be monitored. Additionally, dCarbon, consistent with RRC guidelines and permit conditions, plans to maintain bottomhole injection pressure below formation fracture pressure, and also maintain surface pressure below 0.50 psi/ft gradient when measured from the top of the injection interval. Finally, dCarbon plans to perform periodic pressure fall-off tests (PFOT) to determine and monitor reservoir pressure to ensure unexpected static pressure increases are not observed. These measures are designed to prevent induced fracturing of the formation or increase the likelihood of induced seismicity. Should any unexpected increase in formation pressure be detected, dCarbon Ventures can perform Fault Slip Potential (FSP) analysis[19] to evaluate the risk of induced seismicity on the closest mapped faults and determined that the risk of induced seismicity is minimal. dCarbon plans to update this modeling based on geologic data collected during drilling the Barnett RDC #1 well. If there is a concern related to abnormal pressures or seismicity related to operations at the well, dCarbon will shut-in the well to investigate further.

Furthermore, dCarbon plans to install new ground seismic monitoring arrays near the injection site that are designed to detect any seismic events in the area, natural or induced. Any seismic events detected in the area will be analyzed and geolocated in the subsurface to investigate their origin and if they may have impacts to the injection program or confining layers. Additionally, the TexNet seismic monitoring program will also be monitored to ensure any material seismic events in the area are investigated.

5.7 Leakage from Lateral Migration

The structural dip of the Ellenburger in the vicinity of the Barnett RDC #1 injection site is about one degree up to the west (100 feet/mile) **Figure 23**). The closest well that penetrates the Ellenburger subunit E injection interval up dip from the injection site is more than 10 miles to the

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[19] Walsh, F. R. I., M. D. Zoback, D. Pais, M.Weingartern, and T. Tyrell (2017). FSP 1.0: A Program for Probabilistic Estimation of Fault Slip Potential Resulting from Fluid Injection, available at: https://scits.stanford.edu/software

WSW. The closest well that penetrates the injection interval is downdip to the east approximately five miles (W S Coleman #2).

Dynamic modeling of the CO_2 plume has the maximum extent of the plume traveling less than one mile, with the maximum distance traveled to the west. Given that the distance to the next penetration of the injection interval is on the order 10 times the distance the plume is expected to travel, no leakage from lateral migration is expected.

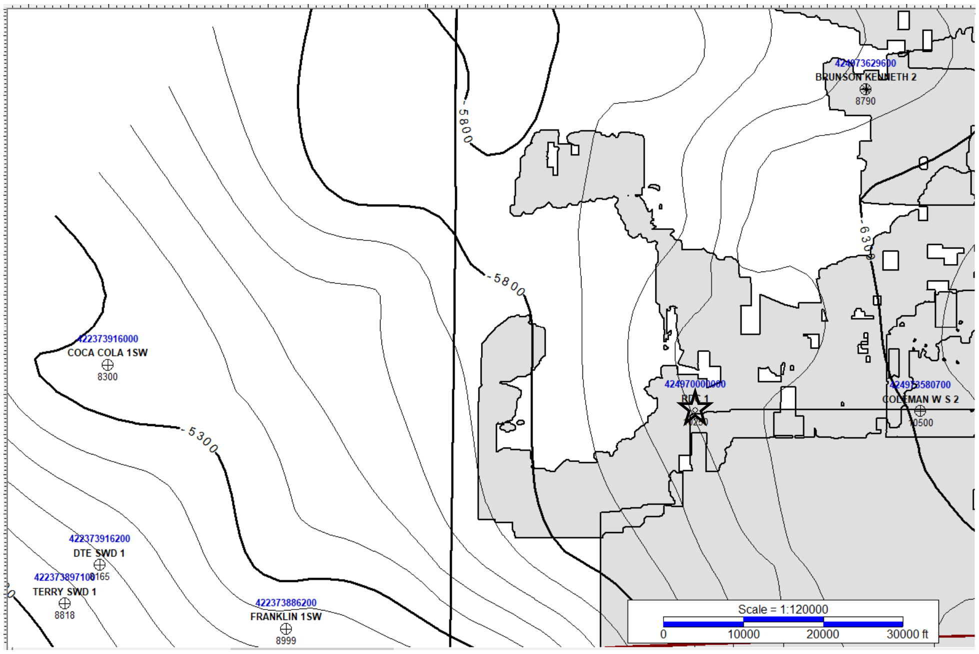

Figure 23. Top of Ordovician Unconformity (top Ellenburger) regional subsea structure in the vicinity of the Barnett RDC #1 location (star). Wells shown penetrate the injection interval. Additional wells (not shown) were used to develop the structure map. Gray areas represent areas covered by 3D seismic data.

Section 6 – Plan of Action for Detecting and Quantifying Surface Leakage of CO_2

This section discusses the strategy that dCarbon will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in previous sections to meet the requirements of 40 CFR §98.448(a)(3). As the injected stream contains both H_2S and CO_2, any observation of H_2S will serve as a preliminary indicator for CO_2 leakage and therefore the monitoring systems to detect H_2S will also suggest a leak of CO_2. This section summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur. Monitoring will occur during the planned 12-year injection period, or otherwise until the cessation of operations, plus a proposed two-year post-injection period.

6.1. Leakage from Surface Equipment

As the CO_2 compressor station, pipeline, and injection well are all designed to handle expected concentrations, temperatures, and pressures of H_2S and CO_2, any leakage from surface equipment would be quickly detected and addressed. The facility is designed to minimize potential leakage points by following ASME, API and other industry standards, including standards pertaining to material selection and construction. Additionally, connections are designed to minimize corrosion and leakage points. The H_2S in the stream is easily detectable and serves as an indicator for the release of CO_2. The facility and well will be monitored for H_2S and CO_2 concentration increases; this monitoring equipment will be set with a high alarm setpoint for H_2S that automatically alerts field personnel of abnormalities. Additionally, all dCarbon and BKV field personnel are required to wear H_2S monitors, which will trigger the alarm at low levels of H_2S (typically 1 ppm). The injection facility will be continuously monitored through automated systems that are designed to identify abnormalities in operational conditions. In addition, field personnel conduct daily AVO field inspections of gauges, monitors, and leak indicators. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system and analysis of liquids collected from the line. These inspections, in addition to the automated systems, allow dCarbon to quickly identify and respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5).

Additionally, CO_2 for injection will be metered in three locations for redundancy. The first will be at an orifice style or Coriolis meter at the interface between the Bridgeport Gas Plant and dCarbon's compressor. This location will meter the CO_2 in gas phase (Figure 24a and Figure 24b). Once the CO_2 is compressed to supercritical, it will pass through a Coriolis meter and gas chromatograph (GC) for measurement and compositional analysis and then be transported approximately 6,815 feet via pipeline (See Figure 15) to the injection well site. The CO_2 will then be metered a final time at the injection well site, immediately upstream of the injection wellhead itself, with another Coriolis meter. The CO_2 is expected to be in a supercritical phase / dense phase at this point. The meters will each be calibrated to industry standards. Any discrepancies in CO_2 throughput between the meters will be investigated and reconciled. Any CO_2 that is determined to have leaked or not been received at the injection wellhead will be quantified using the procedures specified in subpart W of the GHGRP, reported as specified in 40 CFR §98.448(a)(5), and subtracted from reported injection volumes. Gas samples and gas chromatograph analyses will be taken frequently to confirm stream composition and calibrate/re-calibrate meters if necessary. At a minimum, these samples will be taken once a month. Minimal variation of concentration and composition are expected, but will be included in regulatory filings as appropriate.

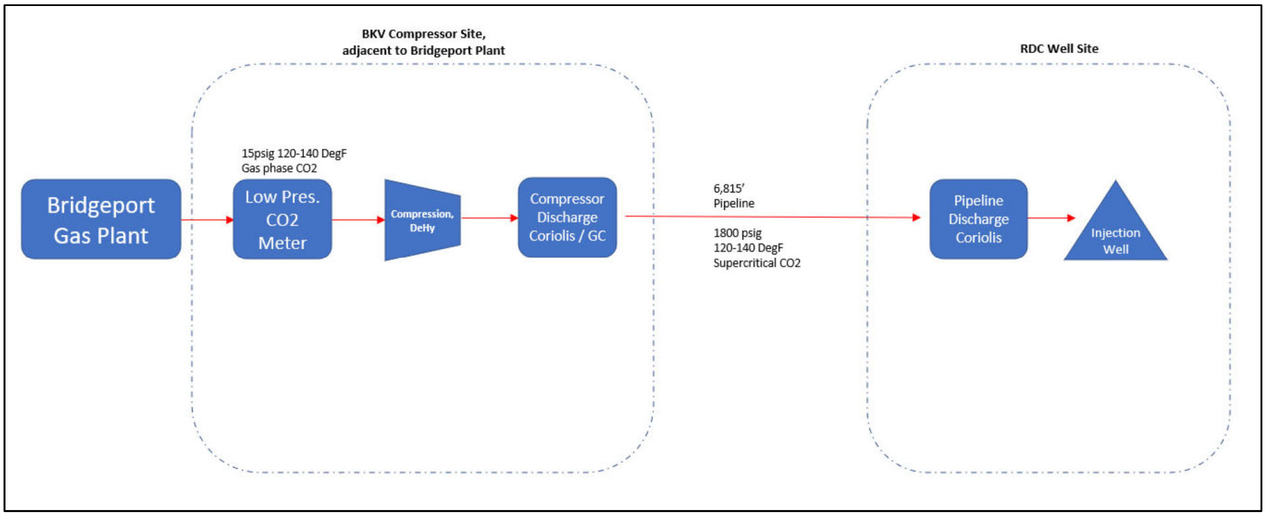

Figure 24a. Facility diagram and two metering points

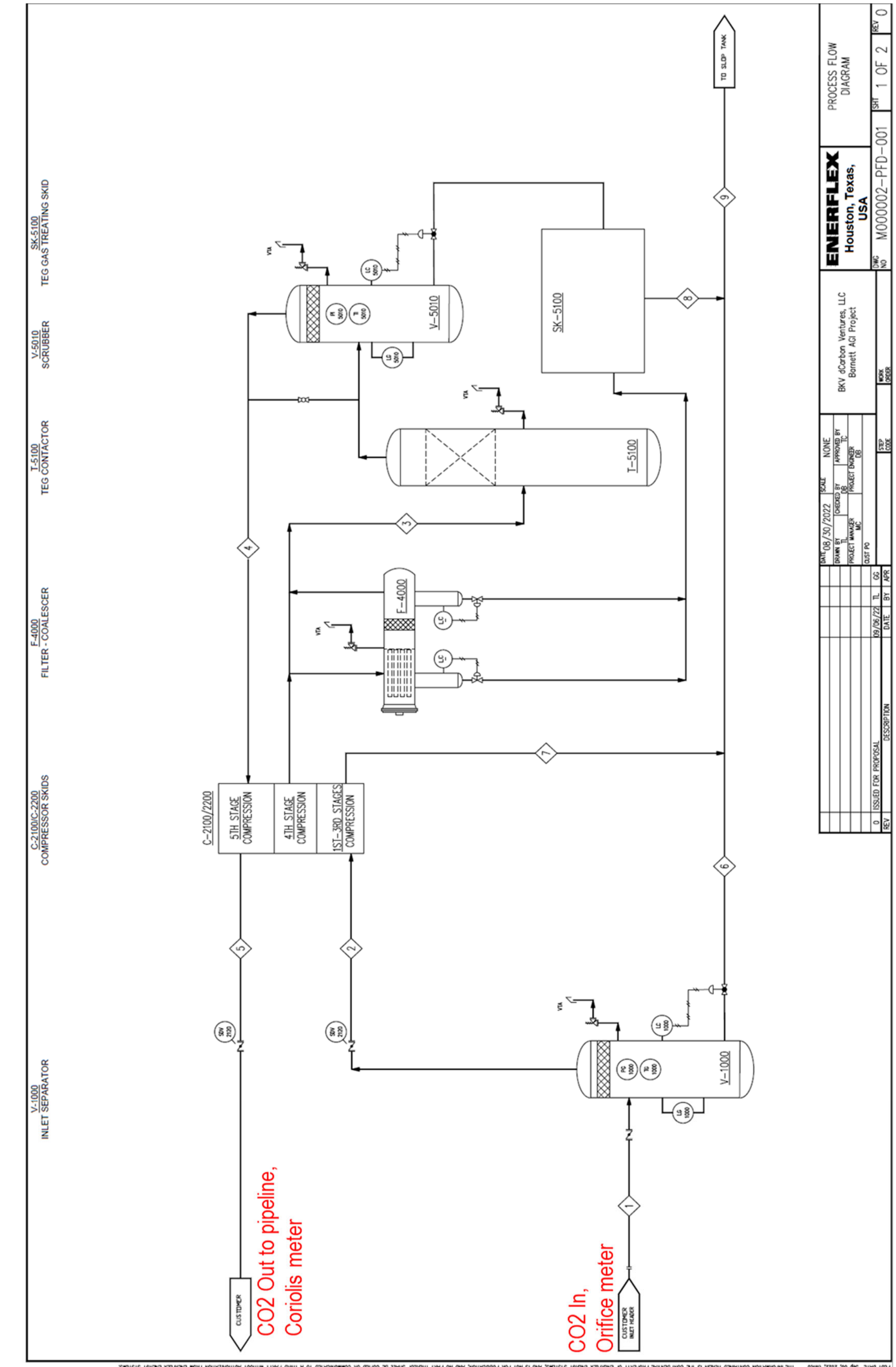

Figure 24b. Compression facility process flow diagram and indicative metering locations

6.2. Leakage from Existing and Future Wells within the Monitoring Area

As previously discussed, there are no wells in the MMA currently existing, approved, or pending which penetrate as deep as the Ellenburger injection zone. However, dCarbon will reverify the status and public information for all proposed and approved drilling permits within the MMA quarterly. If any wells are proposed, permitted, or drilled within the MMA, BKV will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, dCarbon will continuously monitor and collect injection volumes, pressures, temperatures, and gas composition data for the injection well. This data will be reviewed by qualified personnel and will follow response and reporting procedures when data is outside acceptable performance limits. Finally, dCarbon will update the MRV plan if any new wells are drilled within the MMA, or if any other material change to the project occurs.

The injection well has pressure and temperature gauges monitoring the injection stream at the wellhead as well as bottomhole pressure and temperature gauges near the bottom of the tubing. The downhole gauges will monitor the inside of the tubing (injection stream) as well as the annulus. A change of pressure on the annulus would indicate the presence of a possible leak requiring remediation. Mechanical Integrity Tests (MITs) performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated, and the leak mitigated.

In the unlikely event that any CO_2 leaks occur into existing or future wells in the monitoring area, dCarbon will endeavor to work with the operator(s) of those wells and/or midstream providers to take wellhead gas samples to quantify variations or increases of CO_2 compared with historical or baseline CO_2 concentrations. Any measurable increases in CO_2 which may be confidently attributed to injection volumes from the Barnett RDC #1 well will be calculated using standard engineering procedures for estimating potential well leakage determined to be appropriate for the situation, will be documented and reported in the annual monitoring report and subtracted from reported injection volumes. Additionally, dCarbon Ventures will evaluate and execute any additional downhole remediations (eg well workovers, such as adding plugs, remedial cement jobs, etc.) that could address leakage from the injection well to the existing and future wells in the area if necessary and practical.

6.3 Leakage from Faults and Fractures

No faults or fractures have been identified that would allow CO_2 to migrate vertically to zones with USDWs or to the surface In the unlikely event that such leakage from faults or fractures occur, dCarbon will determine which standard engineering techniques for estimating potential leakage from the faults and fractures is appropriate for the situation to estimate any leakage from faults and fractures, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.4. Leakage through Confining Layers

Leakage through confining layers is improbable, given the number and thickness of layers between the injection zone and potable groundwater. Groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple confining layers.

In the unlikely event CO_2 leakage occurs as a result of leakage through the confining seal, it is also unlikely that the leak would result in surface leakage. As with any CO_2 leakage, however, should it occur, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation to estimate any leakage, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.5. Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, dCarbon plans to install a seismic monitoring station in the general area of the Barnett RDC #1 well. This monitoring station will augment the TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, dCarbon will review the injection volumes and pressures at the Barnett RDC #1 well to determine if any significant changes occur that would indicate potential leakage.

In the unlikely event CO_2 leakage occurs due to natural or induced seismicity, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.6. Leakage through Lateral Migration

The distances to the closest penetration of the Ellenburger injection interval are more than ten times the expected plume migration distance. As such, leakage through lateral migration is not expected. In addition, the wells that penetrate the injection interval are saltwater disposal wells. Injection into these wells would be expected to raise the reservoir pressure locally near the well, further limiting the ability of the CO_2 to access the saltwater injector well bore.

In the unlikely event CO_2 leakage occurs due lateral migration, similar to leakage through confining layers, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.7. Quantification of Leakage

In the unlikely event that CO_2 moves vertically past the primary and secondary confining layers as described earlier in Section 6, there are several methods dCarbon may utilize quantify leakage depending on the nature and severity of the leak. dCarbon has designed a monitoring network suited to detect CO_2 leaks before they interact with local resources, infrastructure, or USDW. dCarbon will consider additional standard and specialized engineering methods to quantify leaks as appropriate. dCarbon’s methodology to characterize, monitor, detect, and isolate leaks for quantification is described below.

As a primary monitoring and quantification strategy, dCarbon plans to install a deep groundwater monitoring well in the MMA that will used to monitor the USDW. This well will be deeper than any active groundwater wells in the area that typically draw water from shallow drinking water zones. dCarbon also plans to periodically sample the well to monitor for chemical composition. If BKV notices an increase in groundwater CO_2 concentration compared to baseline measurements, the increase in concentration will be analyzed volumetrically to provide a preliminary estimate of CO_2 leakage.

Any leakage that did extend to the surface could be characterized and quantified through surface surveillance in the project area paired with direct pressure, volume, and temperature (PVT) measurements. Currently available (and continuously improving) atmospheric sensing technology could be used to establish a baseline of ambient CO concentration in the project area and identify any fluctuations. Deviations from baseline concentration along with understanding of distance from potential leak sources can then be coupled with temporally matched meteorological data to semi quantitatively determine leak attribution and rate. Based on the size of leak, these qualified or quantified leak rates can be compared with spatiotemporally monitored PVT data to co-index or further refine leaked volumes from likely point sources.

Any diffuse leak or leak without an obvious single point source may require additional identification and quantification methods. dCarbon is working with a leading environmental services and data company which specializes in monitoring and quantifying gas leaks in various industrial settings. One such methods is involves utilizing fixed monitoring systems to detect CO_2. Additional system capabilities also include the deployment of an unmanned aerial vehicle (UAV) which is outfitted with an industry leading high fidelity CO_2 sensor capable of measuring concentrations as little as parts per billion (ppb). The UAV mobile surveillance platform possesses the ability to be flown on a programmable and highly replicable pattern across the MMA in both X and Y axis (longitude + latitude) as well as Z axis (height). Depending on the system's ability to obtain a reliable baseline across the MMA, areal deviation in CO_2 concentration could be measured, and diffuse leak sources could potentially be identified provided the emissions reach a sufficient threshold. dCarbon will also consider similar technologies with less spatial resolution or fidelity such as fixed wing flyovers and/or improving satellite data with UAV technology to screen for and support diffuse emissions identification and investigation.

Depending on the applicability and monitoring needs, dCarbon will also consider other monitoring quantification methods such as the Eddy Covariance Method (ECM)[20] This method utilizes gas fluxes and ambient meteorological conditions to detect and quantify leaks, although the ability to detect smaller leaks may limited[19]. Additionally, long open path tunable diode lasers could be used to measure distance averaged concentrations of CO_2 in the air, which could help quantify a leak of CO_2. This system could be paired with an array of short, closed path detectors (e.g. gas chromatographs) that are typically placed around a suspected leak or leak area to monitor point-source CO_2 concentration increases and to quantify leakage. BKV may also evaluate other emerging technologies for quantifying CO_2 leakage such as non-dispersive infra-red (NDIR) CO_2 sensors and

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[20] Korre, A., *et al.*, 2011. Quantification techniques for potential CO_2 leakage from geologic sites. Energy Procedia 4 (2011), pgs 3143-3420.

soil flux detectors. BKV may also utilize three-dimensional reservoir models that factor in faults and surface topography to predict CO_2 leakage locations, quantity, and timing. The applicability of such models in predicting and quantifying gas leaks has been tested and documented at the Leroy natural gas storage site in Wyoming, USA[21].

As the technology and equipment to quantify CO_2 leakage is rapidly evolving and expected to improve over time, dCarbon will continue to update its leak detection and quantification plans as appropriate. If dCarbon detects a leak associated with CO_2 injection at the Barnett RDC #1 well, all methods discussed in this section will be considered in addition to emerging technologies to determine the most applicable and effective method of quantification.

[21] Chen, M., *et al.*, 2013. Analysis of fault leakage from Leroy underground natural gas storage facility, Wyoming, USA. *Hydrogeology* (2013) 21, pgs 1429–1445.

Section 7 – Baseline Determinations

This section identifies the strategies that dCarbon will undertake to establish the expected baselines for monitoring CO_2 surface leakage per §98.448(a)(4). dCarbon will use the existing Supervisory Control and Data Acquisition (SCADA) monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. Daily inspections will be conducted by field personnel at the compressor facility and the injection well. These inspections will aid with identifying and addressing issues in a timely fashion in order to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations or abnormal AVO or FLIR observations, corrective actions would be taken to address such issues. As previously discussed, H_2S is present in the injection stream at a low concentration. All field personnel are required to wear personal H_2S monitors, which are set to trigger the alarm at ~1ppm levels of H_2S. Any alarm would trigger an immediate response to protect personnel and verify that the equipment and monitors are working properly. If monitors are working correctly and a leak is detected, immediate actions would be taken to secure the facility.

Any leakage would be detected and managed as per Texas regulations and dCarbon's safety and operations plans. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

Baseline groundwater quality and properties will be determined and monitored through the installation of a groundwater well near the injection well site. Samples will be taken and analyzed by a third-party laboratory to establish the baseline properties of the groundwater in the area.

Baseline seismicity in the area near the Barnett RDC #1 will be determined through the historical data from USGS and TexNet seismic array data. This information will be augmented by additional data from dCarbon's seismic monitoring array.

Section 8 – Site Specific Considerations for Determining the Mass of CO_2 Sequestered

This section identifies how dCarbon will calculate the mass of CO_2 injected, emitted, and sequestered. This also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, per 40 CFR §98.448(a)(5).

8.1. Mass of CO_2 Received

Per 40 CFR §98.443, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR §98.444(a)(4)." 40 CFR §98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received."

The CO_2 received for this injection well is wholly injected and not mixed with any other supply and the annual mass of CO_2 injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

8.2. Mass of CO_2 Injected

Per 40 CFR §98.444(b), since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

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 (metric tons

per quarter)

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

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent

CO_2, expressed as a decimal fraction)

p = Quarter of the year

u = Flow meter

8.3. Mass of CO_2 Produced

The injection well is not part of an enhanced oil recovery project; therefore no CO_2 will be produced.

8.4. Mass of CO_2 Emitted by Surface Leakage

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which may be hazardous for field personnel to perform a direct leak survey. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released as a result of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

$$CO_{2,E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

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

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

X = leakage pathway

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

8.5. Mass of CO_2 Sequestered

The mass of CO_2 sequestered in the subsurface geologic formations will be calculated based off Equation RR-12, as this well will not actively produce any oil or natural gas or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the Barnett RDC #1 facility in the reporting year.

$CO_{2,I}$ = Total annual CO_2 mass injected (metric tons) in the Barnett RDC #1 well in the reporting year.

$CO_{2,E}$ = 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 and the Barnett RDC #1 injection wellhead

Section 9 – Estimated Schedule for Implementation of MRV Plan

The injection well is expected to begin operation in the second half of 2023. Baseline data will be collected before injection begins and the MRV plan will be implemented upon receiving EPA approval.

Section 10 – Quality Assurance

10.1. CO_2 Injected

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a gas composition analyzer or representative sampling consistent with industry best practices.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer specifications

10.2. CO_2 Emissions from Leaks and Vented Emissions

- Gas detectors will be operated continuously, except for maintenance and calibration.
- Gas detectors will be calibrated according to manufacturer recommendations and API standards.
- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

10.3. Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to the requirements in 40 CFR §98.3(i).
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.
- Flow meter calibrations will be traceable to the National Institute of Standards and Technology (NIST).

All measured volumes of CO_2 will be converted to standard cubic feet at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1.0 atmosphere.

10.4. Missing Data

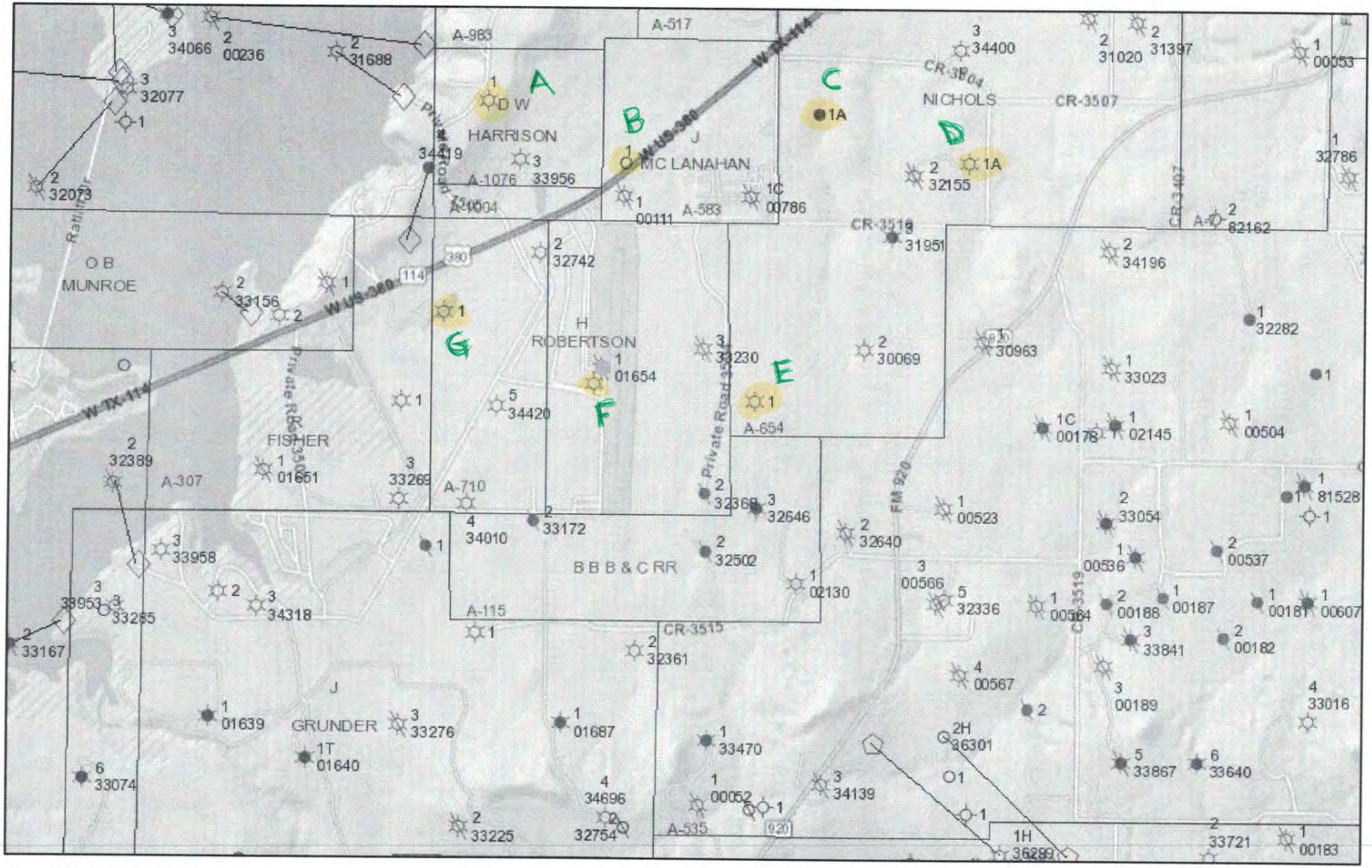
In accordance with 40 CFR §98.445, dCarbon will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in subpart W of 40 CFR §98.

Section 11 – Records Retention

dCarbon will retain records as required by 40 CFR §98.3(g). These records will be retained for at least three years and include:

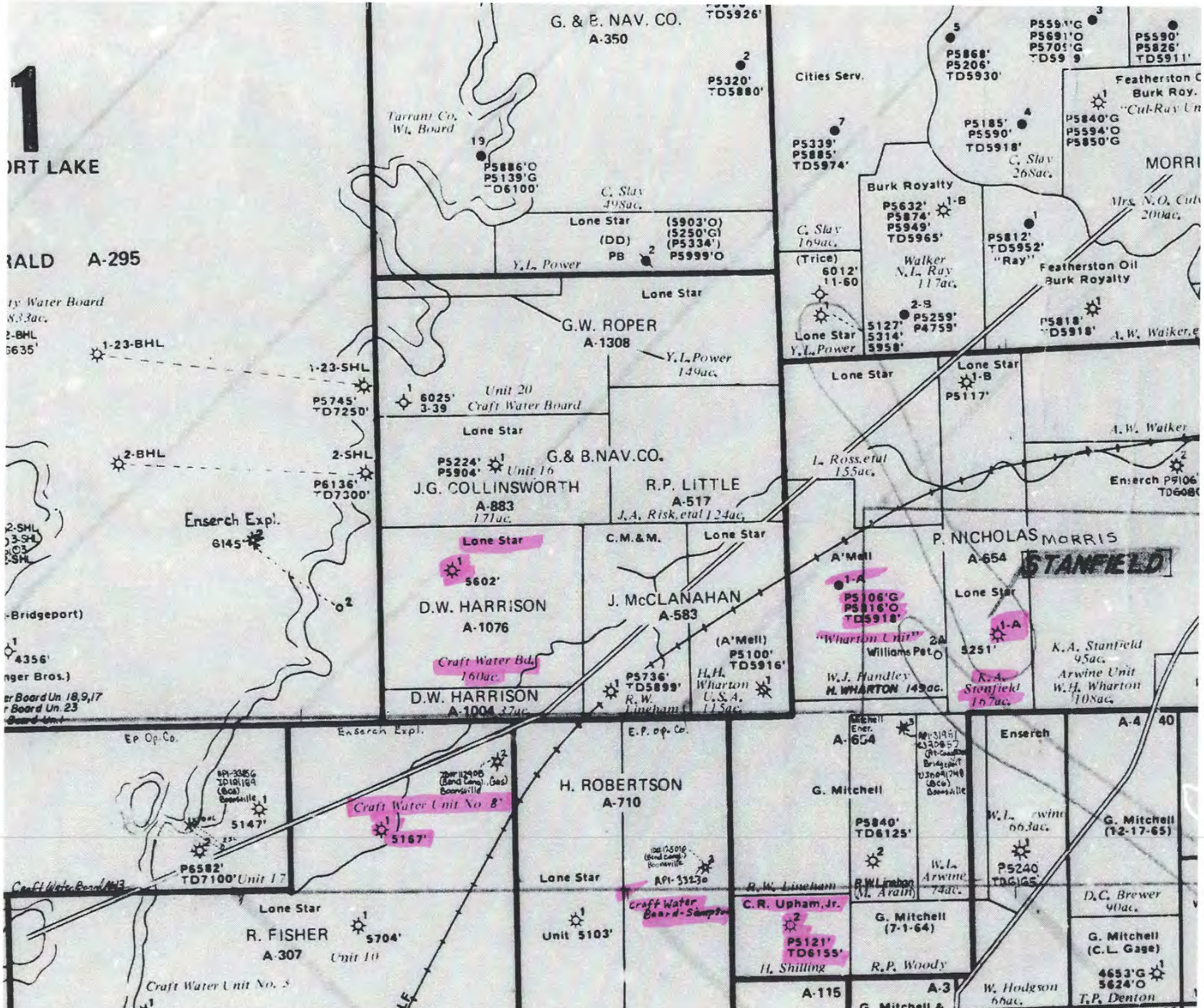
- Quarterly records of the CO_2 injected
- Volumetric flow at standard conditions
- Volumetric flow at operating conditions
- Operating temperature and pressure
- Concentration of the CO_2 stream
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate 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



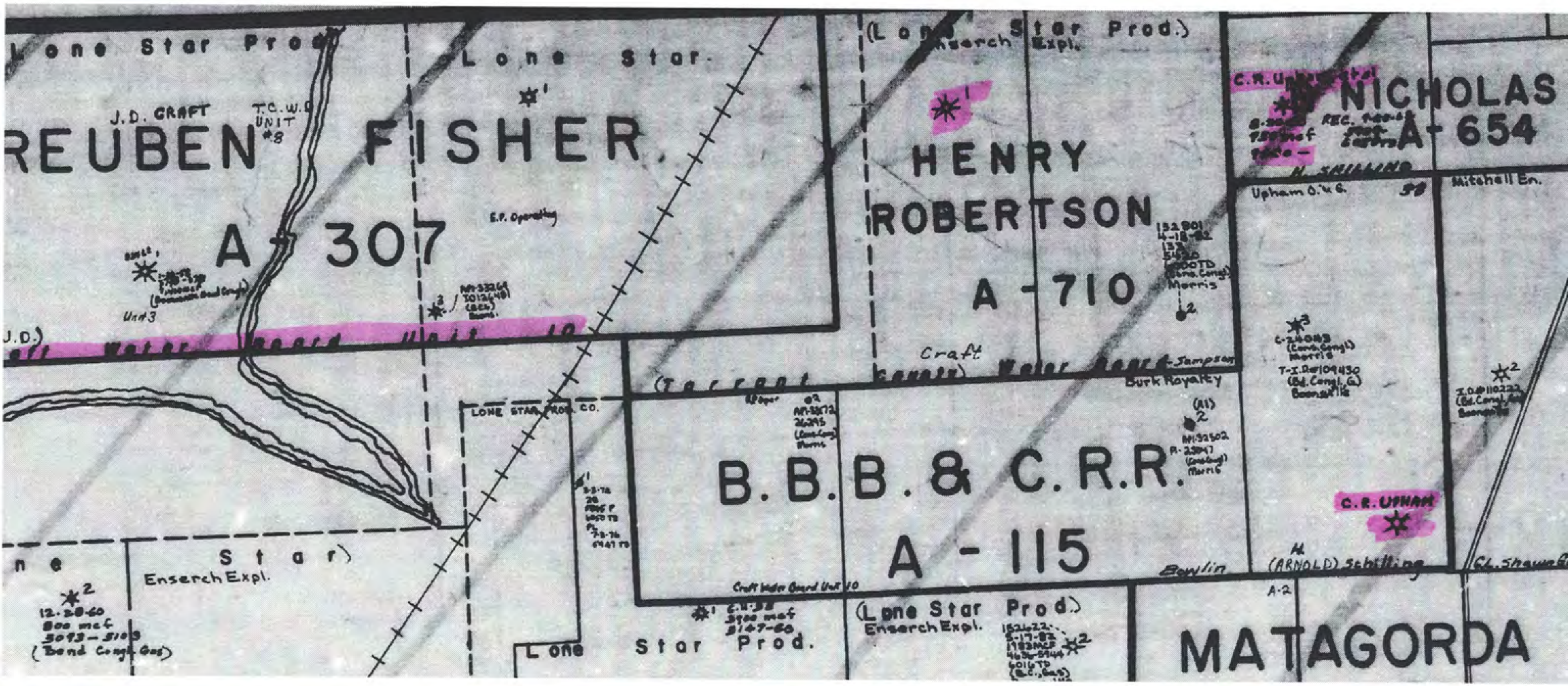
October 25, 2022

1:36,112
0 0.25 0.5 1 mi
0 0.4 0.8 1.6 km

Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand),


ORT LAKE
RALD
A-295
G. & E. NAV. CO.
A-350
Tarrant Co. Wt. Board
C. Slay 498ac.
Lone Star
(DD)
PB
Y.L. Power
Cities Serv.
C. Slay 169ac.
(Trice)
Burk Royalty
Walker N.L. Ray 117ac.
C. Slay 268ac.
Featherston Oil Burk Royalty
Burk Roy.
"Cut-Ray Un
MORRI
Mrs. N.O. Cut 200ac.
G.W. ROPER
A-1308
Y.L. Power 149ac.
Unit 20
Craft Water Board
1-23-BHL
1-23-SHL
2-BHL
2-SHL
G.& B.NAV.CO.
Unit 16
J.G. COLLINSWORTH
A-883
171ac.
R.P. LITTLE
A-517
J.A. Risk, etal 124ac.
L. Ross, etal 155ac.
A.W. Walker
Enserch
Enserch Expl.
-Bridgeport)
nger Bros.)
er Board Un 18,9,17
r Board Un. 23
D.W. HARRISON
A-1076
Craft Water Bd. 160ac.
D.W. HARRISON
A-1004 37ac.
C.M.&M.
J. McCLANAHAN
A-583
(A'Mell)
H.H. Wharton U.S.A. 115ac.
R.W. Lineham
P. NICHOLAS MORRIS
A-654
STANFIELD
A'Mell
"Wharton Unit"
Williams Pet.
W.J. Handley
H. WHARTON 149ac.
K.A. Stanfield 167ac.
K.A. Stanfield 95ac.
Arwine Unit
W.H. Wharton 108ac.
EP Op.Co.
E.P. op. Co.
Craft Water Unit No 8
H. ROBERTSON
A-710
Craft Water Board-Sampson
Unit 17
Lone Star
R. FISHER
A-307
Unit 10
Unit
Craft Water Unit No. 5
A-654
G. Mitchell
R.W. Lineham
C.R. Upham, Jr.
H. Shilling
A-115
G. Mitchell (7-1-64)
R.P. Woody
W.L. Arwine 74ac.
A-3
G. Mitchell &
W. Hodgson 66ac.
D.C. Brewer 90ac.
G. Mitchell (12-17-65)
G. Mitchell (C.L. Gage)
T.P. Denton
A-4
40

(A.L. Boring)
A.L. Boring
(Lone Star Producing Co.)
Enserch Expl., Inc.
Y. L. Power Gas Unit "B"
G.W. ROPER
A-1308
Y. L. Power
Lone Star
3-16-57
CRAFT WATER BOARD UNIT "20"
Lone Star
Craft Water Board Unit 23
Lone Star Producing Co.
Enserch Expl., Inc.
12-1-67
Boonsville (BCG)
Craft Water Board Unit 16 No. 2
Enserch Expl., Inc.
Enserch Expl.
Water Board Unit 17
Craft-Water Board Unit 1
G & B. NAV. CO.
J.G. COLLINSWORTH
CRAFT WATER BOARD UNIT "16"
A-883
Enserch Expl.
R.P. LITTLE
A-517
J.A. Risch
(Kate R. Stanfield "B")
Lone Star
6-8-55
D.W. HARRISON
A-1076
Unit "1"
D. W. HARRISON
A-1064
J.D. Craft-TCWB
McCLANANAN
A-583
Christie, H. & N
Walker
Ray
P. NICHOLAS
A-654
STANFIELD
(5200 CONGL)
Kate Stanfield
1000'
DATE OF BASE
DATE REVISED
BY


Lone Star Prod.
Lone Star.
J.D. CRAFT
T.C.W.D UNIT #8
REUBEN FISHER
A-307
E.F. Operating
Unit 3
Craft Water Board Unit 10
LONE STAR PROD. CO.
Star)
Enserch Expl.
12-28-60
800 mcf
5093-5103
(Bend Cong. Gas)
(Lone Star Prod.)
Enserch Expl.
HENRY ROBERTSON
A-710
Morris
Craft
(Tarrant County) Water Board
Sampson
Burk Royalty
B.B.B. & C.R.R.
A-115
Morris
Bowlin
Craft Water Board Unit 10
Lone Star Prod.
(Lone Star Prod.)
Enserch Expl.
C.R. Upham
NICHOLAS
A-654
H. SHILLING
Upham O. & G.
Mitchell En.
T-I. Dr 109430
(Bd. Cong. G.)
Boonsville
C.R. UPHAM
(ARNOLD) Schilling
CL. Shawn
A-2
MATAGORDA

44447

(C)

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No.

Operator A'Mell Oil Properties Address 1201 Elm St., Dallas, Texas

County Wise Survey J. McClanahan Block No. A-583 Sec. No.

Lease Name H. H. Wharton Well No. 1 Elevation 795 GL (Above Sea Level)

Name of Field in which well is located Booneeville Conglomerate Gas

Form 1 (Notice of Intention to Drill) Was Filed in Name of A'Mell Oil Properties

Is this a NEW WELL? Yes DEEPENING? – or a WORK-OVER? –

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

(Work-Over) (Drilling) Commenced April 27, 19 61 (Work-Over) (Drilling) Completed May 15, 19 61

Correspondence regarding this well should be sent to: Name A'Mell Oil Properties Address 1201 Elm St., Dallas, Texas

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
8-5/8"	153	77	–	–	153	77	
2-7/8"	5204	00	–	–	5204	00	

Initial Production of Gas—Volume 250 MCF 24 hrs. Pressure 500 lbs. per square inch

Initial Production of Oil: Barrels 5 of Frac per day

Initial Production of Distillate: Barrels Trace

Is this an OIL well? No , a GAS well? Yes , or a Dry HOLE?

DESCRIPTION OF PROPERTY

NORTH

WEST

RECEIVED
SEP 18 1961
Railroad Commission of Texas
OIL & GAS DIVISION
WICHITA FALLS, TEXAS

EAST

SOUTH

GENERAL REMARKS

LTR BD OF WATER EN R
DATED April 19, 1961
RECOMMENDS 150 FT.
See letter attached

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof.

FORMATIONS	TOP	BOTTOM
Shale w/sd & lm stks	0	30
Lime	30	37
Shale & Shells	37	45
Lime & Shale	45	72
Shale & Lime	72	130
Lime	130	136
Lime & Shale	136	173
Shale & Lime	173	220
Lime & Shale	220	258
Shale w/lm stks	258	328
Water Sand	328	346
Shale, sd & lm stks	346	890
Shale & lm	890	925
Shale & lm w/sdy stks	925	1067
Lime	1067	1117
Shale w/lmy stks	1117	1165
Sand & Shaley sd	1165	1196
Shale w/lm & sd stks	1196	1477
Shale	1477	1500
Shaley sd	1500	1570
Shale & sd stks	1570	1620
Hard sd	1620	1646
Shaley sd	1646	1896
Shale & sdy shale	1896	2087
Shale w/sd & lm stks	2087	2269
Shale w/sd & lm sh stks	2269	2408
Shale w/sd & lm stks	2408	2429
Shale & chalkey lm	2429	2533
Shale & lm stks	2533	2655
Lime & Shale	2655	2658
Shale w/lm stks	2658	2767
Shale & lm	2767	2804
Shale w/lm & sd stks	2804	2995
Shale & lm	2995	3020
Lmy shale & lm shells	3020	3035
Lime w/specks flo. (no odor)	3035	3052
Shale & lm	3052	3062
Shale	3062	3121
Shale & lm stks	3121	3230
Shale & lm	3230	3336
Shale w/lm stks	3336	3506
Lime	3506	3520
Shale & lm shale	3520	3658
Shale w/lm stks	3658	3840
Lime	3840	3849
Lime	3849,	3861

REMARKS

Shale & Sdy shale	3861	3964
Shale w/lm stks	3964	4020
Shale & sdy sh w/lm	4020	4299
Shale w/lm & sh stks	4299	4544
Lime (Caddo)	4544	4591
Shale & lm	4591	4645
Shale w/lm & sd stks	4645	4731
Shale & lm	4731	4848
Shale & lm shale	4848	5069
Shale	5069	5085
Shale, cong shale & conglomerate	5085	5138
Shale w/cong stks	5138	5159
Shale & lm shale	5159	5202
Shale & lm stks	5202	5220
Hard tight cong.	5220	5232
Shale & cong	5232	5240
Hard tight cong	5240	5241
Shale w/cong stks	5241	5350
Shale & Cong sh stks	5350	5400
Shale & lm shale	5400	5440
Shale & cong stks	5440	5533
Hard tight cong	5533	5540
Broken tight cong	5540	5548
Shale w/cong stks	5548	5557
Shale w/tight congstks	5557	56[illegible]
Shale	5672	57[illegible]
Limey shale	5733	5749
Shale w/tight cong stks	5749	5828
Shale & cong	5828	5841
Cong w/very faint flor	5841	5860
Shale w/cong stks	5860	5916
	TD	

Method of shutting off water No water

Is water completely shut off? Yes

Amount of water with oil NONE per cent

I, A. W. Amell

being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

A W Amell

Representative of Company.

Subscribed and sworn to before me this 22nd day of June, 1961

[illegible]

Notary Public

Dallas County, Texas.

44447

M

Application to Drill, Deepen or Plug Back.

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 1
Rev. 4/60

STATE WHETHER THIS IS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK Drill

SHALL BE FILED IN DUPLICATE (IN TRIPLICATE IF RULE 37) WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED
DATA FURNISHED ON THIS FORM AND ANY ATTACHMENT HERETO MUST BE CLEARLY LEGIBLE.
ANY ILLEGIBLE FORM WILL BE RETURNED WITHOUT COMMISSION ACTION.
(Black Ink or Black Typewriter Ribbon Preferable)

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, fo this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines. Also show the nearest wells on all sides of this location and the distance from the proposed location to those wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equaling 1000 feet; if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THIS PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line 467 feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease - feet

IS THE ACREAGE ON WHICH THIS WELL IS TO BE LOCATED, PRESENTLY ASSIGNED TO ANOTHER WELL IN ANY RESERVOIR FOR WHICH THIS PERMIT IS REQUESTED? No

Date April 18, 1961

Name of company or operator

Name A'Mell Oil Properties

Address 1201 Elm Street,

City Dallas 2, Texas

Description of farm or lease:

Name of Lease Howard H. Wharton

Number of Acres 332 Well No. 1

Number of wells on lease None

Elevation ______ (Ft. above sea level) Section No. ____ Block No. ____

Survey J. McClanahan - A 583

Zone or Reservoir Conglomerate

To be Located in Boonesville(Bend Congl. Gas)

(If Wildcat state above, also state Distance and Direction from nearest Survey Lines.)

Wise County

4 Miles Northwest direction from

Bridgeport, Texas nearest post office or town.

Rotary or Cable Tools Rotary

Date work will start drilling on permit

Depth to which you propose to drill 6200 feet.

Date work will start deepening

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?

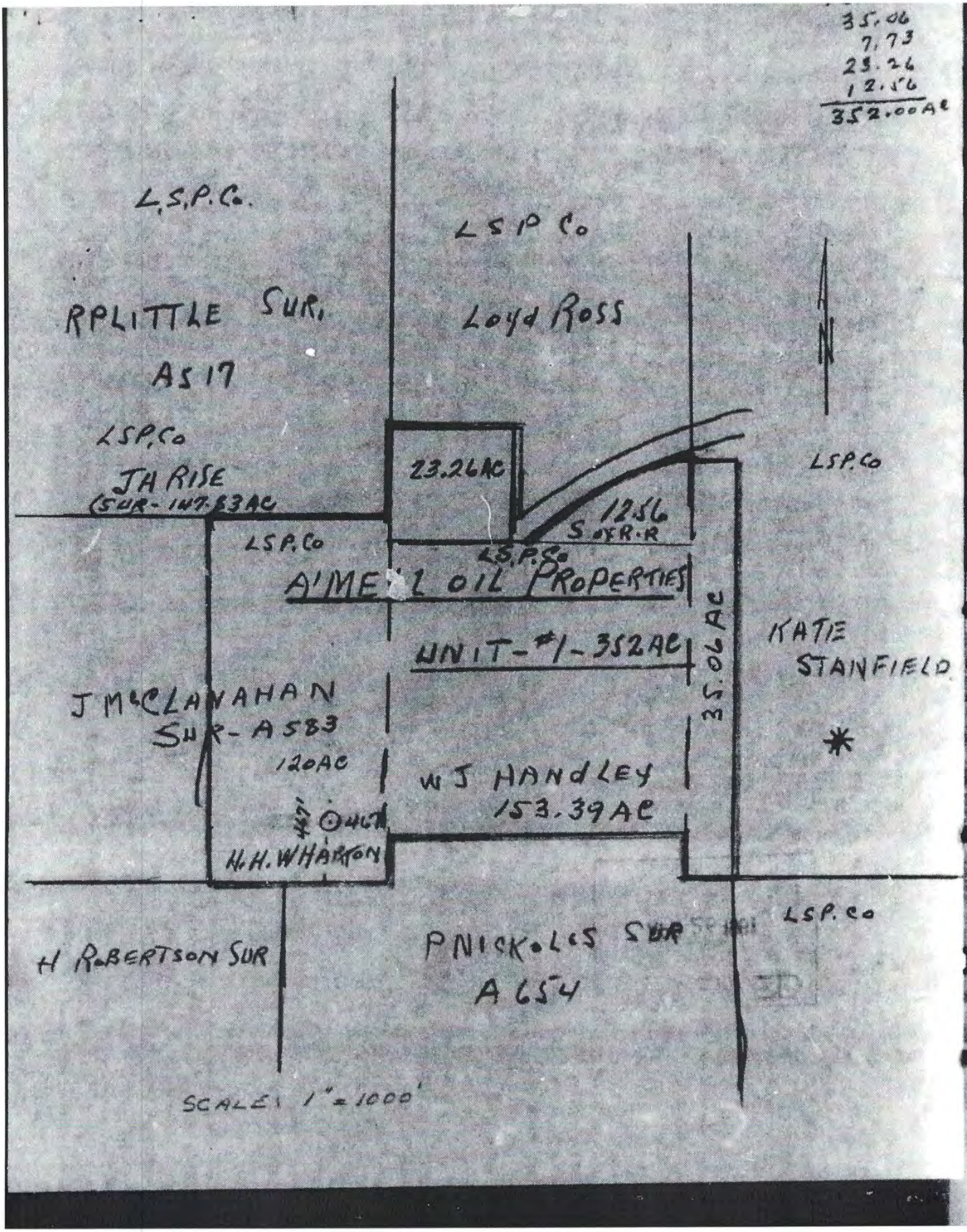
Name

Address

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

25 / DR


35.06
7.73
23.26
12.56
352.00 AC
L.S.P.Co.
LSP Co
RPLITTLE SUR.
AS17
Loyd Ross
N
LSP.Co
JA RISE
(SUR-147.33AC
23.26AC
12.56
S of R.R
LSP.Co
LSP.Co
LS.P.Co
A'ME'L OIL PROPERTIES
UNIT-#1-352AC
35.06 AC
KATIE
STANFIELD
J McCLANAHAN
SUR-A583
120AC
WJ HANDLEY
153.39AC
467
H.H. WHARTON
LSP.co
H ROBERTSON SUR
P NICKOLES SUR
A654
SCALE: 1" = 1000'

1

9

D

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No. ....

Operator LONE STAR PRODUCING COMPANY Address 301 S. Harwood, Dallas, Texas

County Wise Survey Phillips-Nicholas Block No. (A-654) Sec. No.

Lease Name Kate Ann Stanfield "A" Well No. 1-C Elevation 810 (Above Sea Level)

Name of Field in which well is located Boonsville (Bend Conglomerate Gas)

Form 1 (Notice of Intention to Drill) Was Filed in Name of Lone Star Producing Company

Is this a NEW WELL? Yes

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

(Drilling) Commenced 11-17 1959 (Drilling) Completed 12-9- 1959

Correspondence regarding this well should be sent to: Name A. L. Poynor Lone Star Prod. Co. Address Box 767, Jacksboro, Tex.

Has an allowable been assigned to this well? No.

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
9-5/8	324				324		
5½	5400				5400		HOMCO DV Tool @ 3238' packer shoe at 5394'
2-3/8	5217				5217		HOMCO Type "C" Pkr. @ 5217

Initial Production of Gas—Volume 1916 MCF 24 hrs. Pressure 200 lbs. per square inch

Initial Production of Oil: Barrels 23 bbls. (frac oil)

Initial Production of Distillate: Barrels

Is this an OIL well? ...., a GAS well? Yes, or a Dry HOLE?

DESCRIPTION OF PROPERTY
NORTH

See Form 1 filed Oct.1,1959

WEST

EAST

SOUTH

GENERAL REMARKS

This well is dually completed as an oil & gas well. A HOMCO Type "C" permanent packer set @ 5217' to separate the upper zone gas & the lower zone oil. Well is completed w/1 string of 2-3/8" OD tbg. & 2-Garrett Oil Tool circulating sleeves. Lower sleeve is below Type "C" & Upper sleeve above packer.

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMA[redacted]D

Show All Formations, Especially All [redacted]aracter and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS	
Sh W/Sd & Lm Stks.	0	110	Sh W/Lm & Sd Stks	3160
Sd & Lime		165	Shale W/Sdy Stks.	3214
Sh & Sd Stks.		222	Lime	3230
Lime		280	Shale-Lime & Sdy	3306
Sh & Sdy Sh		354	Shale-Sd Stks.	3410
Sh & Sd Stks		433	Sand - Lime	3440
Sh W/Lm & Sd		450	Shale & Sand	3487
Shale		550	Limey Sand & Shale	3505
Sh & Sd Stks		815	Sh - Lmy & sdy.	3544
Sh, Lm & Sd		950	Lime	3555
Sh & Lm		1082	Shale-Sdy-Lime Stks.	3838
Lime		1034	Shale	3875
Sand		1205	Lime	3893
Sh, Sd & Lime Stks		1340	Shale & Sandy Shale	3933
Limey Sh		1380	Limey Sand & Shale	3955
Shale		1560	Limey Sand	3975
Sh W/Sdy Lm		1580	Shale & Sand	3999
Sh - Sdy Shale		1655	Shale-Sand & Lime Stks.	4076
Sh - Sand & Lm		1700	Shale W/Sdy Stks.	4197
Sh & Sdy Sh		1798	Shale	4549
Sand -- No Shows		1835	Shale W/Lime Stks.	4601
Shale & Sd Stks		1865	Shale & Chalky Lime	4606
Lm, Sd & Sh		1929	Limme & Shale	4622
Sh, Lm & Sd		2118	Lime	4639
Sh & Sd Stks		2247	Shale & Limey Shale	4666
Sand		2259	Lime	4672
Sh W/Sand		2410	Lime & Shale	4864
Lm, Sh W/Sd Stks.		2558	Shale	4927
Lime & Shale		2600	Shale & Lime	5216
Lime		2619	Shale	5224
Sh & Sd Lm		2632	Lime	5239
Sh & Lm		2673	Shale	5246
Lime, Sh & Sand		2695	Shale & Lime	5276
Sand & Shale		2724	Congl. (Show)	5276
Shale		2765	Congl. & Lime	5294
Lim - Shale		2847	Shale-Lime & Congl. Stks.	5306
Sh W/Lm & Sd		2863	Shale & Lime	5397
Sh & Sdy Sh		2890	Lime	5422
Sh - Lm & Sd.		2932	Shale & Lime	5503
Sand & Shale		2948	Lime	5513
Sh & Sdy - Lm		3008	Shale-Lime	5518
Sh - Sdy Stks.		3030	Shale	5550
Sd & Shale		3053	Shale & Limey Shale	5598
Sand (Show)		3062	Lime & Shale	5609
Lime		3077	Limey Shale & Lime	5640
Shale		3095	Shale	5651
Sand & Shale		3130	Limy. Shale & Lime	5662

Railroad Commission of Texas
OIL & GAS DIVISION
AUSTIN, TEXAS
JAN 29 1960

Method of shutting off water Cement & Csg. Is water completely shut off? Yes

Amount of water with oil per cent

I, E. L. Smith, Jr.
being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

E. L. Smith, Jr.
Representative of Company.

Subscribed and sworn to before me this 19 day of January, 1960

Lorene Stanfill
Notary Public
Jack County, Texas.

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Shale	5662	5668	
Sh - Lm Sh		5754	
Lime		5778	
Shale & Lime		5783	
Limey Shale & Lime		5806	
Lime		5825	
Shale & Lime		5883	
Lime-Shly. Congl.		5918	
Lime & Congl. Stks.		5930	
Lime & Limey Shale		5964	
Lime		5972	
Shale & Limey Shale		5996	
TOTAL DEPTH			

Method of shutting off water .... Is water completely shut off? ....

Amount of water with oil .... per cent ....

I, ...

being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

....
Representative of Company.

Subscribed and sworn to before me this .... day of ...., 19....

....
Notary Public
.... County, Texas.

File No. [redacted] 52007

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

Operator: Lone Star Producing Co. Address: 301 S. Harwood St. Dallas, Texas

County: Wise Survey: Phillip Nicholas (A-654) Block No. .... Sec. No. ....

Lease Name: Kate Ann Stanfield "A" Well No. 1-T Elevation 810 (Above Sea Level)

Name of Field in which well is located: Bonnville (5085 Atoka Conglo) ~~Stanfield (5250' Congl.)~~ - [redacted]

Form 1 (Notice of Intention to Drill) Was Filed in Name of: Lone Star Producing Co.

Is this a NEW WELL? Yes DEEPENING? .... or a WORK-OVER? ....

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

([redacted]) (Drilling) Commenced 11-17, 1959 [redacted] (Drilling) Completed 12-9, 1959

Correspondence regarding this well should be sent to: Name Mr. A. L. Poynor Address Box 767-Jacksboro, Texas

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
9-5/8	324				324		
5½	5400				5400		HOWCO DV tool @ 3238 packer shoe @ 5394'
2-3/8"	5217				5217		HOWCO Type "C" pkr. @ 5217

Initial Production of Gas—Volume 292 MCF 24 hrs. Pressure 1140# lbs. per square inch

Initial Production of Oil: Barrels 60

Initial Production of Distillate: Barrels ....

Is this an OIL well? Yes, a GAS well? ...., or a Dry HOLE? ....

DESCRIPTION OF PROPERTY

NORTH

WEST

See Form 1 field Oct.1,1959

RECEIVED

JAN 28 1960

Railroad Commission of Texas

EAST

SOUTH

GENERAL REMARKS

This well is dually completed as an oil & gas well A HOWCO Type "C" permanent packer set @ 5217' to separate the upper zone gas & the lower zone oil. Well os completed w/1 string of 2-3/8" OD tbg. & 2-Garrett Oil Tool circulating sleeves Lower sleeve is below Type "C" packer & upper sleeve is a bove packer.

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

52007

Please refer to File No.................

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

RECEIVED
OCT 2 1959
Railroad Commission of Texas
Oil & Gas Division
Wichita Fall, Texas

APPLICATION TO DRILL, DEEPEN OR PLUG BACK

IS THIS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK....DRILL....

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, of this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines.. Also show the nearest wells on all sides of of this location and the distance from the proposed location to these wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equaling 1000 feet; if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THAT PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line..467................feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease.....—...feet.

Date....October 1............. 19..59...

Name of company or operator

Name......Lone Star Producing Company.........

Address...301 S. Harwood Street...............

City......Dallas, Texas.......................

Description of farm or lease:

Name of Lease...Kate Ann Stanfield "A".........

Number of Acres..211.66.......Well No....1.......

Number of wells on lease..none..................

Survey Phillip Nicholas (A-654)

Elevation....810...............Feet (ABOVE SEA LEVEL)

Section No....................Block No..............

Located in..Wildcat..........................Field

(If Wildcat state above)

......Wise.....................................County

......3............Miles...SW.....direction from

....Bridgeport.......nearest postoffice or town.

Rotary or Cable Tools..Rotary...................

Date work will start drilling....on permit........

Depth to which you propose to drill...6,000...feet.

Date work will start deepening......................

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?

Name...

Address..

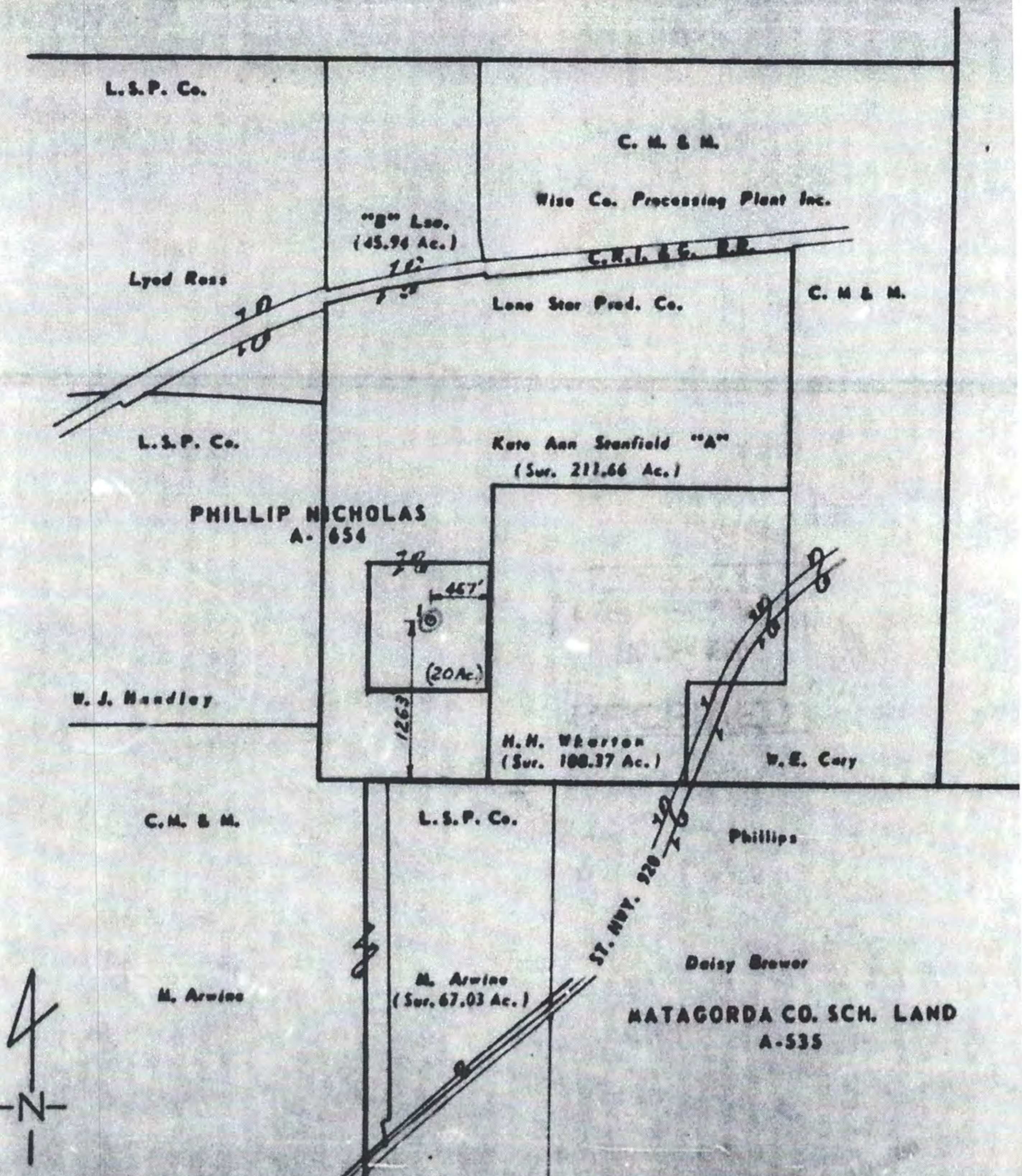
OK
Dr.

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

Subscribed and sworn before me this the 29th day of Sept. 1959 A.D.

Notary Public, Dallas County, Texas



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RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

AUG 12 1971

E

Form G-1

RRC District: 9

RRC Identification Number: D.51023

GAS WELL BACK PRESSURE TEST
COMPLETION OR RECOMPLETION REPORT AND LOG

1. FIELD NAME (as per RRC Records or Wildcat): Boonsville (BCG)

2. LEASE NAME: Harold Shilling

LTR TEX W...

Well Number: 2

OPERATOR: Upham Oil & Gas Company

10. County: Wise

ADDRESS: P. O. Box 940, Mineral Wells, Texas 76067

DATED 5-10-71

11. Purpose of Test: Initial Potential X; Retest; Reclass

5. If Operator has changed within last 60 Days — Give former Operator

RECOMM NL 300 FT

LOCATION (Section, Block, and Survey): P. Nicholas Survey A-654

12. Pipe Line Connection: Not connected

13. If Workover, give former Field (with Reservoir)

14. Completion Date: 7/30/71

List of Offset Operators Notified and Date of Notification

16. Type of Electric or other Log Run: Induct-Elec. & Sonic

Section I — GAS MEASUREMENT DATA

Date of Test: 8/2/71

Gas Measurement Method (Check One): Orifice Meter; Positive Choke; Orifice Vent Meter; Pitot Tube; Critical flow Prover X

Gas produced during test: 277 MCF

Run No.	Line Size	Orifice or Choke Size	24 Hr. Coeff. Orif. or Choke	Static P_m or Choke Press.	Diff. h_w	Flow Temp. °F	Temp. Factor F_{tf}	Gravity Factor F_g	Compress. Factor F_{pv}	Volume MCF/DAY
1	2.00	1.125	28.9803	31		56	1.0039	.9258	1.004	838
2	2.00	.625	8.5694	86		60	1.0000	.9258	1.011	690
3	2.00	.625	8.5694	74		63	0.9971	.9258	1.011	591
4	2.00	.625	8.5694	62		65	0.9952	.9258	1.011	495

Section II — FIELD DATA AND PRESSURE CALCULATIONS

Gravity Dry Gas	Gravity Liquid Hydrocarbon	Gas-Liquid Hydro Ratio	Gravity of Mixture G_{mix}	Avg. Shut-In Temp.	Bottom Hole Temp.
.700	60 Deg. API	105,000 CF/Bbl	.724	103 °F	132°F @ 6155 (Depth)

$D_{eff}^{8/3}$ — GL

C = 1118 ÷ ($D_{eff}^{8/3}$) — GL/C

Run No.	Time of Run Min.	Choke Size	Wellhead Press. P_w PSIA	Wellhead Flow Temp. °F	P_w^2 (Thousands)	R	R^2 (Thousands)	P_f	P_w P_f
Shut-in	72 hrs.		1325	74					
1	5 hrs.	20/64	615	80					
2	2 hrs.	16/64	725	80					
3	1 hr.	12/64	770	80					
4	1 hr.	10/64	787	80					

Run No.	F	K	S	e^{ks}	P_f and P_s	P_f^2 and P_s^2	$P_f^2 - P_s^2$
Shut-in		.1240	1.297	1.175	1557	2424	
1		.1235	1.228	1.164	716	513	1911
2		.1235	1.237	1.166	845	714	1710
3		.1235	1.243	1.167	899	808	1616
4		.1235	1.243	1.167	918	843	1581

Angle of Slope: θ = 45; n = 1.000

Absolute Open Flow: 1,060 MCF/DAY

OPEN FLOW TEST:

Shut-In Press. ____ Psig
Time Shut-In ____ Hrs.
Producing Through ____

In. H2O Time	In. Hg Reading	Time	Psig Reading

REPRESENTATIVE OF COMPANY MAKING TEST

REPRESENTATIVE OF RAILROAD COMMISSION

CERTIFICATE:

I declare under penalties prescribed in Article 6036c, R.C.S., that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete to the best of my knowledge.

REPRESENTATIVE OF COMPANY — Geologist (TITLE) — 8/10/71 (DATE)

497 30085

SECTION III — DATA ON WELL COMPLETION AND LOG (Not Required on Retest)

17. Type of Completion: New Well X | Deepening | Plug Back | Other

18. Date Permit Issued: May 11, 1971

19. [illegible]: Upham Oil & Gas Company

20. If Special Permit, Give Permit Number:

21. Number of Producing Wells on this Lease in This Field (Reservoir) including this Well: One

22. Total Number of Acres in this Lease: 245.27

23. Date Plug Back, Deepening, Workover or Drilling Operations: Commenced June 15,1971 — Completed July 1, 1971

24. Distance to Nearest Well, Same Lease & Reservoir: None

25. Location of Well, Relative to Lease Boundaries of Lease on which this Well is Located: 467 Feet From North Line And 934 Feet From West Line of The Harold Shilling Lease

26. Elevation: 833 GL & 842' RKB

27. Was Directional Survey Made: Yes X No

28. Top of Pay: 5121 — 29. Total Depth: 6155 — 30. P.B. Depth: 5389

31. Surface Casing Determined By: Recommendation of Texas Water Development Board X | Field Rules | Railroad Commission (Special)

32. Is Well Multiple Completion: Yes No X

33. If Multiple Completion List All Reservoir Names:

34. Intervals Drilled By: Rotary Tools Surf.-T.D. | Cable Tools

Name of Drilling Contractor: Bearden Drilling Company

Is Cementing Affidavit Attached: Yes No X

CASING RECORD (Report All Strings Set in Well)

Casing Size	Weight LB FT.	Depth Set	Hole Size	Cementing Record	Amount Pulled
8-5/8	20# & 24#	331	12-1/4"	250 sx Reg. w/2% C.C.	None
5-1/2	15.5#	5418.61	7-7/8"	175 sx Pozmix w/4% Gel.	None

LINER RECORD

Size	Top	Bottom	Sacks Cement	Screen
None				

TUBING RECORD

Size	Depth Set	Packer Set
2-3/8	5258	None

40. Producing Interval (this completion) Indicate Depth of Perforations or Open Hole

From	To
5121	5129
5194	5202
5211	5217
5238	5252

ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

Depth Interval	Amount and Kind of Material Used
5121-5252	1,000 gallons acid and fractured with 10,000 gallons treated salt water and 20,000 pounds of sand. (10/40)

FORMATION RECORD (LIST DEPTHS OF PRINCIPAL GEOLOGICAL MARKERS AND FORMATION TOPS)

Formations	Depth	Formations	Depth
Water Sand	1065 - 1118	Lime (Caddo)	Top 4556
"	Top 1177	Conglomerate (Atoka)	Top 5118
"	Top 1238	Lime (Marble Falls)	Top 6074
Lime	Top 2558		
"	Top 2916		
" (M-1)	Top 3840		

REMARKS

9:06:44 Tuesday, October 25, 2022

```
DISTRICT> 09       GAS WELL DATA INQUIRY - PAGE 1       SCHEDULE  > 11 / 22
FIELD    > BOONSVILLE (BEND CONGL., GAS)     # 10574 520 TYPE FIELD> CAPACITY
OPERATOR> UPHAM OIL & GAS COMPANY            # 878925   DRILL PMT >
LEASE    > SHILLING, HAROLD                             API #     > 497 30085
COUNTY   > WISE            RRCID 051043 WELL #     2    ALLOW EFF > 11/01/2022
TYPE WELL> PRODUCING                                    TOP ALLOW >
OFFSHORE>    BAYS/EST    STATE    DS>     0       0     CYCL ALLOW>
OP LACK>
OTHER  >
SCHED REM >
TOT LEASE ACRES>            COMMINGLING                     CAPABILITY        4
"@" AMOUNT> 999999999   DATE> MM/YYYY   HIGH DLY AVG> 999999999   DATE> MM/YYYY
SPEC ALLOW >        100   CODE> ADMINISTRATIVE
G-10 TEST  >  07/14/2022 TYPE >  R LAST UTIL>           G-1 TEST >    08/02/1971
DELIV      >          4   DELIV LTR EFFEC>              G-1 POTE   >  NOT REQ.
DELIV CODE >              CAL DEL POTE    >             TEMPERATURE>
WH PRESS CD>              SIWH>      90   BHP CD>             BHP >         100
GAS GRAV   >   .758       COND GRAV  >  60.0            GOR        >     270
ACRES-FT   >              ACRES       >         85.2700 G1 TEST GAS>
SUPP ISSUED>  10/17/2022   SUPP REMARKS  >

GO TO RRCID <         > ENTER=PG2 PF1=HELP          PF3=DRL PMT PF4=RESTART
PF5=NEXT WELL PF6=FLD PF7=PROR SCH PF8=P4 PF9=LDGR PF10=G-10 PF11=RMKS PF12=G-1
```

9 (F) Form 2
Well Record

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

File No. ____________

Operator: Lone Star Producing Co. Address: Jacksboro, Texas

County: Wise Survey: Henry Robertson (A-710) Block No. ______ Sec. No. ______

Lease Name: Kraft-Water Board Sampson Unit 1 Well No. 1 Elevation 835' (Above Sea Level)

Name of Field in which well is located: Boonsville (Bend Congl. Gas) Field

Form 1 (Notice of Intention to Drill) Was Filed in Name of: Lone Star Producing Co.

Drilling Commenced 10-5, 19 57 Drilling Completed 10-28, 19 57

Is this a NEW WELL? Yes : DEEPENING? ______ or a WORK-OVER? ______

Correspondence regarding this well should be sent to: Name Lone Star Producing Co. Address Box 1047- Jacksboro, Texas

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
9-5/8"	315'	0.4					HOWCO guide shoe
5½"	5621						HOWCO guide shoe

Initial Production of Gas—Volume 3,120 MCF 24 hrs. Pressure TPG-500# Sep- 200# lbs. per square inch

Initial Production of Oil: Barrels 30 bbls. frac oil /hr.

Initial Production of Distillate: Barrels ______

Is this an OIL well? ______, a GAS well? Yes, or a Dry HOLE? ______

DESCRIPTION OF PROPERTY

NORTH

See Form 1 filed August 20, 1957

WEST

RECEIVED
FEB 13 1958
Railroad Commission of Texas
Oil & Gas Division
Wichita Falls, Texas

SOUTH

GENERAL REMARKS

9-5/8" csg. cemented w/250 sks

5½" csg. cemented w/201 sks

Perforated 5103-5110, 5112-5120 (Schl)

w/4 dyna jets per foot. (60 holes)

Acidized w/500 gal MCA

Fractured w/10,000 gal oil and

10,000# sand.

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

R

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Shale & lime	0	100	
Sand & shale	100	150	
Sh w/lm stks	150	290	
sh & sd stks.	290	360	
sh w/lm & sh stks.	360	646	
sh w/lm & sd stks.	646	1322	
sh w/sd stks.	1322	1550	
sh w/sdy lm stks.	1550	2370	
shale	2370	2536	
sh w/sdy lm stks.	2536	2638	
Lime	2638	2659	
sh w/sd & lm stks.	2659	3495	
sh w/lime shells	3495	3571	
sh w/lime stks.	3571	4000	
sh & sand	4000	4015	No jeep - no odor
sh w/ sd & lm stks.	4015	4550	
Lime	4550	4560	
Lime	4560	4575	Jeep & odor
Lime & shale	4575	4594	
sh & lime congl	4594	4610	
sh & lime stks.	4610	4967	
sh lm & congl	4967	4981	
sh , lm & congl	4981	5100	
sh lm & congl	5100	5174	
Sd & congl stks.	5174	5198	
shaley congl	5198	5207	
sh & congl	5207	5230	Jeep & odor
sh w/lime stks.	5230	5683	
sh & congl stks.	5683	5711	
sh & lime stks.	5711	5790	
sh & sdy congl	5790	5823	
Lime congl	5823	5862	
sh sd & lmy congl	5862	5942	
sh & congl stks.	5942	6027	

RECEIVED
APR 22 1958

FEB 17 1958
OIL & GAS DIVISION
AUSTIN, TEXAS

Method of shutting off water .... Is water completely shut off? ....

Amount of water with oil ....

I, T. R. Pledger being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

T. R. Pledger
Representative of Company.

Subscribed and sworn to before me this 10th day of February, 1958

Lorene Stanfield
Notary Public
Jack County, Texas.

*** OIL AND GAS DIVISION *** INQUIRY

PLUGGING DATA

TYPE/WELL(O/G/D/S): **G** API NUMBER: **497 01654**
DIST: **09** LEASE/ID: **132120** WELL #: **1**
FIELD NAME: **BOONSVILLE (CADDO LIME)**
LEASE NAME: **CRAFT WATER BOARD SAMPSON**
OPER NAME: **ENSERCH EXPLORATION, INC**
DRILL PERM ISSUED: **07 / 21 / 1989** PERMIT #: **361291** SFPC:
DRILL COMPLETED: **04 / 09 / 1989** WELL PLUGGED: **09 / 27 / 1996**
DATE W-3 FILED: **02 / 10 / 1997** TOTAL DEPTH: **6028**
DIST W3 APPR DATE: **MM / DD / YYYY**
WAS THIS A MULTIPLE COMPLETION? **N** WELL WAS CONVERTED TO FRESH WATER USE? **N**

	PLUG 1	PLUG 2	PLUG 3	PLUG 4	PLUG 5	PLUG 6	PLUG 7	PLUG 8
BOTT DEP:	5120	4568	598	385	13			
SACK CEM:	25	25	25	60	5			
CALC TOP:	4900	4348	498	265	3			
TOP/PLUG:	0	0	0	0	0			
TYPE CEM:	C	C	C	C	C			

*

* SCREEN OPTIONS: 17=PLUG CAS/TUB/PERFS, 18=WATER/LOGS/REMARKS *
* SELECT OPTION: __ (01=RETURN TO MENU, 00=HELP AND OTHER OPTIONS) *

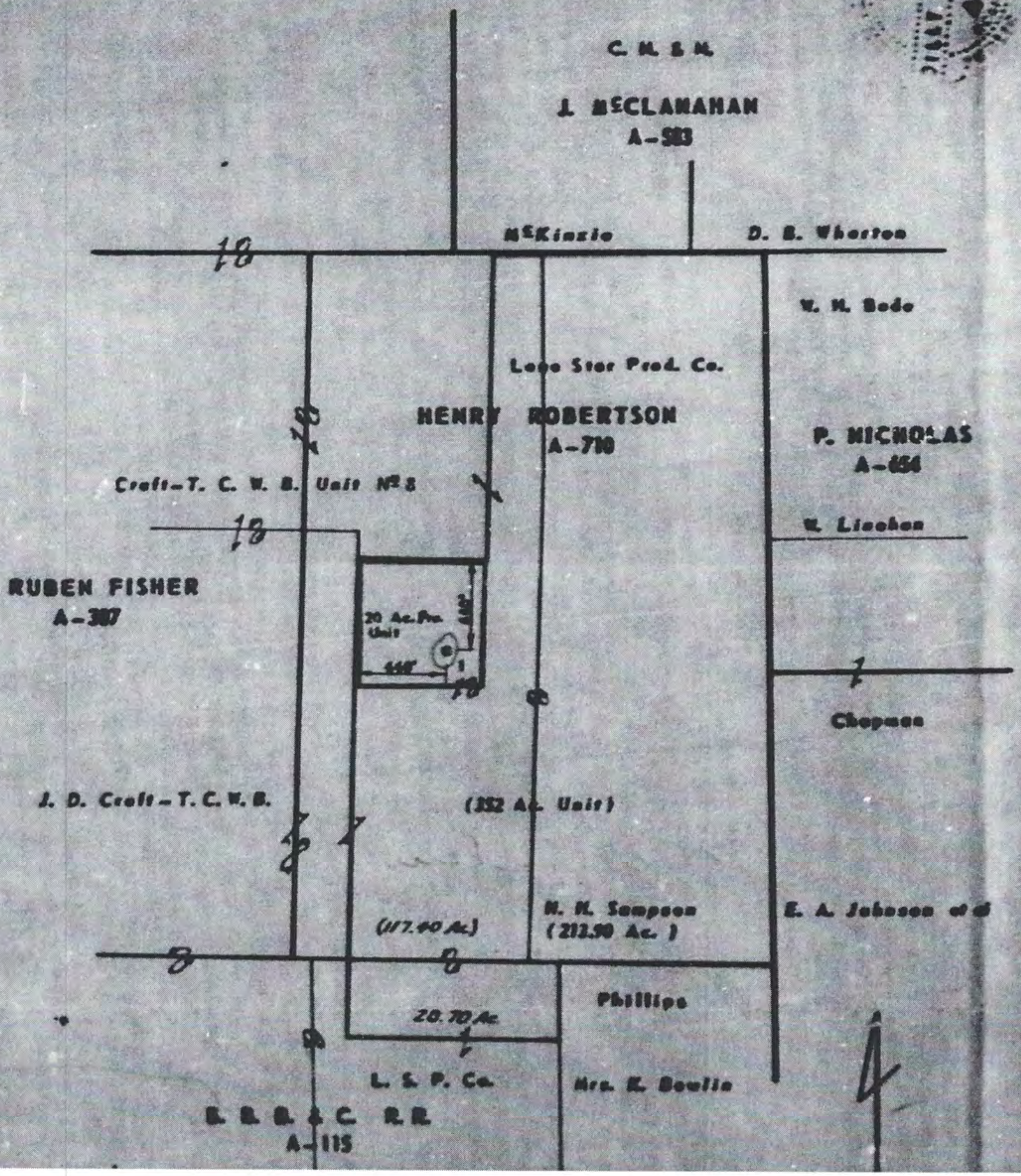
DEPRESS ENTER TO SEE PLUG CASING/TUBING/PERFS

I, BILLY M. SASSE, being duly sworn on oath, state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

Billy M. Sasse
Registered Public Surveyor

Subscribed and sworn before me this the 13th day of August 1957 A. D.

Geraldine Kney
Notary Public, Dallas County, Texas



RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

G

Form 2
Well Record

File No. ____________

Operator Lone Star Producing Co. Address 311 S. Harwood St.- Dallas, Texas

County Wise Survey [illegible] Fisher (A-307) Block No. ____ Sec. No. ____

Lease Name Craft-Wkr. Ed Unit 30 Well No. 1 Elevation 8[illegible] (Above Sea Level)

Name of Field in which well is located Boonsville (Bend Congl. Gas)

Form 1 (Notice of Intention to Drill) Was Filed in Name of Lone Star Prod. Co.- Craft-Wkr. Ed Unit 30 #1

Drilling Commenced 11-17, 19 57 Drilling Completed 12-11, 19 57

Is this a NEW WELL? Yes, DEEPENING? ____ or a WORK-OVER? ____

Correspondence regarding this well should be sent to: Name Lone Star Prod. Co. Address Box 767-Jacksboro, Tex.

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
9-5/8" OD	332				332		1-HOWCO guide shoe
7" OD	5959				5959		1-Baker guide shoe & 1
							Baker Auto Flex flow collar
2-3/8" OD	5774				5774		1-Guiberson KV-30 w/holddown

Initial Production of Gas—Volume 4,475 MCF 24 hrs. Pressure 583 lbs. per square inch

Initial Production of Oil: Barrels ____

Initial Production of Distillate: Barrels 38.2

Is this an OIL well? No, a GAS well? Yes, or a Dry HOLE? No

DESCRIPTION OF PROPERTY
NORTH

See form 1 filed October 30th, 1957

WEST

EAST

SOUTH

GENERAL REMARKS

None

RECEIVED
MAR 26 1958
Railroad Commission of Texas
Oil & Gas Division
Wichita Falls, Texas

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS		
sh w/lime stks	0	617	sh & hrd sdy lm stks	4600	4624
sh,sd & lm stks.	617	765	shale	4624	4633
sh & lime	765	821	sd(show & light odor)	4633	4646
sd & sh	821	851	sh & lm stks	4646	4695
sh & sd & lm stks	851	1065	sh w/sd & lime	4695	4836
lime	1065	1072	sh & lm stks	4836	4966
sh & lime	1072	1119	shale	4966	5038
sh & sd	1119	1142	cong. w/nice show & odor	5038	5071
sh & lm stks	1142	1184	sh & congl stks	5071	5084
sd & sh	1184	1212	shale	5084	5098
sh w/sd & lime	1212	1900	hd sd & lime	5098	5107
lm & shale	1900	1936	sh & lm stks	5107	5144
shale	1936	2032	sh &congl	5144	5148
sh w/sd & lime	2032	2070	congl(weaker -show)	5148	5155
lime	2070	2082	sh & congl stks	5155	5265
sh w/sd & lm stks	2082	2350	sh & lm stks	5265	5290
sh & lime	2350	2426	sh & congl	5290	5293
shale	2426	2509	congl(no show)	5293	5303
lime	2509	2530	sh w/congl stks	5303	5425
sh & lime	2530	2613	sh & lm stks	5425	5504
lime & sd	2613	2664	sh & congl	5504	5684
sd & lime	2664	2676	sh & cong	5684	5697
sh-sd- lime	2676	2701	congl (no show)	5697	5728
sh & sd	2701	2765	sh & congl stks.	5728	5923
sh & lime	2765	2820	sh & lime	5923	5934
sd & sh	2820	2882	sh & sdy lime cherty	5934	5958
sh & lm stks	2882	2933	sh & lime	5958	5965
lime	2933	2943	T.D.		
sh & lime	2943	2972			
lime	2972	2984			
sh & lime	2984	3004			
lime & sd	3004	3016			
shale	3016	3144			
sh w/sd & lime	3144	3199			
sh & sd	3199	3327			
shale	3327	3340			
sdy shale	3340	3356			
sh & sd, & lime stks	3356	3361			
sh & lime stks	3361	3497			
lime	3497	3505			
sh & lm stks	3505	3680			
sh & sd stks	3680	3783			
shale	3783	3844			
sh & sd	3844	4000			
shale	4000	4503			
lime (no show or odor)	4503	4547			
sh & lime	4547	4600			

Method of shutting off water 368 sks cement Is water completely shut off? Yes

Amount of water with oil None per cent

I, L.J. Nelms being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

L. J. Nelms
Representative of Company.

Subscribed and sworn to before me this 25th day of March, 19 58

Lorene Stanfield
Notary Public
Jack County, Texas.

52007

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No.__________

Operator: Lone Star Producing Co. Address: 301 S. Harwood St.-Dallas, Texas

County: Wise Survey: Ruben Fisher A-307 Block No. ______ Sec. No. ______

Lease Name: Craft-Water Board Unit 10 Well No. 1 Elevation 834 (Above Sea Level)

Name of Field in which well is located: Boonsville (Bend Congl. Gas)

Form 1 (Notice of Intention to Drill) Was Filed in Name of: Lone Star Producing Co.

Is this a NEW WELL? ______ DEEPENING? ______ or a WORK-OVER? Yes

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

(Work-Over) Commenced 10-8, 19 60 (Work-Over) Completed 10-24, 19 60

Correspondence regarding this well should be sent to: Name: Mr. A.L. Poynor Address: Box 767-Jacksboro, Texas

Has an allowable been assigned to this well? Yes

Size	Put in Well Ft.	Put in Well In.	Pulled Out Ft.	Pulled Out In.	Left in Well Ft.	Left in Well In.	Packers and Shoes
9-5/8"	332				332		1-HOWCO guide shoe
7"	5860				5860		1-Baker guide shoe & 1-Baker Auto Flex Flow Collar
2-3/8"	5705				5705		Gulberson KVT-30

Initial Production of Gas—Volume 1,734 MCF 24 hrs. Pressure 640 lbs. per square inch

Initial Production of Oil: Barrels 19.35 (Frac Oil)

Initial Production of Distillate: Barrels ______

Is this an OIL well? ______, a GAS well? Yes, or a Dry HOLE? ______

DESCRIPTION OF PROPERTY

NORTH

See Form 1 filed Oct. 30, 1957

WEST

EAST

SOUTH

GENERAL REMARKS

RECEIVED
WICHITA FALLS, TEXAS
NOV 28 1960
OIL & GAS DIVISION

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS		
shw/lm stks	0	617	sh & hd sdy lm stks.	4600	4624
sh,sd & lm stks	617	765	shale	4624	4633
sh & lime	765	821	sd(jeep & lgt odor)	4633	4646
sd & sh	821	851	sh & lm stks	4646	4695
sh & si lm stks	851	1065	sh w/sd & lm	4695	4836
lime	1065	1072	sh & lm stks	4836	4966
sh & lm	1072	1110	shale	4966	5038
sh & sd	1110	1142	congl.w/nice jeep & odor	5038	5071
sh & lm stks	1142	1184	sh & congl stsk	5071	5084
sd & sh	1184	1212	shale	5084	5098
sh w/sd & lime	1212	1900	hd sd & lime	5098	5107
lm & sh	1900	1936	sh & lm stks	5107	5144
sh	1936	2032	sh & congl.	5144	5148
sh w/sd & lm	2032	2070	congl(no odor -jeep)	5148	5155
lime	2070	2082	sh& congl stks	5155	5265
sh w/sd & lm stks	2082	2350	sh & lm stks	5265	5290
sh & lime	2350	2416	sh & congl.	5290	5293
shale	2416	2509	congl(no show)	5293	5303
lime	2509	2530	sh w/congl stks	5303	5425
sh & lime	2530	2613	sh & lm stks	5425	5504
lm & sd	2613	2664	sh & congl	5504	5684
sh & lime	2664	2676	sh & congl	5684	[illegible]
sh-sd lime	2675	2701	congl (no show)	[illegible]	5728
sh & sd	2701	2765	sh & congl(Stks)	5728	5923
sh & lime	2765	2820	sh & lime	5923	5934
sd & sh	2820	2882	sh & sdy lm cherty	5934	5958
sh & lm stks	2882	2933	sh & lm	5958	5965
lime	2933	2943	T.D.		
sh & lm	2943	2972			
lime	2972	2984			
sh & lm	2984	3004			
lm & sd	3004	3046			
sh	3046	3144			
sh w/sd & lm	3144	3199			
sh & sd	3199	3327			
shale	3327	3340			
sdy sh	3340	3356			
sh & sd, & lm stks	3356	3461			
sh & lm stks	3461	3497			
lime	3497	3505			
sh & lm stks	3505	3689			
sh & sd stks	3689	3783			
shale	3783	3944			
sh & sd	3944	4000			
shale	4000	4503			
lm (sd jeep or [illegible]	4503	4547			
sh & lm	4547	4600			

Method of shutting off water Cement & casing Is water completely shut off? Yes

Amount of water with oil None per cent

I, E. L. Smith, Jr. being [illegible] that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

E. L. Smith, Jr.

Representative of Company.

Subscribed and sworn to before me this 25th day of November, 1960

Lorene Stanfield

Notary Public

Jack County, Texas.

52007

Please refer to File No..............

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 1

M

RECEIVED
NOV 6 1957
Railroad Commission of Texas
Oil and Gas Division
Wichita Falls, Texas

APPLICATION TO DRILL, DEEPEN OR PLUG BACK

IS THIS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK....Drill.........?

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, of this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines.. Also show the nearest wells on all sides of of this location and the distance from the proposed location to those wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equaling 1000 feet; if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THIS PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line.....800............feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease.....--...feet.

Date...October 30,............, 19..57...

Name of company or operator

Name....Lone Star Producing Company...........

Address.301 South Harwood Street.............

City....Dallas, Texas.........................

Description of farm or lease:

Name of Lease.Craft-Water Board Unit No. 10..

Number of Acres..352..........Well No.....1.......

Number of wells on lease.......None.............

Survey Ruben Fisher (A-307)

Elevation......834.............Feet
(ABOVE SEA LEVEL)

Section No...................Block No.............

Located in.........Wildcat.................Field

(If Wildcat state above)

...................Wise......................County

..7-1/2............Miles....N.....direction from

...Boonsville.......nearest postoffice or town.

Rotary or Cable Tools.........rotary............

Date work will start drilling...on permit........

Depth to which you propose to drill..6,000...feet.

Date work will start deepening....................

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?

Name...

Address..

830-933 20 Ac.

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

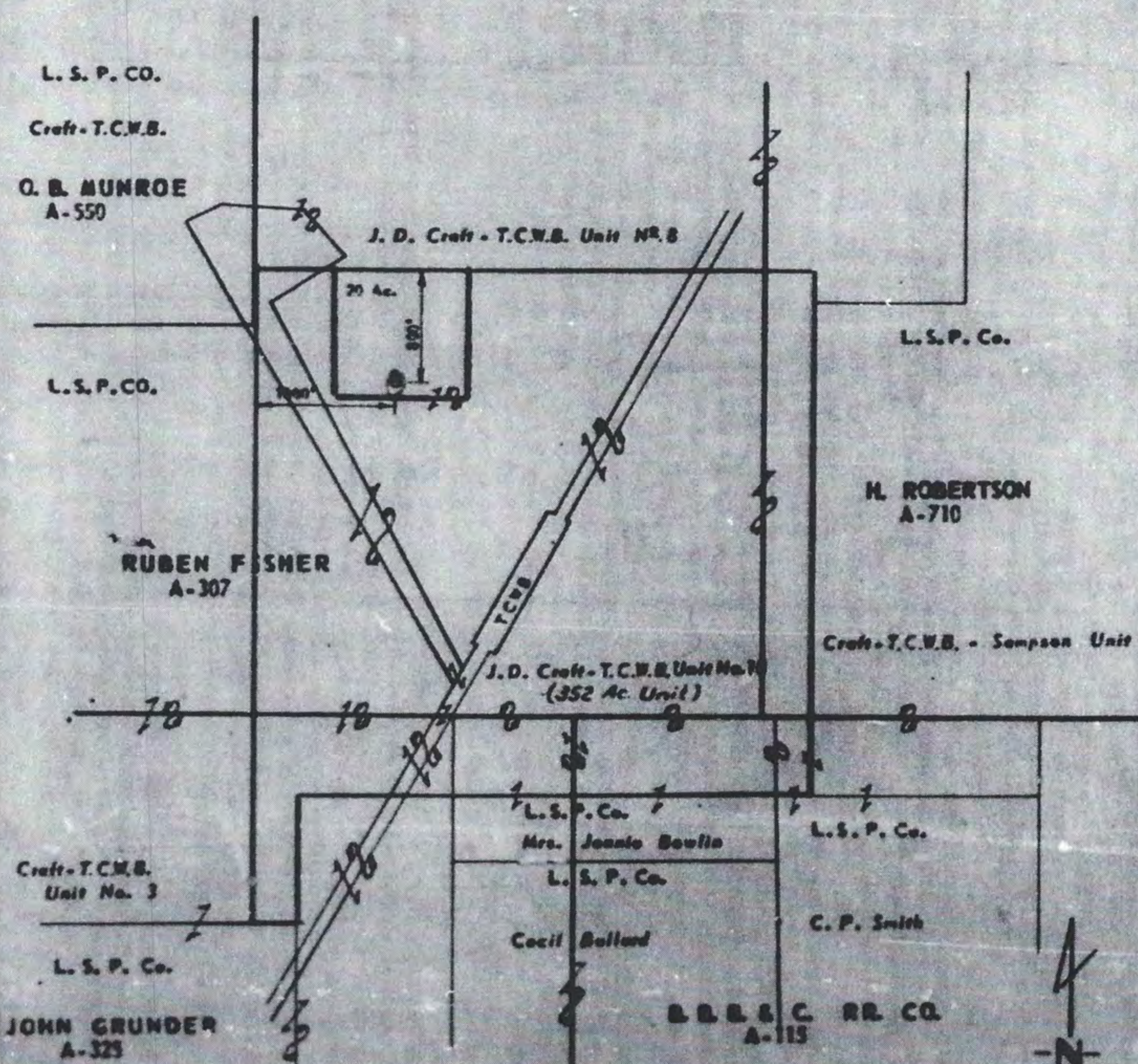
DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

NOV 13 1957

Registered Public Surveyor

Subscribed and sworn before me this the 28th day of Oct. 1957 A. D.

Notary Public, Dallas County, Texas



RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 17090

BKV BARNETT, LLC
1209 CR 1304
BRIDGEPORT, TX 76426

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated July 06, 2022, for the permitted interval(s) of the ELLENBURGER formation(s) and subject to the following terms and special conditions:

BARNETT RDC (00000) LEASE
NEWARK, EAST (BARNETT SHALE) FIELD
WISE COUNTY, DISTRICT 09

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
1	49700000	000125478	Carbon Dioxide (CO_2)	9,350	10,250		14,500		4,500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	49700000	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.** **2. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.** **3. Cement Bond Log (CBL):** **(A) A CBL must be run on the injection string casing. If the CBL does not verify adequate confinement of the injection/disposal interval, the operator must perform a remedial cement squeeze on the casing to achieve adequate confinement immediately above this interval. Adequate confinement is considered to be: annular height of 600 feet of cement based on cement volume calculations; or 250 feet of cement verified by a temperature survey conducted at the time of cementing; or 100 feet of cement verified by a cement bond log that shows the cement is well bonded to the pipe and formation (80% bond or higher) with no indication of channeling.** **(B) The operator must notify and receive approval from the RRC district office prior to performing any remedial cementing work. All cementing work must be appropriately reported on a completion report pursuant to Statewide Rule 16(b). Any CBL run on the well must be submitted. Please use the RRC Digital Well Log submission system to submit the CBL. A copy of any Forms W-15 must also be included with the next Form H-5 for this well.** **4. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.** **5. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.** **6. The operator must notify the Injection-Storage Permits Unit (UIC) and District Office of any event that may have jeopardized the mechanical and/or hydraulic integrity of any segment of the processing, injection, or storage components of the permitted facility.** **7. NOTE: Per operator email dated on July 05, 2022, the CO2 will be from the Bridgeport Processing Plant operated by Enlink Midstream.** **8. An annual annulus pressure test must be performed, and the test results submitted in accordance with the instructions of Form H-5.** **9. The tubing-casing annulus pressure must be monitored at least weekly and reported annually on Form H-10 to the Commission's Austin Offices.**

Note: This document will only be distributed electronically.

		10. Bottomhole Pressure (BHP) Test: 5 Year Lifetime **(A) Operator shall perform an initial static BHP test to quantify reservoir pressure prior to injection into the permitted formation(s).** **(B) Operator shall conduct a BHP test at least once every five (5) years from the date of the test in (A) above and provide the Commission an opportunity to witness the test as stated in (D) below. The analysis of the BHP test shall be provided under the supervision, seal, and signature of a registered professional engineer in Texas. The test analysis shall be filed with the Injection-Storage Permits Unit (UIC) within 30 days of completion of the BHP test.** **(C) Measurement for the BHP test shall be performed via wireline tool(s), or other Commission approved bottom hole pressure measurement technique.** **(D) Operator must notify the District Office 48 hours in advance of the test in order to provide opportunity for the RRC field inspector to witness the test. Operator shall provide raw data from the test to UIC within 48 hours of completing the test.** **11. NOTE: Per operator email dated on July 05, 2022, the CO2 will be from the Bridgeport Processing Plant operated by Enlink Midstream.** **12. 8/26/2022 4. Fluid migration and pressure monitoring report:** **The operator must submit a report of monitoring data, including but not limited to pressure and temperature data, used to determine fluid migration from the disposal well and pressure increases in the reservoir. The report must include, at a minimum, all monitoring data recorded since the last report (or since data recording began for the first report) through the date 30 days before the MIT is due and a summary analysis of the data. The summary analysis must include data trends and anomalies and any likely explanation for those trends or anomalies, for example, any significant operational events. The operator must submit the report with the Mechanical Integrity Test (MIT) filing to the Disposal/Injection Well Pressure Test (H-5) online system.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer.
   b. beginning any work over or remedial operation.
   c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500

Note: This document will only be distributed electronically.

psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON September 08, 2022.

Scott Rosenquist

(for)

Sean Avitt, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

Railroad Commission of Texas

PERMIT TO DRILL, RE-COMPLETE, OR RE-ENTER ON REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

CONDITIONS AND INSTRUCTIONS

Permit Invalidation. It is the operator's responsibility to make sure that the permitted location complies with Commission density and spacing rules in effect on the spud date. The permit becomes invalid automatically if, because of a field rule change or the drilling of another well, the stated location is not in compliance with Commission field rules on the spud date. If this occurs, application for an exception to Statewide Rules 37 and 38 must be made and a special permit granted prior to spudding. Failure to do so may result in an allowable not being assigned and/or enforcement procedures being initiated.

Notice Requirements. Per H.B 630, signed May 8, 2007, the operator is required to provide notice to the surface owner no later than the 15th business day after the Commission issues a permit to drill. Please refer to subchapter Q Sec. 91.751-91.755 of the Texas Natural Resources Code for applicability.

Permit expiration. This permit expires two (2) years from the date of issuance shown on the original permit. The permit period will not be extended.

Drilling Permit Number. The drilling permit number shown on the permit MUST be given as a reference with any notification to the district (see below), correspondence, or application concerning this permit.

Rule 37 Exception Permits. This Statewide Rule 37 exception permit is granted under either provision Rule 37 (h)(2)(A) or 37(h)(2)(B). Be advised that a permit granted under Rule 37(h)(2)(A), notice of application, is subject to the General Rules of Practice and Procedures and if a protest is received under Section 1.3, “Filing of Documents,” and/or Section 1.4, “Computation of Time,” the permit may be deemed invalid.

Before Drilling

Fresh Water Sand Protection. The operator must set and cement sufficient surface casing to protect all usable-quality water, as defined by the Railroad Commission of Texas (RRC) Groundwater Advisory Unit (GWAU). Before drilling a well, the operator must obtain a letter from the Railroad Commission of Texas stating the depth to which water needs protection, Write: Railroad Commission of Texas, Groundwater Advisory Unit (GWAU), P.O. Box 12967, Austin, TX 78711-3087. File a copy of the letter with the appropriate district office.

Accessing the Well Site. If an OPERATOR, well equipment TRANSPORTER or WELL service provider must access the well site from a roadway on the state highway system (Interstate, U.S. Highway, State Highway, Farm-to-Market Road, Ranch-to-Market Road, etc.), an access permit is required from TxDOT. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

Water Transport to Well Site. If an operator intends to transport water to the well site through a temporary pipeline laid above ground on the state’s right-of-way, an additional TxDOT permit is required. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

*NOTIFICATION

The operator is **REQUIRED** to notify the district office when setting surface casing, intermediate casing, and production casing, or when plugging a dry hole. The district office **MUST** also be notified if the operator intends to re-enter a plugged well or re-complete a well into a different regulatory field. Time requirements are given below. The drilling permit number **MUST** be given with such notifications.

During Drilling

Permit at Drilling Site. A copy of the Form W-1 Drilling Permit Application, the location plat, a copy of Statewide Rule 13 alternate surface casing setting depth approval from the district office, if applicable, and this drilling permit must be kept at the permitted well site throughout drilling operations.

***Notification of Setting Casing.** The operator MUST call in notification to the appropriate district office (phone number shown the on permit) a minimum of eight (8) hours prior to the setting of surface casing, intermediate casing, AND production casing. The individual giving notification MUST be able to advise the district office of the drilling permit number.

***Notification of Re-completion/Re-entry.** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of eight (8) hours prior to the initiation of drilling or re-completion operations. The individual giving notification MUST be able to advise the district office of the drilling permit number.

Completion and Plugging Reports

Hydraulic Fracture Stimulation using Diesel Fuel: Most operators in Texas do not use diesel fuel in hydraulic fracturing fluids. Section 322 of the Energy Policy Act of 2005 amended the Underground Injection Control (UIC) portion of the federal Safe Drinking Water Act (42 USC 300h(d)) to define "underground Injection" to *EXCLUDE* " ...the underground injection of fluids or propping agents (*other than diesel fuels*) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities." (italic and underlining added.) Therefore, hydraulic fracturing may be subject to regulation under the federal UIC regulations if diesel fuel is injected or used as a propping agent. EPA defined "diesel fuel" using the following five (5) Chemical Abstract Service numbers: 68334-30-5 Primary Name: Fuels, diesel; 68476-34-6 Primary Name: Fuels, diesel, No. 2; 68476-30-2 Primary Name: Fuel oil No. 2; 68476-31-3 Primary Name: Fuel oil, No. 4; and 8008-20-6 Primary Name: Kerosene. As a result, an injection well permit would be required before performing hydraulic fracture stimulation using diesel fuel as defined by EPA on any well in Texas. Hydraulic fracture stimulation using diesel fuel as defined by EPA on a well in Texas without an injection well permit could result in enforcement action.

Producing Well. Statewide Rule 16 states that the operator of a well shall file with the Commission the appropriate completion report within ninety (90) days after completion of the well or within one hundred and fifty (150) days after the date on which the drilling operation is completed, whichever is earlier. Completion of the well in a field authorized by this permit voids the permit for all other fields included in the permit unless the operator indicates on the initial completion report that the well is to be a dual or multiple completion and promptly submits an application for multiple completion. All zones are required to be completed before the expiration date on the existing permit. Statewide Rule 40(d) requires that upon successful completion of a well in the same reservoir as any other well previously assigned the same acreage, proration plats and P-15s or P-16s (if required) or a lease plat and P-16 must be submitted with no double assignment of acreage unless authorized by rule.

Dry or Noncommercial Hole. Statewide Rule 14(b)(2) prohibits suspension of operations on each dry or non-commercial well without plugging unless the hole is cased and the casing is cemented in compliance with Commission rules. If properly cased, Statewide Rule 14(b)(2) requires that plugging operations must begin within a period of one (1) year after drilling or operations have ceased. Plugging operations must proceed with due diligence until completed. An extension to the one-year plugging requirement may be granted under the provisions stated in Statewide Rule 14(b)(2).

Intention to Plug. The operator must file a Form W-3A (Notice of Intention to Plug and Abandon) with the district office at least five (5) days prior to beginning plugging operations. If, however, a drilling rig is already at work on location and ready to begin plugging operations, the district director or the director’s delegate may waive this requirement upon request, and verbally approve the proposed plugging procedures.

***Notification of Plugging a Dry Hole.** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of four (4) hours prior to beginning plugging operations. The individual giving the notification MUST be able to advise the district office of the drilling permit number and all water protection depths for that location as stated in the Groundwater Advisory Unit letter.

DIRECT INQUIRIES TO: DRILLING PERMIT SECTION, OIL AND GAS DIVISION

PHONE
(512) 463-6751

MAIL:
PO Box 12967
Austin, Texas, 78711-2967

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER 886893	DATE PERMIT ISSUED OR AMENDED Jan 04, 2023	DISTRICT 09
API NUMBER 42-497-38108	FORM W-1 RECEIVED Dec 29, 2022	COUNTY WISE
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 40
OPERATOR 100589 BKV DCARBON VENTURES, LLC 1200 17TH STREET STE 2100 DENVER, CO 80202		NOTICE This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored. **District Office Telephone No:** (940) 723-2153
LEASE NAME BARNETT RDC		WELL NUMBER 1
LOCATION 4.6 miles SW direction from BRIDEGEPORT		TOTAL DEPTH 10800

Section, Block and/or Survey

SECTION ◄ BLOCK ◄ ABSTRACT ◄ 583

SURVEY ◄ MC LANAHAN, J

DISTANCE TO SURVEY LINES 370 ft. E 178 ft. S	DISTANCE TO NEAREST LEASE LINE ft.
DISTANCE TO LEASE LINES 178 ft. S 370 ft. E	DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
NEWARK, EAST (BARNETT SHALE) BARNETT RDC	40.00	10,800	1 0	09

RESTRICTIONS: Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

This well must comply to the new SWR 3.13 requirements concerning the isolation of any potential flow zones and zones with corrosive formation fluids. See approved permit for those formations that have been identified for the county in which you are drilling the well in.

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION
SWR #13 Formation Data

WISE (497) County

Formation	Remarks	Geological Order	Effective Date
OVERCHARGED DISPOSAL ZONE	Chico area; 5 mi radius N. of FM 1810	1	12/17/2013
CANYON		2	12/17/2013
VALERA		3	12/17/2013
STRAWN	4300 in Boonesville Bend area	4	12/17/2013
OVERCHARGED DISPOSAL ZONE	Alvord area; 5 mi radius, hwy 287 SE of Alvord	5	12/17/2013
BRYSON SAND		6	12/17/2013
BRAZOS RIVER		7	12/17/2013
UNDETERMINED	gas producing zones	8	12/17/2013
CADDO		9	12/17/2013
ATOKA CONGLOMERATE		10	12/17/2013
BOONESVILLE BEND CONGL.		11	12/17/2013
MARBLE FALLS		12	12/17/2013
BARNETT SHALE		13	12/17/2013
MISSISSIPIAN		14	12/17/2013
VIOLA LIME		15	12/17/2013
ELLENBURGER		16	12/17/2013

The above list may not be all inclusive, and may also include formations that do not intersect all wellbores. The listing order of the Formation information reflects the general stratigraphic order and relative geologic age. This is a dynamic list subject to updates and revisions. It is the operator's responsibility to make sure that at the time of spudding the well the most current list is being referenced. Refer to the RRC website at the following address for the most recent information.
http://www.rrc.texas.gov/oil-gas/compliance-enforcement/rule-13-geologic-formation-info

API No. 42-497-38108

Drilling Permit # 886893

SWR Exception Case/Docket No.

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

APPLICATION FOR PERMIT TO DRILL, RECOMPLETE, OR RE-ENTER

This facsimile W-1 was generated electronically from data submitted to the RRC.
A certification of the automated data is available in the RRC's Austin office.

FORM W-1 07/2004

Permit Status: Approved

1. RRC Operator No. 100589
2. Operator's Name (as shown on form P-5, Organization Report) BKV DCARBON VENTURES, LLC
3. Operator Address (include street, city, state, zip): 1200 17TH STREET STE 2100 DENVER, CO 80202
4. Lease Name BARNETT RDC
5. Well No. 1

GENERAL INFORMATION

6. Purpose of filing (mark ALL appropriate boxes): [X] New Drill [ ] Recompletion [ ] Reclass [ ] Field Transfer [ ] Re-Enter [ ] Amended [ ] Amended as Drilled (BHL) (Also File Form W-1D)

7. Wellbore Profile (mark ALL appropriate boxes): [X] Vertical [ ] Horizontal (Also File Form W-1H) [ ] Directional (Also File Form W-1D) [ ] Sidetrack

8. Total Depth 10800

9. Do you have the right to develop the minerals under any right-of-way ? [X] Yes [ ] No

10. Is this well subject to Statewide Rule 36 (hydrogen sulfide area)? [ ] Yes [X] No

SURFACE LOCATION AND ACREAGE INFORMATION

11. RRC District No. 09
12. County WISE
13. Surface Location [X] Land [ ] Bay/Estuary [ ] Inland Waterway [ ] Offshore

14. This well is to be located 4.6 miles in a SW direction from Bridegeport which is the nearest town in the county of the well site.

15. Section
16. Block
17. Survey MC LANAHAN, J
18. Abstract No. A-583
19. Distance to nearest lease line: ft.
20. Number of contiguous acres in lease, pooled unit, or unitized tract: 40

21. Lease Perpendiculars: 178 ft from the S line and 370 ft from the E line.
22. Survey Perpendiculars: 370 ft from the E line and 178 ft from the S line.

23. Is this a pooled unit? [ ] Yes [X] No
24. Unitization Docket No:
25. Are you applying for Substandard Acreage Field? [ ] Yes (attach Form W-1A) [X] No

FIELD INFORMATION List all fields of anticipated completion including Wildcat. List one zone per line.

26. RRC District No.	27. Field No.	28. Field Name (exactly as shown in RRC records)	29. Well Type	30. Completion Depth	31. Distance to Nearest Well in this Reservoir	32. Number of Wells on this lease in this Reservoir
09	65280200	NEWARK, EAST (BARNETT SHALE)	Injection Well	10800	0.00	1

BOTTOMHOLE LOCATION INFORMATION is required for DIRECTIONAL, HORIZONTAL, AND AMENDED AS DRILLED PERMIT APPLICATIONS

Remarks

Certificate:

I certify that information stated in this application is true and complete, to the best of my knowledge.

Bill Spencer, Consultant — Name of filer

Dec 29, 2022 — Date submitted

(512)9181062, x2 — Phone

bill@spencerconsulting.org — E-mail Address (OPTIONAL)

RRC Use Only Data Validation Time Stamp: Jan 5, 2023 10:20 AM(Current Version)

Request for Additional Information: Barnett RDC Well No. 1
March 1, 2023

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	NA	NA	We recommend ensuring that references and footnotes are used consistently throughout the MRV plan. For example: • The footnote references are in different citation styles. • Sometimes both in-text citations and footnote references are used in conjunction. • Footnote numbers are inconsistently located before or after the punctuation.	Addressed
2.	NA	NA	Please ensure that all acronyms are defined during their first use within the text of the MRV plan. For example, “USGS” and “FLIR” are not defined.	Addressed

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	NA	NA	There is a lack of consistency with hyphens, bolding, quotation marks, and capitalization throughout the MRV plan. Examples include but are not limited to: CO2 vs CO_2 Figure vs. **Figure** Muenster Arch vs. Muenster arch Subunit vs. subunit vs. sub-unit Subunit E vs. subunit 'C' vs. Unit 'C" Smye vs. Syme Formation vs. formation Smye et al. vs. Gao *et al.* Ellenburger vs Ellenberger We recommend reviewing the formatting in the MRV plan for consistency. Furthermore, we recommend doing an additional review of the entire plan for spelling, grammar, etc.	Addressed
4.	2	6	The MRV plan states that the facility name is "Bridgeport Gas Processing Plant". However, a new facility "Barnett RDC Well No. 1" was created in conjunction with this MRV plan. Because the MRV plan is associated with the facility that will be reporting data under subpart RR, please also reference that facility and ID number in the MRV plan.	We believe we have responded adequately by calling out both facilities in Section 2.
5.	3.3	14	The MRV plan is not clear on what the lower confining unit is. Please address.	Addressed
6.	3.8	30	Figure 16 is still incorrectly referenced within the text. Please ensure that all figures are correctly referenced within the text of the MRV plan. Furthermore, please ensure that all figure captions are consistent and correct throughout the MRV plan.	Addressed
7.	3.8	32	In Figure 18, please clarify what the red dotted line represents and/or update the legend.	Addressed

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
8.	4.1	34	Figure 20 is difficult to read. We recommend enlarging the figure and adding a scale bar, north arrow, and legend. Please ensure that all maps in the MRV plan are legible and display north arrows, scale bars, and legends.	Map has been updated.
9.	5	35	Please ensure that each identified leakage pathway has a characterization of likelihood, timing and magnitude for potential leakage.	Addressed
10.	5.5	39	"Overall, there is in excess of 2,000 feet of impermeable rock between the injection zone and the deepest well penetrations…" 3,000 feet of separation is quoted in section 5.3. Please clarify and ensure that the MRV plan is consistent.	Addressed.
11.	5.6	40	Please expand the discussion on induced seismicity within this section and explain whether monitoring/operational approaches differ from natural seismicity. E.g., will the facility take steps to ensure that operations and injection practices do not induce seismicity?	Section has been expanded
12.	6	42-46	The MRV plan explains that to quantify leakage, the facility "will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation". Do you have examples of what kinds of standard engineering techniques might be used to quantify leakage from surface leakage pathways that are not equipment leaks (e.g., from leakage through faults/fractures or the confining layer)?	Section has been expanded
13.	6.1	42	"The facility and well will be monitored for H_2S and increases in CO_2 concentration and set with a high alarm setpoint for H_2S." Please revise the above sentence for clarity.	Addressed.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
14.	6.2	45	"Additionally, any additional downhole or subsurface remediations that could reduce or eliminate the leakage from the injection well to the existing and future wells in the area expected to be producing injected CO_2 will be investigated and addressed if necessary." Please revise the above sentence for clarity.	Addressed
15.	6.4	46	"In the unlikely event CO_2 leakage occurs as a result of leakage through the confining seal, it is also unlikely that the leak would result in surface leakage." Please revise the above sentence for clarity. Furthermore, this sentence does not explain why CO_2 leakage through the confining seal would not result in surface leakage. Please elaborate.	Addressed

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan

Barnett RDC #1

Wise County, Texas

Prepared by

BKV dCarbon Ventures, LLC

Version 2.0

January 17, 2023

Table of Contents

Section 1 – Introduction

BKV dCarbon Ventures, LLC ("dCarbon") is currently authorized to inject a total of up to 14.5 million standard cubic feet per day (MMscfd), which is equivalent to approximately 280,000 metric tons per year (MT/yr), of Carbon Dioxide (CO_2) in the RDC #1 well under the Texas Railroad Commission (TRRC). The permit allows injection into the Ellenburger formation at a depth of 9,350 feet to 10,250 feet with a maximum allowable surface pressure of 4,500 pounds per square inch gauge (psig).

The well site is located approximately 4.6 miles southwest of Bridgeport, TX in Wise County (**Figure 1**).

The Barnett RDC #1 has approved W-14 injection and W-1 drilling permits with the TRRC (Permit No 17090, UIC Number 000125478, API# 42-497-38108). Additionally, dCarbon plans to drill the well in the first half of 2023, complete the well in mid-2023 and begin injection operations in late 2023. A copy of the approved W-1 and W-14 are included as Attachment A. Although, dCarbon currently plans to initially inject approximately 180,000 MT/yr CO_2 into the well, all calculations in this document have been performed with the maximum injection amount allowed on the TRRC permit (280,000 MT/yr). dCarbon plans to inject for approximately 12 years.

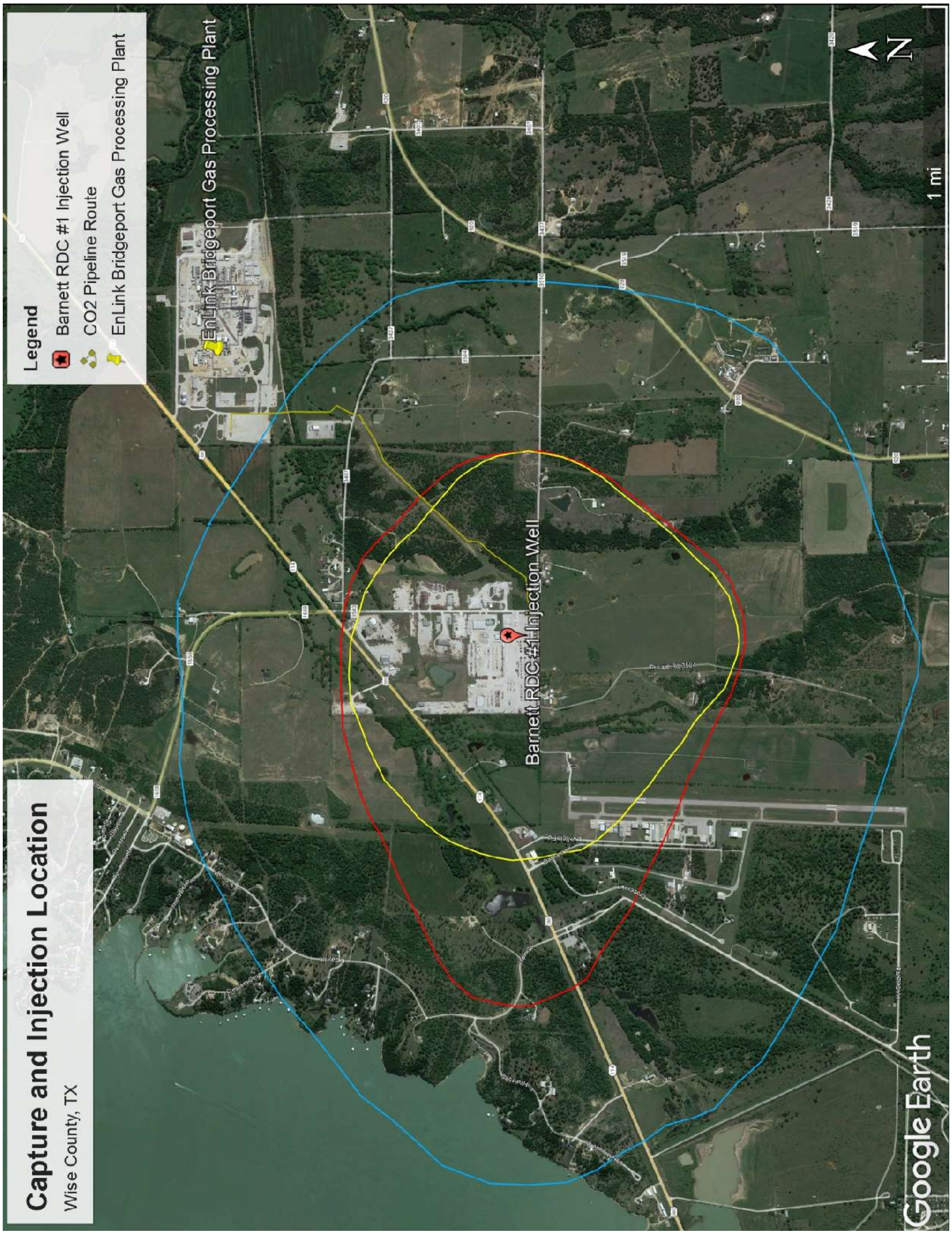
dCarbon is submitting this Monitoring, Reporting, and Verification ("MRV") plan to the EPA for approval under 40 CFR §98.440(a), Subpart RR, of the Greenhouse Gas Reporting Program ("GHGRP").

BKV dCarbon Ventures TRRC operator number is 100589

BKV dCarbon Ventures' EPA number is 110071343305

Figure 1. Location of the Barnett RDC # 1 well and Bridgeport Gas Processing Plant

Maximum Monitoring Area (blue), End of Injection Plume (yellow), and 50-year Post Injection Plume (red) as Modeled at the Barnett RDC #1 Well.



Section 2 – Facility Information

Gas Plant Facility Name: BRIDGEPORT GAS PROCESSING PLANT

415 PRIVATE RD, 3502

BRIDGEPORT, TX, 76426

Latitude: 33° 11.74' N

Longitude: 97° 48.22' W

GHGRP Id: 1006373

FRS Id: 110028052354

NAICS Code: 211130

Currently reporting under Subpart C, W, NN

Underground Injection Control (UIC) Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control ("UIC") Class II program. TRRC classifies the Barnett RDC #1 well as a UIC Class II well. A Class II permit was issued in accordance with Statewide Rule 9 to BKV.

UIC Well Identification Number

Barnett RDC #1, API 42-497-38108, UIC# 000125478

The Bridgeport Gas Processing Plant operated by EnLink Midstream is current emitting CO_2. The Barnett RDC #1 well will be disposing of CO_2 from the Bridgeport Gas Processing Plant.

Section 3 – Project Description

This Project Description discusses the geologic setting, planned injection volumes and process, and the reservoir modeling performed for the proposed BKV dCarbon Ventures RDC #1 Class II injection well. dCarbon prepared this MRV plan to support the storage of CO_2 from gas processing facilities in Wise County, Texas.

3.1. Overview of Geology

The proposed injection site lies in western Wise County, where the Barnett Shale, Viola/Simpson, and Ellenburger formations dip and thicken to the east toward the Muenster Arch as seen in the west to east cross section of **Figure 2**. Similarly, the north to south cross section shows the Ellenberger and overlying formations dipping to the north. One inference from this is that any CO_2 injected may exhibit the tendency to move up dip due to buoyancy, meaning the anticipated plume movement will be westward. This is further represented in the structure contour map of the Ellenburger formation top by Polastro [1](2007) in **Figure 2**.

The Fort Worth Basin sedimentary succession begins with locally abundant Cambrian clastics in the southern section of the basin that unconformably overly the uneven Precambrian basement. The overlying Ordovician age Ellenburger platform carbonates were deposited on a passive margin and contain thicknesses up to 4,000 feet in the Fort Worth Basin. The Ellenberger platform carbonates underwent multiple episodes of regional exposure causing dolomitization and karsting in several units of the Ellenburger. Ordovician Viola and Simpson formations overly the Ellenburger formation and are found in the northern section of the basin near the Muenster Arch. A major erosive interval occurred during the Mississippian, eroding down to the Ordovician formations. Later deposition of the Barnett Shale unconformably overlies the Viola limestone, Simpson formation, and the Ellenberger group (Gao et al., 2021) [2]. Overlying the Barnett Shale is a thick section of mostly Pennsylvanian and Permian carbonates and clastics (Bend, Strawn, and Canyon Groups). **Figure 2** indicates the general regional stratigraphy. While there are multiple storage-confining unit systems that could be evaluated for injection, the focus was on Mississippian-Ordovician section that consists of the Barnett shale and the carbonate Ellenburger group. The Ellenburger group directly overlies the basement rock and is considered the main reservoir target.

[1] "Unconventional shale-gas systems: The Mississippian Barnett Shale of north-central Texas as one model for thermogenic shale-gas assessment", Pollastro RM, American Association of Petroleum Geologists Bulletin, 2007, pgs 475-499

[2] Gao, S et al. "Low pressure buildup with large disposal volumes of oil field water: A flow model of the Ellenburger Group, Fort Worth Basin, northcentral Texas", AAPG Bulletin Vol 105 Number 12, 2021, pgs 2575-2593

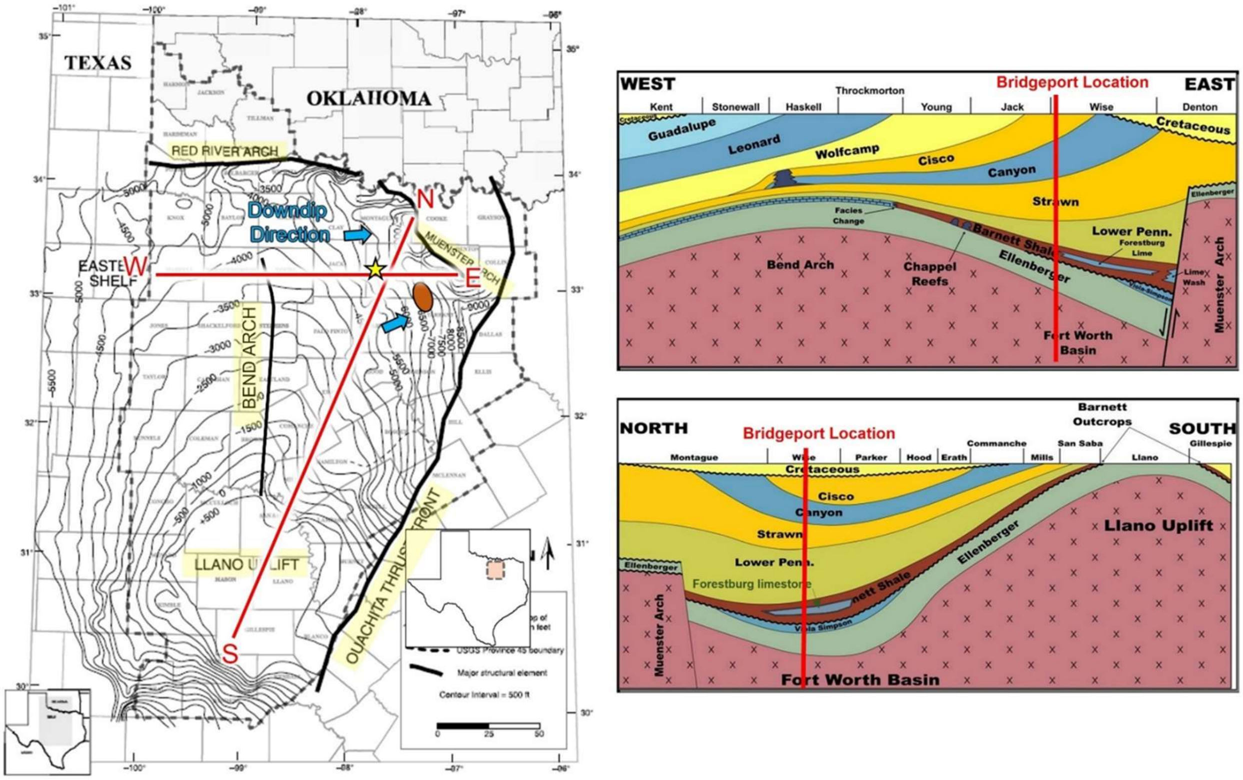


Figure 2. (Left) Ellenberger structural contour map modified from Jarvie and Hill (2007) [3]showing the regional structures within and bounding the Fort Worth Basin, Ellenberger structure contours with respect to the final BKV AOI (yellow star). (Right) Cross sections E-W and N-S show the regional dip of the sedimentary units in the Fort Worth Basin.

3.2. Bedrock Geology

3.2.1. Basin Description

The Fort Worth basin is a flexural basin that formed in the foreland of the advancing Ouachita orogenic belt during the Late Mississippian through Pennsylvanian epochs (Horne, et al. 2020)[4]. As illustrated in Figure 2, the Fort Worth basin is bounded to the east by the Ouachita fold and thrust belt and to the north by the Muenster arch and Red River arch. These arches are characterized by a series of high angle reverse faults. The basin is deepest to the northeast, with as much as ~12,000 feet of sediment infill, where the Ouachita thrust front meets the Muenster arch and is shallowest towards the south.

[3] Jarvie, DM et al, "Unconventional shale-gas systems: The Mississippian Barnett Shale of north-central Texas as one model for thermogenic shale-gas assessment", AAPG Bulletin Volume 91 Number 4, 2007, pgs 475-499

[4] Horne E. A. Hennings P. H., and Zahm C. K. 2021. Basement structure of the Delaware basin, in The Geologic Basement of Texas: A Volume in Honor of Peter Flawn , Callahan O. A., and Eichhubl P. (Editors), The University of Texas at Austin, Bureau of Economic Geology Report of Investigations, Austin, Texas.

System	Series	Stage	Group or Formation	
Cretaceous	Lower	Comanchean	Trinity Group	
Pennsylvanian	Upper	Missourian	Canyon Group	Jasper Creek Formation
	Middle	Desmonesian	Strawn Group	Willow Point Formation
				Lone Camp Formation
				Millsap Lake Formation
			Kickapoo Group	Ratville Formation
				Parks Formation
				Caddo Pool Formation
		Atokan	Bend Group	Caddo Formation
				Smithwick Shale
	Lower			Pregnant Shale
				Big Saline Formation
		Morrowan		Marble Falls Limestone
				Comyn Formation
Mississippian	Chesterian – Meramecian			
			Barnett	Upper Barnett Shale
				Forestberg Limestone
	Osagean			Lower Barnett Shale
Ordovician	Lower		Ellenburger Group	
Precambrian			Basement	

Table 1. Regional stratigraphy at Barnett RDC #1 site in north Texas.

3.2.2 Stratigraphy

The Ellenburger contains alternating limestone and dolomite lithologies, consistent with regional descriptions of the Ellenberger. Vertical changes in properties throughout the Ellenburger were used to divide the unit into 8 subunits (A-G), in agreement with a similar approach demonstrated by Smye et al. (2019)[5]. The main target storage reservoir, subunit E, was identified based on dominant lithology, gross and net reservoir thicknesses, porosity values, and permeability values. In tandem, the Ellenburger subunit ‘B’ and the stratigraphic top portion of Ellenburger subunit ‘C’ were identified as a potential storage caprock. Below this interval, there are baffles of tighter limestone throughout Ellenburger subunits ‘C’, ‘C2’, and ‘D’ that would also act as sealing units to the storage reservoir.

[5] Smye, KM et al. “Stratigraphic architecture and petrophysical characterization of formations for deep disposal in the Fort Worth Basin, Texas”, Texas BEG Report *Interpretation* Vol 7 Number 4, 2019.

Dominant lithologies were determined by comparing the photoelectric factor (PEFZ) log curve with the volume of clay (VCL), sand (VQUA), lime (VCLC), dolomite (VDOL), gas (VUGA), and free water (VUWA) curves in the Tarrant well, as well as the separation of the density and neutron porosity curves. Gross reservoir thickness was determined for each Ellenburger subunit by adding the footage from the top to the bottom of the formation.

The W.S. Coleman #2 (API 42-497-35807) well, 5.4 miles east of the proposed RDC #1 injection well, was used to calculate reservoir zone properties for individual subunits within the Ellenburger formation since currently no well exists at the proposed site. The North Tarrant SWD 1 (42-439-31228) well, located approximately 27 miles to the southeast was also used in well correlations because of its robust well log data across the Ellenburger Group.

Figure 3 shows the correlation of the North Tarrant SWD 1 well up to the W.S. Coleman #2. As an initial observation, Sub-units 'C' and 'E' within the Ellenburger are present and appear to be contiguous in the project area. Subunit 'C" thickness is approximately 750 feet while Subunit 'E' thickness varies across the cross sections. It is estimated there is at least 940 feet of Subunit 'C' at the Barnett RDC #1 proposed site location with 1,250 feet of Ellenberger 'E'. The cross sections confirm regional trends in dip also apply to the AOI wherein the reservoir unit slightly dips down to the north and east.

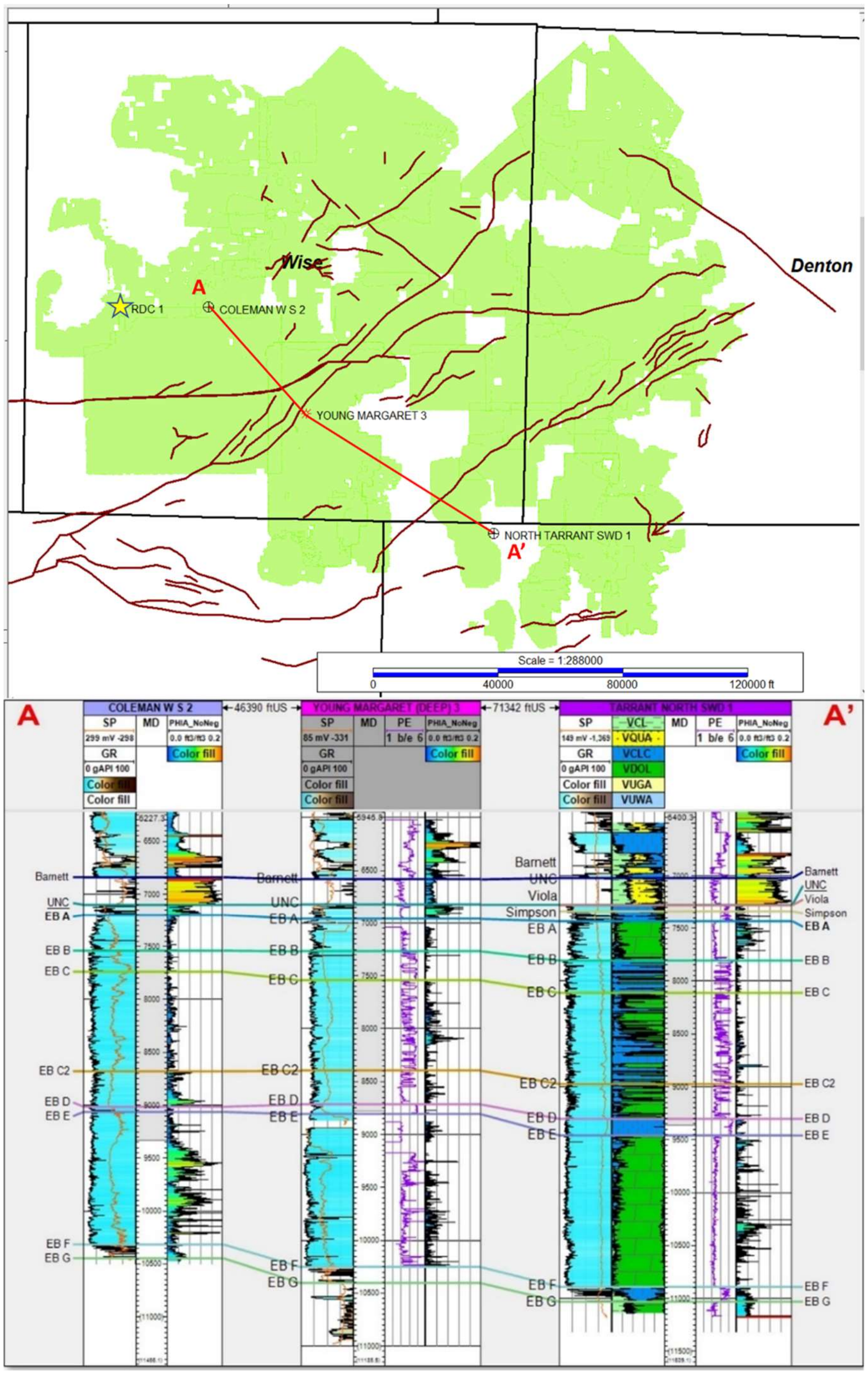


Figure 3. (Top) Map of Wise County with the Barnett RDC #1 (yellow star), faults (brown lines), cross section wells (black circles), BKV 3D seismic extent (green polygon), and a NW-SE cross section (A-A'). (Bottom) Cross section showing Gamma Ray (GR), Spontaneous Potential (SP), Photo Electric Factor (PE), and average porosity (PHIA) from the North Tarrant SWD well to the WS Coleman 2 well. Ellenberger Subunit C (EB C) is the primary caprock and Ellenberger Subunit E (EB E) is the primary reservoir unit.

3.2.3 Faulting

Faults within the Fort Worth basin are generally northeast-trending, high-angle normal faults where most of the faults root into the Precambrian crystalline basement (**Figure 4**). The mechanism for deformation that produced these faults has been attributed to flexure generated by the Ouachita orogenic belt. Deep seated faults that root into the Precambrian crystalline basement generally terminate in the Pennsylvanian age strata and do not continue into the overlying Cretaceous strata, where it is present, suggesting that faults have not experienced significant movement since their formation (Horne et al. 2021). Karsting in the region has resulted in small-scale, concentric faults that originate from the collapse of karst features predominantly within the Ellenburger group.

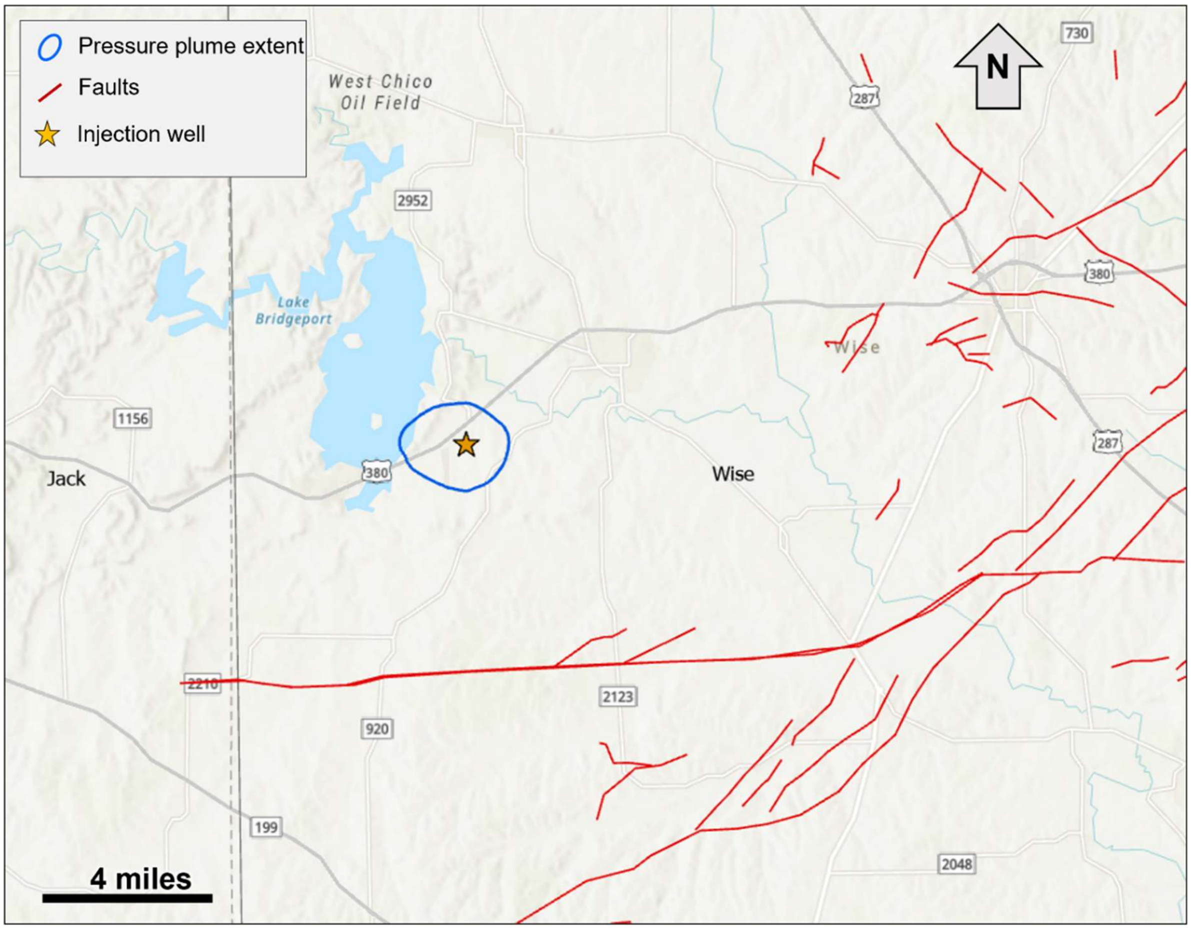


Figure 4. Mapped faults near the proposed injection well from Wood, Victoria, "Reservoir Characterization and Depositional System of the Atokan Grant Sand, Fort Worth Basin, Texas" (2015). Theses and Dissertations[6].

3.3 Lithological and Reservoir Characterizations

[6] Wood, Victoria. "Reservoir Characterization and Depositional System of the Atokan Grant Sand, Fort Worth Basin, Texas", University of Arkansas Thesis, 2015

Syme et al. (2019) provided a detailed description of regional stratigraphy as well as petrophysical attributes of multiple units within the Ellenburger group. Prior to understanding the petrophysical properties of these subunits and assessing their storage reservoir or confining layer potential, it is important to understand the overall lithology. Literature suggests the Ellenburger interval is mostly composed of calcite, dolomite, quartz, and clay. Syme et al. (2019) noted that the carbonate intervals were mostly clean with less than 10% clay by volume. However, the top of the Ordovician section was shown to have an increased clay content (about 40% by volume). This also coincided with an increase in siliciclastic materials (quartz and clay). Porosity in clean carbonate intervals is approximately 5% while that in siliciclastic intervals may reach 20%. The basement lithology was identified as granite wash with hematite contents ranging between 5-10% by volume. **Figure 5** shows the general stratigraphy in the AOI as noted by Syme et al. (2019).

Lithological characterization was focused specifically on the red dotted area shown in this figure in order to better understand local stratigraphy and petrophysics. The Viola Formation and Simpson Group are listed here overlying the Ellenburger A subunit; however these formations pinch out to the east of the proposed Barnett RDC #1 site and are thus not included in subsequent petrophysical analysis.

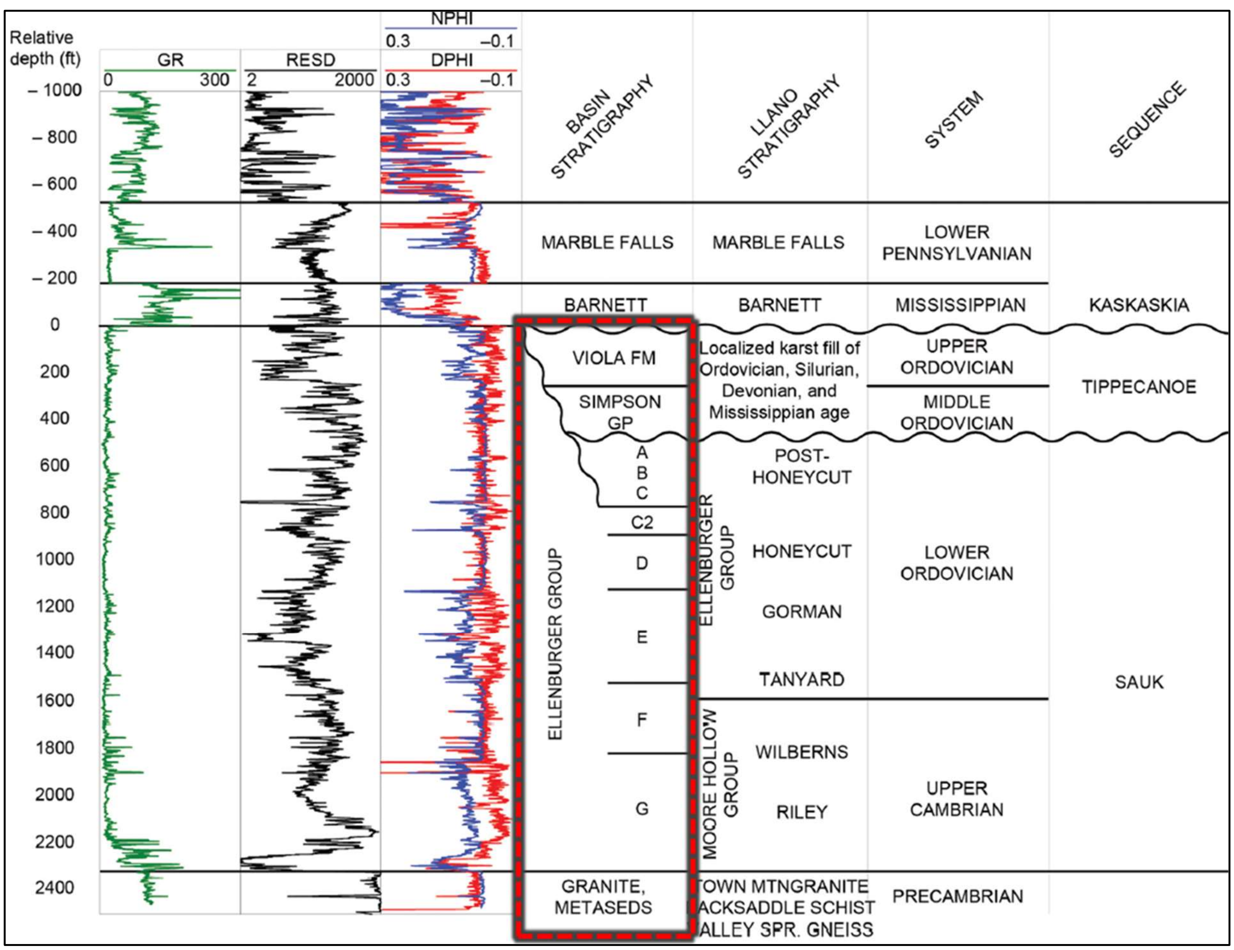


Figure 5. Regional stratigraphy at BKV site in North Texas (modified from Syme et al., 2011).

The Barnett Shale is anticipated to serve as a secondary confining layer. The Barnett Shale is a source rock and an unconventional reservoir which is extensively drilled in the Fort Worth Basin. However, there are no Barnett Shale wells in the MMA of the RDC #1. The porosities and permeabilities in the Barnett Shale lie in the 4-6% and 7-50 nanodarcies ranges, respectively.

Underlying the Barnett is the Ellenburger Group, which is the anticipated injection interval. The Ellenburger could be divided into eight lithostratigraphic units starting with Subunit ‘A’ at the top to Subunit ‘G’ at the bottom which sits on top of the crystalline basement. Subunit ‘G’ is composed of siliciclastic facies and is largely variable across the region. Though the porosity in Subunit ‘G’ is higher compared to other subunits, lateral continuity might be an issue in developing a storage project in this unit. Consequently, Subunit ‘E’ will serve as a potential reservoir given it has ~ 4% matrix porosity. Ellenburger ‘E’ is a clean dolomitic reservoir zone with 49% dolomite by volume. Subunit ‘B’ and Subunit ‘C’ were found to have lower matrix porosities compared to Subunit ‘E’, which implies these subunits could provide vertical confinement or impediment to CO_2 movement. Ellenburger ‘A’ has been proven to be a reservoir zone with multiple saltwater disposal wells completed in Subunit ‘A’. However, as mentioned earlier, karsting features at the top of the Ellenburger imply there is some potential for hydraulic communication between Subunit ‘A’ and the overlying Barnett. **Figure 6** illustrates the log response and petrophysical properties of Ellenburger subunits.

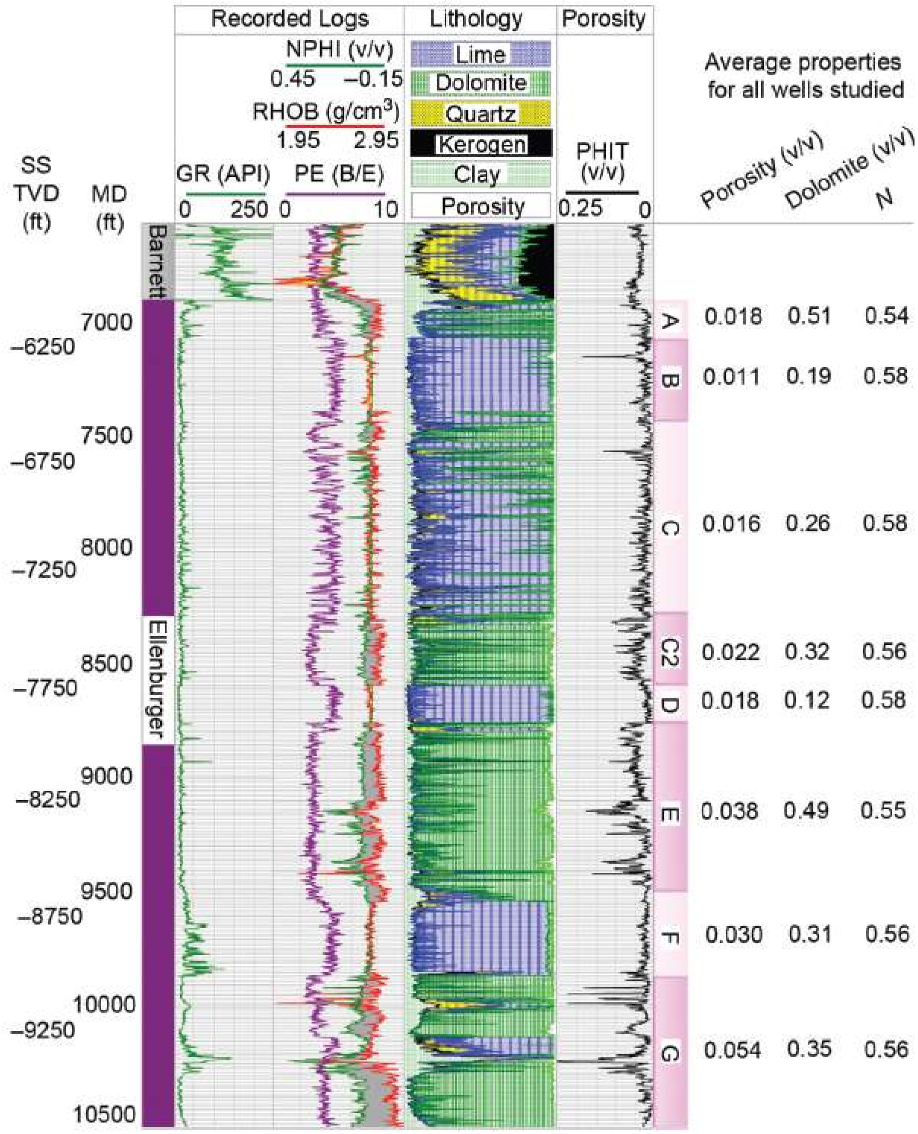


Figure 6. Properties of Ellenburger subunits in the project area (modified from Syme et al., 2019).

The W.S. Coleman #2 injection well located ~ 5 miles from the proposed injection site similarly contains Ellenburger Subunits A through G, as shown below in **Figure 7**. Drilling at the proposed site will result in site specific petrophysical properties like those shown here and in previous figures.

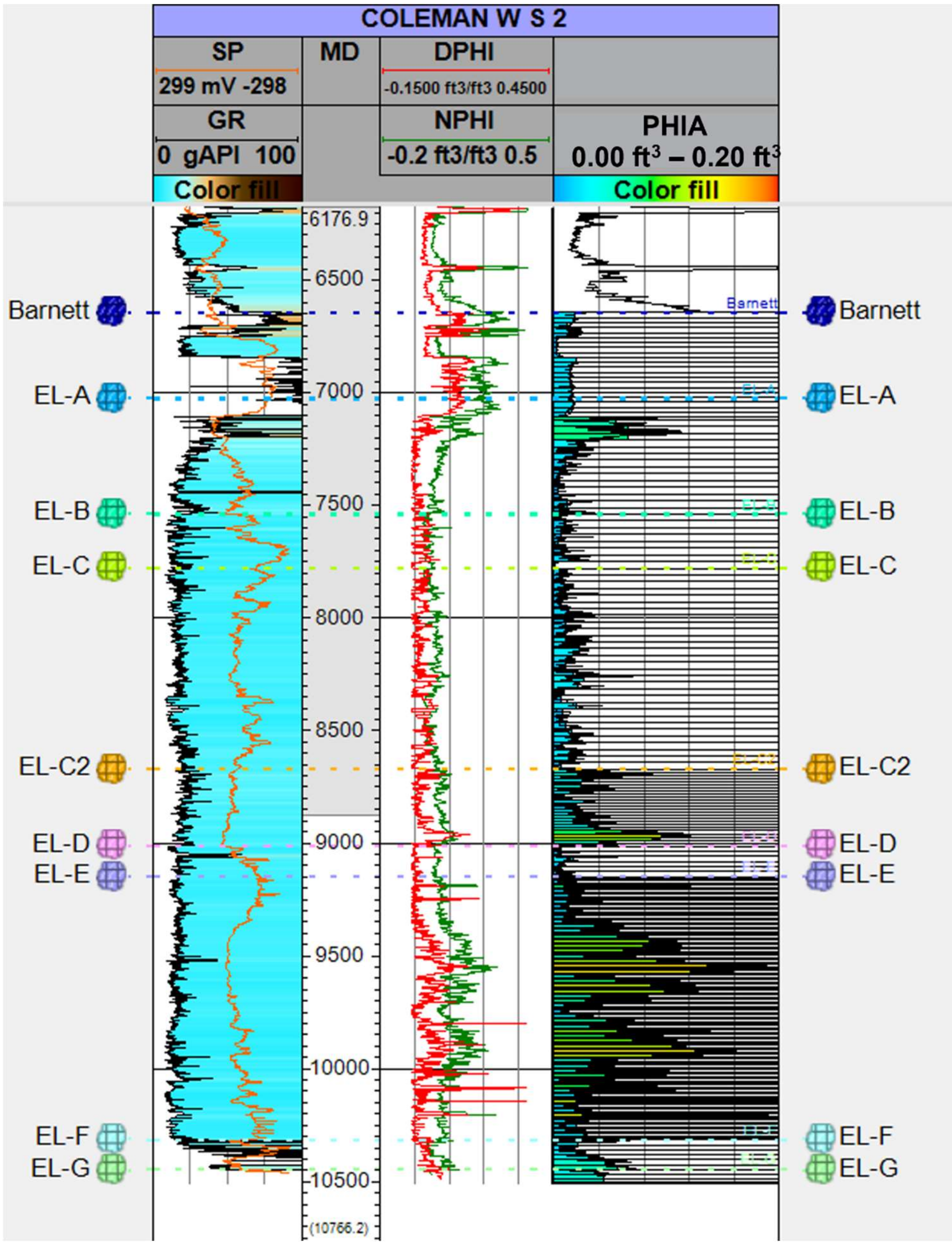


Figure 7. W.S. Coleman #2 well log interpretation; Ellenburger Group Subunits A through G are denoted to the right and left of the log image.

Net reservoir thickness was determined for each subunit of the Ellenburger by summing the footage where the average porosity (PHIA) curve was greater than 2%. It is important to note that such a low matrix porosity value was chosen due to the nature of the reservoir wherein fracture porosity is a significant contributor to reservoir quality. Our understanding and evaluation of the Ellenburger suggested a low log porosity could still result in realizable CO_2 storage potential given the history of injectivity from saltwater disposal in the area (e.g. North Tarrant SWD 1 and W.S. Coleman #2 wells). A net-to-gross ratio was determined for each subunit by dividing the net reservoir thickness by the gross reservoir thickness. Average net reservoir porosity was calculated for each subunit of the Ellenburger by averaging the net reservoir average porosity (PHIA) curve from the top to the bottom of the subunit. These reservoir zone properties were subsequently used to derive preliminary storage resource estimates. **Table 2** lists average petrophysical properties in the Ellenburger.

Table 2. Ellenberger properties assessed at the AOI.

Ellenburger Subunit	Dominant Lithology	Gross Reservoir Thickness (feet)	Net Reservoir Thickness (feet [>2% PHI])	Net-to-Gross Ratio	Average Reservoir Porosity (%)
A	Dolomite	338	63	0.186	1.1
B	Limestone	200	14	0.07	0.8
C	Limestone	940	187	0.198	1.2
C2	Dolomite	335	229	0.683	3.5
D	Limestone	49	3.5	0.072	0.6
E	Dolomite	1252	879	0.702	5.5
F	Limestone	130	88.5	0.677	3.2
G	Dolomite	NA	NA	NA	NA

Permeability data in individual Ellenburger subunits was obtained from literature (Gao et al., 2021).

Other crucial reservoir properties such as pressure and geothermal gradients were obtained from data discussed in Gao et al. (2021). Pressure gradient in the Ellenburger was noted to be 0.47 psi/foot while the geothermal gradient in the Fort Worth basin was estimated at 1.4°F/100 feet. These parameters were used to run preliminary CO_2 storage calculations as discussed in the subsequent section.

3.4 Formation Fluid Chemistry

Nine wells were identified through a review of chemical analyses of oil-field brines from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3 within the Pennsylvanian age strata that are located within 20 miles of the proposed injection well site as shown in **Figure 8**. Formation fluid chemistry analyses for these wells is reported in **Table 3**.

Table 3. Pennsylvanian formation fluid chemistry.

	TDS (mg/L)	pH	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	86,807	6	26,000	5,494	53,392
LOW	21,926	4.4	6,291	978	13,389
HIGH	149,480	7.1	47,203	9,854	91,765

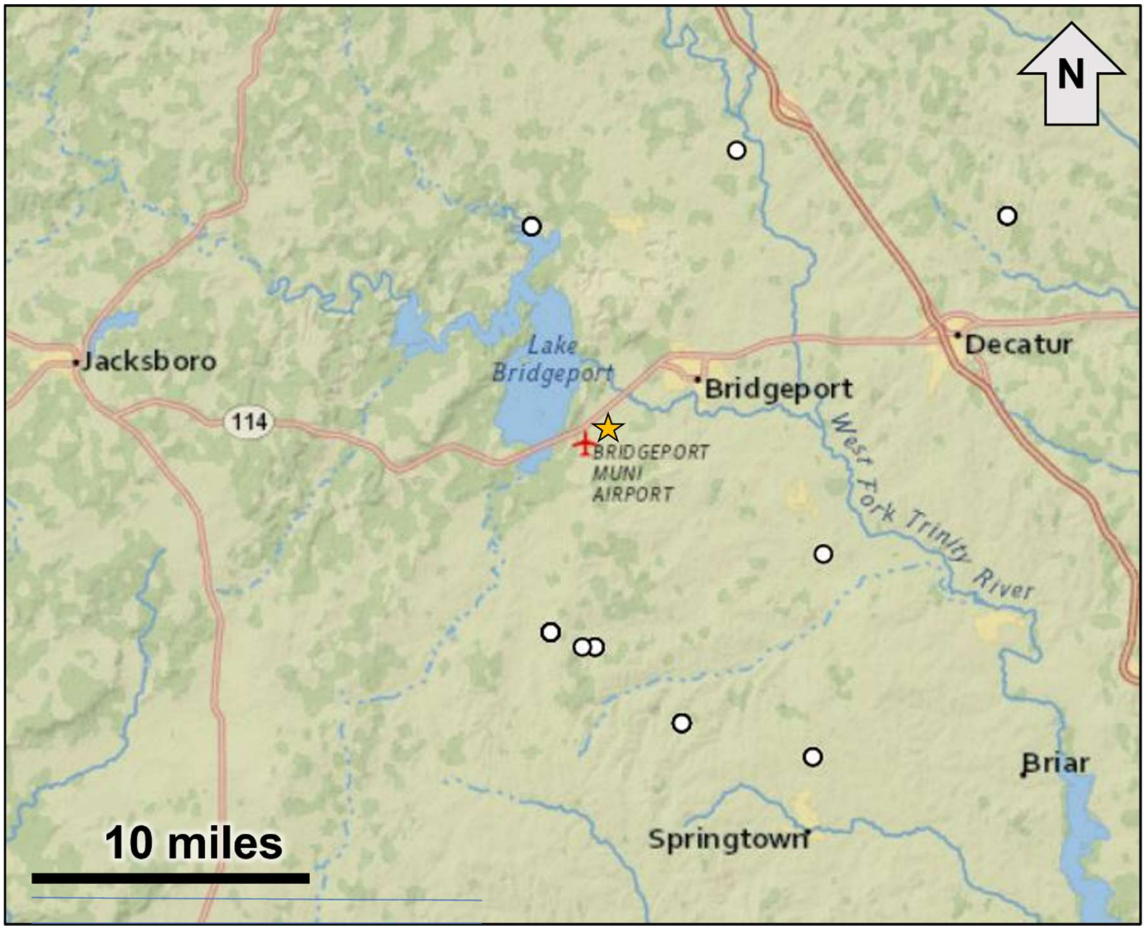


Figure 8. Map showing the location of wells used in the formation fluid chemistry analysis.

The Ellenburger Group has not been extensively drilled within the immediate area surrounding the proposed injection well and consequently formation fluid chemical analysis for the Group are from a basin-wide review. Based on analyses from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3, the Ellenburger fluids have greater than 194,263 parts per million (ppm) total dissolved solids (TDS) within the Fort Worth basin. Formation fluid chemistry analyses for the Ellenburger Group Fort Worth basin wells are reported in **Table 4**.

Table 4. Ellenburger Group formation fluid chemistry.

	TDS (mg/L)	pH	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	212,347	6	55,066	18,523	125,209
LOW	194,263	5.7	30,000	12,800	76,200
HIGH	276,388	6.6	66,482	24,750	153,071

3.5 Potential of Induced Seismicity – Ellenburger

An analysis of historical seismic events within a 100 square mile (5.64 mile radius) surrounding the proposed Class II well injection site shows no recorded seismic activity dating back to January 1, 1971, according to the U. S. Geological Survey (USGS) Earthquake Catalog (**Figure 9**). TexNet seismic activity data supports this conclusion, showing no recorded seismic events around the proposed injection well site. A study by Hennings et al. in 2019 [7]described the fault-slip potential on mapped faults within the Fort Worth Basin. Their findings show that steeply dipping faults that strike north-northeast have the highest fault-slip potential. An injection rate of up to 15,000 bpd has been permitted for a disposal well in Wise County, approximately 8 miles from the proposed injection site, and has been operated without any observed seismic activity.

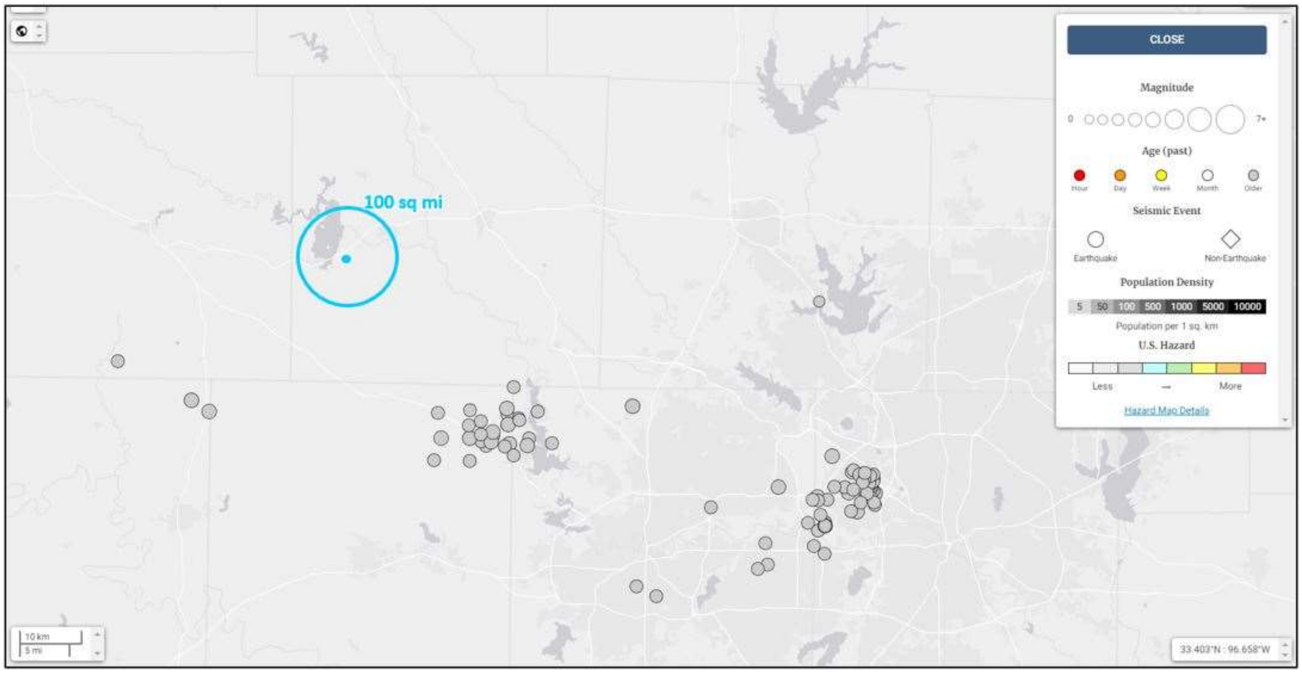


Figure 9. Screenshot from the USGS Earthquake Catalog showing no historical seismic activity in the surrounding 100 square miles to the proposed Bridgeport site.

3.6. Groundwater Hydrology in MMA

Wise County falls within the Upper Trinity Groundwater Conservation District as mapped by the Texas Water Development Board (**Figure 10**). Two aquifers are within the vicinity of the proposed injection site: the Trinity Group Aquifer, a major aquifer, and the Cross Timbers Aquifer, a minor aquifer. The Lower Cretaceous Trinity Group is an important source of groundwater for a portion of northern Texas and consequently Wise County, Texas. Lower Cretaceous strata outcrop throughout the majority of Wise County, especially to the east, but are absent at and around the proposed injection site (**Figure 10** and **Figure 11**). Instead, strata from the Cross Timbers Aquifer outcrop on the surface at the proposed injection site. The Cross Timbers Aquifer includes four Paleozoic-age water-bearing formations including, from oldest to youngest, the Strawn, Canyon, Cisco, and Wichita Groups. The Upper Pennsylvanian Strawn Group Willow Point Formation outcrops on the surface at the proposed injection site, and rocks from the Upper Pennsylvanian Canyon Group Jasper Creek Formation outcrop 0.5 miles to the north-northwest of the proposed injection site (**Figure 12**). Strawn and Canyon Group formations are primarily composed of

[7] Hennings, PH et al. "Injection-Induced Seismicity and Fault-Slip Potential in the Fort Worth Basin, Texas", Bulletin of the Seismological Society Of America Vol 20 Number 20, 2019.

limestones, shales, and sandstones. A stratigraphic column showing the Pennsylvanian through Cretaceous strata is included as **Figure 13**.

The Canyon Group, which outcrops at the proposed injection site, is a sequence of limestones with interstratified shales and sandstones deposited as a part of the Perrin Delta System (Brown et al. 1973)[8]. Deposition of Canyon Group sandstones was localized within valley fill, distributary channel fill, and delta-front deposits (TWDB 2021)[9]. These sandstone bodies are not laterally continuous and therefore did not constitute a regional scale major aquifer. Nearby groundwater well reports list the aquifer as Paleozoic, supporting the conclusion that freshwater in and around the well site is sourced from Pennsylvanian strata. Because the location of the well site does not fall within one of the major aquifer boundaries described by the Texas Water Development Board, describing the Total Dissolved Solids (TDS) contents of water from the Pennsylvanian Canyon Group is challenging. Consequently, this data will be collected during the drilling process. One TDS measurement from the Pennsylvanian group (formation unspecified) near the well site was recorded as 1,600 ppm, according to a USGS water-supply paper from 1956[10]. Thus, freshwater wells in the area are likely drawing from localized sands within the Upper Pennsylvanian strata. The USGS's National Produced Waters Geochemical Database (NPWGD) report several TDS content measurements within the Lower Pennsylvanian Atoka/Bend formation with values ranging from 21,926 ppm to 154,593 ppm[11]. No reported TDS values from the USGS NPWGD fall below the 10,000-ppm minimum required to classify an aquifer as an Underground Source of Drinking Water (USDW). Consequently, the lowermost USDW is likely above the Lower Pennsylvanian strata at around 900 feet.

The direction of groundwater flow within Paleozoic strata is suggested to be in the west-northwest direction according to a conceptual model developed by Nicot, et al. 201112. Recharge into the Canyon Group was estimated to occur at a rate of 0.09 inches/year by the same study. Surface-water salinity decreases downstream toward the Gulf of Mexico. Groundwater salinity increases from younger to older formations toward the east but there is a reversal in the Strawn Group, whose formations can be in hydraulic contact with the overlying Trinity aquifer. The Trinity Aquifer may provide cross-formational flow to Paleozoic aquifers when they overlap with the primary flow direction from the Trinity to the Strawn. This mixing could explain the salinity reversal observed in some parts of Texas within the Strawn Group4. Locally, however, the deepest water well within 2 miles of the proposed injector well is 320 feet deep. This indicates that water wells in the area are drawing fresh water from localized sands within the upper several hundred feet.

[8] Brown Jr., L.F., Cleaves II, A.W., Erxleben, A.W., 1973. Pennsylvanian depositional systems in North Central Texas, a guide for interpreting terrigenous clastic facies in a cratonic basin Texas Univ. Bur. Econ. Geology Guidebook, 14 (1973), p. 132

[9] Blandford, T.N., et al., 2021. Conceptual Model Report for the Cross Timbers Aquifer. Report produced under Texas Water Development Board Contract No. 1948312322.

[10] Winslow, A.G., and Kister, L.R., 1956. Saline-Water Resources of Texas. U.S. Department of Interior Report.

[11] Blondes, M.S., Gans, K.D., Engle, M.A., Kharaka, Y.K., Reidy, M.E., Saraswathula, V., Thordsen, J.J., Rowan, E.L., and Morrissey, E.A., 2018. U.S. Geological Survey National Produced Waters Geochemical Database (ver. 2.3, January 2018): U.S. Geological Survey data release, https://doi.org/10.5066/F7J964W8.

[12] Nicot, J.-P., Huang, Y., Wolaver, B.D., and Costley, R.A., 2013. Flow and Salinity Patterns in the Low-Transmissivity Upper Paleozoic Aquifer of North-Central Texas: Gulf Coast Association of Geological Societies Journal, v. 2, p. 53-67.

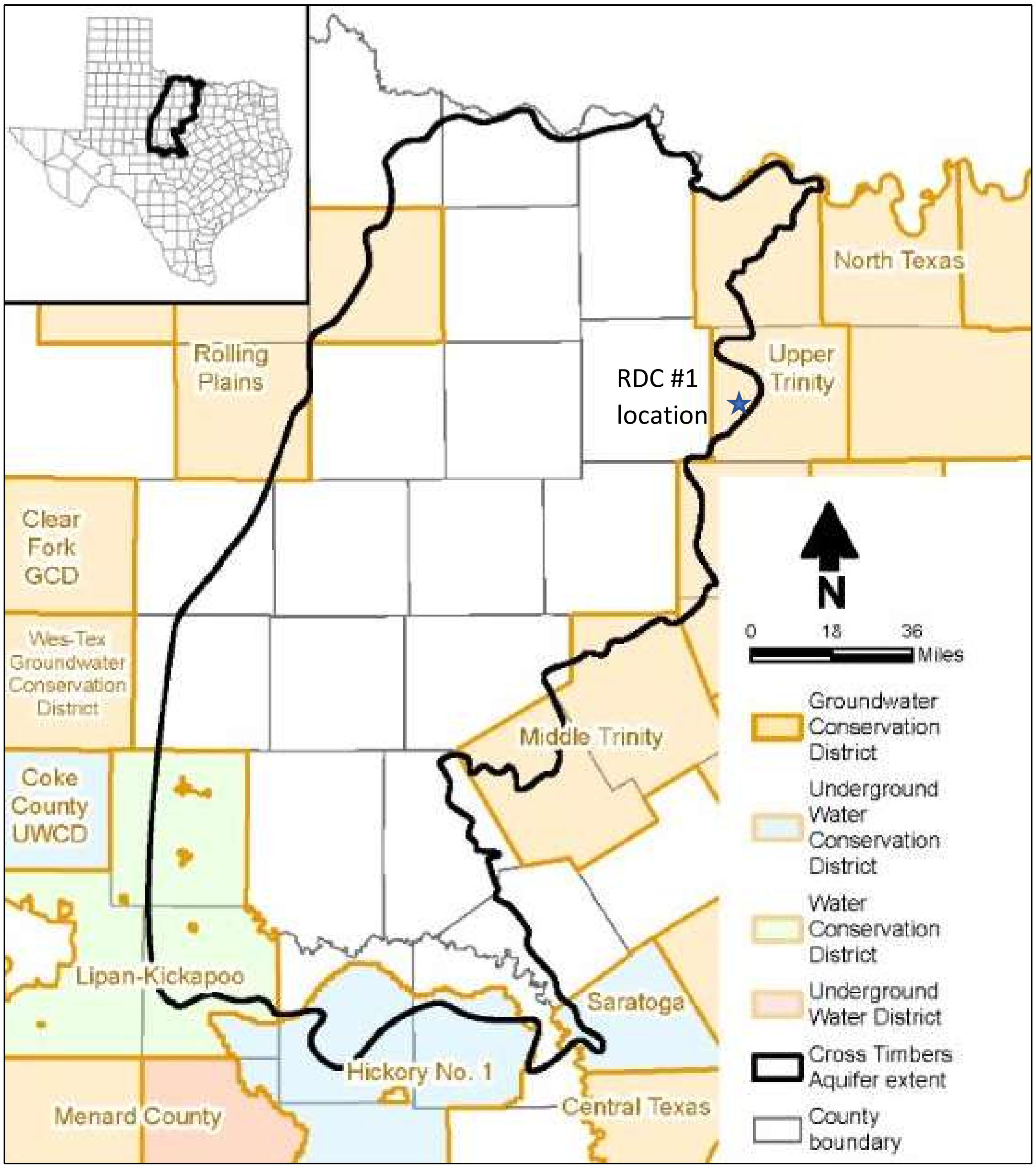


Figure 10. Map of the groundwater conservation districts and the Cross Timbers Aquifer extent within north-central Texas, from the Texas Water Development Board. Location of the proposed injection site, RDC #1, is shown with a star.

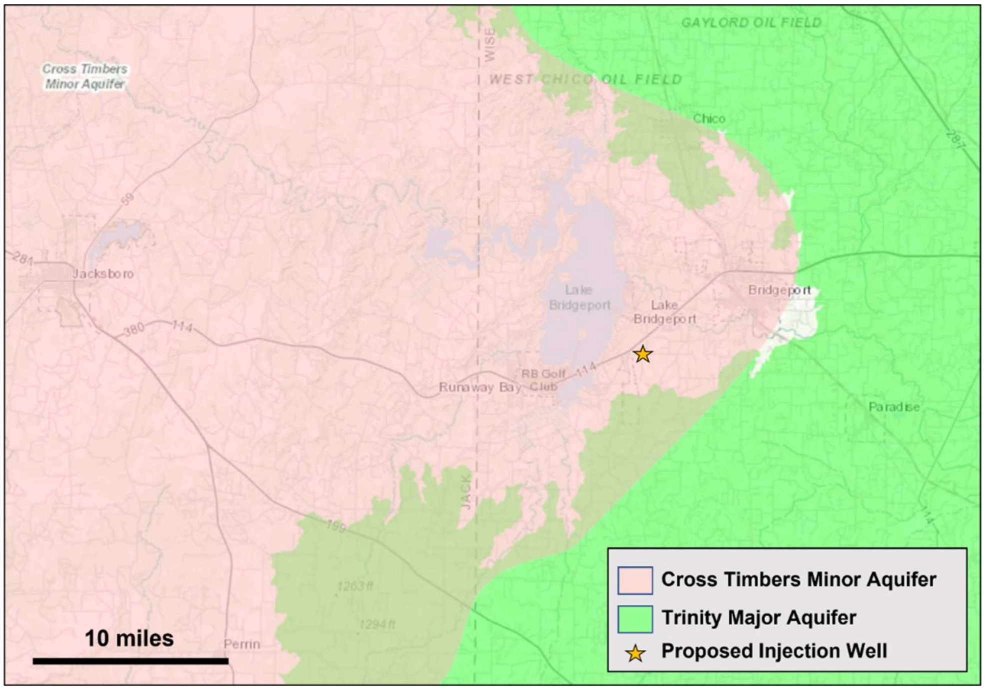


Figure 11. Location of the Cross Timbers minor aquifer and Trinity major aquifer in Texas, with well location labeled.

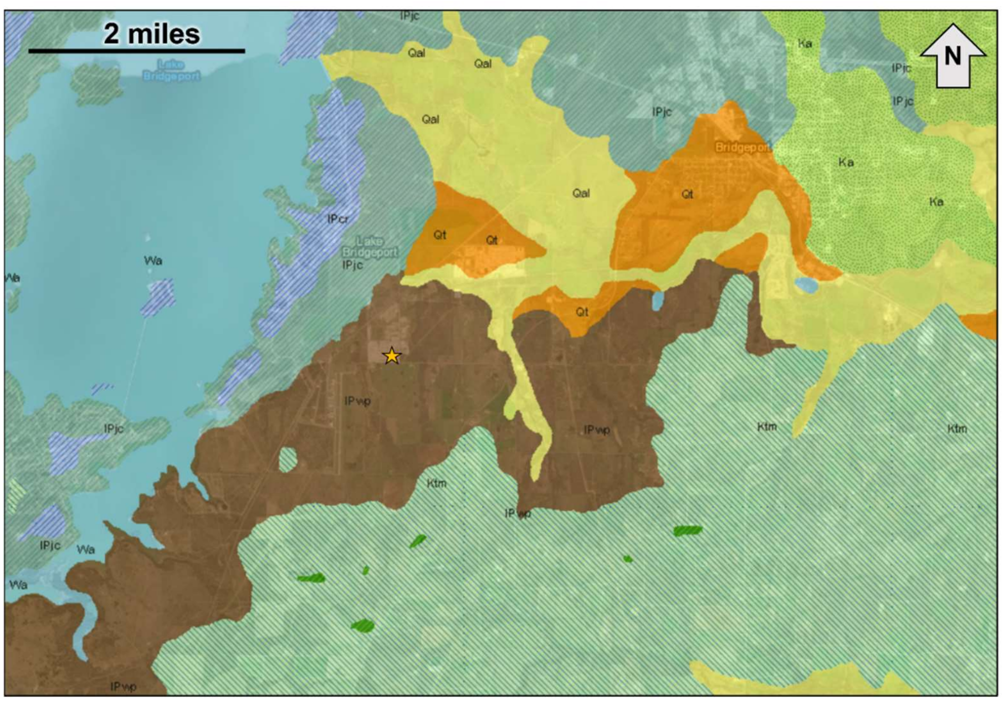


Figure 12. Geologic map of the area near the proposed injection site (yellow star). Geologic formations labeled using the state of Texas' USGS rock units codes, where: Qal = alluvium, Qt = fluviatile terrrace deposits, Wa = water, IPcr = Chico Ridge limestone, IPjc = Jasper Creek formation, IPwp = Willow Point formation, Ktm = Twin Mountaints formation, and Ka = Antlers sand.

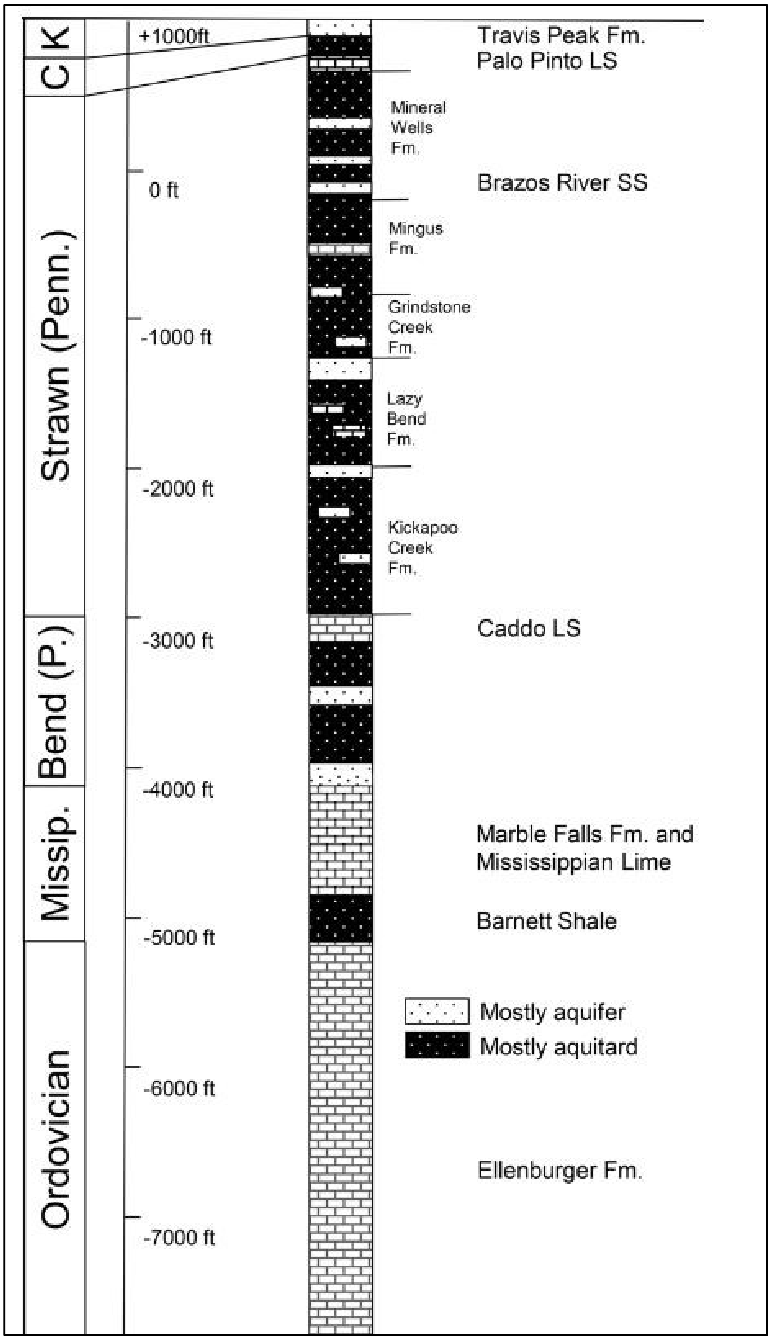


Figure 13. Stratigraphic column including aquifers and aquitards, modified from Nicot et al. 2011[13].

There are 105 freshwater wells within a 2-mile radius and 26 wells within a 1-mile radius of the proposed injection well, according to the Texas Water Development Board Groundwater Data Viewer shown in **Figure 14** and listed in **Table 5**.

[13] Nicot, J, et al, University of Texas, 2011, "Methane occurrences in aquifers in the Barnett Shale area with a focus on Parker County, Texas" https://deepblue.lib.umich.edu/bitstream/handle/2027.42/137724/gwat12508-sup-0001-supinfo.pdf?sequence=1

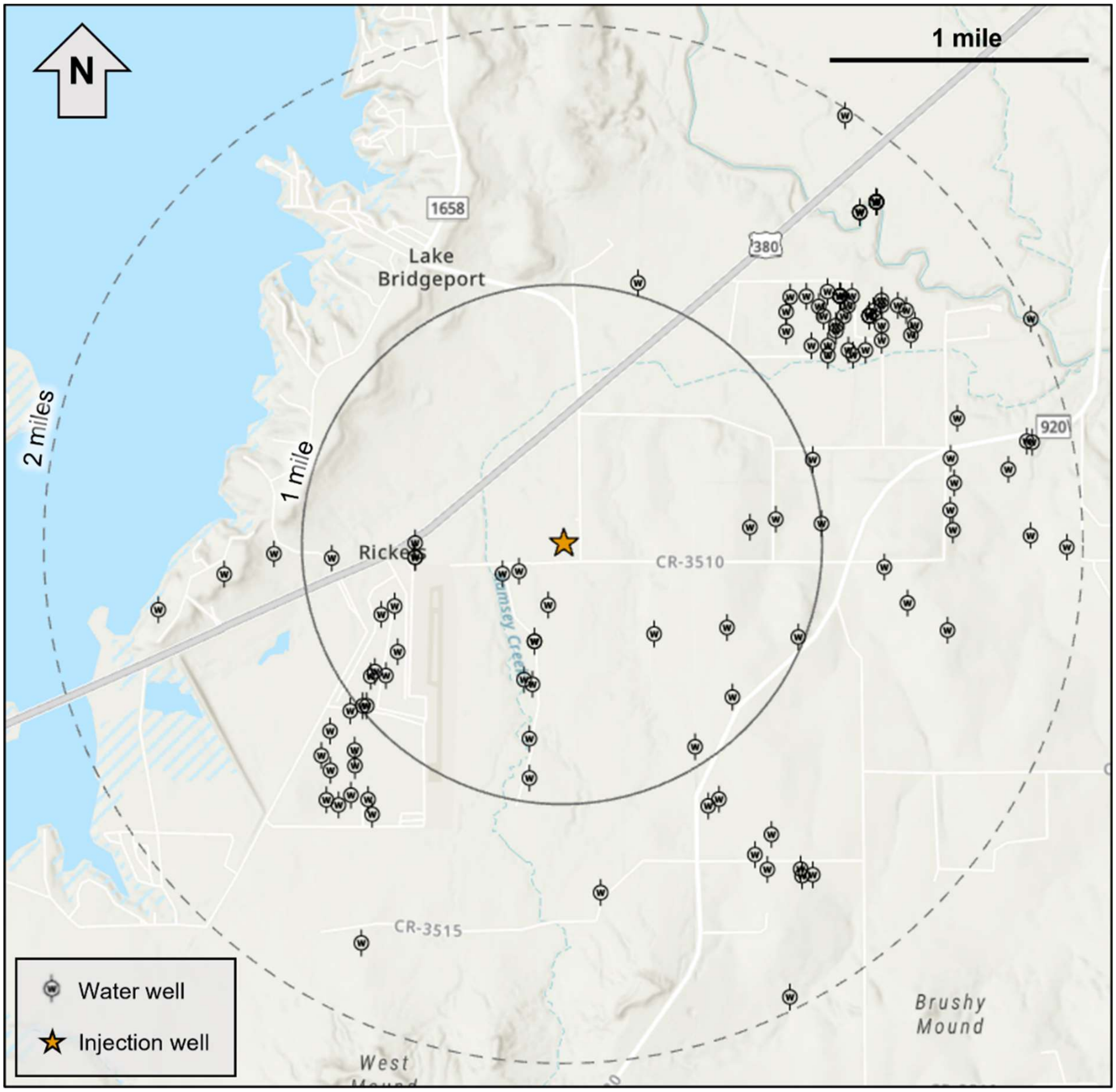


Figure 14. Water wells within 1 and 2 miles from the proposed injection site, data from the Texas Water Development Board.

Table 5. Privately owned groundwater wells in project area.

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
324182	33.157501	-97.805278	180	1.97
85836	33.160834	-97.833889	180	1.74
419698	33.1635	-97.817833	160	1.37
494622	33.16434	-97.80437	140	1.59
522108	33.16439	-97.80365	140	1.61
270093	33.164723	-97.806667	200	1.50
131403	33.164723	-97.804445	110	1.57
33173	33.165556	-97.807501	280	1.42
67830	33.166667	-97.806389	100	1.39
592900	33.16871	-97.80986	155	1.16
135520	33.17	-97.8225	140	0.93
71023	33.171667	-97.811389	120	0.94
214384	33.172222	-97.8225	195	0.78
23271	33.174167	-97.833611	280	1.01
23265	33.174167	-97.833334	140	1.00
12854	33.174444	-97.808889	140	0.89
305950	33.175278	-97.822222	110	0.57
86814	33.175555	-97.822778	213	0.56
570517	33.17587	-97.83202	120	0.86
13278	33.176111	-97.832778	140	0.89
585723	33.17721	-97.83121	160	0.77
527914	33.177694	-97.822083	160	0.40
527919	33.177694	-97.822083	160	0.40
190556	33.177778	-97.804445	210	0.98
428746	33.178047	-97.81408	120	0.50
605428	33.17806	-97.79442	180	1.53
107416	33.178333	-97.809167	140	0.72
509874	33.1793	-97.83231	120	0.76
601491	33.17962	-97.79708	200	1.35
53199	33.179722	-97.847222	150	1.60
196527	33.179722	-97.821111	75	0.25
510354	33.179783	-97.831417	130	0.70
430183	33.1815	-97.824139	170	0.27
81235	33.181667	-97.842778	200	1.32
193088	33.181667	-97.823055	240	0.21
373126	33.181667	-97.798611	160	1.25
351852	33.1825	-97.835556	320	0.90
122077	33.1825	-97.83	205	0.58
143619	33.1825	-97.83	140	0.58

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
474446	33.182659	-97.786404	180	1.95
44219	33.182778	-97.839445	230	1.13
214552	33.183334	-97.83	120	0.58
483302	33.183342	-97.78883	100	1.81
416778	33.18372	-97.79402	180	1.51
479366	33.184019	-97.807589	200	0.72
72275	33.184167	-97.802778	34	1.00
123233	33.184445	-97.805834	32	0.83
457391	33.184833	-97.794167	170	1.50
187174	33.186389	-97.793889	180	1.53
419604	33.187077	-97.790243	180	1.75
574195	33.187771	-97.794087	180	1.53
329665	33.187778	-97.803334	170	1.02
404012	33.188611	-97.788611	260	1.86
422029	33.18865	-97.78897	260	1.84
88487	33.19	-97.793611	103	1.60
72273	33.193611	-97.802223	29	1.25
72269	33.193611	-97.800556	28	1.33
62634	33.193889	-97.800834	33	1.33
72268	33.193889	-97.799722	28	1.39
62627	33.194167	-97.803334	30	1.22
62639	33.194167	-97.802223	28	1.28
219191	33.194445	-97.798611	30	1.46
219202	33.194722	-97.796667	20	1.57
123232	33.195	-97.805001	34	1.19
62632	33.195	-97.801667	33	1.34
329661	33.195278	-97.801667	145	1.35
219187	33.195278	-97.798611	30	1.49
219200	33.195278	-97.796389	24	1.60
219184	33.195556	-97.788611	30	2.01
62616	33.195834	-97.802501	35	1.33
62629	33.195834	-97.801112	35	1.40
49825	33.195834	-97.799445	27	1.47
49826	33.195834	-97.799445	27	1.47
49827	33.195834	-97.799445	27	1.47
49828	33.195834	-97.799445	27	1.47
49829	33.195834	-97.799445	32	1.47
72263	33.196111	-97.805001	30	1.24
62607	33.196111	-97.799167	31	1.50
219198	33.196111	-97.796945	27	1.60
62622	33.196389	-97.802778	38	1.35

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
62628	33.196389	-97.800834	31	1.43
72267	33.196389	-97.798611	35	1.53
219193	33.196389	-97.7975	20	1.59
219181	33.196667	-97.798611	30	1.55
62626	33.196945	-97.804723	16	1.29
62623	33.196945	-97.803612	16	1.34
41283	33.196945	-97.801389	21	1.43
41284	33.196945	-97.801389	15	1.43
41285	33.196945	-97.801389	15	1.43
41286	33.196945	-97.801389	15	1.43
41287	33.196945	-97.801389	15	1.43
72264	33.196945	-97.800556	34	1.47
62618	33.197222	-97.802223	32	1.41
405842	33.197817	-97.814883	60	1.05
240181	33.201667	-97.800001	20	1.72
240182	33.201667	-97.800001	18	1.72
240183	33.201667	-97.800001	17.5	1.72
213490	33.202223	-97.798889	14.5	1.79
213494	33.202223	-97.798889	15	1.79
213495	33.202223	-97.798889	14	1.79
213496	33.202223	-97.798889	14.5	1.79
213499	33.202223	-97.798889	13	1.79
213500	33.202223	-97.798889	12	1.79
213502	33.202223	-97.798889	11	1.79
516919	33.20712	-97.8009	160	1.98
State Groundwater Well				
State Well Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	
1950401	33.17389	-97.83445	147	1.06
1950402	33.17278	-97.83583	146	1.17
1950408	33.16917	-97.83445	147	1.28
1950501	33.17583	-97.83306	82	0.91
1950406	33.16861	-97.83528	147	1.34
1950504	33.16806	-97.83306	147	1.29
1950404	33.17139	-97.83639	147	1.25
1950502	33.16833	-97.81056	121	1.17
1950403	33.16889	-97.83611	147	1.36
1950405	33.17083	-97.83417	147	1.19
1950407	33.17167	-97.83417	147	1.15
1950409	33.17056	-97.83583	147	1.27
1950503	33.16889	-97.83333	147	1.26

3.7 Description of CO_2 Project Facilities

EnLink Midstream has contracted to deliver captured CO_2 from its Bridgeport Gas Processing Plant to dCarbon. The temperature, pressure, composition, and quantity of CO_2 will be measured and metered according to industry standards, with an orifice meter or similar device (eg Coriolis meter). dCarbon will dehydrate and compress the CO_2 to a supercritical physical state at the Bridgeport site. dCarbon Ventures will then transport the CO_2 via pipeline approximately 6,815 feet to the RDC #1 injection site. Once at the well site, the CO_2 stream will again be metered to reverify quantity. The CO_2 will then be injected into the Ellenburger formation. This formation is deeper than other formations known to be productive of oil and gas in the area. A gas analysis of the CO_2 stream is shown in **Table 6**. Although this sample is expected to be representative of the composition of the gas, it is possible that the composition will vary slightly in time as the field development and processing environment change.

Table 6. CO_2 stream analysis for the Barnett RDC #1 site.

Name	Normalized Weight Percent	Normalized Mole Percent	Normalized Liquid Volume Percent
Nitrogen	0.002	0.003	0.002
Carbon Dioxide	99.358	99.054	98.646
Methane	0.105	0.287	0.286
Ethane	0.4	0.584	0.916
Propane	0.018	0.018	0.029
Isobutane	0.003	0.002	0.004
N-butane	0.008	0.006	0.011
Isopentane	0.002	0.001	0.003
N-pentane	0.002	0.001	0.003
Hexanes	0.011	0.008	0.013
Heptanes	0.011	0.002	0.011
Octanes	0.007	0.001	0.007
Nonanes	0.009	0.002	0.009
Decanes plus	0.004	0.001	0.004
BTEX	0.06	0.03	0.056
H2S	0.00002	0.00002	0.00002
Total	100	100	100
Total Sample Properties			
Property	Value		
BTU (Gross)	16.04		
Density (lbs/gal)	12.63		
Molecular weight	43.87		
Specific gravity (Air=1)	1.5147		

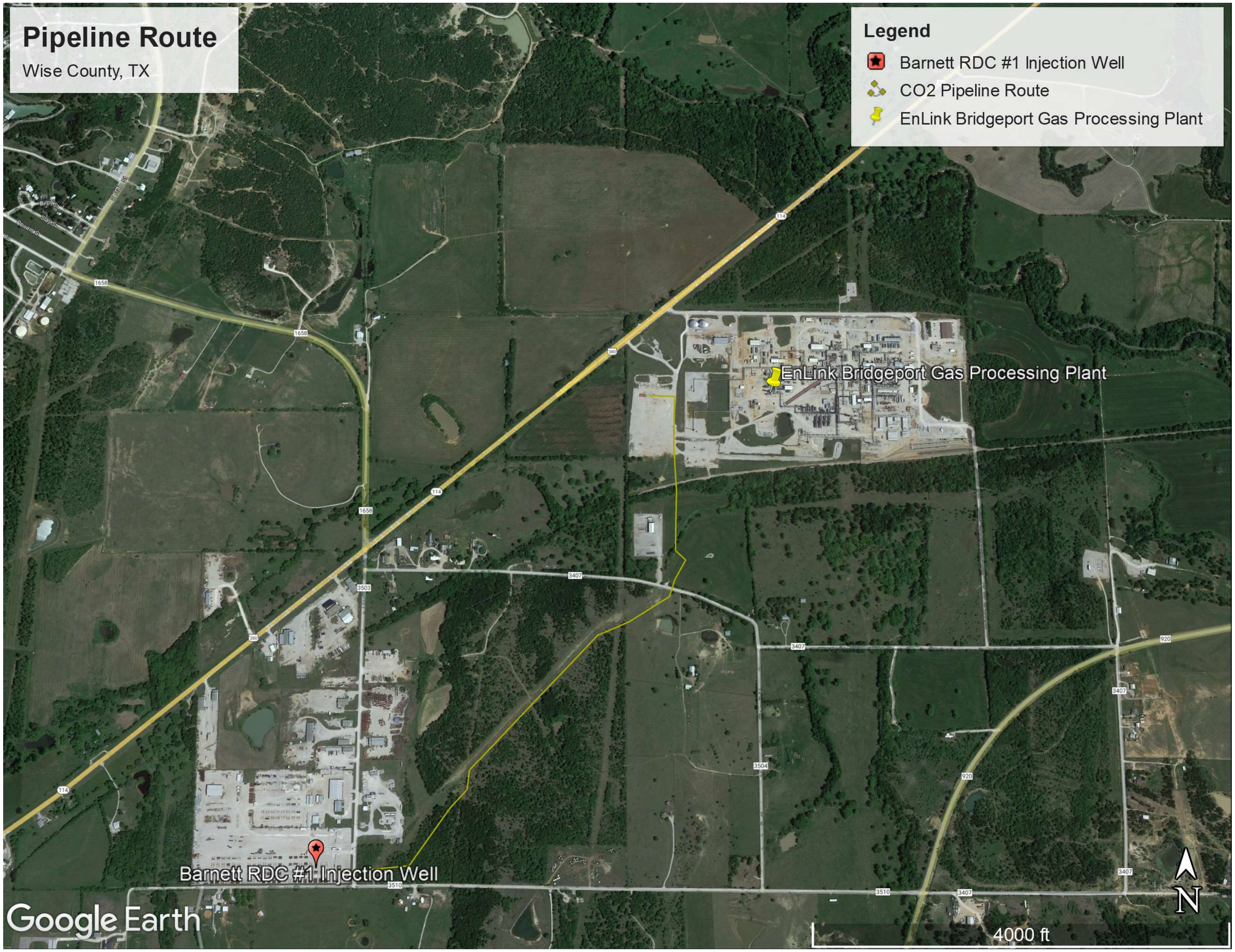


Figure 15. Proposed pipeline route.

3.8. Reservoir Characterization Modeling

A regional modeling encompassing nearby plugged and abandoned wells as well as saltwater disposal wells was created in Schlumberger's Petrel; the model incorporates available well petrophysical data and generate a static earth model (SEM) for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the W.S. Coleman SWD #2 well (~ 5 miles east of Barnett RDC #1) as discussed in previous sections. The reservoir is characterized by low matrix porosities as well as naturally existing fractures which likely contribute to fluid flow. For the current assessment, a single porosity, single permeability distribution model was deemed appropriate given the uniformity of natural fracture distribution within the Ellenburger as well as saltwater disposal rates/volumes into the Ellenburger in nearby counties. These assumptions will be examined and verified using a pressure fall-off test (PFOT) that will be conducted during the construction of the RDC #1 well. If PFOT and logging programs detect deviations from anticipated reservoir behavior, dCarbon will use the new data to update reservoir models as well as injection forecasts and MRV plan if appropriate.

The primary objectives of the simulation model were to:

1. Estimate the maximum areal extent of the injectate plume and its migration post injection
2. Determine the ability of the target formation to handle the required injection rate
3. Characterize potential interaction between the injected CO_2 and any nearby potential leakage pathways.

The CO_2 storage complex, as indicated previously, is anticipated to be confined to the Ellenburger interval. Ellenburger 'E' is modeled as the reservoir unit while Ellenburger 'C' unit is anticipated to provide a primary seal that impedes vertical fluid flow. The Barnett shale is expected to serve as a secondary seal which provides an additional stratigraphic seal to the injected CO_2. A 12-mile by 12-mile tartan grid was generated in Schlumberger's Petrel based on well top information from nearby legacy and saltwater disposal wells. The grid was then exported to Computer Modeling Group (CMG)'s General Equation of State Model (GEM) simulator to account for fully implicit multiphase compositional fluid flow. This simulation was built to model other transport and mixing phenomena such as relative permeability, diffusion, advection, aqueous solubility, and buoyancy to accurately predict the plume movement. The reservoir is modeled to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 200,000 TDS which is typical of the Ellenburger formation in the project area. The injected gas stream is assumed to be fully composed of CO_2. **Figure6** illustrates the vertical layering in the model and depths at which the injection zones and confining layers are expected to be located within the project area.

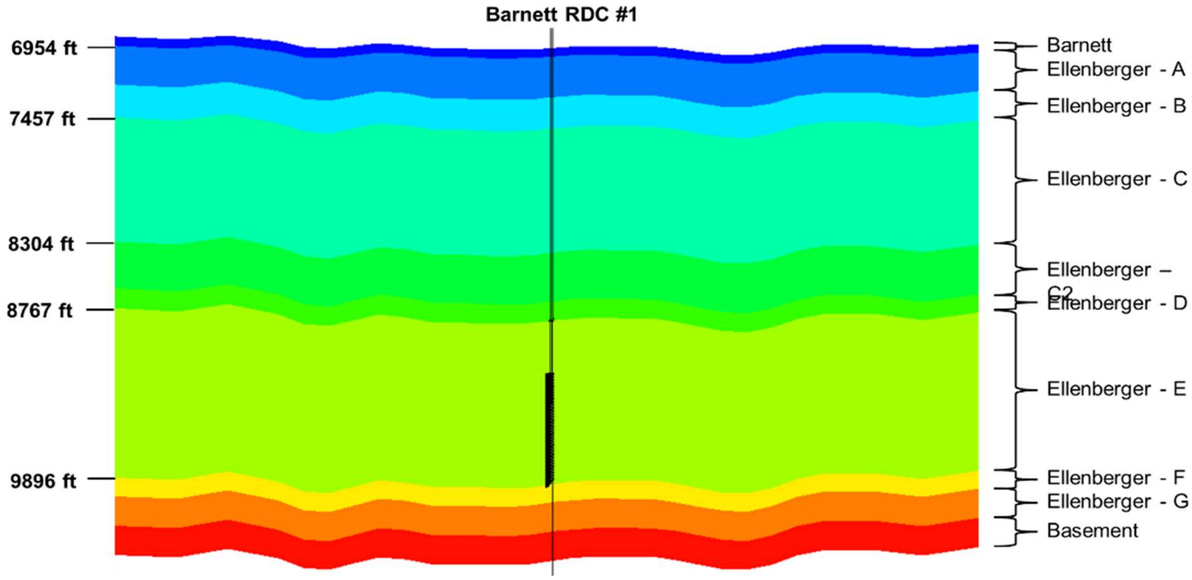


Figure 16. Vertical Profile of the CMG-GEM Model for Barnett RDC #1 Well.

Datasets prepared for simulations were based on published literature. Specifically, the reservoir relative permeability model used in this model were sourced from Bennion and Bachu (2007)[14] using data from the Wabamun Carbonate reservoir formation which exhibited comparable porosities and permeabilities as the Ellenburger. The initial reservoir conditions were developed using gradients typically seen in the area as noted by Gao *et al.* (2021)[15]. The pressure gradient was assumed to be 0.47 psi/foot which resulted in an estimated reservoir pressure of 4,136 psi at the top of the injection interval. The temperature gradient was assumed to be 1.5°F/100 feet, resulting in an estimated temperature of 201°F at the top of the reservoir. Fracture pressures were estimated at 0.7 psi/foot. To ensure CO_2 injection does not induce fractures within the Ellenburger, injection well bottom hole pressure (BHP) was constrained to 90% of calculated fracture pressure, thereby applying a safety factor of 10%. This resulted in a maximum bottom hole injection pressure constraint of 5,524 psi. There are no active wells injecting or producing from the injection interval in the project area. Therefore, no additional wells other than injector were included in the fluid flow simulation model.

Injection was modeled at 280,000 MT/yr. The model simulated 12 years of active injection followed by 100 years without injection to determine when plume migration stops. Plume migration ceased after 50 years post-injection, which is determined to be the maximum extent of the CO_2 plume. **Figure 17** shows the CO_2 plume at the end of injection (yellow) compared to 50 years post injection (red). Injected CO_2 flows due west which is the regional up dip direction. However, the change in

[14] Bennion, D.B., and Bachu, S., 2007. Permeability and Relative Permeability Measurements at Reservoir Conditions for CO_2-Water Systems in Ultra Low Permeability Confining Caprocks. SPE Paper # 106995 presented at the SPE Europec/EAGE Annual Conference

[15] Gao, S., Nicot, J.P., Hennings, P.H., La Pointe, P., Smye, K.M., Horne, E.A. and Dommisse, R., 2021. Low pressure buildup with large disposal volumes of oil field water: A flow model of the Ellenburger Group, Fort Worth Basin, northcentral Texas. AAPG Bulletin, 105(12), pp.2575-2593

CO_2 plume area from end of injection to 50 years post-injection is minimal (~29%) and the plume stops moving after 50 years.

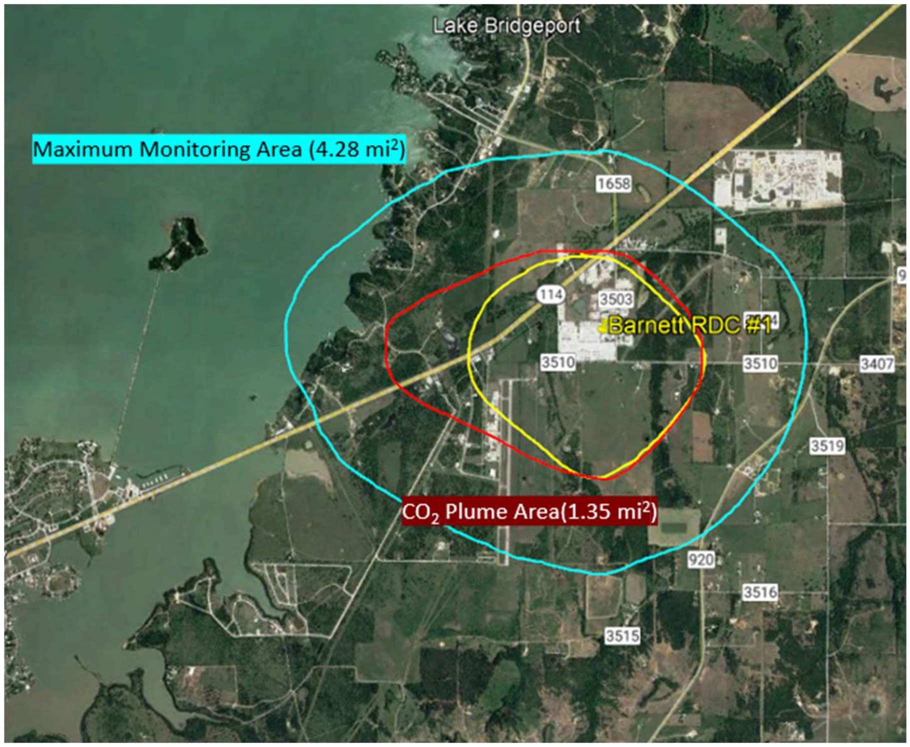


Figure 17. Simulation Results Showing CO_2 Plumes (end of injection – yellow, after 50 years of injection – red) and the Maximum Monitoring Area (blue).

Figure 18 illustrates CO_2 mass injection rate, cumulative CO_2 injection mass, and bottom hole pressure at the Barnett RDC #1 well as modeled. The bottom hole pressure remained well under the bottom hole pressure constraint. The maximum bottom hole pressure reached is 4,434 psi (1,090 psi lower than the BHP constraint) which occurs 6 months after the injection started. This spike is anticipated to be a result of near wellbore effects arising from CO_2 forcing its way into the brine-filled porous media. Upon reaching a critical mass to transition from capillary driven to advection driven flow, the BHP starts to decline until the end of injection while keeping the injection rate constant. The BHP then falls until the end of injection.

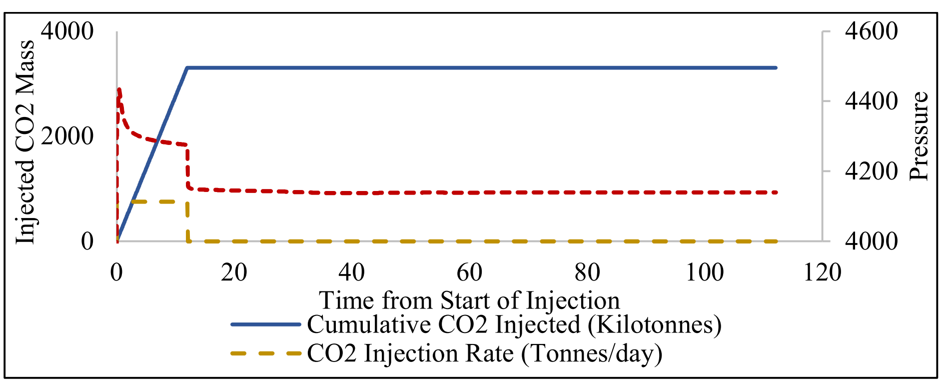


Figure 18. Modeled Injection Profile at Barnett RDC #1 Well.

Section 4 – Delineation of Monitoring Area

4.1. Maximum Monitoring Area (MMA)

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The numerical simulation using CMG-GEM as discussed above was used to estimate the size and migration of the CO_2 plume. The model injected into the Ellenberger E formation. CO_2 injection was modeled for 12 years followed by 100 years post injection. Results indicated that the plume ceased to migrate after 50 years post injection. For more information on the simulation construction and setup, please see the discussion in Section 3.8. A 5% cutoff of molar gas concentration was used to determine the boundary of the CO_2 plume. The area of the maximum monitoring area was determined to be 4.28 square miles with the greatest extent reaching 1.62 miles from the injector. **Figure 19** shows the end of injection plume (yellow), the 50-year post injection plume (red), and the maximum monitoring area using a half mile buffer (blue).

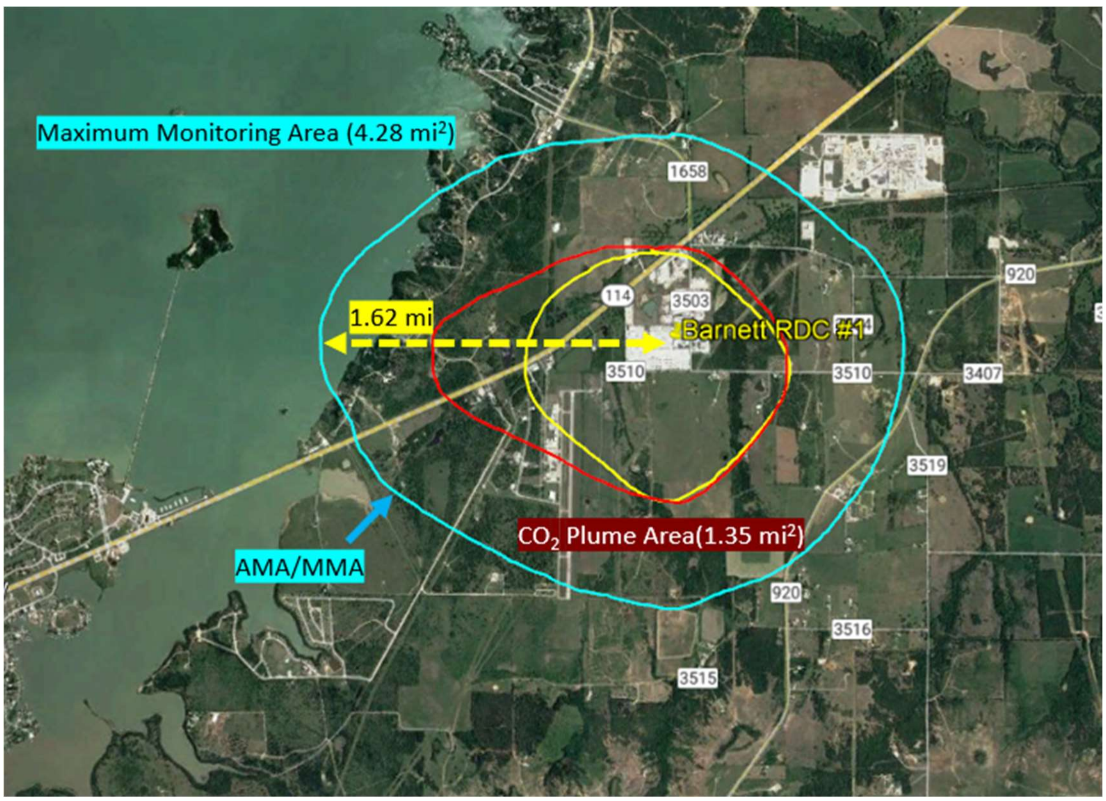


Figure 19. Maximum Monitoring Area (blue), End of Injection Plume (yellow), and 50-year Post Injection Plume (red) as Modeled at the Barnett RDC #1 Well.

Section 4.2. Active Monitoring Area (AMA)

As discussed in Chapter 3, there are no structural/geological features within the project area that could cause the unintended migration of the CO_2 plume. The only potential leakage pathways that exist are well penetrations and the surface equipment. Leakage from groundwater wells, faults and

fractures, leakage through the confining layer, and seismicity events are expected to be highly improbable. That said, these leakage pathways have been considered and options to monitor them are discussed in Section 4 and Section 5. Sufficient care and consideration will be provided to monitoring these pathways, if any, and simulation models will be calibrated with new data as appropriate.

BKV adhered to the definition of AMA provided in 40 CFR 98.449 to delineate the AMA. As noted in Section 6, BKV proposes to monitor the injection site from year one through year 14 which includes 12 years of injection plus two years of post-injection monitoring. As defined in 40 CFR 98.449, the AMA must be delineated by superposition of

(1) The area projected to contain the free phase CO_2 plume at the end of year 14, plus an all-around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

(2) The area projected to contain the free phase CO_2 plume at the end of year 19.

As noted in Section 4.1, BKV utilized the plume area after 50 years of post-injection plus a one-half mile buffer to determine the MMA, which far exceeds the definition of AMA set forth in 40 CFR 98.449. Therefore, the AMA is proposed to have the same boundary as the MMA, which adequately covers the area that is required by 40 CFR 98.449. **Figure 19** shows the MMA which is the same as the AMA. **Figure 20** indicates the AMA/MMA (blue line) and currently existing water and oil/gas wells within this area. None of these wells were found to penetrate the Ellenburger within the project area. Water wells in the region are shallow with drilled depths up to 300 feet from surface. Additional discussion on well infrastructure within the project area can be found in later sections of this document.

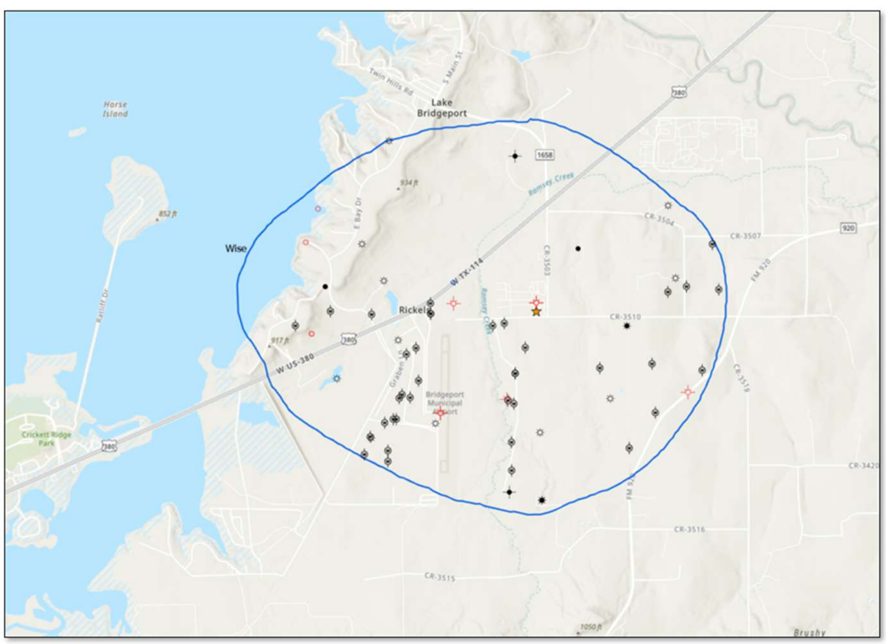


Figure 20. Maximum/Active Monitoring Area (blue) and existing wells within the project AMA/MMA.

Section 5 – Identification and Evaluation of Potential Leakage Pathways to Surface

5.1. Potential Leakage from Surface Equipment

dCarbon's surface facilities at Bridgeport and at the injection well site are specifically designed for injecting the CO_2 stream described above, including 20-30 ppm H_2S, and therefore minimize leakage points such as valves and flanges following industry standards and best practices. All BKV and dCarbon field personal are required to wear gas monitors which detect H_2S. A shut-in valve is located at the wellhead in case of emergency. The compressor will also have an emergency shut down switch which can be activated in case of unexpected operating conditions.

Additionally, the compressor facility, pipeline, and injection well locations will all be subjected to Auditory, Visual, and Olfactory ("AVO") and FLIR leak detection per BKV and dCarbon safety and operations standards. These recurring inspections, which are standard for detecting leaks and malfunctioning equipment in the gas production industry, will aid in the rapid detection of any potential leaks which may occur. As a part of these inspections, operations personnel are frequently able to repair leaks immediately by tightening valves, flanges, or similar equipment. Any leaks that are detected will be analyzed to determine that amount of CO_2 which may have leaked. These quantities, if any exist, will be included in recurring reporting.

5.2. Leakage from Approved, Not Yet Drilled Wells

There are no active well permits within the MMA. There are multiple expired well permits within the MMA which would require re-permitting before being drilled. Details on many of the expired permit locations are included in Attachment B.

5.3. Leakage from Existing Wells

There are 20 existing wells within the MMA. Of these 20 wells, 14 have digital records available on the TRRC website (**Table 6**), and, six wells have been plugged and abandoned, while eight remain active. However, all 14 of these wells are shallower than the proposed disposal interval from this project. In fact, the targeted injection interval (> 9,350 feet) is approximately 3,000 feet deeper and separated by numerous impermeable shales from the deepest well in the MMA (API 42-497-34419 which has a total depth of 6,334 feet). These wells are represented relative to the project MMA in **Figure 20**. The six remaining wells which were drilled within the MMA (Table 7) do not have digital records available on the TRRC website, but dCarbon acquired paper copies of the well permit information, attached herein as Attachment B. All six wells were drilled significantly shallower than the target Ellenburger formation. In fact, the deepest of the six wells was drilled to 6,155 feet TVD, several thousand feet shallower than the Ellenburger formation.

Additionally, the wellbore design of the injection well contains three layers of steel casing, each of which runs entirely to the surface to ensure complete isolation of wellbore fluids. Additionally, each of these three casing strings will be cemented entirely to the surface and inspected with cement bond logs to ensure wellbore integrity. Finally, all injection into the well will occur through a final steel tubing string which is secured in place with a permanent packer. All these aspects of wellbore construction are designed to ensure that all CO_2 is injected into the target formation and that there are no leakage pathways from the wellbore directly into shallower formations.

Table 6. Existing Oil & Gas wells in MMA with digital TRRC records.

API	Well Type	Latitude	Longitude	Status	Total Depth (feet)	Operator	Plug Date	Plug Depth
49730069	Gas	33.17562	-97.8131	Open	6,128	Scout Energy Management, LLC	-	-
49732742	Gas	33.18044	-97.8331	Open	5,900	Eagleridge Operating, LLC	-	-
49733956	Gas	33.18517	-97.8344	Open	5,950	Eagleridge Operating, LLC	-	-
49734400	Gas	33.19088	-97.8075	Open	5,920	Eagleridge Operating, LLC	-	-
49734420	Gas	33.17271	-97.8357	Open	5,950	Eagleridge Operating, LLC	-	-
49734419	Oil	33.18474	-97.8399	Open	6,334	Merit Energy Company	-	-
49734419	Oil	33.18474	-97.8399	Open	6,334	Eagleridge Operating, LLC	-	-
49731951	Oil/Gas	33.18137	-97.8115	Open	6,125	Scout Energy Management, LLC	-	-
49700111	Plugged (Gas)	33.18328	-97.8278	Plugged	5,899	Mitchell Energy Corporation	4/16/1996	5,899
49700786	Plugged (Gas)	33.18328	-97.82	Plugged	5,918	Williams Petroleum Company, Inc.	2/13/2015	5,918
49701654	Plugged (Gas)	33.17462	-97.8292	Plugged	6,028	Enserch Exploration, Inc.	9/27/1996	6,028
49733230	Plugged (Gas)	33.17563	-97.8229	Plugged	5,950	Merit Energy Company	11/5/2012	5,950
49732368	Plugged (Oil)	33.16827	-97.8227	Plugged	6,000	Merit Energy Company	1/8/2001	6,000
49732392	Plugged (Oil)	33.19493	-97.8219	Plugged	5,964	Merit Energy Company	3/19/1999	5,975

Table 7. Existing Oil & Gas wells in MMA WITHOUT digital TRRC records.

API	Well Type	Latitude	Longitude	Status	Total Depth (feet)	Attachment B Label	Operator
497-1	Gas	33.177438	-97.838912	Plugged	5,965	G	Lone Star Production
497-1	Gas	33.1738	-97.829657	Plugged	6,027	F	Lone Star Production
497-1A	Gas	33.1851	-97.806835	Plugged	5,996	D	Lone Star Production
497-1	Gas	33.188107	-97.83638	Plugged	5,602	A	A'Mell Oil Properties
497-1	Gas	33.172971	-97.819788	Plugged	6,155	E	Upham Oil & Gas
497-1	Oil	33.187529	-97.815993	Plugged	6,028	C	Enserch Exploration

5.4. Potential Leakage from Fractures and Faults

Several episodes of fault formation took place in the Fort Worth Basin, based on 3D seismic data interpretation conducted by dCarbon. The oldest set of faults displaced Ordovician rocks but did not displace Mississippian rocks like the Barnett Shale. A younger set of faults displaced Mississippian and older rocks and appear to be related to the Ouachita Front collision. These faults show displacement up into the Pennsylvanian rocks as high as the Strawn. These larger, younger faults have larger displacement but are relatively sparce.

No faulting is interpreted in the MMA around the Barnett RDC #1 based on available subsurface data including 3D seismic data. Dynamic modeling conducted to date indicates that the CO_2 plume will not intersect any mapped faults, based on dCarbon's existing 3D seismic interpretations.

Karst development is present in some areas at the top of the Ellenburger, primarily where the overlying Viola and Simpson Formations were eroded. The karst formation is often developed in the upper several hundred feet of an exposed carbonate (Ellenburger A subunit) where fresh water is able to dissolve the rock. Subsequent loading of sediment can cause the roof of the cave to collapse, with overlying sediment filling the void (Figure 21, Hongliu Zeng, et. al., 2011).[16]

The injection interval, the Ellenburger "E", appears to be below the portion of the upper Ellenburger affected by the karst collapses. This suggests that the Ellenburger "D" will remain a continuous seal in karst areas. There are no interpreted karst features that the CO_2 plume or pressure front intersects based on the dynamic modeling. Small karst features sit at the southern edge of the MMA but only seem to have impacted the upper 200 feet of the Ellenburger, leaving 3,000 feet of Ellenburger apparently unaffected.

Even if the plume reaches the karst features on the south end of the MMA and the Ellenburger "D" seal is not intact, the overlying and impermeable Barnett Shale, Marble Falls Limestone, and the Atoka Shales are expected to prevent migration to shallower depths.

[16] Zeng, H, "Characterizing seismic bright spots in deeply buried, Ordovician Paleokarst strata, Central Tabei uplift, Tarim Basin, Western China", Geophysics Vol 76 Number 4, 2011.

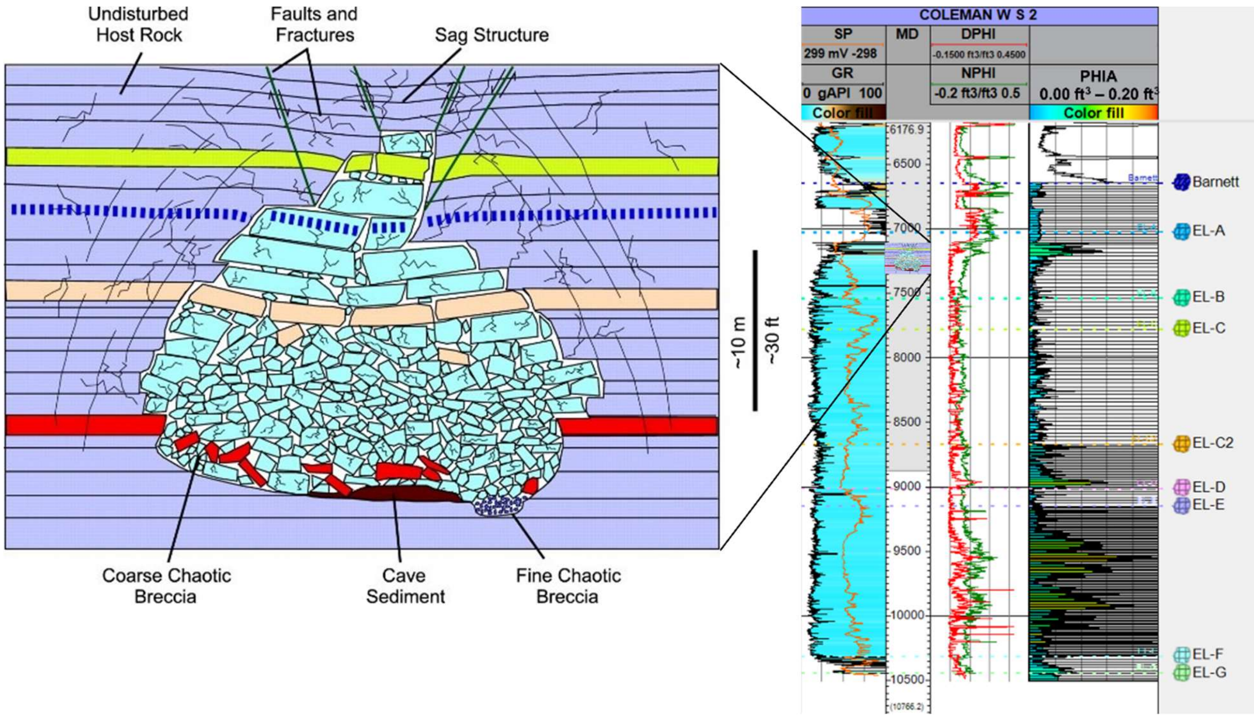


Figure 21. A schematic diagram showing the geometry and component facies of a single cave passage buried in deeper subsurface where collapse and extensive brecciation occurred (modified from Loucks, 1999; used with permission of AAPG). AAPG Bulletin (2011) 95 (12): 2061–2083. The typical scale of the karst features is shown on the right placing the feature on the W.S. Coleman #2 well log. Note that the interpreted karst features are only observed in the upper portion of the Ellenburger, above the confining unit Ellenburger D.

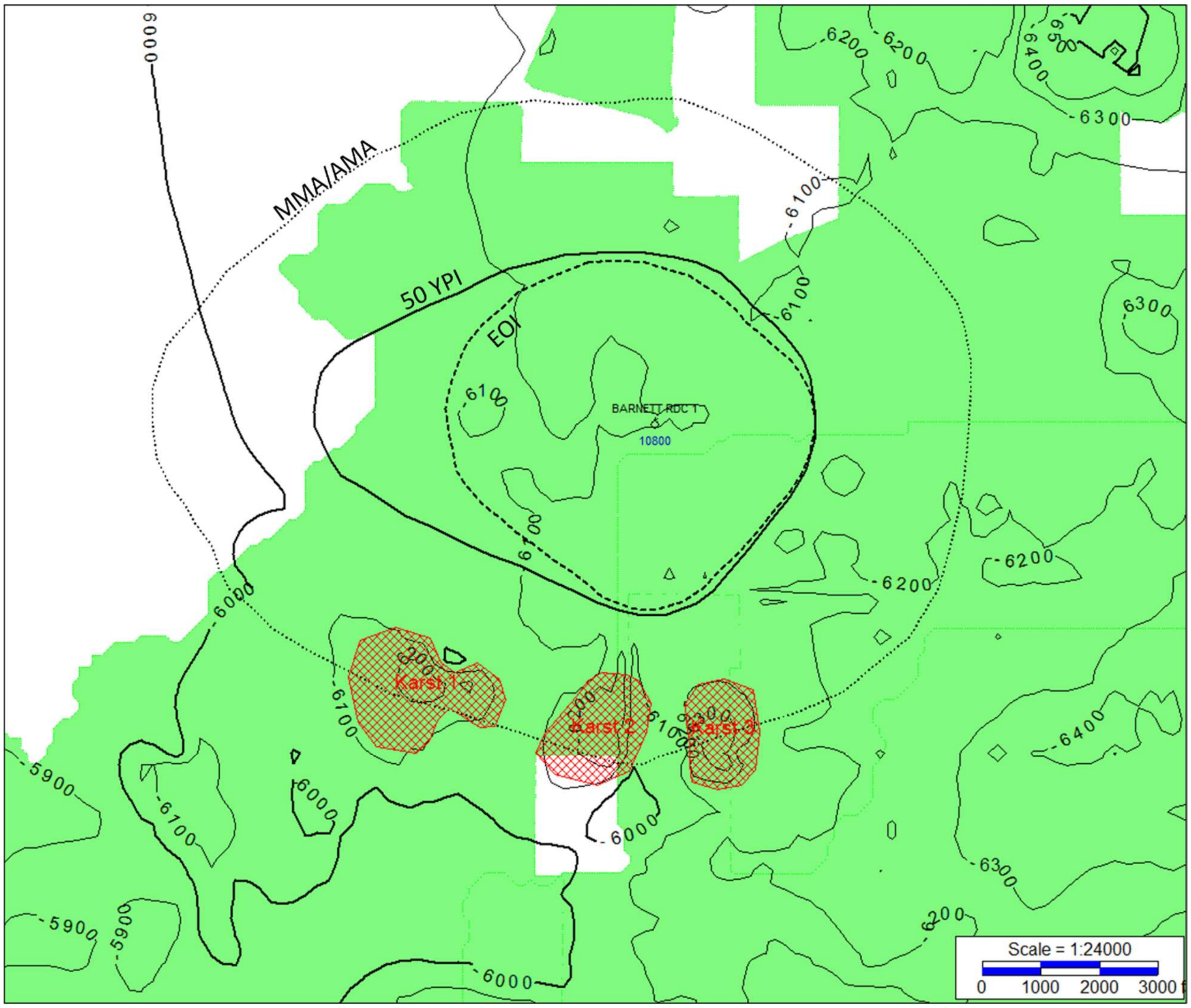


Figure 22. RDC 1 well location with top Ellenburger structural contours (TVDSS), 3D seismic coverage (green), and. mapped Ellenburger karst on the southern edges of the MMA/AMA. The CO_2 plume size at the end of injection and 50 years post-injection are also shown from Figure 19.

5.5 Leakage Through Confining Layers

The Ellenburger "E" injection zone has competent sealing rock above and below with the Ellenburger "D" and "F" zones, respectively. Secondary seals above the Ellenburger "D" include the Ellenburger "C", "B", Barnett Shale, Marble Falls Limestone, and the Atoka Shales. Overall, there is in excess of 2,000 feet of impermeable rock between the injection zone and the deepest well penetrations, making vertical migration past the primary and secondary confining units unlikely.

5.6 Leakage from Natural or Induced Seismicity

The Barnett RDC #1 location is in an area of the Fort Worth Basin that is inactive seismically, as illustrated in Section 3.5. Earthquake catalogs from both the USGS (1950-present) and TexNet (2017-present) indicate no earthquake locations within 20 miles of the Barnett RDC #1.

The closest earthquake locations are 20+ miles to the southeast in an area of larger, regional faulting. In 2013 and 2014, a series of earthquakes were felt near the towns of Reno and Azle, Texas. The Texas Railroad Commission held hearings that investigated whether oil and gas activities near the earthquakes were responsible for the activity. The Railroad Commission was unable to determine whether oil and gas activities were responsible for the earthquake sequence.

Since no faults are mapped that cut from the injection interval through the sealing limestones and shales of the Pennsylvanian, no leakage is expected due to induced seismic activity.

5.7 Leakage from Lateral Migration

The structural dip of the Ellenburger in the vicinity of the Barnett RDC #1 injection site is about one degree up to the west (100 feet/mile) Figure 23). The closest well that penetrates the Ellenburger "E" injection interval up dip from the injection site is more than 10 miles to the WSW. The closest well that penetrates the injection interval is downdip to the east approximately five miles (W S Coleman #2).

Dynamic modeling of the CO2 plume has the maximum extent of the plume traveling less than one mile, with the maximum distance traveled to the west. Given that the distance to the next penetration of the injection interval is on the order 10 times the distance the plume is expected to travel, no leakage from lateral migration is expected.

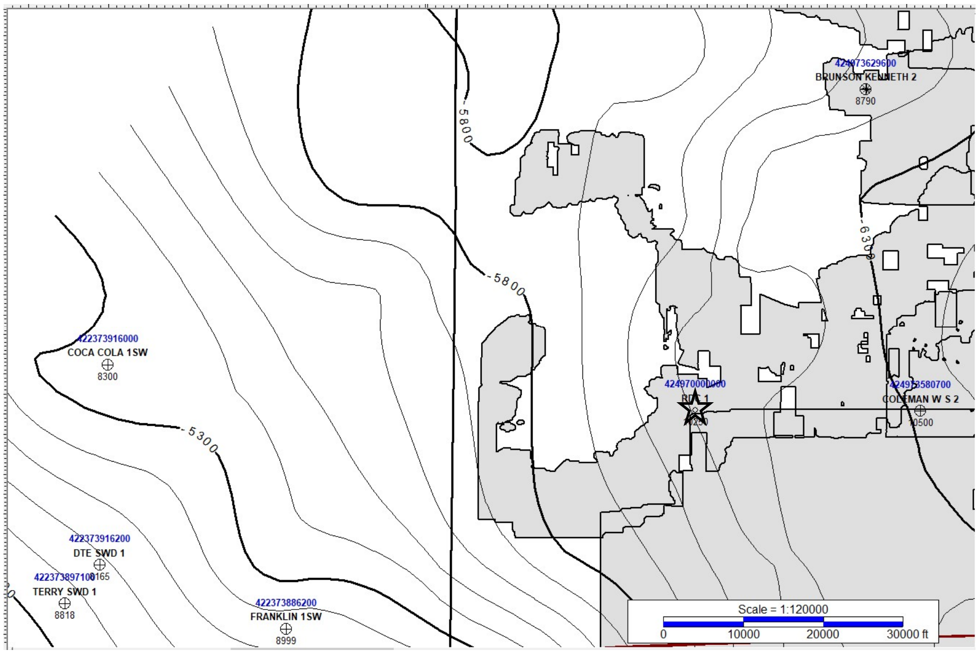


Figure 23. Top of Ordovician Unconformity (top Ellenburger) regional subsea structure in the vicinity of the Barnett RDC #1 location (star). Wells shown penetrate the injection interval. Additional wells (not shown) were used to develop the structure map. Gray areas represent areas covered by 3D seismic data.

Section 6 – Plan of Action for Detecting and Quantifying Surface Leakage of CO_2

This section discusses the strategy that dCarbon will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in previous sections to meet the requirements of 40 CFR §98.448(a)(3). As the injected stream contains both H_2S and CO_2, any observation of H_2S will serve as a preliminary indicator for CO_2 leakage and therefore the monitoring systems to detect H_2S will also suggest a leak of CO_2. This section summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur. Monitoring will occur during the planned 12-year injection period, or otherwise the cessation of operations, plus a proposed two-year post-injection period.

6.1. Leakage from Surface Equipment

As the CO_2 compressor station, pipeline, and injection well are all designed to handle expected concentrations, temperatures, and pressures of H_2S and CO_2, any leakage from surface equipment would be quickly detected and addressed. The facility is designed to minimize potential leakage points by following ASME, API and other industry standards, including standards pertaining to material selection. Additionally, connections are designed to minimize corrosion and leakage points. The H_2S in the stream is easily detectable and serves as an indicator for the release of CO_2. The facility and well will be monitored for H_2S and increases in CO_2 concentration and set with a high alarm setpoint for H_2S. Additionally, all dCarbon and BKV field personnel are required to wear H_2S monitors, which will trigger the alarm at low levels of H_2S (typically 1 ppm). The injection facility will be continuously monitored through automated systems that are designed to identify abnormalities in operational conditions. In addition, field personnel conduct daily AVO field inspections of gauges, monitors, and leak indicators. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system and analysis of liquids collected from the line. These inspections, in addition to the automated systems, allow dCarbon to quickly identify and respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5).

Additionally, CO_2 for injection will be metered in two locations for redundancy. The first will be at an orifice style meter at the interface between the Bridgeport Gas Plant and dCarbon's compressor. This location will meter the CO_2 in gas phase (Figures 24a and 24b). Once the CO_2 is compressed to supercritical, it will be transported approximately 6,815 feet via pipeline (See Figure 15) to the injection well site. The CO_2 will be metered a second time at the injection well site, immediately upstream of the injection wellhead itself, with a Coriolis meter. The CO_2 is expected to be in a supercritical phase / dense phase at this point. The meters will each be calibrated to industry standards. Any discrepancies in CO_2 throughput between the two meters will be investigated and reconciled. Any CO_2 that is determined to have leaked or not been received at the injection wellhead will be quantified using the procedures specified in subpart W of the GHGRP, reported as specified in 40 CFR §98.448(a)(5), and subtracted from reported injection volumes. Gas samples will occasionally be taken to confirm stream composition and calibrate/re-calibrate meters if necessary. At a minumum, these samples will be taken once a year. Minimal variation of concentration and composition are expected, but will be included in regulatory filings as appropriate.

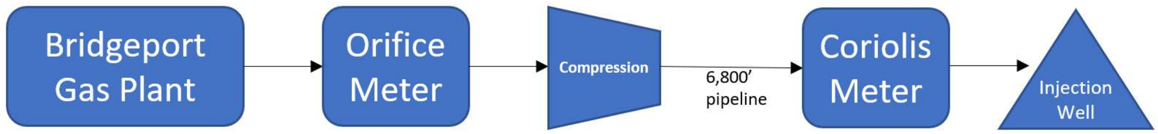


Figure 24a. Facility Diagram and Two Metering Points

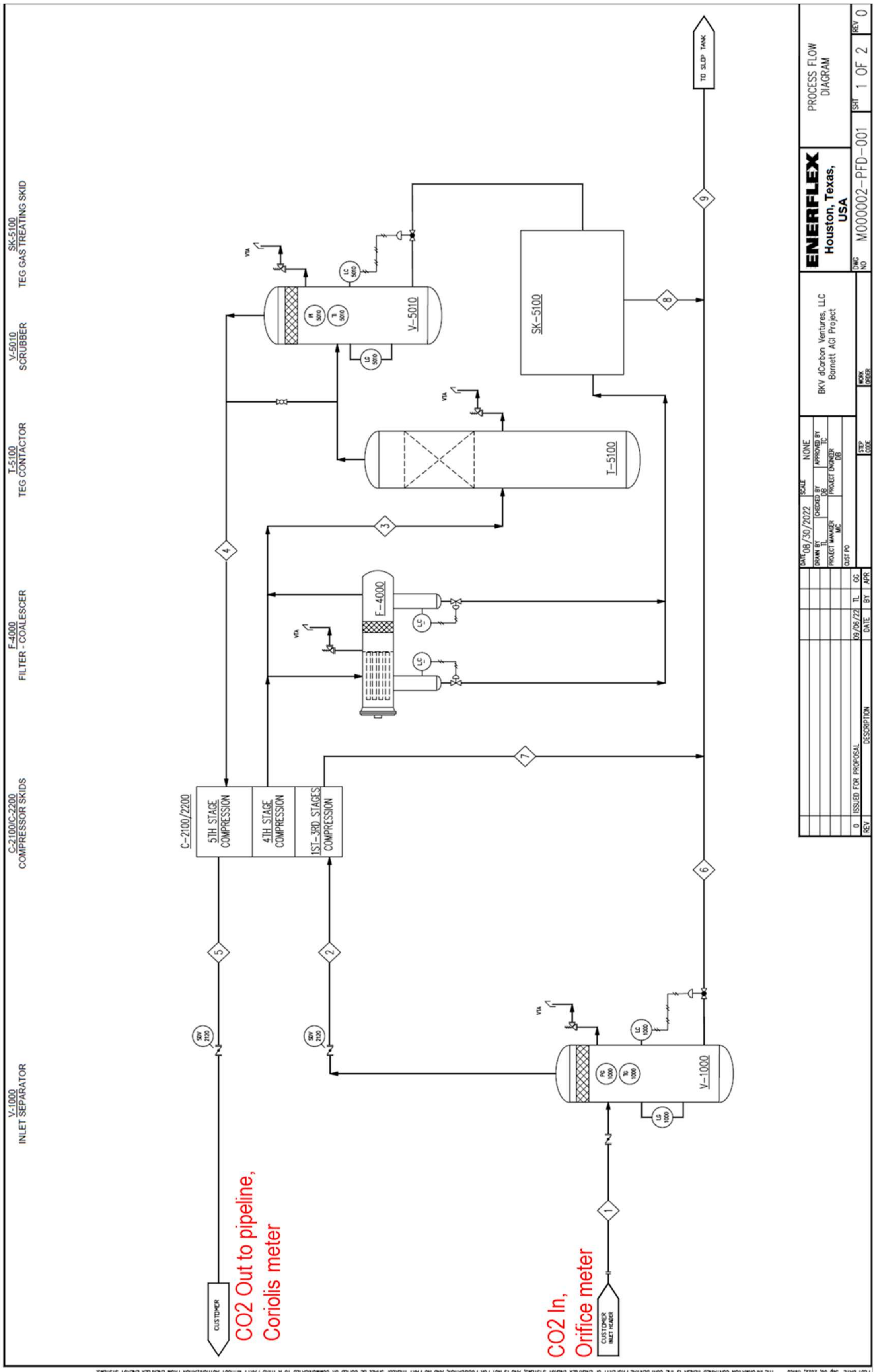


Figure 24b. Compression facility Process Flow Diagram and indicative metering locations

6.2. Leakage from Existing and Future Wells within the Monitoring Area

As previously discussed, there are no wells in the MMA currently existing, approved, or pending which penetrate as deep as the Ellenburger injection zone. However, dCarbon will reverify the status and public information for all proposed and approved drilling permits within the MMA quarterly. If any wells are proposed, permitted, or drilled within the MMA, BKV will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, dCarbon will continuously monitor and collect injection volumes, pressures, temperatures, and gas composition data for the injection well. This data will be reviewed by qualified personnel and will follow response and reporting procedures when data is outside acceptable performance limits. Finally, dCarbon will update the MRV plan if any new wells are drilled within the MMA, or if any other material change to the project occurs.

The injection well has pressure and temperature gauges placed in the injection stream at its wellhead, and a pressure gauge on the casing annulus. A change of pressure on the annulus would indicate the presence of a possible leak. Mechanical Integrity Tests ("MITs") performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated, and the leak mitigated.

In the unlikely event that any CO_2 leaks occur into existing or future wells in the monitoring area, dCarbon will endeavor to work with the operator(s) of those wells and/or midstream providers to take wellhead gas samples to quantify variations or increases of CO_2 compared with historical or baseline CO_2 concentrations. Any measurable increases in CO_2 which may be confidently attributed to injection volumes from the Barnett RDC #1 well will be calculated using standard engineering procedures for estimating potential well leakage determined to be appropriate for the situation, will be documented and reported in the annual monitoring report and subtracted from reported injection volumes. Additionally, any additional downhole or subsurface remediations that could reduce or eliminate the leakage from the injection well to the existing and future wells in the area expected to be producing injected CO_2 will be investigated and addressed if necessary.

6.3 Leakage from Faults and Fractures

No faults or fractures have been identified that would allow CO2 to migrate vertically to zones with USDWs or to the surface In the unlikely event that such leakage from faults or fractures occur, dCarbon will determine which standard engineering techniques for estimating potential leakage from the faults and fractures is appropriate for the situation to estimate any leakage from faults and fractures, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.4. Leakage through Confining Layers

Leakage through confining layers is improbable, given the number and thickness of layers between the injection zone and potable groundwater. Groundwater sampling would be the primary tool for quantifying CO_2 leakage up through the multiple confining layers.

In the unlikely event CO_2 leakage occurs as a result of leakage through the confining seal, it is also unlikely that the leak would result in surface leakage. As with any CO_2 leakage, however, should it occur, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation to estimate any leakage, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.5. Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, dCarbon plans to install a seismic monitoring station in the general area of the Barnett RDC #1 well. This monitoring station will augment the TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, dCarbon will review the injection volumes and pressures at the Barnett RDC #1 well to determine if any significant changes occur that would indicate potential leakage.

In the unlikely event CO_2 leakage occurs due to natural or induced seismicity, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation, and report such leakage estimates and the methodology employed in the annual monitoring report.

6.6. Leakage through Lateral Migration

The distances to the closest penetration of the Ellenburger injection interval are more than ten times the expected plume migration distance. As such, leakage through lateral migration is not expected. In addition, the wells that penetrate the injection interval are saltwater disposal wells. Injection into these wells would be expected to raise the reservoir pressure locally near the well, further limiting the ability of the CO_2 to access the saltwater injector well bore.

In the unlikely event CO_2 leakage occurs due lateral migration, similar to leakage through confining layers, dCarbon will determine which standard engineering techniques for estimating potential leakage is appropriate for the situation, and report such leakage estimates and the methodology employed in the annual monitoring report.

Section 7 – Baseline Determinations

This section identifies the strategies that dCarbon will undertake to establish the expected baselines for monitoring CO_2 surface leakage per §98.448(a)(4). dCarbon will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. Daily inspections will be conducted by field personnel at the compressor facility and the injection well. These inspections will aid with identifying and addressing issues in a timely fashion in order to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions would be taken to address such issues. As previously discussed, H_2S is present in the injection stream at a low concentration. All field personnel are required to wear personal H_2S monitors, which are set to trigger the alarm at ~1ppm levels of H_2S. Any alarm would trigger an immediate response to protect personnel and verify that the equipment and monitors are working properly. If monitors are working correctly and a leak is detected, immediate actions would be taken to secure the facility.

Any CO_2 release would be accompanied by H_2S and therefore the H_2S monitors at the facility would also serve as a CO_2 release warning system. In addition to personal monitors described previously, dCarbon will also conduct routine AVO and FLIR monitoring to detect any CO_2 leakage near the facility or well.

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which may be present unnecessary hazard for field personnel to perform a direct leak survey. Any leakage would be detected and managed as per Texas regulations and dCarbon's safety and operations plans. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

Baseline groundwater quality and properties will be determined and monitored through the installation of a groundwater well near the injection well site. Samples will be taken and analyzed by a third-party laboratory to establish the baseline properties of the groundwater in the area.

Baseline seismicity in the area near the Barnett RDC #1 will be determined through the historical data from USGS and TexNet seismic array data. This information will be augmented by additional data from dCarbon's seismic monitoring array.

Section 8 – Site Specific Considerations for Determining the Mass of CO_2 Sequestered

This section identifies how dCarbon will calculate the mass of CO_2 injected, emitted, and sequestered. This also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, per 40 CFR §98.448(a)(5).

8.1. Mass of CO_2 Received

Per 40 CFR §98.443, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR §98.444(a)(4)." 40 CFR §98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received."

The CO_2 received for this injection well is wholly injected and not mixed with any other supply and the annual mass of CO_2 injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

8.2. Mass of CO_2 Injected

Per 40 CFR §98.444(b), since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

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 (metric tons

per quarter)

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

$C_{CO_{2,p,u}}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent

CO_2, expressed as a decimal fraction)

p = Quarter of the year

u = Flow meter

8.3. Mass of CO_2 Produced

The injection well is not part of an enhanced oil recovery project; therefore no CO_2 will be produced.

8.4. Mass of CO_2 Emitted by Surface Leakage

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which may be hazardous for field personnel to perform a direct leak survey. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released as a result of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

$$CO_{2,E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

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

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

X = leakage pathway

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

8.5. Mass of CO_2 Sequestered

The mass of CO_2 sequestered in the subsurface geologic formations will be calculated based off Equation RR-12, as this well will not actively produce any oil or natural gas or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the Barnett RDC #1 facility in the reporting year.

$CO_{2,I}$ = Total annual CO_2 mass injected (metric tons) in the Barnett RDC #1 well in the reporting year.

$CO_{2,E}$ = 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 and the Barnett RDC #1 injection wellhead

Section 9 – Estimated Schedule for Implementation of MRV Plan

The injection well is expected to begin operation in the second half of 2023. Baseline data will be collected before injection begins and the MRV plan will be implemented upon receiving EPA approval.

Section 10 – Quality Assurance

10.1. CO_2 Injected

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a gas composition analyzer or representative sampling consistent with industry best practices
- The gas composition measurements of the injected stream will be averaged quarterly
- The CO_2 measurement equipment will be calibrated according to manufacturer specificati ons

10.2. CO_2 Emissions from Leaks and Vented Emissions

- Gas detectors will be operated continuously, except for maintenance and calibration.
- Gas detectors will be calibrated according to manufacturer recommendations and API standards
- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

10.3. Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to the requirements in 40 CFR §98.3(i).
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.
- Flow meter calibrations will be traceable to the National Institute of Standards and Technology

All measured volumes of CO_2 will be converted to standard cubic feet at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1.0 atmosphere.

10.4. Missing Data

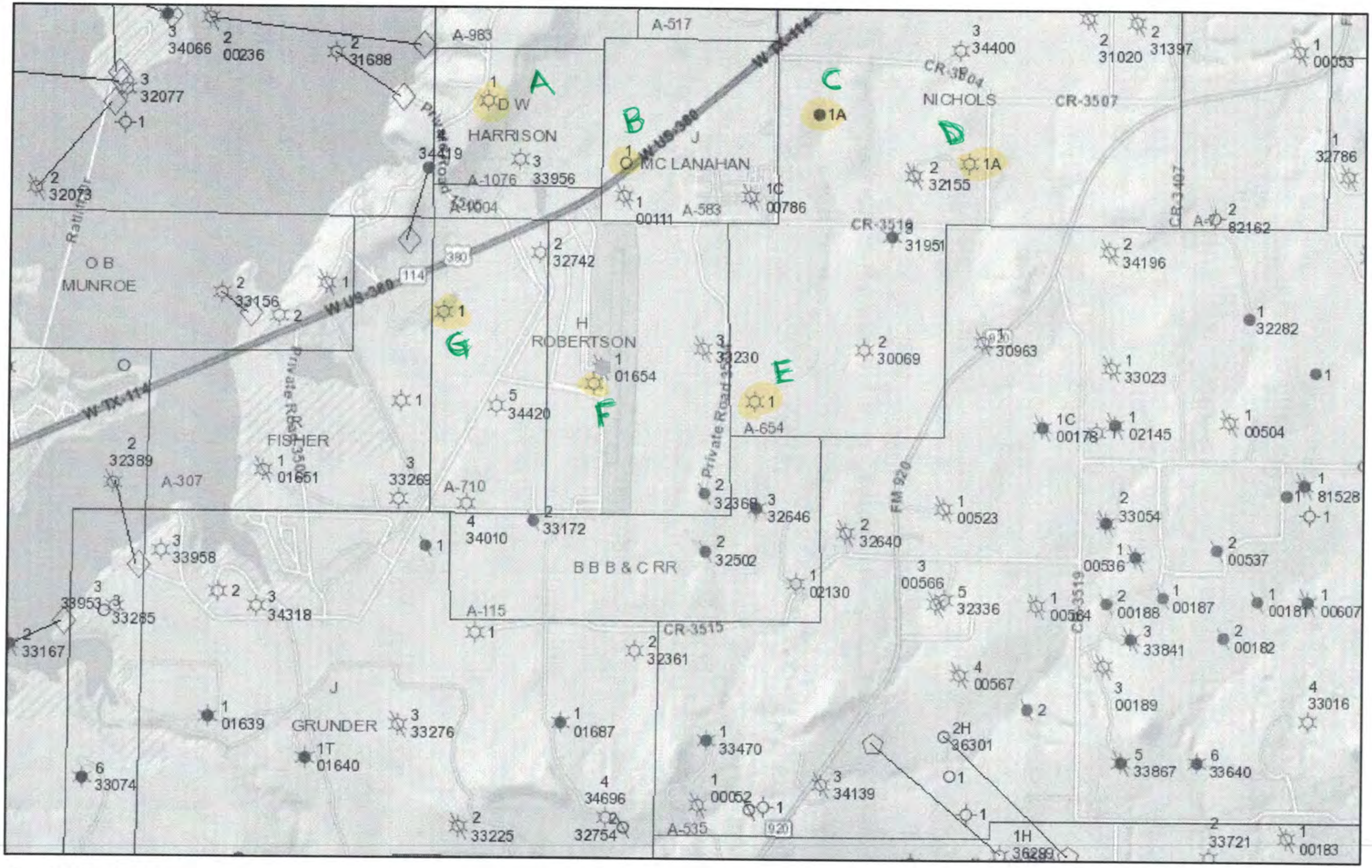
In accordance with 40 CFR §98.445, dCarbon will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in subpart W of 40 CFR §98.

Section 11 – Records Retention

dCarbon will retain records as required by 40 CFR §98.3(g). These records will be retained for at least three years and include:

- Quarterly records of the CO_2 injected
- Volumetric flow at standard conditions
- Volumetric flow at operating conditions
- Operating temperature and pressure
- Concentration of the CO_2 stream
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate 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



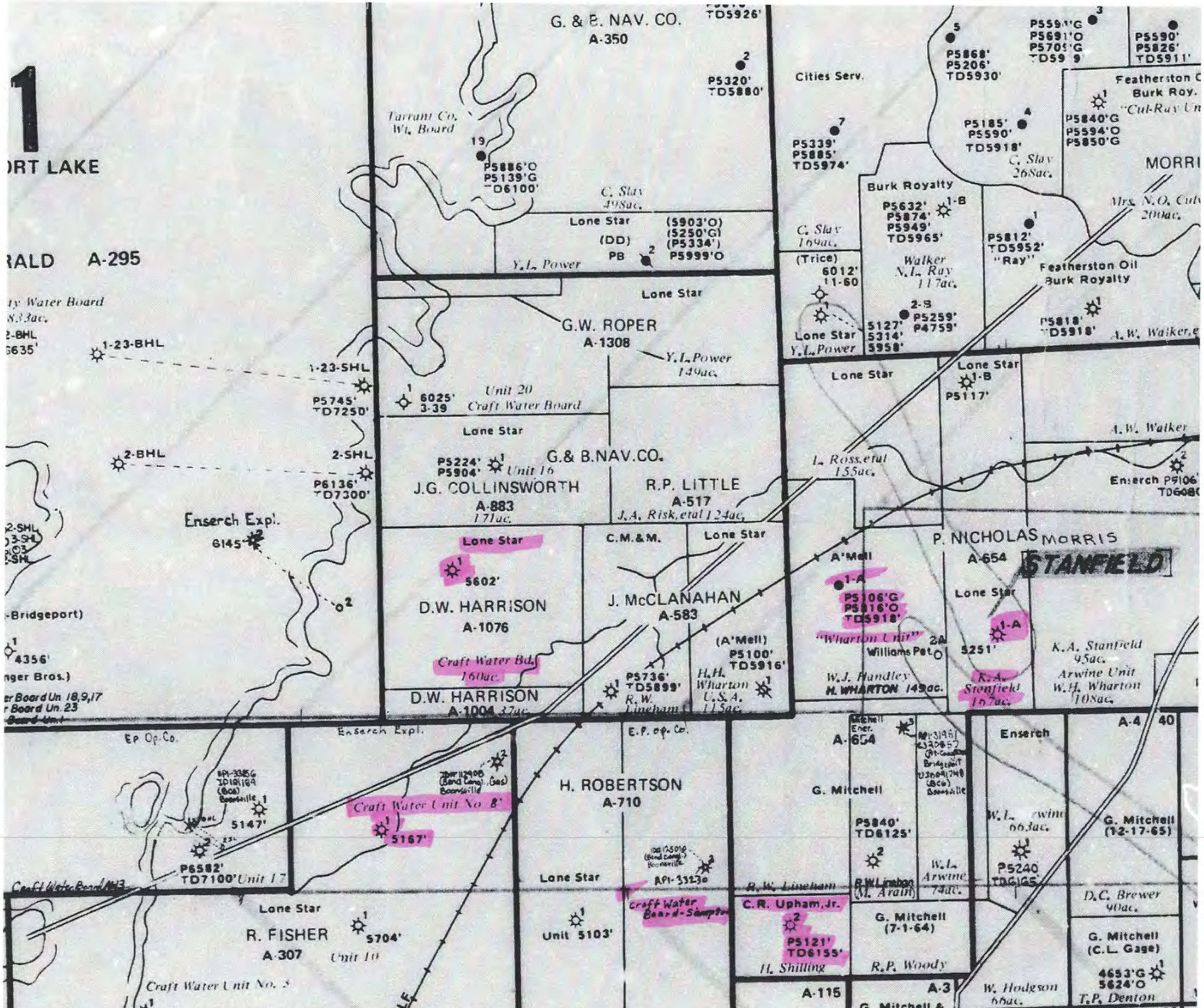
October 25, 2022

1:36,112

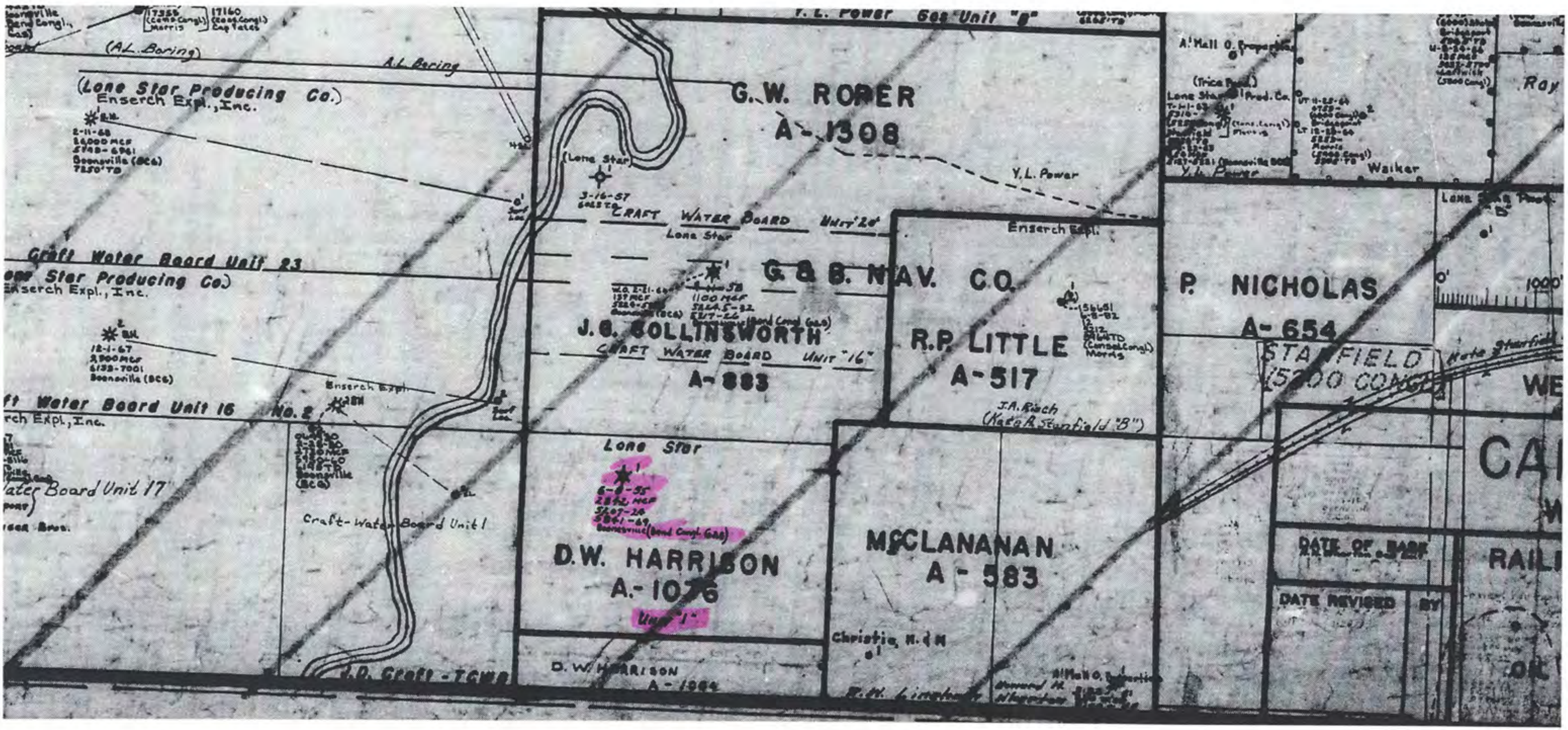
0 0.25 0.5 1 mi

0 0.4 0.8 1.6 km

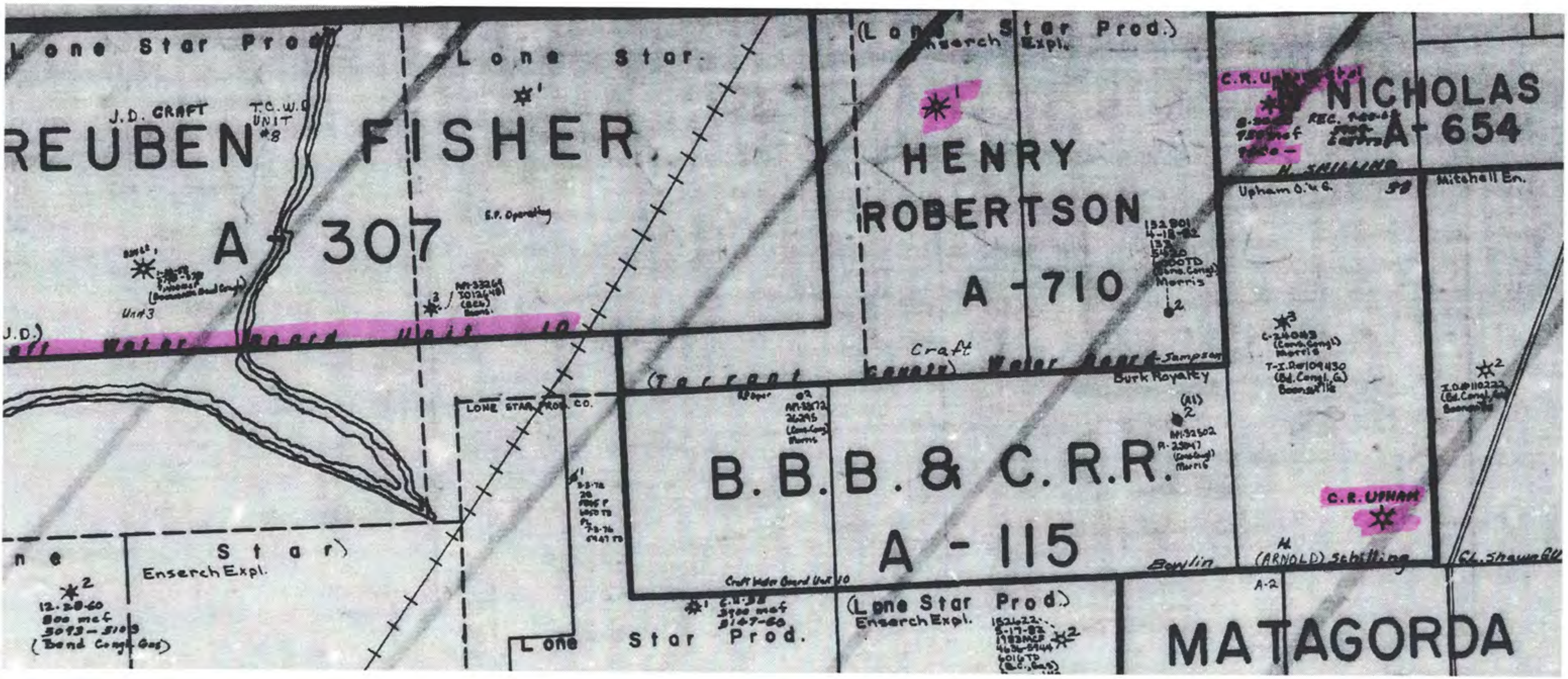
Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand),



ORT LAKE
RALD A-295
G. & E. NAV. CO.
A-350
Cities Serv.
Featherston Oil
Burk Royalty
Burk Royalty
MORRI
G.W. ROPER
A-1308
Y.L. Power
Unit 20
Craft Water Board
G.& B.NAV.CO.
J.G. COLLINSWORTH
A-883
R.P. LITTLE
A-517
Enserch Expl.
D.W. HARRISON
A-1076
Craft Water Bd.
D.W. HARRISON
A-1004
J. McCLANAHAN
A-583
P. NICHOLAS MORRIS
A-654
STANFIELD
"Wharton Unit"
H. WHARTON 149ac.
K.A. Stanfield
Arwine Unit
H. ROBERTSON
A-710
Craft Water Unit No 8
Craft Water Board-Sampson
C.R. Upham, Jr.
R. FISHER
A-307
Lone Star
G. Mitchell
Enserch
Craft Water Unit No. 5



(A.L. Boring)
A.L. Boring
(Lone Star Producing Co.)
Enserch Expl., Inc.
Y. L. Power Gas Unit "B"
G.W. ROPER
A-1308
Y. L. Power
Lone Star
3-16-57
CRAFT WATER BOARD UNIT "2"
Lone Star
Craft Water Board Unit 23
Lone Star Producing Co.
Enserch Expl., Inc.
G & B. NAV. CO.
J.G. COLLINSWORTH
CRAFT WATER BOARD UNIT "16"
A-883
Enserch Expl.
R.P. LITTLE
A-517
J.A. Risch
(Kate R. Stanfield "B")
P. NICHOLAS
A-654
STANFIELD
(5300 CONG
Craft Water Board Unit 16 No. 2
Enserch Expl., Inc.
Enserch Expl.
Water Board Unit 17
Craft-Water Board Unit 1
Lone Star
D.W. HARRISON
A-1076
Unit "1"
McCLANANAN
A-583
Christie, H. & N
D. W. HARRISON
A-1064
J.D. Craft-TCWB
Walker
Ray
A. Hall O. Properties
(Trice Field)
Lone Star Prod. Co.
Kate Starfield
DATE OF BASE
DATE REVISED
BY
0'
1000'
WE
CA
RAIL


Lone Star Prod.
J.D. CRAFT
T.C.W.D. UNIT #8
REUBEN FISHER
A-307
Lone Star
E.P. Operating
Unit 3
Water Board Unit 10
(Tarrant County) Water Board
Craft
Sampson
Burk Royalty
LONE STAR PROD. CO.
Star)
Enserch Expl.
12-28-60
800 mcf
5093-5103
(Bend Congl. Gas)
Lone Star Prod.
(Lone Star Prod.)
Enserch Expl.
HENRY ROBERTSON
A-710
Morris
B.B.B. & C.R.R.
A-115
Craft Water Board Unit 10
C.R. UPHAM
NICHOLAS
A-654
Upham O. & G.
Mitchell En.
T-I. Dar109430
(Bd. Congl. G.)
Boonsville
Bowlin
(ARNOLD) Schilling
A-2
MATAGORDA

44447

©

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No.

Operator A'Mell Oil Properties Address 1201 Elm St., Dallas, Texas

County Wise Survey J. McClanahan Block No. A-583 Sec. No.

Lease Name H. H. Wharton Well No. 1 Elevation 795 GL (Above Sea Level)

Name of Field in which well is located Booneville Conglomerate Gas

Form 1 (Notice of Intention to Drill) Was Filed in Name of A'Mell Oil Properties

Is this a NEW WELL? Yes DEEPENING? – or a WORK-OVER? –

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

(Work-Over) (Drilling) Commenced April 27, 19 61 (Work-Over) (Drilling) Completed May 15, 19 61

Correspondence regarding this well should be sent to: Name A'Mell Oil Properties Address 1201 Elm St., Dallas, Texas

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
8-5/8"	153	77	–	–	153	77	
2-7/8"	5204	00	–	–	5204	00	

Initial Production of Gas—Volume 250 MCF 24 hrs. Pressure 500 lbs. per square inch

Initial Production of Oil: Barrels 5 of Frac per day

Initial Production of Distillate: Barrels Trace

Is this an OIL well? No , a GAS well? Yes , or a Dry HOLE?

DESCRIPTION OF PROPERTY
NORTH

WEST

EAST

SOUTH

GENERAL REMARKS

LTR BD OF WATER EN R

DATED April 19, 1961

RECOMMENDS 150 FT.

See letter attached

RECEIVED
SEP 18 1961
Railroad Commission of Texas
OIL & GAS DIVISION
WICHITA FALLS, TEXAS

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof.

FORMATIONS	TOP	BOTTOM
Shale w/sd & lm stks	0	30
Lime	30	37
Shale & Shells	37	45
Lime & Shale	45	72
Shale & Lime	72	130
Lime	130	136
Lime & Shale	136	173
Shale & Lime	173	220
Lime & Shale	220	258
Shale w/lm stks	258	328
Water Sand	328	346
Shale, sd & lm stks	346	890
Shale & lm	890	925
Shale & lm w/sdy stks	925	1067
Lime	1067	1117
Shale w/lmy stks	1117	1165
Sand & Shaley sd	1165	1196
Shale w/lm & sd stks	1196	1477
Shale	1477	1500
Shaley sd	1500	1570
Shale & sd stks	1570	1620
Hard sd	1620	1646
Shaley sd	1646	1896
Shale & sdy shale	1896	2087
Shale w/sd & lm stks	2087	2269
Shale w/sd & lm sh stks	2269	2408
Shale w/sd & lm stks	2408	2429
Shale & chalkey lm	2429	2533
Shale & lm stks	2533	2655
Lime & Shale	2655	2658
Shale W/lm stks	2658	2767
Shale & lm	2767	2804
Shale W/lm & sd stks	2804	2995
Shale & lm	2995	3020
Lmy shale & lm shells	3020	3035
Lime w/specks flo. (no odor)	3035	3052
Shale & lm	3052	3062
Shale	3062	3121
Shale & lm stks	3121	3230
Shale & lm	3230	3336
Shale w/lm stks	3336	3506
Lime	3506	3520
Shale & lm shale	3520	3658
Shale w/lm stks	3658	3840
Lime	3840	3849
Lime	3849	3861

REMARKS		
Shale & Sdy shale	3861	3964
Shale w/lm stks	3964	4020
Shale & sdy sh w/lm	4020	4299
Shale w/lm & sh stks	4299	4544
Lime (Caddo)	4544	4591
Shale & lm	4591	4645
Shale w/lm & sd stks	4645	4731
Shale & lm	4731	4848
Shale & lm shale	4848	5069
Shale	5069	5085
Shale, cong shale & conglomerate	5085	5138
Shale w/cong stks	5138	5159
Shale & lm shale	5159	5202
Shale & lm stks	5202	5220
Hard tight cong.	5220	5232
Shale & cong	5232	5240
Hard tight cong	5240	5241
Shale w/cong stks	5241	5350
Shale & Cong sh stks	5350	5400
Shale & lm shale	5400	5440
Shale & cong stks	5440	5533
Hard tight cong	5533	5540
Broken tight cong	5540	5548
Shale w/cong stks	5548	5557
Shale w/tight congstks	5557	5672
Shale	5672	5733
Limey shale	5733	5749
Shale w/tight cong stks	5749	5828
Shale & cong	5828	5841
Cong w/very faint flor	5841	5860
Shale w/cong stks	5860	5916
		TD

Method of shutting off water No water   Is water completely shut off? Yes

Amount of water with oil NONE   per cent

I, A. W. Amell

being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

A W Amell
Representative of Company.

Subscribed and sworn to before me this 22nd day of June, 1961

[signature]
Notary Public
Dallas County, Texas.

44447 M

RECEIVED
APR 24 1961
Railroad Commission of Texas
OIL & GAS DIVISION

Application to Drill, Deepen or Plug Back.

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 1
Rev. 4/60

STATE WHETHER THIS IS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK Drill
SHALL BE FILED IN DUPLICATE (IN TRIPLICATE IF RULE 37) WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED
DATA FURNISHED ON THIS FORM AND ANY ATTACHMENT HERETO MUST BE CLEARLY LEGIBLE.
ANY ILLEGIBLE FORM WILL BE RETURNED WITHOUT COMMISSION ACTION.
(Black Ink or Black Typewriter Ribbon Preferable)

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, fo this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines. . Also show the nearest wells on all sides of this location and the distance from the proposed location to those wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equaling 1000 feet; if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THIS PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line 467 feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease - feet

IS THE ACREAGE ON WHICH THIS WELL IS TO BE LOCATED, PRESENTLY ASSIGNED TO ANOTHER WELL IN ANY RESERVOIR FOR WHICH THIS PERMIT IS REQUESTED? No

Date April 18, 19 61

Name of company or operator

Name A'Mell Oil Properties

Address 1201 Elm Street,

City Dallas 2, Texas

Description of farm or lease:

Name of Lease Howard H. Wharton

Number of Acres 332 Well No. 1

Number of wells on lease None

Elevation (Ft. above sea level) Section No. Block No.

Survey J. McClanahan - A 583

Zone or Reservoir Conglomerate

To be Located in Boonesville(Bend Congl. Gas)

(If Wildcat state above, also state Distance and Direction from nearest Survey Lines.)

Wise County

4 Miles Northwest direction from

Bridgeport, Texas nearest post office or town.

Rotary or Cable Tools Rotary

Date work will start drilling on permit

Depth to which you propose to drill 6200 feet.

Date work will start deepening

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?

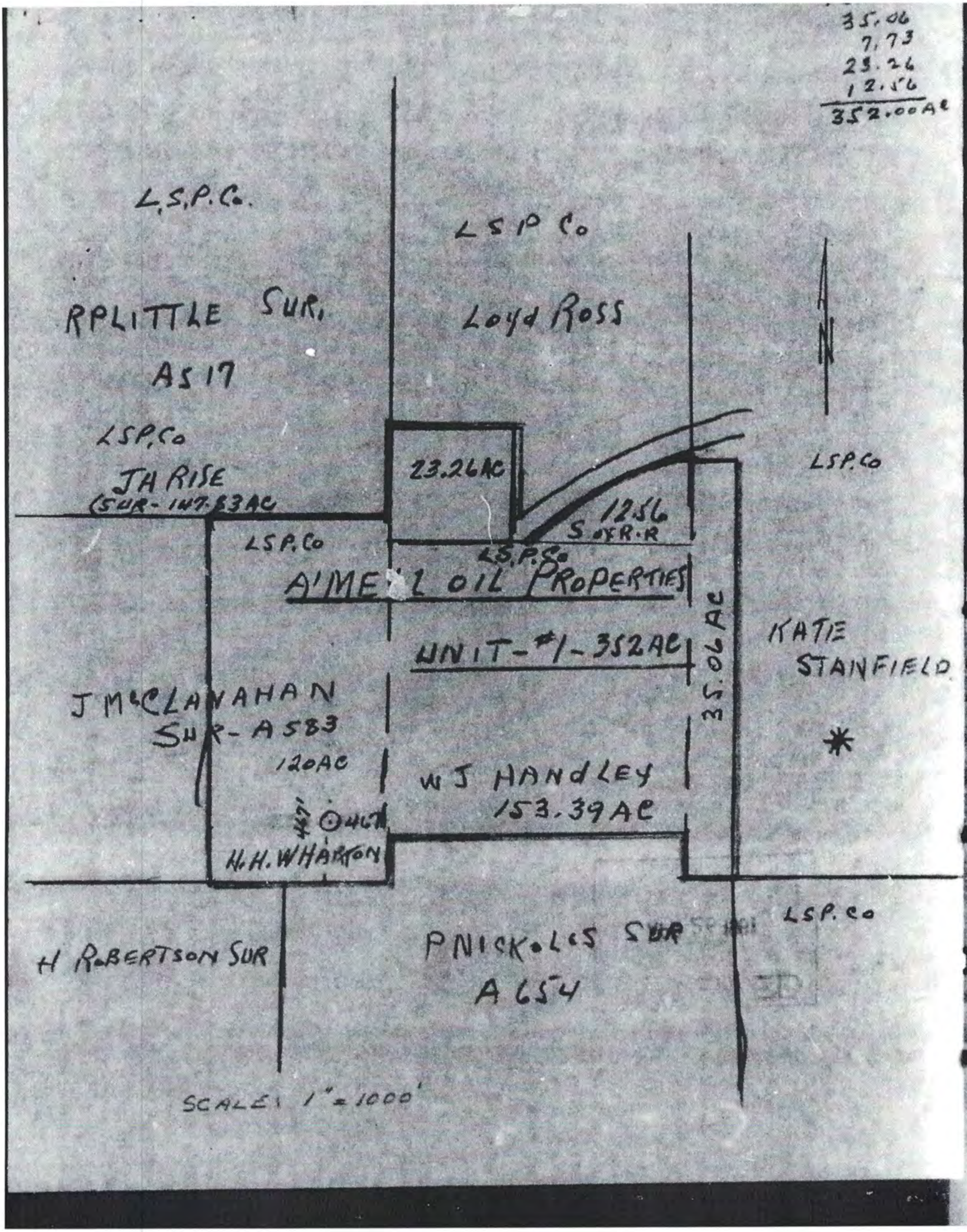
Name

Address

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

25 / DR


35.06
7.73
23.26
12.56
352.00AC
L.S.P.Co.
LSP Co
RPLITTLE SUR.
AS17
Loyd Ross
N
LSP.Co
JA RISE
(SUR-147.33AC
23.26AC
12.56
S of R.R
LSP.Co
LSP.Co
LS.P.Co
OIL PROPERTIES
UNIT-#1-352AC
35.06AC
KATIE
STANFIELD
J McCLANAHAN
SUR-A583
120AC
W J HANDLEY
153.39AC
467
H.H. WHARTON
LSP.co
H ROBERTSON SUR
P NICKOLES SUR
A654
SCALE: 1"=1000'

1

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

9

D

File No.

Operator LONE STAR PRODUCING COMPANY Address 301 S. Harwood, Dallas, Texas

County Wise Survey Phillips-Nicholas Block No. (A-654) Sec. No.

Lease Name Kate Ann Stanfield "A" Well No. 1-C Elevation 810 (Above Sea Level)

Name of Field in which well is located Boonsville (Bend Conglomerate Gas)

Form 1 (Notice of Intention to Drill) Was Filed in Name of Lone Star Producing Company

Is this a NEW WELL? Yes

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

(Drilling) Commenced 11-17 1959 (Drilling) Completed 12-9- 1959

Correspondence regarding this well should be sent to: Name A. L. Poynor Lone Star Prod.Co. Address Box 767, Jacksboro, Tex.

Has an allowable been assigned to this well? No.

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
9-5/8	324				324		
5½	5400				5400		HOMCO DV Tool @ 3238' packer shoe at 5394'
2-3/8	5217				5217		HOMCO Type "C" Pkr. @ 5217

Initial Production of Gas—Volume 1916 MCF 24 hrs. Pressure 200 lbs. per square inch

Initial Production of Oil: Barrels 23 bbls. (frac oil)

Initial Production of Distillate: Barrels

Is this an OIL well? , a GAS well? Yes , or a Dry HOLE?

DESCRIPTION OF PROPERTY
NORTH

See Form 1 filed Oct.1,1959

WEST

EAST

SOUTH

RECEIVED
JAN 28 1960
Railroad Commission of Texas
OIL & GAS DIVISION
WICHITA FALLS, TEXAS

GENERAL REMARKS

This well is dually completed as an oil & gas well. A HOMCO Type "C" permanent packer set @ 5217' to separate the upper zone gas & the lower zone oil. Well is completed w/1 string of 2-3/8" OD tbg. & 2-Garrett Oil Tool circulating sleeves. Lower sleeve is below Type "C" & Upper sleeve above packer.

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMA[redacted]D
Show All Formations, Especially All [redacted]aracter and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS	
Sh W/Sd & Lm Stks.	0	110	Sh W/Lm & Sd Stks	3160
Sd & Lime		165	Shale W/Sdy Stks.	3214
Sh & Sd Stks.		222	Lime	3230
Lime		280	Shale-Lime & Sdy	3306
Sh & Sdy Sh		354	Shale-Sd Stks.	3410
Sh & Sd Stks		433	Sand - Lime	3440
Sh W/Lm & Sd		450	Shale & Sand	3487
Shale		550	Limey Sand & Shale	3505
Sh & Sd Stks		815	Sh - Lmy & sdy.	3544
Sh, Lm & Sd		950	Lime	3555
Sh & Lm		1082	Shale-Sdy-Lime Stks.	3838
Lime		1034	Shale	3875
Sand		1205	Lime	3893
Sh, Sd & Lime Stks		1340	Shale & Sandy Shale	3933
Limey Sh		1380	Limey Sand & Shale	3955
Shale		1560	Limey Sand	3975
Sh W/Sdy Lm		1580	Shale & Sand	3999
Sh - Sdy Shale		1655	Shale-Sand & Lime Stks.	4076
Sh - Sand & Lm		1700	Shale W/Sdy Stks.	4197
Sh & Sdy Sh		1798	Shale	4549
Sand -- No Shows		1835	Shale W/Lime Stks.	4601
Shale & Sd Stks		1865	Shale & Chalky Lime	4606
Lm, Sd & Sh		1929	Limme & Shale	4622
Sh, Lm & Sd		2118	Lime	4639
Sh & Sd Stks		2247	Shale & Limey Shale	4666
Sand		2259	Lime	4672
Sh W/Sand		2410	Lime & Shale	4864
Lm, Sh W/Sd Stks.		2558	Shale	4927
Lime & Shale		2600	Shale & Lime	5216
Lime		2619	Shale	5224
Sh & Sd Lm		2632	Lime	5239
Sh & Lm		2673	Shale	5246
Lime, Sh & Sand		2695	Shale & Lime	5276
Sand & Shale		2724	Congl. (Show)	5276
Shale		2765	Congl. & Lime	5294
Lim - Shale		2847	Shale-Lime & Congl. Stks.	5306
Sh W/Lm & Sd		2863	Shale & Lime	5397
Sh & Sdy Sh		2890	Lime	5422
Sh - Lm & Sd.		2932	Shale & Lime	5503
Sand & Shale		2948	Lime	5513
Sh & Sdy - Lm		3008	Shale-Lime	5518
Sh - Sdy Stks.		3030	Shale	5550
Sd & Shale		3053	Shale & Limey Shale	5598
Sand (Show)		3062	Lime & Shale	5609
Lime		3077	Limey Shale & Lime	5640
Shale		3095	Shale	5651
Sand & Shale		3130	Limy. Shale & Lime	5662

Railroad Commission of Texas
OIL & GAS DIVISION
AUSTIN, TEXAS
JAN 29 1960

Method of shutting off water Cement & Csg. Is water completely shut off? Yes
Amount of water with oil per cent

I, E. L. Smith, Jr.
being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

E. L. Smith, Jr.
Representative of Company.

Subscribed and sworn to before me this 19 day of January, 1960

Lorene Stanfull
Notary Public
Jack County, Texas.

52987

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Shale	5662	5668	
Sh - Lm Sh		5754	
Lime		5778	
Shale & Lime		5783	
Limey Shale & Lime		5806	
Lime		5825	
Shale & Lime		5883	
Lime-Shly. Congl.		5918	
Lime & Congl. Stks.		5930	
Lime & Limey Shale		5964	
Lime		5972	
Shale & Limey Shale		5996	
TOTAL DEPTH			

Method of shutting off water .... Is water completely shut off? ....

Amount of water with oil .... per cent ....

I, ...

being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

....

Representative of Company.

Subscribed and sworn to before me this .... day of ...., 19 ....

....

Notary Public

.... County, Texas.

52007

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No. [redacted]

Operator: Lone Star Producing Co. Address: 301 S. Harwood St. Dallas, Texas

County: Wise Survey: Phillip Nicholas (A-654) Block No. Sec. No.

Lease Name: Kate Ann Stanfield "A" Well No. 1-T Elevation 810 (Above Sea Level)

Name of Field in which well is located: Boonsville (5085 Atoka Conglo) ~~Stanfield (5250' Conglr) - Suggested name.~~

Form 1 (Notice of Intention to Drill) Was Filed in Name of: Lone Star Producing Co.

Is this a NEW WELL? Yes DEEPENING? or a WORK-OVER?

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

([redacted]) (Drilling) Commenced 11-17, 1959 [redacted] (Drilling) Completed 12-9, 1959

Correspondence regarding this well should be sent to: Name Mr. A. L. Poynor Address Box 767-Jacksboro, Texas

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
9-5/8	324				324		
5½	5400				5400		HOWCO DV tool @ 3238 packer shoe @ 5394'
2-3/8"	5217				5217		HOWCO Type "C" pkr. @ 5217

Initial Production of Gas—Volume 292 MCF 24 hrs. Pressure 140# lbs. per square inch

Initial Production of Oil: Barrels 60

Initial Production of Distillate: Barrels

Is this an OIL well? Yes , a GAS well? , or a Dry HOLE?

DESCRIPTION OF PROPERTY

NORTH

See Form 1 field Oct. 1, 1959

WEST

RECEIVED
JAN 28 1960
Railroad Commission of Texas

EAST

SOUTH

GENERAL REMARKS

This well is dually completed as an oil & gas well A HOWCO Type "C" permanent packer set @ 5217' to separate the upper zone gas & the lower zone oil. Well os completed w/1 string of 2-3/8" OD tbg. & 2-Garrett Oil Tool circulating sleeves Lower sleeve is below Type "C" packer & upper sleeve is a bove packer.

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

52007

Please refer to File No..................

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

RECEIVED

OCT 2 1959

Railroad Commission of Texas
Oil & Gas Division
Wichita Fall, Texas

APPLICATION TO DRILL, DEEPEN OR PLUG BACK

IS THIS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK.....DRILL.....

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, of this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines.. Also show the nearest wells on all sides of of this location and the distance from the proposed location to these wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equaling 1000 feet; if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THIS PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line...467..............feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease.....—....feet.

Date....October 1............ 19..59..

Name of company or operator

Name......Lone Star Producing Company........

Address...301 S. Harwood Street...............

City......Dallas, Texas....................

Description of farm or lease:

Name of Lease...Kate Ann Stanfield "A".........

Number of Acres..211.66.......Well No....1.......

Number of wells on lease..none..............

Survey Phillip Nicholas (A-654)

Elevation....810...............Feet
(ABOVE SEA LEVEL)

Section No....................Block No.............

Located in...Wildcat.........................Field

(If Wildcat state above)

.......Wise.................................County

.......3............Miles...SW.....direction from

. ...Bridgeport......nearest postoffice or town.

Rotary or Cable Tools..Rotary..................

Date work will start drilling...on permit........

Depth to which you propose to drill..6,000...feet.

Date work will start deepening.....................

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?

Name...

Address..

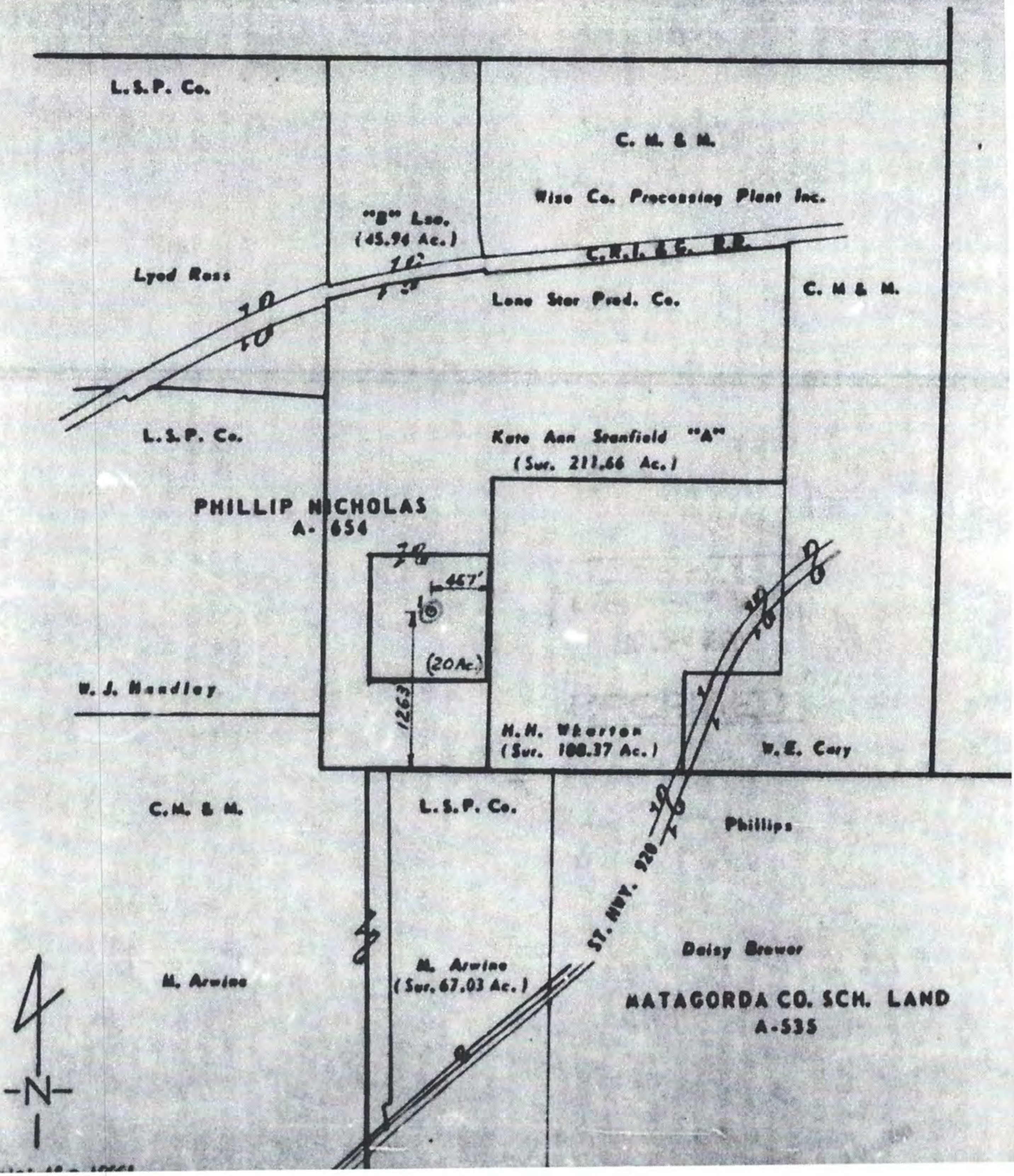
OK
Dr.

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

Subscribed and sworn before me this the 29th day of Sept. 1959 A.D.

Notary Public, Dallas County, Texas



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RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

AUG 12 1971

(E)

Form G-1

RRC District 9

RRC Identification Number D-57093

GAS WELL BACK PRESSURE TEST
COMPLETION OR RECOMPLETION REPORT AND LOG

1. FIELD NAME: Boonsville (BCG)
2. LEASE NAME: Harold Shilling
9. Well Number: 2
Operator: Upham Oil & Gas Company
LTR TEX W...
10. County: Wise
3. ADDRESS: P. O. Box 940, Mineral Wells, Texas 76067
DATED 5-10-71
11. Purpose of Test: Initial Potential X; Retest; Reclass
5. If Operator has changed within last 60 Days — Give former Operator
RECOMM. NL 300 FT
6. LOCATION (Section, Block, and Survey): P. Nicholas Survey A-654
12. Pipe Line Connection: Not connected
13. If Workover, give former Field (with Reservoir)
14. Completion Date: 7/30/71
List of Offset Operators Notified and Date of Notification
16. Type of Electric or other Log Run: Induct-Elec. & Sonic

Section I — GAS MEASUREMENT DATA

Date of Test: 8/2/71 — Gas Measurement Method (Check One): Orifice Meter; Positive Choke; Orifice Vent Meter; Pitot Tube; Critical flow Prover X — Gas produced during test: 277 MCF

Run No.	Line Size	Orifice or Choke Size	24 Hr. Coeff. Orif. or Choke	Static P_m or Choke Press.	Diff. h_w	Flow Temp. °F	Temp. Factor F_{tf}	Gravity Factor F_g	Compress. Factor F_{pv}	Volume MCF/DAY
1	2.00	1.125	28.9803	31		56	1.0039	.9258	1.004	838
2	2.00	.625	8.5694	86		60	1.0000	.9258	1.011	690
3	2.00	.625	8.5694	74		63	0.9971	.9258	1.011	591
4	2.00	.625	8.5694	62		65	0.9952	.9258	1.011	495

Section II — FIELD DATA AND PRESSURE CALCULATIONS

Gravity Dry Gas	Gravity Liquid Hydrocarbon	Gas-Liquid Hydro Ratio	Gravity of Mixture G_{mix}	Avg. Shut-In Temp.	Bottom Hole Temp.
.700	60 Deg. API	105,000 CF/Bbl	.724	103 °F	132°F @ 6155 (Depth)

$D_{eff}^{8/3}$ — GL

C = 1118 ÷ $(D_{eff})^{8/3}$ — GL/C

Run No.	Time of Run Min.	Choke Size	Wellhead Press. P_w PSIA	Wellhead Flow Temp. °F	P_w^2 (Thousands)	R	R^2 (Thousands)	P_t	P_w / P_t
Shut-in	72 hrs.		1325	74					
1	5 hrs.	20/64	615	80					
2	2 hrs.	16/64	725	80					
3	1 hr.	12/64	770	80					
4	1 hr.	10/64	787	80					

Run No.	F	K	S	e^{s}	P_f and P_s	P_f^2 and P_s^2	$P_f^2 - P_s^2$
Shut-in		.1240	1.297	1.175	1557	2424	
1		.1235	1.228	1.164	716	513	1911
2		.1235	1.237	1.166	845	714	1710
3		.1235	1.243	1.167	899	808	1616
4		.1235	1.243	1.167	918	843	1581

Angle of Slope θ = 45
n = 1.000
Absolute Open Flow: 1,060 MCF/DAY

OPEN FLOW TEST:

Shut-In Press. ___ Psig
Time Shut-In ___ Hrs.
Producing Through ___

In. H₂O Time	Reading	In. Hg Time	Reading	Psig Time	Reading

REPRESENTATIVE OF COMPANY MAKING TEST

REPRESENTATIVE OF RAILROAD COMMISSION

CERTIFICATE:

I declare under penalties prescribed in Article 6036c, R.C.S., that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete to the best of my knowledge.

REPRESENTATIVE OF COMPANY — Geologist (TITLE) — 8/10/71 (DATE)

497 30085

SECTION III — DATA ON WELL COMPLETION AND LOG (Not Required on Retest)

17. Type of Completion: New Well X Deepening Plug Back Other	18. Date Permit Issued: May 11, 1971
19. Notice of Intention to Drill this Well was filed in Name of: Upham Oil & Gas Company	20. If Special Permit, Give Permit Number
21. Number of Producing Wells on this Lease in This Field (Reservoir) including this Well: One	22. Total Number of Acres in this Lease: 245.27
23. Date Plug Back, Deepening, Workover or Drilling Operations: Commenced June 15,1971 Completed July 1, 1971	24. Distance to Nearest Well, Same Lease & Reservoir: None
25. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located: 467 Feet From North Line And 934 Feet From West Line of The Harold Shilling Lease	
26. Elevation (DF, RKB, RT, GR, etc.): 833 GL & 842' RKB	27. Was Directional Survey Made: Yes X No
28. Top of Pay 5121 — 29. Total Depth 6155 — 30. P.B. Depth 5389	31. Surface Casing Determined By: Recommendation of Texas Water Development Board X — Field Rules — Railroad Commission (Special)
32. Is Well Multiple Completion? Yes No X — 33. If Multiple Completion List All Reservoir Names	34. Intervals Drilled By: Rotary Tools Surf.-T.D. — Cable Tools
Name of Drilling Contractor: Bearden Drilling Company	36. Is Cementing Affidavit Attached? Yes No X

CASING RECORD (Report All Strings Set in Well)

Casing Size	Weight LB FT.	Depth Set	Hole Size	Cementing Record	Amount Pulled
8-5/8	20# & 24#	331	12-1/4"	250 sx Reg. w/2% C.C.	None
5-1/2	15.5#	5418.61	7-7/8"	175 sx Pozmix w/4% Gel.	None

LINER RECORD

Size	Top	Bottom	Sacks Cement	Screen
None				

TUBING RECORD

Size	Depth Set	Packer Set
2-3/8	5258	None

40. Producing Interval (this completion) Indicate Depth of Perforations or Open Hole

From	5121	To	5129
From	5194	To	5202
From	5211	To	5217
From	5238	To	5252

ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

Depth Interval	Amount and Kind of Material Used
5121-5252	1,000 gallons acid and fractured with 10,000 gallons treated salt water and 20,000 pounds of sand. (10/40)

FORMATION RECORD (LIST DEPTHS OF PRINCIPAL GEOLOGICAL MARKERS AND FORMATION TOPS)

Formations	Depth	Formations	Depth
Water Sand	1065 - 1118	Lime (Caddo)	Top 4556
"	Top 1177	Conglomerate (Atoka)	Top 5118
"	Top 1238	Lime (Marble Falls)	Top 6074
Lime	Top 2558		
"	Top 2916		
" (M-1)	Top 3840		

REMARKS

```
DISTRICT> 09       GAS WELL DATA INQUIRY - PAGE 1       SCHEDULE  > 11 / 22
FIELD    > BOONSVILLE (BEND CONGL., GAS)     # 10574 520 TYPE FIELD> CAPACITY
OPERATOR> UPHAM OIL & GAS COMPANY            # 878925   DRILL PMT >
LEASE    > SHILLING, HAROLD                             API #     > 497 30085
COUNTY   > WISE          RRCID 051043 WELL #     2      ALLOW EFF > 11/01/2022
TYPE WELL> PRODUCING                                    TOP ALLOW >
OFFSHORE>    BAYS/EST    STATE    DS>      0      0     CYCL ALLOW>
OP LACK>
OTHER  >
SCHED REM >
TOT LEASE ACRES>             COMMINGLING                    CAPABILITY         4
"@" AMOUNT> 999999999   DATE> MM/YYYY   HIGH DLY AVG> 999999999   DATE> MM/YYYY
SPEC ALLOW >        100  CODE> ADMINISTRATIVE
G-10 TEST  >  07/14/2022 TYPE >  R LAST UTIL>           G-1 TEST >    08/02/1971
DELIV      >           4 DELIV LTR EFFEC>               G-1 POTE   >  NOT REQ.
DELIV CODE >             CAL DEL POTE    >              TEMPERATURE>
WH PRESS CD>             SIWH>      90   BHP CD>               BHP >       100
GAS GRAV   >   .758      COND GRAV  >  60.0             GOR        >     270
ACRES-FT   >             ACRES       >        85.2700   G1 TEST GAS>
SUPP ISSUED>  10/17/2022   SUPP REMARKS  >

GO TO RRCID <         > ENTER=PG2 PF1=HELP          PF3=DRL PMT PF4=RESTART
PF5=NEXT WELL PF6=FLD PF7=PROR SCH PF8=P4 PF9=LDGR PF10=G-10 PF11=RMKS PF12=G-1
```

9 (F)

RAILROAD COMM[illegible] TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No. ______

Operator: Lone Star Producing Co. Address: Jacksboro, Texas

County: Wise Survey: Henry Robertson (A-710) Block No. ______ Sec. No. ______

Lease Name: Kraft-Water Board Sampson Unit 1 Well No. 1 Elevation 835' (Above Sea Level)

Name of Field in which well is located: Boonsville (Bend Congl. Gas) Field

Form 1 (Notice of Intention to Drill) Was Filed in Name of: Lone Star Producing Co.

Drilling Commenced 10-5, 19 57 Drilling Completed 10-28, 19 57

Is this a NEW WELL? Yes : DEEPENING? ______ or a WORK-OVER? ______

Correspondence regarding this well should be sent to: Name Lone Star Producing Co. Address Box 1047- Jacksboro, Texas

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
9-5/8"	315'	0.4					HOWCO guide shoe
5½"	5621						HOWCO guide shoe

Initial Production of Gas—Volume 3,120 MCF 24 hrs. Pressure TBG-500# Sep- 200# lbs. per square inch

Initial Production of Oil: Barrels 30 bbls. frac oil /hr.

Initial Production of Distillate: Barrels ______

Is this an OIL well? ______, a GAS well? Yes, or a Dry HOLE? ______

DESCRIPTION OF PROPERTY

NORTH

See Form 1 filed August 20, 1957

WEST

SOUTH

GENERAL REMARKS

9-5/8" csg. cemented w/250 sks

5½" csg. cemented w/201 sks

Perforated 5103-5110, 5112-5120 (Schl)

w/4 dyna jets per foot. (60 holes)

Acidized w/500 gal MCA

Fractured w/10,000 gal oil and

10,000# sand.

R

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Shale & lime	0	100	
Sand & shale	100	150	
Sh w/lm stks	150	290	
sh & sd stks.	290	360	
sh w/lm & sh stks.	360	646	
sh w/lm & sd stks.	646	1322	
sh w/sd stks.	1322	1550	
sh w/sdy lm stks.	1550	2370	
shale	2370	2536	
sh w/sdy lm stks.	2536	2638	
Lime	2638	2659	
sh w/sd & lm stks.	2659	3495	
sh w/lime shells	3495	3571	
sh w/lime stks.	3571	4000	
sh & sand	4000	4015	No jeep - no odor
sh w/ sd & lm stks.	4015	4550	
Lime	4550	4560	
Lime	4560	4575	Jeep & odor
Lime & shale	4575	4594	
sh & lime congl	4594	4610	
sh & lime stks.	4610	4967	
sh lm & congl	4967	4981	
sh , lm & congl	4981	5100	
sh lm & congl	5100	5174	
Sd & congl stks.	5174	5198	
shaley congl	5198	5207	
sh & congl	5207	5230	Jeep & odor
sh w/lime stks.	5230	5683	
sh & congl stks.	5683	5711	
sh & lime stks.	5711	5790	
sh & sdy congl	5790	5823	
Lime congl	5823	5862	
sh sd & lmy congl	5862	5942	
sh & congl stks.	5942	6027	

RECEIVED
FEB 17 1958
OIL & GAS DIVISION
AUSTIN, TEXAS

RECEIVED
APR 22 1958

Method of shutting off water .... Is water completely shut off? ....

Amount of water with oil ....

I, T. R. Pledger being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

T. R. Pledger
Representative of Company.

Subscribed and sworn to before me this 10th day of February, 1958

Lorene Stanfield
Notary Public
Jack County, Texas.

*** OIL AND GAS DIVISION *** INQUIRY

PLUGGING DATA

TYPE/WELL(O/G/D/S): **G** API NUMBER: **497 01654**
DIST: **09** LEASE/ID: **132120** WELL #: **1**
FIELD NAME: **BOONSVILLE (CADDO LIME)**
LEASE NAME: **CRAFT WATER BOARD SAMPSON**
OPER NAME: **ENSERCH EXPLORATION, INC**
DRILL PERM ISSUED: **07 / 21 / 1989** PERMIT #: **361291** SFPC:
DRILL COMPLETED: **04 / 09 / 1989** WELL PLUGGED: **09 / 27 / 1996**
DATE W-3 FILED: **02 / 10 / 1997** TOTAL DEPTH: **6028**
DIST W3 APPR DATE: **MM / DD / YYYY**
WAS THIS A MULTIPLE COMPLETION? **N** WELL WAS CONVERTED TO FRESH WATER USE? **N**

	PLUG 1	PLUG 2	PLUG 3	PLUG 4	PLUG 5	PLUG 6	PLUG 7	PLUG 8
BOTT DEP:	5120	4568	598	385	13			
SACK CEM:	25	25	25	60	5			
CALC TOP:	4900	4348	498	265	3			
TOP/PLUG:	0	0	0	0	0			
TYPE CEM:	C	C	C	C	C			

*

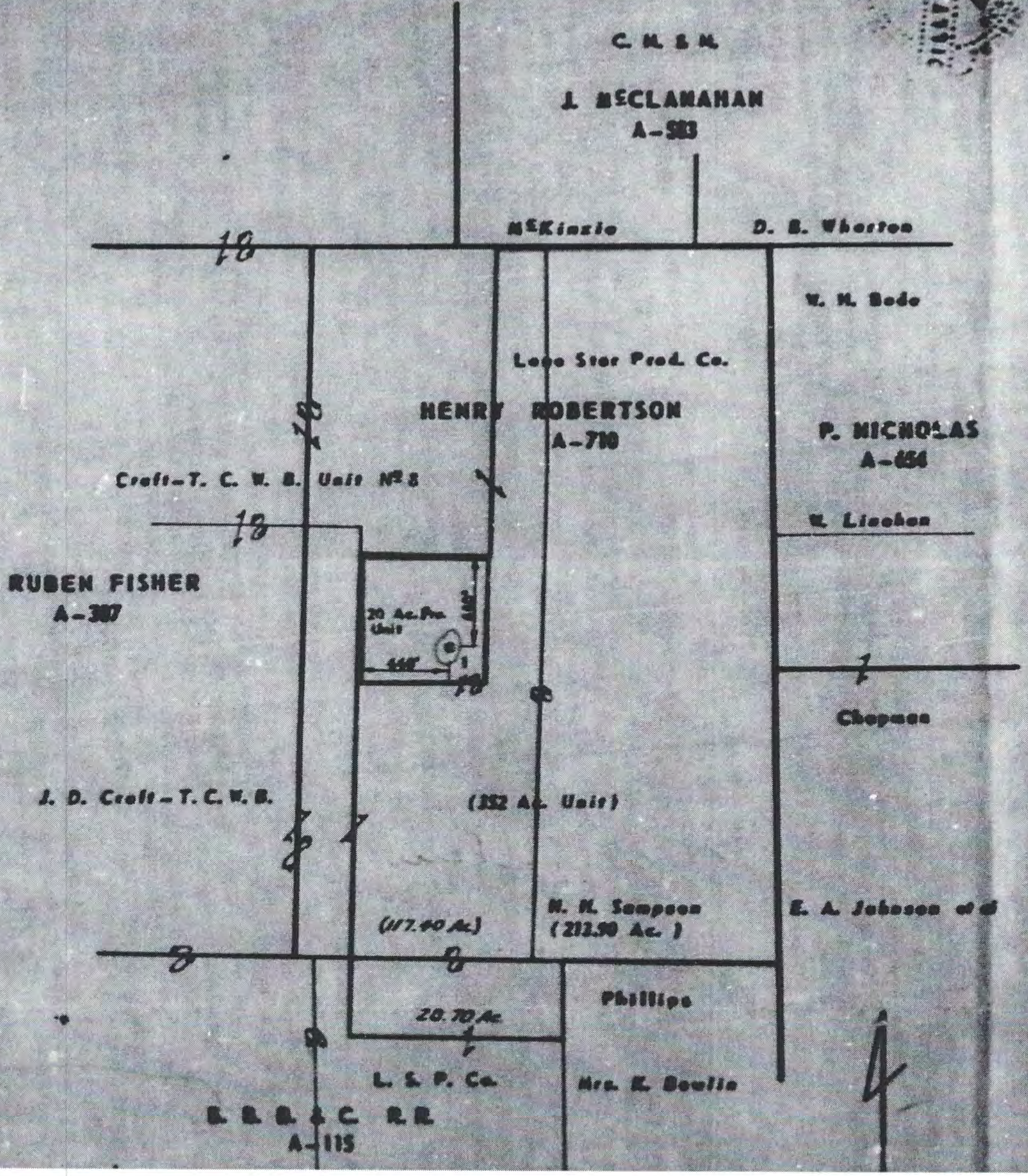
* SCREEN OPTIONS: 17=PLUG CAS/TUB/PERFS, 18=WATER/LOGS/REMARKS *
* SELECT OPTION: __ (01=RETURN TO MENU, 00=HELP AND OTHER OPTIONS) *
DEPRESS ENTER TO SEE PLUG CASING/TUBING/PERFS

I, BILLY M. SASSE, being duly sworn on oath, state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

Billy M. Sasse
Registered Public Surveyor

Subscribed and sworn before me this the 13th day of August 1957 A. D.

Notary Public, Dallas County, Texas



G

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No. ______

Operator: Lone Star Producing Co. Address: 301 S. Harwood St.- Dallas, Texas

County: Wise Survey: [illegible] Fisher (A-307) Block No. ______ Sec. No. ______

Lease Name: Craft-Wtr. Bd Unit 30 Well No. 1 Elevation: [illegible] (Above Sea Level)

Name of Field in which well is located: Boonsville (Bend Congl. Gas)

Form 1 (Notice of Intention to Drill) Was Filed in Name of: Lone Star Prod. Co.- Craft-Wtr. Bd Unit 30 #1

Drilling Commenced 11-17, 19 57 Drilling Completed 12-11, 19 57

Is this a NEW WELL? Yes , DEEPENING? ______ or a WORK-OVER? ______

Correspondence regarding this well should be sent to: Name Lone Star Prod. Co. Address Box 767-Jacksboro, Tex.

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
9-5/8" OD	332				332		1-HOWCO guide shoe
7" OD	5850				5850		1-Baker guide shoe & 1
							Baker Auto Flex flow collar
2-3/8" OD	5774				5774		1-Guiberson KV-30 w/holddown

Initial Production of Gas—Volume 4,475 MCF 24 hrs. Pressure 503 lbs. per square inch

Initial Production of Oil: Barrels ______

Initial Production of Distillate: Barrels 38.2

Is this an OIL well? No , a GAS well? Yes , or a Dry HOLE? No

DESCRIPTION OF PROPERTY

NORTH

See form 1 filed October 30th, 1957

WEST

EAST

SOUTH

GENERAL REMARKS

None

RECEIVED
MAR 26 1958
Railroad Commission of Texas
Oil & Gas Division
Wichita Falls, Texas

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS		
sh w/lime stks	0	617	sh & hrd sdy lm stks	4600	4624
Sh,sd & lm stks.	617	765	shale	4624	4633
sh & lime	765	821	sd(jmp & light odor)	4633	4646
sd & sh	821	851	sh & lm stks	4646	4695
sh & sd & lm stks	851	1065	sh w/sd & lime	4695	4836
Lime	1065	1072	sh & lm stks	4836	4966
sh & lime	1072	1110	shale	4966	5038
sh & sd	1110	1142	cong. w/nice jmp & odor	5038	5071
sh & lm stks	1142	1184	sh & congl stks	5071	5084
sd & sh	1184	1212	shale	5084	5098
sh w/sd & lime	1212	1900	hd sd & lime	5098	5107
lm & shale	1900	1936	sh & lm stks	5107	5144
shale	1936	2032	sh &congl	5144	5148
sh w/sd & lime	2032	2070	congl(weaker -jmp)	5148	5155
lime	2070	2082	sh & congl stks	5155	5265
sh w/sd & lm stks	2082	2350	sh & lm stks	5265	5290
sh & lime	2350	2436	sh & congl	5290	5293
shale	2436	2509	congl(no show)	5293	5303
lime	2509	2530	sh w/congl stks	5303	5425
sh & lime	2530	2613	sh & lm stks	5425	5504
lime & sd	2613	2664	sh & congl	5504	5584
sd & lime	2664	2676	sh & cong	5584	5597
sh-sd- lime	2676	2701	congl (no show)	5597	5728
sh & sd	2701	2765	sh & congl stks.	5728	5923
sh & lime	2765	2820	sh & lime	5923	5934
sd & sh	2820	2882	sh & sdy lime cherty	5934	5958
sh & lm stks	2882	2933	sh & lime	5958	5965
lime	2933	2943	T.D.		
sh & lime	2943	2972			
lime	2972	2984			
sh & lime	2984	3004			
lime & sd	3004	3016			
shale	3016	3144			
sh w/sd & lime	3144	3199			
sh & sd	3199	3327			
shale	3327	3340			
sdy shale	3340	3356			
sh & sd, & lime stks	3356	3361			
sh & lime stks	3361	3497			
Lime	3497	3505			
sh & lm stks	3505	3649			
sh & sd stks	3649	3783			
shale	3783	3844			
sh & sd	3844	4000			
shale	4000	4503			
lime (no jmp or odor)	4503	4547			
sh & lime	4547	4600			

Method of shutting off water 268 sks cement Is water completely shut off? Yes

Amount of water with oil None per cent

I, L. J. Nelms being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

L. J. Nelms

Representative of Company.

Subscribed and sworn to before me this 25th day of March, 1958

Lorene Stanfield

Notary Public

Jack County, Texas.

52007

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No.

Operator Lone Star Producing Co. Address 301 S. Harwood St.-Dallas, Texas

County Wise Survey Ruben Fisher A-307 Block No. Sec. No.

Lease Name Craft-Water Board Unit 10 Well No. 1 Elevation 834 (Above Sea Level)

Name of Field in which well is located Boonsville(Bend Congl. Gas)

Form 1 (Notice of Intention to Drill) Was Filed in Name of Lone Star Producing Co.

Is this a NEW WELL? DEEPENING? or a WORK-OVER? Yes

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

(Work-Over) Commenced 10-8, 19 60 (Work-Over) Completed 10-24, 19 60

Correspondence regarding this well should be sent to: Name Mr. A.L. Poynor Address Box 767-Jacksboro, Texas

Has an allowable been assigned to this well? Yes

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
9-5/8"	332				332		1-HOWCO guide shoe
7"	5860				5860		1-Baker guide shoe & 1-Baker Auto Flex Flow Collar
2-3/8"	5705				5705		Culberson KVT-30

Initial Production of Gas—Volume 1,734 MCF 24 hrs. Pressure 640 lbs. per square inch

Initial Production of Oil: Barrels 19.35 (Frac Oil)

Initial Production of Distillate: Barrels

Is this an OIL well? , a GAS well? Yes , or a Dry HOLE?

DESCRIPTION OF PROPERTY
NORTH

See Form 1 filed Oct. 30,1957

WEST

EAST

SOUTH

GENERAL REMARKS

RECEIVED
WICHITA FALLS, TEXAS
NOV 28 1960
OIL & GAS DIVISION

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS		
shw/lm stks	0	617	sh & hd sdy lm stks.	4600	4624
sh,sd & lm stks	617	765	shale	4624	4633
sh & lime	765	821	sd(jeep & lgt odor)	4633	4646
sd & sh	821	851	sh & lm stks	4646	4695
sh & si lm stks	851	1065	sh w/sd & lm	4695	4836
lime	1065	1072	sh & lm stks	4836	4966
sh & lm	1072	1110	shale	4966	5038
sh & sd	1110	1142	congl.w/nice jeep & odor	5038	5071
sh & lm stks	1142	1184	sh & congl stsk	5071	5084
sd & sh	1184	1212	shale	5084	5098
sh w/sd & lime	1212	1900	hd sd & lime	5098	5107
lm & sh	1900	1936	sh & lm stks	5107	5144
sh	1936	2032	sh & congl.	5144	5148
sh w/sd & lm	2032	2070	congl(no odor -jeep)	5148	5155
lime	2070	2082	sh& congl stks	5155	5265
sh w/sd & lm stks	2082	2350	sh & lm stks	5265	5290
sh & lime	2350	2416	sh & congl.	5290	5293
shale	2416	2509	congl(no show)	5293	5303
lime	2509	2530	sh w/congl stks	5303	5425
sh & lime	2530	2613	sh & lm stks	5425	5504
lm & sd	2613	2664	sh & congl	5504	5684
sh & lime	2664	2675	sh & congl	5684	5698
sh-sd lime	2675	2701	congl (no show)	5698	5728
sh & sd	2701	2765	sh & congl(Stks)	5728	5923
sh & lime	2765	2820	sh & lime	5923	5934
sd & sh	2820	2882	sh & sdy lm cherty	5934	5958
sh & lm stks	2882	2933	sh & lm	5958	5965
lime	2933	2943	T.D.		
sh & lm	2943	2972			
lime	2972	2984			
sh & lm	2984	3004			
lm & sd	3004	3046			
sh	3046	3144			
sh w/sd & lm	3144	3199			
sh & sd	3199	3327			
shale	3327	3340			
sdy sh	3340	3356			
sh & sd, & lm stks	3356	3461			
sh & lm stks	3461	3497			
lime	3497	3505			
sh & lm stks	3505	3689			
sh & sd stks	3689	3783			
shale	3783	3944			
sh & sd	3944	4000			
shale	4000	4503			
lm (sd jeep or [illegible]	4503	4547			
sh & lm	4547	4600			

Method of shutting off water Cement & casing Is water completely shut off? Yes

Amount of water with oil None per cent

I, E. L. Smith, Jr. being [illegible] that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

E. L. Smith, Jr.
Representative of Company.

Subscribed and sworn to before me this 25th day of November, 1960

Lorene Stanfield
Notary Public
Jack County, Texas.

52007

Please refer to File No..............

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 1

M

RECEIVED
NOV 6 1957
Railroad Commission of Texas
Oil and Gas Division
Wichita Falls, Texas

APPLICATION TO DRILL, DEEPEN OR PLUG BACK

IS THIS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK....Drill........?

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, of this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines. Also show the nearest wells on all sides of of this location and the distance from the proposed location to those wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equaling 1000 feet; if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THIS PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line.....800...........feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease.....—...feet.

Date...October 30,..........., 19..57...

Name of company or operator

Name....Lone Star Producing Company..........

Address.301 South Harwood Street..............

City....Dallas, Texas..........................

Description of farm or lease:

Name of Lease.Craft-Water Board Unit No. 10..

Number of Acres..352..........Well No.....1.......

Number of wells on lease.......None..............

Survey.Ruben Fisher (A-307)

Elevation......834.............Feet (ABOVE SEA LEVEL)

Section No...................Block No.............

Located in.........Wildcat..................Field

(If Wildcat state above)

.....................Wise.....................County

..7-1/2............Miles....N.....direction from

...Boonsville........nearest postoffice or town.

Rotary or Cable Tools.........rotary............

Date work will start drilling...on permit........

Depth to which you propose to drill..6,000...feet.

Date work will start deepening....................

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?

Name...

Address..

530-933 20 ac.

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

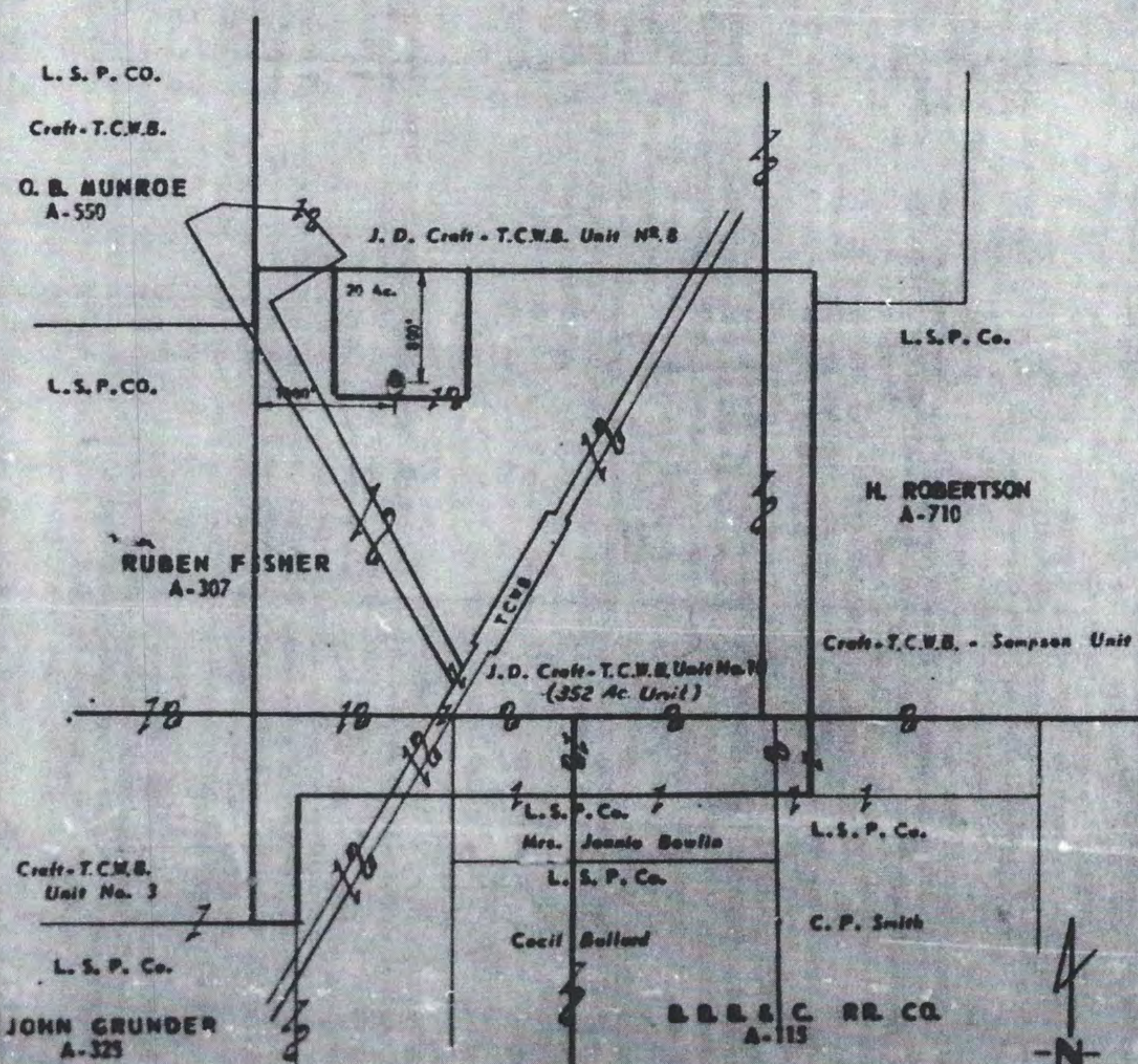
DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

NOV 13 1957

Registered Public Surveyor

Subscribed and sworn before me this the 20th day of Oct. 1957 A. D.

Notary Public, Dallas County, Texas



RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 17090

BKV BARNETT, LLC
1209 CR 1304
BRIDGEPORT, TX 76426

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated July 06, 2022, for the permitted interval(s) of the ELLENBURGER formation(s) and subject to the following terms and special conditions:

BARNETT RDC (00000) LEASE
NEWARK, EAST (BARNETT SHALE) FIELD
WISE COUNTY, DISTRICT 09

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
1	49700000	000125478	Carbon Dioxide (CO_2)	9,350	10,250		14,500		4,500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	49700000	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.** **2. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.** **3. Cement Bond Log (CBL):** **(A) A CBL must be run on the injection string casing. If the CBL does not verify adequate confinement of the injection/disposal interval, the operator must perform a remedial cement squeeze on the casing to achieve adequate confinement immediately above this interval. Adequate confinement is considered to be: annular height of 600 feet of cement based on cement volume calculations; or 250 feet of cement verified by a temperature survey conducted at the time of cementing; or 100 feet of cement verified by a cement bond log that shows the cement is well bonded to the pipe and formation (80% bond or higher) with no indication of channeling.** **(B) The operator must notify and receive approval from the RRC district office prior to performing any remedial cementing work. All cementing work must be appropriately reported on a completion report pursuant to Statewide Rule 16(b). Any CBL run on the well must be submitted. Please use the RRC Digital Well Log submission system to submit the CBL. A copy of any Forms W-15 must also be included with the next Form H-5 for this well.** **4. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.** **5. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.** **6. The operator must notify the Injection-Storage Permits Unit (UIC) and District Office of any event that may have jeopardized the mechanical and/or hydraulic integrity of any segment of the processing, injection, or storage components of the permitted facility.** **7. NOTE: Per operator email dated on July 05, 2022, the CO2 will be from the Bridgeport Processing Plant operated by Enlink Midstream.** **8. An annual annulus pressure test must be performed, and the test results submitted in accordance with the instructions of Form H-5.** **9. The tubing-casing annulus pressure must be monitored at least weekly and reported annually on Form H-10 to the Commission's Austin Offices.**

Note: This document will only be distributed electronically.

		10. Bottomhole Pressure (BHP) Test: 5 Year Lifetime **(A) Operator shall perform an initial static BHP test to quantify reservoir pressure prior to injection into the permitted formation(s).** **(B) Operator shall conduct a BHP test at least once every five (5) years from the date of the test in (A) above and provide the Commission an opportunity to witness the test as stated in (D) below. The analysis of the BHP test shall be provided under the supervision, seal, and signature of a registered professional engineer in Texas. The test analysis shall be filed with the Injection-Storage Permits Unit (UIC) within 30 days of completion of the BHP test.** **(C) Measurement for the BHP test shall be performed via wireline tool(s), or other Commission approved bottom hole pressure measurement technique.** **(D) Operator must notify the District Office 48 hours in advance of the test in order to provide opportunity for the RRC field inspector to witness the test. Operator shall provide raw data from the test to UIC within 48 hours of completing the test.** **11. NOTE: Per operator email dated on July 05, 2022, the CO2 will be from the Bridgeport Processing Plant operated by Enlink Midstream.** **12. 8/26/2022 4. Fluid migration and pressure monitoring report:** **The operator must submit a report of monitoring data, including but not limited to pressure and temperature data, used to determine fluid migration from the disposal well and pressure increases in the reservoir. The report must include, at a minimum, all monitoring data recorded since the last report (or since data recording began for the first report) through the date 30 days before the MIT is due and a summary analysis of the data. The summary analysis must include data trends and anomalies and any likely explanation for those trends or anomalies, for example, any significant operational events. The operator must submit the report with the Mechanical Integrity Test (MIT) filing to the Disposal/Injection Well Pressure Test (H-5) online system.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
    a. running tubing and setting packer.
    b. beginning any work over or remedial operation.
    c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500

Note: This document will only be distributed electronically.

psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON September 08, 2022.

Scott Rosenquist
(for)

Sean Avitt, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

Railroad Commission of Texas

PERMIT TO DRILL, RE-COMPLETE, OR RE-ENTER ON REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

CONDITIONS AND INSTRUCTIONS

Permit Invalidation. It is the operator's responsibility to make sure that the permitted location complies with Commission density and spacing rules in effect on the spud date. The permit becomes invalid automatically if, because of a field rule change or the drilling of another well, the stated location is not in compliance with Commission field rules on the spud date. If this occurs, application for an exception to Statewide Rules 37 and 38 must be made and a special permit granted prior to spudding. Failure to do so may result in an allowable not being assigned and/or enforcement procedures being initiated.

Notice Requirements. Per H.B 630, signed May 8, 2007, the operator is required to provide notice to the surface owner no later than the 15th business day after the Commission issues a permit to drill. Please refer to subchapter Q Sec. 91.751-91.755 of the Texas Natural Resources Code for applicability.

Permit expiration. This permit expires two (2) years from the date of issuance shown on the original permit. The permit period will not be extended.

Drilling Permit Number. The drilling permit number shown on the permit MUST be given as a reference with any notification to the district (see below), correspondence, or application concerning this permit.

Rule 37 Exception Permits. This Statewide Rule 37 exception permit is granted under either provision Rule 37 (h)(2)(A) or 37(h)(2)(B). Be advised that a permit granted under Rule 37(h)(2)(A), notice of application, is subject to the General Rules of Practice and Procedures and if a protest is received under Section 1.3, “Filing of Documents,” and/or Section 1.4, “Computation of Time,” the permit may be deemed invalid.

Before Drilling

Fresh Water Sand Protection. The operator must set and cement sufficient surface casing to protect all usable-quality water, as defined by the Railroad Commission of Texas (RRC) Groundwater Advisory Unit (GWAU). Before drilling a well, the operator must obtain a letter from the Railroad Commission of Texas stating the depth to which water needs protection, Write: Railroad Commission of Texas, Groundwater Advisory Unit (GWAU), P.O. Box 12967, Austin, TX 78711-3087. File a copy of the letter with the appropriate district office.

Accessing the Well Site. If an OPERATOR, well equipment TRANSPORTER or WELL service provider must access the well site from a roadway on the state highway system (Interstate, U.S. Highway, State Highway, Farm-to-Market Road, Ranch-to-Market Road, etc.), an access permit is required from TxDOT. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

Water Transport to Well Site. If an operator intends to transport water to the well site through a temporary pipeline laid above ground on the state’s right-of-way, an additional TxDOT permit is required. Permit applications are submitted to the respective TxDOT Area Office serving the county where the well is located.

*NOTIFICATION

The operator is **REQUIRED** to notify the district office when setting surface casing, intermediate casing, and production casing, or when plugging a dry hole. The district office **MUST** also be notified if the operator intends to re-enter a plugged well or re-complete a well into a different regulatory field. Time requirements are given below. The drilling permit number **MUST** be given with such notifications.

During Drilling

Permit at Drilling Site. A copy of the Form W-1 Drilling Permit Application, the location plat, a copy of Statewide Rule 13 alternate surface casing setting depth approval from the district office, if applicable, and this drilling permit must be kept at the permitted well site throughout drilling operations.

***Notification of Setting Casing.** The operator MUST call in notification to the appropriate district office (phone number shown the on permit) a minimum of eight (8) hours prior to the setting of surface casing, intermediate casing, AND production casing. The individual giving notification MUST be able to advise the district office of the drilling permit number.

***Notification of Re-completion/Re-entry.** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of eight (8) hours prior to the initiation of drilling or re-completion operations. The individual giving notification MUST be able to advise the district office of the drilling permit number.

Completion and Plugging Reports

Hydraulic Fracture Stimulation using Diesel Fuel: Most operators in Texas do not use diesel fuel in hydraulic fracturing fluids. Section 322 of the Energy Policy Act of 2005 amended the Underground Injection Control (UIC) portion of the federal Safe Drinking Water Act (42 USC 300h(d)) to define "underground Injection" to *EXCLUDE* " ...the underground injection of fluids or propping agents (*other than diesel fuels*) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities." (italic and underlining added.) Therefore, hydraulic fracturing may be subject to regulation under the federal UIC regulations if diesel fuel is injected or used as a propping agent. EPA defined "diesel fuel" using the following five (5) Chemical Abstract Service numbers: 68334-30-5 Primary Name: Fuels, diesel; 68476-34-6 Primary Name: Fuels, diesel, No. 2; 68476-30-2 Primary Name: Fuel oil No. 2; 68476-31-3 Primary Name: Fuel oil, No. 4; and 8008-20-6 Primary Name: Kerosene. As a result, an injection well permit would be required before performing hydraulic fracture stimulation using diesel fuel as defined by EPA on any well in Texas. Hydraulic fracture stimulation using diesel fuel as defined by EPA on a well in Texas without an injection well permit could result in enforcement action.

Producing Well. Statewide Rule 16 states that the operator of a well shall file with the Commission the appropriate completion report within ninety (90) days after completion of the well or within one hundred and fifty (150) days after the date on which the drilling operation is completed, whichever is earlier. Completion of the well in a field authorized by this permit voids the permit for all other fields included in the permit unless the operator indicates on the initial completion report that the well is to be a dual or multiple completion and promptly submits an application for multiple completion. All zones are required to be completed before the expiration date on the existing permit. Statewide Rule 40(d) requires that upon successful completion of a well in the same reservoir as any other well previously assigned the same acreage, proration plats and P-15s or P-16s (if required) or a lease plat and P-16 must be submitted with no double assignment of acreage unless authorized by rule.

Dry or Noncommercial Hole. Statewide Rule 14(b)(2) prohibits suspension of operations on each dry or non-commercial well without plugging unless the hole is cased and the casing is cemented in compliance with Commission rules. If properly cased, Statewide Rule 14(b)(2) requires that plugging operations must begin within a period of one (1) year after drilling or operations have ceased. Plugging operations must proceed with due diligence until completed. An extension to the one-year plugging requirement may be granted under the provisions stated in Statewide Rule 14(b)(2).

Intention to Plug. The operator must file a Form W-3A (Notice of Intention to Plug and Abandon) with the district office at least five (5) days prior to beginning plugging operations. If, however, a drilling rig is already at work on location and ready to begin plugging operations, the district director or the director’s delegate may waive this requirement upon request, and verbally approve the proposed plugging procedures.

***Notification of Plugging a Dry Hole.** The operator MUST call in notification to the appropriate district office (phone number shown on permit) a minimum of four (4) hours prior to beginning plugging operations. The individual giving the notification MUST be able to advise the district office of the drilling permit number and all water protection depths for that location as stated in the Groundwater Advisory Unit letter.

DIRECT INQUIRIES TO: DRILLING PERMIT SECTION, OIL AND GAS DIVISION

PHONE
(512) 463-6751

MAIL:
PO Box 12967
Austin, Texas, 78711-2967

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

PERMIT TO DRILL, DEEPEN, PLUG BACK, OR RE-ENTER ON A REGULAR OR ADMINISTRATIVE EXCEPTION LOCATION

PERMIT NUMBER 886893	DATE PERMIT ISSUED OR AMENDED Jan 04, 2023	DISTRICT 09
API NUMBER 42-497-38108	FORM W-1 RECEIVED Dec 29, 2022	COUNTY WISE
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 40

OPERATOR 100589

BKV DCARBON VENTURES, LLC

1200 17TH STREET STE 2100
DENVER, CO 80202

NOTICE
This permit and any allowable assigned may be revoked if payment for fee(s) submitted to the Commission is not honored.
District Office Telephone No:
(940) 723-2153

LEASE NAME BARNETT RDC	WELL NUMBER 1
LOCATION 4.6 miles SW direction from BRIDEGEPORT	TOTAL DEPTH 10800

Section, Block and/or Survey

SECTION BLOCK ABSTRACT 583

SURVEY MC LANAHAN, J

DISTANCE TO SURVEY LINES 370 ft. E 178 ft. S	DISTANCE TO NEAREST LEASE LINE ft.
DISTANCE TO LEASE LINES 178 ft. S 370 ft. E	DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
NEWARK, EAST (BARNETT SHALE) BARNETT RDC	40.00	10,800	1 0	09

RESTRICTIONS: Do not use this well for injection/disposal/hydrocarbon storage purposes without approval by the Environmental Services section of the Railroad Commission, Austin, Texas office.

THE FOLLOWING RESTRICTIONS APPLY TO ALL FIELDS

This well shall be completed and produced in compliance with applicable special field or statewide spacing and density rules. If this well is to be used for brine mining, underground storage of liquid hydrocarbons in salt formations, or underground storage of gas in salt formations, a permit for that specific purpose must be obtained from Environmental Services prior to construction, including drilling, of the well in accordance with Statewide Rules 81, 95, and 97.

This well must comply to the new SWR 3.13 requirements concerning the isolation of any potential flow zones and zones with corrosive formation fluids. See approved permit for those formations that have been identified for the county in which you are drilling the well in.

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

SWR #13 Formation Data

WISE (497) County

Formation	Remarks	Geological Order	Effective Date
OVERCHARGED DISPOSAL ZONE	Chico area; 5 mi radius N. of FM 1810	1	12/17/2013
CANYON		2	12/17/2013
VALERA		3	12/17/2013
STRAWN	4300 in Boonesville Bend area	4	12/17/2013
OVERCHARGED DISPOSAL ZONE	Alvord area; 5 mi radius, hwy 287 SE of Alvord	5	12/17/2013
BRYSON SAND		6	12/17/2013
BRAZOS RIVER		7	12/17/2013
UNDETERMINED	gas producing zones	8	12/17/2013
CADDO		9	12/17/2013
ATOKA CONGLOMERATE		10	12/17/2013
BOONESVILLE BEND CONGL.		11	12/17/2013
MARBLE FALLS		12	12/17/2013
BARNETT SHALE		13	12/17/2013
MISSISSIPIAN		14	12/17/2013
VIOLA LIME		15	12/17/2013
ELLENBURGER		16	12/17/2013

The above list may not be all inclusive, and may also include formations that do not intersect all wellbores. The listing order of the Formation information reflects the general stratigraphic order and relative geologic age. This is a dynamic list subject to updates and revisions. It is the operator's responsibility to make sure that at the time of spudding the well the most current list is being referenced. Refer to the RRC website at the following address for the most recent information.
http://www.rrc.texas.gov/oil-gas/compliance-enforcement/rule-13-geologic-formation-info

API No. 42-497-38108

Drilling Permit # 886893

SWR Exception Case/Docket No.

RAILROAD COMMISSION OF TEXAS
OIL & GAS DIVISION

APPLICATION FOR PERMIT TO DRILL, RECOMPLETE, OR RE-ENTER

This facsimile W-1 was generated electronically from data submitted to the RRC.
A certification of the automated data is available in the RRC's Austin office.

FORM W-1 07/2004

Permit Status: Approved

1. RRC Operator No. 100589
2. Operator's Name (as shown on form P-5, Organization Report) BKV DCARBON VENTURES, LLC
3. Operator Address (include street, city, state, zip): 1200 17TH STREET STE 2100 DENVER, CO 80202
4. Lease Name BARNETT RDC
5. Well No. 1

GENERAL INFORMATION

6. Purpose of filing (mark ALL appropriate boxes): [X] New Drill [ ] Recompletion [ ] Reclass [ ] Field Transfer [ ] Re-Enter [ ] Amended [ ] Amended as Drilled (BHL) (Also File Form W-1D)

7. Wellbore Profile (mark ALL appropriate boxes): [X] Vertical [ ] Horizontal (Also File Form W-1H) [ ] Directional (Also File Form W-1D) [ ] Sidetrack

8. Total Depth 10800

9. Do you have the right to develop the minerals under any right-of-way ? [X] Yes [ ] No

10. Is this well subject to Statewide Rule 36 (hydrogen sulfide area)? [ ] Yes [X] No

SURFACE LOCATION AND ACREAGE INFORMATION

11. RRC District No. 09
12. County WISE
13. Surface Location [X] Land [ ] Bay/Estuary [ ] Inland Waterway [ ] Offshore

14. This well is to be located 4.6 miles in a SW direction from Bridegeport which is the nearest town in the county of the well site.

15. Section
16. Block
17. Survey MC LANAHAN, J
18. Abstract No. A-583
19. Distance to nearest lease line: ft.
20. Number of contiguous acres in lease, pooled unit, or unitized tract: 40

21. Lease Perpendiculars: 178 ft from the S line and 370 ft from the E line.

22. Survey Perpendiculars: 370 ft from the E line and 178 ft from the S line.

23. Is this a pooled unit? [ ] Yes [X] No

24. Unitization Docket No:

25. Are you applying for Substandard Acreage Field? [ ] Yes (attach Form W-1A) [X] No

FIELD INFORMATION List all fields of anticipated completion including Wildcat. List one zone per line.

26. RRC District No.	27. Field No.	28. Field Name (exactly as shown in RRC records)	29. Well Type	30. Completion Depth	31. Distance to Nearest Well in this Reservoir	32. Number of Wells on this lease in this Reservoir
09	65280200	NEWARK, EAST (BARNETT SHALE)	Injection Well	10800	0.00	1

BOTTOMHOLE LOCATION INFORMATION is required for DIRECTIONAL, HORIZONTAL, AND AMENDED AS DRILLED PERMIT APPLICATIONS

Remarks

Certificate:

I certify that information stated in this application is true and complete, to the best of my knowledge.

Bill Spencer, Consultant — Name of filer

Dec 29, 2022 — Date submitted

(512)9181062, x2 — Phone

bill@spencerconsulting.org — E-mail Address (OPTIONAL)

RRC Use Only Data Validation Time Stamp: Jan 5, 2023 10:20 AM(Current Version)

Request for Additional Information: Barnett RDC Well No. 1
November 30, 2022

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

No.	MRV Plan		EPA Questions	Responses/responsible
	Section	Page		
1.	NA	NA	We recommend adding page numbers to the MRV plan.	Done
2.	NA	NA	We recommend adding a table of contents to the MRV plan.	Done
3.	NA	NA	There is an inconsistent use of thousand place separators throughout the MRV plan. We recommend ensuring that thousand place separators are consistent throughout the MRV plan. This should include all tables and figures.	Done

No.	MRV Plan		EPA Questions	Responses/responsible
	Section	Page		
4.	NA	NA	There is a lack of consistency with hyphens, bolding, quotation marks, spelling, and capitalization throughout the MRV plan. Examples include but are not limited to: Figure vs. **Figure** Muenster Arch vs. Muenster arch Subunit vs. subunit Subunit E vs. subunit 'C' vs. Unit 'C" Formation vs. formation Smye vs. Syme Smye et al. vs. Gao *et al.* Ellenburger vs. Ellenberger TXNET vs. TexNet We recommend reviewing the formatting in the MRV plan for consistency. Furthermore, we recommend doing an additional review of the entire plan for spelling, grammar, etc.	Done
5.	1	NA	"(API not yes assigned)" Should this read, "(API number not yet assigned)"?	API has been assigned and added to document
6.	1	NA	"The well is located approximately 4.6 miles SW of Bridgeport, TX **is Wise County…"** The above sentence is unclear. Please address.	Done
7.	1	NA	The legend in Figure 1 shows a white polygon that is supposed to represent the Proposed CCUS well site. However, the map itself does not clearly display this site. Please adjust Figure 1 so that this feature is better defined. In addition, please adjust the capitalization in "**tX**".	Updated.

No.	MRV Plan		EPA Questions	Responses/responsible
	Section	Page		
8.	1	NA	The MRV plan states that the Gas Plant Facility name is "Bridgeport Gas Processing Plant". However, it appears that a new facility "Barnett RDC Well No. 1" (Facility ID: 583361) has been created in conjunction with this MRV plan. Could you please clarify the relationship between these two facilities, and which ID number is applicable to this plan?	The Bridgeport Gas Processing Plant is current emitting CO2. The Barnett RDC #1 well will be disposing of CO2 emitted from the Bridgeport Gas Processing Plant.
9.	2	NA	"Currently reporting under **section** C, W, NN" We recommend changing the above to read, "Subpart C, W, NN".	Done
10.	3.1	NA	"Ordovician Viola limestone and Simpson formation **unconformity overly**…" Please clarify the wording in the above phrase.	Done
11.	3.2	NA	"As illustrated in Figure 1, the Fort Worth basin is bounding to the east by the Ouachita fold and thrust belt…" Figure 1 does not display these features. Please ensure that the correct figures are referenced throughout the MRV plan.	Done
12.	3.2.2	NA	"… well correlations because of its available log data and **injection** into the Ellenburger Group" The above sentence is unclear. Please address.	Done
13.	3.2.2	NA	The left map on Figure 3 is difficult to read. We recommend making this map larger.	Updated

No.	MRV Plan		EPA Questions	Responses/responsible
	Section	Page		
14.	3.3	NA	"However, there are no Barnett Shale wells in the **AOR** of the RDC #1" "AOR" is not defined in the MRV plan but is used several times. Please ensure that all acronyms are defined before first use in the MRV plan. If "AOR" is supposed to refer to the MMA, please adjust throughout the MRV plan.	Updated throughout document.
15.	3.6	NA	"… sandstones deposited as a part of the Perrin Delta System (Brown et al. **19731**)." It appears there is a typo in the reference above. Please address.	Done
16.	3.6	NA	"… according to **a Geological** survey…" Please specify the party that completed the geological survey.	Done
17.	3.6	NA	We recommend adding a marker to identify the location of the proposed injection well on Figure 10.	Done
18.	3.8	NA	There are two 3.8 sections. Please address.	Done
19.	3.8	NA	H_2S or acid gas is not mentioned in the MRV plan before this section. Please clarify in the MRV plan whether this is an acid gas injection project. Furthermore, we recommend including the H_2S percent in Table 6. Additionally, because H_2S monitors are listed as a leak detection tool, we recommend including the detection limit of the monitors.	Updated
20.	3.8	NA	Please review the legend of Figure 15 and adjust as necessary. For example, what does the blue outline on the figure indicate?	Done

No.	MRV Plan		EPA Questions	Responses/responsible
	Section	Page		
21.	3.8	NA	"**Figure6** illustrates the vertical…" Is this the correct referenced figure? Please address.	Figures updated
22.	3.8	NA	"Injection was modeled at 280 kilotonnes per annum (KTPA)." Please ensure that the MRV plan does not switch between metric and imperial units. This is also an issue in Figure 18.	Done
23.	3.8	NA	"…100 years of **post-injection to** determine…" It appears the above line may have a missing word. Please address.	Done
24.	4.1	NA	The sizes of the MMA and the plume described in the text of section 4.1 do not match what is seen in Figure 19. Please address.	Done
25.	4.2	NA	Per 40 CFR 98.449, "Active monitoring area" (AMA) is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas: (1) The area projected to contain the free phase CO2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile. (2) The area projected to contain the free phase CO2 plume at the end of year t + 5. Please ensure that the discussion in section 4.2 clearly describes how the AMA conforms to the definition of the AMA in 40 CFR 98.449 and how the delineation of the AMA in the MRV plan meets the requirements in 40 CFR 98.448(a)(1).	Done
26.	5.1	NA	"Any leaks that are detected will be analyzed for determine that amount of CO2 which may have leaked…" The above sentence is unclear. Please address.	Done

No.	MRV Plan		EPA Questions	Responses/responsible
	Section	Page		
27.	5.2	NA	"There no permitted but not drilled well within the AOR…" The above sentence is unclear. Please address.	Done
28. S	5.3	NA	"There are 20 existing wells within the AOR of this project Of these 20… It appears that the above section of text is missing a period. Please address.	Done
29.	5.3	NA	"These wells are represented relative to the project MMA in Figure 21." Although the well can be seen in Figure 21, the MMA is not present. Please either adjust the wording of this sentence or add the MMA to the Figure.	Done
30.	5.4	NA	Section 5.4 discusses 3D seismic interpretation. Did BKV interpret this seismic? If not, who did? Please clarify.	Done
31.	5.6	NA	Please expand the discussion on induced seismicity within this section. E.g., will the facility take operational precautions to reduce the risk of induced seismicity?	Done
32.	5.6	NA	"…TexNet (2017-present) **locate** no…" Please clarify the above phrasing.	Done
33.	6.1	NA	"…it will be transported approximately **6,800 feet** via pipeline…" This length differs from the previous length of 6,900 feet as given in section 3.8.	Done
34.	6.1	NA	"Gas samples **will occasionally** be taken to confirm…" Is there a consistent schedule with which gas samples will be taken?	Done

No.	MRV Plan		EPA Questions	Responses/responsible
	Section	Page		
35.	6.2	NA	"However, dCarbon will reverify the status and public information for all proposed and approved drilling permits within the MMA quarterly. If any wells are proposed, permitted, or drilled within the MMA, BKV will investigate the proposal and determine if any additional risks are introduced through the new well proposal." 40 CFR 98.448(d) and 40 CFR 98.448(d)(1) state that "…You must revise and submit the MRV plan within 180 days to the Administrator for approval if…" material changes occur such as "the construction of new injection wells not identified in the MRV plan". We recommend stating in the MRV plan that any new well construction or other material changes would result in a MRV plan resubmission.	Done
36.	6	NA	Sections 6.3, 6.4, and 6.5 do not discuss the quantification of CO2 leakage from these leakage pathways. Please include details on how CO2 leakage would be quantified from all leakage pathways. Additionally, Section 5.5 does not have a corresponding section on detecting and quantifying leakage through the confining layer. Please add such a section.	Done
37.	10.4	NA	"**Stakeholder** will use the following…" "Stakeholder" is not mentioned in the rest of the MRV plan. Please clarify.	Done
38.	10	NA	There are two sections labeled as "Section 10". Please address.	Done

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan

Barnett RDC #1

Wise County, Texas

Prepared by

BKV dCarbon Ventures, LLC

Version 1.0

November 8, 2022

Section 1 – Introduction

BKV dCarbon Ventures, LLC ("dCarbon") is currently authorized to inject a total of up to 14.5 million standard cubic feet per day (MMscfd), which is equivalent to approximately 280,000 metric tons (MT) per year, of Carbon Dioxide (CO_2) in the RDC #1 well (API not yet assigned) under the Texas Railroad Commission (TRRC). The permit allows injection into the Ellenburger formation at a depth of 9,350 feet to 10,250 feet with a maximum allowable surface pressure of 4500 pounds per square inch gauge (psig).

The well is located approximately 4.6 miles SW of Bridgeport, TX is Wise County (**Figure 1**).

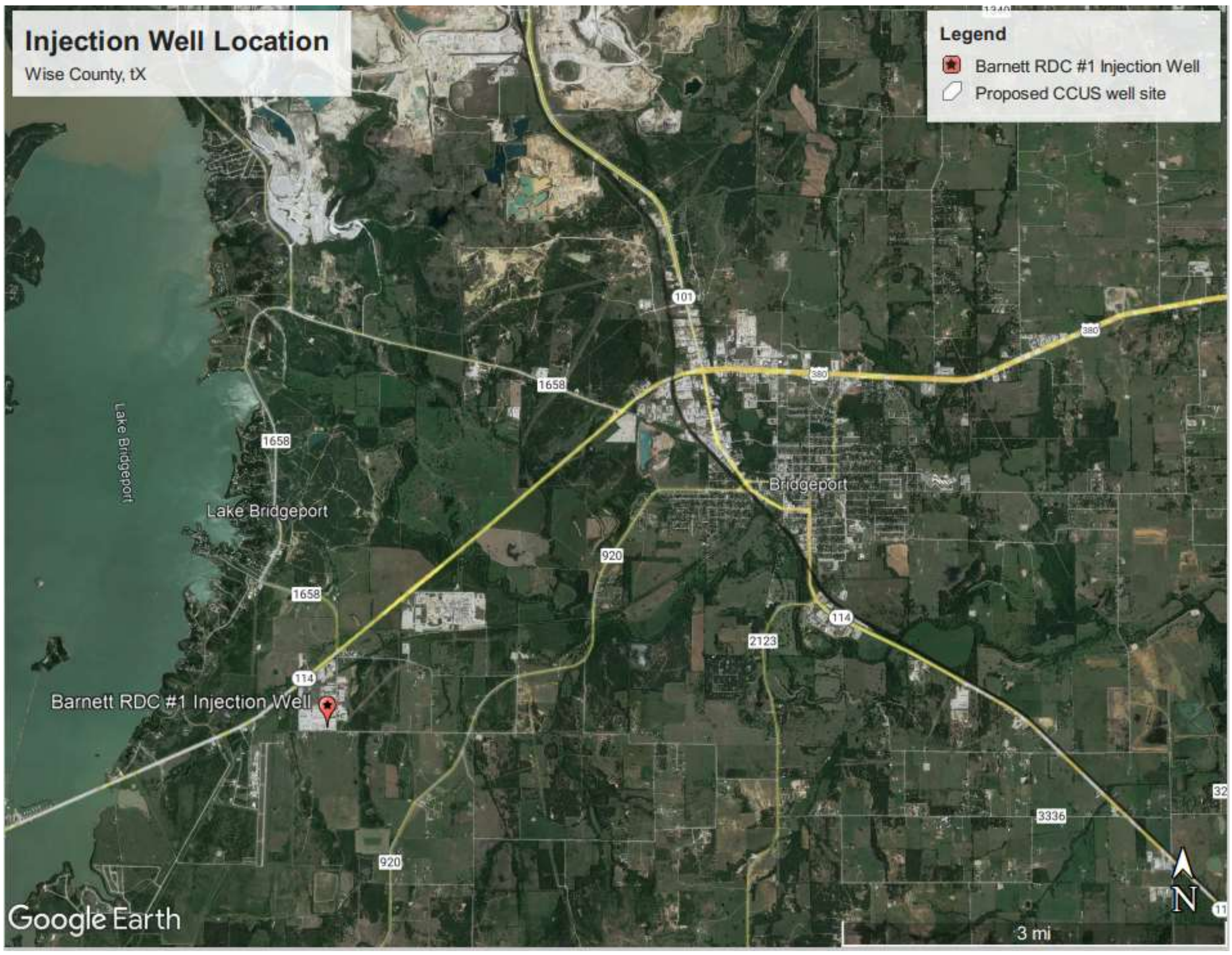


Figure 1. Location of the Barnett RDC # 1 well

The RDC #1 has an approved W-14 injection Permit with the TRRC (Permit No 17090, UIC Number 000125478). The drilling permit is pending with the TRRC. Additionally, dCarbon plans to drill the well in early 2023 and complete the well in mid-2023 and begin injection operations in late 2023. A copy of the approved W-14 permit is included as Attachment A. Although, dCarbon currently plans to initially inject approximately 180,000 MT/yr CO_2 into the well, all calculations in this document have been performed with the maximum injection amount allowed on the TRRC permit (280,000 MT/yr). dCarbon plans to inject for approximately 12 years.

dCarbon is submitting this Monitoring, Reporting, and Verification ("MRV") plan to the EPA for approval under 40 CFR §98.440(a), Subpart RR, of the Greenhouse Gas Reporting Program ("GHGRP").

BKV dCarbon Ventures TRRC operator number is 100589

BKV dCarbon Ventures' EPA number is 110071343305

Section 2 – Facility Information

Gas Plant Facility Name: BRIDGEPORT GAS PROCESSING PLANT

415 PRIVATE RD, 3502

BRIDGEPORT, TX, 76426

Latitude: 33° 11.74' N

Longitude: 97° 48.22' W

GHGRP Id: 1006373

FRS Id: 110028052354

NAICS Code: 211130

Currently reporting under section C, W, NN

Underground Injection Control (UIC) Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control ("UIC") Class II program. TRRC classifies the Barnett RDC #1 well as a UIC Class II well. A Class II permit was issued in accordance to Statewide Rule 9 to BKV.

UIC Well Identification Number

Barnett RDC #1, API# (not yet assigned), UIC# 000125478

Section 3 – Project Description

This Project Description discusses the geologic setting, planned injection volumes and process, and the reservoir modeling performed for the proposed BKV dCarbon Ventures RDC #1 Class II injection well. dCarbon prepared this MRV plan to support the storage of CO_2 from gas processing facilities in Wise County, Texas.

3.1. Overview of Geology

The proposed injection site lies in western Wise County, where the Barnett Shale, Viola/Simpson, and Ellenburger formations dip and thicken to the east toward the Muenster Arch as seen in the west to east cross section of **Figure 2**. Similarly, the north to south cross section shows the Ellenberger and overlying formations dipping to the north. One inference from this is that any CO_2 injected at the area of interest (AOI) may exhibit the tendency to move up dip due to buoyancy, meaning the anticipated plume movement will be west. This is further represented in the structure contour map of the Ellenburger formation top by Polastro (2007) in **Figure 2**.

The Fort Worth basin sedimentary succession begins with locally abundant Cambrian clastics in the southern section of the basin that unconformably overly the uneven Precambrian basement. The overlying Ordovician age Ellenburger platform carbonates were deposited on a passive margin and contain thicknesses up to 4,000 feet in the Fort Worth Basin. The Ellenberger platform carbonates underwent multiple episodes of regional exposure causing dolomitization and karsting in several units of the Ellenburger. Ordovician Viola limestone and Simpson formation unconformity overly the Ellenburger formation and are found in the northern section of the basin near the Muenster Arch. A major erosive interval occurred during the Mississippian eroding down to the Ordovician formations and was followed by deposition of the Barnett Shale that unconformably overlies the Viola limestone, Simpson formation, and the Ellenberger group (Gao et al., 2021). Overlying the Barnett Shale is a a thick section of mostly Pennsylvanian and Permian carbonates and clastics (Bend, Strawn, and Canyon Groups). **Figure 2** indicates the general regional stratigraphy. While there are multiple storage-confining unit systems that could be evaluated for injection, focus was on Mississippian-Ordovician section that consists of the Barnett shale and the carbonate Ellenburger group. The Ellenburger group directly overlies the basement rock and is considered the main reservoir target.

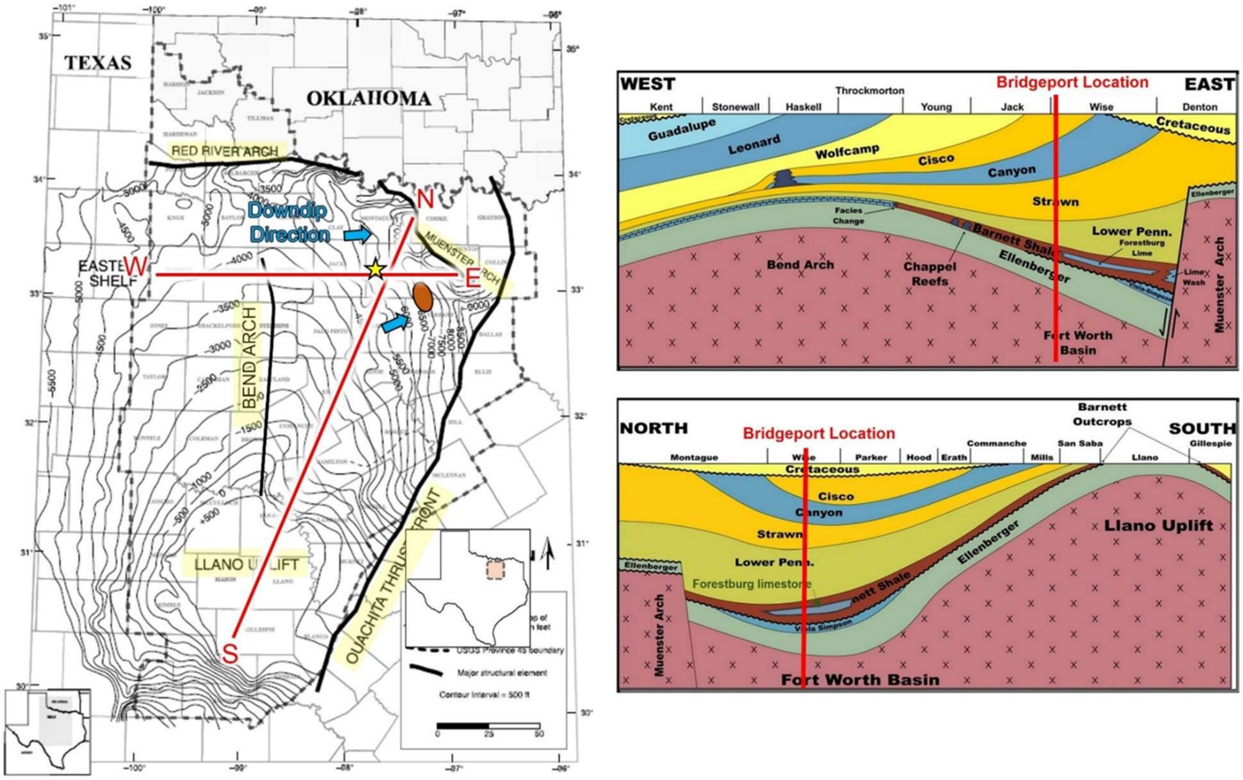


Figure 2. (Left) Ellenberger structural contour map modified from Jarvi and Hill (2007) showing the regional structures within and bounding the Fort Worth Basin, Ellenberger structure contours with respect to the final BKV AOI (yellow star). (Right) Cross sections E-W and N-S show the regional dip of the sedimentary units in the Fort Worth Basin.

3.2. Bedrock Geology

3.2.1. Basin Description

The Fort Worth basin is a flexural basin that formed in the foreland of the advancing Ouachita orogenic belt during the Late Mississippian through Pennsylvanian epochs (Horne, et al. 2020). As illustrated in Figure 1, the Fort Worth basin is bounded to the east by the Ouachita fold and thrust belt and to the north by the Muenster arch and Red River arch. These arches are characterized by a series of high angle reverse faults. The basin is deepest to the northeast, with as much as ~12,000 feet of sediment infill, where the Ouachita thrust front meets the Muenster arch and is shallowest towards the south.

System	Series	Stage	Group or Formation	
Cretaceous	Lower	Comanchean	Trinity Group	
Pennsylvanian	Upper	Missourian	Canyon Group	Jasper Creek Formation
	Middle	Desmonesian	Strawn Group	Willow Point Formation
				Lone Camp Formation
				Millsap Lake Formation
			Kickapoo Group	Ratville Formation
				Parks Formation
				Caddo Pool Formation
		Atokan	Bend Group	Caddo Formation
				Smithwick Shale
	Lower			Pregnant Shale
				Big Saline Formation
		Morrowan		Marble Falls Limestone
				Comyn Formation
Mississippian	Chesterian – Meramecian			
			Barnett	Upper Barnett Shale
				Forestberg Limestone
	Osagean			Lower Barnett Shale
Ordovician	Lower		Ellenburger Group	
Precambrian			Basement	

Table 1. Regional stratigraphy at BKV site in north Texas.

3.2.2 Stratigraphy

Well locations and digital logs for the region were provided by dCarbon. Several wells were included that penetrate deep into the Ellenburger and were used to develop well ties and stratigraphic correlations for a better understanding of the regional stratigraphy. The

W.S. Coleman #2 (4249735807) well, the closest well with appropriate porosity logs through the proposed injection interval, 5.4 miles east of the proposed RDC #1 injection well, was used to calculate reservoir zone properties for individual subunits within the Ellenburger formation since currently no well exists at the proposed site. This data will be updated once the proposed well is logged. The North Tarrant SWD 1 well, located approximately 27 miles to the southeast was also used in well correlations because of its available log data and injection into the Ellenburger Group. The Ellenburger contains alternating limestone and dolomite lithologies, consistent with regional descriptions of the Ellenberger. Vertical changes in properties throughout the Ellenburger were used to divide the unit into 8 subunits (A-G), in agreement with a similar approach demonstrated by Smye et al. (2019). The main target storage reservoir, subunit E, was identified based on dominant lithology, gross and net reservoir thicknesses, porosity values, and permeability values. In tandem, the Ellenburger subunit ‘B’ and the stratigraphic top portion of Ellenburger subunit ‘C’ were identified as a potential storage caprock. Below this interval, there are baffles of tighter limestone throughout Ellenburger subunits ‘C’, ‘C2’, and ‘D’ that would also act as sealing units to the storage reservoir.

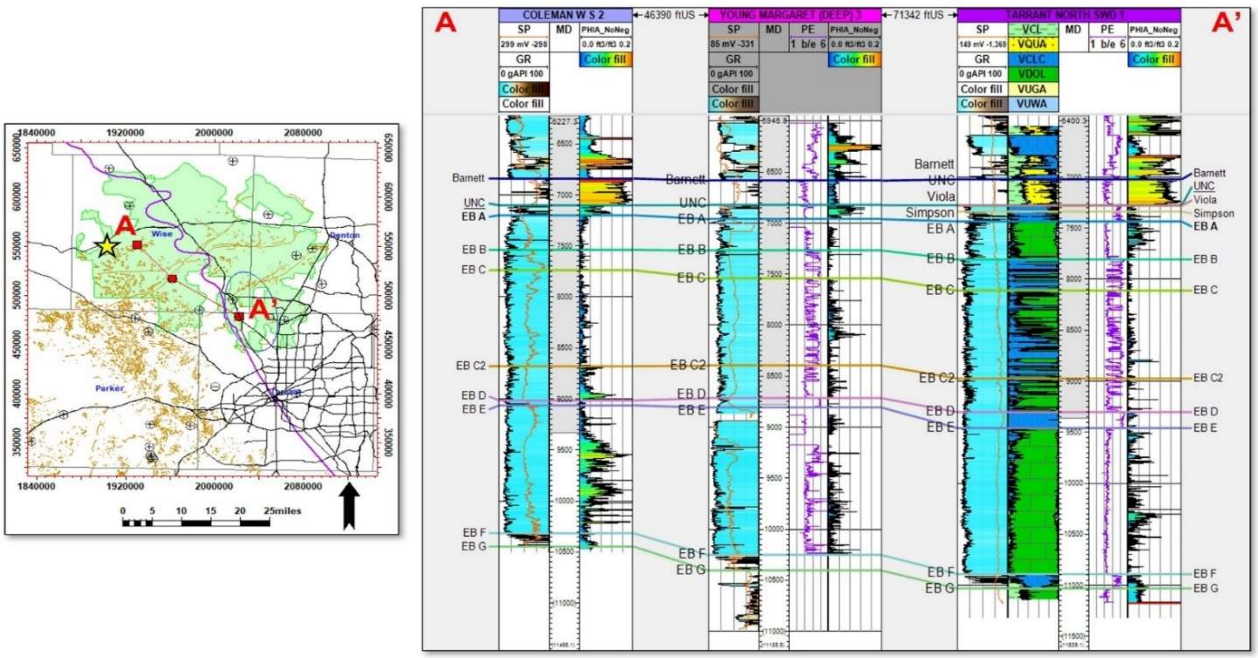


Figure 3. (Left) Map of Wise County with the BKV AOI (yellow star), Viola/Simpson formation extent (purple line), roads (black lines), faults and other structures (brown lines), wells penetrating the Ellenberger with log data (black circles), BKV 3D seismic extent (green polygon), and a NW-SW cross section. (Right) Cross section showing Gamma Ray (GR), Spontaneous Potential (SP), Photo Electric Factor (PE), and average porosity (PHIA) from the Tarrant SWD well to the Coleman WS 2 well. Ellenberger Unit C (EB C) is the primary caprock and Ellenberger Unit E (EB E) is the primary reservoir unit.

Dominant lithologies were determined by comparing the photoelectric factor (PEFZ) log curve with the volume of clay (VCL), sand (VQUA), lime (VCLC), dolomite (VDOL), gas (VUGA), and free water (VUWA) curves in the Tarrant well, as well as the separation of the density and neutron porosity curves. Gross reservoir thickness was determined for each Ellenburger subunit by adding the footage from the top to the bottom of the formation.

Figure 3 shows the correlation of the North Tarrant SWD 1 well up to the proposed RDC #1 site. As an initial observation, units ‘C’ and ‘E’ within the Ellenburger were present and appear to be contiguous in the project area. Unit ‘C” thickness is approximately 750 feet while unit ‘E’ thickness varies across the cross sections. It is estimated there is at least 940 feet of unit ‘C’ at the RDC #1 proposed site location with 1,250 feet of Ellenburger ‘E’. The cross sections confirm regional trends in dip also apply to the AOI wherein the reservoir unit slightly dips down to the north and east.

3.2.3 Faulting

Faults within the Fort Worth basin are generally northeast-trending, high-angle normal faults where most of the faults root into the Precambrian crystalline basement (**Figure 4**). The mechanism for deformation that produced these faults has been attributed to flexure generated by the Ouachita orogenic belt. Deep seated faults that root into the Precambrian crystalline basement generally terminate in the Pennsylvanian age strata and do not continue into the overlying Cretaceous strata, where it is present, suggesting that faults have not experienced significant movement since their formation (Horne et al. 2020). Karsting in the region has resulted in small-scale, concentric faults that originate from the collapse of karst features predominantly within the Ellenburger group.

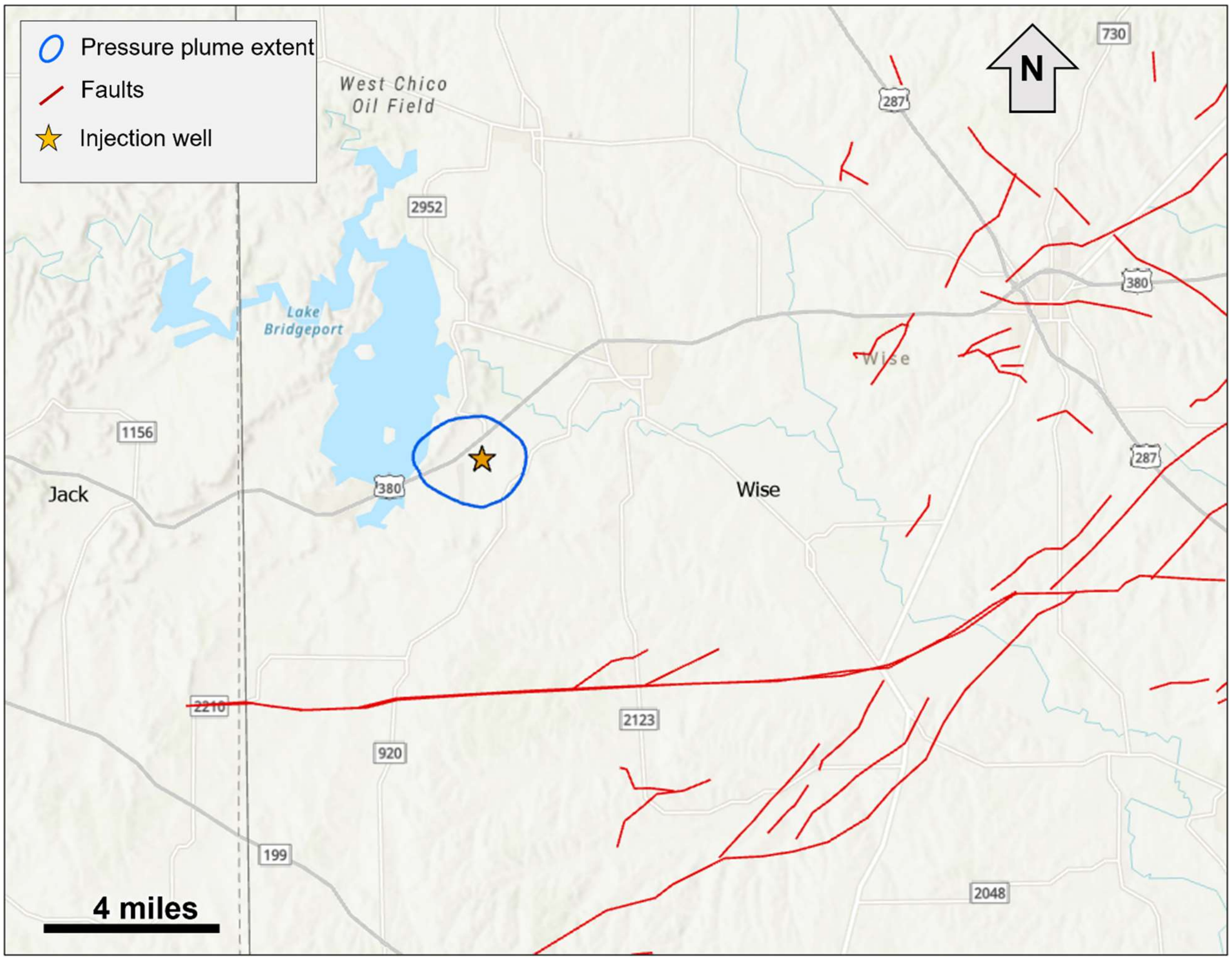


Figure 4. Mapped faults near the proposed injection well from Wood, Victoria, "Reservoir Characterization and Depositional System of the Atokan Grant Sand, Fort Worth Basin, Texas" (2015).Theses and Dissertations. 1392. .

3.3 Lithological and Reservoir Characterizations

Syme et al. (2019) provided a detailed description of regional stratigraphy as well as petrophysical attributes of multiple units within the Ellenburger group. Prior to understanding the petrophysical properties of these sub-units and assessing their storage reservoir or confining layer potential, it is important to understand the overall lithology. Literature suggests the Ellenburger interval is mostly composed of calcite, dolomite, quartz, and clay. Syme et al. (2019) noted that the carbonate intervals were mostly clean with less than 10% clay by volume. However, the top of the Ordovician section was shown to have an increased clay content (about 40% by volume). This also coincided with an increase in siliciclastic materials (quartz and clay). Porosity in clean carbonate intervals is approximately 5% while that in siliciclastic intervals may reach 20%. The basement lithology was identified as granite wash with hematite contents ranging between 5-10% by volume. **Figure 5** shows the general stratigraphy in the AOI as noted by Syme et al. (2019).

Lithological characterization was focused specifically on the red dotted area shown in this figure in order to better understand local stratigraphy and petrophysics. The Viola Formation and Simpson Group are listed here overlying the Ellenburger A sub-unit, however these units pinch out to the east of the proposed RDC #1 site and are thus not included in subsequent petrophysical analysis.

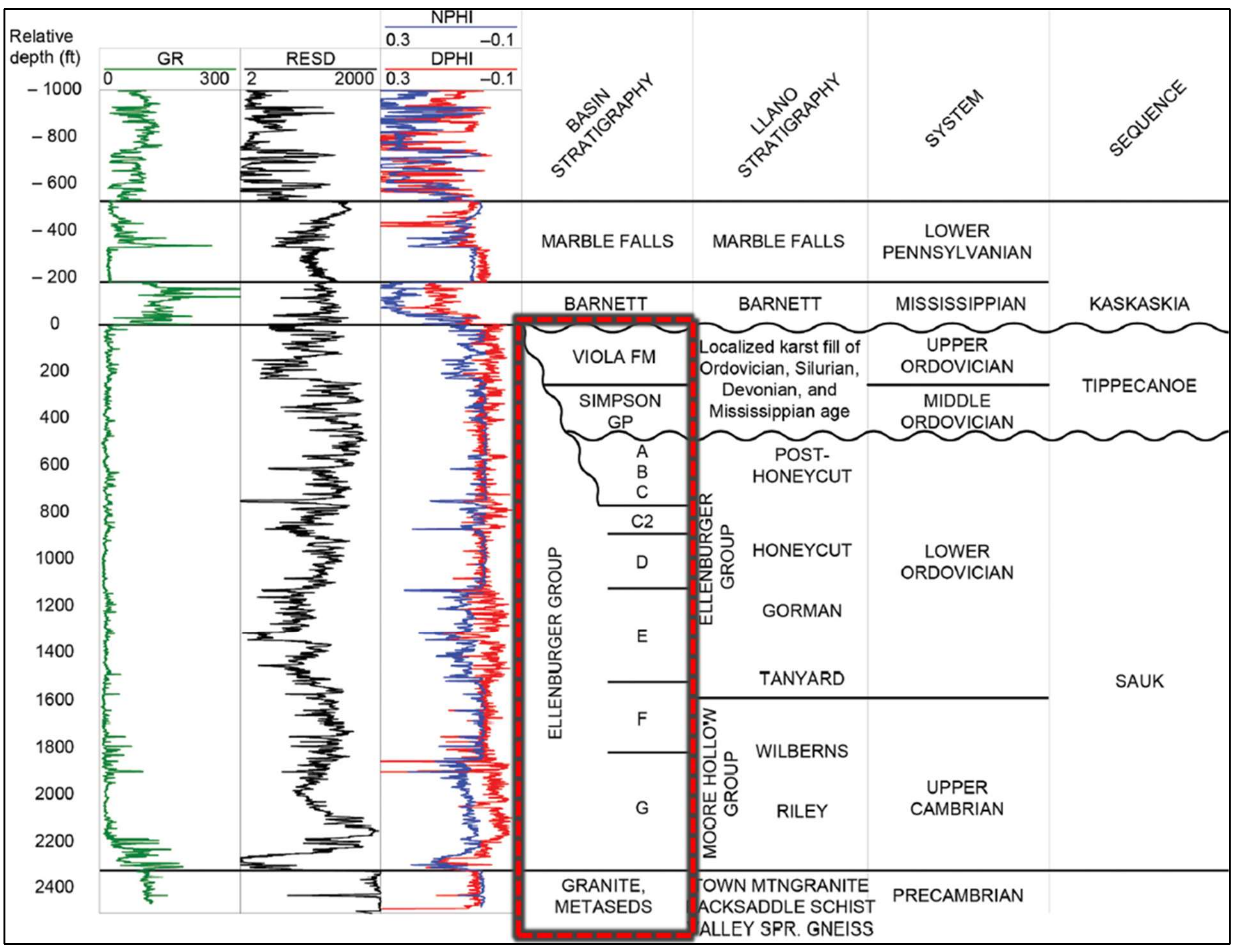


Figure 5. Regional stratigraphy at BKV site in North Texas (modified from Syme et al., 2011).

The Barnett shale is anticipated to serve as a confining layer. The Barnett shale is a source rock which is extensively drilled in the Fort Worth Basin. However, there are no Barnett Shale wells in the AOR of the RDC #1. The porosities and permeabilities in the Barnett lie in the 4-6% and 7-50 nanodarcies range, respectively. Underlying the Barnett is the Ellenburger Group, which is the anticipated injection interval. The Ellenburger could be divided into eight lithostratigraphic units starting with unit ‘A’ at the top to unit ‘G’ at the bottom which sits on top of the crystalline basement. Unit ‘G’ is composed of siliciclastic facies and is largely variable across the region. Though the porosity in unit ‘G’ is higher compared to other subunits, lateral continuity might be an issue in developing a storage project in this unit. Consequently, unit ‘E’ will serve as a potential reservoir given it has ~4% matrix porosity. Ellenburger ‘E’ is a clean dolomitic reservoir zone with 49% dolomite by volume. Unit ‘B’ and unit ‘C’ were found to have lower matrix porosities compared to unit ‘E’, which implies these subunits could provide vertical confinement or impediment to CO_2 movement. Ellenburger ‘A’ has been proven to be a reservoir zone with multiple saltwater disposal wells completed in unit ‘A’. However, as mentioned earlier, karsting features at the top of the Ellenburger imply there is some potential for hydraulic communication between unit ‘A’ and the overlying Barnett. **Figure 6** illustrates the log response and petrophysical properties of Ellenburger subunits.

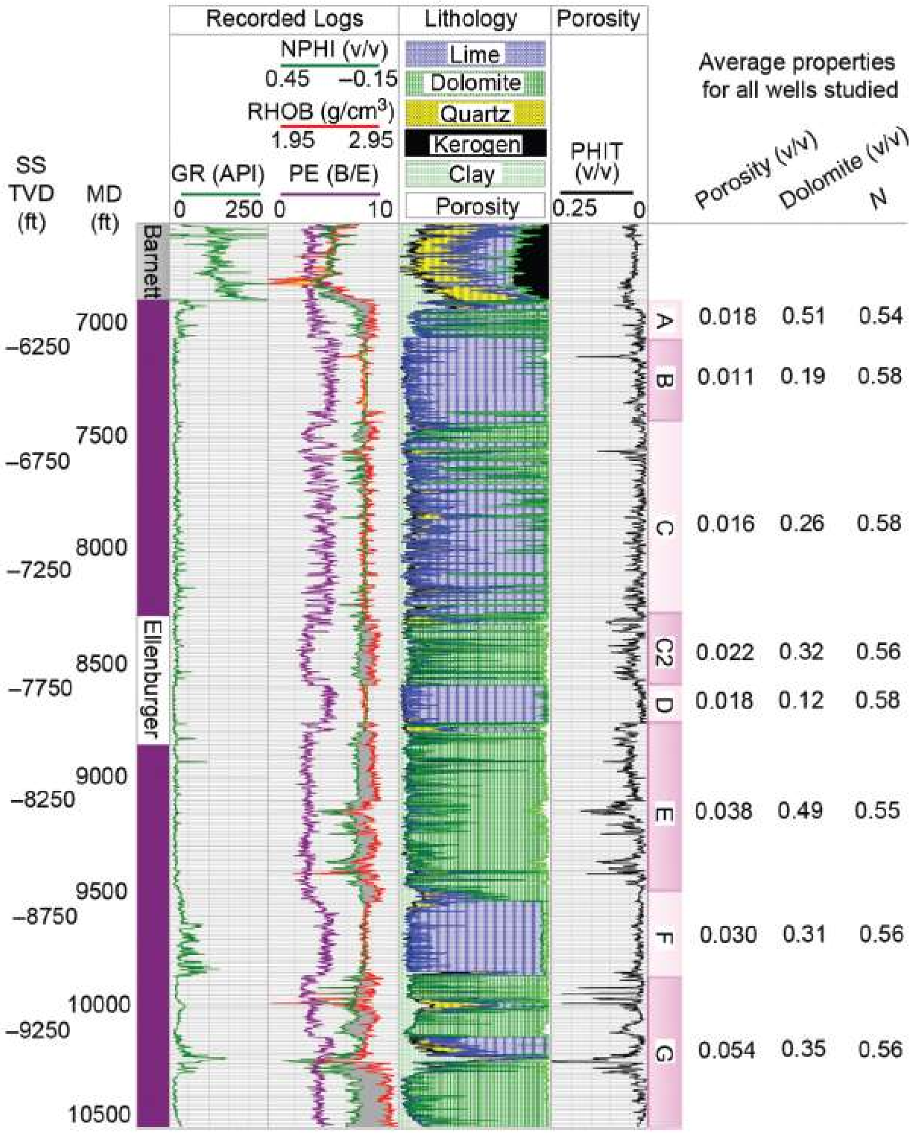


Figure 6. Properties of Ellenburger subunits in the project area (modified from Syme et al. (2019).

The W.S. Coleman #2 injection well located ~5 miles from the proposed injection site similarly contains Ellenburger units A through G, as shown below in **Figure 7**. Drilling at the proposed site will result in site specific petrophysical properties like those shown here and in previous figures.

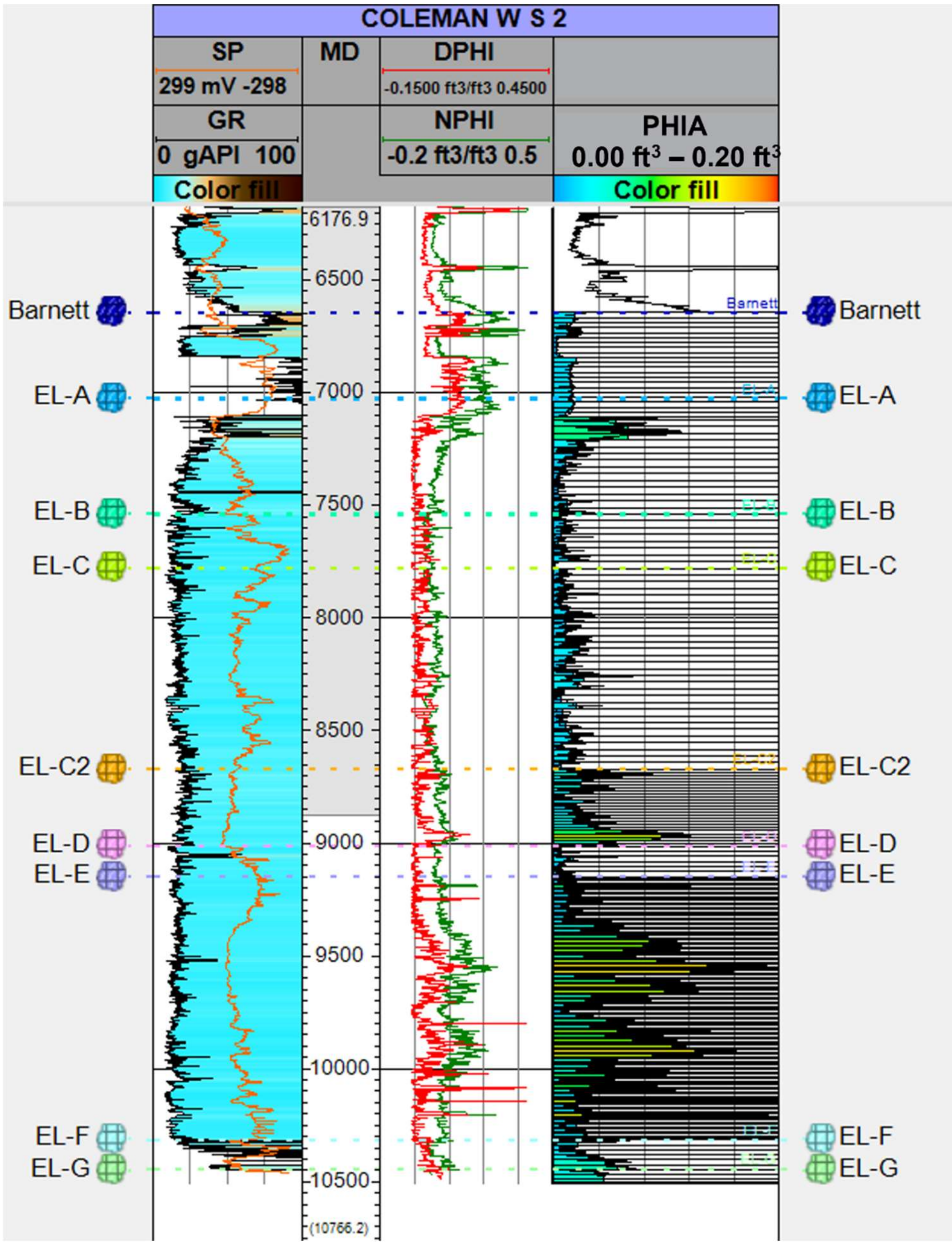


Figure 7. W.S. Coleman #2 well log interpretation; Ellenburger Group units A through G are denoted to the right and left of the log image.

Net reservoir thickness was determined for each subunit of the Ellenburger by summing the footage where the average porosity (PHIA) curve was greater than 2%. It is important to note that such a low matrix porosity value was chosen due to the nature of the reservoir wherein fracture porosity is a significant contributor to reservoir quality. Our understanding and evaluation of the Ellenburger suggested a low log porosity could still result in realizable CO_2 storage potential given the history of injectivity from saltwater disposal in the area (e.g. North Tarrant SWD 1 and W.S. Coleman #2 wells). A net to gross ratio was determined for each sub-unit by dividing the net reservoir thickness by the gross reservoir thickness. Average net reservoir porosity was calculated for each sub-unit of the Ellenburger by averaging the net reservoir average porosity (PHIA) curve from the top to the bottom of the sub-unit. These reservoir zone properties were subsequently used to derive preliminary resource estimates. **Table 2** lists average petrophysical properties in the Ellenburger.

Table 2. Ellenberger properties assessed at the AOI.

Ellenburger Subunit	Dominant Lithology	Gross Reservoir Thickness (feet)	Net Reservoir Thickness (feet [>2% PHI])	Net to Gross Ratio	Average Reservoir Porosity (%)
A	Dolomite	338	63	0.186	1.1
B	Limestone	200	14	0.07	0.8
C	Limestone	940	187	0.198	1.2
C2	Dolomite	335	229	0.683	3.5
D	Limestone	49	3.5	0.072	0.6
E	Dolomite	1252	879	0.702	5.5
F	Limestone	130	88.5	0.677	3.2
G	Dolomite	NA	NA	NA	NA

Permeability data in individual Ellenburger units was obtained from literature (Gao et al., 2021).

Other crucial reservoir properties such as pressure and geothermal gradients were obtained from data discussed in Gao et al. (2021). Pressure gradient in the Ellenburger was noted to be 0.47 psi/foot while the geothermal gradient in the Fort Worth basin was estimated at 1.4°F/100 feet. These parameters were used to run preliminary CO_2 storage calculations as discussed in the subsequent section.

3.4 Formation Fluid Chemistry

Nine wells were identified through a review of chemical analyses of oil-field brines from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3 within the Pennsylvanian age strata that are located within 20 miles of the proposed injection well site as shown in **Figure 8**. Formation fluid chemistry analyses for these wells is reported in **Table 3**.

Table 3. Pennsylvanian formation fluid chemistry.

	TDS (mg/L)	pH	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	86807	6	26000	5494	53392
LOW	21926	4.4	6291	978	13389
HIGH	149480	7.1	47203	9854	91765

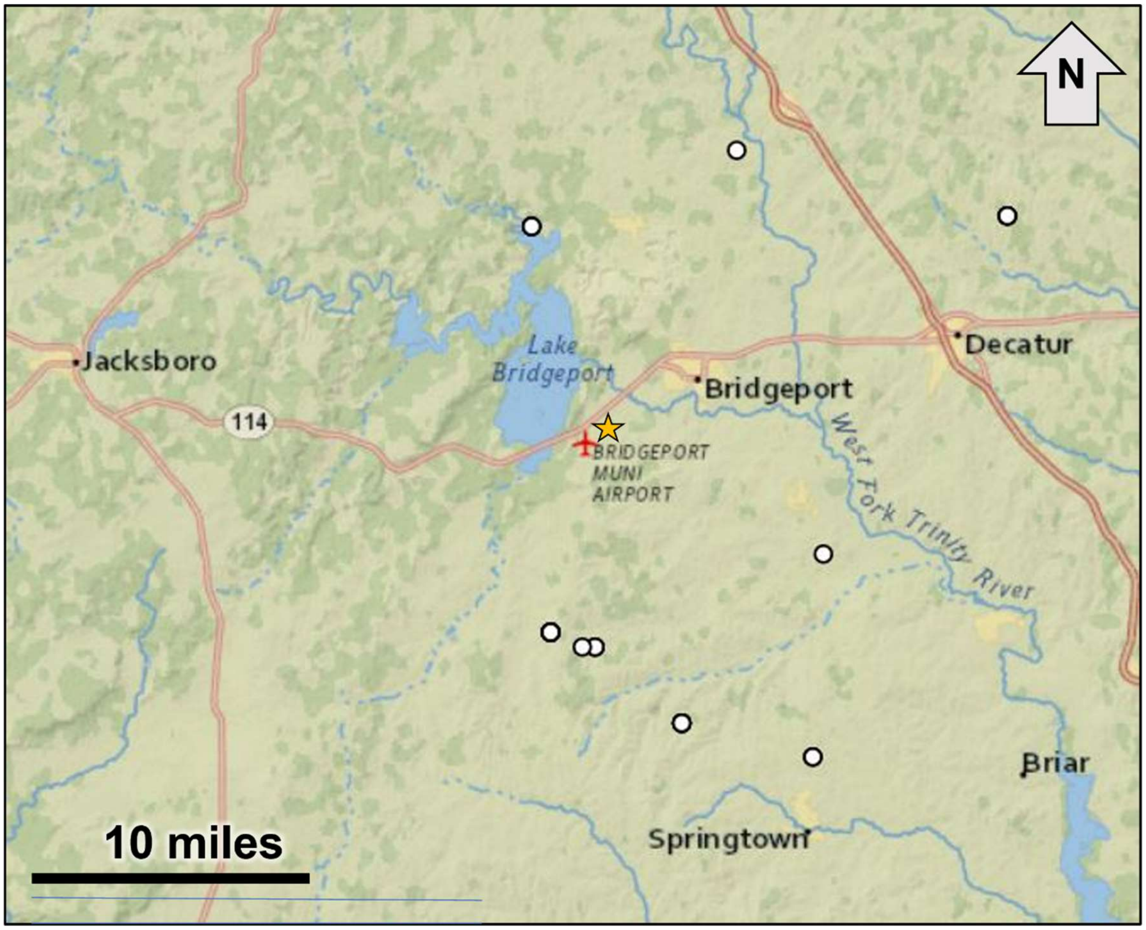


Figure 8. Map showing the location of wells used in the formation fluid chemistry analysis.

The Ellenburger Group has not been extensively drilled within the immediate area surrounding the proposed well injection and consequently formation fluid chemical analysis for the Group are from a basin-wide review. Based on analyses from the U.S. Geological Survey National Produced Waters Geochemical Database v2.3, the Ellenburger fluids have greater than 194,263 parts per million (ppm) total dissolved solids (TDS) within the Fort Worth basin. Formation fluid chemistry analyses for the Ellenburger Group Fort Worth basin wells are reported in **Table 4**.

Table 4. Ellenburger Group formation fluid chemistry.

	TDS (mg/L)	pH	Na (ppm)	Ca (ppm)	Cl (ppm)
AVG	212347	6	55066	18523	125209
LOW	194263	5.7	30000	12800	76200
HIGH	276388	6.6	66482	24750	153071

3.5 Potential of Induced Seismicity – Ellenburger

An analysis of historical seismic events within a 100 square miles (5.64 mile radius) surrounding the proposed Class II well injection site shows no recorded seismic activity dating back to January 1, 1971, according to the USGS Earthquake Catalog (**Figure 9**). TexNet seismic activity data supports this conclusion, showing no recorded seismic events around the proposed injection site. A study by Hennings et al. in 2019 described the fault-slip potential on mapped faults within the Fort Worth Basin. Their findings show that steeply dipping faults that strike north-northeast have the highest fault-slip potential. An injection rate of up to 15,000 bpd has been permitted for a disposal well in Wise County, approximately 8 miles from the proposed injection site, and operated without any observed seismic activity.

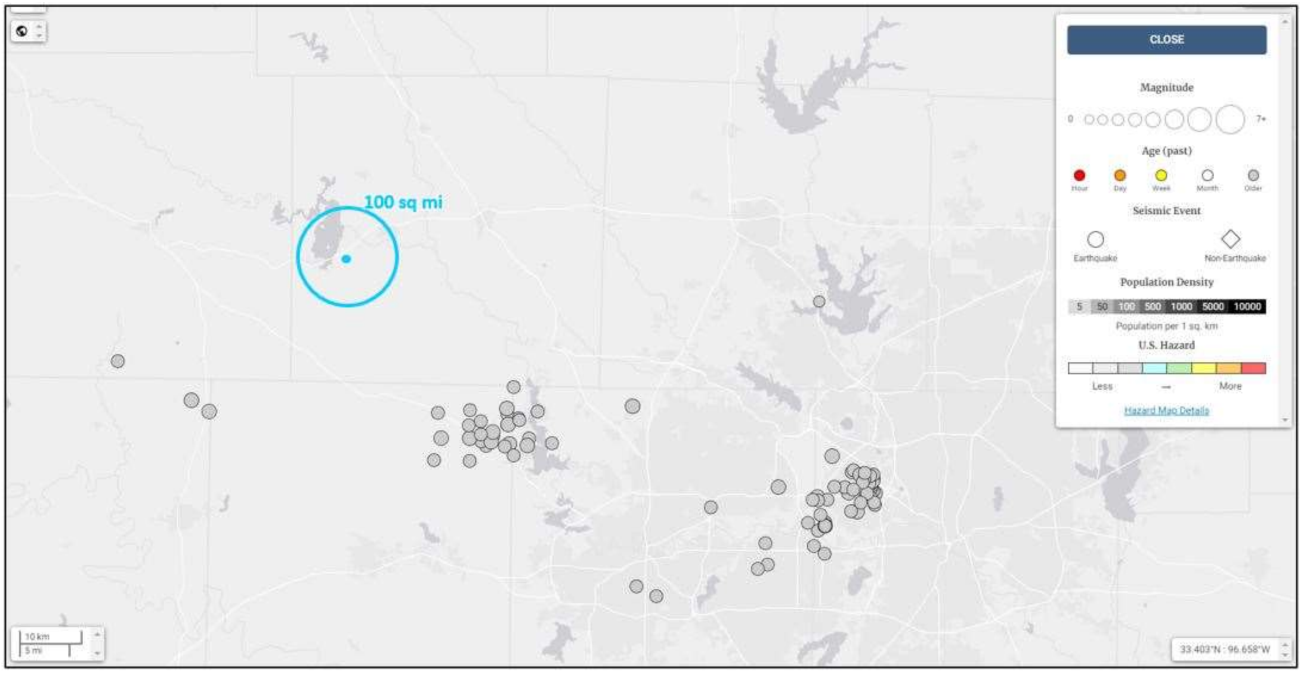


Figure 9. Screenshot from the USGS Earthquake Catalog showing no historical seismic activity in the surrounding 100 square miles to the proposed Bridgeport site.

3.6. Groundwater Hydrology in AOR

Wise County falls within the Upper Trinity Groundwater Conservation District as mapped by the Texas Water Development Board (**Figure 10**). Two aquifers are within the vicinity of the proposed injection site: the Trinity Group Aquifer, a major aquifer, and the Cross Timbers Aquifer, a minor aquifer. The Lower Cretaceous Trinity Group is an important source of groundwater for a portion of northern Texas and consequently Wise County, Texas. Lower Cretaceous strata outcrop throughout the majority of Wise County, especially to the east, but are absent at and around the proposed injection site (**Figure 10** and **Figure 11**). Instead, strata from the Cross Timbers Aquifer outcrop on the surface at the proposed injection site. The Cross Timbers Aquifer includes four Paleozoic-age water-bearing formations including, from oldest to youngest, the Strawn, Canyon, Cisco, and Wichita Groups. The Upper Pennsylvanian Strawn Group Willow Point Formation outcrops on the surface at the proposed injection site, and rocks from the Upper Pennsylvanian Canyon Group Jasper Creek Formation outcrop 0.5 miles to the north-northwest of the proposed injection site (**Figure 12**). Strawn and Canyon Group formations are primarily composed of limestones, shales, and sandstones. A stratigraphic column showing the Pennsylvanian through Cretaceous strata is included as **Figure 13**.

The Canyon Group, which outcrops at the proposed injection site, is a sequence of limestones with interstratified shales and sandstones deposited as a part of the Perrin Delta System (Brown et al. 19731)[1]. Deposition of Canyon Group sandstones was localized within valley fill, distributary channel fill, and delta-front deposits (TWDB 2021)[2]. These sandstone bodies are not laterally continuous and therefore did not constitute a regional scale major aquifer. Nearby groundwater well reports list the aquifer as Paleozoic, supporting the conclusion that freshwater in and around the well site is sourced from Pennsylvanian strata. Because the location of the well site does not fall within one of the major aquifer boundaries described by the Texas Water Development Board, describing the Total Dissolved Solids (TDS) contents of water from the Pennsylvanian Canyon Group is challenging. Consequently, this data will be collected during the drilling process. One TDS measurement from the Pennsylvanian group (formation unspecified) near the well site was recorded as 1600 ppm, according to a Geological survey water-supply paper from 1956[3]. Thus, freshwater wells in the area are likely drawing from localized sands within the Upper Pennsylvanian strata. The USGS's National Produced Waters Geochemical Database (NPWGD) report several TDS content measurements within the Lower Pennsylvanian Atoka/Bend formation with values ranging from 21,926 ppm to 154,593 ppm[4]. No reported TDS values from the USGS NPWGD fall below the 10,000-ppm minimum required to classify an aquifer as an Underground Source of Drinking Water (USDW). Consequently, the lowermost USDW is likely above the Lower Pennsylvanian strata at around 900 feet.

The direction of groundwater flow within Paleozoic strata is suggested to be in the west-northwest direction according to a conceptual model developed by Nicot et al. 2011[5]. Recharge into the Canyon Group was estimated to occur at a rate of 0.09 inches/year by the same study. Surface-water salinity decreases downstream toward the Gulf of Mexico. Groundwater salinity increases from younger to older formations toward the east but there is a reversal in the Strawn Group, whose formations can be in hydraulic contact with the overlying Trinity aquifer. The Trinity Aquifer may provide cross-formational flow to Paleozoic aquifers when they overlap with the primary flow direction from the Trinity to the Strawn. This mixing could explain the salinity reversal observed in some parts of Texas within the Strawn Group[4]. Locally, however, the deepest water well within 2 miles of the proposed injector well is 320 feet deep. This indicates that water wells in the area are drawing fresh water from localized sands within the upper several hundred feet.

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[1] Brown Jr., L.F., Cleaves II, A.W., Erxleben, A.W., 1973. Pennsylvanian depositional systems in North Central Texas, a guide for interpreting terrigenous clastic facies in a cratonic basin Texas Univ. Bur. Econ. Geology Guidebook, 14 (1973), p. 132

[2] Blandford, T.N., et al., 2021. Conceptual Model Report for the Cross Timbers Aquifer. Report produced under Texas Water Development Board Contract No. 1948312322.

[3] Winslow, A.G., and Kister, L.R., 1956. Saline-Water Resources of Texas. U.S. Department of Interior Report.

[4] Blondes, M.S., Gans, K.D., Engle, M.A., Kharaka, Y.K., Reidy, M.E., Saraswathula, V., Thordsen, J.J., Rowan, E.L., and Morrissey, E.A., 2018. U.S. Geological Survey National Produced Waters Geochemical Database (ver. 2.3, January 2018): U.S. Geological Survey data release, https://doi.org/10.5066/F7J964W8.

[5] Nicot, J.-P., Huang, Y., Wolaver, B.D., and Costley, R.A., 2013. Flow and Salinity Patterns in the Low-Transmissivity Upper Paleozoic Aquifer of North-Central Texas: Gulf Coast Association of Geological Societies Journal, v. 2, p. 53-67.

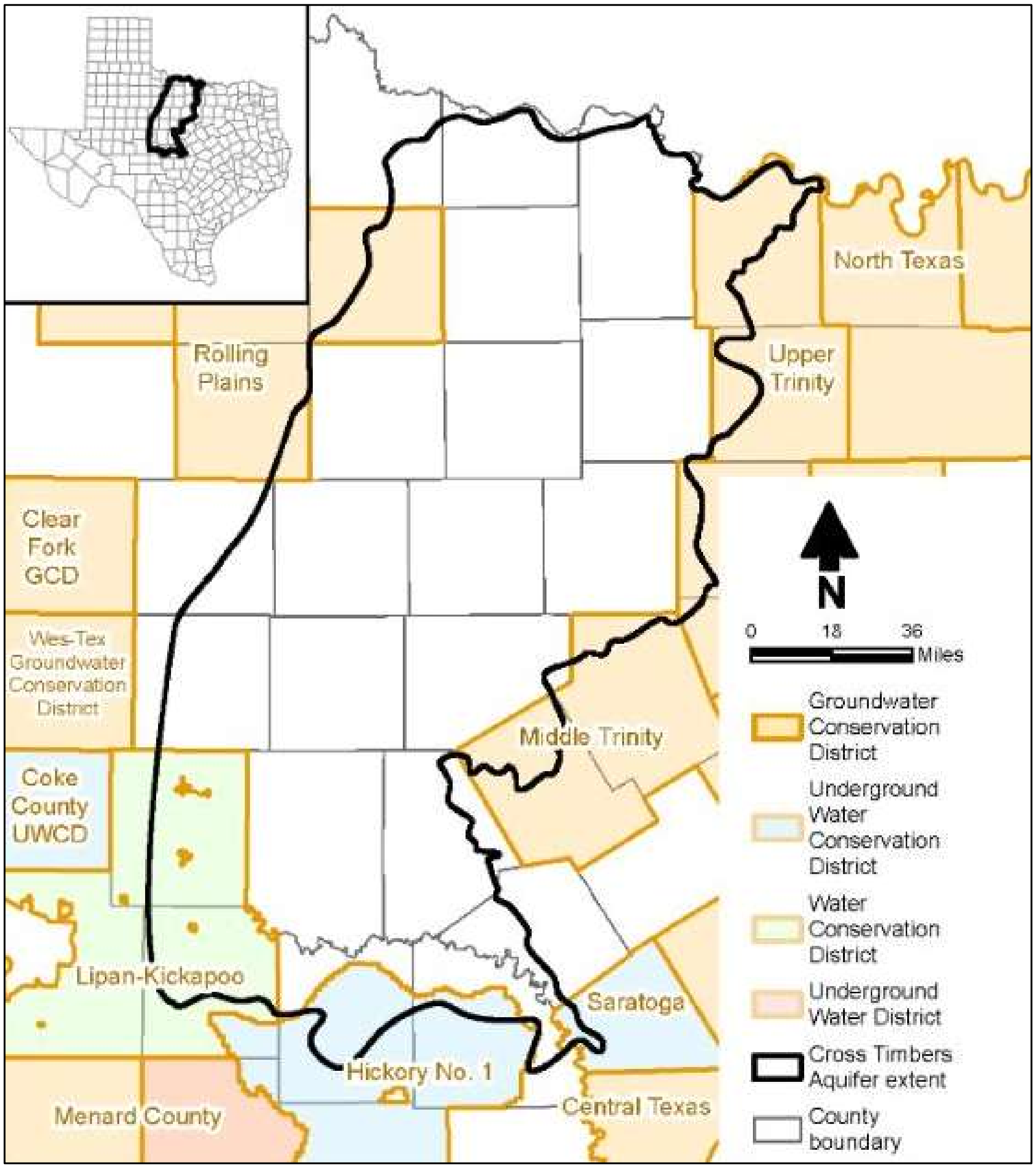

Figure 10. Map of the groundwater conservation districts and the Cross Timbers Aquifer extent within north-central Texas, from the Texas Water Development Board.

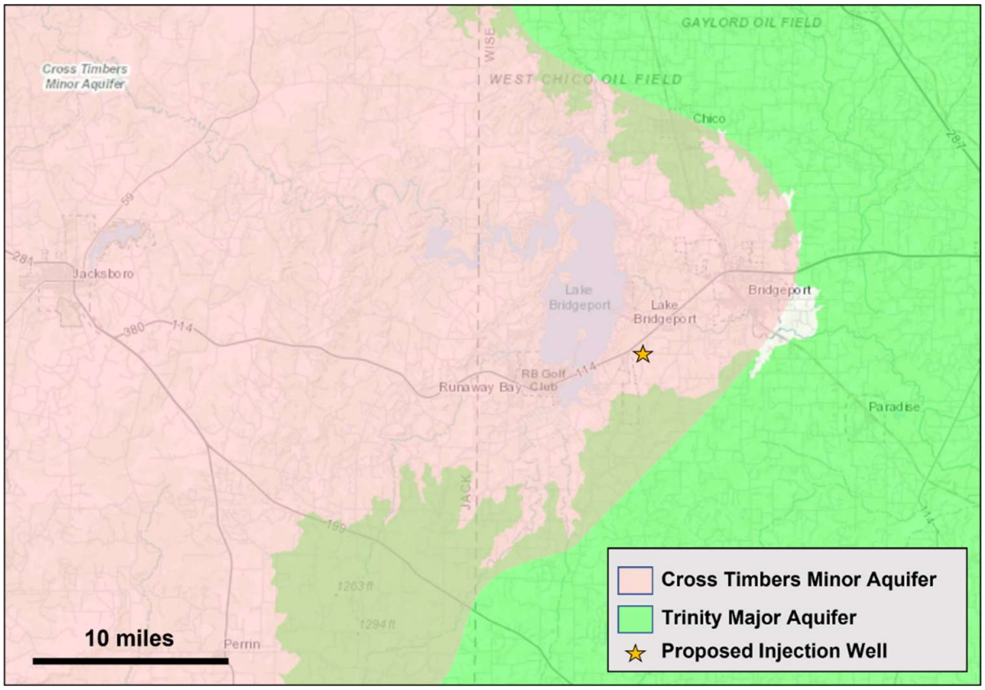

Figure 11. Location of the Cross Timbers minor aquifer and Trinity major aquifer in Texas, with well location labeled.

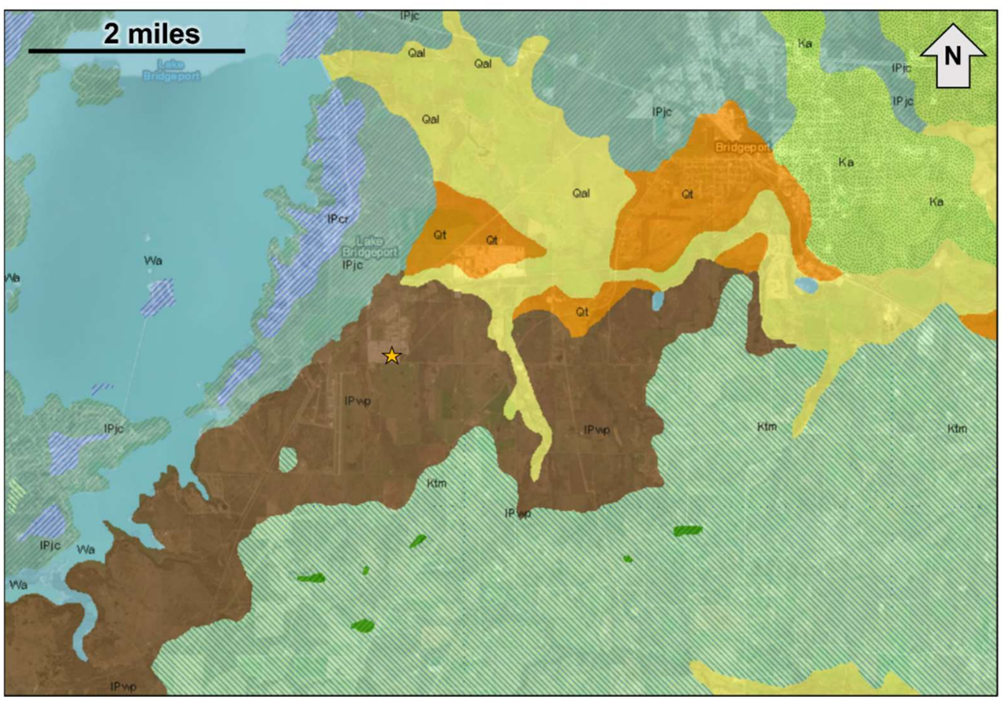

Figure 12. Geologic map of the area near the proposed injection site (yellow star). Geologic formations labeled using the state of Texas' USGS rock units codes, where: Qal = alluvium, Qt = fluviatile terrrace deposits, Wa = water, IPcr = Chico Ridge limestone, IPjc = Jasper Creek formation, IPwp = Willow Point formation, Ktm = Twin Mountaints formation, and Ka = Antlers sand.

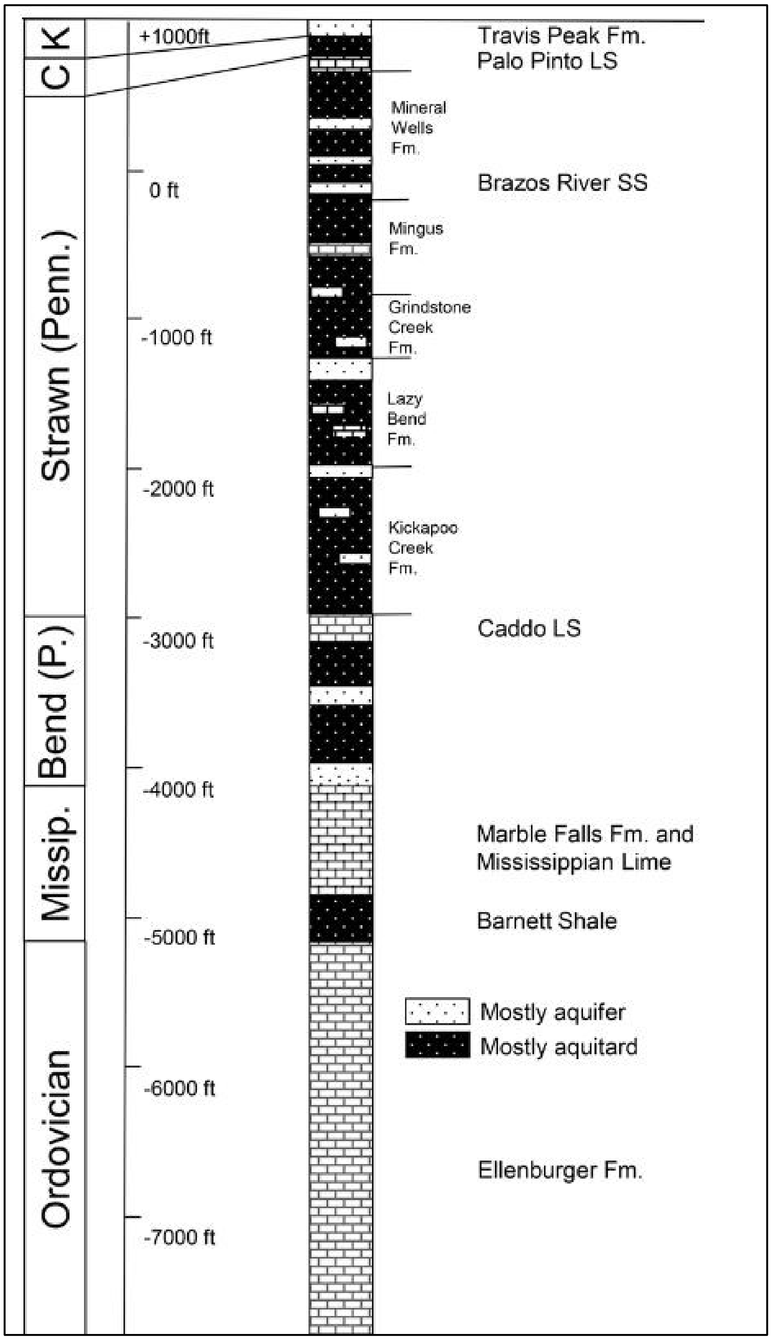

Figure 13. Stratigraphic column including aquifers and aquitards, modified from Nicot et al. 2011.

There are 105 freshwater wells within a 2-mile radius and 26 wells within a 1-mile radius of the proposed injection well, according to the Texas Water Development Board Groundwater Data Viewer shown in **Figure 14** and listed in **Table 5**.

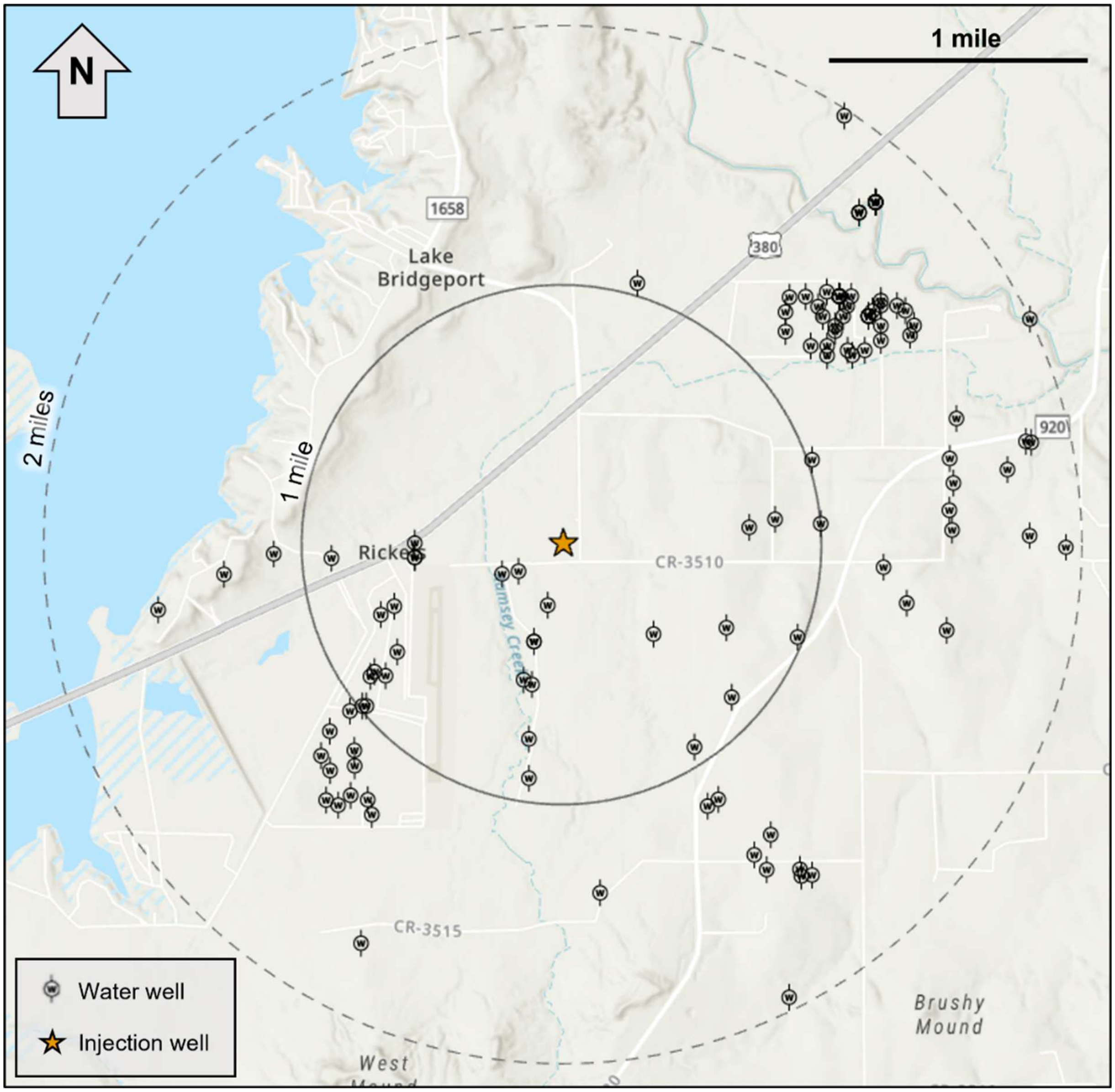

Figure 14. Water wells within 1 and 2 miles from the proposed injection site, data from the Texas Water Development Board.

Table 5. Privately owned groundwater wells in project area.

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
324182	33.157501	-97.805278	180	1.97
85836	33.160834	-97.833889	180	1.74
419698	33.1635	-97.817833	160	1.37
494622	33.16434	-97.80437	140	1.59
522108	33.16439	-97.80365	140	1.61
270093	33.164723	-97.806667	200	1.50
131403	33.164723	-97.804445	110	1.57
33173	33.165556	-97.807501	280	1.42
67830	33.166667	-97.806389	100	1.39
592900	33.16871	-97.80986	155	1.16
135520	33.17	-97.8225	140	0.93
71023	33.171667	-97.811389	120	0.94
214384	33.172222	-97.8225	195	0.78
23271	33.174167	-97.833611	280	1.01
23265	33.174167	-97.833334	140	1.00
12854	33.174444	-97.808889	140	0.89
305950	33.175278	-97.822222	110	0.57
86814	33.175555	-97.822778	213	0.56
570517	33.17587	-97.83202	120	0.86
13278	33.176111	-97.832778	140	0.89
585723	33.17721	-97.83121	160	0.77
527914	33.177694	-97.822083	160	0.40
527919	33.177694	-97.822083	160	0.40
190556	33.177778	-97.804445	210	0.98
428746	33.178047	-97.81408	120	0.50
605428	33.17806	-97.79442	180	1.53
107416	33.178333	-97.809167	140	0.72
509874	33.1793	-97.83231	120	0.76
601491	33.17962	-97.79708	200	1.35
53199	33.179722	-97.847222	150	1.60
196527	33.179722	-97.821111	75	0.25
510354	33.179783	-97.831417	130	0.70
430183	33.1815	-97.824139	170	0.27
81235	33.181667	-97.842778	200	1.32
193088	33.181667	-97.823055	240	0.21
373126	33.181667	-97.798611	160	1.25
351852	33.1825	-97.835556	320	0.90
122077	33.1825	-97.83	205	0.58
143619	33.1825	-97.83	140	0.58

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
474446	33.182659	-97.786404	180	1.95
44219	33.182778	-97.839445	230	1.13
214552	33.183334	-97.83	120	0.58
483302	33.183342	-97.78883	100	1.81
416778	33.18372	-97.79402	180	1.51
479366	33.184019	-97.807589	200	0.72
72275	33.184167	-97.802778	34	1.00
123233	33.184445	-97.805834	32	0.83
457391	33.184833	-97.794167	170	1.50
187174	33.186389	-97.793889	180	1.53
419604	33.187077	-97.790243	180	1.75
574195	33.187771	-97.794087	180	1.53
329665	33.187778	-97.803334	170	1.02
404012	33.188611	-97.788611	260	1.86
422029	33.18865	-97.78897	260	1.84
88487	33.19	-97.793611	103	1.60
72273	33.193611	-97.802223	29	1.25
72269	33.193611	-97.800556	28	1.33
62634	33.193889	-97.800834	33	1.33
72268	33.193889	-97.799722	28	1.39
62627	33.194167	-97.803334	30	1.22
62639	33.194167	-97.802223	28	1.28
219191	33.194445	-97.798611	30	1.46
219202	33.194722	-97.796667	20	1.57
123232	33.195	-97.805001	34	1.19
62632	33.195	-97.801667	33	1.34
329661	33.195278	-97.801667	145	1.35
219187	33.195278	-97.798611	30	1.49
219200	33.195278	-97.796389	24	1.60
219184	33.195556	-97.788611	30	2.01
62616	33.195834	-97.802501	35	1.33
62629	33.195834	-97.801112	35	1.40
49825	33.195834	-97.799445	27	1.47
49826	33.195834	-97.799445	27	1.47
49827	33.195834	-97.799445	27	1.47
49828	33.195834	-97.799445	27	1.47
49829	33.195834	-97.799445	32	1.47
72263	33.196111	-97.805001	30	1.24
62607	33.196111	-97.799167	31	1.50
219198	33.196111	-97.796945	27	1.60
62622	33.196389	-97.802778	38	1.35

Well Report Tracking Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	Distance from proposed injector (mi)
62628	33.196389	-97.800834	31	1.43
72267	33.196389	-97.798611	35	1.53
219193	33.196389	-97.7975	20	1.59
219181	33.196667	-97.798611	30	1.55
62626	33.196945	-97.804723	16	1.29
62623	33.196945	-97.803612	16	1.34
41283	33.196945	-97.801389	21	1.43
41284	33.196945	-97.801389	15	1.43
41285	33.196945	-97.801389	15	1.43
41286	33.196945	-97.801389	15	1.43
41287	33.196945	-97.801389	15	1.43
72264	33.196945	-97.800556	34	1.47
62618	33.197222	-97.802223	32	1.41
405842	33.197817	-97.814883	60	1.05
240181	33.201667	-97.800001	20	1.72
240182	33.201667	-97.800001	18	1.72
240183	33.201667	-97.800001	17.5	1.72
213490	33.202223	-97.798889	14.5	1.79
213494	33.202223	-97.798889	15	1.79
213495	33.202223	-97.798889	14	1.79
213496	33.202223	-97.798889	14.5	1.79
213499	33.202223	-97.798889	13	1.79
213500	33.202223	-97.798889	12	1.79
213502	33.202223	-97.798889	11	1.79
516919	33.20712	-97.8009	160	1.98
State Groundwater Well				
State Well Number	Latitude (DD)	Longitude (DD)	Borehole Depth (feet)	
1950401	33.17389	-97.83445	147	1.06
1950402	33.17278	-97.83583	146	1.17
1950408	33.16917	-97.83445	147	1.28
1950501	33.17583	-97.83306	82	0.91
1950406	33.16861	-97.83528	147	1.34
1950504	33.16806	-97.83306	147	1.29
1950404	33.17139	-97.83639	147	1.25
1950502	33.16833	-97.81056	121	1.17
1950403	33.16889	-97.83611	147	1.36
1950405	33.17083	-97.83417	147	1.19
1950407	33.17167	-97.83417	147	1.15
1950409	33.17056	-97.83583	147	1.27
1950503	33.16889	-97.83333	147	1.26

3.8 Description of CO_2 Project Facilities

EnLink Midstream has contracted to deliver CO_2 from its Bridgeport Gas Processing Plant to dCarbon. The temperature, pressure, composition, and quantity of CO_2 will be measured and metered according to industry standards, with an orifice meter or similar device. dCarbon will dehydrate and compress the CO_2 to a supercritical physical state at the Bridgeport site. dCarbon Ventures will then transport the CO_2 via pipeline approximately 6900' to the RDC #1 injection site. Once at the well site, the CO_2 stream will again be metered to reverify quantity. The CO_2 will then be injected into the Ellenburger formation. This formation is deeper than other formations known to be productive of oil and gas in the area. A gas analysis of the CO_2 stream is shown in **Table 6**. Although this sample is expected to be representative of the composition of the gas, it is possible that the composition will vary slightly in time as the field development and processing environment change. The 20-30 ppm H_2S is not shown on the analysis below.

Table 6. CO_2 stream analysis for the Barnett RDC #1 site.

Name	Normalized Weight Percent	Normalized Mole Percent	Normalized Liquid Volume Percent
Nitrogen	0.002	0.003	0.002
Carbon Dioxide	99.358	99.054	98.646
Methane	0.105	0.287	0.286
Ethane	0.4	0.584	0.916
Propane	0.018	0.018	0.029
Isobutane	0.003	0.002	0.004
N-butane	0.008	0.006	0.011
Isopentane	0.002	0.001	0.003
N-pentane	0.002	0.001	0.003
Hexanes	0.011	0.008	0.013
Heptanes	0.011	0.002	0.011
Octanes	0.007	0.001	0.007
Nonanes	0.009	0.002	0.009
Decanes plus	0.004	0.001	0.004
BTEX	0.06	0.03	0.056
Total	100	100	100
Total Sample Properties			
Property	Value		
BTU (Gross)	16.04		
Density (lbs/gal)	12.63		
Molecular weight	43.87		
Specific gravity (Air=1)	1.5147		

Figure 15. Proposed pipeline route.

3.8. Reservoir Characterization Modeling

A regional modeling encompassing nearby plugged and abandoned wells as well as saltwater disposal wells was created in Schlumberger's Petrel to store available well petrophysical data and generate a static earth model (SEM) for fluid flow simulations. Well tops and petrophysical data required to populate the model were sourced from digital logs available for the W.S. Coleman SWD #2 well (~5miles east of RDC #1) as discussed in previous sections. The reservoir is characterized by low matrix porosities while it is expected that naturally existing fractures contribute to fluid flow. For the current assessment, a single porosity, single permeability distribution model was deemed appropriate given the uniformity of natural fracture distribution within the Ellenburger as well as saltwater disposal rates/volumes facilitated by the Ellenburger unit in nearby counties. These assumptions will be examined and verified using a pressure fall-off test (PFOT) that will be conducted during the construction of the RDC #1 well. If PFOT and logging programs detect deviations from anticipated reservoir behavior, BKV will use the new evidence to update reservoir models as well as injection forecasts.

The primary objectives of the model simulation were to:

1. Estimate the maximum areal extent of the injectate plume and its migration post injection
2. Determine the ability of the target formation to handle the required injection rate
3. Interaction with the injected CO_2 with any nearby leakage pathways.

The CO_2 storage complex, as indicated in previous section, is anticipated to be confined to the Ellenburger interval. Ellenburger 'E' is modeled as the reservoir unit while Ellenburger 'C' unit is anticipated to provide a primary seal that impeded vertical fluid flow. The Barnett shale is expected to serve as a secondary seal which provides an additional stratigraphic seal to the injected CO_2. A 12-mile by 12-mile tartan grid was generated in Schlumberger's Petrel based on well top information from nearby legacy and saltwater disposal wells. The grid was then exported to Computer Modeling Group (*CMG)'s General Equation of State Model (GEM) simulator to account for fully implicit multiphase compositional fluid flow. This simulation was built to model other transport and mixing phenomena such as relative permeability, diffusion, advection, aqueous solubility, and buoyancy to accurately predict the plume movement. The reservoir is modeled to be an aquifer filled with 100% brine. The salinity of the formation is estimated to be 200,000 TDS which is typical of the Ellenburger formation in the project area. The injected gas stream is assumed to be fully composed of CO_2. **Figure6** illustrates the vertical layering in the model and depths at which the injection zones and confining layers are expected to be located within the project area.

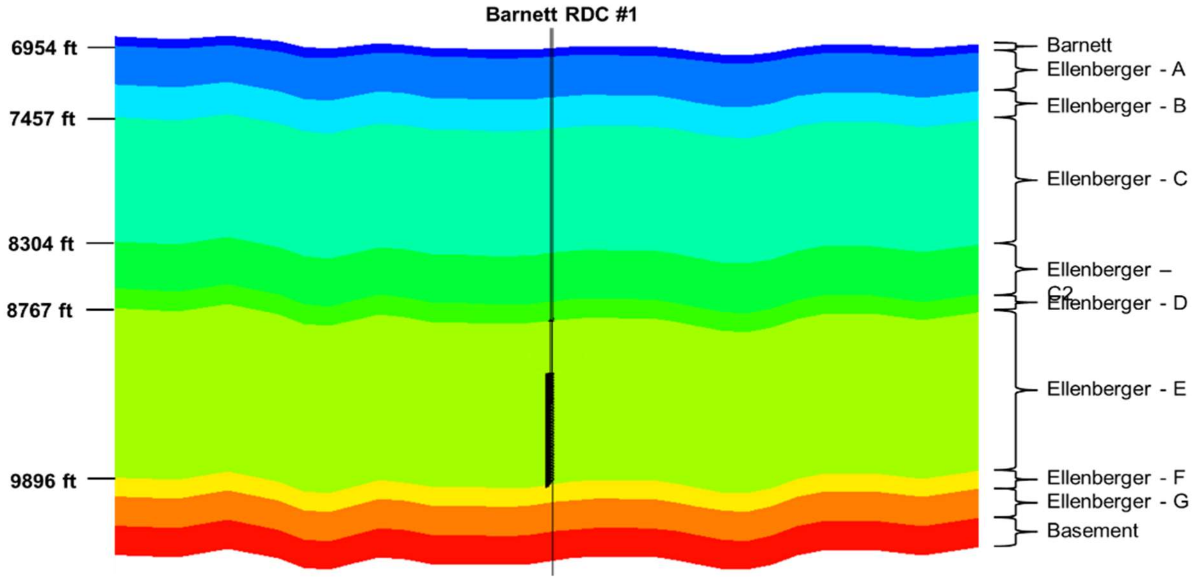

Figure 16. Vertical Profile of the CMG-GEM Model for Barnett RDC #1 Well.

Datasets prepared for simulations were based on published literature. Specifically, the reservoir relative permeability model used in this model were sourced from Bennion and Bachu (2007)[6] using data from Wabamun Carbonate reservoir formation which exhibited comparable porosities and permeabilities as the Ellenburger. The initial reservoir conditions were developed using gradients typically seen in the area as noted by Gao *et al.* (2021)[7]. The pressure gradient was assumed to be 0.47 psi/foot which resulted in an estimated reservoir pressure of 4,136 psi at the top of the injection interval. The temperature gradient was assumed to be 1.5ºF/100feet, resulting in an estimated temperature of 201ºF at the top of the reservoir. Fracture pressures were estimated at 0.7 psi/foot. To ensure CO_2 injection does not induce artificial fractures within the Ellenburger, injection well bottom hole pressure (BHP) was constrained to 90% of calculated fracture pressure, thereby applying a safety factor of 10%. This resulted in a maximum bottom hole injection pressure constraint of 5,524 psi. There are no active wells injecting or producing from the injection interval in the project area. Therefore, no additional wells to the injector were included in the fluid flow simulation model.

Injection was modeled at 280 kilotonnes per annum (KTPA). The model simulated injecting at the respective rates for 12 years followed by 100 years of post-injection to determine when plume migration stops. Plume migration ceased after 50 years post-injection, which is determined to be the maximum extent of the CO_2 plume. **Figure 17** shows the CO_2 plume at the end of injection (yellow) compared to 50 years post injection (red). Injected CO_2 flows due west which is the

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[6] Bennion, D.B., and Bachu, S., 2007. Permeability and Relative Permeability Measurements at Reservoir Conditions for CO_2-Water Systems in Ultra Low Permeability Confining Caprocks. SPE Paper # 106995 presented at the SPE Europec/EAGE Annual Conference

[7] Gao, S., Nicot, J.P., Hennings, P.H., La Pointe, P., Smye, K.M., Horne, E.A. and Dommisse, R., 2021. Low pressure buildup with large disposal volumes of oil field water: A flow model of the Ellenburger Group, Fort Worth Basin, northcentral Texas. AAPG Bulletin, 105(12), pp.2575-2593

regional up dip direction. However, the change in CO_2 plume area from end of injection to 50 years post-injection is minimal (~29%) and the plume stops moving after 50 years.

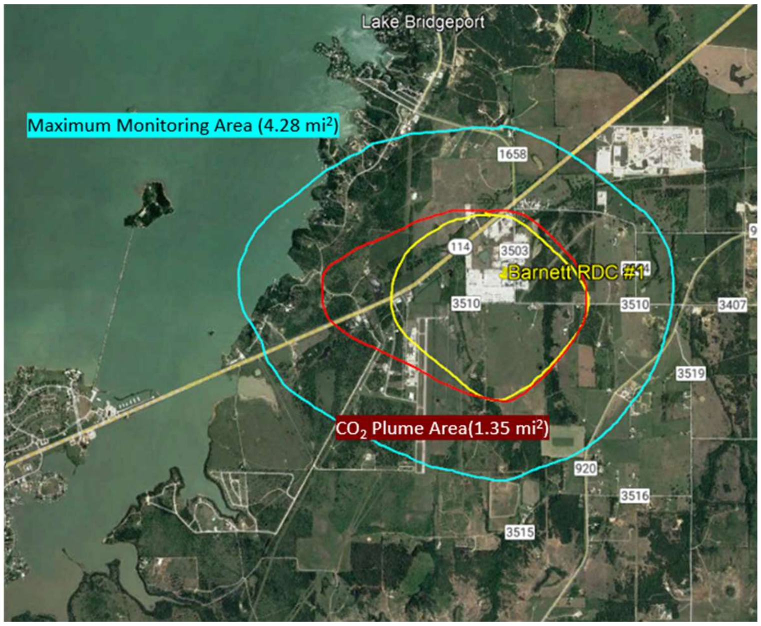


Figure 17. Simulation Results Showing CO_2 Plumes (end of injection – yellow, after 50 years of injection – red) and the Maximum Monitoring Area (blue).

Figure 18 illustrates CO_2 mass injection rate, cumulative CO_2 injection mass, and bottom hole pressure at the Barnett RDC #1 well as modeled. The bottom hole pressure remained well under the bottom hole pressure constraint. The maximum bottom hole pressure reached is 4,434 psi (1,090 psi under the BHP constraint) which occurs 6 months after the injection started. This spike is anticipated to be a result of near wellbore effects arising from CO_2 forcing its way into the brine-filled porous media. Upon reaching a critical mass to transition from capillary driven to advection driven flow, the BHP starts to decline until the end of injection while keeping the injection rate constant. Injection rate then falls until the end of injection.

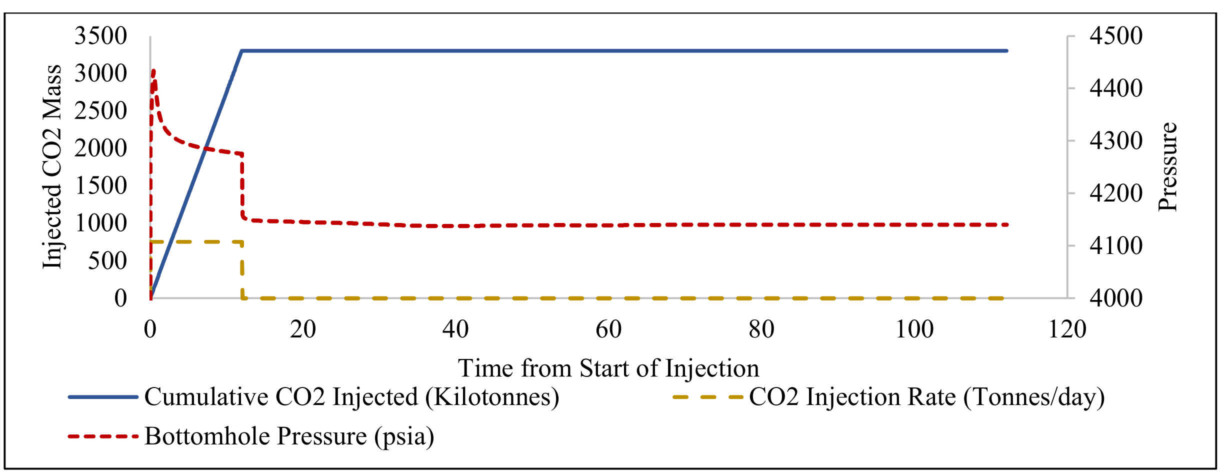


Figure 18. Modeled Injection Profile at Barnett RDC #1 Well.

Section 4 – Delineation of Monitoring Area

4.1. Maximum Monitoring Area (MMA)

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile. The numerical simulation using CMG-GEM as discussed above was used to estimate the size and migration of the CO_2 plume. The model injected into the Ellenberger – E formation. CO_2 injection was modeled for 12 years followed by 100 years post injection. Results indicated that the plume ceased to migrate after 50 years post injection. For more information on the simulation construction and setup, please see the discussion in Section 3.8. A 5% cutoff of molar gas concentration was used to determine the boundary of the CO_2 plume. The area of the maximum monitoring area was determined to be 3.6 square miles with the greatest extent reaching 1.34 miles from the injector. **Figure 19** shows the end of injection plume (yellow), the 50-year post injection plume (red), and the maximum monitoring area using a half mile buffer (blue).

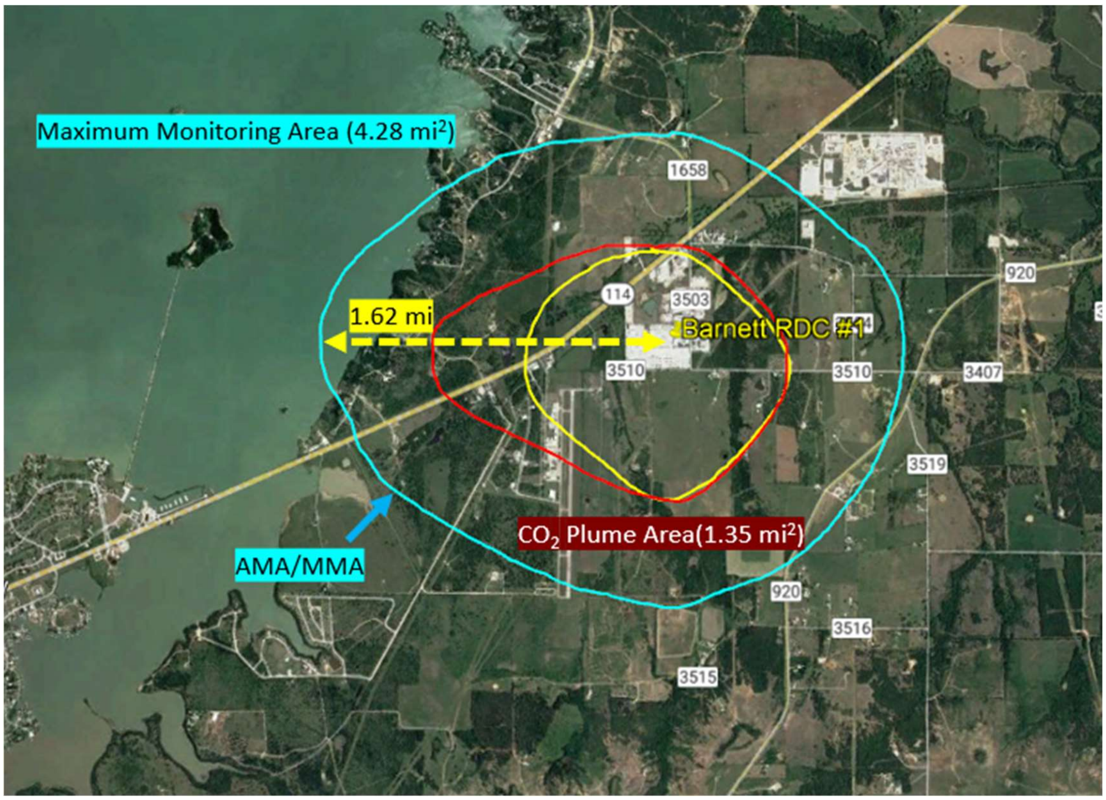


Figure 19. Maximum Monitoring Area (blue), End of Injection Plume (yellow), and 50-year Post Injection Plume (red) as Modeled at the Barnett RDC #1 Well.

Section 4.2. Active Monitoring Area (AMA)

As discussed in Chapter 3, there are no structural/geological features within the project area that could cause the unintended migration of the CO_2 plume. The only potential leakage pathways that exist are well penetrations and the surface equipment. Leakage from groundwater wells, faults and

fractures, leakage through the confining layer, and seismicity events are expected to be highly improbable. That said, these leakage pathways have been considered and options to monitor them are discussed in Section 4 and Section 5. Sufficient care and consideration will be provided to monitoring these pathways, if any, and simulation models will be calibrated with new data as appropriate. Therefore, the AMA is proposed to have the same boundary as the MMA, which adequately covers the area that is required to be monitored for CO_2 leakage. **Figure 19** shows the MMA which is the same as the AMA. **Figure 20** indicates the AMA/MMA (blue line) and currently existing water and oil/gas wells within this area. None of these wells were found to penetrate the Ellenburger within the project area. Water wells in the region are shallow with drilled depths up to 300 feet from surface. Additional discussion on well infrastructure within the project area can be found in later sections of this document.

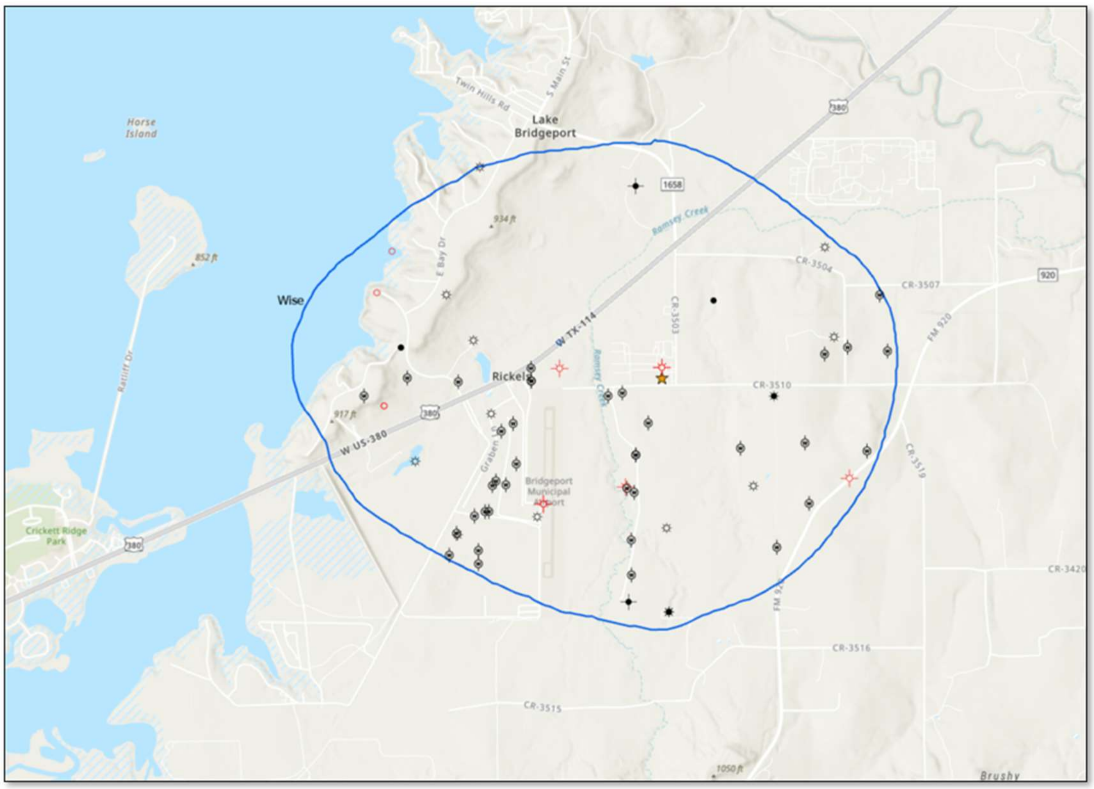


Figure 20. Maximum/Active Monitoring Area (blue) and existing wells within the project AMA/MMA.

Section 5 – Identification and Evaluation of Potential Leakage Pathways to Surface

5.1. Potential Leakage from Surface Equipment

dCarbon's surface facilities at Bridgeport and at the injection well site are specifically designed for injecting the CO_2 stream described above, including 20-30 ppm H_2S, and therefore minimize leakage points such as valves and flanges following industry standards and best practices. All BKV and dCarbon field personal are required to wear gas monitors which detect H_2S. A shut-in valve is located at the wellhead in case of emergency. The compressor will also have an emergency shut down switch which can be activated in case of unexpected operating conditions.

Additionally, the compressor facility, pipeline, and injection well locations will all be subjected to Auditory, Visual, and Olfactory ("AVO") and FLIR leak detection per BKV safety and operations standards. These recurring inspections, which are standard for detecting leaks and malfunctioning equipment in the gas production industry, will aid in the rapid detection of any potential leaks which may occur. As a part of these inspections, operations personnel are frequently able to repair leaks immediately by tightening valves, flanges or similar. Any leaks that are detected will be analyzed for determine that amount of CO_2 which may have leaked. These quantities, if any exist, will be included in recurring reporting.

5.2. Leakage from Approved, Not Yet Drilled Wells

There no permitted but not drilled well within the AOR. One expired well permit falls within the AOR. The original permit for this well was shallower than the Ellenburger formation by several thousand feet. This expired permit location (33.184969, -97.827819) is labeled as "B" on the first page map of Attachment B.

5.3. Leakage from Existing Wells

There are 20 existing wells within the AOR of this project Of these 20 wells, 14 have digital records available on the TRRC website (**Table 6**)., and, six wells have been plugged and abandoned while eight remain active. However, all 14 of these wells are shallower than the proposed disposal interval from this project. In fact, the targeted injection interval (>9350 feet) is approximately 3,000 feet deeper and separated by numerous impermeable shales from the deepest well in the AOR (API 42-497-34419 which has a total depth of 6334 feet). These wells are represented relative to the project MMA in **Figure 21**. The six remaining wells which were drilled within the AOR (Table 7) do not have digital records available on the TRRC website, but dCarbon acquired paper copies of the well permit information, attached herein as Attachment B. All six wells were drilled significantly shallower than the Ellenburger formation. In fact, the deepest of the six wells was drilled to 6155 feet TVD, several thousand feet shallower than the Ellenburger formation.

Additionally, the wellbore design of the injection well contains three layers of steel casing, each of which runs entirely to the surface wellhead to ensure complete isolation of wellbore fluids. Additionally, each of these three casing strings will be cemented entirely to the surface and inspected with cement bond logs to ensure wellbore integrity. Finally, all injection into the well will occur through a final steel tubing string which is secured in place with a permanent packer. All of these aspects of wellbore construction are designed to ensure that all CO_2 is injected into the target formation and that there are zero leakage pathways from the wellbore directly into shallower formations.

Table 6. Existing Oil & Gas wells in AOR with digital TRRC records.

API	Well Type	Latitude	Longitude	Status	Total Depth (feet)	Operator	Plug Date	Plug Depth
49730069	Gas	33.17562	-97.8131	Open	6128	Scout Energy Management, LLC	-	-
49732742	Gas	33.18044	-97.8331	Open	5900	Eagleridge Operating, LLC	-	-
49733956	Gas	33.18517	-97.8344	Open	5950	Eagleridge Operating, LLC	-	-
49734400	Gas	33.19088	-97.8075	Open	5920	Eagleridge Operating, LLC	-	-
49734420	Gas	33.17271	-97.8357	Open	5950	Eagleridge Operating, LLC	-	-
49734419	Oil	33.18474	-97.8399	Open	6334	Merit Energy Company	-	-
49734419	Oil	33.18474	-97.8399	Open	6334	Eagleridge Operating, LLC	-	-
49731951	Oil/Gas	33.18137	-97.8115	Open	6125	Scout Energy Management, LLC	-	-
49700111	Plugged (Gas)	33.18328	-97.8278	Plugged	5899	Mitchell Energy Corporation	4/16/1996	5899
49700786	Plugged (Gas)	33.18328	-97.82	Plugged	5918	Williams Petroleum Company, Inc.	2/13/2015	5918
49701654	Plugged (Gas)	33.17462	-97.8292	Plugged	6028	Enserch Exploration, Inc.	9/27/1996	6028
49733230	Plugged (Gas)	33.17563	-97.8229	Plugged	5950	Merit Energy Company	11/5/2012	0
49732368	Plugged (Oil)	33.16827	-97.8227	Plugged	6000	Merit Energy Company	1/8/2001	6000
49732392	Plugged (Oil)	33.19493	-97.8219	Plugged	5964	Merit Energy Company	3/19/1999	5975

Table 7. Existing Oil & Gas wells in AOR WITHOUT digital TRRC records.

API	Well Type	Latitude	Longitude	Status	Total Depth (feet)	Attachment B Label	Operator
497-1	Gas	33.177438	-97.838912	Plugged	5965	G	Lone Star Production
497-1	Gas	33.1738	-97.829657	Plugged	6027	F	Lone Star Production
497-1A	Gas	33.1851	-97.806835	Plugged	5996	D	Lone Star Production
497-1	Gas	33.188107	-97.83638	Plugged	5602	A	A'Mell Oil Properties
497-1	Gas	33.172971	-97.819788	Plugged	6155	E	Upham Oil & Gas
497-1	Oil	33.187529	-97.815993	Plugged	6028	C	Enserch Exploration

5.4. Potential Leakage from Fractures and Faults

Dynamic modeling conducted to date indicates that the CO_2 plume will not intersect any mapped faults, based on 3D seismic interpretation.

Several episodes of fault formation took place in the Fort Worth Basin, based on 3D seismic data mapping. The oldest set of faults displace Ordovician rocks but do not displace Mississippian rocks like the Barnett Shale.

A younger set of faults displace Mississippian and older rocks and appear to be related to the Ouachita Front collision. These faults show displacement up into the Pennsylvanian rocks as high as the Strawn. These larger, younger faults have larger displacement but are relatively sparce.

No faulting is interpreted in the AOR around the RDC #1 based on available subsurface data including 3D seismic data.

Karst development is present in some areas at the top of the Ellenburger, primarily where the overlying Viola and Simpson Formations were eroded. Karst formation is often developed in the upper several hundred feet of an exposed carbonate where fresh water is able to dissolve the rock. Subsequent loading of sediment can cause the roof of the cave to collapse, with overlying sediment filling the void.

The injection interval, the Ellenburger "E", appears to be below the portion of the Ellenburger affected by the karst collapses. This suggests that the Ellenburger "D" will remain a seal in karsted areas. There are no interpreted karst features that the CO_2 plume intersects based on the dynamic modeling. Small karst features sit at the southern edge of the AOR but only seem to have impacted the upper 200 feet of Ellenburger, leaving 3,000 feet of Ellenburger apparently unaffected.

Even if the plume reaches the karst features on the south end of the AOR and the Ellenburger "D" seal is not intact, the overlying and impermeable Barnett Shale, Marble Falls Limestone and the Atoka Shales are expected to prevent migration to shallower depths.

5.5 Leakage Through Confining Layers

The Ellenburger "E" injection zone has competent sealing rock above and below with the Ellenburger "D" and "F" zones respectively. Secondary seals above the Ellenburger "D" include the Ellenburger "C", "B", Barnett Shale, Marble Falls Limestone, and the Atoka Shales. Overall, there is in excess of 1600 feet of impermeable rock above the injection zone, making vertical migration past the secondary confining unit unlikely.

5.6 Leakage from Natural or Induced Seismicity

The RDC #1 location is in an area of the Fort Worth Basin that is inactive seismically, as illustrated in Section 3.5. Earthquake catalogs from both the USGS (1950-present) and TexNet (2017-present) locate no earthquakes within 20 miles of the RDC #1.

The closest seismic activity is 20+ miles to the southeast in an area of larger, regional faulting. In 2013 and 2014, a series of earthquakes were felt near the town of Azle. The Texas Railroad Commission held hearings that investigated whether oil and gas activities near the earthquakes were responsible for the activity. The Railroad Commission was unable to determine whether or not oil and gas activities were responsible for the earthquake sequence.

5.7 Leakage from Lateral Migration

The structural dip of the Ellenburger in the vicinity of the RDC #1 injection site is about one degree up to the west (100 feet/mile) **Figure 21**). The closest well that penetrates the Ellenburger "E" injection interval up dip from the injection site is more than 10 miles to the WSW. The closest well that penetrates the injection interval is downdip to the east approximately five miles (W S Coleman #2).

Dynamic modeling of the CO_2 plume has the maximum extent of the plume traveling less than one mile, with the maximum distance traveled to the west. Given that the distance to the next penetration of the injection interval is on the order 10 times the distance the plume is expected to travel, no leakage from lateral migration is expected.

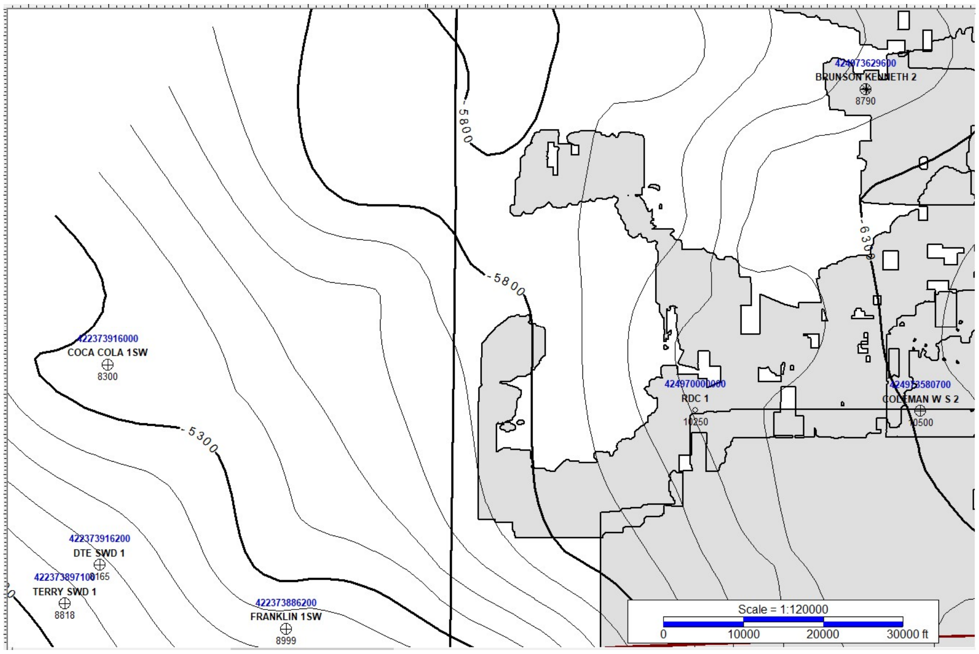


Figure 21. Top of Ordovician Unconformity (top Ellenburger) subsea structure in the vicinity of the RDC #1 location. Wells shown penetrate the injection interval. Additional wells (not shown) were used to develop the structure map. Gray areas represent areas covered by 3D seismic data.

Section 6 – Plan of Action for Detecting and Quantifying Surface Leakage of CO_2

This section discusses the strategy that dCarbon will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in previous sections to meet the requirements of 40 CFR §98.448(a)(3). As injected stream contains both H_2S and CO_2, the H_2S will serve as an indicator for CO_2 leakage and therefore the monitoring systems to detect H_2S will also indicate a leak of CO_2. This section summarizes the monitoring of potential leakage pathways to the surface, and the methods for quantifying leakage should it occur. Monitoring will occur during the planned 12-year injection period, or cessation of operations, plus a proposed two-year post-injection period.

6.1. Leakage from Surface Equipment

As the CO_2 compressor station, pipeline, and injection well are all designed to handle H_2S and CO_2, leakage from surface equipment is unlikely to occur and would likely be quickly detected and addressed. The facility is designed to minimize potential leakage points by following ASM, API and other industry standards, including material selection. Additionally, connections are designed to minimize corrosion and leakage points. The H_2S in the stream is easily detectable and serves as an indicator for the release of CO_2. The facility and well will be monitored for H_2S and increases in CO_2 concentration, set with a high alarm setpoint for H_2S. Additionally, all dCarbon and BKV field personnel are required to wear H_2S monitors, which trigger the alarm at low levels of H_2S. The injection facility will be continuously monitored through automated systems that are designed to identify abnormalities in operational conditions. In addition, field personnel conduct daily AVO field inspections of gauges, monitors, and leak indicators. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the system, analysis of liquids collected from the line. These inspections, in addition to the automated systems, allow dCarbon to quickly identify and respond to any leakage situation. Monitoring will occur for the duration of injection and the post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5).

Additionally, CO_2 for injection will be metered in two locations for redundancy. The first will be an orifice style meter at the interface between the Bridgeport Gas Plant and dCarbon's compressor. This location will meter the CO_2 in gas phase (See Figures 22a and 22b). Once the CO_2 is compressed to supercritical, it will be transported approximately 6,800 feet via pipeline to the injection well site. The CO_2 will be metered a second time at the injection well site, immediately upstream of the injection wellhead itself, with a Coriolis meter. The CO_2 is expected to be in a supercritical phase / dense phase at this point. The meters will each be calibrated to industry standards. Any discrepancies in CO_2 throughput between the meters will be investigated and mitigated. Any CO_2 that is determined to have leaked or not been received at the injection wellhead will be subtracted from reported injection volumes. Gas samples will occasionally be taken to confirm stream composition and calibrate/re-calibrate meters if necessary.

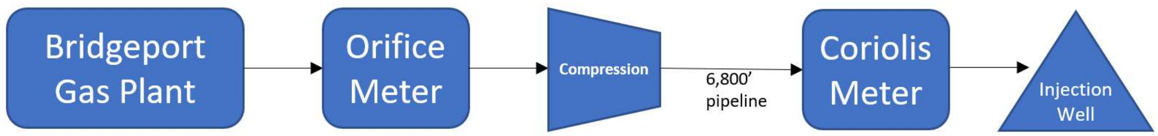


Figure 22a. Facility Diagram and Two Metering Points

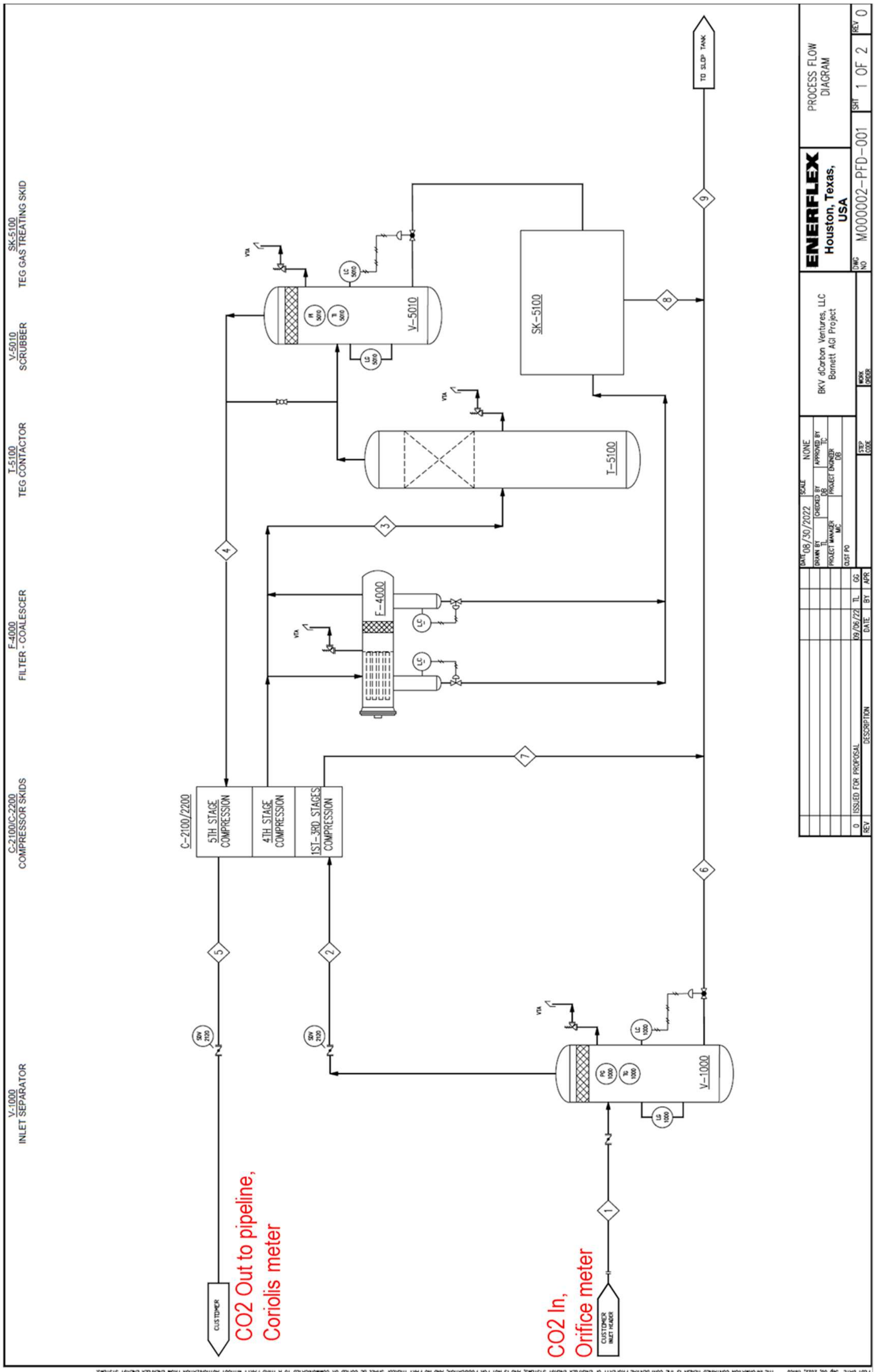


Figure 22b. Compression facility Process Flow Diagram and indicative metering locations

6.2. Leakage from Existing and Future Wells within the Monitoring Area

As previously discussed, there are no wells in the MMA currently existing, approved, or pending which penetrate as deep as the Ellenburger injection zone. However, dCarbon will reverify the status and public information for all proposed and approved drilling permits within the MMA quarterly. If any wells are proposed, permitted, or drilled within the MMA, BKV will investigate the proposal and determine if any additional risks are introduced through the new well proposal. Additionally, dCarbon will continuously monitor and collect injection volumes, pressures, temperatures, and gas composition data for the injection well. This data will be reviewed by qualified personnel and will follow response and reporting procedures when data is outside acceptable performance limits.

The injection well has pressure and temperature gauges placed in the injection stream at its wellhead, and a pressure gauge on the casing annulus. A change of pressure on the annulus would indicate the presence of a possible leak. Mechanical Integrity Tests ("MITs") performed annually would also indicate the presence of a leak. Upon a negative MIT, the well would immediately be isolated, and the leak mitigated.

In the unlikely event that any CO_2 leaks occur into existing or future wells in the monitoring area, dCarbon will endeavor to work with the operator(s) of those wells and/or midstream providers to take wellhead gas samples to quantify variations or increases of CO_2 compared with historical or baseline CO_2 concentrations. Any measurable increases in CO_2 which may be confidently attributed to injection volumes from the RDC #1 well will be calculated and subtracted from reported injection volumes. Additionally, any additional downhole or subsurface remediations that could reduce or eliminate the leakage from the injection well to the existing and future wells in the area expected to be producing injected CO_2 will be investigated and considered.

6.3 Leakage from Faults and Fractures

dCarbon will continuously monitors the operations of the injection well through automated systems. Any deviation from normal operating conditions, including any nearby events registered by the TXNET seismic monitoring system, indicating movement into a potential pathway such as a fault or breakthrough of the confining seal would trigger an alert. Any such alert would be reviewed by field personnel and action taken to shut in the well, if necessary. Field H_2S monitoring systems would alert field personnel for any release of H_2S/CO_2 caused by such leakage

6.4. Leakage through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is extremely low, dCarbon plans to install a seismic monitoring station in the general area of the RDC #1 well. This monitoring station will augment the Bureau of Economic Geology's TexNet Seismic Monitoring system. If a seismic event of 3.0 magnitude or greater is detected, dCarbon will review the injection volumes and pressures at the RDC #1 well to determine if any significant changes occur that would indicate potential leakage.

6.5. Leakage through Lateral Migration

The distances to the closest penetration of the Ellenburger injection interval are more than ten times the expected plume migration distance. As such, leakage through lateral migration is not expected. In addition, the wells that penetrate the injection interval are saltwater disposal wells. Injection into these wells would be expected to raise the reservoir pressure locally near the well, further limiting the ability of the CO_2 to access the saltwater injector well bore.

Section 7 – Baseline Determinations

This section identifies the strategies that dCarbon will undertake to establish the expected baselines for monitoring CO_2 surface leakage per §98.448(a)(4). dCarbon will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. Daily inspections will be conducted by field personnel at the compressor facility and the injection well. These inspections will aid with identifying and addressing issues in a timely fashion in order to minimize the possibility of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions would be taken to address such issues. As previously discussed, H_2S is present in the injection stream at a low concentration. All field personnel are required to wear personal H_2S monitors, which are set to trigger the alarm at low levels of H_2S. Any alarm would trigger an immediate response to protect personnel and verify that the equipment and monitors are working properly. If monitors are working correctly and a leak is detected, immediate actions would be taken to secure the facility.

Any CO_2 release would be accompanied by H_2S and therefore the H_2S monitors at the facility would also serve as a CO_2 release warning system. In addition to personal monitors described previously, dCarbon will also conduct routine AVO and FLIR monitoring to detect any CO_2 leakage near the facility or well.

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which may be present unnecessary hazard for field personnel to perform a direct leak survey. Any leakage would be detected and managed as per Texas regulations and dCarbon's safety and operations plans. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

Baseline groundwater quality and properties will be determined and monitored through the installation of a groundwater well near the injection well site. Samples will be taken and analyzed by a third-party laboratory to establish the baseline properties of the groundwater in the area.

Baseline seismicity in the area near the RDC #1 will be determined through the historical data from USGS and TexNet seismic array data. This information will be augmented by additional data from dCarbon's seismic monitoring array.

Section 8 – Site Specific Considerations for Determining the Mass of CO_2 Sequestered

This section identifies how dCarbon will calculate the mass of CO_2 injected, emitted, and sequestered. This also includes site-specific variables for calculating the CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and the injection well, per 40 CFR §98.448(a)(5).

8.1. Mass of CO_2 Received

Per 40 CFR §98.443, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR §98.444(a)(4)." 40 CFR §98.444(a)(4) states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received."

The CO_2 received for this injection well is wholly injected and not mixed with any other supply and the annual mass of CO_2 injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

8.2. Mass of CO_2 Injected

Per 40 CFR §98.444(b), since the flow rate of CO_2 injected will be measured with a volumetric flow meter, the total annual mass of CO_2, in metric tons, will be calculated by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR-5:

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}}$$

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 (metric tons

per quarter)

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

$C_{CO_{2,p,u}}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent

CO_2, expressed as a decimal fraction)

p = Quarter of the year

u = Flow mete

8.3. Mass of CO_2 Produced

The injection well is not part of an enhanced oil recovery project; therefore no CO_2 will be produced.

8.4. Mass of CO_2 Emitted by Surface Leakage

Mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly as the injection stream for this well contains H_2S which may be hazardous for field personnel to perform a direct leak survey. Any leakage would be detected and managed as a major upset event. Gas detectors and continuous monitoring systems would trigger an alarm upon a release. The mass of the CO_2 released would be calculated for the operating conditions at the time, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR §98.448(a)(5), allowing the operator to calculate site-specific variables used in the mass balance equation.

In the unlikely event that CO_2 was released as a result of surface leakage, the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as follows:

$$CO_{2,E} = \sum_{x=1}^{X} CO_{2,x}$$

Where:

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

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

X = leakage pathway

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

8.5. Mass of CO_2 Sequestered

The mass of CO_2 sequestered in the subsurface geologic formations will be calculated based off Equation RR-12, as this well will not actively produce any oil or natural gas or any other fluids, as follows:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI}$$

Where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the Barnett RDC #1 facility in the reporting year.

$CO_{2,I}$ = Total annual CO_2 mass injected (metric tons) in the Barnett RDC #1 well in the reporting year.

$CO_{2,E}$ = 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 and the Barnett RDC #1 injection wellhead

Section 9 – Estimated Schedule for Implementation of MRV Plan

The injection well is expected to begin operation in the second half of 2023. Baseline data will be collected before injection begins and the MRV plan will be implemented upon receiving EPA approval.

Section 10 – Quality Assurance

10.1. CO_2 Injected

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with industry best practices. These flow rates will be compiled quarterly.
- The composition of the CO_2 stream will be measured upstream of the volumetric flow meter with a gas composition analyzer or representative sampling consistent with industry best practices
- The gas composition measurements of the injected stream will be averaged quarterly
- The CO_2 measurement equipment will be calibrated according to manufacturer specificati ons

10.2. CO_2 Emissions from Leaks and Vented Emissions

- Gas detectors will be operated continuously, except for maintenance and calibration.
- Gas detectors will be calibrated according to manufacturer recommendations and API standards
- Calculation methods from subpart W will be used to calculate CO_2 emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead

10.3. Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to the requirements in 40 CFR §98.3(i).
- Flow meters will be operated per an appropriate standard method as published by a consensus-based standards organization.
- Flow meter calibrations will be traceable to the National Institute of Standards and Technology

All measured volumes of CO_2 will be converted to standard cubic feet at a temperature of 60 degrees Fahrenheit and an absolute pressure of 1.0 atmosphere.

10.4. Missing Data

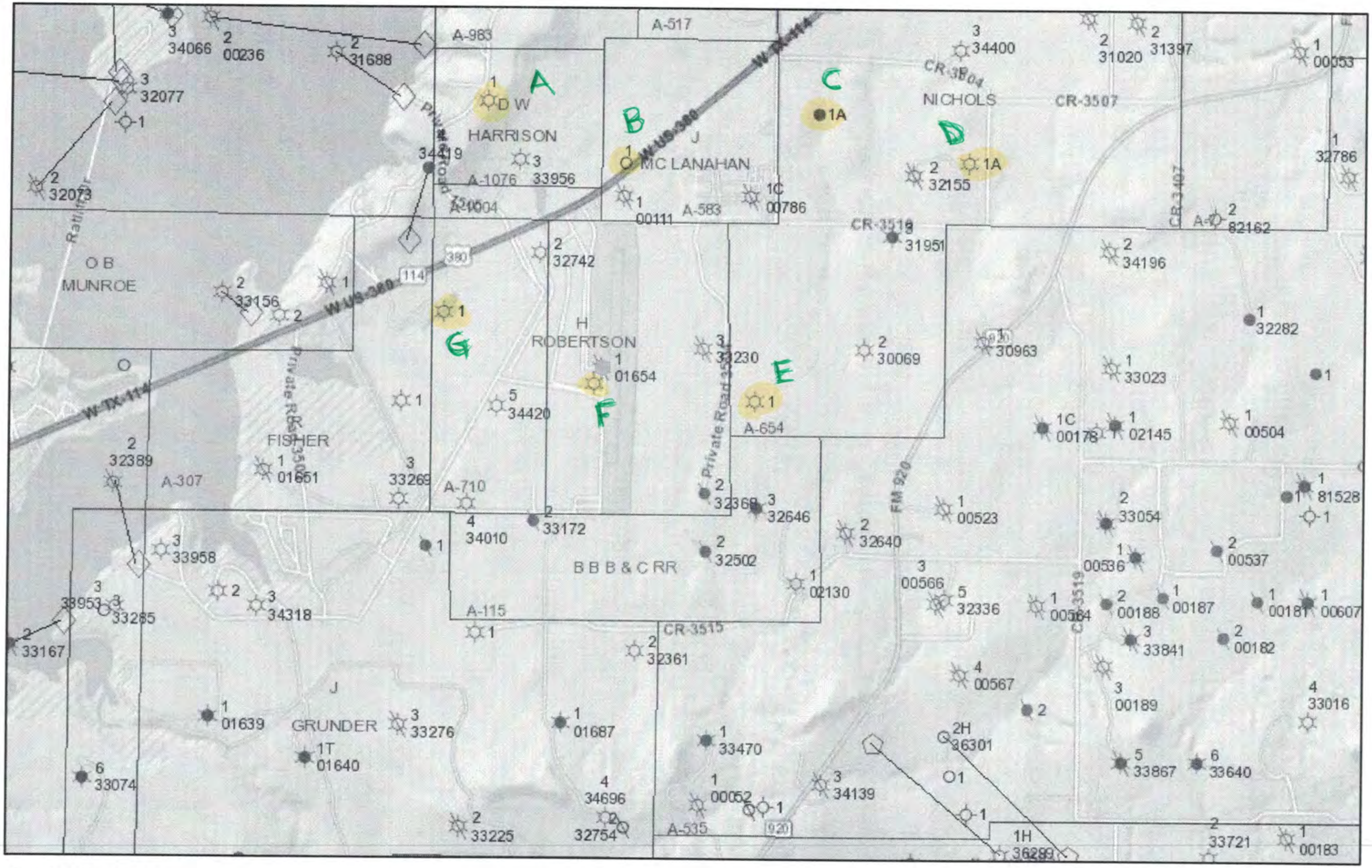
In accordance with 40 CFR §98.445, Stakeholder will use the following procedures to estimate missing data if unable to collect the data needed for the mass balance calculations:

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.
- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in subpart W of 40 CFR §98.

Section 10 – Records Retention

dCarbon will retain records as required by 40 CFR §98.3(g). These records will be retained for at least three years and include:

- Quarterly records of the CO_2 injected
- Volumetric flow at standard conditions
- Volumetric flow at operating conditions
- Operating temperature and pressure
- Concentration of the CO_2 stream
- Annual records of the information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate 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



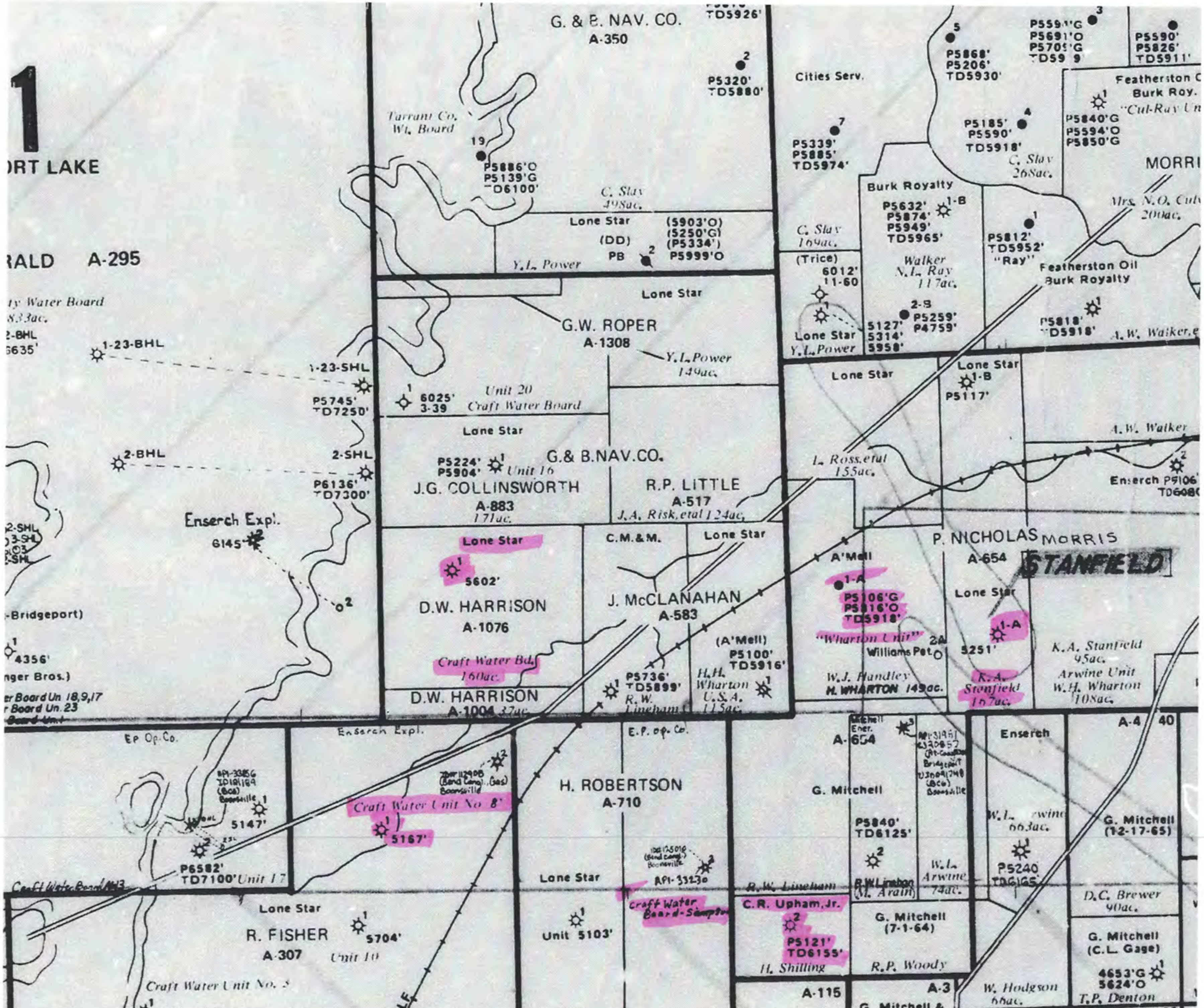
October 25, 2022

1:36,112

0 0.25 0.5 1 mi

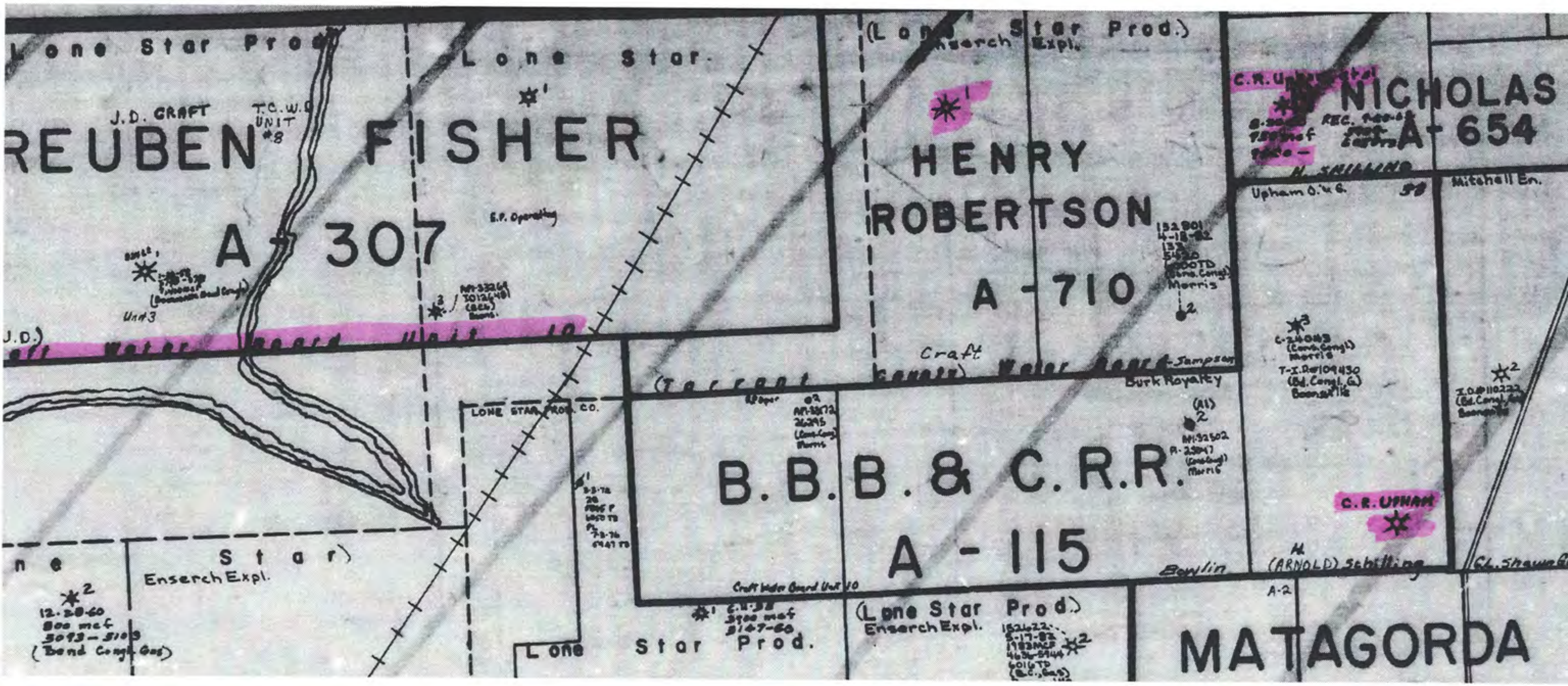
0 0.4 0.8 1.6 km

Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand),



1
ORT LAKE
RALD A-295
G. & E. NAV. CO.
A-350
Tarrant Co. Wt. Board
C. Slay 49Sac.
Lone Star
Y.L. Power
Cities Serv.
Burk Royalty
Walker N.L. Ray 117ac.
Featherston Oil Burk Royalty
Featherston C Burk Roy. "Cul-Ray Un
MORRI
Mrs. N.O. Culv 200ac.
G.W. ROPER
A-1308
Y.L. Power 149ac.
Unit 20 Craft Water Board
G.& B.NAV.CO.
J.G. COLLINSWORTH
A-883
171ac.
R.P. LITTLE
A-517
J.A. Risk, etal 124ac.
L. Ross, etal 155ac.
A.W. Walker
Enserch Expl.
D.W. HARRISON
A-1076
Craft Water Bd. 160ac.
D.W. HARRISON
A-1004 37ac.
C.M.&M.
J. McCLANAHAN
A-583
H.H. Wharton U.S.A. 115ac.
P. NICHOLAS MORRIS
A-654
STANFIELD
"Wharton Unit"
Williams Pet.
W.J. Handley
H. WHARTON 149ac.
K.A. Stanfield 167ac.
K.A. Stanfield 95ac.
Arwine Unit
W.H. Wharton 108ac.
Ep Op. Co.
Craft Water Unit No 8
H. ROBERTSON
A-710
E.P. op. Co.
Craft Water Board-Sampson
C.R. Upham, Jr.
H. Shilling
R.W. Lineham
G. Mitchell
G. Mitchell (7-1-64)
R.P. Woody
G. Mitchell (12-17-65)
D.C. Brewer 90ac.
G. Mitchell (C.L. Gage)
W. Hodgson 66ac.
T.P. Denton
R. FISHER
A-307
Unit 10
Craft Water Unit No. 5
Unit 5103'
-Bridgeport)
nger Bros.)
A-115
A-3
A-4
40


G.W. ROPER
A-1308
Y. L. Power
Y.L. Power Gas Unit "B"
(A.L. Boring)
A.L. Boring
(Lone Star Producing Co.)
Enserch Expl., Inc.
Craft Water Board Unit 23
Lone Star Producing Co.)
Enserch Expl., Inc.
Craft Water Board Unit 16 No. 2
Enserch Expl.
Craft-Water Board Unit 1
CRAFT WATER BOARD UNIT "20"
Lone Star
G & B NAV. CO.
J.G. COLLINSWORTH
CRAFT WATER BOARD UNIT "16"
A-883
R.P. LITTLE
A-517
Enserch Expl.
J.A. Risch
(Kate R. Stanfield "B")
P. NICHOLAS
A-654
STANFIELD
(5200 CONG)
Lone Star
D.W. HARRISON
A-1076
Unit 1
D. W. HARRISON
A-1064
J.D. Craft - TCWB
McCLANANAN
A-583
Christie, H. & N
Walker
Ray
DATE OF BASE
DATE REVISED
BY
1000'



Lone Star Prod.
J.D. CRAFT
T.C.W.D. UNIT #8
REUBEN FISHER
A-307
Lone Star.
E.F. Operating
Unit 3
Lone Star Prod. Co.
Enserch Expl.
12-28-60
800 mcf
5093-5103
(Bend Congl. Gas)
(Lone Star Prod.)
Enserch Expl.
HENRY ROBERTSON
A-710
Morris
Craft
Burk Royalty
B.B.B. & C.R.R.
A-115
Craft Water Board Unit 10
Lone Star Prod.
(Lone Star Prod.)
Enserch Expl.
NICHOLAS
A-654
Upham O. & G.
Mitchell En.
C.R. UPHAM
(ARNOLD) Schilling
Bowlin
A-2
MATAGORDA

44447

©

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No.

Operator A'Mell Oil Properties Address 1201 Elm St., Dallas, Texas

County Wise Survey J. McClanahan Block No. A-583 Sec. No.

Lease Name H. H. Wharton Well No. 1 Elevation 795 GL (Above Sea Level)

Name of Field in which well is located Boonesville Conglomerate Gas

Form 1 (Notice of Intention to Drill) Was Filed in Name of A'Mell Oil Properties

Is this a NEW WELL? Yes DEEPENING? – or a WORK-OVER? –

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

(Work-Over) (Drilling) Commenced April 27, 19 61 (Work-Over) (Drilling) Completed May 15, 19 61

Correspondence regarding this well should be sent to: Name A'Mell Oil Properties Address 1201 Elm St., Dallas, Texas

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
8-5/8"	153	77	–	–	153	77	
2-7/8"	5204	00	–	–	5204	00	

Initial Production of Gas—Volume 250 MCF 24 hrs. Pressure 500 lbs. per square inch

Initial Production of Oil: Barrels 5 of Frac per day

Initial Production of Distillate: Barrels Trace

Is this an OIL well? No , a GAS well? Yes , or a Dry HOLE?

DESCRIPTION OF PROPERTY

NORTH

WEST

EAST

SOUTH

RECEIVED
SEP 18 1961
Railroad Commission of Texas
OIL & GAS DIVISION
WICHITA FALLS, TEXAS

GENERAL REMARKS

LTR BD OF WATER EN R
DATED April 19, 1961
RECOMMENDS 150 FT.
See letter attached

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS		
Shale w/sd & lm stks	0	30	Shale & Sdy shale	3861	3964
Lime	30	37	Shale w/lm stks	3964	4020
Shale & Shells	37	45	Shale & sdy sh w/lm	4020	4299
Lime & Shale	45	72	Shale w/lm & sh stks	4299	4544
Shale & Lime	72	130	Lime (Caddo)	4544	4591
Lime	130	136	Shale & lm	4591	4645
Lime & Shale	136	173	Shale w/lm & sd stks	4645	4731
Shale & Lime	173	220	Shale & lm	4731	4848
Lime & Shale	220	258	Shale & lm shale	4848	5069
Shale w/lm stks	258	328	Shale	5069	5085
Water Sand	328	346	Shale, cong shale & conglomerate	5085	5138
Shale, sd & lm stks	346	890	Shale w/cong stks	5138	5159
Shale & lm	890	925	Shale & lm shale	5159	5202
Shale & lm w/sdy stks	925	1067	Shale & lm stks	5202	5220
Lime	1067	1117	Hard tight cong.	5220	5232
Shale w/lmy stks	1117	1165	Shale & cong	5232	5240
Sand & Shaley sd	1165	1196	Hard tight cong	5240	5241
Shale w/lm & sd stks	1196	1477	Shale w/cong stks	5241	5350
Shale	1477	1500	Shale & Cong sh stks	5350	5400
Shaley sd	1500	1570	Shale & lm shale	5400	5440
Shale & sd stks	1570	1620	Shale & cong stks	5440	5533
Hard sd	1620	1646	Hard tight cong	5533	5540
Shaley sd	1646	1896	Broken tight cong	5540	5548
Shale & sdy shale	1896	2087	Shale w/cong stks	5548	5557
Shale w/sd & lm stks	2087	2269	Shale w/tight congstks	5557	5672
Shale w/sd & lm sh stks	2269	2408	Shale	5672	5733
Shale w/sd & lm stks	2408	2429	Limey shale	5733	5749
Shale & chalkey lm	2429	2533	Shale w/tight cong stks	5749	5828
Shale & lm stks	2533	2655	Shale & cong	5828	5841
Lime & Shale	2655	2658	Cong w/very faint flor	5841	5860
Shale w/lm stks	2658	2767	Shale w/cong stks	5860	5916
Shale & lm	2767	2804		TD	
Shale w/lm & sd stks	2804	2995			
Shale & lm	2995	3020			
Lmy shale & lm shells	3020	3035			
Lime w/specks flo. (no odor)	3035	3052			
Shale & lm	3052	3062			
Shale	3062	3121			
Shale & lm stks	3121	3230			
Shale & lm	3230	3336			
Shale w/lm stks	3336	3506			
Lime	3506	3520			
Shale & lm shale	3520	3658			
Shale w/lm stks	3658	3840			
Lime	3840	3849			
Lime	3849	3861			

Method of shutting off water No water Is water completely shut off? Yes

Amount of water with oil NONE per cent

I, A. W. Amell being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

A W Amell
Representative of Company.

Subscribed and sworn to before me this 22nd day of June, 19 61

[signature]
Notary Public
Dallas County, Texas.

RECEIVED
APR 24 1961
Railroad Commission of Texas
OIL & GAS DIVISION
AUSTIN, TEXAS

44447

M

Application to Drill, Deepen or Plug Back.

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 1
Rev. 4/60

STATE WHETHER THIS IS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK Drill

SHALL BE FILED IN DUPLICATE (IN TRIPLICATE IF RULE 37) WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED
DATA FURNISHED ON THIS FORM AND ANY ATTACHMENT HERETO MUST BE CLEARLY LEGIBLE.
ANY ILLEGIBLE FORM WILL BE RETURNED WITHOUT COMMISSION ACTION.
(Black Ink or Black Typewriter Ribbon Preferable)

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, to this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines. Also show the nearest wells on all sides of this location and the distance from the proposed location to those wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equaling 1000 feet; if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THIS PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line 467 feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease - feet.

IS THE ACREAGE ON WHICH THIS WELL IS TO BE LOCATED, PRESENTLY ASSIGNED TO ANOTHER WELL IN ANY RESERVOIR FOR WHICH THIS PERMIT IS REQUESTED? No

Date April 18, 1961

Name of company or operator

Name A'Mell Oil Properties

Address 1201 Elm Street,

City Dallas 2, Texas

Description of farm or lease:

Name of Lease Howard H. Wharton

Number of Acres 332 Well No. 1

Number of wells on lease None

Elevation ______ (Ft. above sea level) Section No. ____ Block No. ____

Survey J. McClanahan - A 583

Zone or Reservoir Conglomerate

To be Located in Boonesville(Bend Congl. Gas)

(If Wildcat state above, also state Distance and Direction from nearest Survey Lines.)

Wise County

4 Miles Northwest direction from

Bridgeport, Texas nearest post office or town.

Rotary or Cable Tools Rotary

Date work will start drilling on permit

Depth to which you propose to drill 6200 feet.

Date work will start deepening

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?

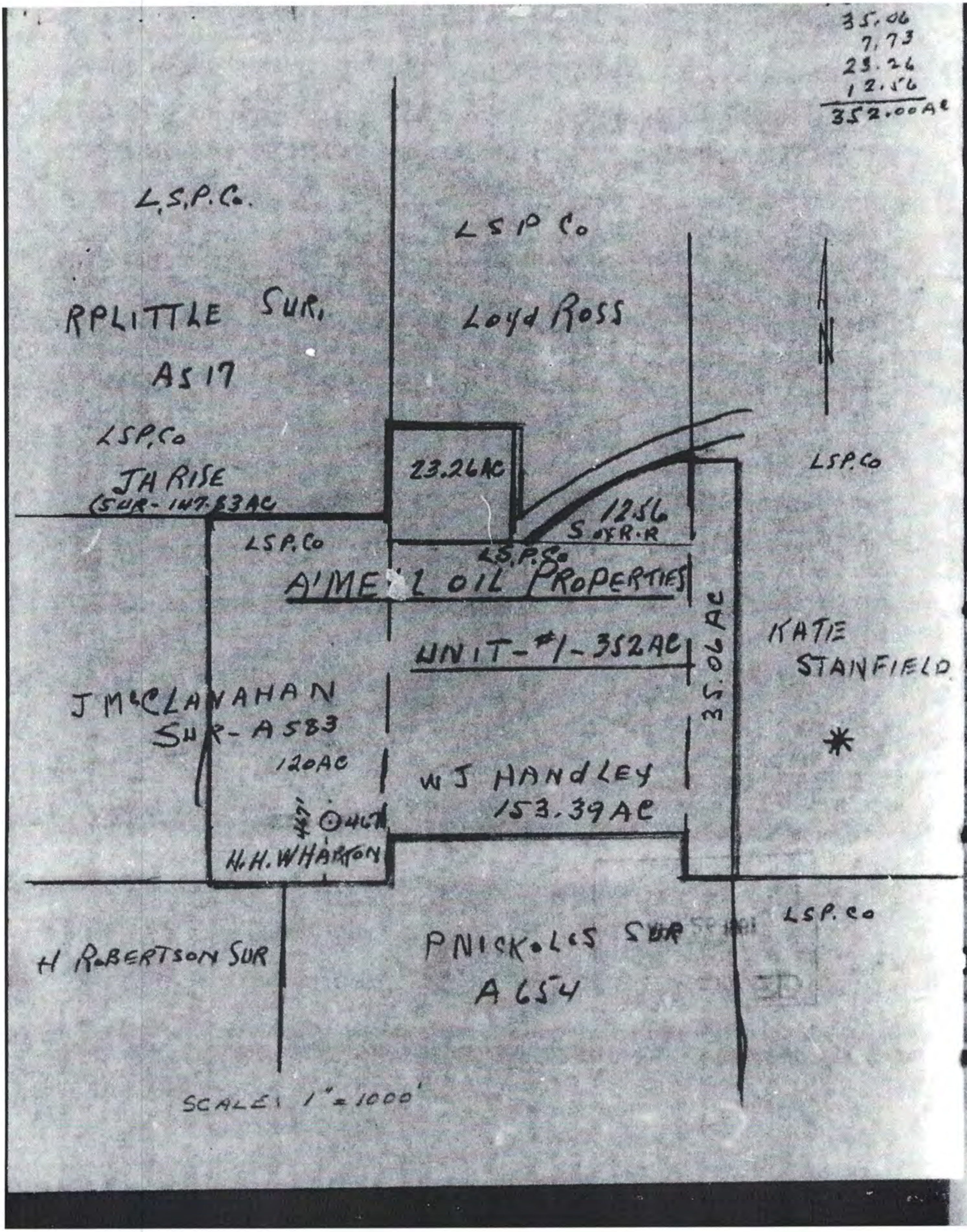
Name

Address

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

25 / DR



35.06
7.73
23.26
12.56
352.00AC
L.S.P.Co.
LSP Co
RPLITTLE SUR.
AS17
Loyd Ross
N
LSP.Co
JA RISE
(SUR-147.33AC
23.26AC
12.56
S of R.R
LSP.Co
LSP.Co
LS.P.Co
A'ME L OIL PROPERTIES
UNIT-#1-352AC
35.06AC
KATE
STANFIELD
J McCLANAHAN
SUR-A583
120AC
WJ HANdLEY
153.39AC
H.H. WHARTON
LSP.co
H ROBERTSON SUR
P NICKOLCS SUR
A654
SCALE: 1"=1000'

9

(D)

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No.

Operator LONE STAR PRODUCING COMPANY Address 301 S. Harwood, Dallas, Texas

County Wise Survey Phillips-Nicholas Block No. (A-654) Sec. No.

Lease Name Kate Ann Stanfield "A" Well No. 1-C Elevation 810 (Above Sea Level)

Name of Field in which well is located Boonsville (Bend Conglomerate Gas)

Form 1 (Notice of Intention to Drill) Was Filed in Name of Lone Star Producing Company

Is this a NEW WELL? Yes

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

(Drilling) Commenced 11-17 1959 (Drilling) Completed 12-9- 1959

Correspondence regarding this well should be sent to: Name A. L. Poynor Lone Star Prod. Co. Address Box 767, Jacksboro, Tex.

Has an allowable been assigned to this well? No.

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
9-5/8	324				324		
5½	5400				5400		HOWCO DV Tool @ 3238' packer shoe at 5394'
2-3/8	5217				5217		HOWCO Type "C" Pkr. @ 5217

Initial Production of Gas—Volume 1916 MCF 24 hrs. Pressure 200 lbs. per square inch

Initial Production of Oil: Barrels 23 bbls. (frac oil)

Initial Production of Distillate: Barrels

Is this an OIL well? , a GAS well? Yes , or a Dry HOLE?

DESCRIPTION OF PROPERTY
NORTH

See Form 1 filed Oct.1,1959

WEST

EAST

SOUTH

GENERAL REMARKS

This well is dually completed as an oil & gas well. A HOWCO Type "C" permanent packer set @ 5217' to separate the upper zone gas & the lower zone oil. Well is completed w/1 string of 2-3/8" OD tbg. & 2-Garrett Oil Tool circulating sleeves. Lower sleeve is below Type "C" & Upper sleeve above packer.

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMA[redacted]D

Show All Formations, Especially All [redacted] Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS	
Sh W/Sd & Lm Stks.	0	110	Sh W/Lm & Sd Stks	3160
Sd & Lime		165	Shale W/Sdy Stks.	3214
Sh & Sd Stks.		222	Lime	3230
Lime		280	Shale-Lime & Sdy	3306
Sh & Sdy Sh		354	Shale-Sd Stks.	3410
Sh & Sd Stks		433	Sand - Lime	3440
Sh W/Lm & Sd		450	Shale & Sand	3487
Shale		550	Limey Sand & Shale	3505
Sh & Sd Stks		815	Sh - Lmy & sdy.	3544
Sh, Lm & Sd		950	Lime	3555
Sh & Lm		1082	Shale-Sdy-Lime Stks.	3838
Lime		1034	Shale	3875
Sand		1205	Lime	3893
Sh, Sd & Lime Stks		1340	Shale & Sandy Shale	3933
Limey Sh		1380	Limey Sand & Shale	3955
Shale		1560	Limey Sand	3975
Sh W/Sdy Lm		1580	Shale & Sand	3999
Sh - Sdy Shale		1655	Shale-Sand & Lime Stks.	4076
Sh - Sand & Lm		1700	Shale W/Sdy Stks.	4197
Sh & Sdy Sh		1798	Shale	4549
Sand -- No Shows		1835	Shale W/Lime Stks.	4601
Shale & Sd Stks		1865	Shale & Chalky Lime	4606
Lm, Sd & Sh		1929	Limme & Shale	4622
Sh, Lm & Sd		2118	Lime	4639
Sh & Sd Stks		2247	Shale & Limey Shale	4666
Sand		2259	Lime	4672
Sh W/Sand		2410	Lime & Shale	4864
Lm, Sh W/Sd Stks.		2558	Shale	4927
Lime & Shale		2600	Shale & Lime	5216
Lime		2619	Shale	5224
Sh & Sd Lm		2632	Lime	5239
Sh & Lm		2673	Shale	5246
Lime, Sh & Sand		2695	Shale & Lime	5276
Sand & Shale		2724	Congl. (Show)	5276
Shale		2765	Congl. & Lime	5294
Lim - Shale		2847	Shale-Lime & Congl. Stks.	5306
Sh W/Lm & Sd		2863	Shale & Lime	5397
Sh & Sdy Sh		2890	Lime	5422
Sh - Lm & Sd.		2932	Shale & Lime	5503
Sand & Shale		2948	Lime	5513
Sh & Sdy - Lm		3008	Shale-Lime	5518
Sh - Sdy Stks.		3030	Shale	5550
Sd & Shale		3053	Shale & Limey Shale	5598
Sand (Show)		3062	Lime & Shale	5609
Lime		3077	Limey Shale & Lime	5640
Shale		3095	Shale	5651
Sand & Shale		3130	Limy, Shale & Lime	5662

Railroad Commission of Texas
OIL & GAS DIVISION
AUSTIN, TEXAS
JAN 29 1960

Method of shutting off water Cement & Csg. Is water completely shut off? Yes

Amount of water with oil .... per cent ....

I, E. L. Smith, Jr.
being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

E. L. Smith, Jr.
Representative of Company.

Subscribed and sworn to before me this 19 day of January, 1960

Lorene Stanfield
Notary Public
Jack County, Texas.

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Shale	5662	5668	
Sh - Lm Sh		5754	
Lime		5778	
Shale & Lime		5783	
Limey Shale & Lime		5806	
Lime		5825	
Shale & Lime		5883	
Lime-Shly. Congl.		5918	
Lime & Congl. Stks.		5930	
Lime & Limey Shale		5964	
Lime		5972	
Shale & Limey Shale		5996	
TOTAL DEPTH			

Method of shutting off water .... Is water completely shut off? ....

Amount of water with oil .... per cent ....

I, ...

being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

....

Representative of Company.

Subscribed and sworn to before me this .... day of ...., 19.......

....

Notary Public

.... County, Texas.

52007

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No.

Operator Lone Star Producing Co. Address 301 S. Harwood St. Dallas, Texas

County Wise Survey Phillip Nicholas (A-654) Block No. Sec. No.

Lease Name Kate Ann Stanfield "A" Well No. 1-T Elevation 810 (Above Sea Level)

Name of Field in which well is located Bonnville (5085 Atoka Conglo) ~~Stanfield (5250' Congl.)~~ - [redacted]

Form 1 (Notice of Intention to Drill) Was Filed in Name of Lone Star Producing Co.

Is this a NEW WELL? Yes DEEPENING? or a WORK-OVER?

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

([redacted]) (Drilling) Commenced 11-17, 1959 [redacted] (Drilling) Completed 12-9, 1959

Correspondence regarding this well should be sent to: Name Mr. A. L. Poynor Address Box 767-Jacksboro, Texas

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
9-5/8	324				324		
5½	5400				5400		HOWCO DV tool @ 3238 packer shoe @ 5394'
2-3/8"	5217				5217		HOWCO Type "C" pkr. @ 5217

Initial Production of Gas—Volume 292 MCF 24 hrs. Pressure 140# lbs. per square inch

Initial Production of Oil: Barrels 60

Initial Production of Distillate: Barrels

Is this an OIL well? Yes, a GAS well? or a Dry HOLE?

DESCRIPTION OF PROPERTY
NORTH

See Form 1 field Oct. 1, 1959

WEST

RECEIVED
JAN 28 1960
Railroad Commission of Texas

EAST

SOUTH

GENERAL REMARKS

This well is dually completed as an oil & gas well A HOWCO Type "C" permanent packer set @ 5217' to separate the upper zone gas & the lower zone oil. Well os completed w/1 string of 2-3/8" OD tbg. & 2-Garrett Oil Tool circulating sleeves Lower sleeve is below Type "C" packer & upper sleeve is a bove packer.

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

52007

Please refer to File No.................

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

RECEIVED
OCT 2 1959
Railroad Commission of Texas
Oil & Gas Division
Wichita Fall, Texas

APPLICATION TO DRILL, DEEPEN OR PLUG BACK

IS THIS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK....DRILL....

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, of this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines.. Also show the nearest wells on all sides of of this location and the distance from the proposed location to these wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equaling 1000 feet; if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THIS PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line...467...............feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease.....—...feet.

Date....October 1............ 19..59...

Name of company or operator

Name......Lone Star Producing Company........

Address...301 S. Harwood Street...............

City......Dallas, Texas...................

Description of farm or lease:

Name of Lease...Kate Ann Stanfield "A".........

Number of Acres..211.66.......Well No....1.......

Number of wells on lease..none...............

Survey Phillip Nicholas (A-654)

Elevation....810...............Feet (ABOVE SEA LEVEL)

Section No....................Block No.............

Located in...Wildcat..........................Field

(If Wildcat state above)

.......Wise..................................County

.......3............Miles...SW.....direction from

....Bridgeport......nearest postoffice or town.

Rotary or Cable Tools..Rotary...................

Date work will start drilling...on permit........

Depth to which you propose to drill..6,000...feet.

Date work will start deepening....................

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?

Name...

Address..

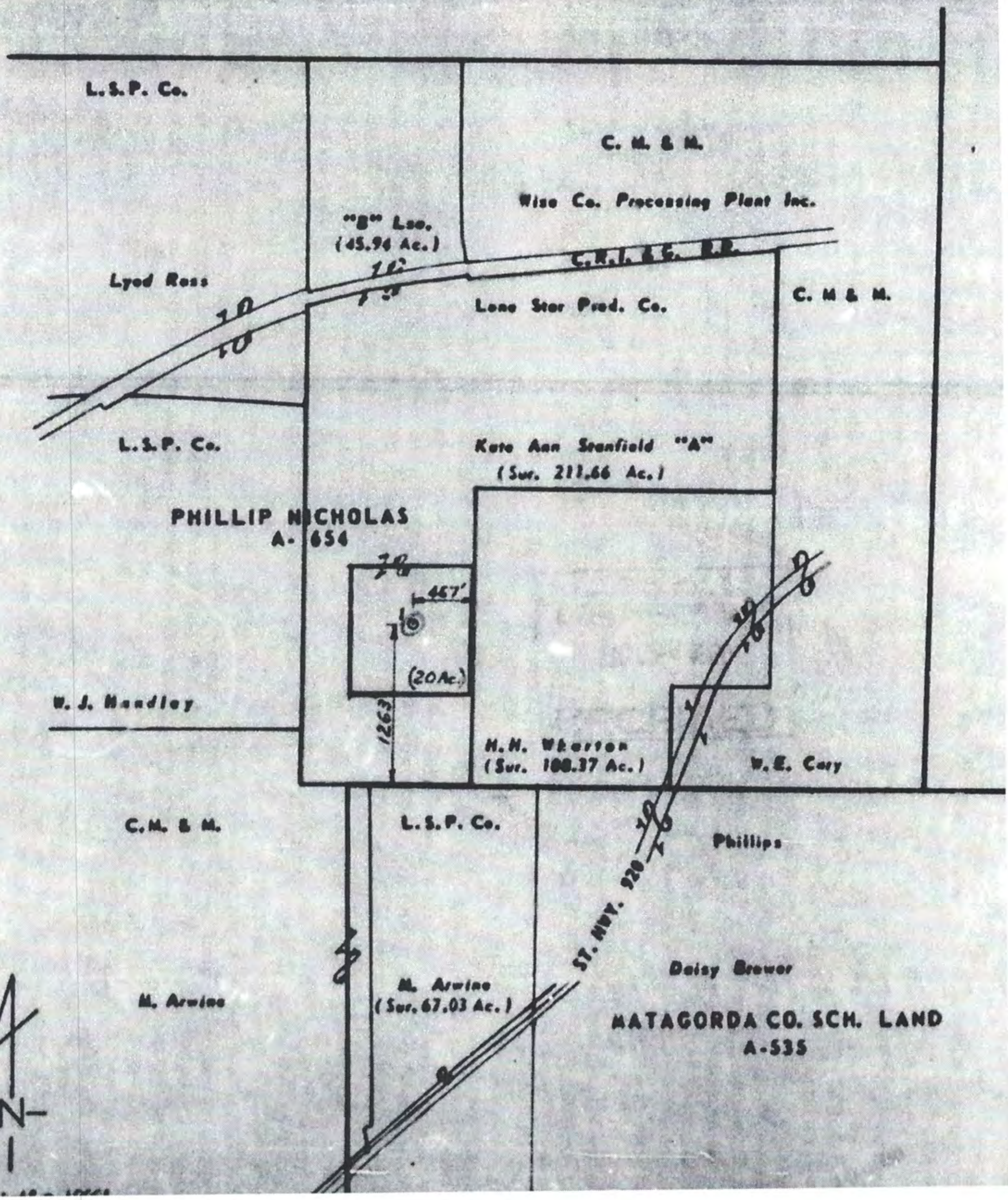
OK
Dr.

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

Subscribed and sworn before me this the 29th day of Sept. 1959 A.D.

Notary Public, Dallas County, Texas



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RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

AUG 12 1971

(E)

Form G-1

RRC District: 9

RRC Identification Number: 51023

GAS WELL BACK PRESSURE TEST
COMPLETION OR RECOMPLETION REPORT AND LOG

1. FIELD NAME: Boonsville (BCG)

2. LEASE NAME: Harold Shilling

LTR TEX W...

Well Number: 2

OPERATOR: Upham Oil & Gas Company

10. County: Wise

3. ADDRESS: P. O. Box 940, Mineral Wells, Texas 76067

DATED 5-10-71

11. Purpose of Test: Initial Potential X

5. If Operator has changed within last 90 Days — Give former Operator

RECOMM. NL 300 FT

Retest

Reclass

6. LOCATION (Section, Block, and Survey): P. Nicholas Survey A-654

12. Pipe Line Connection: Not connected

13. If Workover, give former Field (with Reservoir)

14. Completion Date: 7/30/71

List of Offset Operators Notified and Date of Notification

16. Type of Electric or other Log Run: Induct-Elec. & Sonic

Section I — GAS MEASUREMENT DATA

Date of Test: 8/2/71

Gas Measurement Method (Check One): Orifice Meter / Positive Choke / Orifice Vent Meter / Pitot Tube / Critical flow Prover X

Gas produced during test: 277 MCF

Run No.	Line Size	Orifice or Choke Size	24 Hr. Coeff. Orif. or Choke	Static P_m or Choke Press.	Diff. h_w	Flow Temp. °F	Temp. Factor F_{tf}	Gravity Factor F_g	Compress. Factor F_{pv}	Volume MCF/DAY
1	2.00	1.125	28.9803	31		56	1.0039	.9258	1.004	838
2	2.00	.625	8.5694	86		60	1.0000	.9258	1.011	690
3	2.00	.625	8.5694	74		63	0.9971	.9258	1.011	591
4	2.00	.625	8.5694	62		65	0.9952	.9258	1.011	495

Section II — FIELD DATA AND PRESSURE CALCULATIONS

Gravity Dry Gas	Gravity Liquid Hydrocarbon	Gas-Liquid Hydro Ratio	Gravity of Mixture G_{mix}	Avg. Shut-In Temp.	Bottom Hole Temp.
.700	60 Deg. API	105,000 CF/Bbl	.724	103 °F	132°F @ 6155 (Depth)

$D_{eff}^{8.3}$

GL

C = 1128 ÷ $(D_{eff})^{8.3}$

GL / C

Run No.	Time of Run Min.	Choke Size	Wellhead Press. P_w PSIA	Wellhead Flow Temp. °F	P_w^2 (Thousands)	R	R^2 (Thousands)	P_f	P_w P_f
Shut-in	72 hrs.		1325	74					
1	5 hrs.	20/64	615	80					
2	2 hrs.	16/64	725	80					
3	1 hr.	12/64	770	80					
4	1 hr.	10/64	787	80					

Run No.	F	K	S	e^{s}	P_f and P_s	P_f^2 and P_s^2	$P_f^2 - P_s^2$
Shut-in		.1240	1.297	1.175	1557	2424	
1		.1235	1.228	1.164	716	513	1911
2		.1235	1.237	1.166	845	714	1710
3		.1235	1.243	1.167	899	808	1616
4		.1235	1.243	1.167	918	843	1581

Angle of Slope

θ = 45

n = 1.000

Absolute Open Flow: 1,060 MCF/DAY

OPEN FLOW TEST:

Shut-In Press. Psig

Time Shut-In Hrs.

Producing Through

In. H₂O Time	In. Hg Reading	Time	Psig Reading

REPRESENTATIVE OF COMPANY MAKING TEST

REPRESENTATIVE OF RAILROAD COMMISSION

CERTIFICATE:

I declare under penalties prescribed in Article 6036c, R.C.S., that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct, and complete to the best of my knowledge.

REPRESENTATIVE OF COMPANY

Geologist — TITLE

8/10/71 — DATE

497 30085

SECTION III — DATA ON WELL COMPLETION AND LOG (Not Required on Retest)

17. Type of Completion: New Well X — Deepening — Plug Back — Other

18. Date Permit Issued: May 11, 1971

19. Notice of Intention to Drill this Well was filed in Name of: Upham Oil & Gas Company

20. If Special Permit, Give Permit Number:

21. Number of Producing Wells on this Lease in This Field (Reservoir) including this Well: One

22. Total Number of Acres in this Lease: 245.27

23. Date Plug Back, Deepening, Workover or Drilling Operations: Commenced June 15,1971 — Completed July 1, 1971

24. Distance to Nearest Well, Same Lease & Reservoir: None

25. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located: 467 Feet From North Line And 934 Feet From West Line of The Harold Shilling Lease

26. Elevation: 833 GL & 842' RKB

27. Was Directional Survey Made: Yes X No

28. Top of Pay: 5121 — 29. Total Depth: 6155 — 30. P.B. Depth: 5389

31. Surface Casing Determined By: Recommendation of Texas Water Development Board X — Field Rules — Railroad Commission (Special)

32. Is Well Multiple Completion: Yes — No X

33. If Multiple Completion, List All Reservoir Names:

34. Intervals Drilled By: Rotary Tools Surf.-T.D. — Cable Tools

Name of Drilling Contractor: Bearden Drilling Company

Is Cementing Affidavit Attached: Yes — No X

CASING RECORD (Report All Strings Set in Well)

Casing Size	Weight LB FT.	Depth Set	Hole Size	Cementing Record	Amount Pulled
8-5/8	20# & 24#	331	12-1/4"	250 sx Reg. w/2% C.C.	None
5-1/2	15.5#	5418.61	7-7/8"	175 sx Pozmix w/4% Gel.	None

LINER RECORD

Size	Top	Bottom	Sacks Cement	Screen
None				

TUBING RECORD

Size	Depth Set	Packer Set
2-3/8	5258	None

40. Producing Interval (this completion) Indicate Depth of Perforations or Open Hole

From	To
5121	5129
5194	5202
5211	5217
5238	5252

ACID, SHOT, FRACTURE, CEMENT SQUEEZE, ETC.

Depth Interval	Amount and Kind of Material Used
5121-5252	1,000 gallons acid and fractured with 10,000 gallons treated salt water and 20,000 pounds of sand. (10/40)

FORMATION RECORD (LIST DEPTHS OF PRINCIPAL GEOLOGICAL MARKERS AND FORMATION TOPS)

Formations	Depth	Formations	Depth
Water Sand	1065 - 1118	Lime (Caddo)	Top 4556
"	Top 1177	Conglomerate (Atoka)	Top 5118
"	Top 1238	Lime (Marble Falls)	Top 6074
Lime	Top 2558		
"	Top 2916		
" (M-1)	Top 3840		

REMARKS

```
DISTRICT> 09        GAS WELL DATA INQUIRY - PAGE 1       SCHEDULE  > 11 / 22
FIELD    > BOONSVILLE (BEND CONGL., GAS)      # 10574 520 TYPE FIELD> CAPACITY
OPERATOR> UPHAM OIL & GAS COMPANY             # 878925   DRILL PMT >
LEASE    > SHILLING, HAROLD                              API #     > 497 30085
COUNTY   > WISE             RRCID 051043 WELL #     2    ALLOW EFF > 11/01/2022
TYPE WELL> PRODUCING                                     TOP ALLOW >
OFFSHORE>    BAYS/EST    STATE    DS>     0       0      CYCL ALLOW>
OP LACK>
OTHER  >
SCHED REM >
TOT LEASE ACRES>            COMMINGLING                      CAPABILITY        4
"@" AMOUNT> 999999999   DATE> MM/YYYY   HIGH DLY AVG> 999999999   DATE> MM/YYYY
SPEC ALLOW >       100  CODE> ADMINISTRATIVE
G-10 TEST  >  07/14/2022 TYPE >  R LAST UTIL>            G-1 TEST >    08/02/1971
DELIV      >          4  DELIV LTR EFFEC>                G-1 POTE   >  NOT REQ.
DELIV CODE >             CAL DEL POTE    >               TEMPERATURE>
WH PRESS CD>             SIWH>      90   BHP CD>               BHP >         100
GAS GRAV   >   .758      COND GRAV  >  60.0              GOR        >     270
ACRES-FT   >             ACRES      >          85.2700   G1 TEST GAS>
SUPP ISSUED>  10/17/2022   SUPP REMARKS  >

GO TO RRCID <         > ENTER=PG2 PF1=HELP          PF3=DRL PMT PF4=RESTART
PF5=NEXT WELL PF6=FLD PF7=PROR SCH PF8=P4 PF9=LDGR PF10=G-10 PF11=RMKS PF12=G-1
```

9 (F)

RAILROAD COMM[redacted] TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No. ______

Operator Lone Star Producing Co. Address Jacksboro, Texas

County Wise Survey Henry Robertson (A-710) Block No. ______ Sec. No. ______

Lease Name Kraft-Water Board Sampson Unit 1 Well No. 1 Elevation 835' (Above Sea Level)

Name of Field in which well is located Boonsville (Bend Congl. Gas) Field

Form 1 (Notice of Intention to Drill) Was Filed in Name of Lone Star Producing Co.

Drilling Commenced 10-5, 19 57 Drilling Completed 10-28, 19 57

Is this a NEW WELL? Yes : DEEPENING? ______ or a WORK-OVER? ______

Correspondence regarding this well should be sent to: Name Lone Star Producing Co. Address Box 1047- Jacksboro, Texas

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL		PULLED OUT		LEFT IN WELL		PACKERS AND SHOES
	Ft.	In.	Ft.	In.	Ft.	In.	
9-5/8"	315'	0.4					HOWCO guide shoe
5½"	5621						HOWCO guide shoe

Initial Production of Gas—Volume 3,120 MCF 24 hrs. Pressure TBG-500# Sep- 200# lbs. per square inch

Initial Production of Oil: Barrels 30 bbls. frac oil 1hr.

Initial Production of Distillate: Barrels ______

Is this an OIL well? ______, a GAS well? Yes, or a Dry HOLE? ______

DESCRIPTION OF PROPERTY

NORTH

See Form 1 filed August 20, 1957

WEST

RECEIVED
FEB 13 1958
Railroad Commission of Texas
Oil & Gas Division
Wichita Falls, Texas

SOUTH

GENERAL REMARKS

9-5/8" csg. cemented w/250 sks

5½" csg. cemented w/201 sks

Perforated 5103-5110, 5112-5120 (Schl)

w/4 dyno jets per foot. (60 holes)

Acidized w/500 gal MCA

Fractured w/10,000 gal oil and

10,000# sand.

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS
Shale & lime	0	100	
Sand & shale	100	150	
Sh w/lm stks	150	290	
sh & sd stks.	290	360	
sh w/lm & sh stks.	360	646	
sh w/lm & sd stks.	646	1322	
sh w/sd stks.	1322	1550	
sh w/sdy lm stks.	1550	2370	
shale	2370	2536	
sh w/sdy lm stks.	2536	2638	
Lime	2638	2659	
sh w/sd & lm stks.	2659	3495	
sh w/lime shells	3495	3571	
sh w/lime stks.	3571	4000	
sh & sand	4000	4015	No jeep - no odor
sh w/ sd & lm stks.	4015	4550	
Lime	4550	4560	
Lime	4560	4575	Jeep & odor
Lime & shale	4575	4594	
sh & lime congl	4594	4610	
sh & lime stks.	4610	4967	
sh lm & congl	4967	4981	
sh , lm & congl	4981	5100	
sh lm & congl	5100	5174	
Sd & congl stks.	5174	5198	
shaley congl	5198	5207	
sh & congl	5207	5230	Jeep & odor
sh w/lime stks.	5230	5683	
sh & congl stks.	5683	5711	
sh & lime stks.	5711	5790	
sh & sdy congl	5790	5823	
Lime congl	5823	5862	
sh sd & lmy congl	5862	5942	
sh & congl stks.	5942	6027	

Method of shutting off water .... Is water completely shut off? ....

Amount of water with oil ....

I, T. R. Pledger being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

T. R. Pledger
Representative of Company.

Subscribed and sworn to before me this 10th day of February, 1958

Lorene Stanfield
Notary Public
Jack County, Texas.

*** OIL AND GAS DIVISION *** INQUIRY
PLUGGING DATA

TYPE/WELL(O/G/D/S): **G** API NUMBER: **497 01654**
DIST: **09** LEASE/ID: **132120** WELL #: **1**
FIELD NAME: **BOONSVILLE (CADDO LIME)**
LEASE NAME: **CRAFT WATER BOARD SAMPSON**
OPER NAME: **ENSERCH EXPLORATION, INC**
DRILL PERM ISSUED: **07 / 21 / 1989** PERMIT #: **361291** SFPC:
DRILL COMPLETED: **04 / 09 / 1989** WELL PLUGGED: **09 / 27 / 1996**
DATE W-3 FILED: **02 / 10 / 1997** TOTAL DEPTH: **6028**
DIST W3 APPR DATE: **MM / DD / YYYY**
WAS THIS A MULTIPLE COMPLETION? **N** WELL WAS CONVERTED TO FRESH WATER USE? **N**

	PLUG 1	PLUG 2	PLUG 3	PLUG 4	PLUG 5	PLUG 6	PLUG 7	PLUG 8
BOTT DEP:	5120	4568	598	385	13			
SACK CEM:	25	25	25	60	5			
CALC TOP:	4900	4348	498	265	3			
TOP/PLUG:	0	0	0	0	0			
TYPE CEM:	C	C	C	C	C			

*

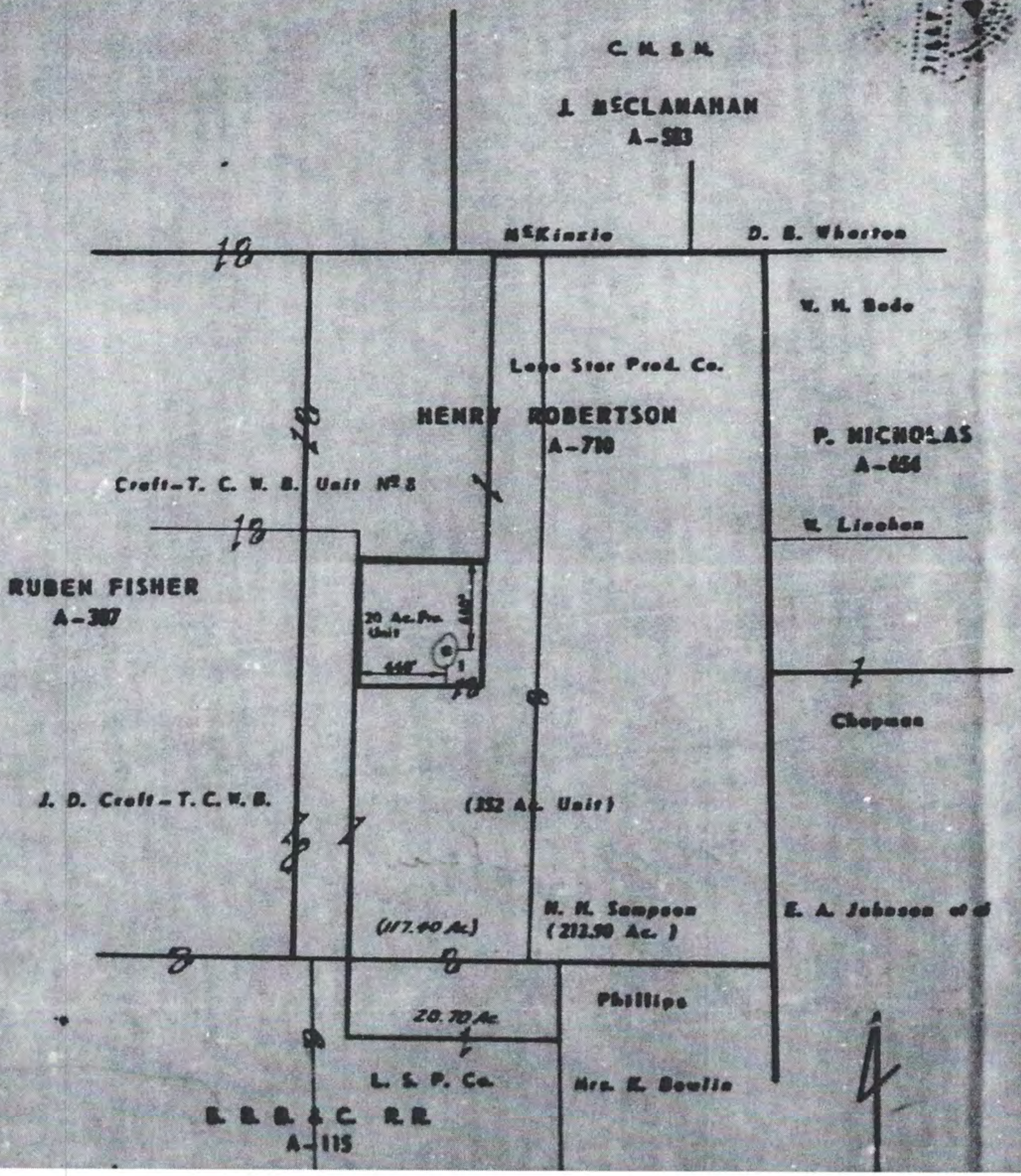
* SCREEN OPTIONS: 17=PLUG CAS/TUB/PERFS, 18=WATER/LOGS/REMARKS *
* SELECT OPTION: __ (01=RETURN TO MENU, 00=HELP AND OTHER OPTIONS) *
DEPRESS ENTER TO SEE PLUG CASING/TUBING/PERFS

I, BILLY M. SASSE, being duly sworn on oath, state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

Billy M. Sasse
Registered Public Surveyor

Subscribed and sworn before me this the 13th day of August 1957 A. D.

Geraldine Kney
Notary Public, Dallas County, Texas



RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

G

Form 2
Well Record

File No. ______

Operator: Lone Star Producing Co. Address: 301 S. Harwood St.- Dallas, Texas

County: Wise Survey: Ruben Fisher (A-307) Block No. ______ Sec. No. ______

Lease Name: Craft-Wtr. Bd Unit 30 Well No. 1 Elevation 836 (Above Sea Level)

Name of Field in which well is located: Boonsville (Bend Congl. Gas)

Form 1 (Notice of Intention to Drill) Was Filed in Name of: Lone Star Prod. Co.- Craft-Wtr. Bd Unit 30 #1

Drilling Commenced 11-17, 19 57 Drilling Completed 12-11, 19 57

Is this a NEW WELL? Yes , DEEPENING? ______ or a WORK-OVER? ______

Correspondence regarding this well should be sent to: Name Lone Star Prod. Co. Address Box 767-Jacksboro, Tex.

Has an allowable been assigned to this well? No

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
9-5/8" OD	332				332		1-HOWCO guide shoe
7" OD	5869				5869		1-Baker guide shoe & 1
							Baker Auto Flex flow collar
2-3/8" OD	5774				5774		1-Guiberson KV-30 w/holddown

Initial Production of Gas—Volume 4,475 MCF 24 hrs. Pressure 503 lbs. per square inch

Initial Production of Oil: Barrels ______

Initial Production of Distillate: Barrels 38.2

Is this an OIL well? No , a GAS well? Yes , or a Dry HOLE? No

DESCRIPTION OF PROPERTY
NORTH

See form 1 filed October 30th, 1957

WEST

EAST

SOUTH

GENERAL REMARKS

None

RECEIVED
MAR 26 1958
Railroad Commission of Texas
Oil & Gas Division
Wichita Falls, Texas

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS		
sh w/lime stks	0	617	sh & hrd sdy lm stks	4600	4624
Sh, sd & lm stks.	617	765	shale	4624	4633
sh & lime	765	821	sd(show & light odor)	4633	4646
sd & sh	821	851	sh & lm stks	4646	4695
sh & sd & lm stks	851	1065	sh w/sd & lime	4695	4836
lime	1065	1072	sh & lm stks	4836	4966
sh & lime	1072	1110	shale	4966	5038
sh & sd	1110	1142	cong. w/nice show & odor	5038	5071
sh & lm stks	1142	1184	sh & congl stks	5071	5084
sd & sh	1184	1212	shale	5084	5098
sh w/sd & lime	1212	1900	hd sd & lime	5098	5107
lm & shale	1900	1936	sh & lm stks	5107	5144
shale	1936	2032	sh &congl	5144	5148
sh w/sd & lime	2032	2070	congl(weaker -show)	5148	5155
lime	2070	2082	sh & congl stks	5155	5265
sh w/sd & lm stks	2082	2350	sh & lm stks	5265	5290
sh & lime	2350	2436	sh & congl	5290	5293
shale	2436	2509	congl(no show)	5293	5303
lime	2509	2530	sh w/congl stks	5303	5425
sh & lime	2530	2613	sh & lm stks	5425	5504
lime & sd	2613	2664	sh & congl	5504	5684
sd & lime	2664	2676	sh & cong	5684	5697
sh-sd- lime	2676	2701	congl (no show)	5697	5728
sh & sd	2701	2765	sh & congl stks.	5728	5923
sh & lime	2765	2820	sh & lime	5923	5934
sd & sh	2820	2882	sh & sdy lime cherty	5934	5958
sh & lm stks	2882	2933	sh & lime	5958	5965
lime	2933	2943	T.D.		
sh & lime	2943	2972			
lime	2972	2984			
sh & lime	2984	3004			
lime & sd	3004	3016			
shale	3016	3144			
sh w/sd & lime	3144	3199			
sh & sd	3199	3327			
shale	3327	3340			
sdy shale	3340	3356			
sh & sd, & lime stks	3356	3461			
sh & lime stks	3461	3497			
lime	3497	3505			
sh & lm stks	3505	3680			
sh & sd stks	3680	3783			
shale	3783	3844			
sh & sd	3844	4000			
shale	4000	4503			
lime (no show or odor)	4503	4547			
sh & lime	4547	4600			

Method of shutting off water 268 sks cement Is water completely shut off? Yes

Amount of water with oil None per cent

I, L.J. Nelms being first duly sworn on oath state that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

L. J. Nelms

Representative of Company.

Subscribed and sworn to before me this 25th day of March, 19 58

Lorene Stanfield

Notary Public

Jack County, Texas.

52007

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 2
Well Record

File No. ______

Operator Lone Star Producing Co. Address 301 S. Harwood St.-Dallas, Texas

County Wise Survey Ruben Fisher A-307 Block No. ______ Sec. No. ______

Lease Name Craft-Water Board Unit 10 Well No. 1 Elevation 83_ (Above Sea Level)

Name of Field in which well is located Boonsville (Bend Congl. Gas)

Form 1 (Notice of Intention to Drill) Was Filed in Name of Lone Star ProducingCo.

Is this a NEW WELL? ______ DEEPENING? ______ or a WORK-OVER? Yes

If this is a NEW WELL, show when drilling commenced and when drilling was completed.

If this is a PLUG-BACK or DEEPENING operation to a different reservoir, show when work-over commenced and when completed.

(Work-Over) Commenced 10-8, 19 60 (Work-Over) Completed 10-24, 19 60

Correspondence regarding this well should be sent to: Name Mr. A.L. Peyner Address Box 767-Jacksboro, Texas

Has an allowable been assigned to this well? Yes

SIZE	PUT IN WELL Ft.	PUT IN WELL In.	PULLED OUT Ft.	PULLED OUT In.	LEFT IN WELL Ft.	LEFT IN WELL In.	PACKERS AND SHOES
9-5/8"	332				332		1-HOWCO guide shoe
7"	5860				5860		1-Baker guide shoe & 1-Baker Auto Flex Flow Collar
2-3/8"	5705				5705		Culberson KVT-30

Initial Production of Gas—Volume 1,734 MCF 24 hrs. Pressure 640 lbs. per square inch

Initial Production of Oil: Barrels 19.35 (Frac Oil)

Initial Production of Distillate: Barrels ______

Is this an OIL well? ______, a GAS well? Yes, or a Dry HOLE? ______

DESCRIPTION OF PROPERTY

NORTH

See Form 1 filed Oct. 30,1957

WEST

EAST

SOUTH

GENERAL REMARKS

RECEIVED
WICHITA FALLS, TEXAS
NOV 28 1960
OIL & GAS DIVISION

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

52007

FORMATION RECORD

Show All Formations, Especially All Sands and Character and Contents Thereof

FORMATIONS	TOP	BOTTOM	REMARKS		
shm/lm stks	0	617	sh & hd sdy lm stks.	4600	4624
sh, sd & lm stks	617	765	shale	4624	4633
sh & lime	765	821	sd(jeep & lgt odor)	4633	4646
sd & sh	821	851	sh & lm stks	4646	4695
sh & si lm stks	851	1065	sh w/sd & lm	4695	4836
lime	1065	1072	sh & lm stks	4836	4966
sh & lm	1072	1110	shale	4966	5038
sh & sd	1110	1142	congl.w/nice jeep & odor	5038	5071
sh & lm stks	1142	1184	sh & congl stsk	5071	5084
sd & sh	1184	1212	shale	5084	5098
sh w/sd & lime	1212	1900	hd sd & lime	5098	5107
lm & sh	1900	1936	sh & lm stks	5107	5144
sh	1936	2032	sh & congl.	5144	5148
sh w/sd & lm	2032	2070	congl(no odor -jeep)	5148	5155
lime	2070	2082	sh& congl stks	5155	5265
sh w/sd & lm stks	2082	2350	sh & lm stks	5265	5290
sh & lime	2350	2416	sh & congl.	5290	5293
shale	2416	2509	congl(no show)	5293	5303
lime	2509	2530	sh w/congl stks	5303	5425
sh & lime	2530	2613	sh & lm stks	5425	5504
lm & sd	2613	2664	sh & congl	5504	5684
sh & lime	2664	2675	sh & congl	5684	[illegible]
sh-sd lime	2675	2701	congl (no show)	[illegible]	5728
sh & sd	2701	2765	sh & congl(Stks)	5728	5923
sh & lime	2765	2820	sh & lime	5923	5934
sd & sh	2820	2882	sh & sdy lm cherty	5934	5958
sh & lm stks	2882	2933	sh & lm	5958	5965
lime	2933	2943	T.D.		
sh & lm	2943	2972			
lime	2972	2984			
sh & lm	2984	3004			
lm & sd	3004	3046			
sh	3046	3144			
sh w/sd & lm	3144	3199			
sh & sd	3199	3327			
shale	3327	3340			
sdy sh	3340	3356			
sh & sd, & lm stks	3356	3461			
sh & lm stks	3461	3497			
lime	3497	3505			
sh & lm stks	3505	3689			
sh & sd stks	3689	3783			
shale	3783	3944			
sh & sd	3944	4000			
shale	4000	4503			
lm (sd jeep or [illegible]	4503	4547			
sh & lm	4547	4600			

Method of shutting off water Cement & casing Is water completely shut off? Yes

Amount of water with oil None per cent

I, E. L. Smith, Jr. being [illegible] that I have knowledge of the facts and matter herein set forth and that the same are true and correct.

E. L. Smith, Jr.

Representative of Company.

Subscribed and sworn to before me this 25th day of November, 19 60

Lorene Stanfield

Notary Public

Jack County, Texas.

52007

Please refer to File No..............

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

Form 1

M

RECEIVED
NOV 6 1957
Railroad Commission of Texas
Oil and Gas Division
Wichita Fall, Texas

APPLICATION TO DRILL, DEEPEN OR PLUG BACK

IS THIS AN APPLICATION TO DRILL, DEEPEN OR PLUG BACK....Drill........?

FILE IN DUPLICATE WITH DEPUTY SUPERVISOR OF DISTRICT IN WHICH WELL IS LOCATED

READ CAREFULLY AND COMPLY FULLY

In order that it may be ascertained whether or not the proposed location covered by this notice conforms to the applicable spacing regulations set down by the Railroad Commission, there are two important footages that must be shown; that is, THE NEAREST DISTANCE OF PROPOSED LOCATION FROM LEASE OR PROPERTY LINE AND DISTANCE OF PROPOSED LOCATION FROM THE NEAREST WELL ON THE SAME LEASE. Do not begin drilling operations on any location prior to filing Form 1 and until permit granted by the Commission has been received and waiting clause period has terminated.

For the purpose of this determination draw on the back side hereof a neat, accurate sketch, made to scale, of this lease, block, or lot locating thereon the proposed site for this location with reference to the two nearest lease lines. Also show the nearest wells on all sides of of this location and the distance from the proposed location to those wells. In addition to the foregoing, unit boundary designations must be shown for each producing well on the lease and shall include proposed unit boundaries for the location herein applied for showing the acreage to be assigned this well. Give names and addresses of adjoining lease or property owners, and designate all property by lease and company name. You may attach a blue print showing this information if you so desire.

DO NOT CONFUSE SURVEY LINES WITH LEASE LINES. IF THE SKETCH OR BLUE PRINT SHOWS ONLY A SECTION, BLOCK, OR LOT OUT OF YOUR LEASE, DESIGNATE SAME AS BEING ONLY THAT PART OF THE LEASE.

Where the size of the tract will permit, use scale of one inch equaling 1000 feet; if less than 2 acres use scale of one inch equaling 100 feet. DESIGNATE SCALE TO WHICH PLAT OR SKETCH IS DRAWN. ALSO DESIGNATE NORTHERLY DIRECTION ON THE SKETCH OR PLAT.

FILL IN BELOW IN THE SPACES RESERVED FOR THIS PURPOSE THE FOOTAGES ASKED FOR:

Nearest distance from proposed location to property or lease line.....800............feet.

Distance from proposed location to nearest drilling, completed, or applied for well on same lease.....--...feet.

Date...October 30,............, 19..57...

Name of company or operator

Name....Lone Star Producing Company..........

Address.301 South Harwood Street.............

City....Dallas, Texas..........................

Description of farm or lease:

Name of Lease.Craft-Water Board Unit No. 10..

Number of Acres..352..........Well No.....1.......

Number of wells on lease.......None.............

Survey Ruben Fisher (A-307)

Elevation......834.............Feet (ABOVE SEA LEVEL)

Section No...................Block No.............

Located in.........Wildcat..................Field

(If Wildcat state above)

..................Wise......................County

..7-1/2...........Miles....N.....direction from

...Boonsville.......nearest postoffice or town.

Rotary or Cable Tools.........rotary............

Date work will start drilling...on permit........

Depth to which you propose to drill..6,000...feet.

Date work will start deepening.....................

IF LEASE PURCHASED WITH ONE OR MORE WELLS DRILLED, FROM WHOM PURCHASED?

Name...

Address..

530-933 20 Ac.

NOTICE: Before sending in this form be sure that you have given all information requested. Much unnecessary correspondence will thus be avoided.

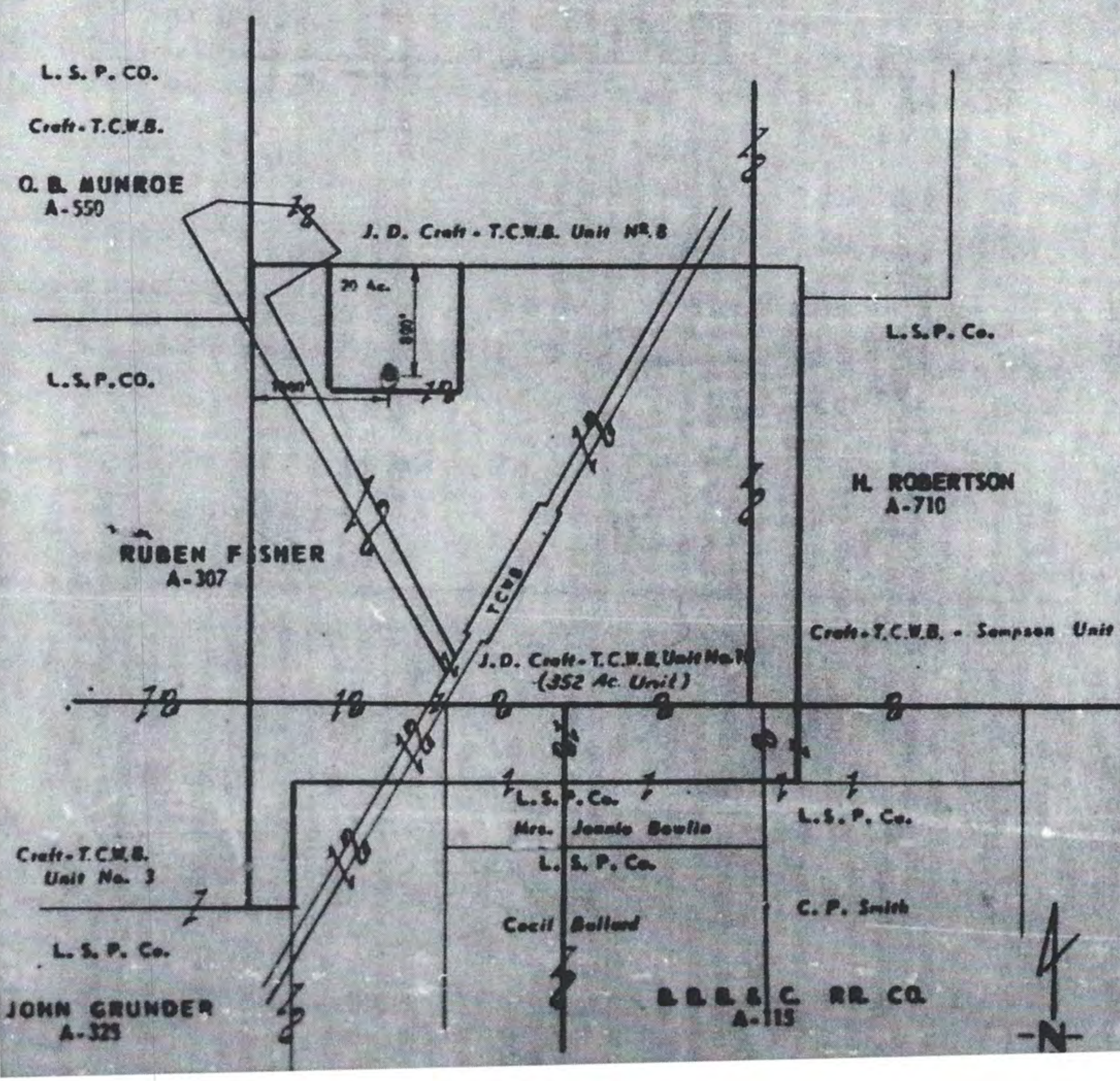
DRAW SKETCH AND MAKE AFFIDAVIT ON REVERSE SIDE

NOV 13 1957

Billy M. [signature]
Registered Public Surveyor

Subscribed and sworn before me this the 20th day of Oct. 1957 A. D.

[signature]
Notary Public, Dallas County, Texas



WAYNE CHRISTIAN, CHAIRMAN
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DIRECTOR, OIL AND GAS DIVISION
PAUL DUBOIS, P.E.
ASSISTANT DIRECTOR, TECHNICAL PERMITTING

RAILROAD COMMISSION OF TEXAS

OIL AND GAS DIVISION

PERMIT TO DISPOSE OF NON-HAZARDOUS OIL AND GAS WASTE BY INJECTION INTO A POROUS FORMATION NOT PRODUCTIVE OF OIL AND GAS

PERMIT NO. 17090

BKV BARNETT, LLC
1209 CR 1304
BRIDGEPORT, TX 76426

Authority is granted to inject Non-Hazardous Oil and Gas waste into the well identified herein in accordance with Statewide Rule 9 of the Railroad Commission of Texas and based on information contained in the application (Form W-14) dated July 06, 2022, for the permitted interval(s) of the ELLENBURGER formation(s) and subject to the following terms and special conditions:

BARNETT RDC (00000) LEASE
NEWARK, EAST (BARNETT SHALE) FIELD
WISE COUNTY, DISTRICT 09

WELL IDENTIFICATION AND PERMIT PARAMETERS:

Well No.	API No.	UIC Number	Permitted Fluids	Top Interval (feet)	Bottom Interval (feet)	Maximum Liquid Daily Injection Volume (BBL/day)	Maximum Gas Daily Injection Volume (MCF/day)	Maximum Surface Injection Pressure for Liquid (PSIG)	Maximum Surface Injection Pressure for Gas (PSIG)
1	49700000	000125478	Carbon Dioxide (CO_2)	9,350	10,250		14,500		4,500

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	49700000	**1. For wells with long string casing set more than 100 feet below the permitted injection interval, the plug back depth shall be within 100 feet of the bottom of the permitted injection interval. For wells with open hole completions, the plug back depth shall be no deeper than the bottom of the permitted injection interval.** **2. The operator shall provide to UIC a geophysical log and a mud log of the subject well with the top(s) and bottom(s) of the permitted formation(s) and the top and base of the injection interval annotated on the log. Top and bottom of the permitted injection interval may be modified based on geophysical log or mud log indications of the top and bottom of the permitted formation.** **3. Cement Bond Log (CBL):** **(A) A CBL must be run on the injection string casing. If the CBL does not verify adequate confinement of the injection/disposal interval, the operator must perform a remedial cement squeeze on the casing to achieve adequate confinement immediately above this interval. Adequate confinement is considered to be: annular height of 600 feet of cement based on cement volume calculations; or 250 feet of cement verified by a temperature survey conducted at the time of cementing; or 100 feet of cement verified by a cement bond log that shows the cement is well bonded to the pipe and formation (80% bond or higher) with no indication of channeling.** **(B) The operator must notify and receive approval from the RRC district office prior to performing any remedial cementing work. All cementing work must be appropriately reported on a completion report pursuant to Statewide Rule 16(b). Any CBL run on the well must be submitted. Please use the RRC Digital Well Log submission system to submit the CBL. A copy of any Forms W-15 must also be included with the next Form H-5 for this well.** **4. This is not an Underground Injection Control (UIC) Class VI permit for geologic sequestration of CO2. Geologic sequestration of CO2 that occurs incidental to oil and gas operations is authorized under a Class II UIC permit under certain circumstances, including but not limited to there being a legitimate/material oil and gas exploration/production purpose for the injection that does not cause or contribute to an increased risk to USDW.** **5. Injection shall be no deeper than 100 feet above the base of the deepest formation overlying the top of Cambrian-period stratum or top of Precambrian stratum if Cambrian is not preserved at the well location. Specifically, the formation(s) referred to may be within the Devonian, Silurian or Ordovician-period strata.** **6. The operator must notify the Injection-Storage Permits Unit (UIC) and District Office of any event that may have jeopardized the mechanical and/or hydraulic integrity of any segment of the processing, injection, or storage components of the permitted facility.** **7. NOTE: Per operator email dated on July 05, 2022, the CO2 will be from the Bridgeport Processing Plant operated by Enlink Midstream.** **8. An annual annulus pressure test must be performed, and the test results submitted in accordance with the instructions of Form H-5.** **9. The tubing-casing annulus pressure must be monitored at least weekly and reported annually on Form H-10 to the Commission's Austin Offices.**

Note: This document will only be distributed electronically.

		10. Bottomhole Pressure (BHP) Test: 5 Year Lifetime **(A) Operator shall perform an initial static BHP test to quantify reservoir pressure prior to injection into the permitted formation(s).** **(B) Operator shall conduct a BHP test at least once every five (5) years from the date of the test in (A) above and provide the Commission an opportunity to witness the test as stated in (D) below. The analysis of the BHP test shall be provided under the supervision, seal, and signature of a registered professional engineer in Texas. The test analysis shall be filed with the Injection-Storage Permits Unit (UIC) within 30 days of completion of the BHP test.** **(C) Measurement for the BHP test shall be performed via wireline tool(s), or other Commission approved bottom hole pressure measurement technique.** **(D) Operator must notify the District Office 48 hours in advance of the test in order to provide opportunity for the RRC field inspector to witness the test. Operator shall provide raw data from the test to UIC within 48 hours of completing the test.** **11. NOTE: Per operator email dated on July 05, 2022, the CO2 will be from the Bridgeport Processing Plant operated by Enlink Midstream.** **12. 8/26/2022 4. Fluid migration and pressure monitoring report:** **The operator must submit a report of monitoring data, including but not limited to pressure and temperature data, used to determine fluid migration from the disposal well and pressure increases in the reservoir. The report must include, at a minimum, all monitoring data recorded since the last report (or since data recording began for the first report) through the date 30 days before the MIT is due and a summary analysis of the data. The summary analysis must include data trends and anomalies and any likely explanation for those trends or anomalies, for example, any significant operational events. The operator must submit the report with the Mechanical Integrity Test (MIT) filing to the Disposal/Injection Well Pressure Test (H-5) online system.**

STANDARD CONDITIONS:

1. Injection must be through tubing set on a packer. The packer must be set no higher than 100 feet above the top of the permitted interval.

2. The District Office must be notified 48 hours prior to:
   a. running tubing and setting packer.
   b. beginning any work over or remedial operation.
   c. conducting any required pressure tests or surveys.

3. The wellhead must be equipped with a pressure observation valve on the tubing and for each annulus.

4. Prior to beginning injection and subsequently after any work over, an annulus pressure test must be performed. The test pressure must equal the maximum authorized injection pressure or 500

Note: This document will only be distributed electronically.

psig, whichever is less, but must be at least 200 psig. The test must be performed, and the results submitted in accordance with the instructions of Form H-5.

5. The injection pressure and injection volume must be monitored at least monthly and reported annually on Form H-10 to the Commission's Austin office.

6. Within 30 days after completion, conversion to disposal, or any work over which results in a change in well completion, a new Form W-2 or G-1 must be filed to show the current completion status of the well. The date of the disposal well permit, and the permit number must be included on the new Form W-2 or G-1.

7. Written notice of intent to transfer the permit to another operator by filing Form P-4 must be submitted to the Commission at least 15 days prior to the date of the transfer.

8. This permit will expire when the Form W-3, Plugging Record, is filed with the Commission. Furthermore, permits issued for wells to be drilled will expire three (3) years from the date of the permit unless drilling operations have commenced.

Provided further that, should it be determined that such injection fluid is not confined to the approved interval, then the permission given herein is suspended and the disposal operation must be stopped until the fluid migration from such interval is eliminated. Failure to comply with all of the conditions of this permit may result in the operator being referred to enforcement to consider assessment of administrative penalties and/or the cancellation of the permit.

APPROVED AND ISSUED ON September 08, 2022.

Scott Rosenquist

(for)

Sean Avitt, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.