OFFICE OF AIR AND RADIATION
WASHINGTON, D.C. 20460

February 8, 2024

Mr. Robert Eales
Environmental Director
EOG SPG Holdings, Inc.
1111 Bagby Street
Houston, Texas 77002

Re: Monitoring, Reporting and Verification (MRV) Plan for SPG CO_2 Bowie Facility

Dear Mr. Eales:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for SPG CO_2 Bowie Facility, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by SPG CO_2 Bowie Facility on December 21, 2023, as the final MRV plan. The MRV Plan Approval Number is 1014507-1. This decision is effective February 13, 2024 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78. In conjunction with this MRV plan approval, we recommend reviewing the Subpart PP regulations to determine whether your facility may also be required to report data as a supplier of carbon dioxide. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

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

Sincerely,

Julius Banks,
Chief, Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for SPG CO_2 Bowie Facility (SBF)

February 2024

Contents

<u>**Appendices**</u>

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 EOG SPG Holdings, Inc. (EOG) for its SPG CO_2 Bowie Facility (SBF) acid gas injection project into the Ellenburger formation. Note that this evaluation pertains only to the Subpart RR MRV plan for the SBF, 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

SBF states in section 1.0 of the MRV plan that it currently has a Class II disposal permit issued by the Texas Railroad Commission (TRRC) for the Hinkle Trust #1 injection well. This permit currently authorizes EOG to inject up to 12 million standard cubic feet per day (MMSCFD) of acid gas waste, composed primarily of carbon dioxide (CO_2), nitrogen (N_2), hydrogen sulfide (H_2S), and other trace hydrocarbons. This waste is generated by four natural gas amine treatment facilities located in Montague County, TX and operated by EOG. These facilities separate the acid gas components from the natural gas stream produced from the Barnett Shale by approximately 1,100 wells across the Newark East Field, also operated by EOG. Historically, the separated CO_2 stream has been emitted to the atmosphere while the H_2S was incinerated by a thermal oxidizer with the resulting sulfur dioxide (SO_2) emitted to the atmosphere. In 2022, the aggregate total reportable greenhouse gas (GHG) emissions from all four amine separation facilities were approximately 180,000 metric tons (MT) of CO_2.

The MRV plan states that SBF has four central gas gathering sites that take produced gas from the field at low pressure (25-35 pounds per square inch gauge (psig)) and condition the gas to go through high pressure (750-900 psig) gathering lines to deliver the produced gas to a central gas treatment facility. SBF uses 4-stage booster compressors to increase the pressure of the CO_2-rich gas from low pressure (5 psig) off of the amine still to high pressure (750-850 psig). Over the proposed 12-year project life, SBF states that injection rates will decline from an initial rate of approximately 10 MMSCFD down to 4 MMSCFD. Injection operations began in February 2023 with CO_2 volumes supplied from only one facility, injection operations with CO_2 from the other facilities began in June 2023. The MRV plan also calls for a 5-year post-injection monitoring period.

In section 2.0 of the MRV plan, SBF describes the geologic setting and injection process for the Hinkle Trust #1 injection well. The MRV plan states that the Ellenburger is the main formation of interest and injection formation for this project, while the overlying Simpson, Viola, and Barnett formations are secondary interests. As stated in the MRV plan, a large sea level change between the Ordovician and Mississippian Periods resulted in an unconformity that removed previously deposited Silurian and Devonian aged rocks. The late-Paleozoic Ouachita Orogeny formed the structural Fort Worth Basin and influenced sedimentation patterns through Permian time, with additional influence on the character and thickness of sediments by local structure perturbations. The plan also states that the injection project is located in a structurally deep part of the Fort Worth Basin that is adjacent to the Muenster Arch. Sea level drops during and following Ellenburger deposition also yields complex and extensive karsting. Karst features are present within the proposed injection area and likely provide the primary Ellenburger storage within the proposed injection interval.

The MRV plan states that the injection zone is an approximately 1,000 feet thick primarily dolomitic and limestone portion of the middle Ellenburger, a karsted carbonate reservoir. Observed porosity and permeability ranges were less than 1% to over 15% and microdarcy to millidarcy respectively. The upper confining zone is defined as the upper Ellenburger, Simpson, Viola formations and the base of Barnett shale. It is 2,220 feet thick, and a significant portion of the zone consists of sealing limestones and dolomites with varying amounts of clay and clay-rich shale. Specifically, the upper Ellenburger is mostly tight limestone with some dolomite stringers, the Simpson formation is primarily limestone with minor to moderate clay content, and the Viola is tight limestone. Image log analysis and dynamic injection testing and surveys show a lack of karst features or transmissive fractures and faults, leading to the upper confining zone having excellent long-term sealing capacity according to the MRV plan.

The MRV plan states that an approximately 1,000-foot-thick section between the granitic basement and the base of the middle Ellenburger injection zone will serve as the lower confining zone. The lower confining zone is composed of primarily tight limestone with minor clay within it and a few clay stringers. Similar to the upper confining zone, the lower confining zone lacks karst features or transmissive fractures and faults.

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

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

As part of the MRV plan, the reporter must identify and delineate both the maximum monitoring area (MMA) and active monitoring area (AMA), pursuant to 40 CFR 98.448(a)(1). Subpart RR defines maximum monitoring area as "the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase 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.

As stated in the MRV plan, initialization of the reservoir model conditions was based on data acquired during the drilling and characterization of the project wells. Before CO_2 injection forecast simulations were run, the model was rigorously history-matched to the water injection step-rate and pressure interference testing that was conducted between the Hinkle Trust #1 injection well and the Billy Henderson #5 monitoring well. A base case injection forecast was run using the calibrated reservoir model and the proposed 12-year CO_2 volumes schedule. An additional 200 years of post-injection shut-in time was simulated to observe the long-term reservoir response and predict the stabilized extent and shape of the separate phase CO_2 plume after buoyant migration has ceased. At the end of the 12-year injection period, the bottom-hole pressure (BHP) drops to within 20 psi of initial static conditions instantly due to the high system permeability/injectivity of the middle Ellenburger. The period of pressure decline observed at the injection well through the year 2060 is a result of the natural decompression of the infinite-acting reservoir system in combination with the gradual buoyant equilibration of the compressible CO_2 plume. Overall, the plume grows by roughly 33% during the 200-year post-injection simulated period and completely stabilizes around year 2225 (190 years after injection stops), showing no visible areal expansion thereafter.

The MRV plan states that by using a 3% CO_2 saturation threshold - the estimated saturation of gas breakthrough from mercury injection capillary pressure (MICP) measurements - the boundary of the stabilized, separate phase plume was determined from the simulation results. The resulting boundary and a half-mile buffer are defined as the MMA. The MMA is displayed in Figure 23 of the MRV plan. Regarding the AMA, the MRV plan lays out an initial monitoring period of 12 years that was chosen based on the expected injection duration for the project. As a result, the separate phase CO_2 at the end of injection in year 2035, assuming the same 3% CO_2 saturation threshold plus the required half-mile buffer was defined. Per the definition of the AMA in Subpart RR, this area was superimposed against the projected plume outline in the year 2040, t + 5. The AMA is displayed in Figure 24 of the MRV plan.

The delineations of the MMA and AMA were determined to be acceptable per the requirements in 40 CFR 98.448(a)(1). The MMA and AMA described in the MRV plan are clearly 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). In section 3.0 of their MRV plan, SBF identified the following potential leakage pathways that required consideration:

- Surface Facilities
- Wellbores
- Faults and Fractures
- Confining System

3.1 Surface Facilities

The MRV plan states that leakage from surface facilities downstream of the injection meter is unlikely. SBF states that the high-pressure injection meter is placed near the high-pressure compressor outlet and less than 210 ft upstream of the wellhead. Therefore, SBF asserts that this placement will minimize the potential leakage points between the metering of the stream and downhole injection pressure. The

MRV plan also states that the piping and flanges between the injection meter and the wellhead are Class 2500 rated by the American National Standards Institute, and all welds are certified by x-ray inspection.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected from surface facilities.

3.2 Wellbores

The MRV plan states the only wellbores that penetrate the injection zone in the AMA and MMA are those that were constructed specifically for the SBF project. SBF states that both the Billy Henderson #5 monitor well and the Hinkle Trust #1 injection well were specifically constructed: 1) to mitigate leakage risks from CO_2 injection, and 2) to provide for monitoring of near-wellbore conditions prior to, during, and after injection operations.

The MRV plan states that the Billy Henderson #5 monitor well was designed to mitigate the risk of CO_2 migration out of the injection zone. A CO_2-resistant cement blend, EverCrete, was used to bond the long string casing in place in the Billy Henderson #5 monitor well. The top of the cement sits above the top of the upper confining system designed from the project. The Hinkle Trust #1 injection well was also designed to mitigate the risk of CO_2 migration out of the injection zone. All strings of casing were cemented to surface and a CO_2-resistent resin product, WellLock, was used to cement the liner of the long string casing sitting directly above the open hole injection interval for the Hinkle Trust #1 injection well.

The MRV plan also states that there are additional wellbores present in the AMA and MMA, but they do not penetrate the injection zone. Texas Railroad Commission records, including completion reports, well plugging reports, drilling permits, and injection permits, as well as any available digital and raster log data, were analyzed for these wells. While the minimum vertical separation between the injection zone and overlying wells within the MMA is over 1,400 ft, most of the existing wellbores are 2,000 to 3,500 feet above the injection zone. A detailed analysis of these wellbores is presented in figures 27 through 29.

SBF states that they do not anticipate new wellbores to penetrate the injection zone as the formation does not contain commercial hydrocarbon accumulations within the vicinity of the project site. Should new wells be permitted and drilled within one-quarter mile of the Hinkle Trust injection well, operators would be subject to Railroad Commission of Texas (TXRRC) Rule 13 compliance on wellbore construction. Rule 13 requires operators to set steel casing across and above all formations permitted for injection. Rule 13 requires operators to set casing and cement across and above all zones with the potential for flow or containing corrosive formation fluids. Furthermore, SBF intends to monitor permitting activity across the entire project area on a quarterly basis and take appropriate action if any proposed wells present a potential risk for leakage within the MMA. In the case that any new wells are drilled within the MMA and create a material change to the surface leakage risk, the MRV plan would be updated to reflect this change and the potential risk for leakage presented by these wells would be evaluated based on the most current operational and monitoring data. As such, the MRV plan states that the potential for surface leakage through existing or future wells in the SBF project area is highly unlikely.

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

3.3 Faults and Fractures

The MRV plan states that cross-fault leakage is unlikely. To assess the risk of leakage through faults, SBF performed a Fault Slip Potential (FSP) analysis on large-scale basement-rooted faults traversing the proposed injection area and interval. The FSP analysis simultaneously assesses both induced seismicity and fault leakage likelihood. The FSP revealed that major faults are not critically-stressed in the present-day stress field and are, therefore, not expected to be hydraulically-conductive leakage pathways during CO_2 injection.

According to the U.S. Geological Survey, only one earthquake in Montague County has been recorded in the last 100 years despite significant saltwater disposal (SWD) injection within the Ellenburger. The FSP results are consistent with generally stable fault behavior in larger Montague County - and within the proposed injection area - as evident by the lack of detectable seismicity despite the presence of numerous Ellenburger SWD injection wells within the county.

Cross-fault leakage is also unlikely due to fault sense-of-slip and displacement. The dominant strike-slip sense of motion on major faults in the area decreases the likelihood of vertically juxtaposing injection intervals with containment intervals. In addition, cross-fault leakage is also likely inhibited by development of a thick, low-permeability fault core due to significant fault displacement.

The MRV plan also states that natural fractures pose a minor risk for surface leakage. To assess the potential fracture leakage, SBF compared fracture characteristics (orientation, density) with various indicators of fluid conductivity (e.g., temperature anomalies, injection testing) in the proposed injection well. The MRV plan states that orientation and density do not correlate with either temperature reductions or primary permeability pathways inferred from injection testing, suggesting natural fractures are not the dominant transport (i.e., permeability) mechanisms within the injection interval.

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

3.4 Confining System

The MRV plan states that surface leakage through the confining system is expected to be extremely unlikely. To assess potential leakage from an excess pressure (i.e., hydraulic fracturing), SBF used injection tests to measure the pore pressure, and minimum horizontal stress tests were conducted in the overlying seal interval. These injection tests determined that approximately 2,000 pounds per square inch (psi) of downhole excess pressure is required to generate and propagate hydraulic fractures. The MRV plan states that plume injection modeling and offset Ellenburger SWD injection data all indicate maximum bottomhole pressure buildups on the order of 10s of psi for comparable injection volumes and rates - nearly two orders of magnitude lower than would be required to generate a hydraulic fracture. Therefore, SBF concludes that CO_2 leakage through hydraulic fracture generation/propagation is therefore highly unlikely. SBF also concludes that CO_2 migration and excess pressure buildup downward toward the lower confining and basement intervals is not anticipated.

The MRV plan states that that the 2,200-foot-thick geologic confining zone, composed of the Ellenburger, Simpson, Viola, and lower Barnett shale, is expected to provide excellent long-term containment. The MRV plan states that this conclusion is due to: 1) the low matrix porosities and permeabilities measured in core samples taken throughout this interval; 2) the lack of pervasive karsting or conducive fractures observed in core and image log data; and 3) the absence of flow observed in this interval during dynamic injection testing and surveys conducted in the project wells. Furthermore, SBF states that the results from reservoir simulation of the proposed injection volumes show no appreciable pressure change or fluid migration in the model layers immediately above the middle Ellenburger injection zone.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through the confining system.

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

Table 8: Leakage detection methodologies to be employed for the Bowie Project.

Leakage Pathway	Monitoring Activity	Frequency	Coverage
Surface facilities	Wellhead pressure monitoring	Continuous	Flowmeter to injection wellhead
	Visual inspection	Weekly	
	Personal H_2S monitors	Weekly	
In-Zone Wellbores	P/T* gauges & fiber on casing/tubing	Continuous	Surface through injection zone
	Annulus pressure monitoring	Continuous	
	Integrity testing (MIT) per Class II permit	Yearly	
	Periodic corrosion monitoring surveys	Yearly	
Faults/fractures	Pressure monitoring	Continuous	Project site/plume extent
	Pressure transient analysis	Yearly	
Confining system	Pressure monitoring	Continuous	Project site/plume extent
	P/T gauges & fiber on casing	Continuous	
	Pressure transient analysis	Yearly	
	Time-lapse saturation surveys	Yearly	

*P/T = Pressure and temperature

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 3.0 of the MRV plan discusses the strategies SBF will employ for monitoring and quantifying surface leakage of CO_2 through the pathways identified in the previous section to meet the requirements of 40 CFR §98.448(a)(3). Section 3.7 of the MRV plan discusses the strategies that SBF will use for establishing expected baselines for CO_2 leakage. A summary table of SBF's leakage detection methodologies for CO_2 leakage or loss can be found in Table 8 of the MRV plan and copied above. A summary table of SBF's leakage quantification strategy summary can be found in Table 10 of the MRV plan and copied below.

Table 10: Leakage quantification methodologies for the Bowie Project.

Leakage Pathway	**Quantification Method***	**Qualitative Accuracy**
Surface facilities	Calculation based on process conditions at time of leakage and dimensions of leakage pathway	High
	Comparison & calculation against recent historical trends	High
	Direct measurement of leakage (if accessible and safe)	Very High
In-Zone Wellbores	Calculation against recent historical injection trends (using surface & downhole P/T data)	High
	Estimation from change in saturation profile within reservoir and/or confining zones in project wells	Moderately High
	Enhanced surveillance (e.g., saturation surveys) on nearby wells operated by EOG	Moderately High
Faults/fractures	Use reservoir model to simulate the CO_2 leakage required to generate the observed pressure transient behavior	Moderate
	Use reservoir model to simulate the CO_2 leakage required to generate the observed nearby well surveillance response	Moderate
	Enhanced surveillance (e.g., saturation surveys) on multiple nearby wells operated by EOG	Moderately High
	Conduct additional geophysical imaging surveys near potential leak pathways	Moderately High
	Drill additional monitoring wells in strategic locations	High
Confining system	Use reservoir model to simulate the CO_2 leakage required to generate the observed pressure transient behavior	Moderate
	Use reservoir model to simulate the CO_2 leakage required to generate the observed nearby well surveillance response	Moderate
	Enhanced surveillance (e.g., saturation surveys) on multiple nearby wells operated by EOG	Moderately High
	Conduct additional geophysical imaging surveys near potential leak pathways	Moderately High
	Drill additional monitoring wells in strategic locations	High

*Quantification methods presented in order of practical implementation.

Should leakage be verified through one of the discussed leakage pathways, SBF would implement the methodologies summarized in Table 10 of the MRV plan to quantify the mass of CO_2 that has leaked to shallow aquifers or to the surface. The MRV plan states that CO_2 leakage through several of the pathways cannot be directly measured or visualized but must be indirectly inferred. Therefore, SBF states that reservoir simulation will likely be an essential tool to quantify the magnitude of the leak in those cases. For example, while the precise pathway of a CO_2 leak may not be known, SBF asserts that it may be possible to measure the pressure or saturation change created along the leakage pathway in the subsurface (e.g., the Billy Henderson #5 monitoring well or a nearby production well operated by SBF). Through the iterative history matching process, SBF believes that it is possible to replicate the observed subsurface response by invoking some potential leakage mechanism(s) in the reservoir model. The resulting volume or mass of CO_2 that yields the best match to the observed data is likely to be a reasonable estimate of the magnitude of the leak.

Furthermore, the MRV plan states that by considering several different plausible leakage cases with the model, the magnitude of the leak can be quantified across a range of potential outcomes. Due to the non-unique nature of numerical simulations, SBF states that they will also consider conducting additional appropriate geophysical imaging surveys or drilling additional monitoring wells in strategic locations to further constrain and refine the leakage quantification estimates yielded by the models.

4.1 Detection of Leakage From Surface Facilities

The MRV plan states that leakage from surface facilities downstream of the injection meter is unlikely. Nevertheless, the MRV plan states that continuous wellhead pressure monitoring, visual inspections, and personal H_2S monitors will be used to detect potential leakage through surface facilities. The MRV plan states that leakage from surface equipment is detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release in accordance with 40 CFR §98.448(5).

Table 8 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected from surface facilities. Thus, the MRV plan provides adequate characterization of SBF's approach to detect potential leakage from surface facilities as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage Through Wellbores

The MRV plan states that the potential for surface leakage through existing or future wells in the project area is highly unlikely. Even still, the MRV plan states data from downhole instrumentation is collected and archived continuously across both the Billy Henderson #5 monitor well and the Hinkle Trust #1 injection well. For the Billy Henderson #5 monitor well, pressure-temperature gauges and fiber monitoring instrumentation were installed across the injection zone (gauges and fiber), below the injection zone (fiber only) and above the injection zone (gauges and fiber) to allow for monitoring of pressure and temperature responses across the wellbore. For the Hinkle Trust #1 injection well, pressure-temperature gauges and fiber monitoring instrumentation were installed on the intermediate casing above the injection zone and on the injection tubing to allow for monitoring of pressure and temperature responses in the tubing, long string annular space, and above the injection zone.

The MRV plan states that the aggradation and analysis of this data from the wellbores will allow SBF to quickly detect any leakage present within the wellbores. Furthermore, the MRV plan states that an annual mechanical integrity test (MIT) will be conducted in the injection well as prescribed in the Class II UIC Permit. SBF states that periodic corrosion monitoring surveys will also be conducted to detect leakage in wellbores. If leakage is detected, SBF asserts that they will use the recorded operating conditions at the time of the leak to estimate the volume of CO_2 released and then take appropriate corrective action.

Regarding leakage due to CO_2 migrating from the primary injection zone into an existing or future wellbore, SBF states that they would first estimate the likelihood of the proposed leak against the latest operational data, monitoring data, and reservoir simulation projections. If a potential relationship between injection and leakage is confirmed, SBF would coordinate efforts with the owner(s) of the well in question to characterize the change in gas composition against historical baselines (if available), estimate the point in time when the composition changed from the historical baseline, measure the approximate flow rate associated with the leak (if possible), quantify the incremental CO_2 mass associated with the leakage pathway over the effective time period, and develop and implement an appropriate wellbore remediation design and a supplementary monitoring program to ensure the leak has been permanently eliminated. The MRV plan also states that any CO_2 mass associated with this leakage would be noted in the annual monitoring report and reflected in the total mass of CO_2 sequestered.

Table 8 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through wellbores. Thus, the MRV plan provides adequate characterization of SBF's approach to detect potential leakage through wellbores as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage Through Faults and Fractures

The MRV plan states the risk of leakage through faults is highly unlikely. The MRV plan also states that natural fractures pose a minor leakage risk. Nevertheless, the MRV plan states that downhole pressure instruments installed in the project wells will be continuously monitored via the project's real time data acquisition system. These monitoring events will include pressure monitoring and pressure transient analyses. The MRV plan also states that appropriate alarms and operational set points for surface equipment will be established to ensure that downhole conditions do not exceed the safety thresholds which could potentially trigger a fault-slip event in the most conservative case.

Table 8 of the MRV plan provides a detailed characterization of CO_2 leakage that could be expected through faults and fractures. Thus, the MRV plan provides adequate characterization of SBF'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 the Confining System

The MRV plan states that surface leakage through the confining system is expected to be extremely unlikely. The MRV plan also states that SBF will employ pressure monitoring, P-T gauges and fiber on casing, pressure transient analysis, and time-lapse saturation surveys to detect leakage through the confining system.

Table 8 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through the confining system. Thus, the MRV plan provides adequate characterization of SBF's approach to detect potential leakage through the confining system as required by 40 CFR 98.448(a)(3).

4.5 Determination of Baselines

Section 3.7 of the MRV plan identifies the strategies that SBF will use to establish the baselines for monitoring CO_2 surface leakage per §98.448(a)(4). SBF states that they have existing automated continuous data collection systems in place that allow for aggradation and analysis of operations data to: 1) establish trends in operational performance parameters, and 2) identify deviations from these trends. The MRV plan states that non-continuous data will also be collected periodically to augment and enhance the analysis of continuous data throughout the project. SBF states that baselines for operational performance parameters are expected to be completed by July 17th, 2023, which will provide for several weeks of data collection with the entire system operational. The following baseline surveys for non-continuous data have already been completed as described in the MRV plan:

Audio, Visual, Olfactory (AVO) Inspections

As described in the MRV plan, field personnel will conduct daily to weekly inspections at the injection site pre/post-injection. Any indication of surface leakage of CO_2 will be addressed via appropriate corrective action in a timely manner. Personnel will wear personal H_2S monitors calibrated to Occupational Safety and Health Administration (OSHA) standards with a detection sensitivity of 0.5 parts per million (ppm) and a low-level alarm threshold of 10 ppm. Indications of H_2S present will serve as a proxy for CO_2 presence as the injection stream contains both components.

Continuous Monitoring

As described in the MRV plan, continuous monitoring systems are in place for both the surface process facilities and wells. Pressure and temperature gauges installed on both casing and tubing strings, Distributed Temperature Sensor (DTS) fiber-based data, and surface pressures on all strings of casing is collected continuously in both wells. Operational baselines will be determined from analysis of this data over a reasonable period once the system is fully operational (see comments on timing above). Any deviations from these operational baselines will be investigated to determine if the deviation is a leakage signal.

Well Integrity Testing

As described in the MRV plan, SBF will conduct an annual MIT on the Hinkle Trust #1 injection well as required by the Class II permit issued by the TRRC. Subsequent MIT results will be compared to initial MIT results and TRRC standards to establish a baseline. An initial MIT and subsequent interpretation of test results has already been performed on the Hinkle Trust #1 injection well as part of the Class II permit requirements.

Pressure Transient Analysis

SBF states in the MRV plan that they have conducted initial pressure transient analyses using injection test data. Subsequent pressure transient analyses are in progress and will continue to be performed when operationally feasible to establish and re-establish expected baseline reservoir behavior throughout the project. Comparison of these analyses over time will aid in diagnosing consistency in the long-term behavior of the injection and confining zones.

Wellbore Surveys

As described in the MRV plan, the Billy Henderson #5 monitor well and Hinkle Trust #1 injection well are both constructed to allow for time-lapse saturation and mechanical integrity logging. Initial pre-injection surveys have been conducted for both saturation and mechanical integrity and will serve to establish baselines for comparison of future logging datasets.

Thus, SBF provides an acceptable approach for establishing expected baselines for monitoring CO_2 surface leakage in accordance with 40 CFR 98.448(a)(4).

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

5.1 Determining Mass of CO_2 Received

The MRV plan states that the CO_2 stream received via the gathering pipeline will be wholly injected and not mixed, thus Equation RR-4 will be used to calculate the mass of CO_2 received per CFR 98.444(a)(4):

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

where:
$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.
$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).
$C_{CO2,p,u}$ = 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.

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

5.2 Determining Mass of CO_2 Injected

Section 3.8.2 of the MRV plan states that the mass of CO_2 injected will be measured with a mass flow meter. The total annual mass of CO_2, in metric tons, will be calculated by multiplying the mass flow by the CO_2 concentration in the flow according to Equation RR-4:

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

where:
$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.
$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).
$C_{CO2,p,u}$ = 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.

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

5.3 Mass of CO_2 Produced

SBF states in the MRV plan that no CO_2 will be produced in this project. Therefore, SBF states that the mass of CO_2 produced is not applicable to the MRV plan.

5.4 Calculation of Mass of CO_2 Emitted

Equipment Leaks and Vented Emissions

The MRV plan states the likelihood of any fugitive CO_2 emissions between the injection meter and the injection wellhead is expected to be extremely low due to the material specifications of the installed equipment and the minimal number of components along this flow path. Any intentional venting of CO_2 emissions would occur upstream of the injection meter used to measure the injection quantity and therefore would not need to be subtracted from the total mass injected. Nevertheless, this equipment will still be subject to regular AVO inspections and H_2S monitoring. If it is determined that CO_2 has leaked between the injection meter and injection wellhead, the methods outlined in 40 CFR 98.233(q) will be used to quantify this amount.

Surface Leakage

The MRV plan states that if surface leakage had occurred or is actively occurring through any of the identified pathways, this leakage would be quantified and be used to estimate the mass emitted from each pathway and summed using Equation RR-10:

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

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

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

5.5 Calculation of Mass of CO_2 Sequestered

The MRV plan states that since this project will not actively produce oil, natural gas, or any other fluids, the mass of CO_2 sequestered in subsurface geologic formations will be calculated using equation RR-12:

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{(Eq. RR-12)}$$

where:

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

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

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

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

The MRV plan states that in accordance with §98.448(a)(7), the date to begin collecting data for calculating the total amount sequestered shall be after 1) expected baselines are established and 2) implementation of the leakage detection and quantification strategy within the initial AMA. A proposed date of July 17th, 2023 is stated to be the start date of data collection for calculating total amount of CO_2 sequestered.

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

6 Summary of Findings

The Subpart RR MRV plan for EOG's SPG CO_2 Bowie Facility is acceptable requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the SPG CO_2 Bowie Facility MRV plan.

Subpart RR MRV Plan Requirement	SPG CO_2 Bowie Facility MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 3.0 of the MRV plan describes the MMA and AMA. The AMA boundary was established by superimposing the area based on a half-mile buffer around the anticipated plume location at the end of injection (2035) with the area of the projected free-phase CO_2 plume at five additional years (2040). Since the AMA boundary was determined to fall within the MMA boundary, the defined MMA was also used to define the effective AMA.
40 CFR 98.448(a)(2): Identification of potential surface leakage pathways for CO_2 in the MMA and the likelihood, magnitude,	Section 3.0 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: leakage from surface facilities; leakage through wellbores; leakage through faults and fractures; and leakage

and timing, of surface leakage of CO_2 through these pathways.	through the confining system. The MRV plan analyzes the likelihood, magnitude, and timing of surface leakage through these pathways.
40 CFR 98.448(a)(3): A strategy for detecting and quantifying any surface leakage of CO_2.	Section 3.0 of the MRV plan describes SBF's strategy for how the facility would detect CO_2 leakage to the surface and how the leakage would be quantified, should leakage occur. Leaks would be detecting using methods such as pressure monitoring, MITs, visual inspection, and personal H_2S monitors.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 3.0 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage. SBF's approach to collection information for the determination of baselines include AVO Inspections, Continuous Monitoring, Well Integrity Testing, Pressure Transient Analysis, and Wellbore Surveys.
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 3.0 of the MRV plan describes SBF's approach to determining the amount of CO_2 sequestered using the Subpart RR mass balance equation, including as related to calculation of total annual mass emitted from equipment leakage.
40 CFR 98.448(a)(6): For each injection well, report the well identification number used for the UIC permit (or the permit application) and the UIC permit class.	Appendix A of the MRV plan provides the well identification number for the Hinkle Trust #1 injection well. The MRV plan specifies that the well has been issued a UIC Class II permit under TRRC Rule 9.
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 3.0 of the MRV plan states that the mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12 and assumes an expected injection start date of July 17th, 2023.

Appendix A: Final MRV Plan

EOG SPG Holdings, Inc.

Subpart RR Monitoring, Reporting, and Verification Plan for SPG CO_2 Bowie Facility

Montague County, TX

Version 3
December 2023

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1 Introduction

EOG SPG Holdings, Inc. (SPG) - a subsidiary of EOG Resources, Inc. - recently received authorization from the Railroad Commission of Texas (TXRRC) to drill and operate a Class II disposal well (Hinkle Trust #1) under Texas Administrative Code (TAC) Title 16, Part 1, § 3.9. Under this permit (No. 17041), SPG can inject up to 12 million standard cubic feet per day (MMSCFD) of acid gas waste - composed primarily of CO_2, N_2, H_2S, and other trace hydrocarbons - generated by four natural gas amine treatment facilities located in Montague County, TX and operated by EOG Resources, Inc. (EOG). These facilities separate the acid gas components from the natural gas stream produced from the Barnett Shale by approximately 1,100 wells across the Newark East Field, also operated by EOG. Historically, the separated CO_2 stream has been emitted to the atmosphere while the H_2S was incinerated by a thermal oxidizer with the resulting SO_2 emitted to the atmosphere. In 2022, the aggregate total reportable greenhouse gas (GHG) emissions from all four amine separation facilities were approximately 180,000 metric tons (MT) of CO_2.

EOG is submitting this Monitoring, Reporting, and Verification (MRV) plan to the Environmental Protection Agency (EPA) for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) in connection with qualifying for the tax credits in section 45Q of the Internal Revenue Code.

1.1 Document Organization

This MRV plan is organized into three main sections: 1) this introductory section; 2) project details; and 3) a description of the development and administration of the MRV plan.

Section 1 introduces the injection project. It provides a high-level overview of the existing natural gas amine treatment facilities that are the sources of the CO_2 emissions as well as the capture, compression, and pipeline gathering systems that have recently been constructed as part of the injection project infrastructure. The section concludes with a general description of the subsurface storage complex including the target storage reservoir, the confining system, and the operational history that is relevant to the planned injection operations.

Section 2 provides more detailed presentations of the regional geology in the project area and the operational infrastructure including:

- a more detailed review of the source of the CO_2 emissions and the capture, compression, and pipeline gathering systems that will be used to deliver the CO_2 to the injection site;
- a summary of the proposed injection volume rates and the projected cumulative mass of CO_2 to be stored over the expected project life;
- the stratigraphy of the underburden, storage reservoir, and confining system;
- the structural features and subsurface stress characteristics within the project area;
- a more detailed review of the Barnabus (Ellenburger) field history; and
- a description of the fluid transport characteristics of both the storage reservoir and the confining system;

Section 3 describes the specific technical elements of the proposed MRV plan and how the plan will be administered over the expected project life, including:

- a description of the geologic and reservoir models used to simulate the long-term injection performance and CO_2 plume behavior;
- the delineation of the Active and Maximum Monitoring Areas (AMA and MMA, respectively);
- a description and assessment of the potential surface leakage pathways in the project area;
- a discussion of the methods and techniques that will be used to detect, verify, and quantify potential surface leaks of the injected CO_2;
- a presentation of the routine and regular operational monitoring that will establish baseline operating conditions, against which future monitoring surveys and results will be compared;

- a description of the various measurement and mass balance accounting techniques that will be employed to quantify the mass of the various CO_2 streams;
- an explanation of how quality assurance and quality control (QA/QC) will be maintained across all aspects of the project operations;
- an acknowledgment of the requirements to submit revisions to the MRV plan in the event of material changes to the project; and
- a summary of the records that will be retained throughout the expected project life.

1.2 Surface Infrastructure Overview

EOG operates four natural gas amine treatment facilities that provide CO_2 to the Hinkle Trust #1 injection well. Figure 1 shows the geographic location of these facilities as well as the pipeline network that delivers CO_2 to the injection site. The names, TXRRC serial numbers, EPA GHGRP site identification numbers, and the CO_2 emissions for the 2022 reporting year of each of these facilities are summarized in Table 1. Section 2.1 provides a more detailed description of the gas treatment process and the CO_2 delivery infrastructure associated with the project.

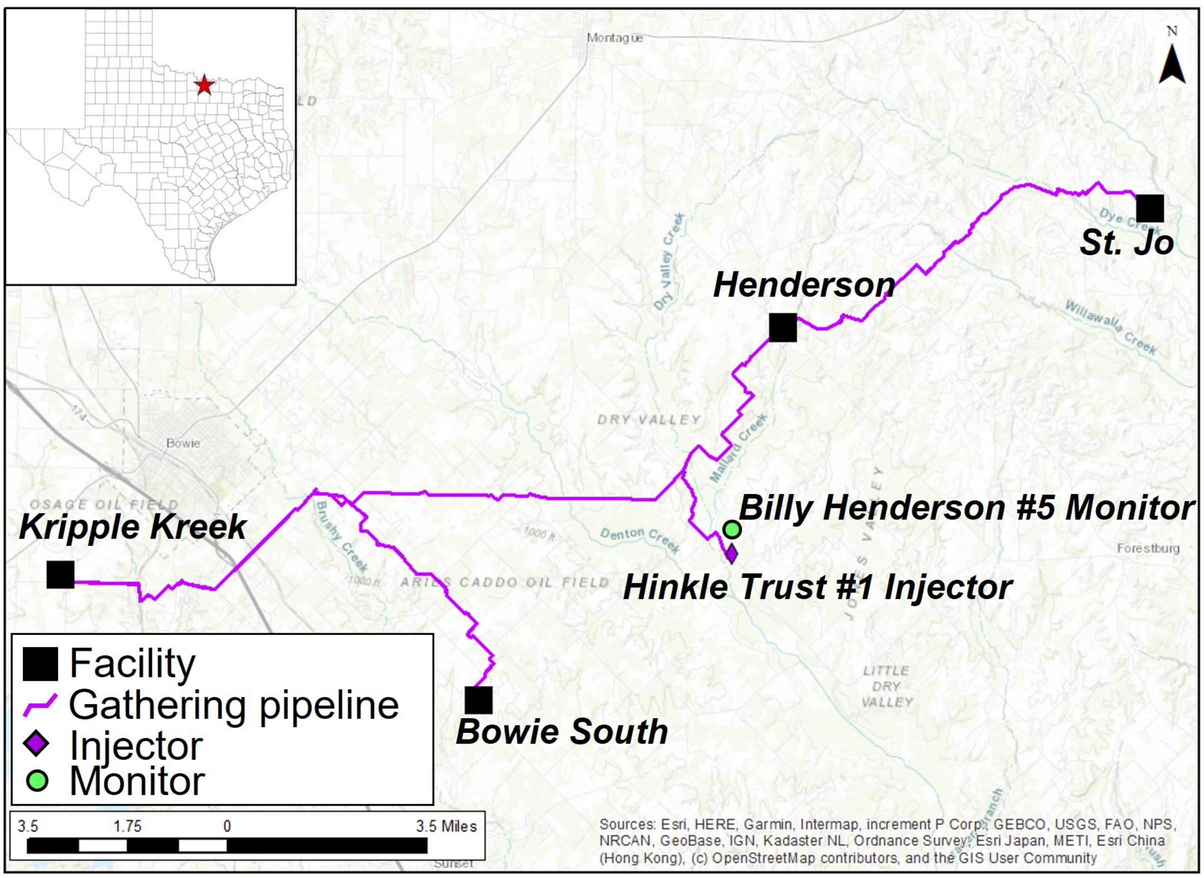


Figure 1: Project site map showing four gas amine treatment facilities providing CO_2 to the project, the pipeline network connecting processing facilities to the injection site, and the injection and monitoring well locations.

Table 1: Registration details and associated 2022 emissions for EOG gas amine treatment facilities.

Facility Name	TXRRC Serial No.	GHGRP ID	2022 Reported CO_2 Emissions (MT)
Bowie South[a]	09-0415	566952	54,352
Henderson[a]	09-0405	566952	20,584
Kripple Kreek	09-0401	528742	61,709
Saint Jo[a]	09-0406	566952	43,509
Total	—	—	**180,154**

[a]Previously reported as part of EOG Resources, Inc. 420 Fort Worth Syncline Basin Gathering & Boosting facility under Subpart W.

1.3 Subsurface Storage Complex Overview

The subsurface stratigraphy of interest for this project consists of the approximately four thousand feet of rock below the Barnett Shale formation, which is the primary hydrocarbon-producing interval within the project area. The middle Ellenburger formation is the main injection target for the project, which is an approximately one thousand foot thick dolomitic karst reservoir. Overlying the middle Ellenburger dolomite is over two thousand feet of mixed carbonates in the upper Ellenburger formation, mixed shale and limestone in the Simpson formation, and limestone in the Viola formation. These units contain ample footages of tight limestones, tight dolomites, and low permeability shales, and serve as the upper confining system for the project. Below the middle Ellenburger injection zone is approximately one thousand feet of tight limestone, which serves as the lower confining zone between the middle Ellenburger injection zone and the underlying granitic basement.

Two wells were drilled for this injection project. The Billy Henderson #5 is a vertical pilot and monitoring well that was drilled into granitic basement. This well provided project site-specific data across the injection and confining zones and was subsequently completed as a monitor well for the project. The Hinkle Trust #1 is the injection well for the project. This slightly-deviated well was drilled approximately 1,600 feet (ft) away from the Billy Henderson #5 monitor to a depth only a few hundred feet below the base of the injection zone. Evaluation data was also collected in this well for further subsurface characterization of the project site. The Hinkle Trust #1 was completed as an openhole injector into the middle Ellenburger dolomite.

2 Project Details

2.1 Source and Gathering of CO_2 for Injection

The Bowie Production Area has four central gas gathering sites that take produced gas from the field at low pressure (25-35 pounds per square inch-gauge, psig) and condition the gas to go through high pressure (750-900 psig) gathering lines to deliver the produced gas to a central gas treatment facility. Each of the gas gathering sites - Saint Jo, Henderson, Bowie South, and Bowie East Compressor Stations - have 3-stage compressors to increase the pressure of the gas before it goes through treatment to remove water and other impurities. Three of these gas gathering sites - Saint Jo, Henderson, and Bowie South - have amine treatment using Methyl-diethanolamine (MDEA) and Piperazine to remove CO_2 and H_2S from produced gas in the field down from 8%-15% CO_2 to 4% CO_2. The gas is then dehydrated using Triethylene Glycol (TEG) to remove water down to 7 pounds (lbs) per MMSCF (million standard cubic feet) before being sent to Kripple Kreek Gas Plant to go through final treatment. At the Kripple Kreek Gas Processing Plant, the remaining CO_2 in the high pressure produced gas is removed using MDEA and Piperazine from 4% CO_2 down to 100-200 parts per million (ppm) CO_2. The high pressure produced gas is dehydrated to a -300 °F dewpoint using TEG then mol sieve dehydration where the gas is then sent for final processing to separate the residue gas from the natural gas liquids (NGLs) for final sale. The residue gas is compressed and sold into a residue gas pipeline system, where the NGLs are subsequently sold and pumped into a y-grade NGL pipeline system.

The SPG CO_2 Bowie Facility (referred to as the injection facility or the Bowie injection project; GHGRP ID 583201) gathers the CO_2 from each of the four existing amine treatment facilities (at Saint Jo, Henderson, Bowie South, and Kripple Kreek) using 4-stage booster compressors to increase the pressure of the CO_2-rich gas from low pressure (5 psig) off of the amine still to high pressure (750-850 psig). The CO_2-rich gas is then conditioned using a TEG dehydration unit to lower the dew point below 0 °F to ensure free water is not condensed during normal operations. The CO_2-rich gas is then sent through a measurement section to record the mass flowrate, composition, temperature, pressure, oxygen content, and water content before being introduced into the CO_2 gathering system. Based on routine measurements from the gas chromatograph (GC) installed at the injection facility, the CO_2-rich gas will be >98% CO_2 by weight with the remainder being a mixture of nitrogen, small amounts of various hydrocarbons, water and trace H_2S (see Table 2). As such, the injected gas stream is nominally described by its principal component (CO_2) throughout the MRV plan.

Table 2: Compositional analysis of gas stream to be injected at SPG CO2 Bowie Facility.

Component Name	**Normalized Mol %**	**Normalized Weight %**
Hydrogen Sulfide	0.0034	0.0027
Nitrogen	2.2536	1.4487
Carbon Dioxide	97.3991	98.3634
Methane	0.2207	0.0813
Ethane	0.0359	0.0247
Propane	0.0347	0.0351
i-Butane	0.0015	0.002
n-Butane	0.0061	0.008
i-Pentane	0.0021	0.0035
n-Pentane	0.0025	0.0041
C6+	0.0057	0.0122
Water	0.0347	0.0144
Total	100	

The gathering system consists of 36 miles of 6-inch nominal diameter Flexsteel composite pipe that collects the CO_2 streams from each of the four processing sites. The CO_2 is then sent to the injection facility where the gas enters the site and goes through an inlet heater for conditioning to ensure it is in the vapor phase before it goes through a measurement section to record the mass flowrate, composition, temperature, pressure, oxygen content, and water content before the gas is compressed from high pressure (750-850 psig) to supercritical (1,600-2,200 psig) in the final 2-stage unit. The supercritical CO_2 leaving the compressor is left hot to then be routed to the heater to cross exchange and provide heat for the inlet gas from the CO_2 gathering pipeline. The supercritical CO_2 is then sent through final measurement to collect the mass flowrate before the gas enters the wellhead and is injected in the subsurface. Figures 2 and 3 depict the general process flow that delivers conditioned CO_2 to the injection facility as well as the detailed plot plan of the injection well site. Both figures identify the location of the final coriolis meter (Meter ID: FW46045INJ) which will serve as the reference injection measurement used in the mass balance accounting under Subpart RR.

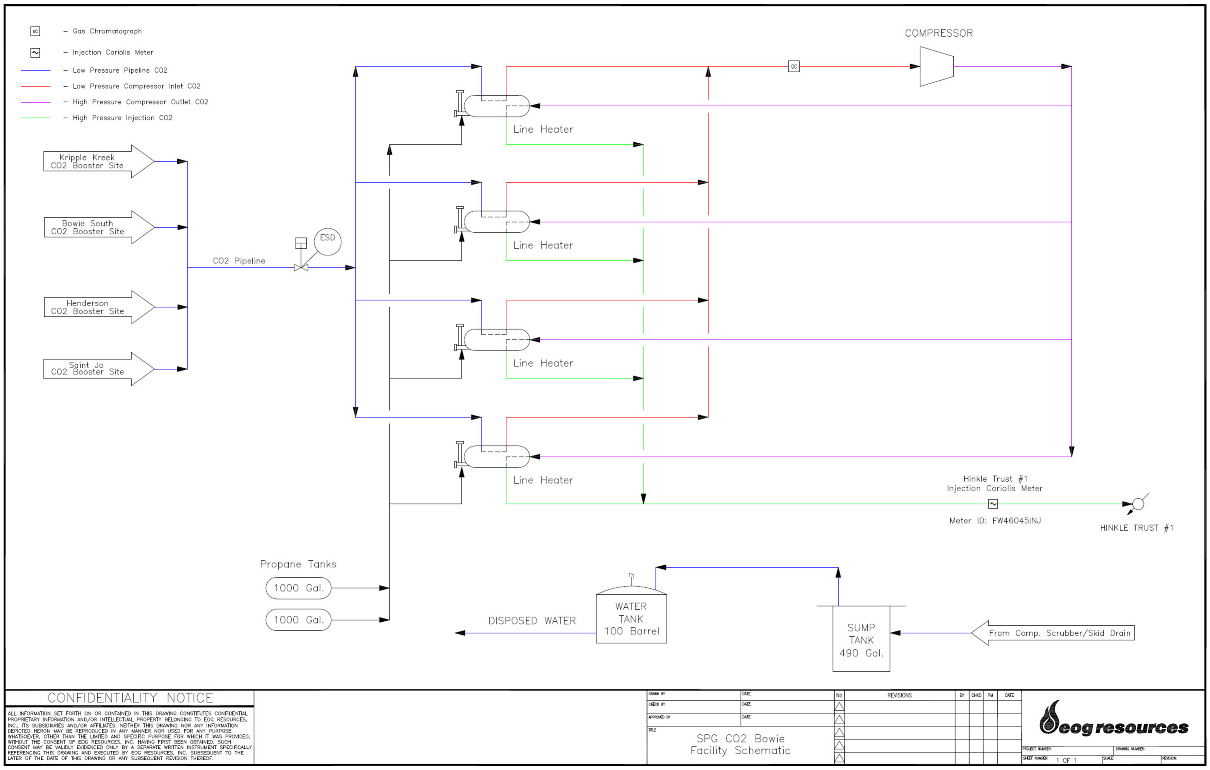


Figure 2: General flow diagram for SPG CO2 Bowie Facility.

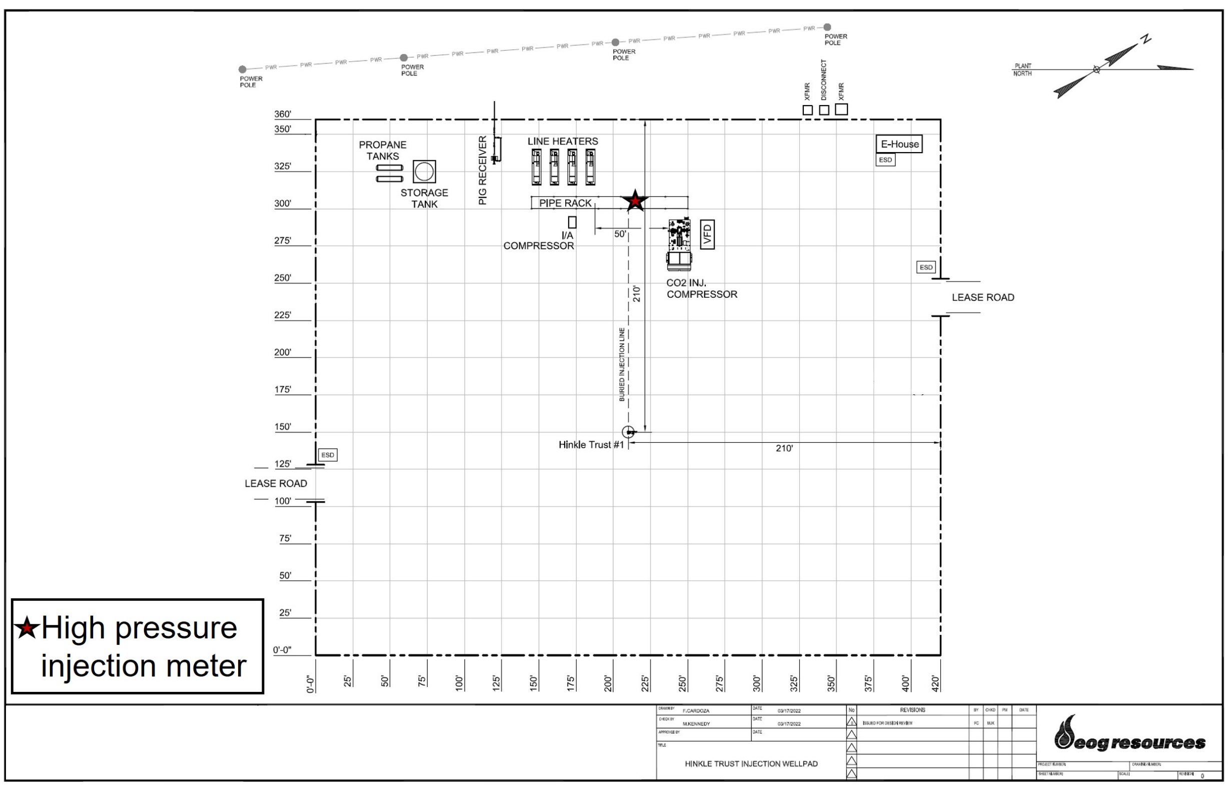


Figure 3: Plot plan for Hinkle Trust #1 injection pad.

2.2 Proposed Injection Volumes

The proposed CO_2 injection stream is separated from the natural gas produced by EOG's nearly 1,100 active Barnett wells in Montague County. Since these wells are on a natural depletion decline (and additional development drilling is not currently planned), the projected CO_2 volumes will follow a similar decline trend. Over the proposed 12-year project life, injection rates will decline from an initial rate of approximately 10 MMSCFD (~520 MT-CO_2/day) down to 4 MMSCFD (~200 MT-CO_2/day), resulting in a total cumulative injected mass of approximately 1.45 million MT-CO_2 (Figure 4). Injection operations began in February 2023 with CO_2 volumes supplied from the Henderson facility only. Injection operations from all four amine treatment facilities that will supply CO_2 to the gathering system commenced in June 2023, following completion of start-up and commissioning tests.

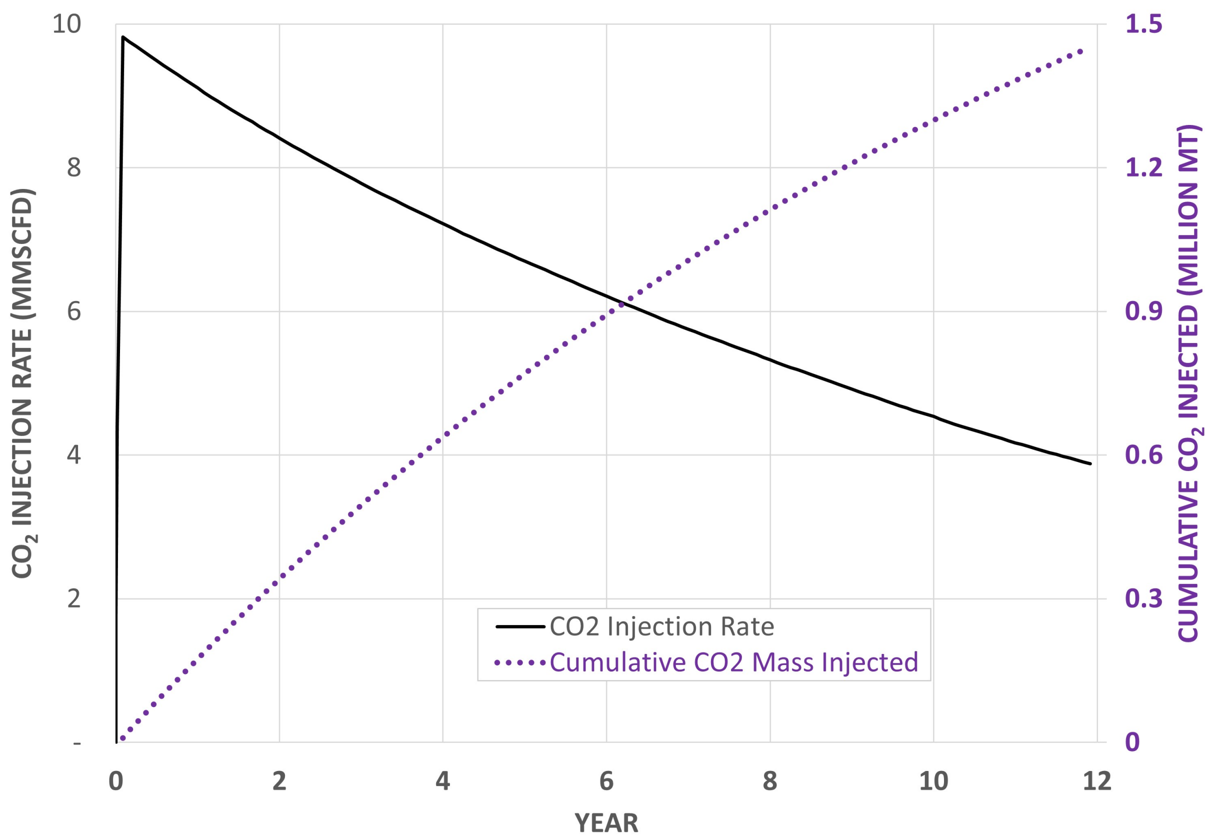


Figure 4: Projected CO_2 injection rate and cumulative mass injected over the proposed 12-year injection period.

2.3 Regional Geology

The project is located in the northern Fort Worth Basin which is a Paleozoic foreland basin associated with the Ouachita Orogenic belt (Figure 5). It exhibits stratigraphy similar to other Paleozoic structural basins found in North America [Meckel et al. (1992)]. The main hydrocarbon producing intervals are Mississippian to Pennsylvanian in age [Pollastro et al. (2007)]. The formations of interest for this injection project are pre-Mississippian-aged marine sediments, which sit below the major productive oil and gas intervals, and are separated from the underlying granitic basement by Cambrian aged sediments sitting below the injection zone (Figure 6) [Alsalem et al. (2018)]. The Ellenburger is the main formation of interest for this project, with secondary formations of interest being the overlying Simpson, Viola, and Barnett in stratigraphic order.

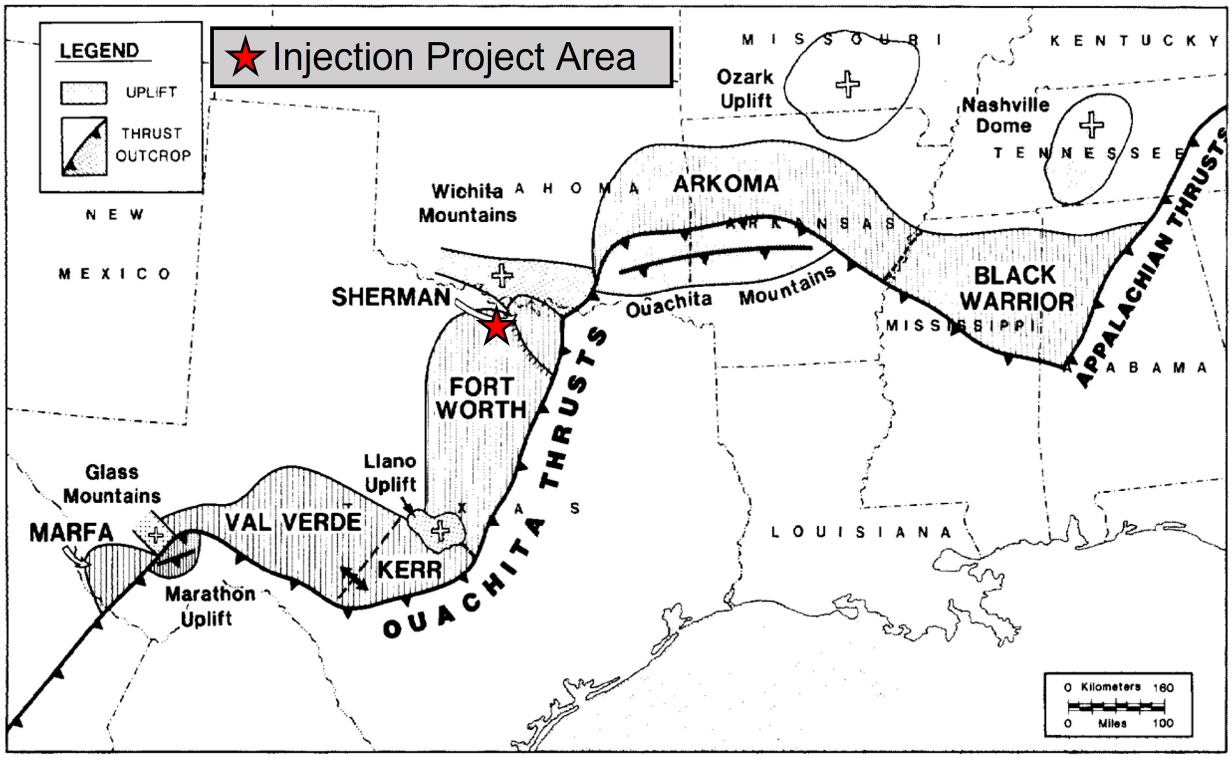


Figure 5: Location of Bowie injection project in northern Fort Worth Basin in reference to Ouachita front and related structural features. Figure modified from Meckel et al. (1992).

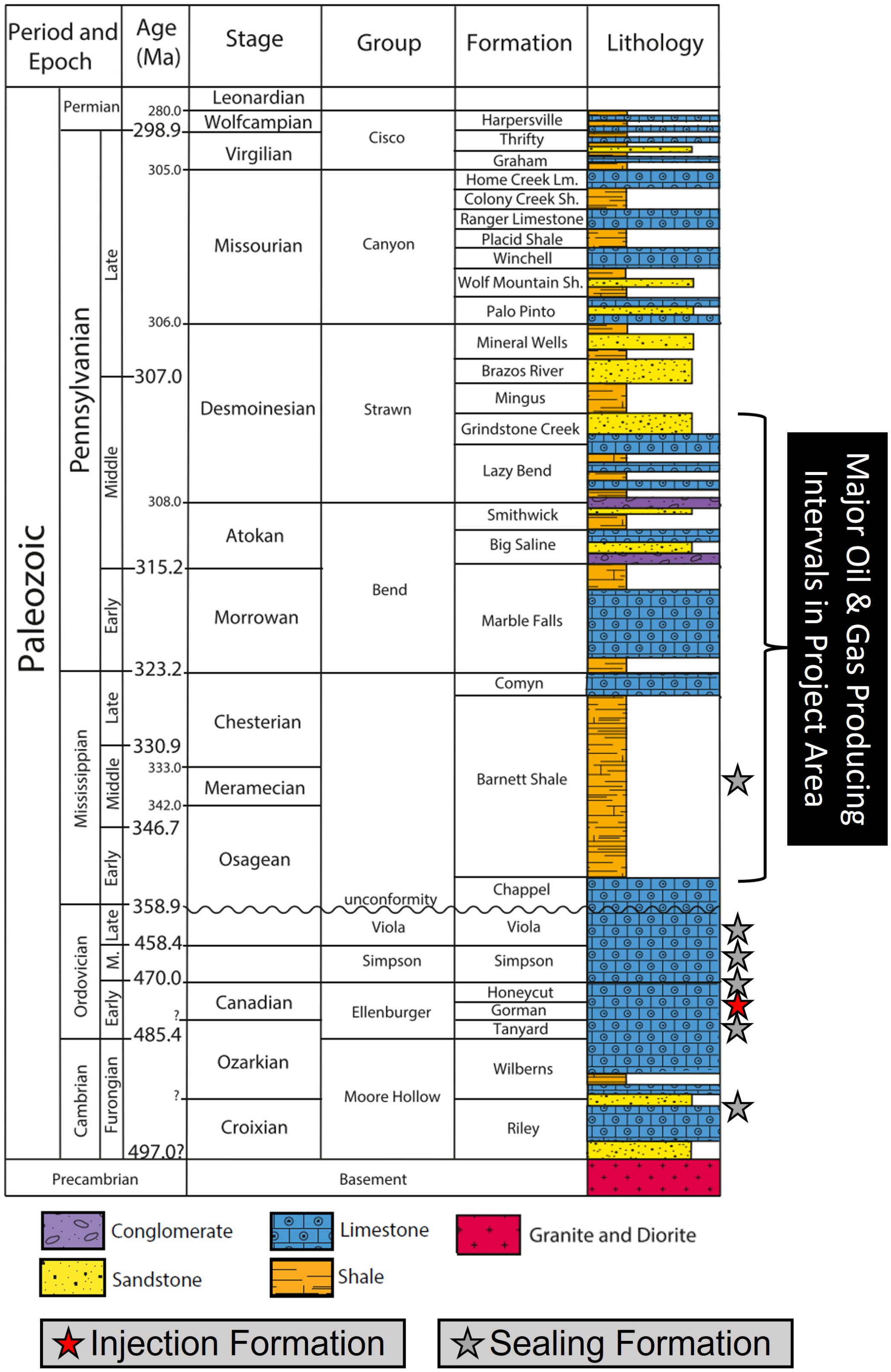


Figure 6: Generalized stratigraphic column of the Fort Worth Basin. Note that thicknesses of formations depicted within this illustration are not to scale for any particular location within the basin. Figure modified from Alsalem et al. (2018).

Prior to the formation of the Fort Worth structural basin in the project area, these Cambrian and Ordovician-aged sediments of interest were deposited on an epeiric carbonate platform developed on the Laurentian margin. This carbonate platform is commonly referred to as the Great American carbonate bank, which extended across the entirety of North America and rimmed the stable cratonic interior (Figure 7) [Derby et al. (2012)].

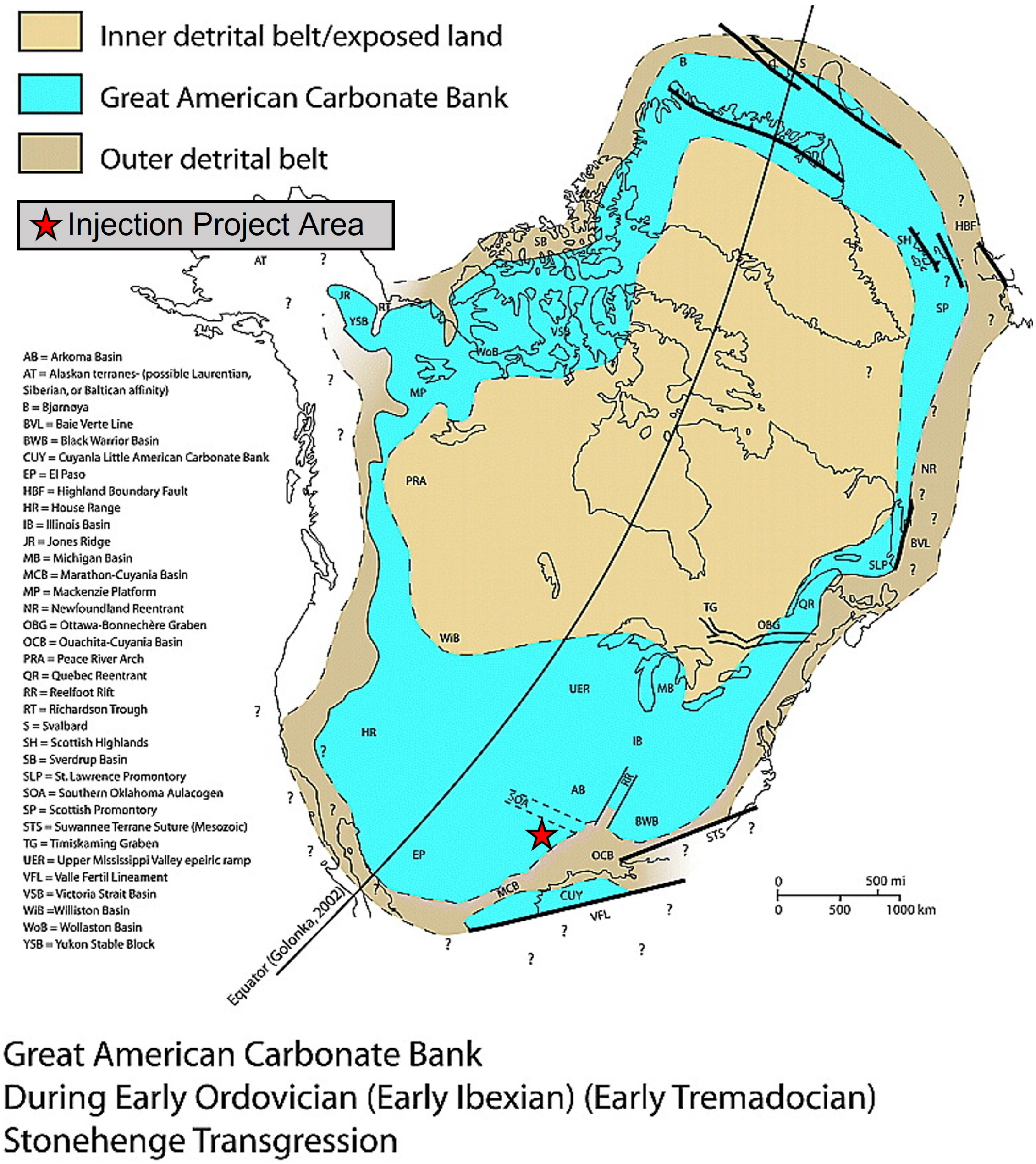


Figure 7: Location of Bowie injection project in reference to Great American carbonate bank paleogeography. Figure modified from Derby et al. (2012).

A large sea level change between the Ordovician and Mississippian resulted in an unconformity that removed any Silurian or Devonian rocks that may have been deposited. It was upon this unconformity that the Mississippian sediments, including the Barnett shale, were deposited. The late-Paleozoic Ouachita Orogeny formed the structural Fort Worth Basin and influenced sedimentation patterns through Permian time, with additional influence on the character

and thickness of sediments by local structure perturbations. In the northern Fort Worth Basin, these local structures include the Muenster Arch and Red River Arch. Pennsylvanian and early Permian sediments include both siliciclastics and carbonates, with siliciclastics being more dominant in the mid to late Pennsylvanian and Permian [Pollastro et al. (2007)]. In the eastern part of the Fort Worth Basin, the Cretaceous Trinity group rests unconformably on the Permian and Pennsylvanian-aged sediments [Fort Worth Geological Society (1955)]. The Trinity group contains the major freshwater aquifer units where present in the Fort Worth Basin, with no minor aquifers present (Figure 8) [George et al. (2011)].

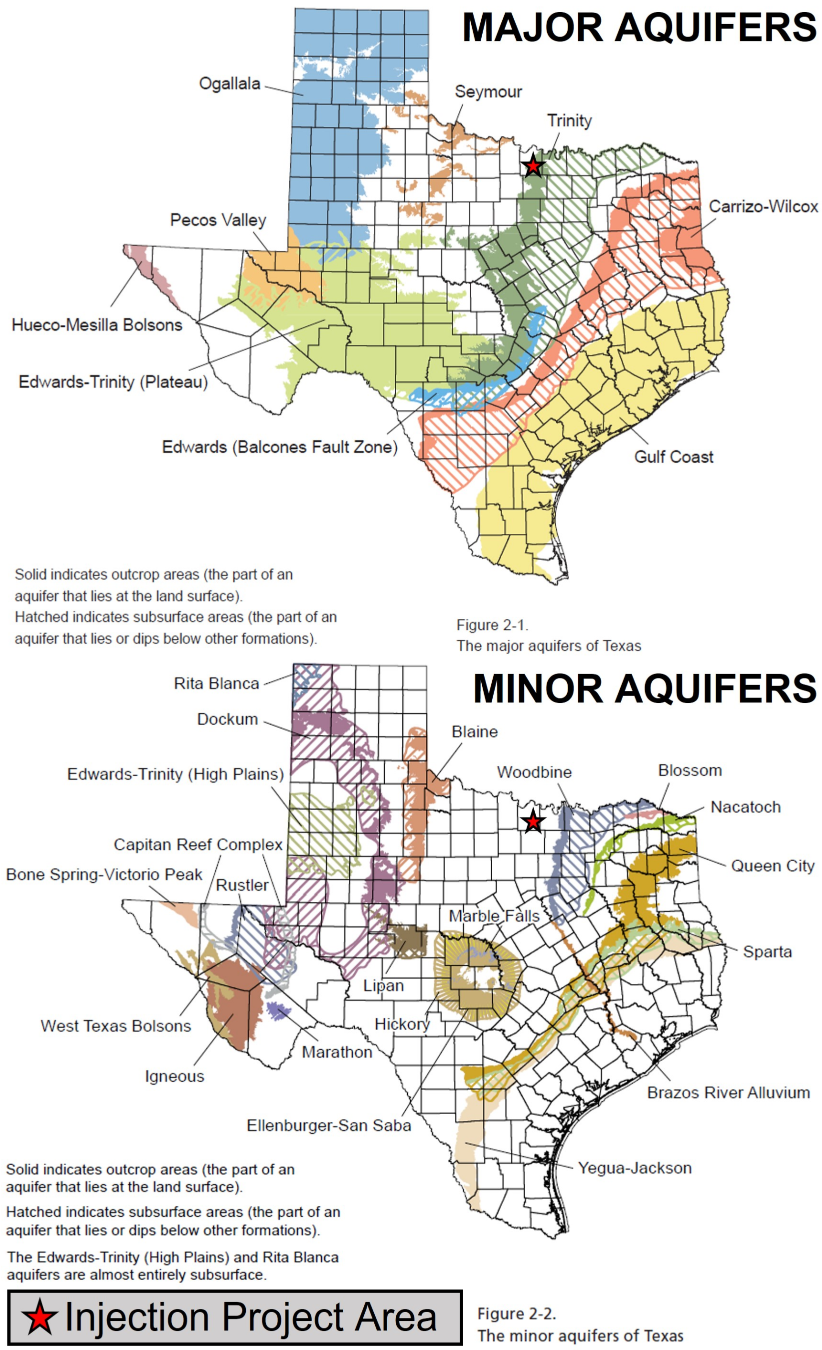


Figure 8: Project site referenced to Texas major and minor aquifers as identified by the Texas Water Development Board. Figure modified from George et al. (2011).

The injection project is located in Montague County, in the far northern part of Fort Worth Basin, in a structurally deep part of the basin adjacent to the Muenster Arch. Figure 9 shows the location of the project, structure contours on the top Ellenburger, and regional structural elements, including the Muenster Arch. The Muenster Arch has reactivated numerous times since the Precambrian, influencing local depositional patterns in Paleozoic strata.

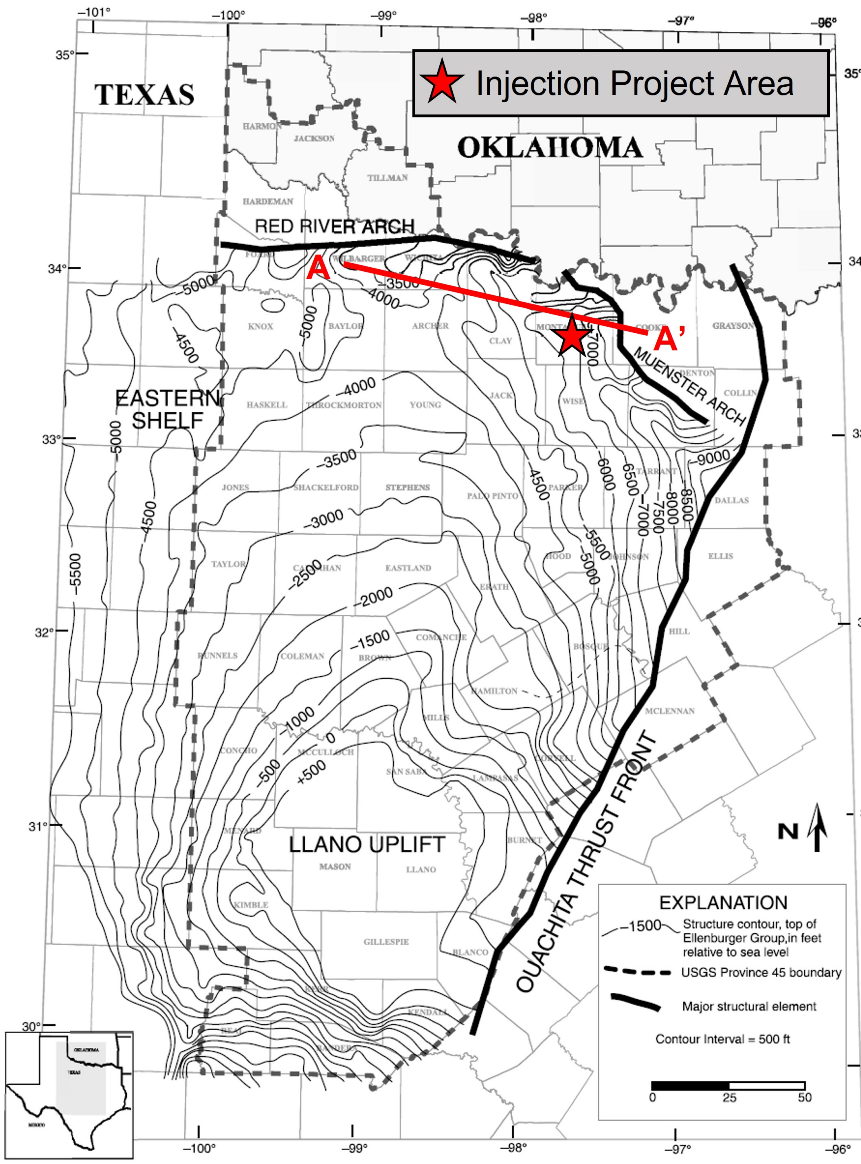


Figure 9: Location of Bowie injection project in Northern Fort Worth Basin, with top Ellenburger subsea true vertical depth (SSTVD) structure contours. Figure modified from Pollastro et al. (2007).

2.4 Stratigraphy of the Project Area

Figure 10 shows the regional character of the stratigraphy near the project area in Montague County. Formations between the basement and lower Penn (labeled top "Caddo") thicken and deepen towards the Muenster Arch, showing its influence on both deposition and present-day structural position. The Muenster Arch is shown as a series of high angle thrusts that place Ordovician Ellenburger above younger Mississippian and Penn sediments. Penn and Permian sediments thicken towards the Ouachita front and Muenster Arch and are truncated by the base Cretaceous unconformity. The Cretaceous-age Trinity group is present in Montague County and sits above this unconformity.

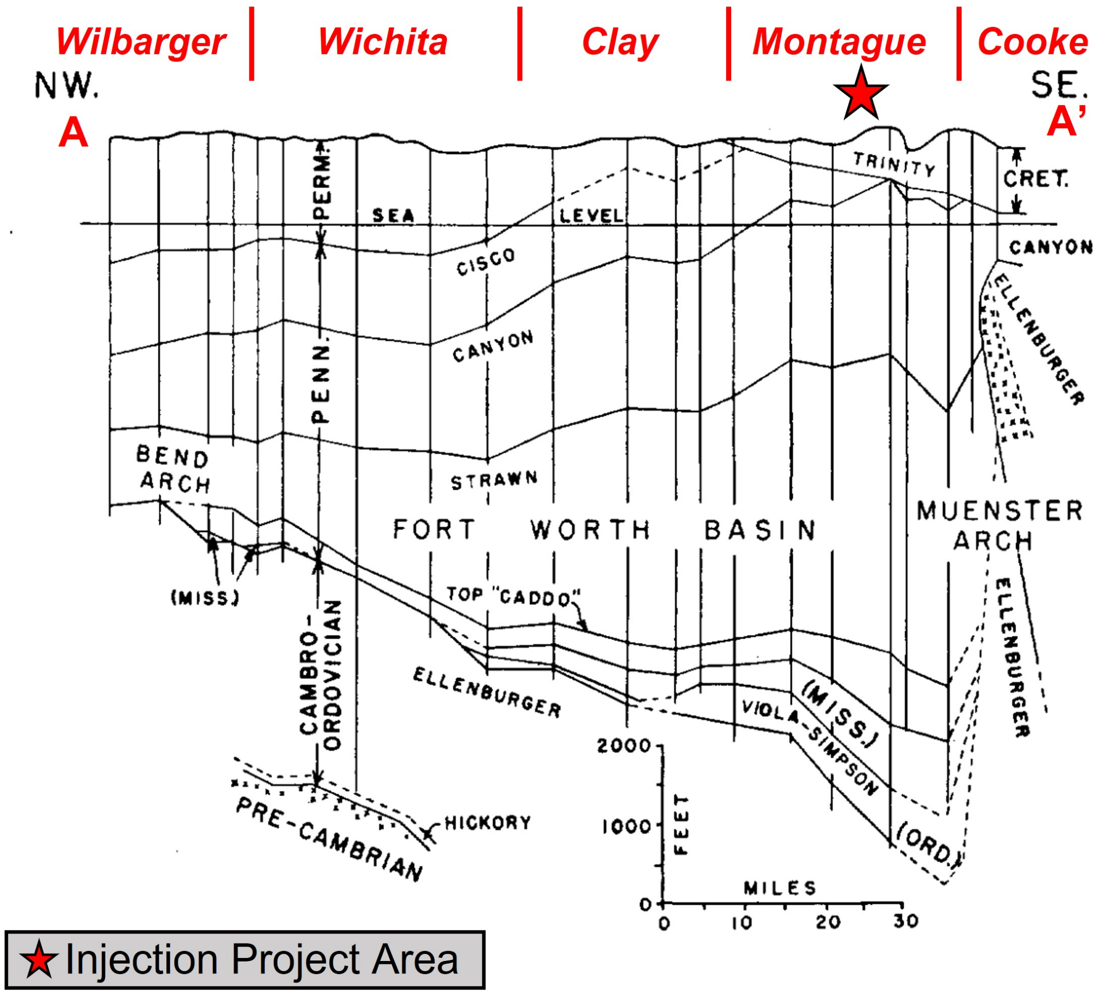


Figure 10: Generalized stratigraphic cross-section of North Fort Worth Basin with counties annotated on section. Figure modified from Fort Worth Geological Society (1955). Location of section shown in Figure 9.

Figure 11 shows the specific stratigraphic units present in the project area which are described below. Geologic descriptions are based on literature and internal EOG data collected across the stratigraphy for this project and others. The Precambrian basement within the project site is granitic and is variably cut by mafic intrusives. The carbonate section from the basement to the top of the Ellenburger has been broken in three units that can be correlated across Montague County. These three units are the basal carbonate (from basement to Base M. Ellenburger in typelog), middle Ellenburger, and upper Ellenburger. Above these units, the Simpson, Viola, and Barnett Shale are observed to be present within the project site [Pollastro et al. (2007)]. More detail will be presented on the lower carbonate through lower Barnett shale in the sections describing the injection and confining zones for the project (Section 2.7). The overlying Pennsylvanian stratigraphy has been broken out using both regional and local nomenclature for the stratigraphic units. At the top of the section is the base of the Trinity aquifer unit, which crops out within the project site (see Figure 12) [George et al. (2011)].

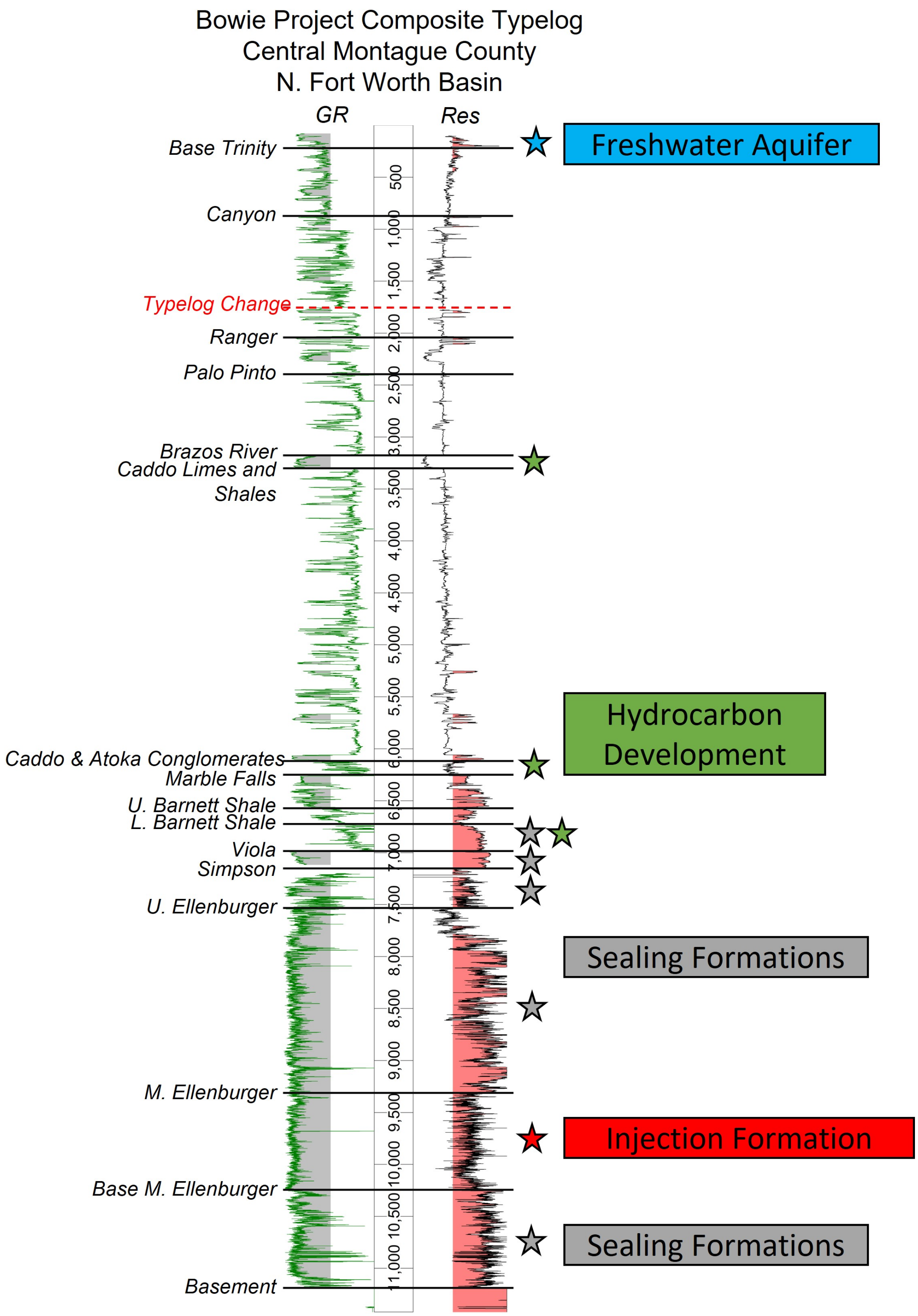


Figure 11: Project site-specific typelog utilizing well log data collected from the Billy Henderson #5 (lower Canyon to basement section) and Hinkle Trust #1 (surface to lower Canyon section).

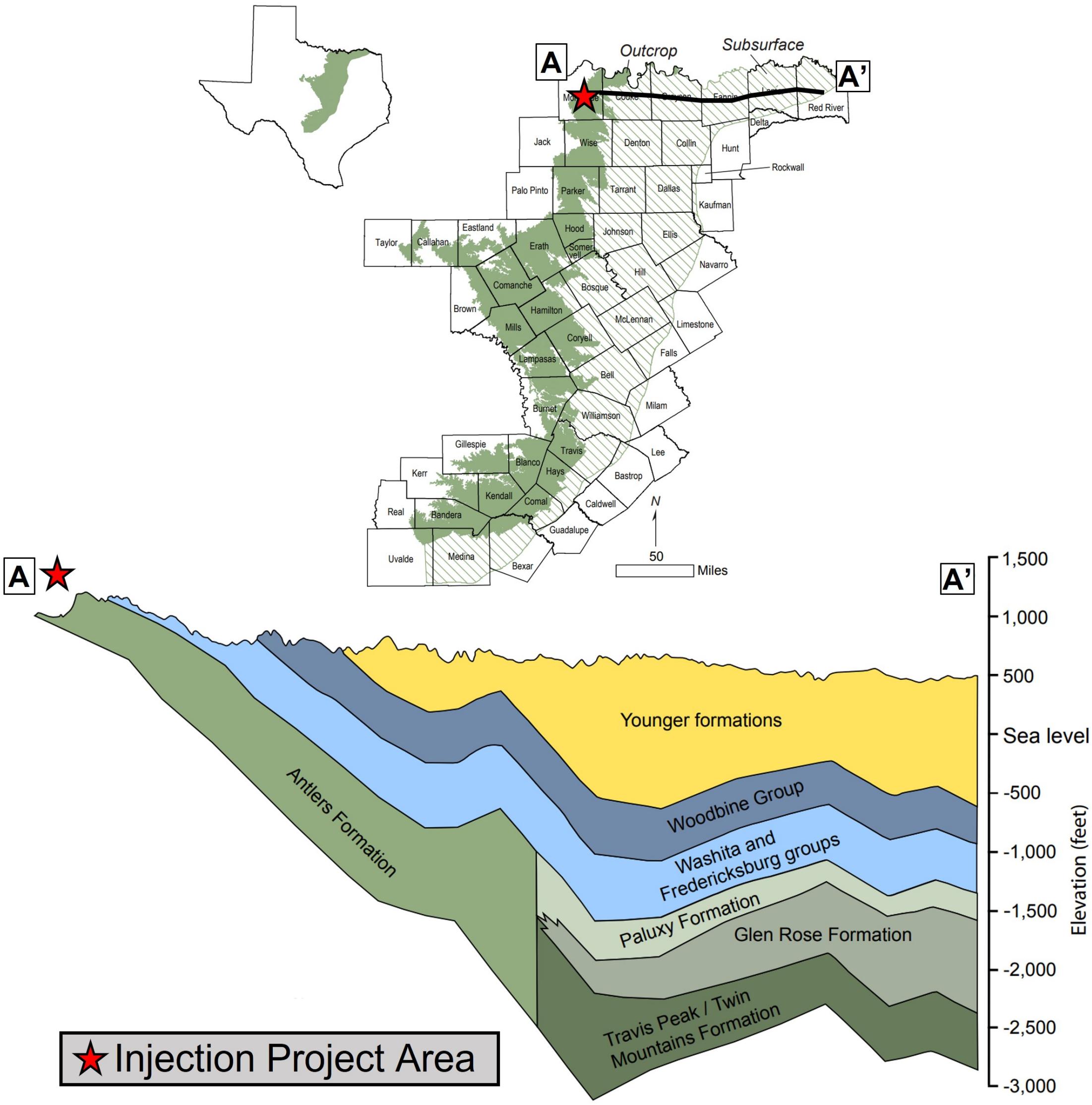


Figure 12: Trinity aquifer extent and geometry in the vicinity of the project area. Figure modified from George et al. (2011).

2.5 Structural Geology of the Project Area

The injection area is bounded by the Muenster Arch to the east and northeast and the Red River Arch to the north, both of which are positive, basement-rooted structural features formed during the Paleozoic Oklahoma aulacogen and were reactivated during Ouachita orogenic compression [Walper (1982)]. The injection area is characterized by three key structural components: basement-rooted faulting, natural fracturing, and, specifically within the Ellenburger, extensive karst formation. Within the injection area, these structural components are characterized with three-dimensional (3D) seismic data, core, and well log data, and are discussed in further detail below.

Basement faulting: The injection area is characterized by a variety of fault orientations and styles reflecting multiple tectonic episodes during Fort Worth Basin evolution. Prominent basement faults generally strike east-west, largely exhibit strike-slip characteristics including extensive flower structures, and were likely formed during the Oklahoma aulacogen [Walper (1982), Pollastro et al. (2007)]. Most prominent basement faults either truncate within the basement or splay into smaller faults upon entering the Ellenburger, though some larger faults may extend up to Pennsylvanian

Strawn or Bend groups (Figure 13). A secondary basement fault set strikes north-northeast to south-southwest (NNE-SSW), paralleling present-day Ellenburger structural strike, though is less prevalent and does not extend above the basement within the injection area. Several basement-level faults intersect the injection interval (Figure 13), and are discussed as potential leakage pathways in section 3.5.3.

Natural fracturing: Ellenburger natural fractures, characterized by wellbore image logs and core data in the injection and monitoring wells, exhibit highly variable strike and dip, and likely originated from a combination of tectonic forces and intra-karst collapse and brecciation [Kerans (1988), Ijirigho and Schreiber Jr (1988)]. Natural fractures also generally appear cemented (Figure 32). The karst features themselves appear to be restricted to the injection zone, and do not appear to extend into the confining zone within the project area. Therefore, the fracturing associated with the karsts is not interpreted to be present across the confining zone.

Karsting: Ordovician Ellenburger group carbonates were deposited on a carbonate platform on a stable cratonic shelf. Sea level drops during and following Ellenburger deposition yielded subareal platform exposure and complex, extensive karsting, which was subsequently filled with Simpson Group clastics [Kerans (1988)]. Karst features are present within the proposed injection area and likely provide the primary Ellenburger storage (i.e., pore space) within the proposed injection interval.

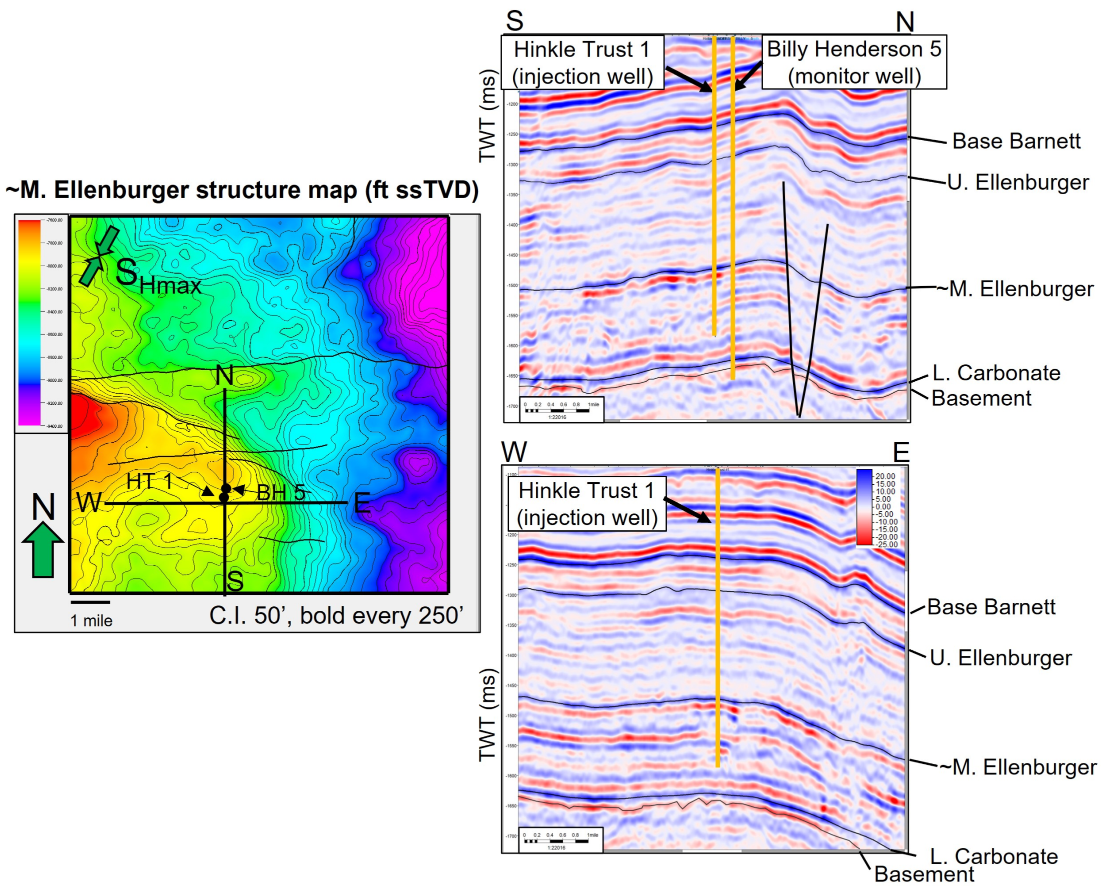


Figure 13: Middle Ellenburger structure map (top injection zone) and seismic cross-sections over proposed injection area. Black lines denote major faults.

2.6 Barnabus Ellenburger Field History

The Hinkle Trust #1 is permitted as an acid gas injector (AGI) within the TXRRC-defined field known as the Barnabus Ellenburger field. Across EOG's productive Barnett acreage in Montague County, this zone has historically been used

extensively for the disposal of produced water (i.e., SWD, or saltwater disposal). Of the six wells drilled into the Ellenburger for SWD by EOG, only four penetrated the middle Ellenburger - the zone intended for long-term CO_2 injection and storage. These four wells are shown on the map in Figure 14 in relation to the Hinkle Trust #1 and Billy Henderson #5, the injection and monitoring wells drilled for this project. Only two of these wells - the Cox and the Davenport - are still active SWD injectors while the other two have been permanently plugged and abandoned. Of the remaining active injectors, the Cox is the closest to the project area, located approximately 6 miles to the north.

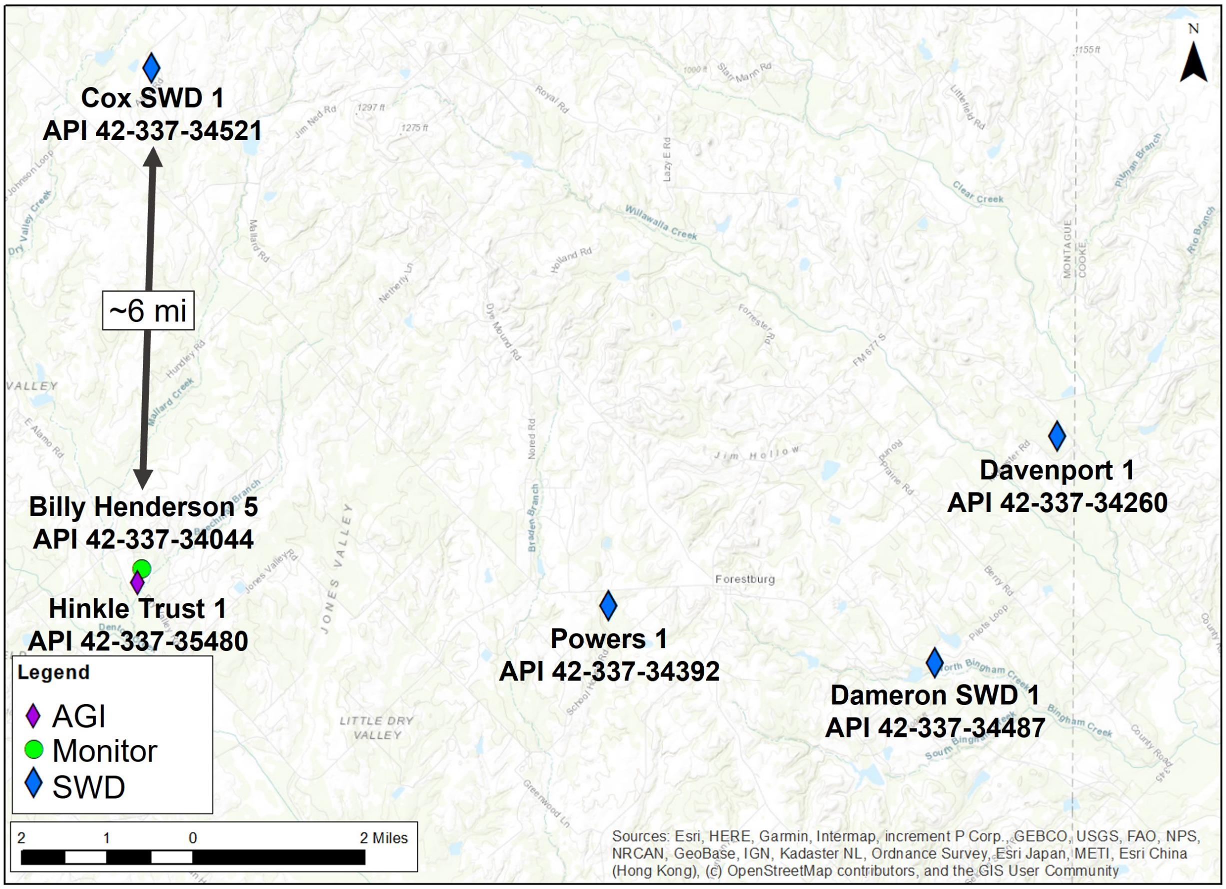


Figure 14: Map of SWD wells drilled into the middle Ellenburger in relation to the CO_2 injection project area.

Figure 15 shows the historical combined monthly injection rates and total cumulative volume injected from all four deep SWD wells from 2010 to 2022. What is notable in these injection trends are the very high rates from 2010 to 2014, when EOG's Barnett development was at its peak. During those years, the SWD wells were each injecting nearly 500,000 barrels (BBL) per month - indicating good injection characteristics in the middle Ellenburger. Over time, as development drilling and field production declined, so did the volume of produced water, which explains the tapering off in the use of the SWD wells from 2014 to 2022. During the entire active period, the four SWD wells injected nearly 90 MM BBL into the middle Ellenburger - suggestive of a large reservoir storage capacity. A relatively small amount of SWD injection is presently active in the Cox and Davenport wells at average rates of 4,200 and 3,700 BBL/day, respectively, with both wells showing stable and consistent injection pressure trends.

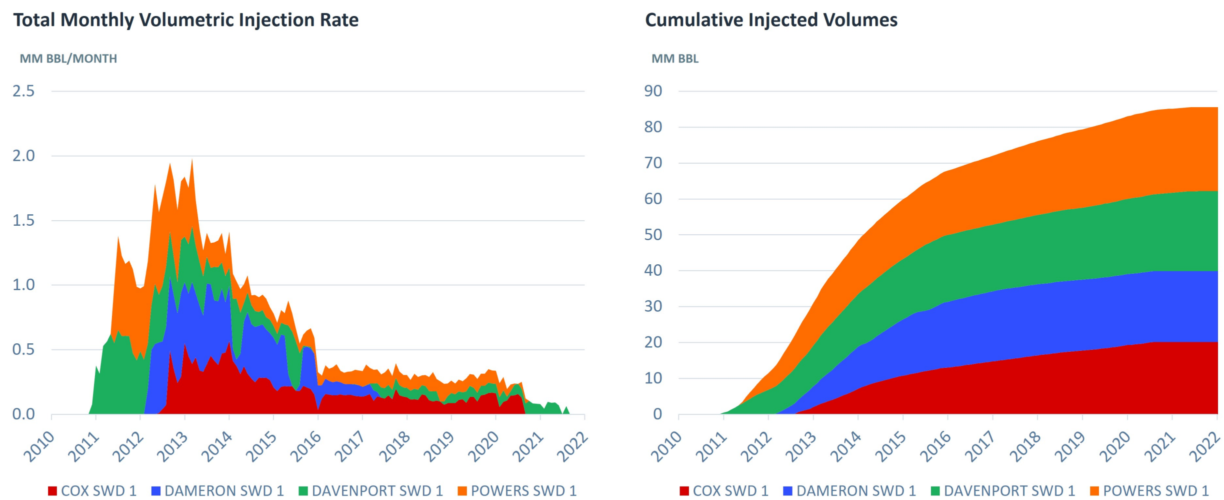


Figure 15: Combined monthly SWD injection rate (left) and cumulative injected water volumes (right) of deep Ellenburger SWD wells from 2010 to 2022.

2.7 Injection and Confining Zone Details

This section provides both quantitative and qualitative descriptions of the injection and confining zones. Observations presented are based on core, petrophysical well log, and 3D seismic data sets that have been integrated across appropriate scales. Petrophysical logs for the injection, upper confining, and lower confining zones were chosen to represent the character and thicknesses observed in the subsequent sections (Figures 16-18). Raw petrophysical logs are shown with the exception of a modeled lithology, which is calibrated to x-ray diffraction mineralogical measurements from core plugs. Core and seismic data are consistent with the characteristics exemplified by the petrophysical logs shown across the injection and confining zones.

2.7.1 Injection Zone

The injection zone for this project is the middle Ellenburger, which is a karsted carbonate reservoir. The injection zone is approximately one thousand feet thick in the project area. The lithology is primarily dolomite, with minor interbedded limestones (Figure 16). The limestones within the injection zone are nonporous and have low permeability based on log and core measurements. The dolomites within in the injection zone host the observed porosity and favorable permeability and range in texture from nonporous, overdolomitized to mesoscale vuggy sucrosic to karst breccias with significant macroscale pore networks. Pervasive dolomitization and karsting is associated with a shallow marine carbonate depositional setting and post-depositional sea level fluctuations allowing for formation of repeated unconformities and karst development across the section.

Qualitative and quantitative descriptive methods were tailored to capture relevant data across this range of textures. Multiscale core measurements and detailed borehole image log analyses were combined with traditional petrophysical modeling to provide the best quantitative interpretation of the injection section for modeling purposes. Matrix scale measurements were made using routine core analysis on plugs taken from a conventional core cut within the injection zone and from rotary sidewall cores collected off wireline in the Billy Henderson #5. These measurements illustrate the range in matrix porosity and permeability observed within the injection zone. Observed porosity and permeability ranges were less than 1% to over 15% and microdarcy to millidarcy, respectively (Table 3).

Matrix scale measurements were combined with methods more suited to measure porosity and permeability within mesoscale karst textures. Two methods were employed: full-diameter, whole core porosity and permeability mechanical measurements and high-resolution computed tomography (CT) scan digital modeling and measurements. A series of whole core porosity and permeability measurements were made on approximately 6-inch long pieces of whole (unslabbed) core sections. Samples were also CT-scanned and then the images were interpreted to create a 3D model of the pore network within the samples. The 3D digital model was then used to generate a set of high resolution poros-

ity curves for each sample. Quantitative data from these mesoscale measurements shows the wide range of values expected for this karst system (Table 4).

The permeabilities measured within the mesoscale to macroscale karst textures were observed to be significantly higher than that of the matrix rock. Interpretation of these observations combined with dynamic injection testing and flow allocation surveys suggests that fluid flow is significantly impacted by the presence or absence of these karst textures. Therefore, methods employed in the creation of a representative geomodel and reservoir simulation for the project incorporate all scales of measurement, which is discussed in detail in subsequent sections of this document.

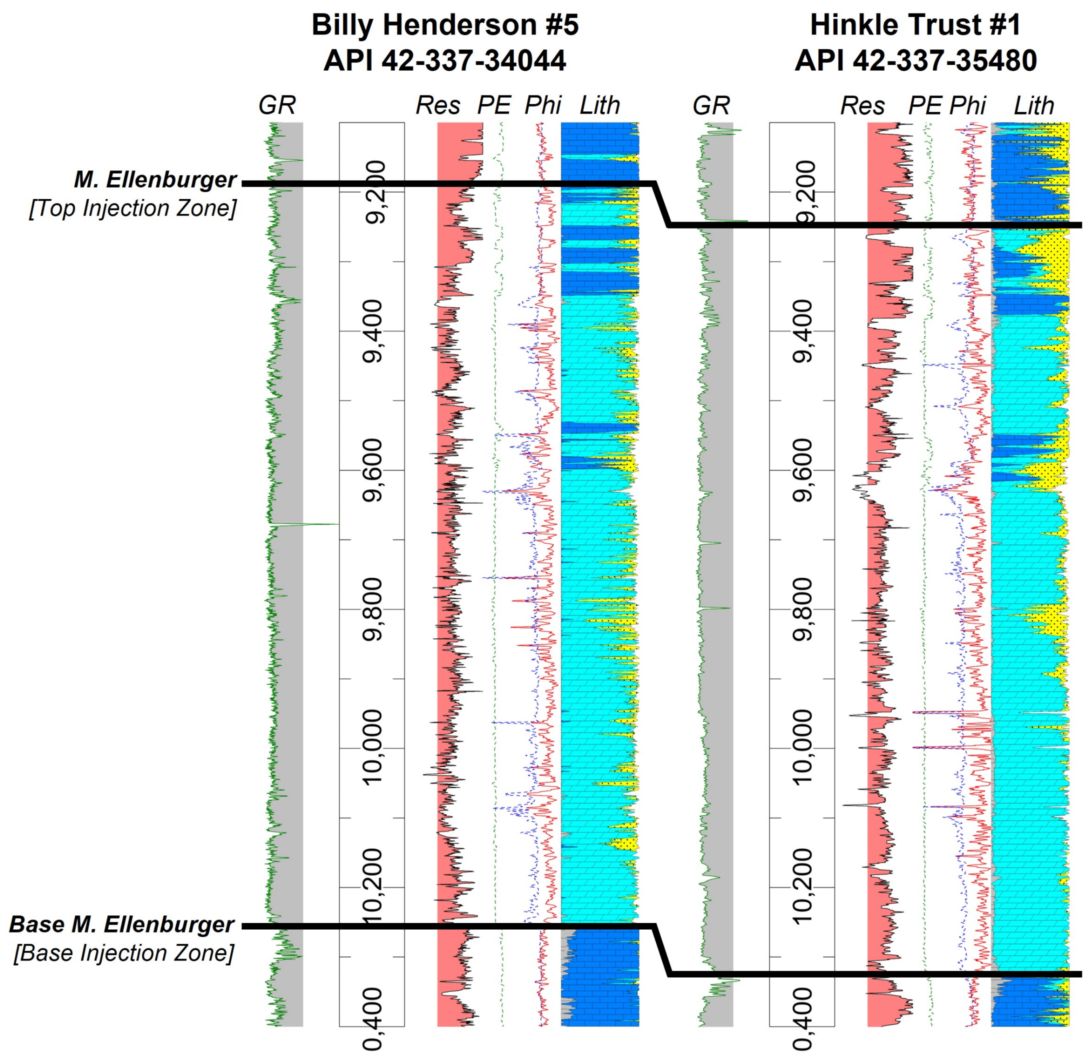


Figure 16: Petrophysical log interpretation in true vertical depth (TVD) for the Middle Ellenburger injection zone at the Bowie project site. Lithologic model presented includes dolomite (cyan), limestone (blue), silica (yellow), clay (gray), and organics (green).

2.7.2 Upper Confining Zone

The upper confining zone for this project is defined as the upper Ellenburger, Simpson, Viola, and base of Barnett shale. The upper confining zone is approximately 2,200 ft thick within the project site. A significant portion of the confining zone consists of sealing tight limestones and dolomites with varying amounts of clay and clay-rich shale. Other rock types present include variably-porous dolomites and limestones (Figure 17). The units within the upper

confining zone appear present and of similar thickness and character across the project site based on 3D seismic and well log interpretation.

The base of the upper Ellenburger consists of approximately 600 ft of mostly tight limestone with a few low porosity dolomite stringers directly overlying the injection zone. This contact is interpreted as a significant unconformity due to the sharp contrasts observed above and below the surface. Petrographic and petrophysical modeling of this zone indicates the presence of tightly-cemented, fine-grained mudstones and wackestones.

Above the lower blocky, tight limestone is interbedded tight limestone and variably porous dolomite. The interbedded lithologies and variable porosities observed are interpreted as coarsening upward depositional cycles with tight limestones at the base grading to variably porous dolomites that cap the cycles. Tight limestones here are similar to those observed in the base of the upper Ellenburger. Depositional textures within the dolomites are more difficult to ascertain due to dolomitization, but it is probable that some of these facies were coarser packstones and grainstones as well as muddier carbonate facies.

At the top of the upper Ellenburger, a blocky porous dolomite section is observed. The top of the Ellenburger likely represents another significant unconformity, but does not show the pervasive karst textures observed within the middle Ellenburger. Minor karst textures are observed, but most porosity in this part of the section seems to be associated with the matrix of the rock.

The Simpson formation is primarily limestone with minor to moderate clay content. It consists of an upper and lower section with higher clay content and a cleaner limestone facies in the middle of the section. Within the project area, the Simpson is approximately 400 ft thick. The upper and lower sections consist of fine-grained, muddy carbonate facies with varying amounts of fine-grained siliciclastics. The clean limestones contain coarser carbonate facies with minor preserved porosity. The Viola within the project area is approximately 180 ft of tight limestone. Observations from a nearby proprietary core just outside the project site suggest the Viola consists mainly of nonporous carbonate mudstones and wackestones within the project area.

At the top of the confining zone is the lower Barnett shale. The lower Barnett is the main hydrocarbon development horizon within the project site. As such, the main focus on the lower Barnett for confinement is restricted to the base of the section below the horizontally-drilled development target. The rock volume within the Barnett that has not been stimulated by hydraulic fracturing, however, likely contributes to confinement within the project area as well.

Matrix scale measurements were made using routine core analysis on plugs taken from several sources. Data for the upper Ellenburger and Simpson comes from plugs from a conventional core cut within the upper Ellenburger and from rotary sidewall cores collected via wireline in the Billy Henderson #5 well. Data for the Simpson and the Barnett come from plugs cut from analog cores near the project site. Quantitative measurements indicate the low porosity, low permeability nature of the pervasive sealing facies within the upper Ellenburger, Simpson, Viola, and lower Barnett shale (Table 3).

The quantitative data presented here were incorporated into the geomodel for the confining zone. In contrast to the injection zone, no pervasive karst textures were observed within the confining zone in the project area. Image log analysis and dynamic injection testing and surveys also indicate an apparent lack of karst features, as well as a lack of transmissive fractures and faults within the upper confining zone at the injection site. As such, the upper confining system as described above is expected to provide excellent long-term sealing capacity.

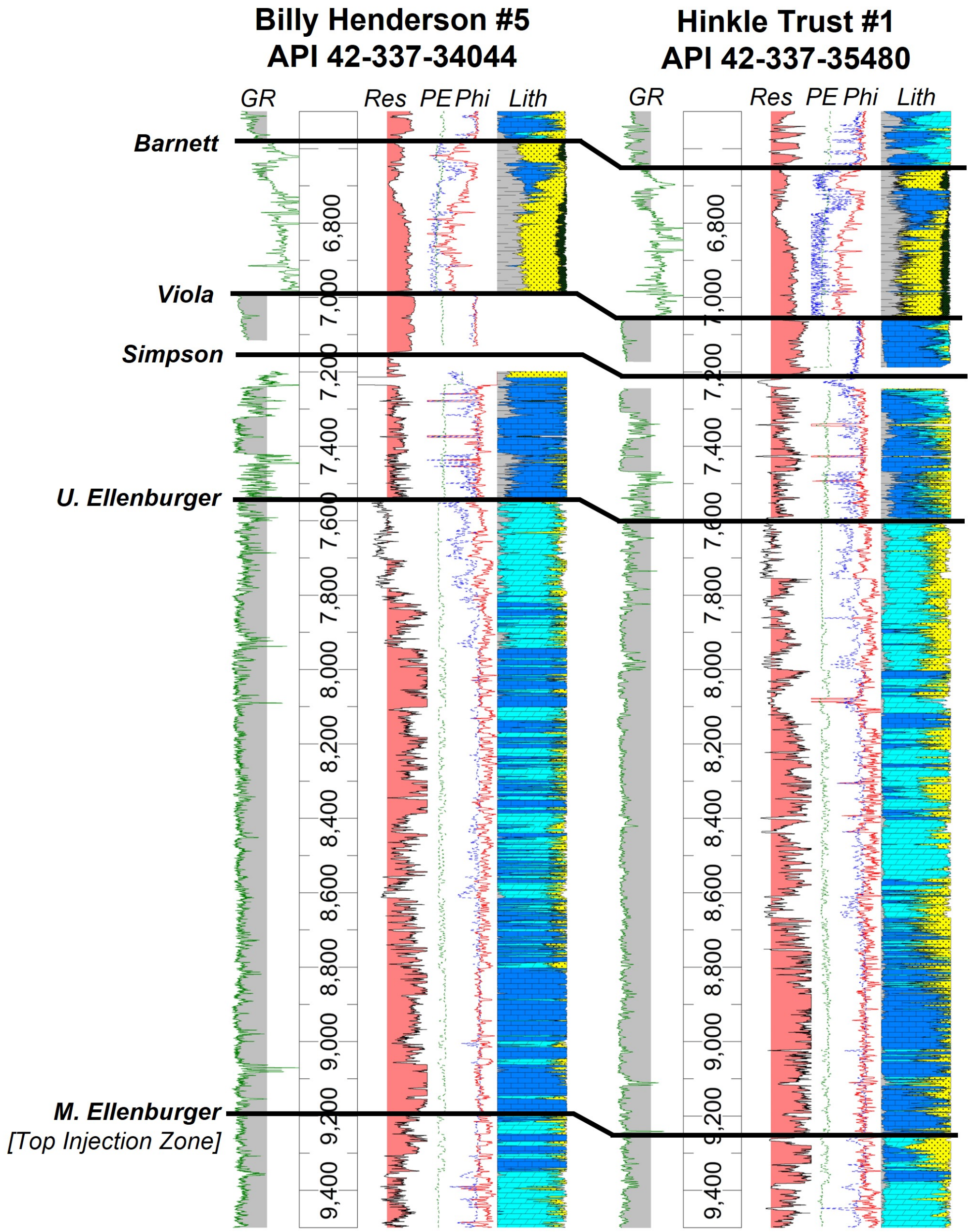


Figure 17: Petrophysical log interpretation in true vertical depth (TVD) for the upper Ellenburger to Barnett upper confining zone within the Bowie project site. Lithologic model presented includes dolomite (cyan), limestone (blue), silica (yellow), clay (gray), and organics (green).

2.7.3 Lower Confining Zone

The lower confining zone consists of the section between the granitic basement and the base of the middle Ellenburger injection zone. This zone consists of approximately 1,000 ft of primarily tight limestone with minor clay within the limestones and a few clay stringers in the project area (Figure 18). Petrographic analysis indicates the presence of heavily cemented limestone facies ranging from mudstones to packstones. A few porous limestone beds are preserved near the clay-rich stringers, but porous limestones are relatively rare across the entirety of the section.

Quantitative routine core analysis data confirms the presence of low porosity, low permeability limestone facies across much of the section. As with the upper confining zone, these matrix scale measurements were used in the geomodel and subsequent reservoir simulation for the lower confining zone. Image log analysis, dynamic injection testing, and injection surveys also indicate a lack of karst features within the lower confining zone, as well as an apparent lack of transmissive fractures and faults within the lower confining zone at the injection site.

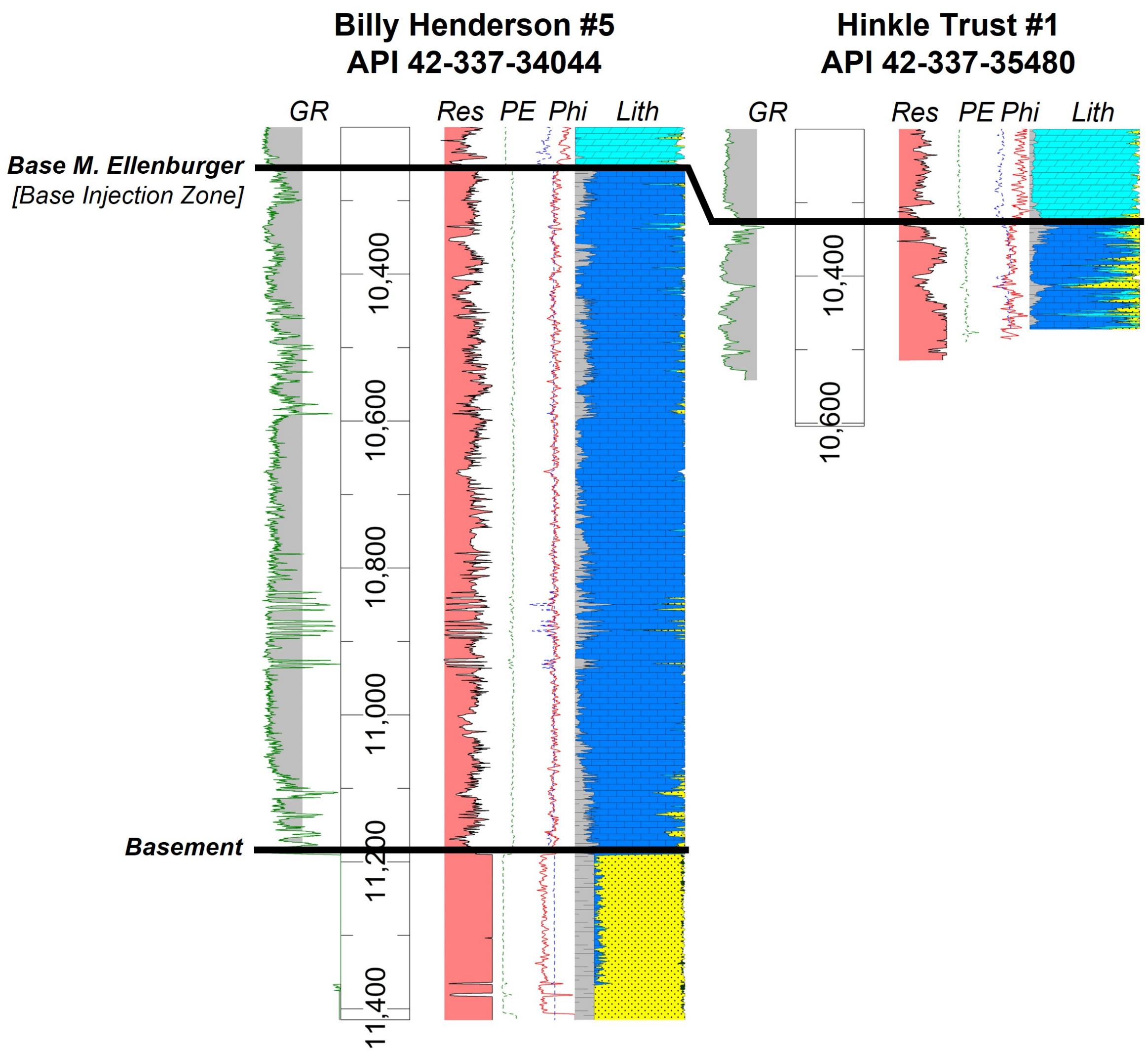


Figure 18: Petrophysical log interpretation in true vertical depth (TVD) for the base Ellenburger to middle Ellenburger lower confining zone within the Bowie project site. Lithologic model presented includes dolomite (cyan), limestone (blue), silica (yellow), clay (gray), and organics (green).

Table 3: Summary of routine core analysis (RCA) data collected for the project by system and formation.

System	**Formation**	**Porosity Minimum** %	**Porosity Maximum** %	**Permeability Minimum** md	**Permeability Maximum** md
Upper Confining	L. Barnett	1.29	8.29	3.02E-06[b]	7.24E-04[b]
	Viola	1.68	6.59	5.00E-04	1.60E-02
	Simpson	1.60	4.32	4.90E-03	6.34E-01
	U. Ellenburger	0.36	13.85	<1.00E-03[c]	5.58E00
Injection	M. Ellenburger	0.29	15.96	<1.00E-03[c]	1.68E00
Lower Confining	L. Carbonate	0.35	15.87	<1.00E-03[c]	9.40E00

[b]Denotes permeability measurements made using pressure decay methods.
[c]Denotes permeability values were below the measurement threshold of the routine core analysis technique. Therefore, the value presented represents an upper limit of minimum permeability. Minimum permeabilities could be significantly lower than the values presented.

Table 4: Summary of full diameter core mesoscale data over the injection interval collected for the project.

	Test Method	
Measurement	Full Diameter Mechanical	Computed Tomography (CT) Digital
Porosity Minimum (%)	2.2	<0.01
Porosity Maximum (%)	6.3	51.9
Horizontal Permeability Minimum (md)	6.96E-02	—
Horizontal Permeability Maximum (md)	1.86E04	—
Vertical Permeability Minimum (md)	1.64E-04	—
Vertical Permeability Maximum (md)	2.83E00	—
Ratio Vert./Horiz. Perm. (Minimum)	4.0E-07	—
Ratio Vert./Horiz. Perm. (Maximum)	7.5E-01	—
Ratio Vert./Horiz. Perm. (Median)	1.0E-03	—

3 Development and Administration of the MRV Plan

As required under §98.448(a)(1)-(2) of Subpart RR, the MRV plan is developed around and tailored to the potential surface leakage pathways within the active and maximum monitoring areas (AMA and MMA, respectively) defined in §98.449. Since the AMA and MMA are both dependent on the expected long-term behavior of CO_2 in the subsurface, numerical reservoir simulation is the generally-accepted best practice to represent the dynamic behavior and complex fluid interactions that influence the CO_2 plume extent and shape during and after injection operations. The next two sections describe the development of a detailed geologic model using the available regional and site-specific data that serves as the basis for predictive numerical reservoir simulations to delineate the AMA and MMA extents for the proposed injection volumes.

3.1 Geologic Model

A geologic model was developed with the proposed injection project at the approximate center of the gridded region. The general grid properties are summarized in Table 5 and the overall grid geometry and structure is depicted in Figure 19. Major stratigraphic surfaces - from the Lower Barnett through the upper Granitic Basement - and regional structure were interpreted from EOG's in-house 3D seismic data and depth-tied to well log correlations from the deep penetrations in the project area. Although faulting and fracturing is generally present within the proposed injection

area, injection testing and geomechanical modeling suggests faults and fractures are not primary permeability pathways. Consequently, they are not included in the initial simulation model. Grid layer thicknesses in the over- and under-burden horizons are generally coarse (ranging from 70 to more than 700 feet) since little change is expected in these regions, whereas the layers in the primary injection horizon (i.e., the middle Ellenburger) were selectively refined (ranging from 15 to ~50 feet) to capture the geologic heterogeneity that is likely to influence the CO_2 flow distribution within the storage reservoir.

Table 5: Summary of geologic model grid properties

	i-dir	**j-dir**	**k-dir**
Increment (ft)	200	200	variable
Layer Count	126	126	35
Total Length (ft)	26,200	26,200	~5,400
Total Cell Count		555,660	

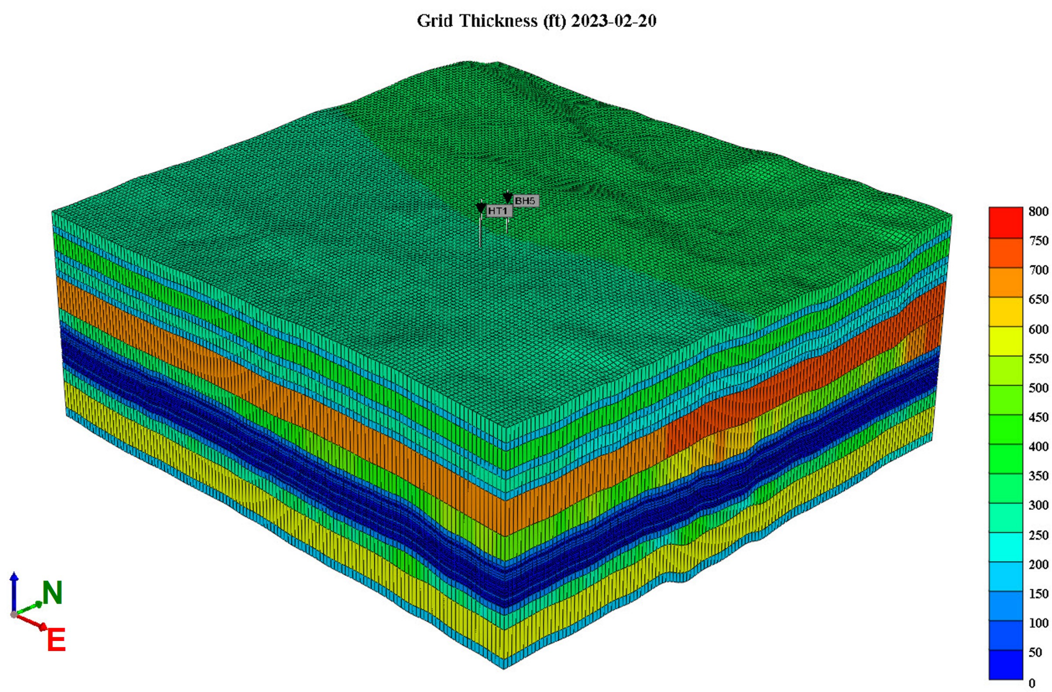


Figure 19: Northwest-looking 3D-view of the overall model grid structure; grid cell thickness property displayed.

Petrophysical transport properties (e.g., porosity and permeability) for each geologic horizon were subsequently propagated throughout the grid framework based on the rigorous integration and characterization of the core, log, and seismic data sets available in the project area (and described in the previous Section 2.7). The statistical range and spatial variability of all geologic intervals included in the model were considered in this multiscale analysis, with particular emphasis on representing the extreme heterogeneity observed in the karsted, dolomitized injection interval of the middle Ellenburger. The iterative property modeling workflow adopted for this project is summarized by the following general steps:

1. comparison and calibration of log response to measured core values (plug and full-diameter samples);
2. identification of key facies associated with injection/storage versus baffling/containment at well scale;

3. development of porosity-permeability transforms and net-to-gross (NTG) relationships for each facies type at well scale;
4. development of independent ties between well-scale porosity and NTG to seismic-scale attributes;
5. probabilistic spatial modeling of porosity and NTG via collocated co-kriging with associated seismic attributes;
6. calculation of permeability properties (i.e., vertical and horizontal) based on established porosity transforms for each geologic horizon.

Figure 20 depicts a representative layer from the resulting baseline realization of the geologic model which was used in the subsequent reservoir simulation forecasts. Of particular note is the heterogeneous nature in the spatial distribution of both the porosity and permeability properties in the middle Ellenburger, which is guided by amplitudes and patterns in the seismic data interpreted to be associated with large-scale karst features. The transport characteristics associated with these features are expected to have a first-order influence on the CO_2 plume growth over time and the workflow described above incorporates the available data - at the appropriate scales - to rigorously represent them in the model.

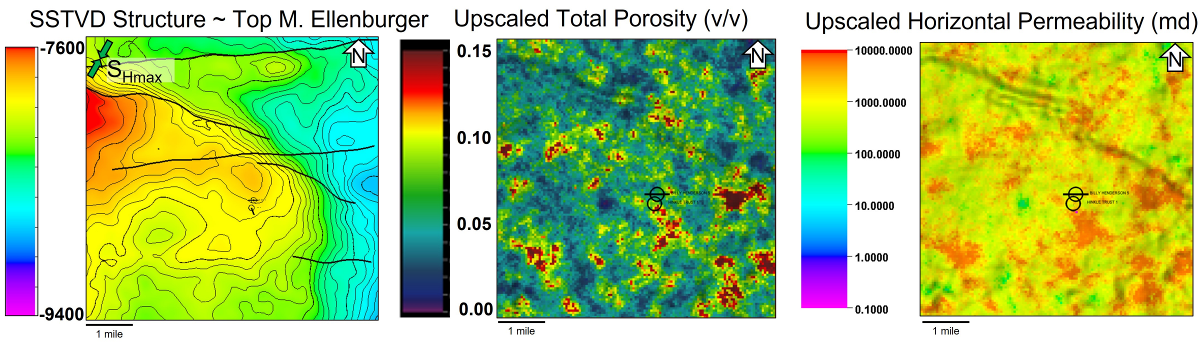


Figure 20: Example character of geomodel structural inputs in subsea true vertical depth (SSTVD) and property distributions (total porosity and horizontal permeability) within the middle Ellenburger storage zone. Note the varied distribution of high porosity and permeability representative of a karst reservoir.

Due to the limited availability of vertical permeability data in the project area, a simpler deterministic approach was taken to distribute vertical permeability throughout the model grid. For the main injection zone - the middle Ellenburger - the median value of the measured vertical-to-horizontal permeability ratios of 1.0E-03 was used (see Table 4). This choice captures the extremely heterogeneous nature of the injection interval, which is characterized by high permeability karst features interspersed with low porosity and very low permeability host rock. In the underlying and overlying confining zones, a vertical-to-horizontal permeability ratio of 1.0 was applied due to the more homogeneous nature of these intervals, which are characterized by low permeability matrix rock with little secondary enhancement.

3.2 Reservoir Simulation Model

With a representative static geologic model established, the grid and associated properties were then imported into Computer Modeling Group's (CMG) GEM v2022.30 compositional reservoir simulation software to forecast the long-term CO_2 plume behavior. GEM is a state-of-the-art finite difference solver which uses a compositional equation-of-state (EOS) methodology to represent the complex, multi-component thermodynamic interactions of fluid components during transport in porous media [Computer Modeling Group, LTD. (2021)]. As noted in other MRV plans recently approved by the EPA [Stakeholder Midstream Gas Services, LLC (2022)], GEM has become a generally-accepted software package for technical evaluation of geologic sequestration projects and is cited as such in the EPA's area of review guidance document for Class VI injection permits [US EPA (2013)].

Initialization of the reservoir model conditions was based on data acquired during the drilling and characterization of the project wells. Table 6 summarizes key inputs for the main injection interval in the middle Ellenburger, including

reference subsea true vertical depth (SSTVD), pressure, temperature, water saturation (S_w), and total dissolved solids (TDS) of the native formation brine in ppm. These data were obtained from wireline-conveyed dynamic testing and sampling tools deployed during logging operations on the Billy Henderson #5 and are representative of the reservoir throughout the project area. Pressure and temperature gradients were extended from the reference depth through all grid layers based on fluid density measurements and stabilized fiber-optic distributed temperature sensor (DTS) measurements, respectively.

Table 6: Basic middle Ellenburger reservoir conditions

Depth SSTVD ft	**Pressure** psia[a]	**Temperature** °F	**S_w** v/v[b]	**TDS** ppm
-9,275	4,993	195	1	211,961

[a]psia = pounds per square inch-absolute
[b]v/v = porous volume per unit bulk rock volume

Other key transport parameters and dynamic fluid processes for both the injection and confining horizons represented in the simulation include:

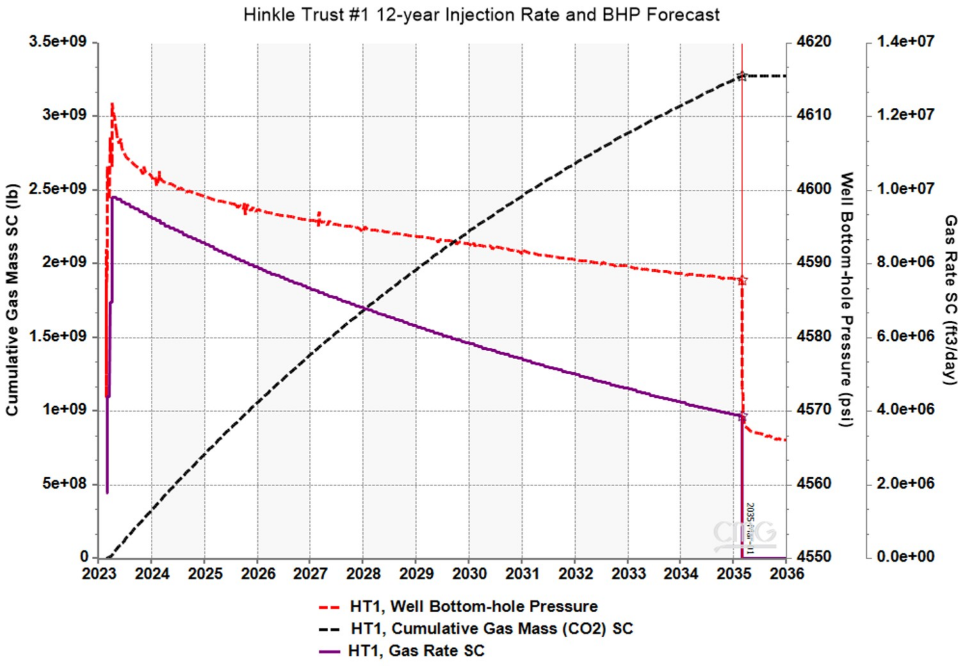
1. Drainage and imbibition capillary pressure functions for the CO_2-brine system derived from intrusion and extrusion mercury injection capillary pressure measurements (MICP) on core samples;
2. Porosity- and permeability-scaling of capillary pressure according to the Leverett J-function [Leverett (1941)];
3. Drainage and imbibition relative permeability functions calculated from the corresponding capillary pressure profiles;
4. Hysteresis trapping of the phases between drainage and imbibition cycles; and
5. Salinity concentration in the water (i.e., brine) phase and solubility between CO_2 and brine phases.

Before CO_2 injection forecast simulations were run, the model was rigorously history-matched to the water injection step-rate and pressure interference testing that was conducted between the Hinkle Trust #1 injection well and the Billy Henderson #5 monitoring well. Transient analysis of the pressure fall-off and interference test data revealed a single-porosity reservoir response with no apparent far-field boundary influence (i.e., an infinite-acting reservoir). In addition, pressure data obtained during the test from multiple gauges installed in both wells provided a robust data set against which to further calibrate and adjust the porosity, permeability, rock compressibility, and boundary conditions of the simulation model. This crucial step provides additional confidence in the simulated injection performance and long-term CO_2 plume development projections.

Another important constraint to consider when evaluating the simulated injection performance and long-term storage integrity is the fracture pressure of the injection and confining zones. As discussed later in section 3.5, the minimum horizontal stress gradient of the upper confining system was demonstrated via discrete micro-frac injection test to be 0.69 psi/ft, which equates to an absolute pressure of approximately ~5,500 psia at 7,980 ft - the TVD of the measurement. A continuous geomechanical earth model was subsequently constructed and calibrated to this measured data to assess the minimum horizontal stress profile in the injection zone, since it was impractical to initiate a fracture in this zone due to the extremely high permeability/injectivity. The resulting estimate of the minimum horizontal stress at the top of the injection zone (~9,350 ft TVD; see Figure 26) is approximately ~5,890 psia or an effective gradient of 0.63 psi/ft. Applying a 90% safety factor to that estimate yields an effective gradient of approximately ~0.57 psi/ft or 5,300 psia.

A base case injection forecast was run using the calibrated reservoir model and the proposed 12-year CO_2 volumes schedule in Figure 4. An additional 200 years of post-injection shut-in time was simulated to observe the long-term reservoir response and predict the stabilized extent and shape of the separate phase CO_2 plume after buoyant migration has ceased. Simulated bottom-hole pressure (BHP) at the Hinkle Trust #1 injection well and CO_2 saturation (S_g) maps at the top of the middle Ellenburger injection zone - for both the 12-year injection and 212-year total simulation periods - are shown in Figures 21 and 22, respectively. Of particular note in Figure 21 is the relatively low BHP increase above the initial static pressure of ~4,550 psia: at the maximum injection rate of ~10 MMSCFD, the BHP reaches a maximum value slightly above 4,610 psia or 60 psi above initial static conditions. This pressure increase is well below the safe operational threshold of 5,300 psia discussed above. Over the proposed 12-year injection schedule, the risk of over-pressurization in the injection zone decreases since the BHP gradually declines with the declining CO_2 injection rate. At the end of the 12-year injection period, the BHP drops to within 20 psi of initial static conditions instantly due to the high system permeability/injectivity of the middle Ellenburger. The period of pressure decline observed at the injection well through the year 2060 is a result of the natural decompression of the infinite-acting reservoir system in combination with the gradual buoyant equilibration of the compressible CO_2 plume.

Inspection of the CO_2 saturation maps (Figure 22) reveals the influence of reservoir heterogeneity and structure in the distribution, shape, and migrational path of the separate phase plume over time. After 12 years of CO_2 injection - or ~1.45 million MT-CO_2 injected - the plume takes on an amorphous elliptical shape that is ~9,000 ft in length and ~6,000 ft in width and roughly centered on the injection well. When comparing the example porosity and permeability distributions in the middle Ellenburger (Figure 20) and the 12-year CO_2 saturation map, similar patterns can be seen between the tortuous edges of the plume footprint and the high porosity/permeability regions where the CO_2 has found preferable pathways during injection. During the 200-year post-injection simulated period, geologic structure in the middle Ellenburger is observed to have more influence in the buoyant growth of the plume over time as evidenced by the expansion of the plume to the north (up structural dip) and the extension of a narrow "limb" of CO_2 to the west along a structural ridge in the middle of the grid. This ridge can be identified on the map of structural contours in the left panel of Figure 20. Overall the plume grows by roughly 33% during the 200-year post-injection simulated period and completely stabilizes around year 2225 (190 years after injection stops), showing no visible areal expansion thereafter.



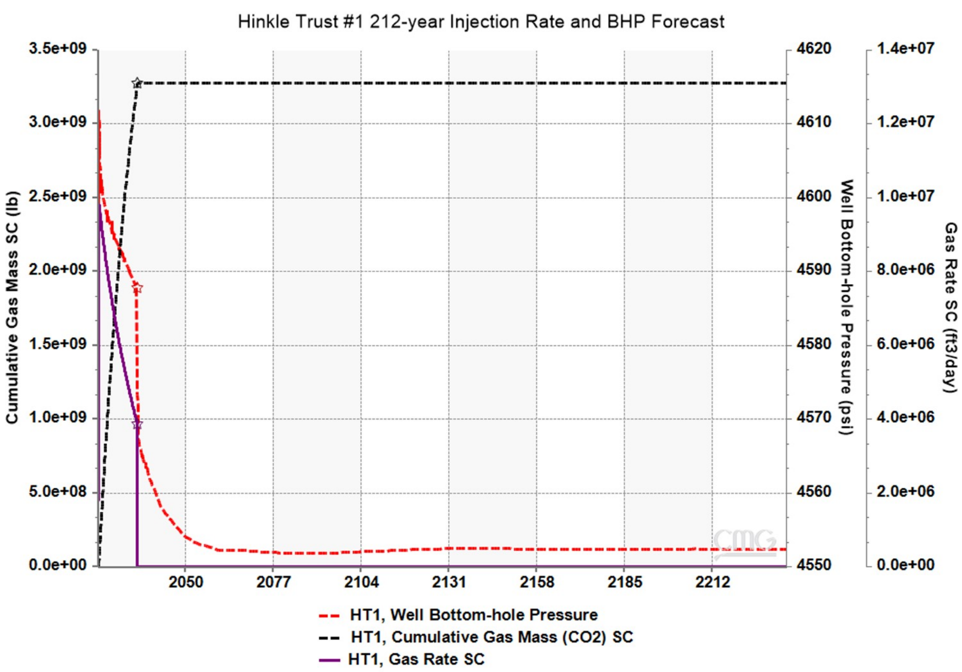


Figure 21: Modeled CO_2 rates, pressures, and cumulative volume for 12-year (top) and 212-year (bottom) time steps.

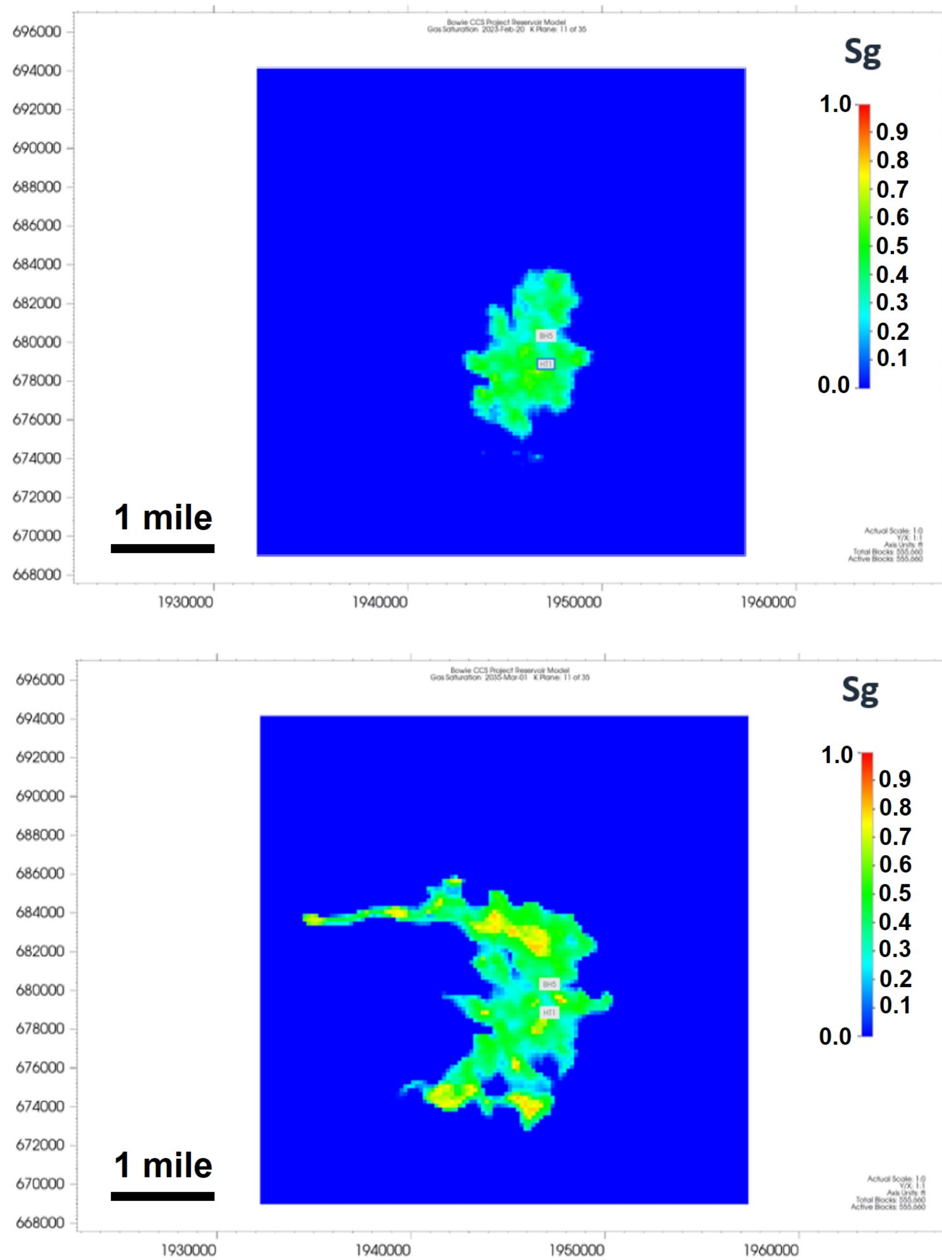


Figure 22: Modeled CO_2 saturation (S_g) distribution for 12-year (top) and 212-year (bottom) time steps. Note that the Hinkle Trust #1 injector is labeled "HT1" and Billy Henderson #5 monitor is labeled "BH5" on the saturation maps.

3.3 Maximum Monitoring Area (MMA)

In Subpart RR, the maximum monitoring area (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. Using a 3% CO_2 saturation threshold - the estimated saturation of gas breakthrough from mercury injection capillary pressure (MICP) measurements - the boundary of the stabilized, separate phase plume was determined from the simulation results in Figure 22. This boundary, plus the required half-mile buffer, is depicted in Figure 23 with the injection and monitoring wells for context.

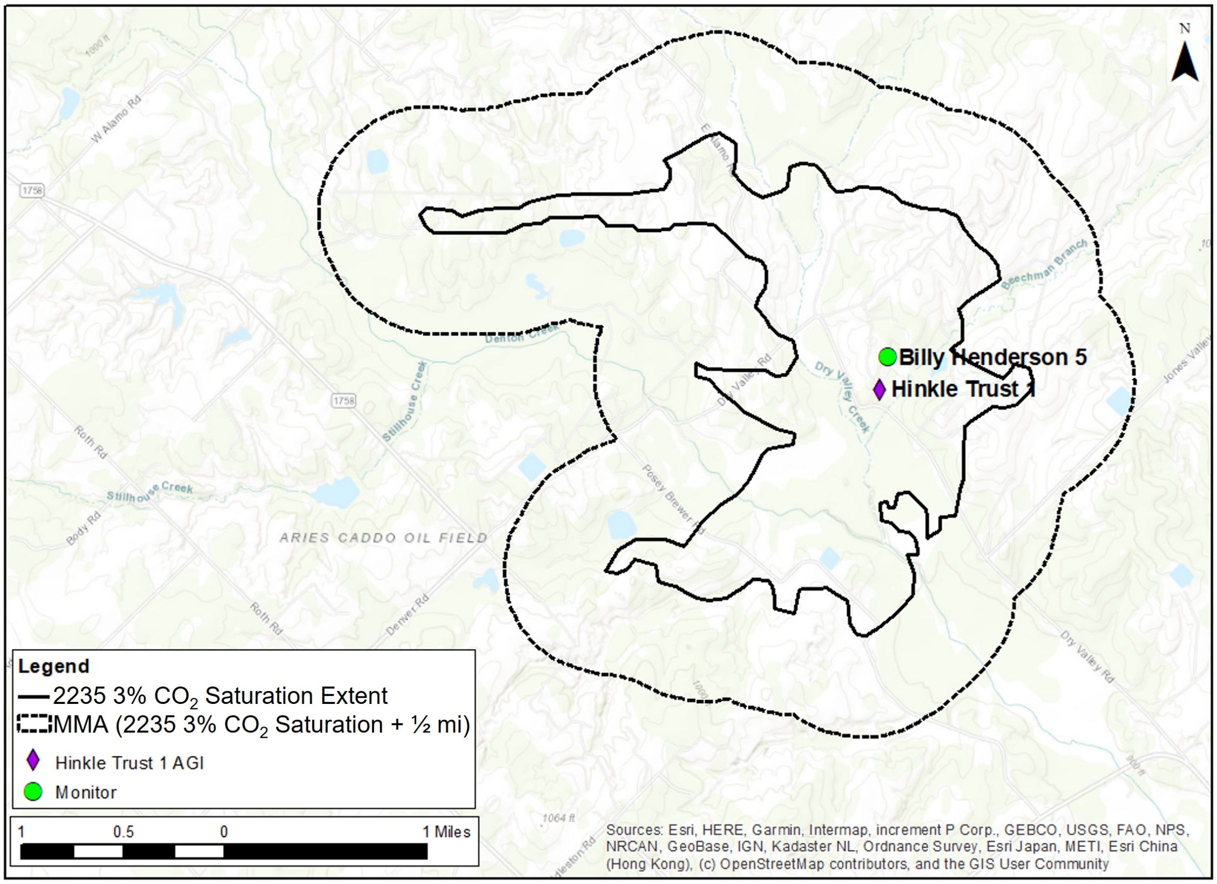


Figure 23: Maximum monitoring area for Bowie project.

3.4 Active Monitoring Area (AMA)

To define the active monitoring area (AMA), the initial monitoring period of 12 years was chosen based on the expected injection duration for the project. As a result, the separate phase CO_2 at the end of injection in year 2035 (i.e., "t") - assuming the same 3% CO_2 saturation threshold - plus the required half-mile buffer was defined (blue dashed contour in Figure 24). Per the definition of the AMA in Subpart RR, this area was superimposed against the projected plume outline in the year 2040 (i.e.,"t + 5") - the green outline in Figure 24. Since the green outline lies entirely within the blue dashed outline, the AMA is defined by the plume outline in the year 2035 plus the half-mile buffer.

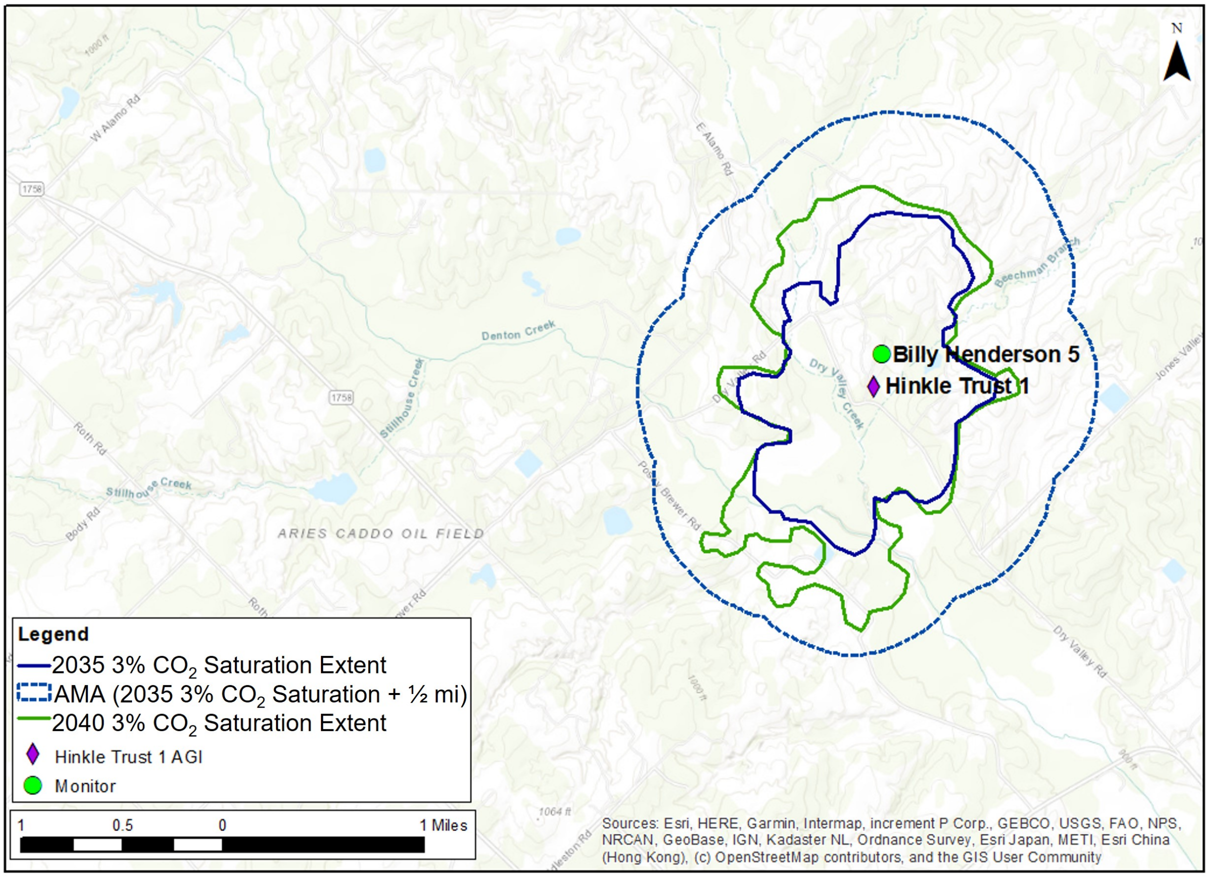


Figure 24: Active monitoring area for Bowie project.

3.5 Potential Surface Leakage Pathways

Per Subpart RR requirements, SPG has addressed the potential surface leakage pathways in the project area associated with surfaces facilities, faults and fractures, wellbores, and the confining system in a two-part approach. Part one de-risks the project site through various characterization methods, taking into account both static character and dynamic performance of the system through injection scenario modeling. This first part is addressed in the document subsections immediately below. Part two presents the required plan for detection, verification, and quantification of potential leaks and is addressed in subsection 3.6.

3.5.1 Surface Facilities

Leakage from surface facilities downstream of the injection meter is unlikely. The high pressure injection meter is placed near the high pressure compressor outlet and less than 210 ft upstream of the wellhead (Figure 3), minimizing potential leakage points between the metering of the stream and downhole injection point. Furthermore, the piping and flanges between the injection meter and the wellhead are Class 2500 rated by the American National Standards Institute and all welds are certified by x-ray inspection. If leakage from surface equipment is detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release in accordance with 40 CFR §98.448(5).

3.5.2 Wellbores

Dedicated Project Wellbores

The only wellbores that penetrate the injection zone in the AMA and MMA are those that were constructed specifically for this project. Both the Billy Henderson #5 and Hinkle Trust #1 were constructed 1) to mitigate leakage risks from CO_2 injection and 2) to provide for monitoring of near-wellbore conditions prior to, during, and after injection operations.

The Billy Henderson #5 monitor was designed to mitigate the risk of CO_2 migration out of the injection zone. A CO_2-resistant cement blend, EverCrete [SLB (2021)], was used to bond the long string casing in place. The top of cement sits above the top of the upper confining system defined for the project. In addition, pressure-temperature gauges and fiber monitoring instrumentation were installed across the injection zone (gauges and fiber), below the injection zone (fiber only) and above the injection zone (gauges and fiber) to allow for monitoring of pressure and temperature responses across the wellbore (Figure 25).

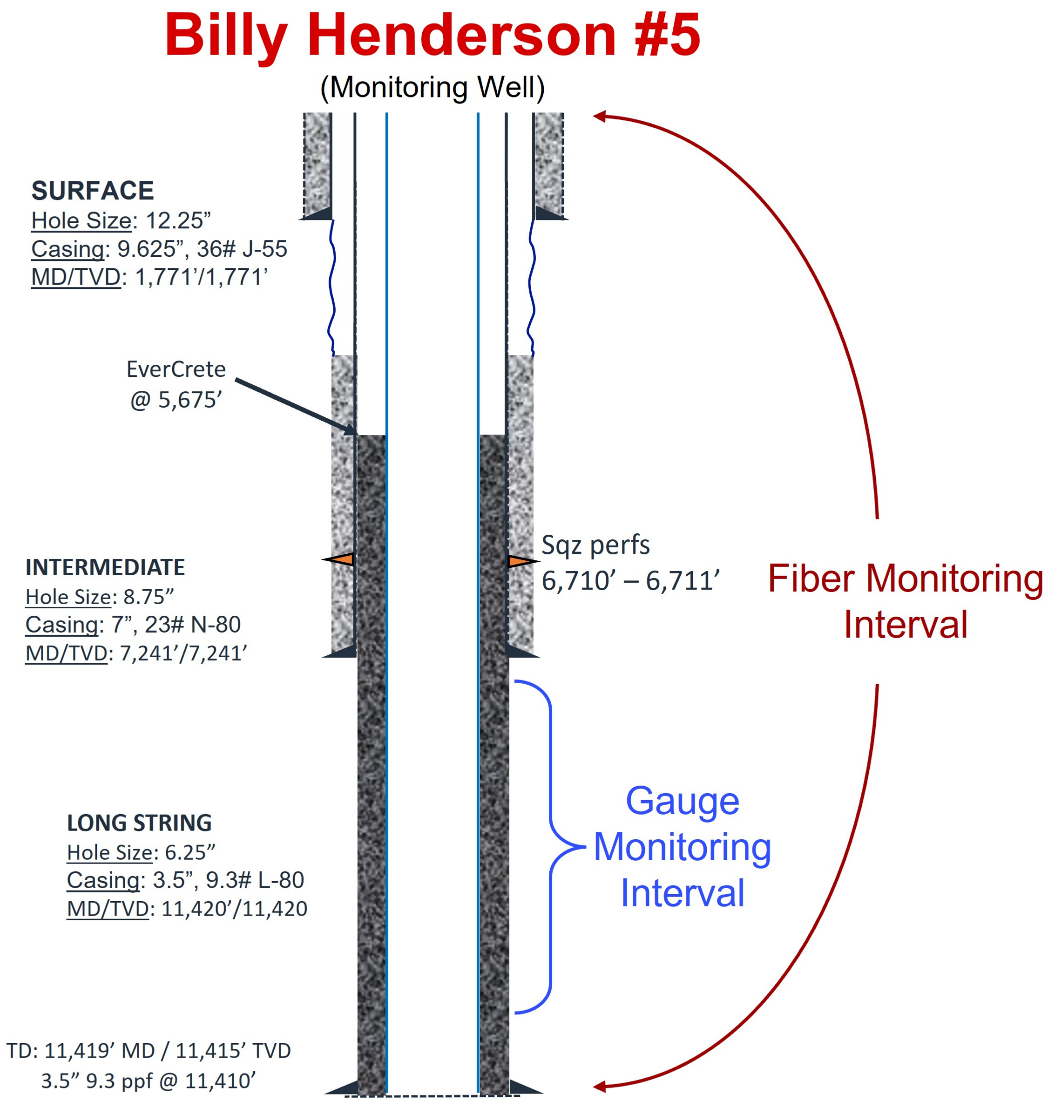


Figure 25: Billy Henderson #5 wellbore diagram.

The Hinkle Trust #1 injection well was also designed to mitigate the risk of CO_2 migration out of the injection zone. All strings of casing were cemented to surface and a CO_2-resistant resin product, WellLock [Halliburton (2017)], was used to cement the liner section of the long string casing sitting directly above the open hole injection interval. In addition, pressure-temperature gauges and fiber monitoring instrumentation were installed on the intermediate casing above the injection zone and on the injection tubing to allow for monitoring of pressure and temperature responses in the tubing, long string annular space, and above the injection zone (Figure 26).

Data from downhole instrumentation is collected and archived continuously across both wells. Aggradation and analysis of this data will allow SPG to quickly detect any leakage present within the wellbore. In addition, an annual mechanical integrity test (MIT) will be conducted in the injection well as prescribed in the Class II Underground Injection Control (UIC) permit (see Appendix A). The first MIT has already been conducted during the initial completion of the well. If leakage is detected, EOG will use the recorded operating conditions at the time of the leak to estimate the volume of CO_2 released and then take appropriate corrective action.

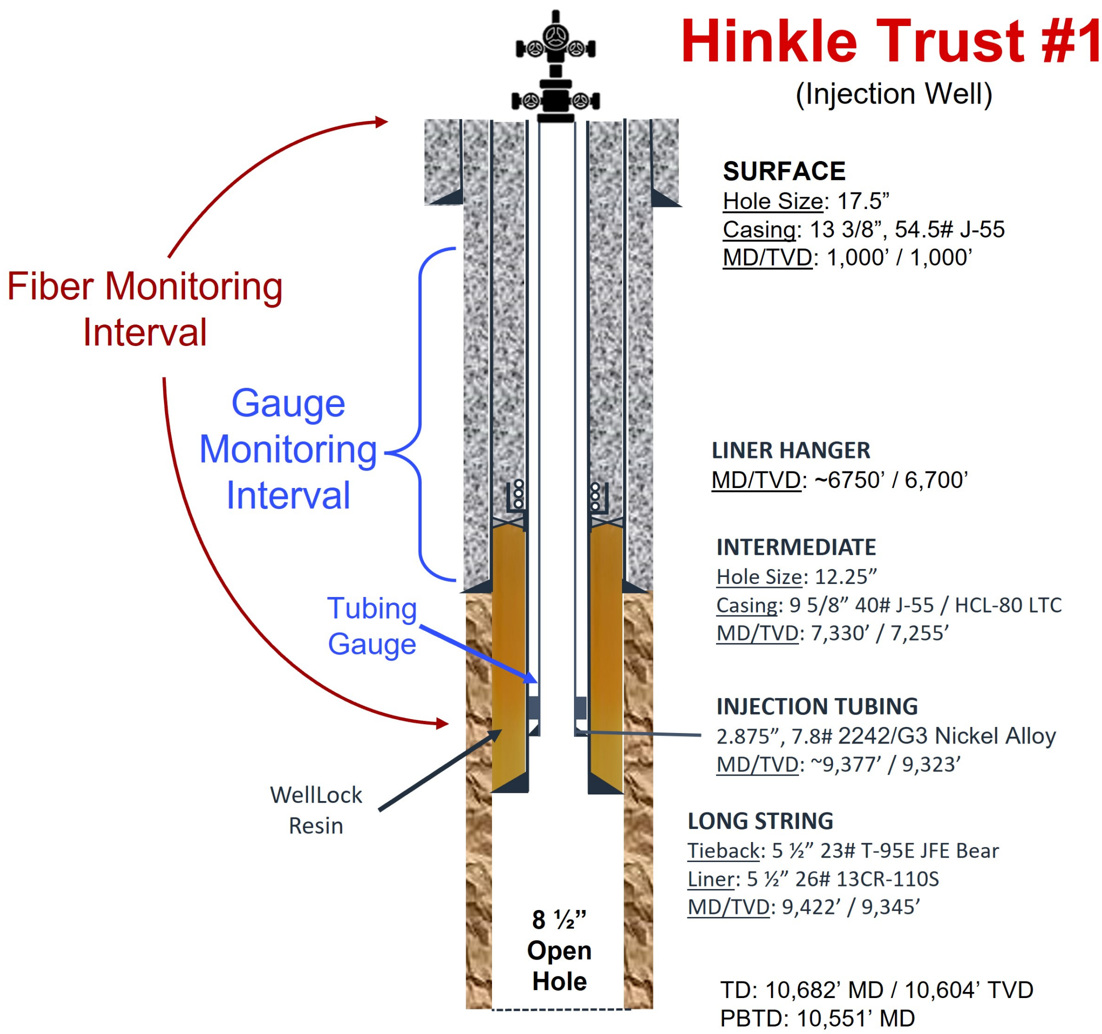


Figure 26: Hinkle Trust #1 wellbore diagram.

Other Existing and Potential Future Wellbores

There are additional wellbores present in the AMA and MMA, but they do not penetrate the injection zone. Texas Railroad Commission records, including completion reports, well plugging reports, drilling permits, and injection permits, as well as any available digital and raster log data, were analyzed for these wells. Table 7 and Figure 27 provide a high-level summary of the existing wells and location permits within or intersecting the MMA, with a more detailed tabulation of the records provided in Appendix C.

Table 7: Summary of existing wells within the MMA.

Entity	Quantity
Total well- or permit-level records analyzed	125
Plugged wells	54
Open (non-plugged) wells	56
Expired permits	14
Active permits	1

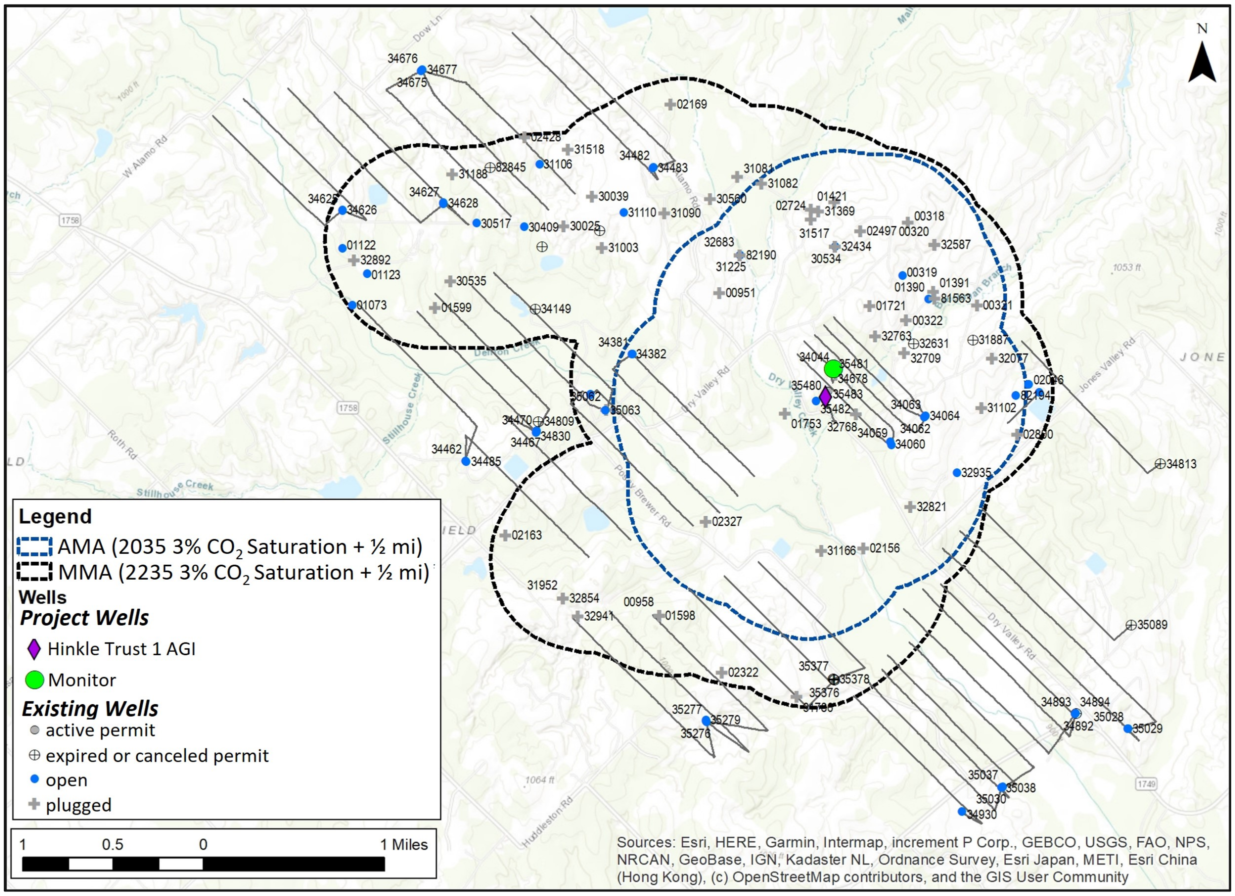


Figure 27: Existing wells and all previously permitted locations within the AMA and MMA symbolized by well and permit status.

Figure 28 shows the distribution of existing well maximum true vertical depth and Figure 29 shows the distribution of vertical separation in feet between the existing wellbores and top of the injection zone within the MMA. The minimum vertical separation between the injection zone and any overlying well within the MMA is over 1,400 feet. The majority of existing wellbores are 2,000 to 3,500 feet above the middle Ellenburger injection zone.

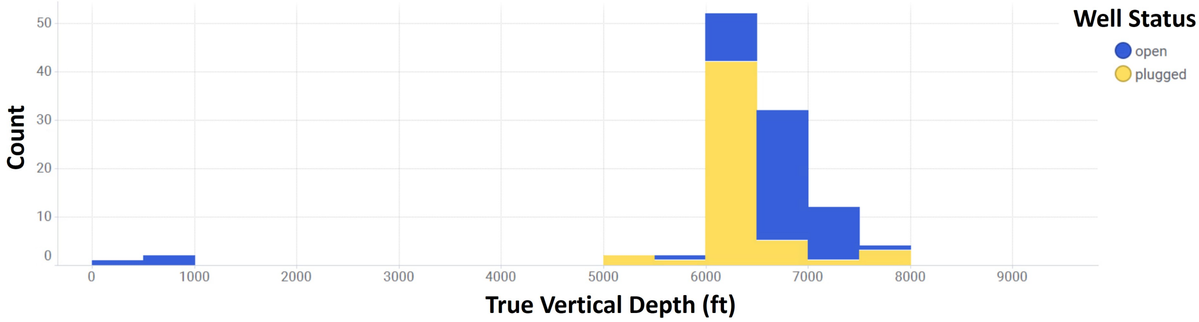


Figure 28: Distribution of maximum true vertical depth of existing wells in the MMA. Data is binned in 500 foot intervals.

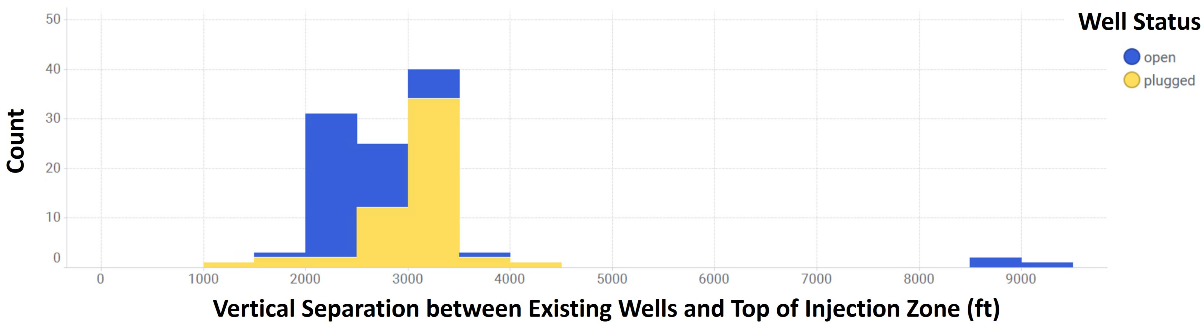


Figure 29: Distribution of vertical separation between maximum true vertical depth of existing wells and the top of the injection zone in the MMA. Seismic structure mapping was used to constrain the top of the injection zone. Data is binned in 500 foot intervals.

With regard to future drilling in the MMA, SPG does not anticipate new wellbores to penetrate the injection zone as the formation does not contain commercial hydrocarbon accumulations within the vicinity of the project site. This was one of the key criteria for siting the project in this area. In addition, the single existing active permit within the MMA is currently permitted to 675 feet total depth, which if drilled, would be over 8,000 feet above the injection zone.

If new wells were to be permitted and drilled within one-quarter mile of the Hinkle Trust #1 injection well, operators would be subject to TXRRC Rule 13 compliance on wellbore construction since the Ellenburger is identified in the drilling permit as one of the formations requiring such compliance (see Appendix B). Rule 13 requires operators to set steel casing and cement across and above all formations permitted for injection (under TXRRC Rules 9 or 46) as well as across and above all zones with the potential for flow or containing corrosive formation fluids [Texas Administrative Code (2023)]. Furthermore, SPG intends to monitor permitting activity across the entire project area on a quarterly basis and take appropriate action if any proposed wells present a potential risk for leakage within the MMA. In the case that any new wells are drilled within the MMA and create a material change to the surface leakage risk, the MRV plan would be updated to reflect this change and the potential risk for leakage presented by these wells would be evaluated based on the most current operational and monitoring data. Any additional monitoring activities deemed necessary to enhance the surveillance in the areas of these new wells would also be included in an updated version of the MRV plan at that time.

In summary, the potential for surface leakage through existing or future wells in the project area is highly unlikely. However, if it were suspected that CO_2 had migrated from the primary injection zone and was leaking into an existing or future wellbore within the MMA, SPG would first estimate the likelihood of the proposed leak against the latest operational data, monitoring data, and reservoir simulation projections. If these data and interpretations confirm the potential relationship between the Bowie injection project and the leak, SPG would then coordinate efforts with the owner(s) of the well to 1) characterize the change in gas composition against historical baselines (if available); 2) estimate the point in time when the composition changed from the historical baseline; 3) measure the approximate flow rate associated with the leak (if possible); 4) quantify the incremental CO_2 mass associated with this leakage pathway over the effective time period; and 5) develop and implement an appropriate wellbore remediation design and a supplementary monitoring program to ensure the leak has been permanently eliminated. Any CO_2 mass associated with this unlikely leakage scenario would be noted in the annual monitoring report and reflected in the total mass of CO_2 sequestered per the procedure documented in Section 3.8.5.

3.5.3 Faults and Fractures

The Ellenburger and underlying basement at the injection site are characterized by large scale strike-slip faults and prevalent natural fracturing. The propensity for each of these characteristics to serve as surface leakage pathways is discussed below.

To assess the risk of leakage through faults, a Fault Slip Potential (FSP) analysis [Walsh et al. (2017)] was performed on large-scale basement-rooted faults traversing the proposed injection area and interval. The FSP analysis probabilistically evaluates the likelihood of excess pressure generated by fluid injection to trigger shear slip on pre-existing faults. As faults which are able to slip in shear in the present-day stress field with minor excess pressure (critically-stressed) tend to be those which are hydraulically-conductive [Barton et al. (1995)], the FSP analysis simultaneously assesses both induced seismicity and fault leakage likelihood. The FSP analysis includes faults mapped from 3D seismic data, directly measured reservoir and fluid properties from logs and core, and the planned CO_2 injection schedule. FSP results are shown in Figure 30, and indicate all major faults within the planned injection area and interval exhibit a very low (<10%) fault slip likelihood over the CO_2 injection timeline. In other words, the major faults are not critically-stressed in the present-day stress field and are, therefore, not expected to be hydraulically-conductive leakage pathways during CO_2 injection. Nevertheless, downhole pressure instruments installed in the project wells (described in the previous section) will be continuously monitored via the project's real-time data acquisition system. Appropriate alarms and operational set points for surface equipment will be established to ensure that downhole conditions do not exceed the safety thresholds which could potentially trigger a fault-slip event in the most conservative case.

Only one earthquake in Montague County has been recorded in the last 100 years [U.S. Geological Survey (2023)] despite significant SWD injection within the Ellenburger. The FSP results are consistent with generally stable fault behavior in larger Montague County - and within the proposed injection area - as evident by the lack of detectable seismicity despite the presence of numerous Ellenburger SWD injection wells within the county (Figure 31).

Cross-fault leakage is also unlikely due to fault sense-of-slip and displacement. The dominant strike-slip sense of motion on major faults in the area decreases the likelihood of vertically juxtaposing injection intervals with containment intervals. In addition, cross-fault leakage is also likely inhibited by development of a thick, a low-permeability fault core due to significant fault displacement [Torabi et al. (2019), Caine et al. (1996)].

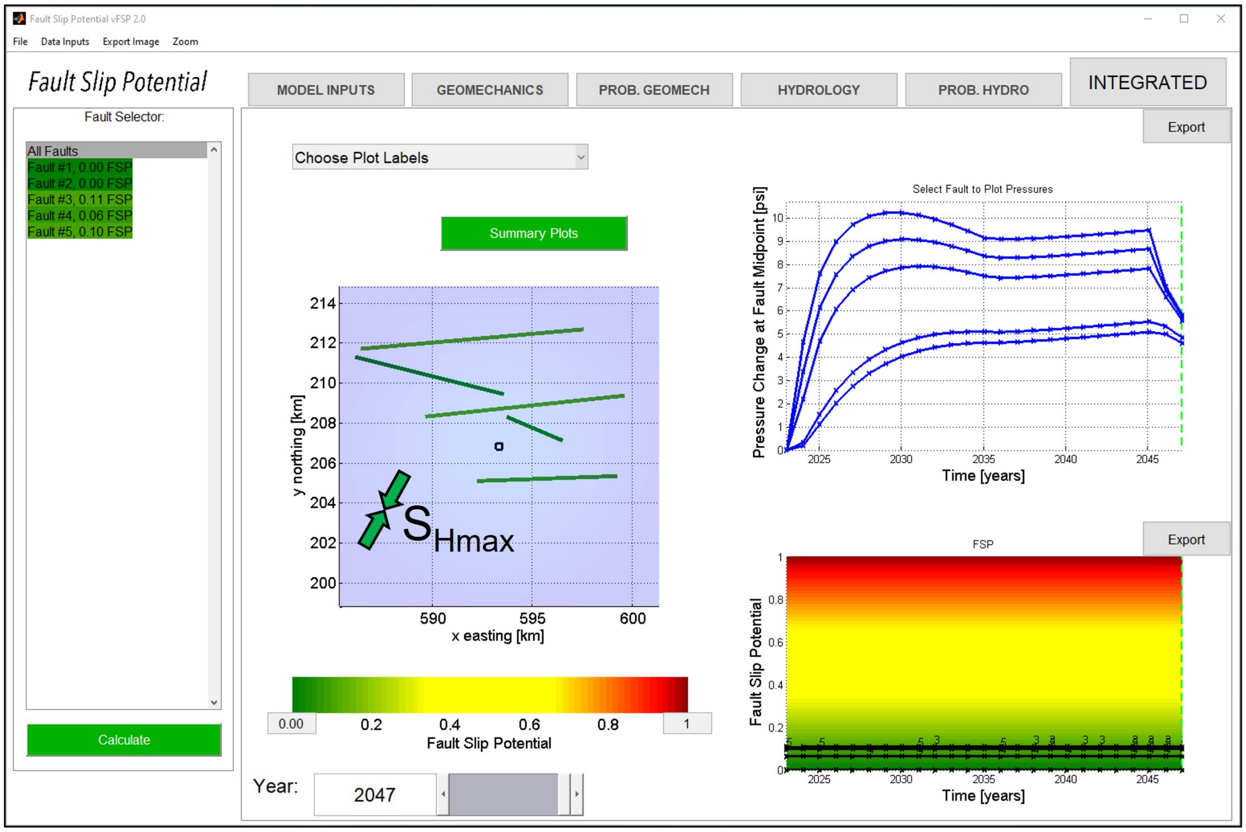


Figure 30: Fault slip potential analysis results.

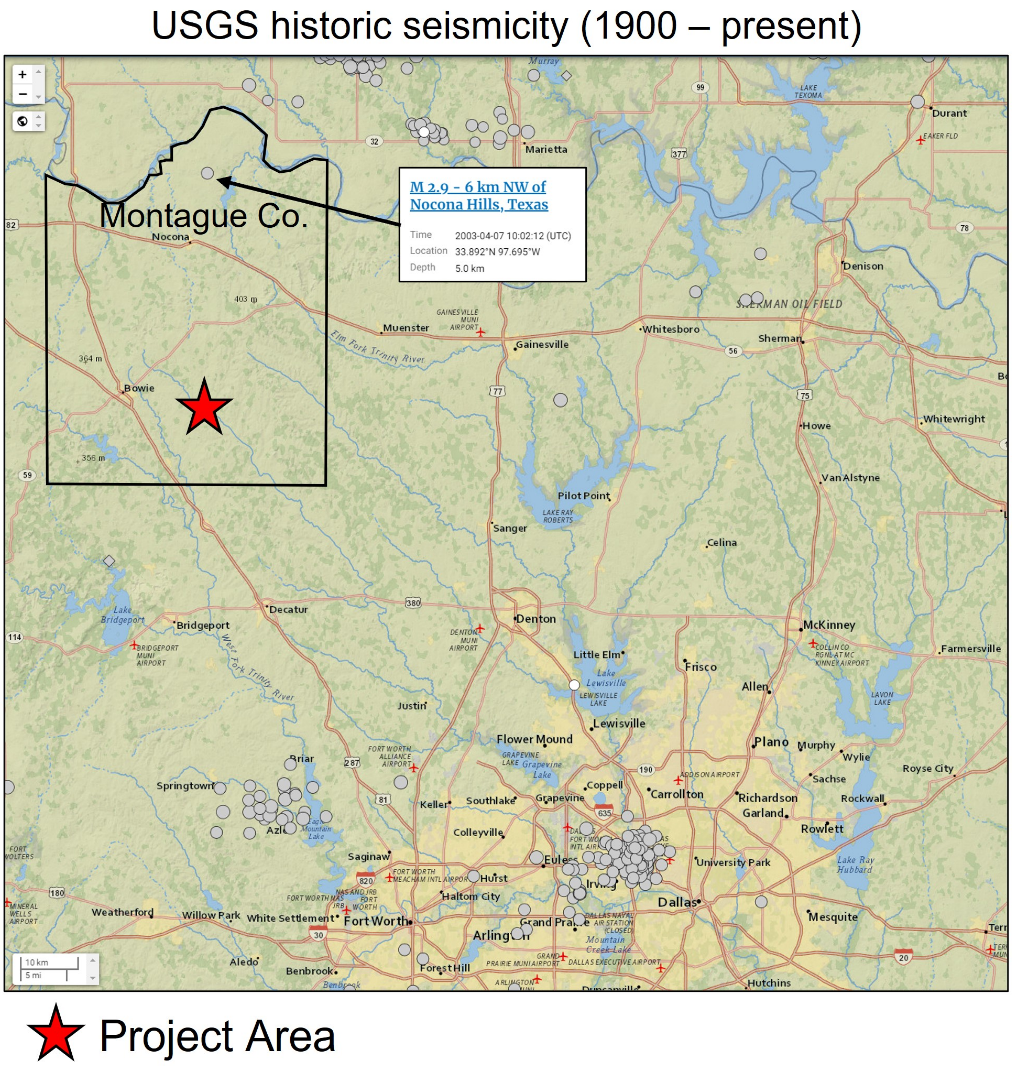


Figure 31: Historical records of regional seismicity from the United States Geological Survey (USGS).

To assess potential fracture leakage, fracture characteristics (orientation, density) as inferred from wellbore image logs in the proposed injection well are compared with various indicators of fluid conductivity (e.g., temperature anomalies, injection testing) in the proposed injection well. Natural fracture orientation and density do not correlate with either temperature reductions or primary permeability pathways inferred from injection testing, suggesting natural fractures are not the dominant transport (i.e., permeability) mechanisms within the injection interval (Figure 32) and therefore pose minor leakage risk.

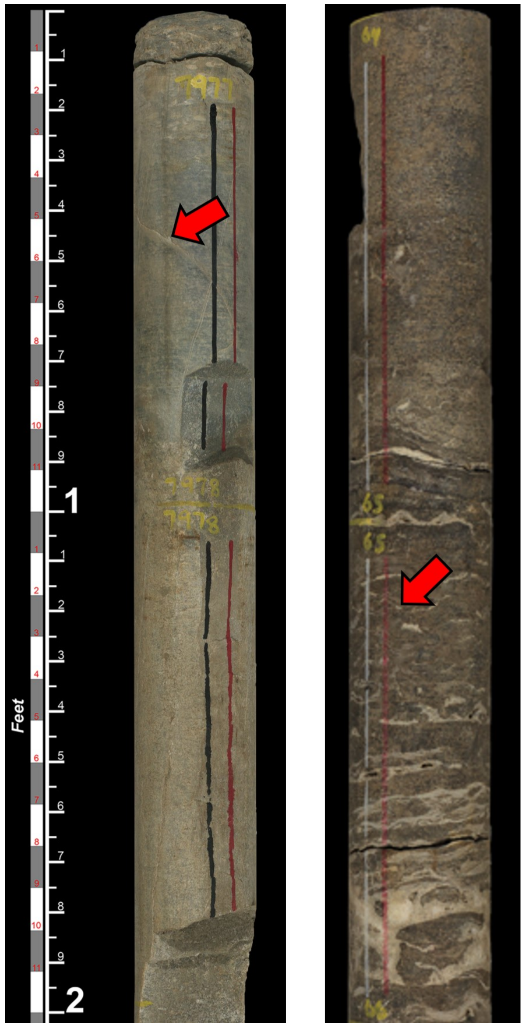


Figure 32: Representative whole core examples of confining (left) and injection (right) zones illustrating natural fractures (generally cemented, red arrows).

3.5.4 Confining System

To assess potential leakage from an excess pressure (i.e., hydraulic fracturing) perspective, injection tests to measure pore pressure and the minimum horizontal stress (S_{hmin}) were conducted in the overlying seal interval. The tests yielded a pore pressure estimate of 0.49 psi/ft and S_{hmin} estimate of 0.69 psi/ft, or roughly 4,900 psi and 6,900 psi bottomhole, respectively, when extrapolated to the injection interval around 10,000 ft TVD. Thus, ~2,000 psi downhole excess pressure is required to generate and propagate hydraulic fractures. Plume injection modeling and offset Ellenburger SWD injection data all indicate maximum bottomhole pressure buildups on the order of 10s of psi for comparable injection volumes and rates - nearly two orders of magnitude lower than would be required to generate a hydraulic fracture. CO_2 leakage through hydraulic fracture generation/propagation is therefore highly unlikely. Furthermore, as CO_2 is anticipated to be the buoyant phase relative to the *in situ* brine within the Ellenburger injection interval, CO_2 migration and excess pressure buildup downward toward the lower confining and basement intervals is not anticipated.

With regard to the risk of diffuse displacement of fluids from the injection zone through the confining system, the 2,200 foot-thick geologic sequence including the upper Ellenburger, Simpson, Viola, and lower Barnett shale (as discussed in section 2.7.2) is expected to provide excellent long-term containment. This general assessment is attributable to 1) the low matrix porosities and permeabilities measured in core samples taken throughout this interval (Table 3); 2) the lack of pervasive karsting or conductive fractures observed in core and image log data; and 3) the absence of flow observed

in this interval during dynamic injection testing and surveys conducted in the project wells. Furthermore, results from reservoir simulation of the proposed injection volumes show no appreciable pressure change or fluid migration in the model layers immediately above the middle Ellenburger injection zone. Thus, surface leakage through the confining system is expected to be extremely unlikely.

3.6 Detection, Verification, and Quantification of Potential Leaks

This subsection addresses the detection, verification and quantification of potential leaks associated with surfaces facilities, faults and fractures, wellbores, and the confining system.

3.6.1 Detection of Leaks

Table 8 summarizes the methods and procedures SPG plans to employ to detect potential leaks across the various potential pathways previously discussed.

Table 8: Leakage detection methodologies to be employed for the Bowie Project.

Leakage Pathway	**Monitoring Activity**	**Frequency**	**Coverage**
Surface facilities	Wellhead pressure monitoring	Continuous	Flowmeter to injection wellhead
	Visual inspection	Weekly	
	Personal H_2S monitors	Weekly	
In-Zone Wellbores	P/T* gauges & fiber on casing/tubing	Continuous	Surface through injection zone
	Annulus pressure monitoring	Continuous	
	Integrity testing (MIT) per Class II permit	Yearly	
	Periodic corrosion monitoring surveys	Yearly	
Faults/fractures	Pressure monitoring	Continuous	Project site/plume extent
	Pressure transient analysis	Yearly	
Confining system	Pressure monitoring	Continuous	Project site/plume extent
	P/T gauges & fiber on casing	Continuous	
	Pressure transient analysis	Yearly	
	Time-lapse saturation surveys	Yearly	

*P/T = Pressure and temperature

3.6.2 Verification of Leaks

If the detection methods described above indicate a leak through one of the potential leakage pathways, SPG would take the actions summarized in Table 9 to verify its presence or confirm a potential “false positive”.

Table 9: Leakage verification actions to be taken for the Bowie Project.

Leakage Pathway	**Verification Action**
Surface facilities	Auditory, Visual, and Olfactory (AVO) Inspection
	Forward Looking Infrared (FLIR) camera inspection
	Enhanced gas monitoring
In-Zone Wellbores	Validation of calibration & functionality of downhole sensors
	Deployment of additional wireline sensors
	Additional saturation logging survey
	Additional MIT and corrosion logging survey
Faults/fractures	Extended pressure transient analysis
	Additional saturation logging survey
	Enhanced surveillance on nearby wells operated by EOG
Confining system	Validation of calibration & functionality of downhole sensors
	Deployment of additional wireline sensors
	Additional saturation logging survey
	Extended pressure transient analysis
	Enhanced surveillance on nearby wells operated by EOG

3.6.3 Quantification of Leaks

If leakage through one of the identified pathways is verified, SPG would implement the methodologies summarized in Table 10 in an effort to quantify the mass of CO_2 that has leaked to shallow aquifers or to the surface. Because CO_2 leakage through several of the pathways cannot be directly measured or visualized but must be indirectly inferred, reservoir simulation will likely be an essential tool to quantify the magnitude of the leak in those cases. For example, while the precise pathway of a CO_2 leak may not be known, it may be possible to measure the pressure or saturation change created along the leakage pathway in the subsurface (e.g., the Billy Henderson #5 monitoring well or a nearby production well operated by EOG). Through the iterative history matching process, it is possible to replicate the observed subsurface response by invoking some potential leakage mechanism(s) in the reservoir model. The resulting volume or mass of CO_2 that yields the best match to the observed data is likely to be a reasonable estimate of the magnitude of the leak. Furthermore, by considering several different plausible leakage cases with the model, the magnitude of the leak can be quantified across a range of potential outcomes. Due to the non-unique nature of numerical simulations, however, SPG will also consider conducting additional appropriate geophysical imaging surveys or drilling additional monitoring wells in strategic locations to further constrain and refine the leakage quantification estimates yielded by the models.

Table 10: Leakage quantification methodologies for the Bowie Project.

Leakage Pathway	Quantification Method*	Qualitative Accuracy
Surface facilities	Calculation based on process conditions at time of leakage and dimensions of leakage pathway	High
	Comparison & calculation against recent historical trends	High
	Direct measurement of leakage (if accessible and safe)	Very High
In-Zone Wellbores	Calculation against recent historical injection trends (using surface & downhole P/T data)	High
	Estimation from change in saturation profile within reservoir and/or confining zones in project wells	Moderately High
	Enhanced surveillance (e.g., saturation surveys) on nearby wells operated by EOG	Moderately High
Faults/fractures	Use reservoir model to simulate the CO_2 leakage required to generate the observed pressure transient behavior	Moderate
	Use reservoir model to simulate the CO_2 leakage required to generate the observed nearby well surveillance response	Moderate
	Enhanced surveillance (e.g., saturation surveys) on multiple nearby wells operated by EOG	Moderately High
	Conduct additional geophysical imaging surveys near potential leak pathways	Moderately High
	Drill additional monitoring wells in strategic locations	High
Confining system	Use reservoir model to simulate the CO_2 leakage required to generate the observed pressure transient behavior	Moderate
	Use reservoir model to simulate the CO_2 leakage required to generate the observed nearby well surveillance response	Moderate
	Enhanced surveillance (e.g., saturation surveys) on multiple nearby wells operated by EOG	Moderately High
	Conduct additional geophysical imaging surveys near potential leak pathways	Moderately High
	Drill additional monitoring wells in strategic locations	High

*Quantification methods presented in order of practical implementation.

3.7 Baseline Determination

SPG has developed a strategy to establish baselines for monitoring CO_2 surface leakage that is in agreement with 40 CFR §98.448(a)(4). “Expected baseline” is defined as the anticipated value of a monitored parameter that is compared to the measured monitored parameter. SPG has existing automated continuous data collection systems in place that allow for aggradation and analysis of operations data to 1) establish trends in operational performance parameters and 2) identify deviations from these trends. Non-continuous data will also be collected periodically to augment and enhance the analysis of continuous data throughout the project. Baseline surveys for non-continuous data have already been collected as described below. Baselines for operational performance parameters are expected to be completed by July 17th, 2023, which will provide for several weeks of data collection with the entire system operational.

AVO Inspections: Field personnel will conduct daily to weekly inspections at the injection site pre-, during, and post-injection. Any indications of surface leakage of CO_2 will be addressed via appropriate corrective action in a timely manner. Personnel will wear personal H_2S monitors calibrated to OSHA standards with a detection sensitivity of 0.5 ppm and a low-level alarm threshold of 10 ppm. Indications of H_2S present will serve as a proxy for CO_2 presence as the injection stream contains both components.

Continuous Monitoring: Continuous monitoring systems are in place for both the surface process facilities and wells. Pressure and temperature gauges installed on both casing and tubing strings, DTS fiber-based data, and surface pressures on all strings of casing is collected continuously in both wells. Operational baselines will be determined from analysis of this data over a reasonable period once the system is fully operational (see comments on timing above). Any deviations from these operational baselines will be investigated to determine if the deviation is a leakage signal.

Well Integrity Testing: EOG will conduct an annual MIT on the Hinkle Trust #1 as required by the Class II permit issued by TXRRC. Subsequent MIT results will be compared to initial MIT results and TXRRC standards to establish a baseline. An initial MIT and subsequent interpretation of test results has already been performed on the Hinkle Trust #1 as part of the Class II permit requirements.

Pressure Transient Analysis: EOG has conducted initial pressure transient analyses using injection test data. Subsequent pressure transient analyses are in progress and will continue to be performed when operationally feasible to establish and re-establish expected baseline reservoir behavior throughout the project. Comparison of these analyses over time will aid in diagnosing consistency in the long-term behavior of the injection and confining zones.

Wellbore Surveys: The Billy Henderson #5 and Hinkle Trust #1 are both constructed to allow for time-lapse saturation and mechanical integrity logging. Initial pre-injection surveys have been conducted for both saturation and mechanical integrity and will serve to establish baselines for comparison of future logging datasets.

3.8 Site Specific Modifications to the Mass Balance Equation

3.8.1 Mass of CO_2 Received

Following the Subpart RR requirements under §98.444(a)(4), equation RR-4 (Figure 33) will be used for calculating the mass of CO_2 received since the CO_2 stream received via the gathering pipeline will be wholly injected and not mixed. The mass flow rate measured at the coriolis meter immediately downstream of the high pressure injection compressor (Figure 2) will be used as input to equation RR-4. This measurement will account for the concentration of CO_2 in the injection stream using the measurement from the gas chromatograph immediately upstream of the high pressure compressor, which will be validated quarterly via gas sample analysis as per the requirements under §98.444(b).

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

where:
$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.
$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).
$C_{CO2,p,u}$ = 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.

Figure 33: Equation RR-4 as defined in 40 CFR §98 Subpart RR.

3.8.2 Mass of CO_2 Injected

The annual mass of CO_2 injected will be calculated using equation RR-4 as per Subpart RR §98.443(c)(1) since a high pressure coriolis meter will be used to measure the mass flow rate as described in the previous section 3.8.1. The high pressure coriolis mass meter used in the system has an accuracy of ±0.15% and concentration inputs to the calculation will be provided by the gas chromatograph immediately upstream of the high pressure compressor which will be validated quarterly in accordance with §98.444(b).

3.8.3 Mass of CO_2 Produced

Mass of CO_2 produced is not applicable to this project as no CO_2 will be produced.

3.8.4 Mass of CO_2 Emitted

Equipment Leaks and Vented Emissions

The likelihood of any fugitive CO_2 emissions between the injection meter and the injection wellhead is expected to be extremely low due to the material specifications of the installed equipment and the minimal number of components along this flow path (Figure 2). Any intentional venting of CO_2 emissions - in the case of a planned compressor blow-down before maintenance, for example - would occur upstream of the injection meter used to measure the injection quantity and therefore would not need to be subtracted from the total mass injected. Nevertheless, this equipment will still be subject to regular AVO inspections and H_2S monitoring. If the determination is made that CO_2 has leaked between the injection meter used to measure injection quantity and the injection wellhead, the methods outlined in 40 CFR §98 subpart W will be used to quantify those amounts.

Since CO_2 will not be produced in the scope of this proposed injection project, the consideration of leaks from production-related equipment is not applicable.

Surface Leakage

If it were determined that surface leakage had occurred or is actively occurring through any of the identified pathways, the quantification methodology described in Section 3.6.3 would be used to estimate the mass emitted from each pathway and summed using equation RR-10 (Figure 34).

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

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

Figure 34: Equation RR-10 as defined in 40 CFR §98 Subpart RR.

3.8.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated using equation RR-12 (Figure 35) since this project will not actively produce oil, natural gas, or any other fluids.

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{(Eq. RR-12)}$$

where:

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

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

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

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

Figure 35: Equation RR-12 as defined in 40 CFR §98 Subpart RR.

In accordance with §98.448(a)(7), the date to begin collecting data for calculating the total amount sequestered shall be after 1) expected baselines are established and 2) implementation of the leakage detection and quantification strategy within the initial AMA. SPG proposes the date of July 17th, 2023 as the date to begin collecting data for calculating the total amount sequestered for the SPG CO_2 Bowie Facility.

3.9 Implementation Schedule For MRV Plan

The final MRV plan will be implemented upon receiving approval from the EPA, and no later than the day after the day on which the plan becomes final, as described in §98.448(c). The Hinkle Trust #1 is currently permitted to inject under a TXRRC Class II UIC permit (see Appendix A) and the SPG CO_2 Bowie Facility is expected to operate for 12 years. Once approved, the MRV plan will be implemented throughout the 12-year operational period in accordance with 40 CFR §98 Subpart RR and for an additional 5-year post-injection monitoring period.

3.10 Quality Assurance

3.10.1 Monitoring QA/QC

SPG will implement quality assurance procedures that are in compliance with requirements stated in 40 CFR §98.444 as detailed below.

CO_2 Injected:

- The flow rate of the CO_2 injection stream is measured continuously with a high pressure mass flow meter that has an accuracy of ±0.15%.
- The composition of the CO_2 injection stream is measured with a high accuracy gas chromatograph upstream of the flow meter.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer recommendations.

CO_2 Emissions from Leaks and Vented Emissions:

- Calculation methods from 40 CFR §98 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.

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).

3.10.2 Missing Data

Missing data will be estimated as prescribed by 40 CFR §98.445 if SPG is unable to collect the data required 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 and venting from facility surface equipment will be estimated and reported per the procedures specified in 40 CFR §98 subpart W.

3.10.3 MRV Plan Revisions

If any of the changes outlined in 40 CFR §98.448(d) occur, SPG will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

3.11 Records Retention

SPG will retain all records as required by 40 CFR §98.3(g). Records will be retained for at least three years, and will include, but will not be limited to:

- Quarterly records of injected CO_2 including mass flow rate at standard conditions, mass flow rate at operating conditions, operating temperature and pressure, and concentration of the injected CO_2 stream.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

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A Class II UIC Permit for Hinkle Trust #1

WAYNE CHRISTIAN, CHAIRMAN
CHRISTI CRADDICK, COMMISSIONER
JIM WRIGHT, COMMISSIONER

DANNY SORRELLS
ASSISTANT EXECUTIVE DIRECTOR
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. 17041

EOG SPG HOLDINGS, INC.
ATTN SETH WOODARD
PO BOX 4362
HOUSTON TX 77210

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 April 01, 2022, for the permitted interval(s) of the ELLENBURGER formation(s) and subject to the following terms and special conditions:

HINKLE TRUST (00000) LEASE
BARNABUS (ELLENBURGER) FIELD
MONTAGUE 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	33700000	000125307	Carbon Dioxide (CO2); Hydrogen Sulfide (H2S); Natural Gas	7,300	13,000		12,000		4,100

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	33700000	**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. An annual annulus pressure test must be performed and the test results submitted in accordance with the instructions of Form H-5.** **3. The tubing-casing annulus pressure must be monitored at least weekly and reported annually on Form H-10 to the Commission's Austin Offices.** **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. 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.** **6. 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.** **7. 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.**

Note: This document will only be distributed electronically.

		8. NOTE: Per operator email dated on June 01, 2022, the four plants are operated by EOG Resources, Inc. They are permitted under Pecan Pipeline Company (P-5 #648675) and Pecan Pipeline is EOG Resources. **Below are the names and RRC Serial Numbers for each plant:** **Bowie South – 09-0415** **St. Jo – 09-0406** **Henderson – 09-0405** **Kripple Kreek – 09-0401**

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 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.

Note: This document will only be distributed electronically.

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 July 18, 2022.

Sean Avitt, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

B Drilling Permit for Hinkle Trust #1

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 879709	DATE PERMIT ISSUED OR AMENDED May 10, 2022	DISTRICT * 09
API NUMBER 42-337-35480	FORM W-1 RECEIVED May 03, 2022	COUNTY MONTAGUE
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 682.83
OPERATOR 100178 EOG SPG HOLDINGS, INC. ATTN SETH WOODARD PO BOX 4362 HOUSTON, TX 77210		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 HINKLE TRUST		WELL NUMBER 1
LOCATION 9.4 miles SE direction from MONTAGUE, TX		TOTAL DEPTH 15000

Section, Block and/or Survey
SECTION ◄ BLOCK ◄ ABSTRACT ◄ 538
SURVEY ◄ MC DONALD, J

DISTANCE TO SURVEY LINES 1150 ft. NE 277 ft. SE	DISTANCE TO NEAREST LEASE LINE ft.
DISTANCE TO LEASE LINES 604 ft. SW 204 ft. SE	DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
BARNABUS (ELLENBURGER) HINKLE TRUST	682.83	13,000	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

MONTAGUE (337) County

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

C Existing Wellbores in the AMA and MMA

Table 11: Details of existing wellbores in the MMA

API	Latitude[d]	Longitude[d]	Type[e]	Measured Depth (ft)	True Vertical Depth[f] (ft)	Vertical Separation[g] (ft)	Status	Plugging Date
4233700318	33.5476473	-97.6680356	V	6,316	6,316	3,281	plugged	8/23/1948
4233700319	33.5433524	-97.6685669	V	6,185	6,185	3,239	open	-
4233700320	33.54584	-97.6654879	V	6,150	6,150	3,359	plugged	9/26/2003
4233700321	33.5409871	-97.6613966	V	6,185	6,185	3,295	plugged	9/9/1949
4233700322	33.5397595	-97.6682099	V	6,075	6,075	3,332	plugged	11/30/1949
4233700331	33.5492584	-97.6751192	V	6,180	6,180	3,290	plugged	6/23/1952
4233700951	33.5419592	-97.6861446	V	6,200	6,200	3,209	plugged	8/9/1974
4233700958	33.5160018	-97.6918485	V	6,350	6,350	3,085	plugged	9/6/1952
4233701073	33.5409088	-97.7213681	V	6,023	6,023	3,127	open	-
4233701122	33.5454835	-97.7223205	V	6,033	6,033	3,086	open	-
4233701123	33.5434121	-97.7199676	V	6,200	6,200	2,950	open	-
4233701390	33.5414571	-97.666039	V	6,930	6,930	2,497	open	-
4233701391	33.5420799	-97.6656006	V	6,185	6,185	3,254	plugged	4/30/1958
4233701421	33.5486792	-97.6773436	V	6,330	6,330	3,065	plugged	6/23/1952
4233701598	33.5160018	-97.6918485	V	6,263	6,263	2,919	plugged	7/10/1951
4233701599	33.5407157	-97.7134382	V	6,391	6,388	2,864	plugged	3/21/2017
4233701721	33.5409308	-97.6717112	V	6,233	6,233	3,178	plugged	12/8/1953
4233701753	33.5322683	-97.6798167	V	6,215	6,215	3,190	plugged	5/8/1958
4233702046	33.5346366	-97.6564126	V	6,292	6,292	3,270	open	-
4233702156	33.5214402	-97.6722279	V	6,197	6,197	3,179	plugged	6/2/1955
4233702163	33.5224329	-97.7066105	V	6,215	6,215	3,207	plugged	4/19/1955
4233702169	33.5570792	-97.6908437	V	6,460	6,460	2,981	plugged	7/12/1954
4233702322	33.5114096	-97.6858321	V	6,287	6,287	3,223	plugged	5/24/1955
4233702327	33.5235695	-97.6873659	V	7,703	7,703	1,658	plugged	10/2/1953
4233702428	33.5544365	-97.704817	V	6,510	6,510	2,804	plugged	11/20/2001
4233702497	33.5469321	-97.6726204	V	6,300	6,300	3,184	plugged	9/22/2003
4233702720	33.5449729	-97.6841474	V	6,235	6,235	3,073	open	-
4233702724	33.5478849	-97.6773222	V	6,322	6,322	3,063	plugged	12/4/2007
4233702800	33.5306035	-97.6575182	V	6,265	6,265	3,315	plugged	9/3/1964
4233730025	33.5472796	-97.7010957	V	6,650	6,650	2,640	plugged	9/19/2006
4233730039	33.549693	-97.698387	V	6,350	6,350	3,016	plugged	10/23/2008
4233730409	33.5472133	-97.7049151	V	7,500	7,500	1,754	open	-
4233730500	33.5456717	-97.6750313	V	6,250	6,250	3,138	plugged	8/4/1976
4233730517	33.5475022	-97.7094562	V	6,290	6,290	2,984	open	-
4233730534	33.5456717	-97.6750313	V	6,280	6,280	3,170	open	-
4233730535	33.5428675	-97.7119696	V	6,198	6,198	3,056	plugged	10/10/2012
4233730560	33.5494984	-97.6870224	V	6,300	6,300	3,031	plugged	11/21/2018
4233731003	33.5455463	-97.697421	V	6,409	6,409	2,879	plugged	7/28/2006
4233731081	33.5513089	-97.6844319	V	6,397	6,397	2,950	plugged	4/12/1996
4233731082	33.5507531	-97.6820947	V	6,500	6,500	2,878	plugged	12/4/2006
4233731090	33.548335	-97.691426	V	6,400	6,400	2,950	plugged	5/19/2023
4233731102	33.5327209	-97.6609319	V	6,269	6,269	3,228	plugged	11/1/1984
4233731106	33.5522614	-97.7034382	V	6,460	6,460	2,827	open	-
4233731110	33.548384	-97.69536	V	6,397	6,397	2,963	open	-
4233731166	33.5212553	-97.6762734	V	6,338	6,338	3,041	plugged	12/19/1978
4233731188	33.551443	-97.7117592	V	6,502	6,502	2,838	plugged	12/28/2020
4233731225	33.5449729	-97.6841474	V	7,336	7,336	2,013	open	-
4233731369	33.5485133	-97.6766576	V	6,370	6,370	3,038	plugged	8/9/2022
4233731481	33.5339855	-97.6554106	V	985	985	8,593	open	-
4233731517	33.5456717	-97.6750313	V	7,673	7,673	1,794	plugged	4/8/1981
4233731518	33.5534751	-97.7007102	V	7,880	7,880	1,474	plugged	3/5/1988

Continued on next page

Table 11 – continued from previous page

API	Latitude[d]	Longitude[d]	Type[e]	Measured Depth (ft)	True Vertical Depth[f] (ft)	Vertical Separation[g] (ft)	Status	Plugging Date
4233731786	33.5094884	-97.6786147	V	6,317	6,317	3,141	plugged	2/11/1983
4233731952	33.5173691	-97.7010647	V	6,300	6,300	3,087	plugged	8/14/1982
4233732077	33.5367212	-97.6599446	V	7,200	7,200	2,323	plugged	7/25/1983
4233732434	33.5456717	-97.6750313	V	6,300	6,300	3,138	plugged	9/28/1998
4233732570	33.5354122	-97.6749735	V	6,300	6,300	3,087	plugged	3/4/1998
4233732587	33.54584	-97.6654879	V	5,550	5,550	3,894	plugged	9/2/1998
4233732683	33.5449729	-97.6841474	V	6,400	6,400	2,927	plugged	1/14/1987
4233732709	33.5371514	-97.6683467	V	6,200	6,200	3,212	plugged	10/25/1998
4233732763	33.5384755	-97.6711482	V	6,300	6,300	3,073	plugged	9/25/2003
4233732768	33.5322426	-97.6729935	V	6,150	6,150	3,275	plugged	8/17/1988
4233732821	33.5247848	-97.6677227	V	6,226	6,226	3,206	plugged	3/18/1990
4233732854	33.5173691	-97.7010647	V	6,265	6,265	3,207	plugged	12/11/1990
4233732892	33.544519	-97.721225	V	6,410	6,410	2,721	plugged	10/10/2012
4233732935	33.5275003	-97.663315	V	7,190	7,190	2,276	open	-
4233732941	33.5159471	-97.6996498	V	5,380	5,380	3,992	plugged	5/12/1993
4233734044[h]	33.5358702	-97.6751655	V	11,419	11,415	-	open	-
4233734059	33.5297189	-97.669596	H	10,486	6,951	2,449	open	-
4233734060	33.5299917	-97.6696954	H	10,565	6,877	2,511	open	-
4233734062	33.5319777	-97.6664584	H	10,825	7,043	2,391	open	-
4233734063	33.5320278	-97.6664	H	10,643	6,884	2,528	open	-
4233734064	33.532075	-97.6663417	H	10,675	6,971	2,430	open	-
4233734381	33.53702	-97.69446	H	11,515	6,876	2,533	open	-
4233734382	33.53701	-97.69455	H	11,714	6,879	2,511	open	-
4233734383	33.53378	-97.6985	H	11,614	6,899	2,477	open	-
4233734384	33.53371	-97.69848	H	11,665	6,889	2,474	open	-
4233734462	33.5283945	-97.7104741	H	11,765	6,980	2,406	open	-
4233734467	33.5308216	-97.7036631	H	11,390	6,854	2,424	open	-
4233734470	33.530757	-97.7036925	H	11,408	6,856	2,419	open	-
4233734482	33.55202	-97.69247	H	12,428	6,691	2,633	open	-
4233734483	33.55198	-97.69253	H	12,492	6,705	2,593	open	-
4233734485	33.528352	-97.7104097	H	11,780	6,907	2,318	open	-
4233734625	33.5484861	-97.7223667	H	11,053	6,674	2,335	open	-
4233734626	33.5485528	-97.7223528	H	11,525	6,680	2,341	open	-
4233734627	33.54907	-97.71264	H	12,042	6,688	2,347	open	-
4233734628	33.54914	-97.71264	H	12,086	6,709	2,362	open	-
4233734675	33.5597583	-97.7148194	H	11,763	6,787	2,566	open	-
4233734676	33.5598	-97.71475	H	11,280	6,723	2,642	open	-
4233734677	33.55984	-97.71469	H	11,162	6,699	2,689	open	-
4233734813	33.52826	-97.6437701	-	-	-	-	expired permit	-
4233734830	33.5306885	-97.7037284	H	11,884	6,932	2,474	open	-
4233734892	33.5082164	-97.6518451	-	-	-	-	expired permit	-
4233734893	33.50816	-97.65192	H	13,083	7,145	2,341	open	-
4233734894	33.50819	-97.65188	H	12,952	7,083	2,396	open	-
4233734930	33.50028	-97.66277	H	12,250	7,103	2,393	open	-
4233735021	33.5022397	-97.6589206	H	12,220	7,071	2,374	open	-
4233735028	33.50694	-97.64689	H	14,965	6,992	2,460	open	-
4233735029	33.5069683	-97.6468561	H	15,080	5,779	3,678	open	-
4233735030	33.50221	-97.65896	H	12,220	7,154	2,283	open	-
4233735037	33.50226	-97.65889	H	12,165	7,125	2,327	open	-
4233735038	33.5022	-97.65899	H	12,225	7,143	2,288	open	-
4233735062	33.5325183	-97.6969905	H	11,512	6,772	2,439	plugged	8/22/2022
4233735063	33.532491	-97.6970572	H	11,642	6,915	2,298	open	-
4233735089	33.5152982	-97.6465287	-	-	-	-	expired permit	-
4233735276	33.5074642	-97.6873168	H	12,840	7,024	2,348	open	-

Continued on next page

Table 11 – continued from previous page

API	Latitude[d]	Longitude[d]	Type[e]	Measured Depth (ft)	True Vertical Depth[f] (ft)	Vertical Separation[g] (ft)	Status	Plugging Date
4233735277	33.5075236	-97.687336	H	12,870	6,938	2,484	open	-
4233735279	33.5075832	-97.6873554	H	11,945	6,976	2,456	open	-
4233735376	33.5108452	-97.6750413	-	-	-	-	expired permit	-
4233735377	33.5108847	-97.6750867	-	-	-	-	expired permit	-
4233735378	33.5109245	-97.6751324	-	-	-	-	expired permit	-
4233735480[h]	33.5335602	-97.6759106	V	10,682	10,604	-	open	-
4233781563	33.5415486	-97.6654882	V	5,223	5,223	4,204	plugged	5/18/1979
4233782190	33.5449729	-97.6841474	V	6,050	6,050	3,258	plugged	8/9/1974
4233782845	33.551994	-97.7081803	-	-	-	-	expired permit	-
-	33.5456338	-97.7031434	-	-	-	-	expired permit	-
-	33.5469238	-97.6976345	-	-	-	-	expired permit	-
4233734149	33.5406337	-97.7038043	-	-	-	-	expired permit	-
4233734809	33.5316025	-97.7035052	-	-	-	-	canceled permit	-
4233782194	33.5337573	-97.6576655	V	-	-	-	open	-
4233731887	33.5382044	-97.6617854	-	-	-	-	expired permit	-
4233732631	333.5379144	-97.6675013	-	-	-	-	expired permit	-
4233735482	33.5332824	-97.676859	V	840	840	8,565	open	-
4233735483	33.5340654	-97.675702	V	-	-	-	active permit[i]	-
4233734678	33.5359944	-97.675356	-	-	-	-	expired permit	-
4233735481	33.5362434	-97.675106	V	340	340	9,060	open	-

[d]Denotes surface hole location for both vertical and horizontal wells in North American Datum 1927 (NAD84).
[e]Denotes vertical (V) or horizontal (H) wellbores.
[f]Denotes total depth as specified for vertical wells or maximum TVD (true vertical depth) for horizontal wells using directional surveys.
[g]Denotes vertical separation in feet between existing wellbores and top of middle Ellenburger injection zone based on seismic structure mapping and maximum true vertical depth of wellbores from well records analyses.
[h]Denotes wellbore constructed for this project.
[i]Currently permitted to 675 ft depth.

Appendix B: Submissions and Responses to Requests for Additional Information

EOG SPG Holdings, Inc.

Subpart RR Monitoring, Reporting, and Verification Plan for SPG CO_2 Bowie Facility

Montague County, TX

Version 3
December 2023

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1 Introduction

EOG SPG Holdings, Inc. (SPG) - a subsidiary of EOG Resources, Inc. - recently received authorization from the Railroad Commission of Texas (TXRRC) to drill and operate a Class II disposal well (Hinkle Trust #1) under Texas Administrative Code (TAC) Title 16, Part 1, § 3.9. Under this permit (No. 17041), SPG can inject up to 12 million standard cubic feet per day (MMSCFD) of acid gas waste - composed primarily of CO_2, N_2, H_2S, and other trace hydrocarbons - generated by four natural gas amine treatment facilities located in Montague County, TX and operated by EOG Resources, Inc. (EOG). These facilities separate the acid gas components from the natural gas stream produced from the Barnett Shale by approximately 1,100 wells across the Newark East Field, also operated by EOG. Historically, the separated CO_2 stream has been emitted to the atmosphere while the H_2S was incinerated by a thermal oxidizer with the resulting SO_2 emitted to the atmosphere. In 2022, the aggregate total reportable greenhouse gas (GHG) emissions from all four amine separation facilities were approximately 180,000 metric tons (MT) of CO_2.

EOG is submitting this Monitoring, Reporting, and Verification (MRV) plan to the Environmental Protection Agency (EPA) for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) in connection with qualifying for the tax credits in section 45Q of the Internal Revenue Code.

1.1 Document Organization

This MRV plan is organized into three main sections: 1) this introductory section; 2) project details; and 3) a description of the development and administration of the MRV plan.

Section 1 introduces the injection project. It provides a high-level overview of the existing natural gas amine treatment facilities that are the sources of the CO_2 emissions as well as the capture, compression, and pipeline gathering systems that have recently been constructed as part of the injection project infrastructure. The section concludes with a general description of the subsurface storage complex including the target storage reservoir, the confining system, and the operational history that is relevant to the planned injection operations.

Section 2 provides more detailed presentations of the regional geology in the project area and the operational infrastructure including:

- a more detailed review of the source of the CO_2 emissions and the capture, compression, and pipeline gathering systems that will be used to deliver the CO_2 to the injection site;
- a summary of the proposed injection volume rates and the projected cumulative mass of CO_2 to be stored over the expected project life;
- the stratigraphy of the underburden, storage reservoir, and confining system;
- the structural features and subsurface stress characteristics within the project area;
- a more detailed review of the Barnabus (Ellenburger) field history; and
- a description of the fluid transport characteristics of both the storage reservoir and the confining system;

Section 3 describes the specific technical elements of the proposed MRV plan and how the plan will be administered over the expected project life, including:

- a description of the geologic and reservoir models used to simulate the long-term injection performance and CO_2 plume behavior;
- the delineation of the Active and Maximum Monitoring Areas (AMA and MMA, respectively);
- a description and assessment of the potential surface leakage pathways in the project area;
- a discussion of the methods and techniques that will be used to detect, verify, and quantify potential surface leaks of the injected CO_2;
- a presentation of the routine and regular operational monitoring that will establish baseline operating conditions, against which future monitoring surveys and results will be compared;

- a description of the various measurement and mass balance accounting techniques that will be employed to quantify the mass of the various CO_2 streams;
- an explanation of how quality assurance and quality control (QA/QC) will be maintained across all aspects of the project operations;
- an acknowledgment of the requirements to submit revisions to the MRV plan in the event of material changes to the project; and
- a summary of the records that will be retained throughout the expected project life.

1.2 Surface Infrastructure Overview

EOG operates four natural gas amine treatment facilities that provide CO_2 to the Hinkle Trust #1 injection well. Figure 1 shows the geographic location of these facilities as well as the pipeline network that delivers CO_2 to the injection site. The names, TXRRC serial numbers, EPA GHGRP site identification numbers, and the CO_2 emissions for the 2022 reporting year of each of these facilities are summarized in Table 1. Section 2.1 provides a more detailed description of the gas treatment process and the CO_2 delivery infrastructure associated with the project.

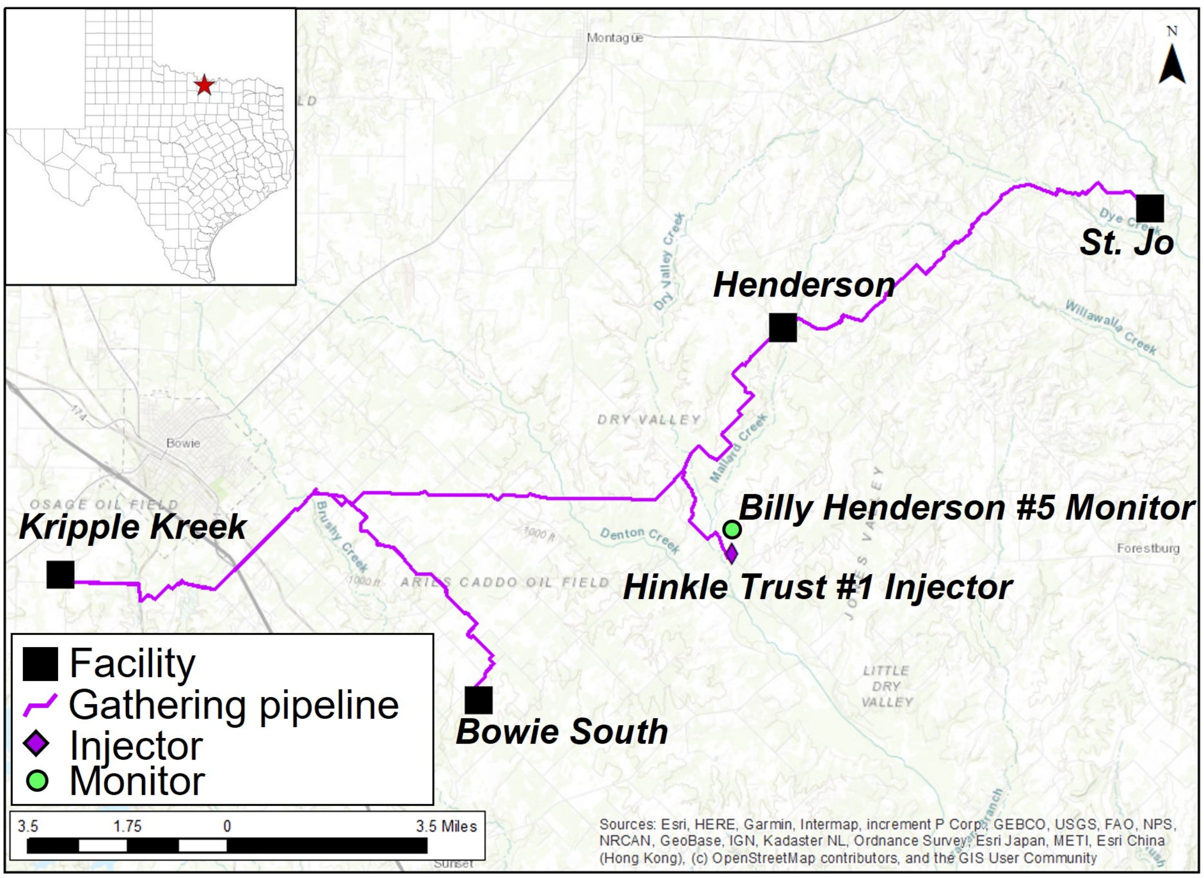

Figure 1: Project site map showing four gas amine treatment facilities providing CO_2 to the project, the pipeline network connecting processing facilities to the injection site, and the injection and monitoring well locations.

Table 1: Registration details and associated 2022 emissions for EOG gas amine treatment facilities.

Facility Name	TXRRC Serial No.	GHGRP ID	2022 Reported CO_2 Emissions (MT)
Bowie South[a]	09-0415	566952	54,352
Henderson[a]	09-0405	566952	20,584
Kripple Kreek	09-0401	528742	61,709
Saint Jo[a]	09-0406	566952	43,509
Total	—	—	**180,154**

[a]Previously reported as part of EOG Resources, Inc. 420 Fort Worth Syncline Basin Gathering & Boosting facility under Subpart W.

1.3 Subsurface Storage Complex Overview

The subsurface stratigraphy of interest for this project consists of the approximately four thousand feet of rock below the Barnett Shale formation, which is the primary hydrocarbon-producing interval within the project area. The middle Ellenburger formation is the main injection target for the project, which is an approximately one thousand foot thick dolomitic karst reservoir. Overlying the middle Ellenburger dolomite is over two thousand feet of mixed carbonates in the upper Ellenburger formation, mixed shale and limestone in the Simpson formation, and limestone in the Viola formation. These units contain ample footages of tight limestones, tight dolomites, and low permeability shales, and serve as the upper confining system for the project. Below the middle Ellenburger injection zone is approximately one thousand feet of tight limestone, which serves as the lower confining zone between the middle Ellenburger injection zone and the underlying granitic basement.

Two wells were drilled for this injection project. The Billy Henderson #5 is a vertical pilot and monitoring well that was drilled into granitic basement. This well provided project site-specific data across the injection and confining zones and was subsequently completed as a monitor well for the project. The Hinkle Trust #1 is the injection well for the project. This slightly-deviated well was drilled approximately 1,600 feet (ft) away from the Billy Henderson #5 monitor to a depth only a few hundred feet below the base of the injection zone. Evaluation data was also collected in this well for further subsurface characterization of the project site. The Hinkle Trust #1 was completed as an openhole injector into the middle Ellenburger dolomite.

2 Project Details

2.1 Source and Gathering of CO_2 for Injection

The Bowie Production Area has four central gas gathering sites that take produced gas from the field at low pressure (25-35 pounds per square inch-gauge, psig) and condition the gas to go through high pressure (750-900 psig) gathering lines to deliver the produced gas to a central gas treatment facility. Each of the gas gathering sites - Saint Jo, Henderson, Bowie South, and Bowie East Compressor Stations - have 3-stage compressors to increase the pressure of the gas before it goes through treatment to remove water and other impurities. Three of these gas gathering sites - Saint Jo, Henderson, and Bowie South - have amine treatment using Methyl-diethanolamine (MDEA) and Piperazine to remove CO_2 and H_2S from produced gas in the field down from 8%-15% CO_2 to 4% CO_2. The gas is then dehydrated using Triethylene Glycol (TEG) to remove water down to 7 pounds (lbs) per MMSCF (million standard cubic feet) before being sent to Kripple Kreek Gas Plant to go through final treatment. At the Kripple Kreek Gas Processing Plant, the remaining CO_2 in the high pressure produced gas is removed using MDEA and Piperazine from 4% CO_2 down to 100-200 parts per million (ppm) CO_2. The high pressure produced gas is dehydrated to a -300 °F dewpoint using TEG then mol sieve dehydration where the gas is then sent for final processing to separate the residue gas from the natural gas liquids (NGLs) for final sale. The residue gas is compressed and sold into a residue gas pipeline system, where the NGLs are subsequently sold and pumped into a y-grade NGL pipeline system.

The SPG CO_2 Bowie Facility (referred to as the injection facility or the Bowie injection project; GHGRP ID 583201) gathers the CO_2 from each of the four existing amine treatment facilities (at Saint Jo, Henderson, Bowie South, and Kripple Kreek) using 4-stage booster compressors to increase the pressure of the CO_2-rich gas from low pressure (5 psig) off of the amine still to high pressure (750-850 psig). The CO_2-rich gas is then conditioned using a TEG dehydration unit to lower the dew point below 0 °F to ensure free water is not condensed during normal operations. The CO_2-rich gas is then sent through a measurement section to record the mass flowrate, composition, temperature, pressure, oxygen content, and water content before being introduced into the CO_2 gathering system. Based on routine measurements from the gas chromatograph (GC) installed at the injection facility, the CO_2-rich gas will be >98% CO_2 by weight with the remainder being a mixture of nitrogen, small amounts of various hydrocarbons, water and trace H_2S (see Table 2). As such, the injected gas stream is nominally described by its principal component (CO_2) throughout the MRV plan.

Table 2: Compositional analysis of gas stream to be injected at SPG CO2 Bowie Facility.

Component Name	Normalized Mol %	Normalized Weight %
Hydrogen Sulfide	0.0034	0.0027
Nitrogen	2.2536	1.4487
Carbon Dioxide	97.3991	98.3634
Methane	0.2207	0.0813
Ethane	0.0359	0.0247
Propane	0.0347	0.0351
i-Butane	0.0015	0.002
n-Butane	0.0061	0.008
i-Pentane	0.0021	0.0035
n-Pentane	0.0025	0.0041
C6+	0.0057	0.0122
Water	0.0347	0.0144
Total	100	

The gathering system consists of 36 miles of 6-inch nominal diameter Flexsteel composite pipe that collects the CO_2 streams from each of the four processing sites. The CO_2 is then sent to the injection facility where the gas enters the site and goes through an inlet heater for conditioning to ensure it is in the vapor phase before it goes through a measurement section to record the mass flowrate, composition, temperature, pressure, oxygen content, and water content before the gas is compressed from high pressure (750-850 psig) to supercritical (1,600-2,200 psig) in the final 2-stage unit. The supercritical CO_2 leaving the compressor is left hot to then be routed to the heater to cross exchange and provide heat for the inlet gas from the CO_2 gathering pipeline. The supercritical CO_2 is then sent through final measurement to collect the mass flowrate before the gas enters the wellhead and is injected in the subsurface. Figures 2 and 3 depict the general process flow that delivers conditioned CO_2 to the injection facility as well as the detailed plot plan of the injection well site. Both figures identify the location of the final coriolis meter (Meter ID: FW46045INJ) which will serve as the reference injection measurement used in the mass balance accounting under Subpart RR.

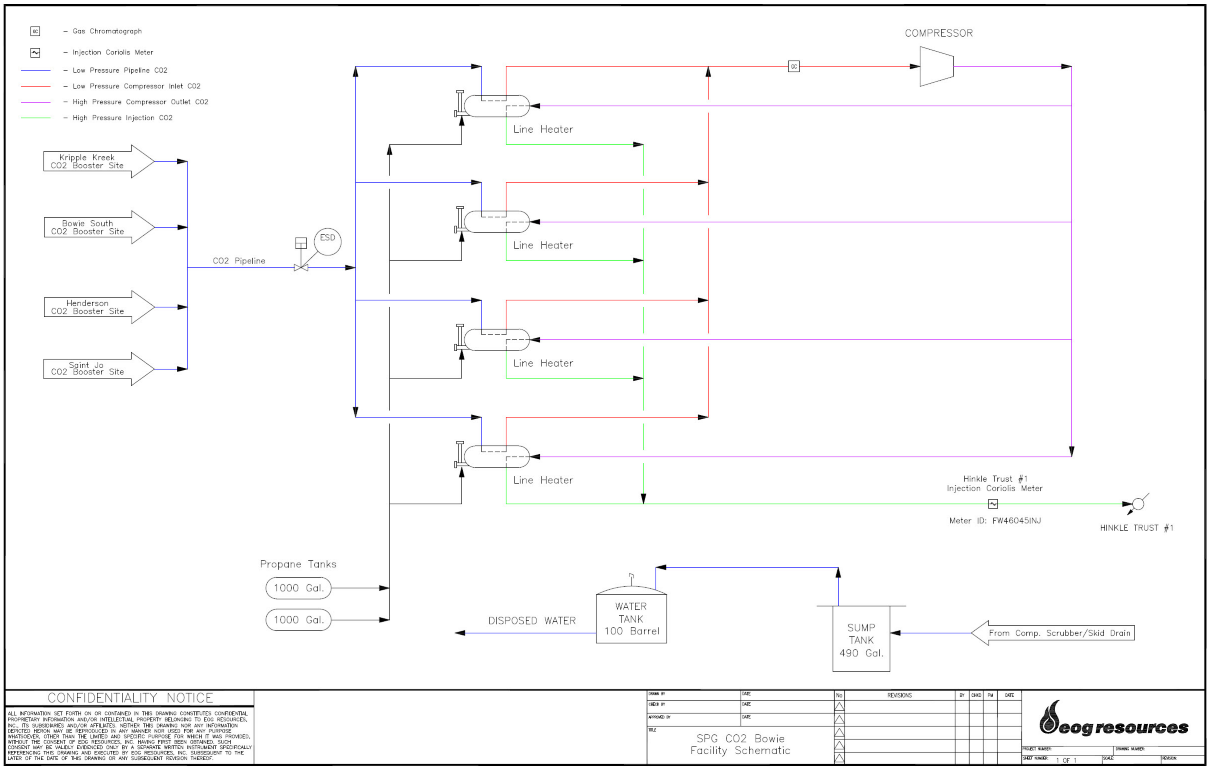

Figure 2: General flow diagram for SPG CO2 Bowie Facility.

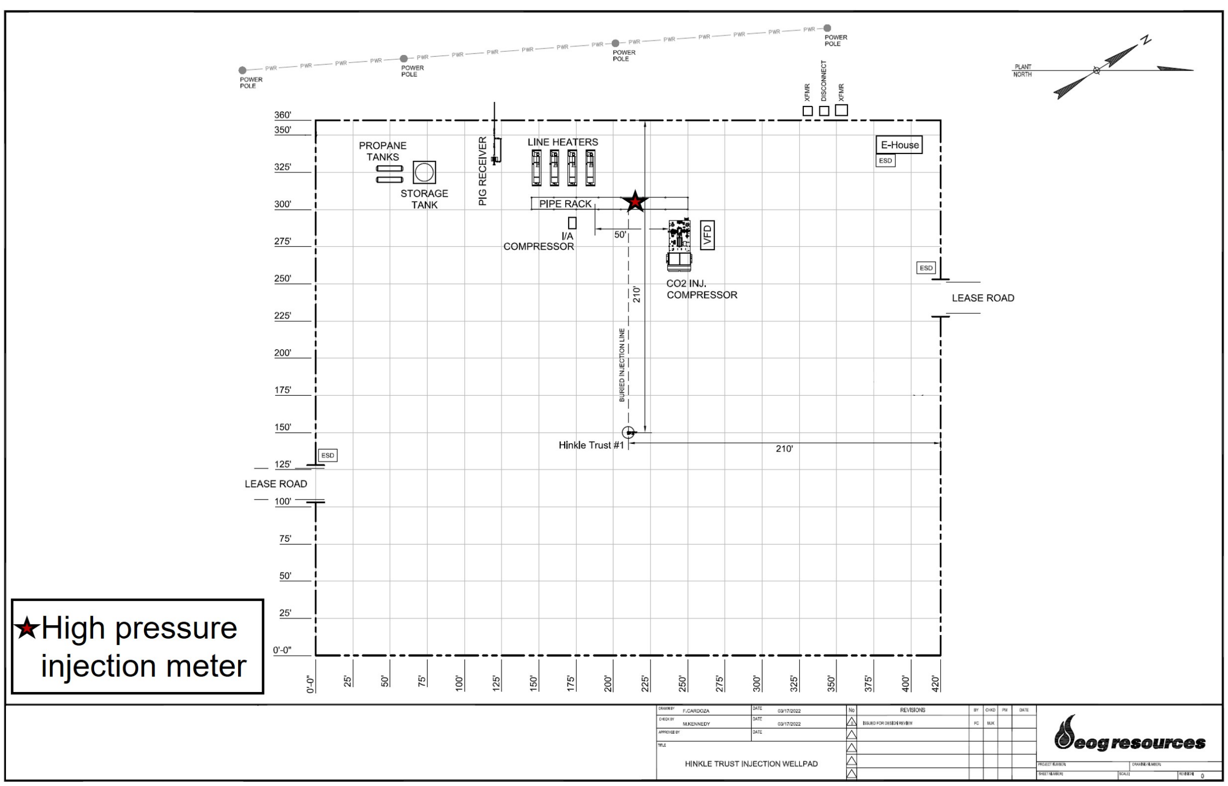

Figure 3: Plot plan for Hinkle Trust #1 injection pad.

2.2 Proposed Injection Volumes

The proposed CO_2 injection stream is separated from the natural gas produced by EOG's nearly 1,100 active Barnett wells in Montague County. Since these wells are on a natural depletion decline (and additional development drilling is not currently planned), the projected CO_2 volumes will follow a similar decline trend. Over the proposed 12-year project life, injection rates will decline from an initial rate of approximately 10 MMSCFD (~520 MT-CO_2/day) down to 4 MMSCFD (~200 MT-CO_2/day), resulting in a total cumulative injected mass of approximately 1.45 million MT-CO_2 (Figure 4). Injection operations began in February 2023 with CO_2 volumes supplied from the Henderson facility only. Injection operations from all four amine treatment facilities that will supply CO_2 to the gathering system commenced in June 2023, following completion of start-up and commissioning tests.

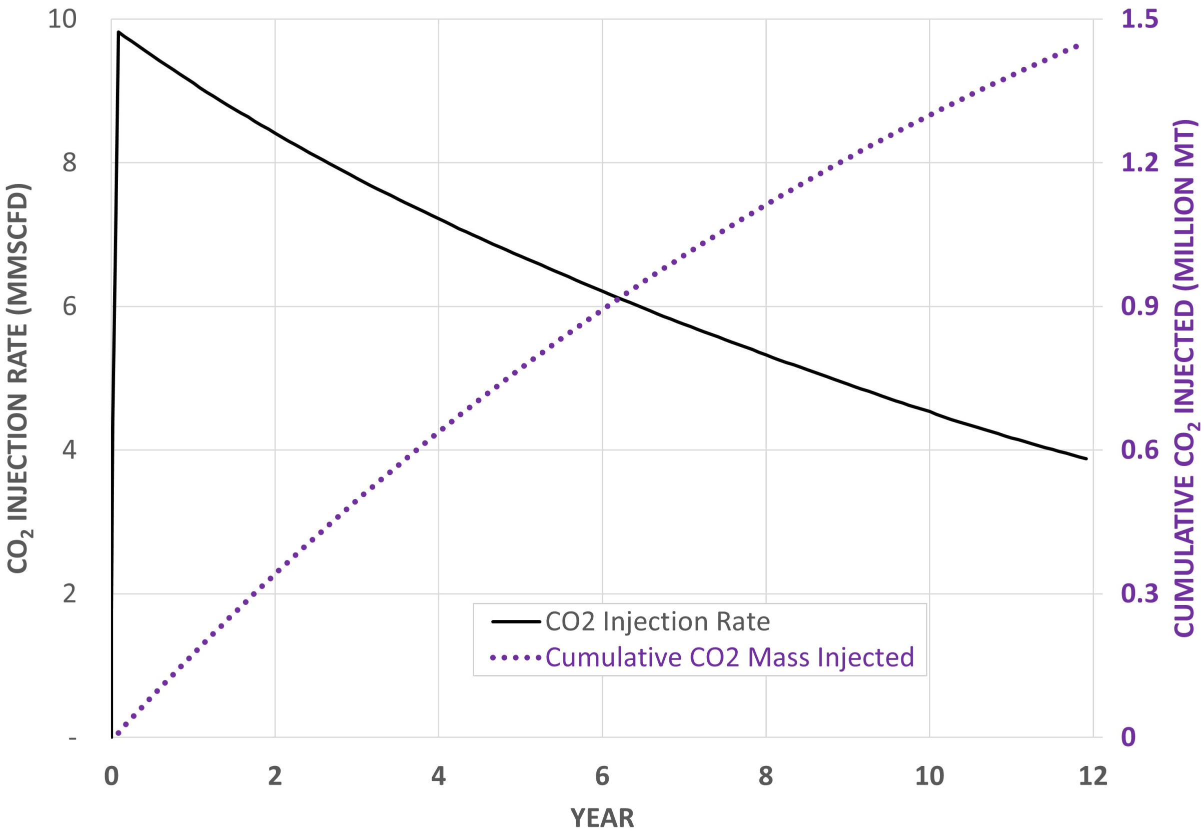

Figure 4: Projected CO_2 injection rate and cumulative mass injected over the proposed 12-year injection period.

2.3 Regional Geology

The project is located in the northern Fort Worth Basin which is a Paleozoic foreland basin associated with the Ouachita Orogenic belt (Figure 5). It exhibits stratigraphy similar to other Paleozoic structural basins found in North America [Meckel et al. (1992)]. The main hydrocarbon producing intervals are Mississippian to Pennsylvanian in age [Pollastro et al. (2007)]. The formations of interest for this injection project are pre-Mississippian-aged marine sediments, which sit below the major productive oil and gas intervals, and are separated from the underlying granitic basement by Cambrian aged sediments sitting below the injection zone (Figure 6) [Alsalem et al. (2018)]. The Ellenburger is the main formation of interest for this project, with secondary formations of interest being the overlying Simpson, Viola, and Barnett in stratigraphic order.

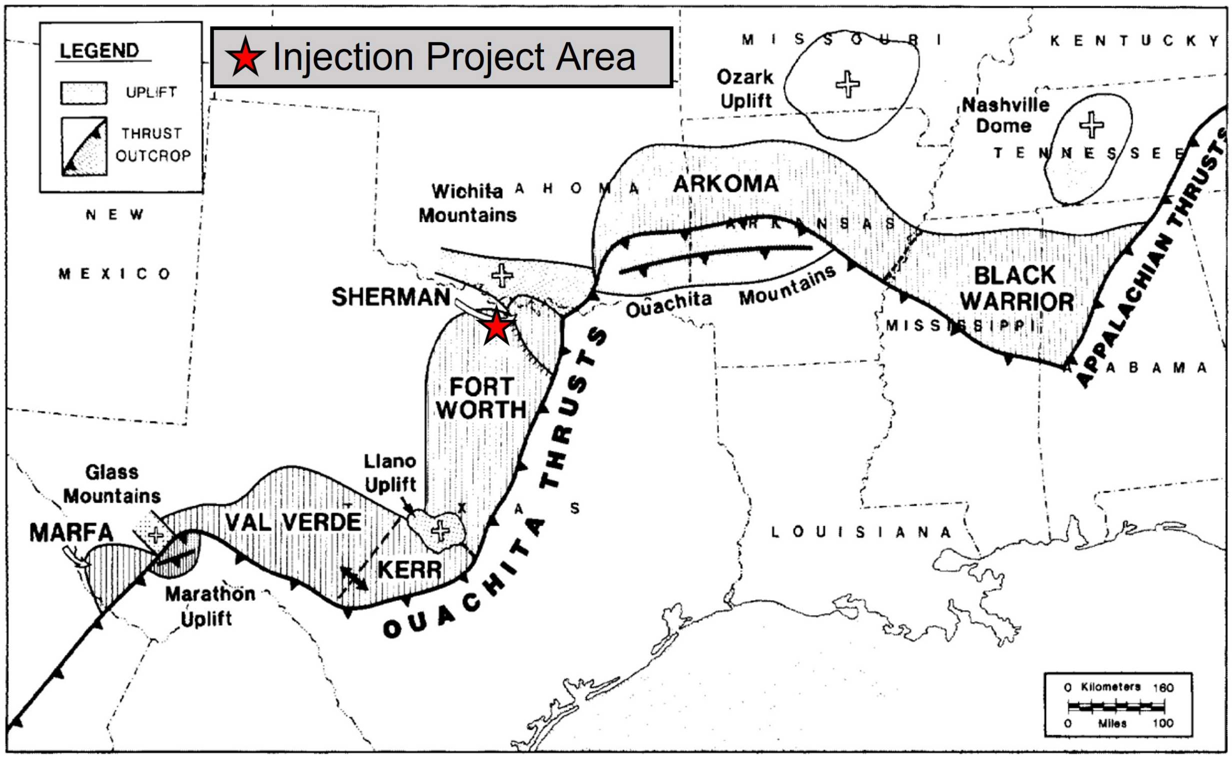

Figure 5: Location of Bowie injection project in northern Fort Worth Basin in reference to Ouachita front and related structural features. Figure modified from Meckel et al. (1992).

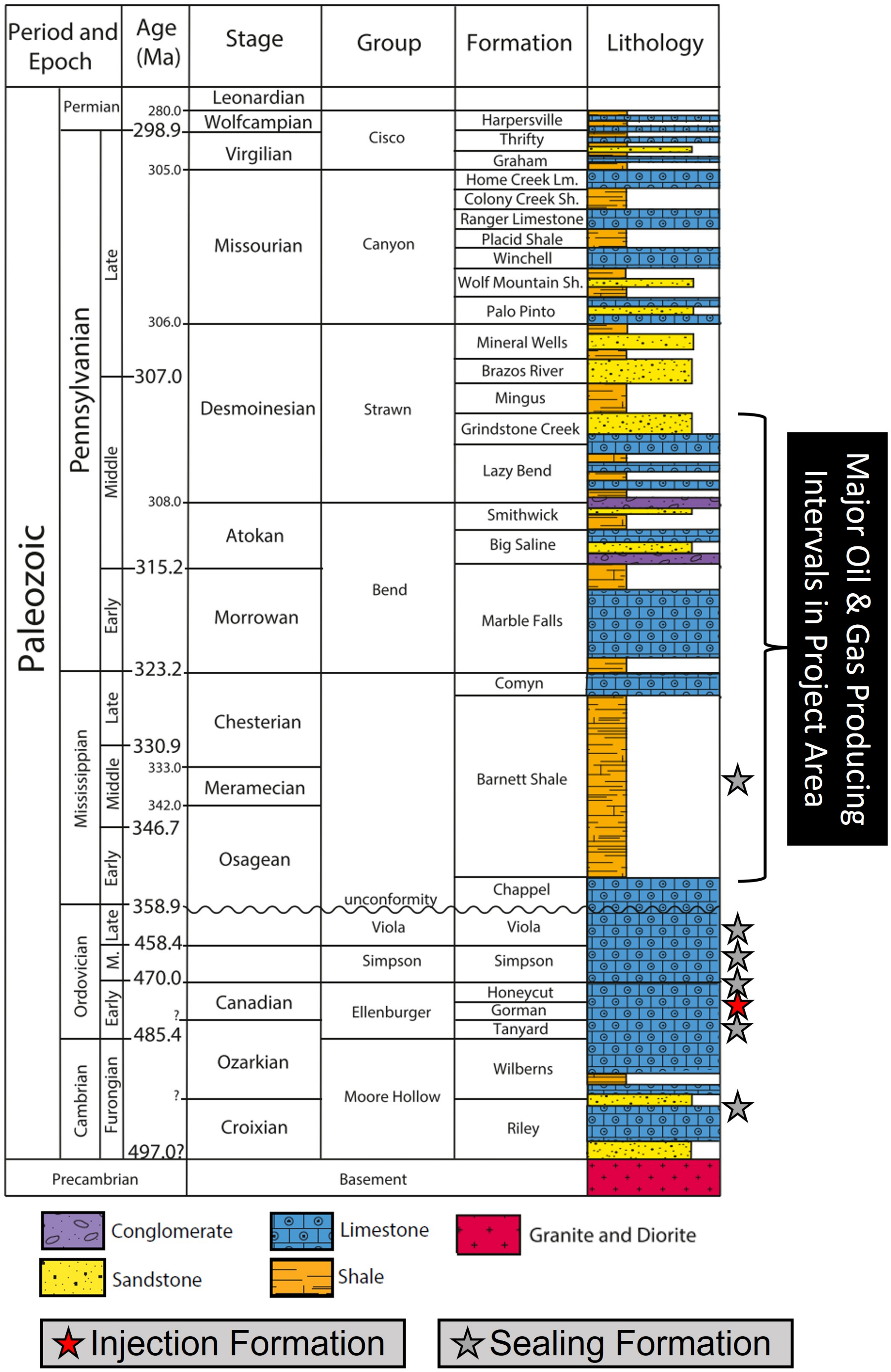

Figure 6: Generalized stratigraphic column of the Fort Worth Basin. Note that thicknesses of formations depicted within this illustration are not to scale for any particular location within the basin. Figure modified from Alsalem et al. (2018).

Prior to the formation of the Fort Worth structural basin in the project area, these Cambrian and Ordovician-aged sediments of interest were deposited on an epeiric carbonate platform developed on the Laurentian margin. This carbonate platform is commonly referred to as the Great American carbonate bank, which extended across the entirety of North America and rimmed the stable cratonic interior (Figure 7) [Derby et al. (2012)].

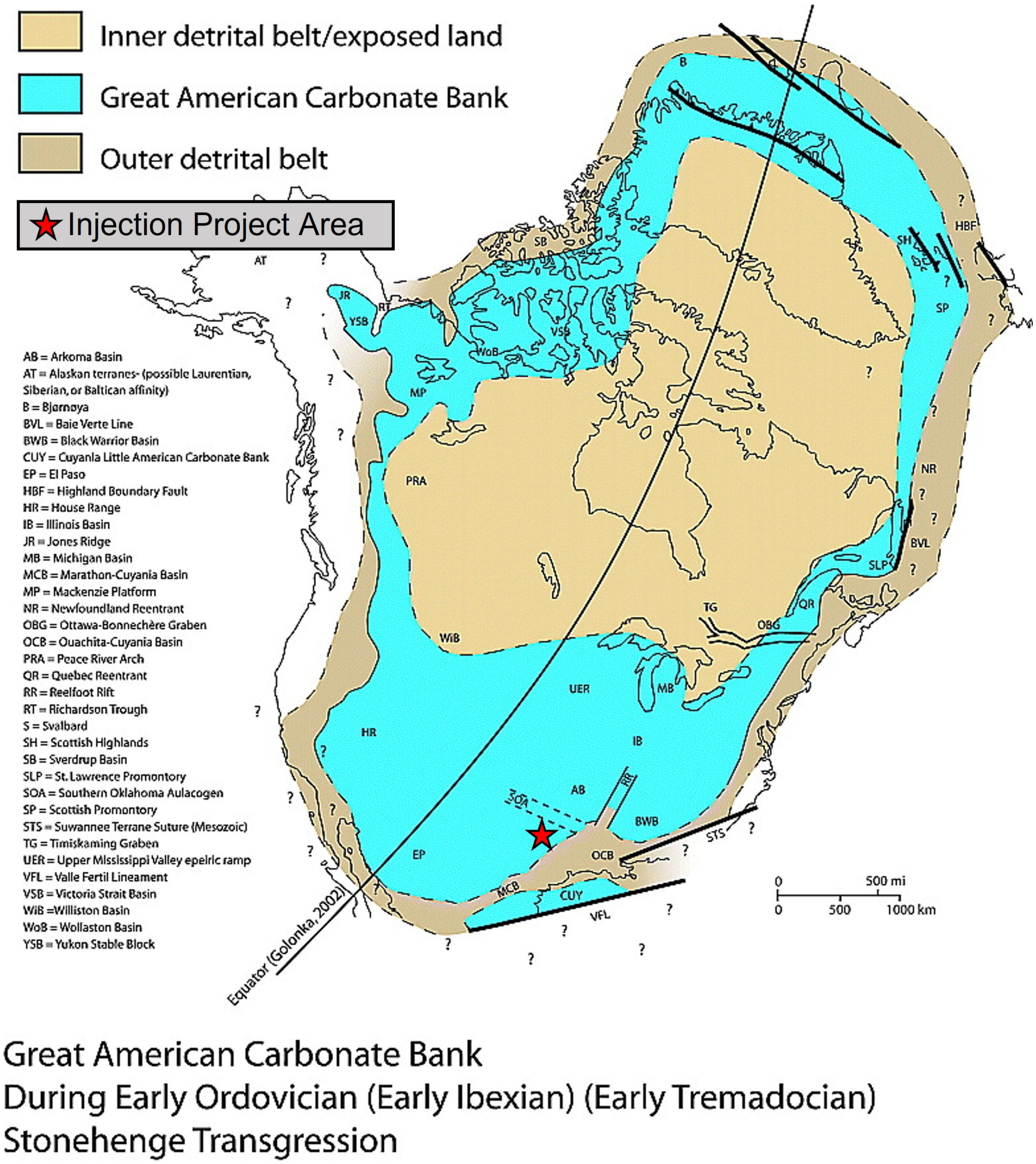

Figure 7: Location of Bowie injection project in reference to Great American carbonate bank paleogeography. Figure modified from Derby et al. (2012).

A large sea level change between the Ordovician and Mississippian resulted in an unconformity that removed any Silurian or Devonian rocks that may have been deposited. It was upon this unconformity that the Mississippian sediments, including the Barnett shale, were deposited. The late-Paleozoic Ouachita Orogeny formed the structural Fort Worth Basin and influenced sedimentation patterns through Permian time, with additional influence on the character

and thickness of sediments by local structure perturbations. In the northern Fort Worth Basin, these local structures include the Muenster Arch and Red River Arch. Pennsylvanian and early Permian sediments include both siliciclastics and carbonates, with siliciclastics being more dominant in the mid to late Pennsylvanian and Permian [Pollastro et al. (2007)]. In the eastern part of the Fort Worth Basin, the Cretaceous Trinity group rests unconformably on the Permian and Pennsylvanian-aged sediments [Fort Worth Geological Society (1955)]. The Trinity group contains the major freshwater aquifer units where present in the Fort Worth Basin, with no minor aquifers present (Figure 8) [George et al. (2011)].

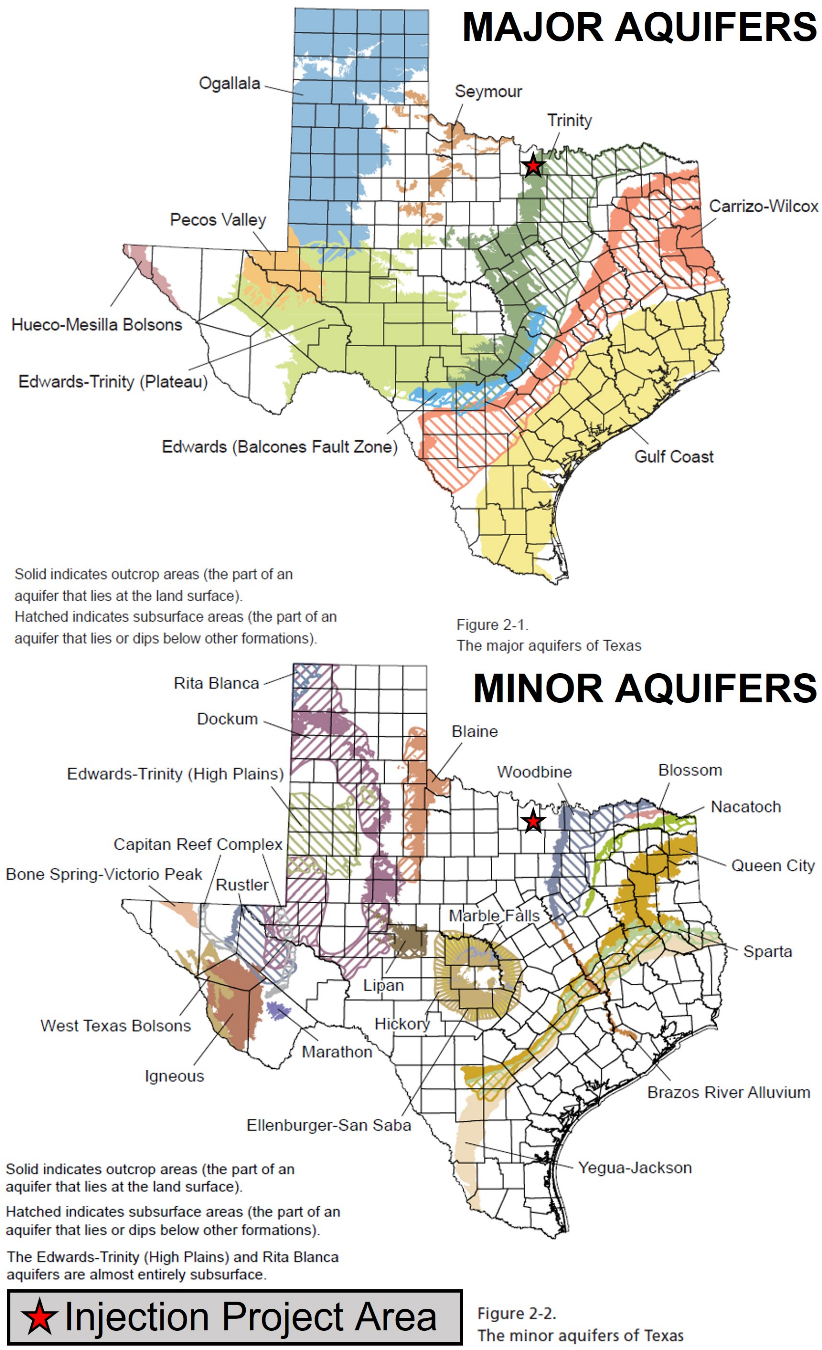

Figure 8: Project site referenced to Texas major and minor aquifers as identified by the Texas Water Development Board. Figure modified from George et al. (2011).

The injection project is located in Montague County, in the far northern part of Fort Worth Basin, in a structurally deep part of the basin adjacent to the Muenster Arch. Figure 9 shows the location of the project, structure contours on the top Ellenburger, and regional structural elements, including the Muenster Arch. The Muenster Arch has reactivated numerous times since the Precambrian, influencing local depositional patterns in Paleozoic strata.

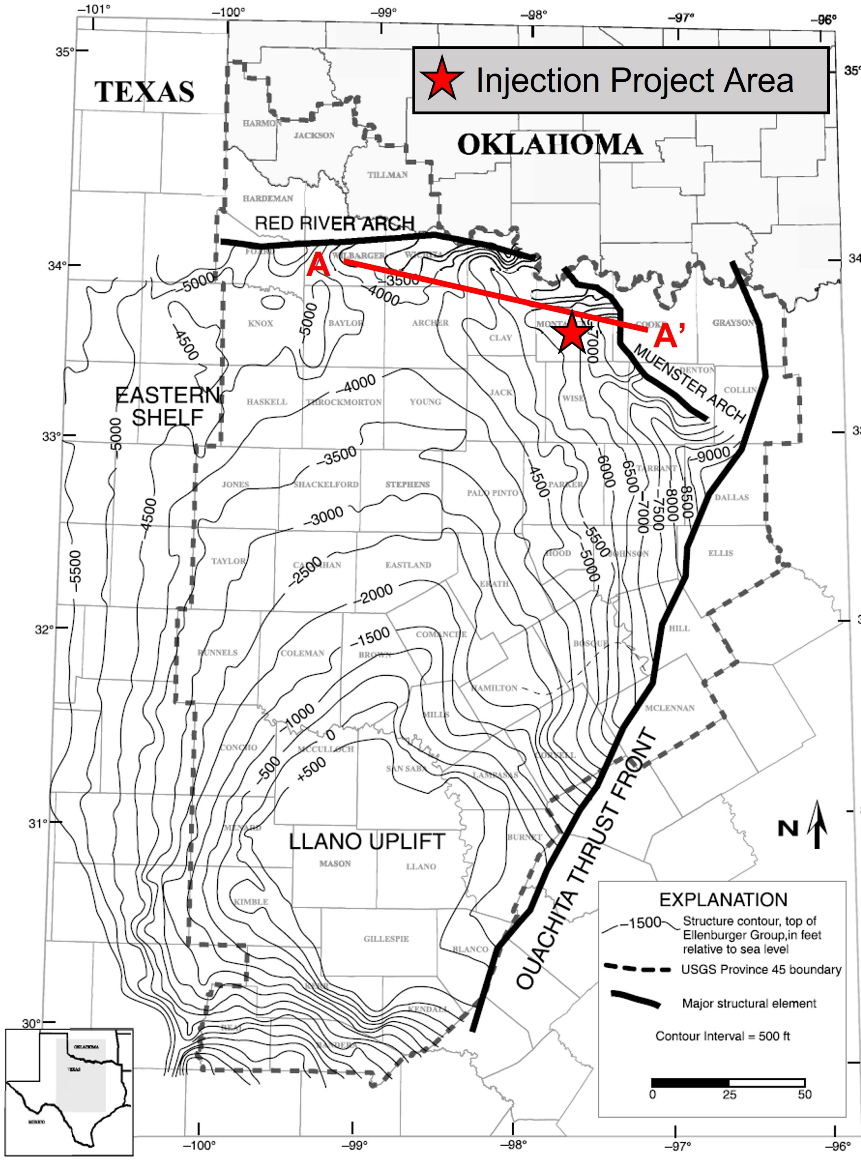

Figure 9: Location of Bowie injection project in Northern Fort Worth Basin, with top Ellenburger subsea true vertical depth (SSTVD) structure contours. Figure modified from Pollastro et al. (2007).

2.4 Stratigraphy of the Project Area

Figure 10 shows the regional character of the stratigraphy near the project area in Montague County. Formations between the basement and lower Penn (labeled top "Caddo") thicken and deepen towards the Muenster Arch, showing its influence on both deposition and present-day structural position. The Muenster Arch is shown as a series of high angle thrusts that place Ordovician Ellenburger above younger Mississippian and Penn sediments. Penn and Permian sediments thicken towards the Ouachita front and Muenster Arch and are truncated by the base Cretaceous unconformity. The Cretaceous-age Trinity group is present in Montague County and sits above this unconformity.

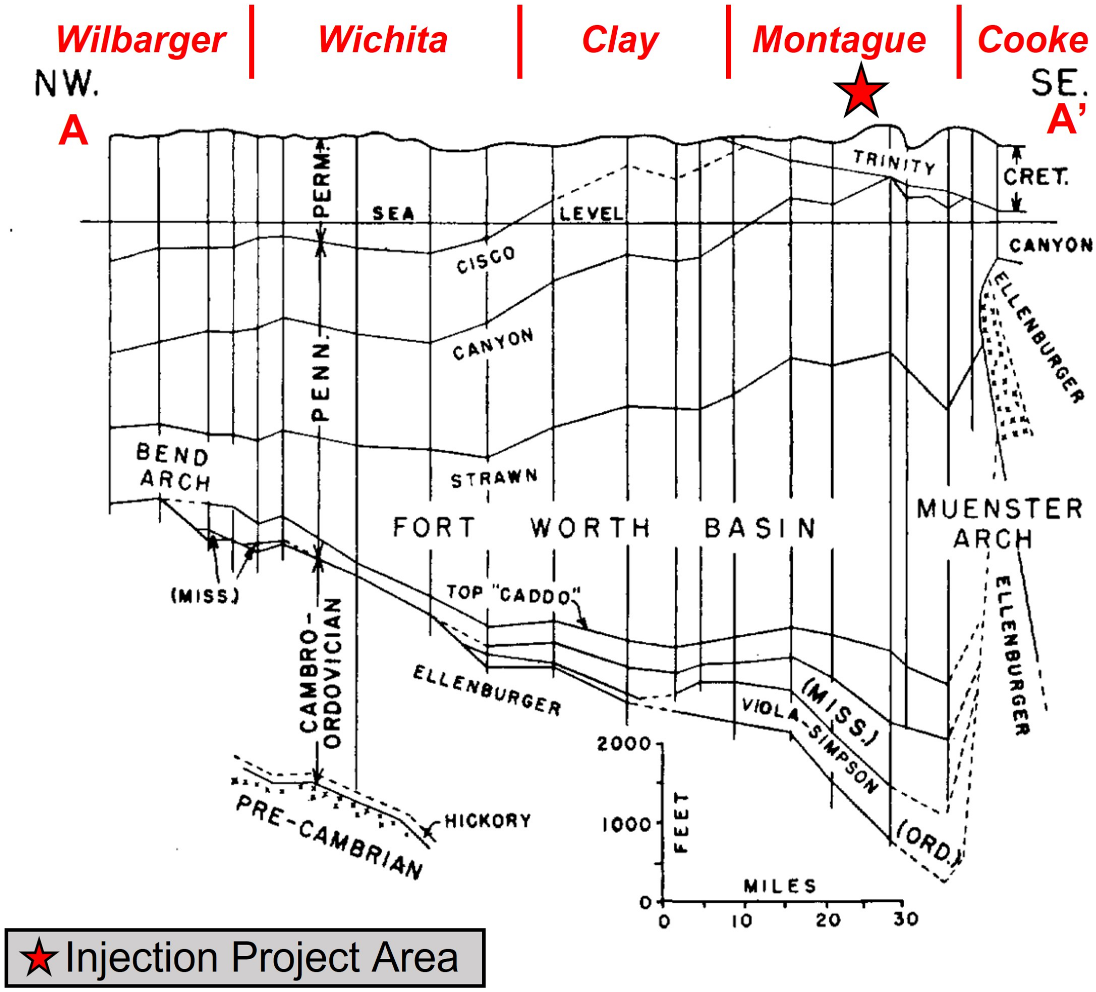

Figure 10: Generalized stratigraphic cross-section of North Fort Worth Basin with counties annotated on section. Figure modified from Fort Worth Geological Society (1955). Location of section shown in Figure 9.

Figure 11 shows the specific stratigraphic units present in the project area which are described below. Geologic descriptions are based on literature and internal EOG data collected across the stratigraphy for this project and others. The Precambrian basement within the project site is granitic and is variably cut by mafic intrusives. The carbonate section from the basement to the top of the Ellenburger has been broken in three units that can be correlated across Montague County. These three units are the basal carbonate (from basement to Base M. Ellenburger in typelog), middle Ellenburger, and upper Ellenburger. Above these units, the Simpson, Viola, and Barnett Shale are observed to be present within the project site [Pollastro et al. (2007)]. More detail will be presented on the lower carbonate through lower Barnett shale in the sections describing the injection and confining zones for the project (Section 2.7). The overlying Pennsylvanian stratigraphy has been broken out using both regional and local nomenclature for the stratigraphic units. At the top of the section is the base of the Trinity aquifer unit, which crops out within the project site (see Figure 12) [George et al. (2011)].

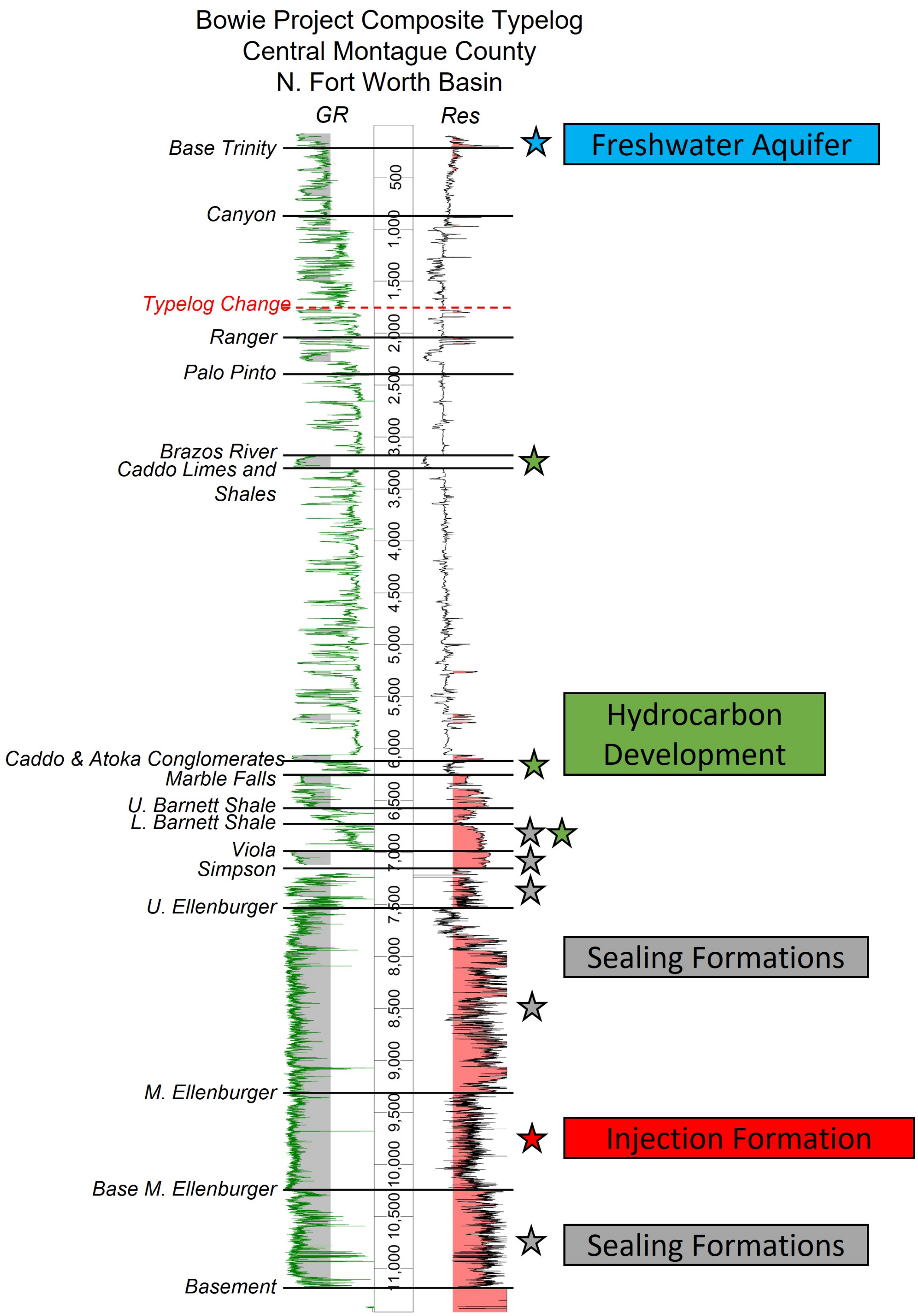

Figure 11: Project site-specific typelog utilizing well log data collected from the Billy Henderson #5 (lower Canyon to basement section) and Hinkle Trust #1 (surface to lower Canyon section).

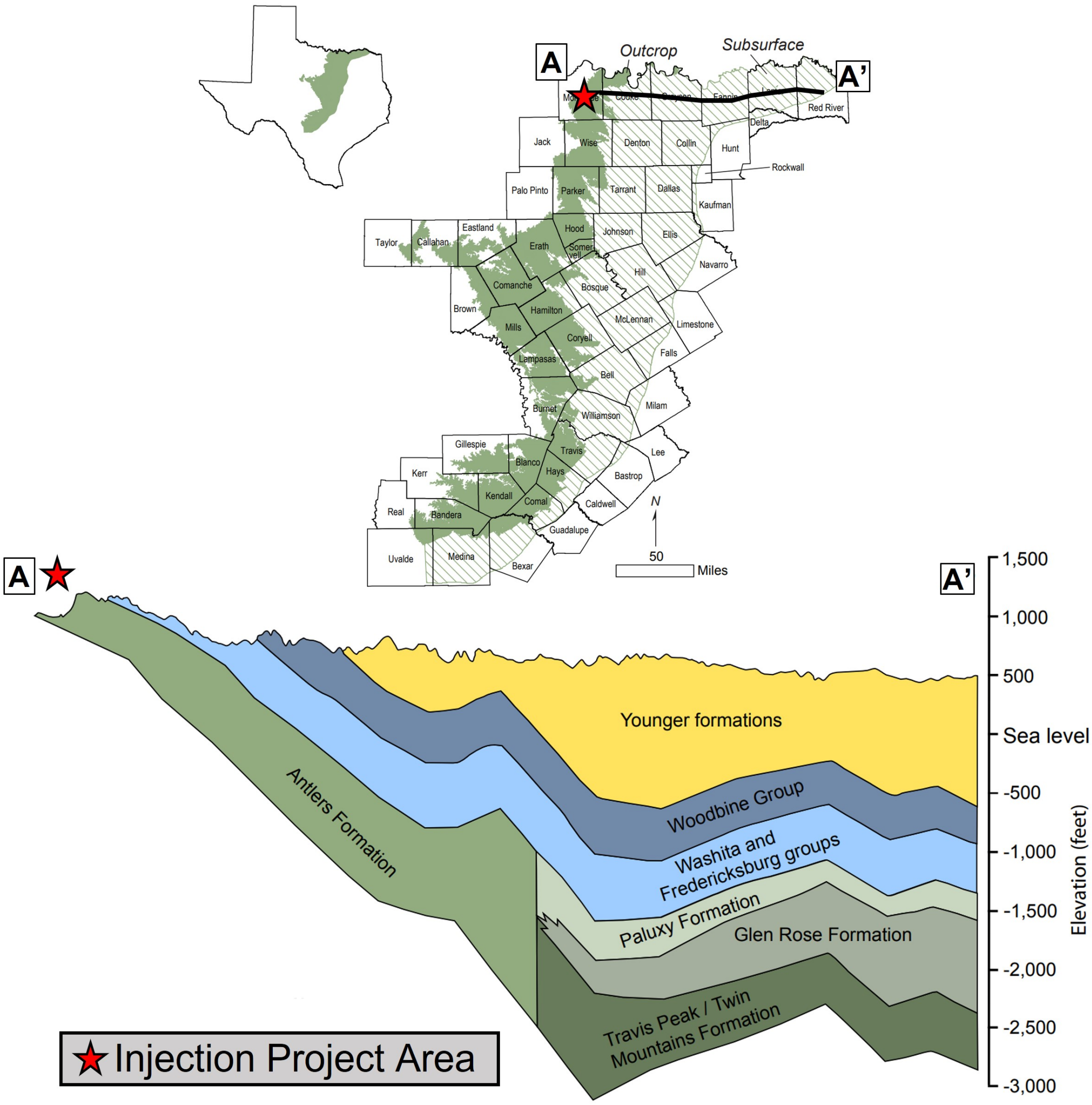

Figure 12: Trinity aquifer extent and geometry in the vicinity of the project area. Figure modified from George et al. (2011).

2.5 Structural Geology of the Project Area

The injection area is bounded by the Muenster Arch to the east and northeast and the Red River Arch to the north, both of which are positive, basement-rooted structural features formed during the Paleozoic Oklahoma aulacogen and were reactivated during Ouachita orogenic compression [Walper (1982)]. The injection area is characterized by three key structural components: basement-rooted faulting, natural fracturing, and, specifically within the Ellenburger, extensive karst formation. Within the injection area, these structural components are characterized with three-dimensional (3D) seismic data, core, and well log data, and are discussed in further detail below.

Basement faulting: The injection area is characterized by a variety of fault orientations and styles reflecting multiple tectonic episodes during Fort Worth Basin evolution. Prominent basement faults generally strike east-west, largely exhibit strike-slip characteristics including extensive flower structures, and were likely formed during the Oklahoma aulacogen [Walper (1982), Pollastro et al. (2007)]. Most prominent basement faults either truncate within the basement or splay into smaller faults upon entering the Ellenburger, though some larger faults may extend up to Pennsylvanian

Strawn or Bend groups (Figure 13). A secondary basement fault set strikes north-northeast to south-southwest (NNE-SSW), paralleling present-day Ellenburger structural strike, though is less prevalent and does not extend above the basement within the injection area. Several basement-level faults intersect the injection interval (Figure 13), and are discussed as potential leakage pathways in section 3.5.3.

Natural fracturing: Ellenburger natural fractures, characterized by wellbore image logs and core data in the injection and monitoring wells, exhibit highly variable strike and dip, and likely originated from a combination of tectonic forces and intra-karst collapse and brecciation [Kerans (1988), Ijirigho and Schreiber Jr (1988)]. Natural fractures also generally appear cemented (Figure 32). The karst features themselves appear to be restricted to the injection zone, and do not appear to extend into the confining zone within the project area. Therefore, the fracturing associated with the karsts is not interpreted to be present across the confining zone.

Karsting: Ordovician Ellenburger group carbonates were deposited on a carbonate platform on a stable cratonic shelf. Sea level drops during and following Ellenburger deposition yielded subareal platform exposure and complex, extensive karsting, which was subsequently filled with Simpson Group clastics [Kerans (1988)]. Karst features are present within the proposed injection area and likely provide the primary Ellenburger storage (i.e., pore space) within the proposed injection interval.

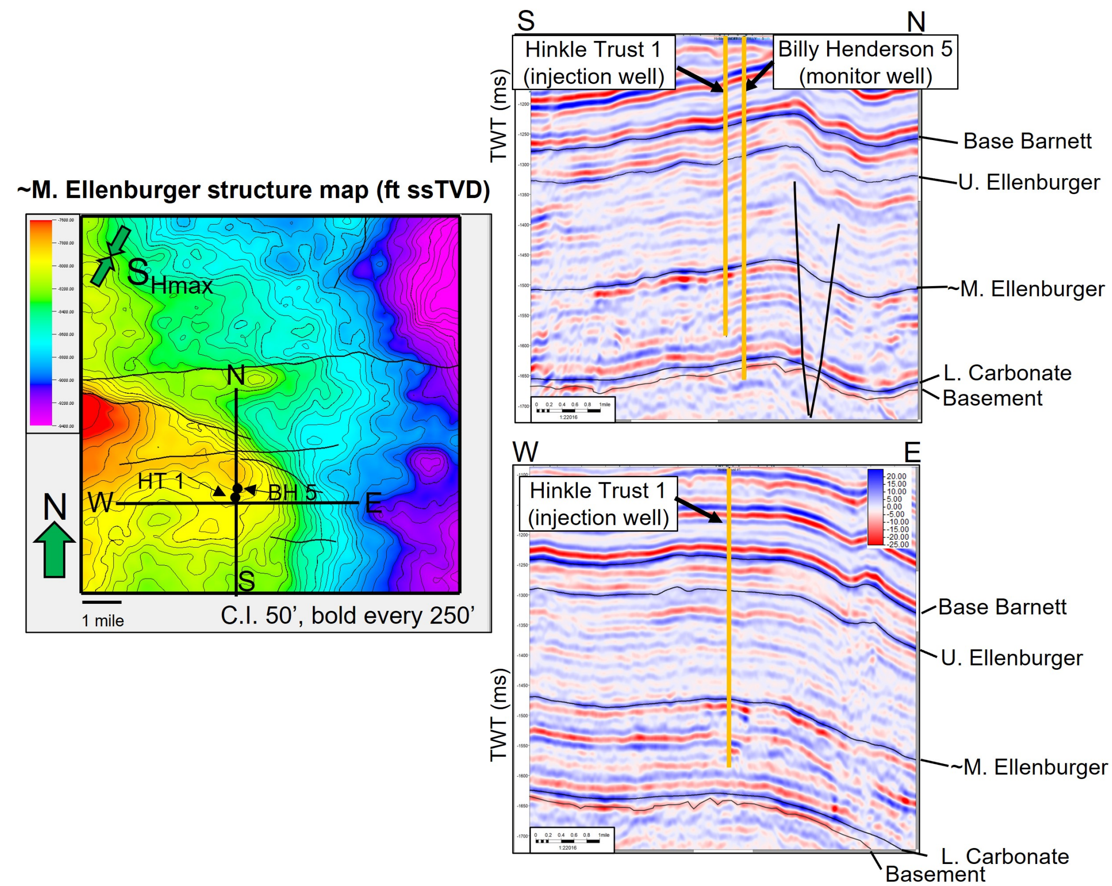

Figure 13: Middle Ellenburger structure map (top injection zone) and seismic cross-sections over proposed injection area. Black lines denote major faults.

2.6 Barnabus Ellenburger Field History

The Hinkle Trust #1 is permitted as an acid gas injector (AGI) within the TXRRC-defined field known as the Barnabus Ellenburger field. Across EOG's productive Barnett acreage in Montague County, this zone has historically been used

extensively for the disposal of produced water (i.e., SWD, or saltwater disposal). Of the six wells drilled into the Ellenburger for SWD by EOG, only four penetrated the middle Ellenburger - the zone intended for long-term CO_2 injection and storage. These four wells are shown on the map in Figure 14 in relation to the Hinkle Trust #1 and Billy Henderson #5, the injection and monitoring wells drilled for this project. Only two of these wells - the Cox and the Davenport - are still active SWD injectors while the other two have been permanently plugged and abandoned. Of the remaining active injectors, the Cox is the closest to the project area, located approximately 6 miles to the north.

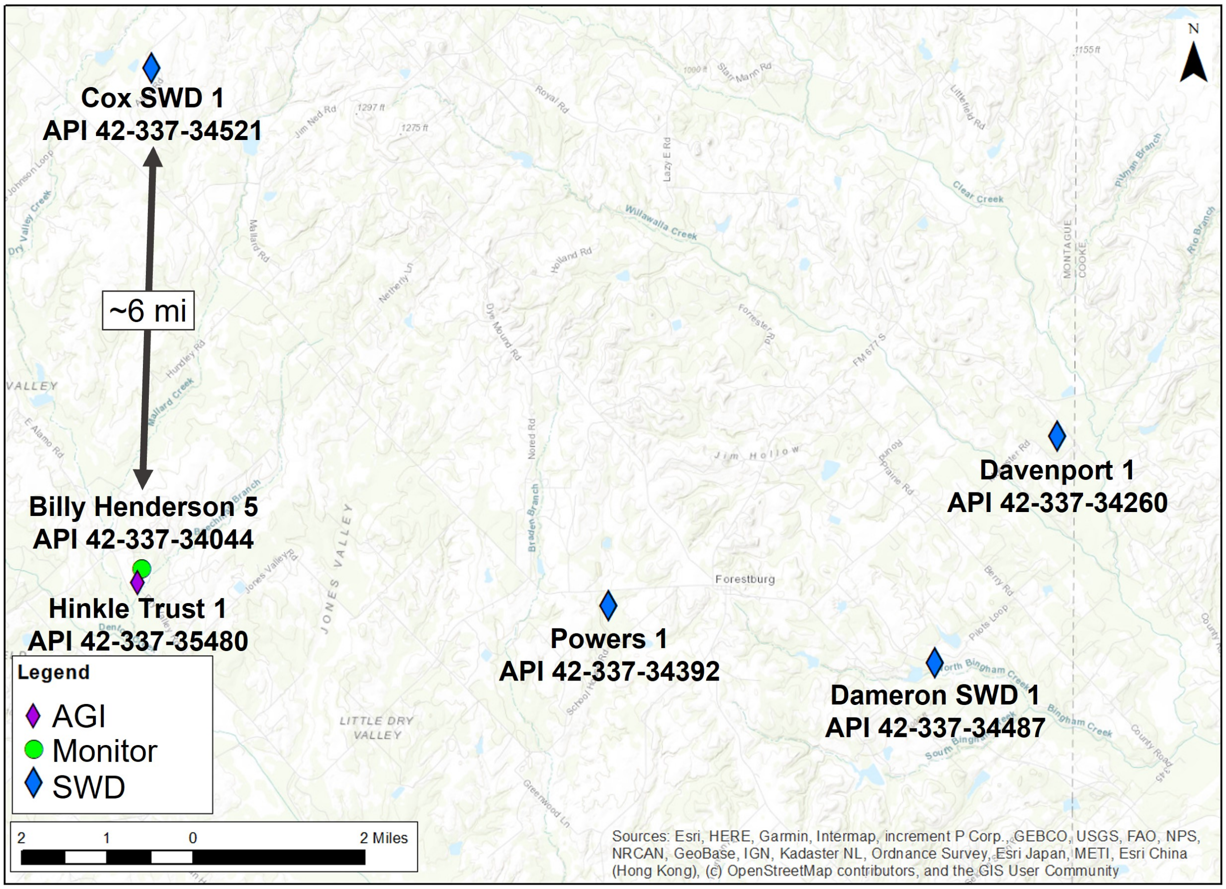

Figure 14: Map of SWD wells drilled into the middle Ellenburger in relation to the CO_2 injection project area.

Figure 15 shows the historical combined monthly injection rates and total cumulative volume injected from all four deep SWD wells from 2010 to 2022. What is notable in these injection trends are the very high rates from 2010 to 2014, when EOG's Barnett development was at its peak. During those years, the SWD wells were each injecting nearly 500,000 barrels (BBL) per month - indicating good injection characteristics in the middle Ellenburger. Over time, as development drilling and field production declined, so did the volume of produced water, which explains the tapering off in the use of the SWD wells from 2014 to 2022. During the entire active period, the four SWD wells injected nearly 90 MM BBL into the middle Ellenburger - suggestive of a large reservoir storage capacity. A relatively small amount of SWD injection is presently active in the Cox and Davenport wells at average rates of 4,200 and 3,700 BBL/day, respectively, with both wells showing stable and consistent injection pressure trends.

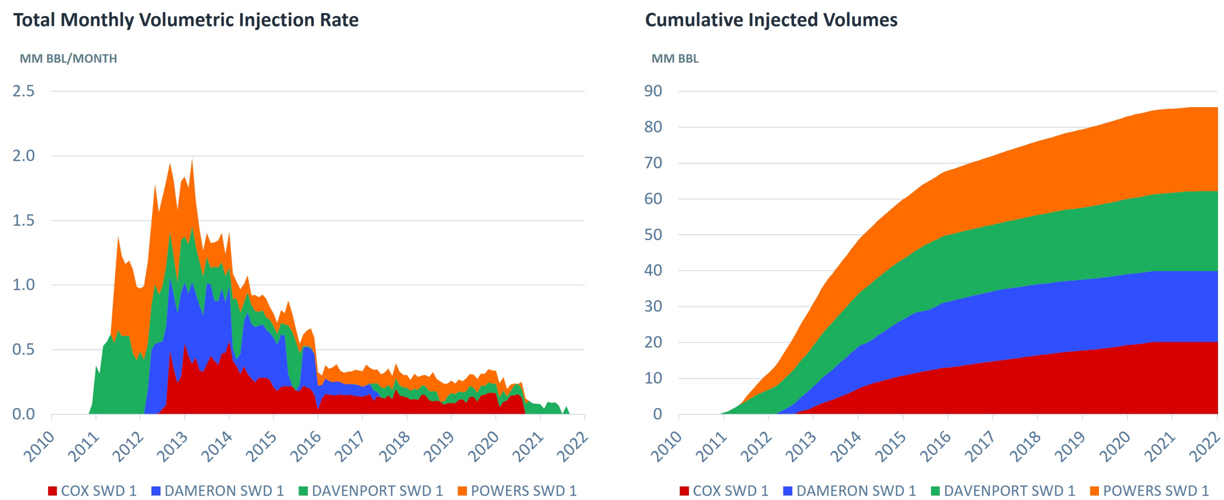

Figure 15: Combined monthly SWD injection rate (left) and cumulative injected water volumes (right) of deep Ellenburger SWD wells from 2010 to 2022.

2.7 Injection and Confining Zone Details

This section provides both quantitative and qualitative descriptions of the injection and confining zones. Observations presented are based on core, petrophysical well log, and 3D seismic data sets that have been integrated across appropriate scales. Petrophysical logs for the injection, upper confining, and lower confining zones were chosen to represent the character and thicknesses observed in the subsequent sections (Figures 16-18). Raw petrophysical logs are shown with the exception of a modeled lithology, which is calibrated to x-ray diffraction mineralogical measurements from core plugs. Core and seismic data are consistent with the characteristics exemplified by the petrophysical logs shown across the injection and confining zones.

2.7.1 Injection Zone

The injection zone for this project is the middle Ellenburger, which is a karsted carbonate reservoir. The injection zone is approximately one thousand feet thick in the project area. The lithology is primarily dolomite, with minor interbedded limestones (Figure 16). The limestones within the injection zone are nonporous and have low permeability based on log and core measurements. The dolomites within in the injection zone host the observed porosity and favorable permeability and range in texture from nonporous, overdolomitized to mesoscale vuggy sucrosic to karst breccias with significant macroscale pore networks. Pervasive dolomitization and karsting is associated with a shallow marine carbonate depositional setting and post-depositional sea level fluctuations allowing for formation of repeated unconformities and karst development across the section.

Qualitative and quantitative descriptive methods were tailored to capture relevant data across this range of textures. Multiscale core measurements and detailed borehole image log analyses were combined with traditional petrophysical modeling to provide the best quantitative interpretation of the injection section for modeling purposes. Matrix scale measurements were made using routine core analysis on plugs taken from a conventional core cut within the injection zone and from rotary sidewall cores collected off wireline in the Billy Henderson #5. These measurements illustrate the range in matrix porosity and permeability observed within the injection zone. Observed porosity and permeability ranges were less than 1% to over 15% and microdarcy to millidarcy, respectively (Table 3).

Matrix scale measurements were combined with methods more suited to measure porosity and permeability within mesoscale karst textures. Two methods were employed: full-diameter, whole core porosity and permeability mechanical measurements and high-resolution computed tomography (CT) scan digital modeling and measurements. A series of whole core porosity and permeability measurements were made on approximately 6-inch long pieces of whole (unslabbed) core sections. Samples were also CT-scanned and then the images were interpreted to create a 3D model of the pore network within the samples. The 3D digital model was then used to generate a set of high resolution poros-

ity curves for each sample. Quantitative data from these mesoscale measurements shows the wide range of values expected for this karst system (Table 4).

The permeabilities measured within the mesoscale to macroscale karst textures were observed to be significantly higher than that of the matrix rock. Interpretation of these observations combined with dynamic injection testing and flow allocation surveys suggests that fluid flow is significantly impacted by the presence or absence of these karst textures. Therefore, methods employed in the creation of a representative geomodel and reservoir simulation for the project incorporate all scales of measurement, which is discussed in detail in subsequent sections of this document.

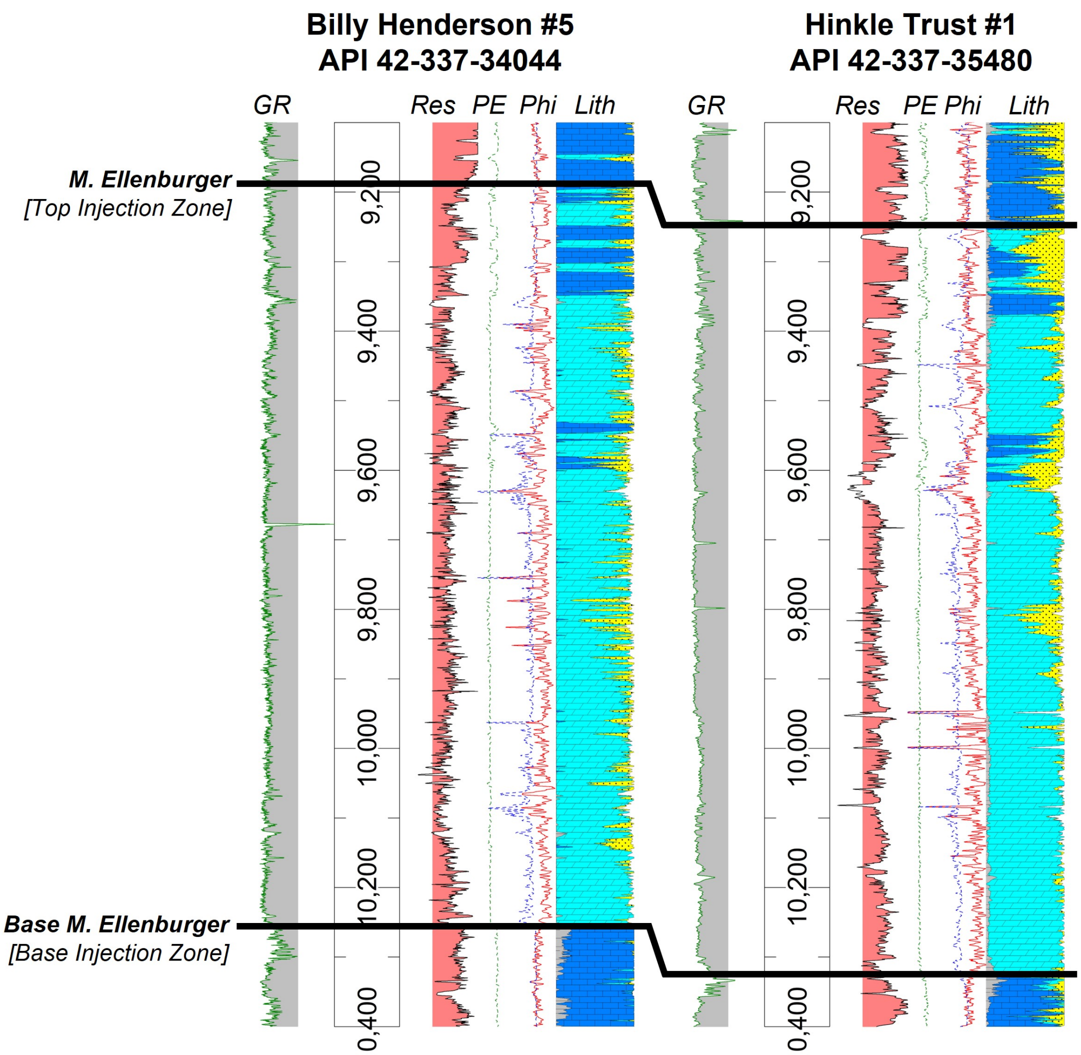

Figure 16: Petrophysical log interpretation in true vertical depth (TVD) for the Middle Ellenburger injection zone at the Bowie project site. Lithologic model presented includes dolomite (cyan), limestone (blue), silica (yellow), clay (gray), and organics (green).

2.7.2 Upper Confining Zone

The upper confining zone for this project is defined as the upper Ellenburger, Simpson, Viola, and base of Barnett shale. The upper confining zone is approximately 2,200 ft thick within the project site. A significant portion of the confining zone consists of sealing tight limestones and dolomites with varying amounts of clay and clay-rich shale. Other rock types present include variably-porous dolomites and limestones (Figure 17). The units within the upper

confining zone appear present and of similar thickness and character across the project site based on 3D seismic and well log interpretation.

The base of the upper Ellenburger consists of approximately 600 ft of mostly tight limestone with a few low porosity dolomite stringers directly overlying the injection zone. This contact is interpreted as a significant unconformity due to the sharp contrasts observed above and below the surface. Petrographic and petrophysical modeling of this zone indicates the presence of tightly-cemented, fine-grained mudstones and wackestones.

Above the lower blocky, tight limestone is interbedded tight limestone and variably porous dolomite. The interbedded lithologies and variable porosities observed are interpreted as coarsening upward depositional cycles with tight limestones at the base grading to variably porous dolomites that cap the cycles. Tight limestones here are similar to those observed in the base of the upper Ellenburger. Depositional textures within the dolomites are more difficult to ascertain due to dolomitization, but it is probable that some of these facies were coarser packstones and grainstones as well as muddier carbonate facies.

At the top of the upper Ellenburger, a blocky porous dolomite section is observed. The top of the Ellenburger likely represents another significant unconformity, but does not show the pervasive karst textures observed within the middle Ellenburger. Minor karst textures are observed, but most porosity in this part of the section seems to be associated with the matrix of the rock.

The Simpson formation is primarily limestone with minor to moderate clay content. It consists of an upper and lower section with higher clay content and a cleaner limestone facies in the middle of the section. Within the project area, the Simpson is approximately 400 ft thick. The upper and lower sections consist of fine-grained, muddy carbonate facies with varying amounts of fine-grained siliciclastics. The clean limestones contain coarser carbonate facies with minor preserved porosity. The Viola within the project area is approximately 180 ft of tight limestone. Observations from a nearby proprietary core just outside the project site suggest the Viola consists mainly of nonporous carbonate mudstones and wackestones within the project area.

At the top of the confining zone is the lower Barnett shale. The lower Barnett is the main hydrocarbon development horizon within the project site. As such, the main focus on the lower Barnett for confinement is restricted to the base of the section below the horizontally-drilled development target. The rock volume within the Barnett that has not been stimulated by hydraulic fracturing, however, likely contributes to confinement within the project area as well.

Matrix scale measurements were made using routine core analysis on plugs taken from several sources. Data for the upper Ellenburger and Simpson comes from plugs from a conventional core cut within the upper Ellenburger and from rotary sidewall cores collected via wireline in the Billy Henderson #5 well. Data for the Simpson and the Barnett come from plugs cut from analog cores near the project site. Quantitative measurements indicate the low porosity, low permeability nature of the pervasive sealing facies within the upper Ellenburger, Simpson, Viola, and lower Barnett shale (Table 3).

The quantitative data presented here were incorporated into the geomodel for the confining zone. In contrast to the injection zone, no pervasive karst textures were observed within the confining zone in the project area. Image log analysis and dynamic injection testing and surveys also indicate an apparent lack of karst features, as well as a lack of transmissive fractures and faults within the upper confining zone at the injection site. As such, the upper confining system as described above is expected to provide excellent long-term sealing capacity.

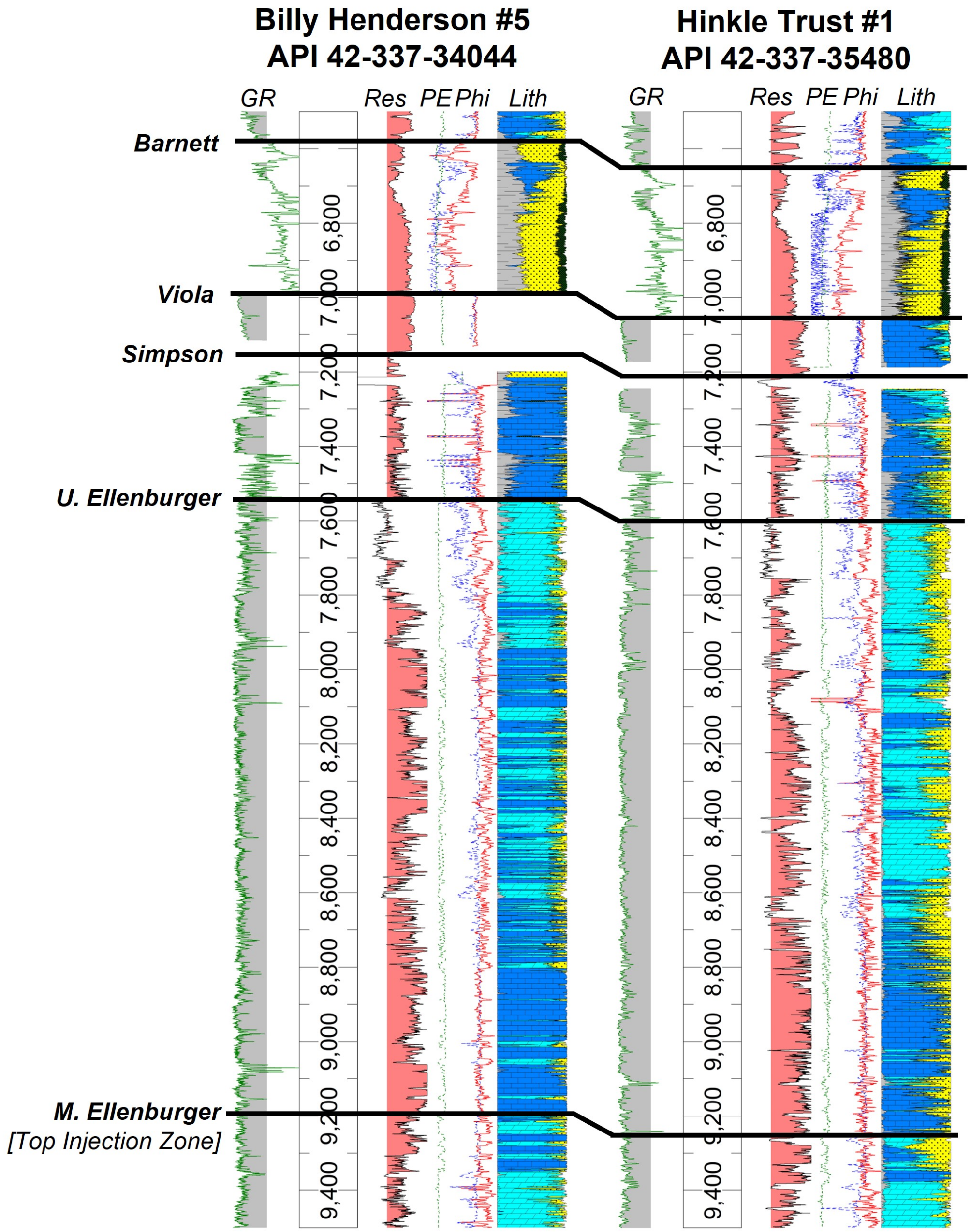

Figure 17: Petrophysical log interpretation in true vertical depth (TVD) for the upper Ellenburger to Barnett upper confining zone within the Bowie project site. Lithologic model presented includes dolomite (cyan), limestone (blue), silica (yellow), clay (gray), and organics (green).

2.7.3 Lower Confining Zone

The lower confining zone consists of the section between the granitic basement and the base of the middle Ellenburger injection zone. This zone consists of approximately 1,000 ft of primarily tight limestone with minor clay within the limestones and a few clay stringers in the project area (Figure 18). Petrographic analysis indicates the presence of heavily cemented limestone facies ranging from mudstones to packstones. A few porous limestone beds are preserved near the clay-rich stringers, but porous limestones are relatively rare across the entirety of the section.

Quantitative routine core analysis data confirms the presence of low porosity, low permeability limestone facies across much of the section. As with the upper confining zone, these matrix scale measurements were used in the geomodel and subsequent reservoir simulation for the lower confining zone. Image log analysis, dynamic injection testing, and injection surveys also indicate a lack of karst features within the lower confining zone, as well as an apparent lack of transmissive fractures and faults within the lower confining zone at the injection site.

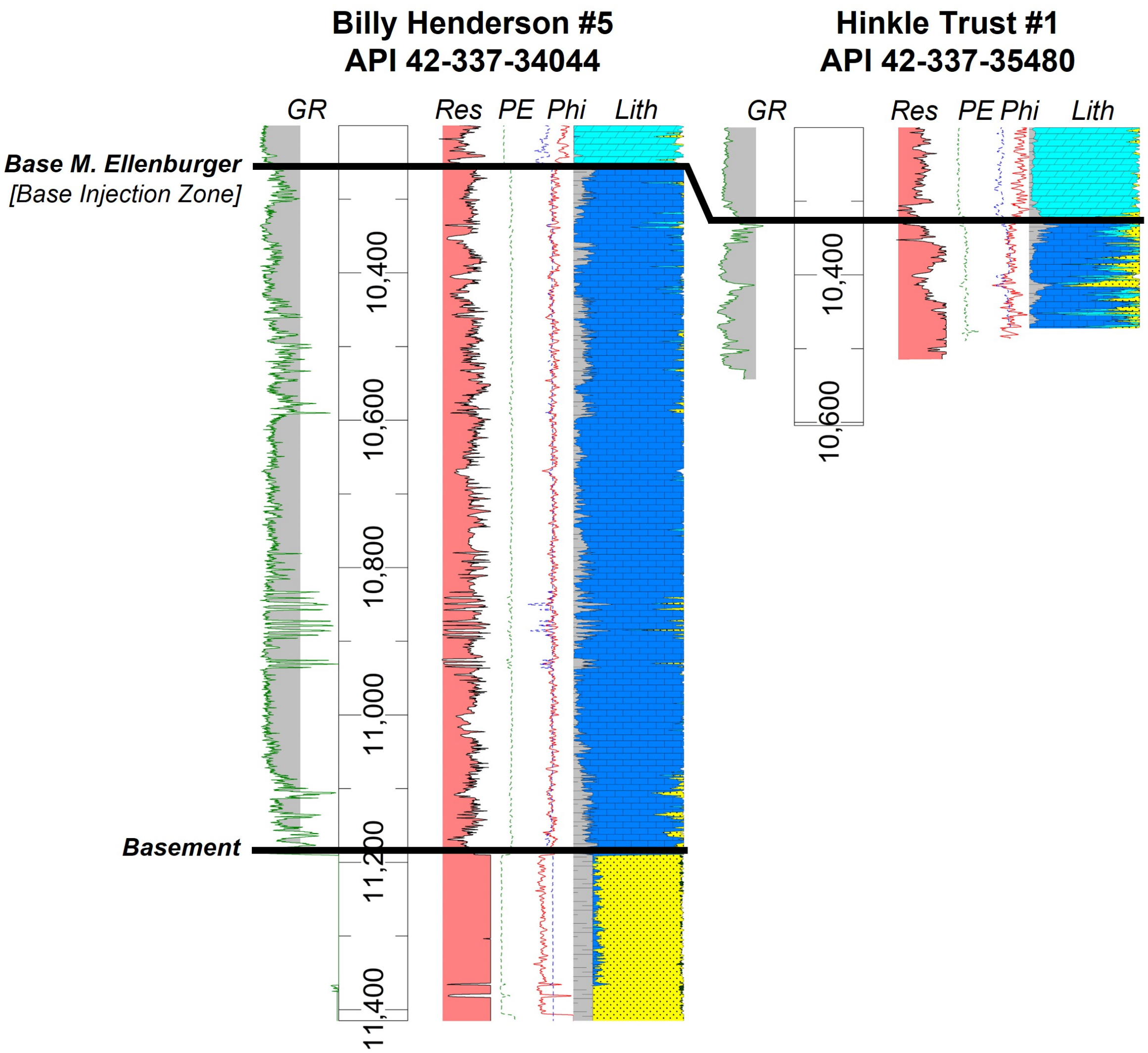

Figure 18: Petrophysical log interpretation in true vertical depth (TVD) for the base Ellenburger to middle Ellenburger lower confining zone within the Bowie project site. Lithologic model presented includes dolomite (cyan), limestone (blue), silica (yellow), clay (gray), and organics (green).

Table 3: Summary of routine core analysis (RCA) data collected for the project by system and formation.

System	Formation	Porosity Minimum %	Porosity Maximum %	Permeability Minimum md	Permeability Maximum md
Upper Confining	L. Barnett	1.29	8.29	3.02E-06[b]	7.24E-04[b]
	Viola	1.68	6.59	5.00E-04	1.60E-02
	Simpson	1.60	4.32	4.90E-03	6.34E-01
	U. Ellenburger	0.36	13.85	<1.00E-03[c]	5.58E00
Injection	M. Ellenburger	0.29	15.96	<1.00E-03[c]	1.68E00
Lower Confining	L. Carbonate	0.35	15.87	<1.00E-03[c]	9.40E00

[b]Denotes permeability measurements made using pressure decay methods.
[c]Denotes permeability values were below the measurement threshold of the routine core analysis technique. Therefore, the value presented represents an upper limit of minimum permeability. Minimum permeabilities could be significantly lower than the values presented.

Table 4: Summary of full diameter core mesoscale data over the injection interval collected for the project.

	Test Method	
Measurement	Full Diameter Mechanical	Computed Tomography (CT) Digital
Porosity Minimum (%)	2.2	<0.01
Porosity Maximum (%)	6.3	51.9
Horizontal Permeability Minimum (md)	6.96E-02	—
Horizontal Permeability Maximum (md)	1.86E04	—
Vertical Permeability Minimum (md)	1.64E-04	—
Vertical Permeability Maximum (md)	2.83E00	—
Ratio Vert./Horiz. Perm. (Minimum)	4.0E-07	—
Ratio Vert./Horiz. Perm. (Maximum)	7.5E-01	—
Ratio Vert./Horiz. Perm. (Median)	1.0E-03	—

3 Development and Administration of the MRV Plan

As required under §98.448(a)(1)-(2) of Subpart RR, the MRV plan is developed around and tailored to the potential surface leakage pathways within the active and maximum monitoring areas (AMA and MMA, respectively) defined in §98.449. Since the AMA and MMA are both dependent on the expected long-term behavior of CO_2 in the subsurface, numerical reservoir simulation is the generally-accepted best practice to represent the dynamic behavior and complex fluid interactions that influence the CO_2 plume extent and shape during and after injection operations. The next two sections describe the development of a detailed geologic model using the available regional and site-specific data that serves as the basis for predictive numerical reservoir simulations to delineate the AMA and MMA extents for the proposed injection volumes.

3.1 Geologic Model

A geologic model was developed with the proposed injection project at the approximate center of the gridded region. The general grid properties are summarized in Table 5 and the overall grid geometry and structure is depicted in Figure 19. Major stratigraphic surfaces - from the Lower Barnett through the upper Granitic Basement - and regional structure were interpreted from EOG's in-house 3D seismic data and depth-tied to well log correlations from the deep penetrations in the project area. Although faulting and fracturing is generally present within the proposed injection

area, injection testing and geomechanical modeling suggests faults and fractures are not primary permeability pathways. Consequently, they are not included in the initial simulation model. Grid layer thicknesses in the over- and under-burden horizons are generally coarse (ranging from 70 to more than 700 feet) since little change is expected in these regions, whereas the layers in the primary injection horizon (i.e., the middle Ellenburger) were selectively refined (ranging from 15 to ~50 feet) to capture the geologic heterogeneity that is likely to influence the CO_2 flow distribution within the storage reservoir.

Table 5: Summary of geologic model grid properties

	i-dir	**j-dir**	**k-dir**
Increment (ft)	200	200	variable
Layer Count	126	126	35
Total Length (ft)	26,200	26,200	~5,400
Total Cell Count		555,660	

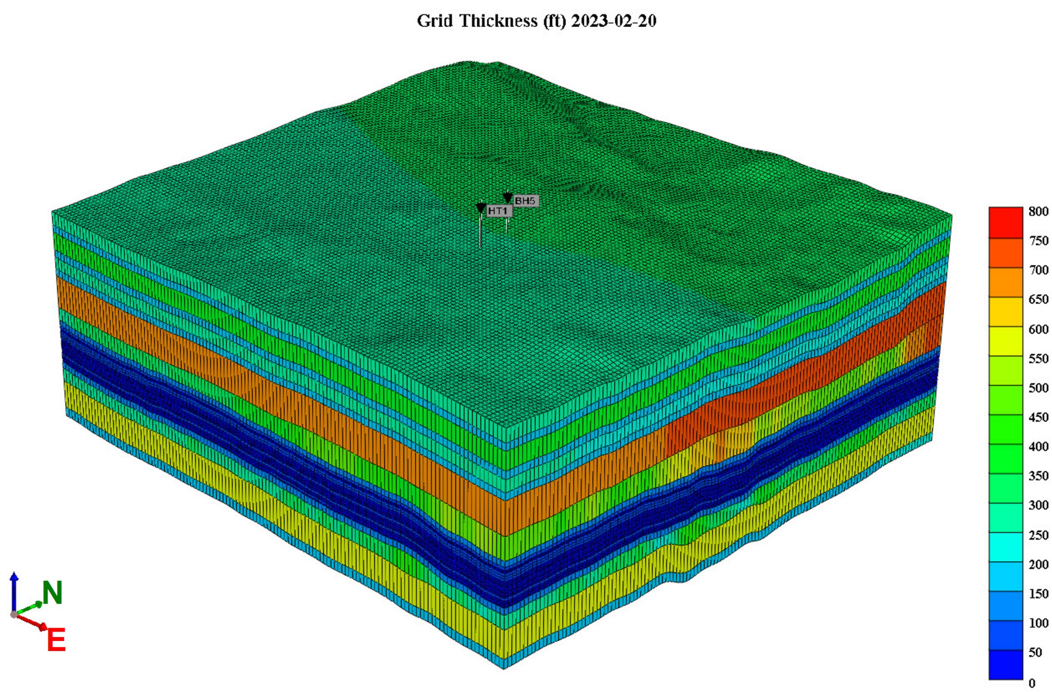

Figure 19: Northwest-looking 3D-view of the overall model grid structure; grid cell thickness property displayed.

Petrophysical transport properties (e.g., porosity and permeability) for each geologic horizon were subsequently propagated throughout the grid framework based on the rigorous integration and characterization of the core, log, and seismic data sets available in the project area (and described in the previous Section 2.7). The statistical range and spatial variability of all geologic intervals included in the model were considered in this multiscale analysis, with particular emphasis on representing the extreme heterogeneity observed in the karsted, dolomitized injection interval of the middle Ellenburger. The iterative property modeling workflow adopted for this project is summarized by the following general steps:

1. comparison and calibration of log response to measured core values (plug and full-diameter samples);

2. identification of key facies associated with injection/storage versus baffling/containment at well scale;

3. development of porosity-permeability transforms and net-to-gross (NTG) relationships for each facies type at well scale;
4. development of independent ties between well-scale porosity and NTG to seismic-scale attributes;
5. probabilistic spatial modeling of porosity and NTG via collocated co-kriging with associated seismic attributes;
6. calculation of permeability properties (i.e., vertical and horizontal) based on established porosity transforms for each geologic horizon.

Figure 20 depicts a representative layer from the resulting baseline realization of the geologic model which was used in the subsequent reservoir simulation forecasts. Of particular note is the heterogeneous nature in the spatial distribution of both the porosity and permeability properties in the middle Ellenburger, which is guided by amplitudes and patterns in the seismic data interpreted to be associated with large-scale karst features. The transport characteristics associated with these features are expected to have a first-order influence on the CO_2 plume growth over time and the workflow described above incorporates the available data - at the appropriate scales - to rigorously represent them in the model.

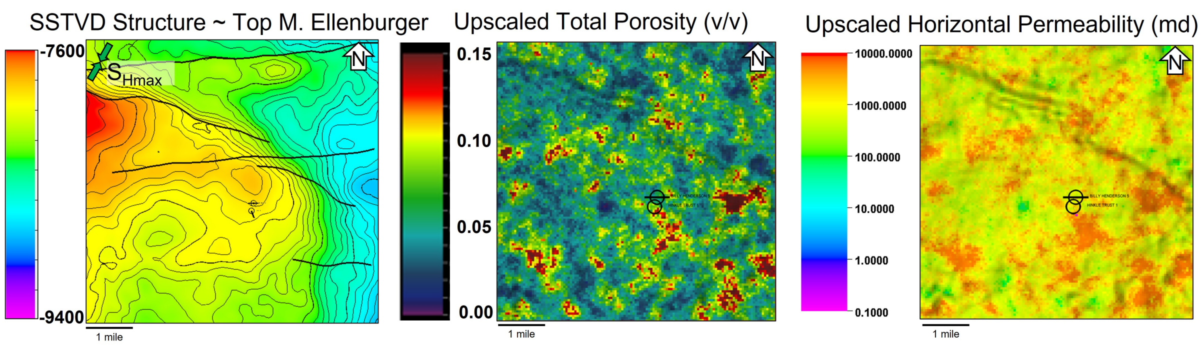

Figure 20: Example character of geomodel structural inputs in subsea true vertical depth (SSTVD) and property distributions (total porosity and horizontal permeability) within the middle Ellenburger storage zone. Note the varied distribution of high porosity and permeability representative of a karst reservoir.

Due to the limited availability of vertical permeability data in the project area, a simpler deterministic approach was taken to distribute vertical permeability throughout the model grid. For the main injection zone - the middle Ellenburger - the median value of the measured vertical-to-horizontal permeability ratios of 1.0E-03 was used (see Table 4). This choice captures the extremely heterogeneous nature of the injection interval, which is characterized by high permeability karst features interspersed with low porosity and very low permeability host rock. In the underlying and overlying confining zones, a vertical-to-horizontal permeability ratio of 1.0 was applied due to the more homogeneous nature of these intervals, which are characterized by low permeability matrix rock with little secondary enhancement.

3.2 Reservoir Simulation Model

With a representative static geologic model established, the grid and associated properties were then imported into Computer Modeling Group's (CMG) GEM v2022.30 compositional reservoir simulation software to forecast the long-term CO_2 plume behavior. GEM is a state-of-the-art finite difference solver which uses a compositional equation-of-state (EOS) methodology to represent the complex, multi-component thermodynamic interactions of fluid components during transport in porous media [Computer Modeling Group, LTD. (2021)]. As noted in other MRV plans recently approved by the EPA [Stakeholder Midstream Gas Services, LLC (2022)], GEM has become a generally-accepted software package for technical evaluation of geologic sequestration projects and is cited as such in the EPA's area of review guidance document for Class VI injection permits [US EPA (2013)].

Initialization of the reservoir model conditions was based on data acquired during the drilling and characterization of the project wells. Table 6 summarizes key inputs for the main injection interval in the middle Ellenburger, including

reference subsea true vertical depth (SSTVD), pressure, temperature, water saturation (S_w), and total dissolved solids (TDS) of the native formation brine in ppm. These data were obtained from wireline-conveyed dynamic testing and sampling tools deployed during logging operations on the Billy Henderson #5 and are representative of the reservoir throughout the project area. Pressure and temperature gradients were extended from the reference depth through all grid layers based on fluid density measurements and stabilized fiber-optic distributed temperature sensor (DTS) measurements, respectively.

Table 6: Basic middle Ellenburger reservoir conditions

Depth SSTVD ft	**Pressure** psia[a]	**Temperature** °F	**S_w** v/v[b]	**TDS** ppm
-9,275	4,993	195	1	211,961

[a]psia = pounds per square inch-absolute
[b]v/v = porous volume per unit bulk rock volume

Other key transport parameters and dynamic fluid processes for both the injection and confining horizons represented in the simulation include:

1. Drainage and imbibition capillary pressure functions for the CO_2-brine system derived from intrusion and extrusion mercury injection capillary pressure measurements (MICP) on core samples;
2. Porosity- and permeability-scaling of capillary pressure according to the Leverett J-function [Leverett (1941)];
3. Drainage and imbibition relative permeability functions calculated from the corresponding capillary pressure profiles;
4. Hysteresis trapping of the phases between drainage and imbibition cycles; and
5. Salinity concentration in the water (i.e., brine) phase and solubility between CO_2 and brine phases.

Before CO_2 injection forecast simulations were run, the model was rigorously history-matched to the water injection step-rate and pressure interference testing that was conducted between the Hinkle Trust #1 injection well and the Billy Henderson #5 monitoring well. Transient analysis of the pressure fall-off and interference test data revealed a single-porosity reservoir response with no apparent far-field boundary influence (i.e., an infinite-acting reservoir). In addition, pressure data obtained during the test from multiple gauges installed in both wells provided a robust data set against which to further calibrate and adjust the porosity, permeability, rock compressibility, and boundary conditions of the simulation model. This crucial step provides additional confidence in the simulated injection performance and long-term CO_2 plume development projections.

Another important constraint to consider when evaluating the simulated injection performance and long-term storage integrity is the fracture pressure of the injection and confining zones. As discussed later in section 3.5, the minimum horizontal stress gradient of the upper confining system was demonstrated via discrete micro-frac injection test to be 0.69 psi/ft, which equates to an absolute pressure of approximately ~5,500 psia at 7,980 ft - the TVD of the measurement. A continuous geomechanical earth model was subsequently constructed and calibrated to this measured data to assess the minimum horizontal stress profile in the injection zone, since it was impractical to initiate a fracture in this zone due to the extremely high permeability/injectivity. The resulting estimate of the minimum horizontal stress at the top of the injection zone (~9,350 ft TVD; see Figure 26) is approximately ~5,890 psia or an effective gradient of 0.63 psi/ft. Applying a 90% safety factor to that estimate yields an effective gradient of approximately ~0.57 psi/ft or 5,300 psia.

A base case injection forecast was run using the calibrated reservoir model and the proposed 12-year CO_2 volumes schedule in Figure 4. An additional 200 years of post-injection shut-in time was simulated to observe the long-term reservoir response and predict the stabilized extent and shape of the separate phase CO_2 plume after buoyant migration has ceased. Simulated bottom-hole pressure (BHP) at the Hinkle Trust #1 injection well and CO_2 saturation (S_g) maps at the top of the middle Ellenburger injection zone - for both the 12-year injection and 212-year total simulation periods - are shown in Figures 21 and 22, respectively. Of particular note in Figure 21 is the relatively low BHP increase above the initial static pressure of ~4,550 psia: at the maximum injection rate of ~10 MMSCFD, the BHP reaches a maximum value slightly above 4,610 psia or 60 psi above initial static conditions. This pressure increase is well below the safe operational threshold of 5,300 psia discussed above. Over the proposed 12-year injection schedule, the risk of over-pressurization in the injection zone decreases since the BHP gradually declines with the declining CO_2 injection rate. At the end of the 12-year injection period, the BHP drops to within 20 psi of initial static conditions instantly due to the high system permeability/injectivity of the middle Ellenburger. The period of pressure decline observed at the injection well through the year 2060 is a result of the natural decompression of the infinite-acting reservoir system in combination with the gradual buoyant equilibration of the compressible CO_2 plume.

Inspection of the CO_2 saturation maps (Figure 22) reveals the influence of reservoir heterogeneity and structure in the distribution, shape, and migrational path of the separate phase plume over time. After 12 years of CO_2 injection - or ~1.45 million MT-CO_2 injected - the plume takes on an amorphous elliptical shape that is ~9,000 ft in length and ~6,000 ft in width and roughly centered on the injection well. When comparing the example porosity and permeability distributions in the middle Ellenburger (Figure 20) and the 12-year CO_2 saturation map, similar patterns can be seen between the tortuous edges of the plume footprint and the high porosity/permeability regions where the CO_2 has found preferable pathways during injection. During the 200-year post-injection simulated period, geologic structure in the middle Ellenburger is observed to have more influence in the buoyant growth of the plume over time as evidenced by the expansion of the plume to the north (up structural dip) and the extension of a narrow “limb” of CO_2 to the west along a structural ridge in the middle of the grid. This ridge can be identified on the map of structural contours in the left panel of Figure 20. Overall the plume grows by roughly 33% during the 200-year post-injection simulated period and completely stabilizes around year 2225 (190 years after injection stops), showing no visible areal expansion thereafter.

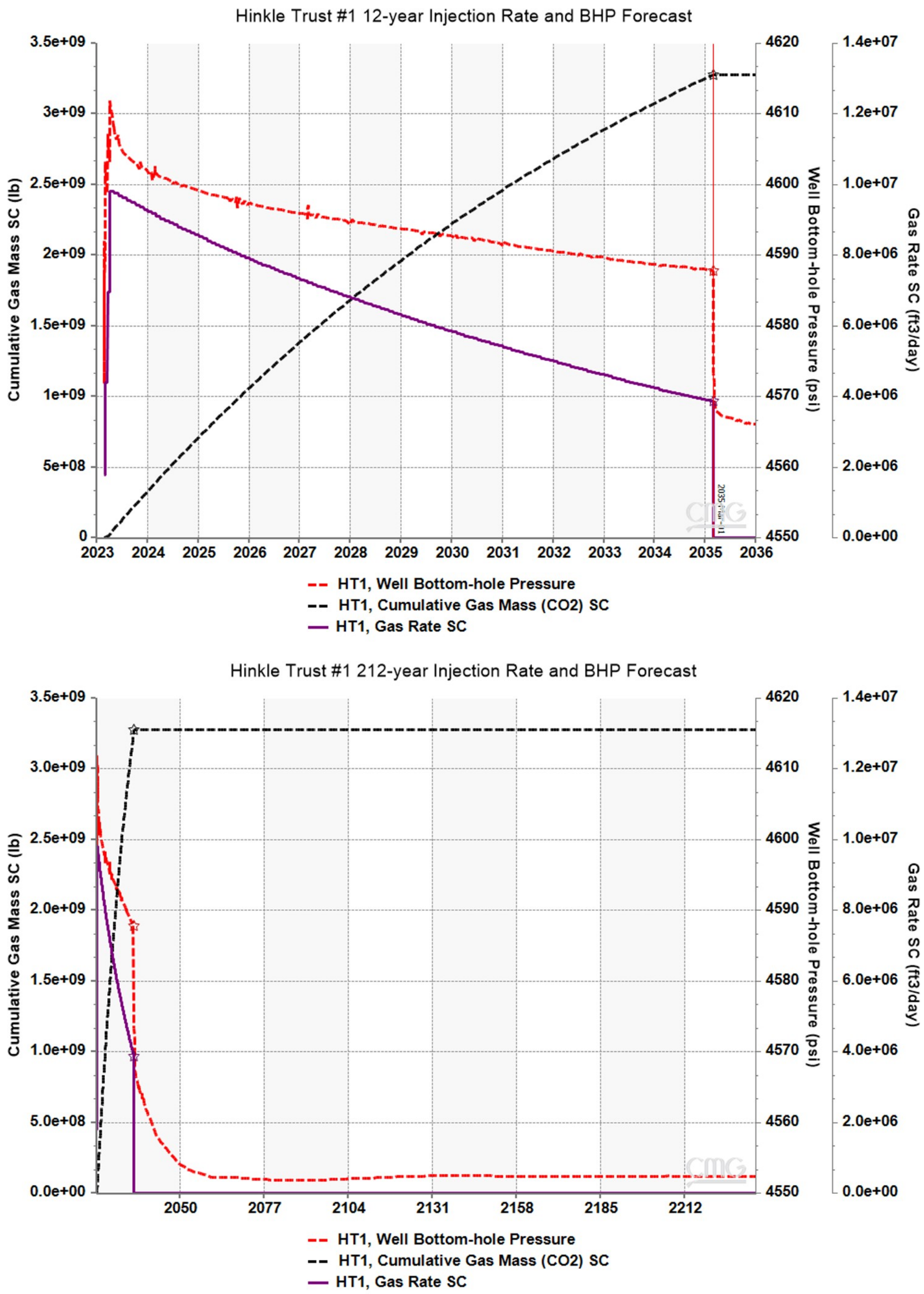

Figure 21: Modeled CO_2 rates, pressures, and cumulative volume for 12-year (top) and 212-year (bottom) time steps.

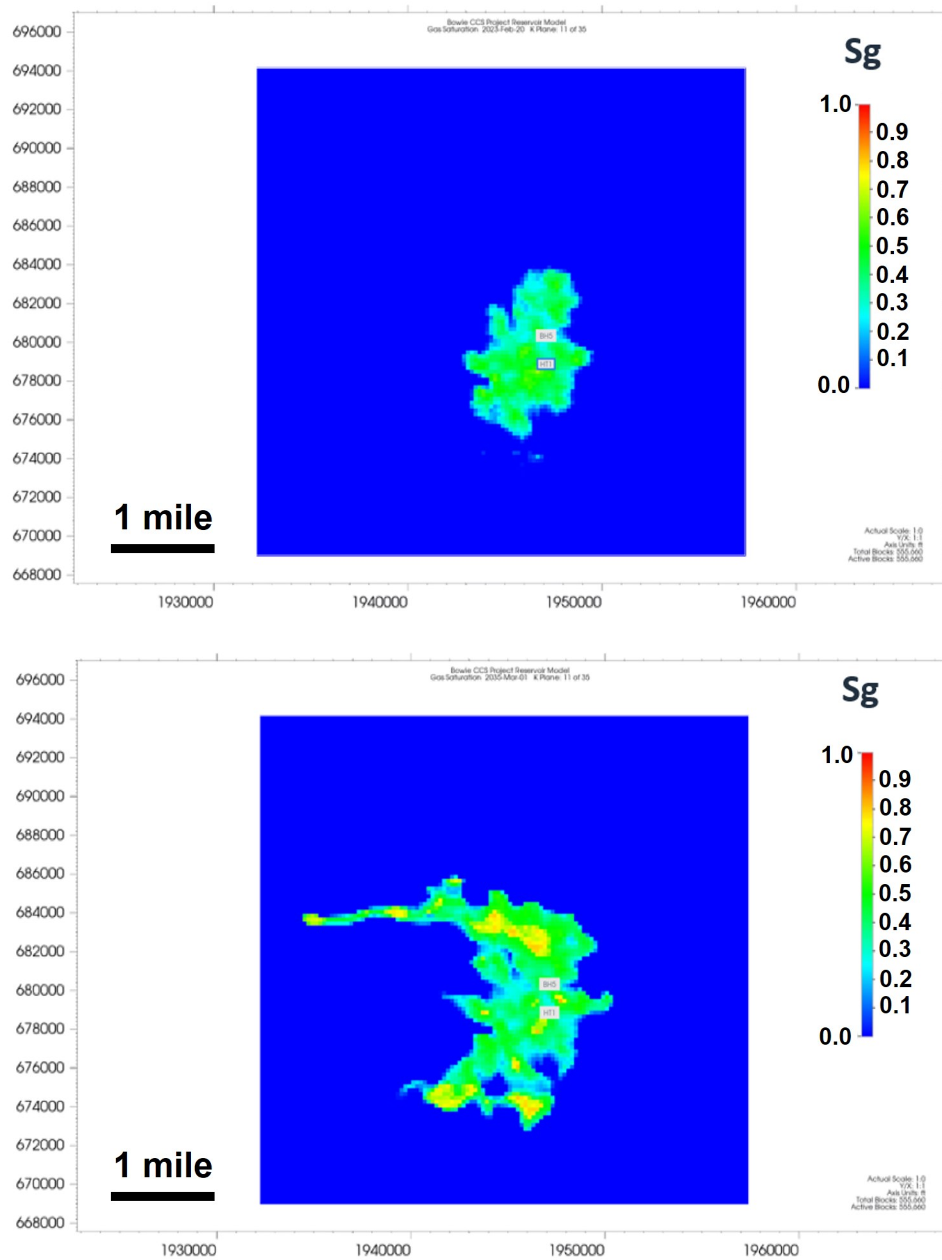

Figure 22: Modeled CO_2 saturation (S_g) distribution for 12-year (top) and 212-year (bottom) time steps. Note that the Hinkle Trust #1 injector is labeled "HT1" and Billy Henderson #5 monitor is labeled "BH5" on the saturation maps.

3.3 Maximum Monitoring Area (MMA)

In Subpart RR, the maximum monitoring area (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. Using a 3% CO_2 saturation threshold - the estimated saturation of gas breakthrough from mercury injection capillary pressure (MICP) measurements - the boundary of the stabilized, separate phase plume was determined from the simulation results in Figure 22. This boundary, plus the required half-mile buffer, is depicted in Figure 23 with the injection and monitoring wells for context.

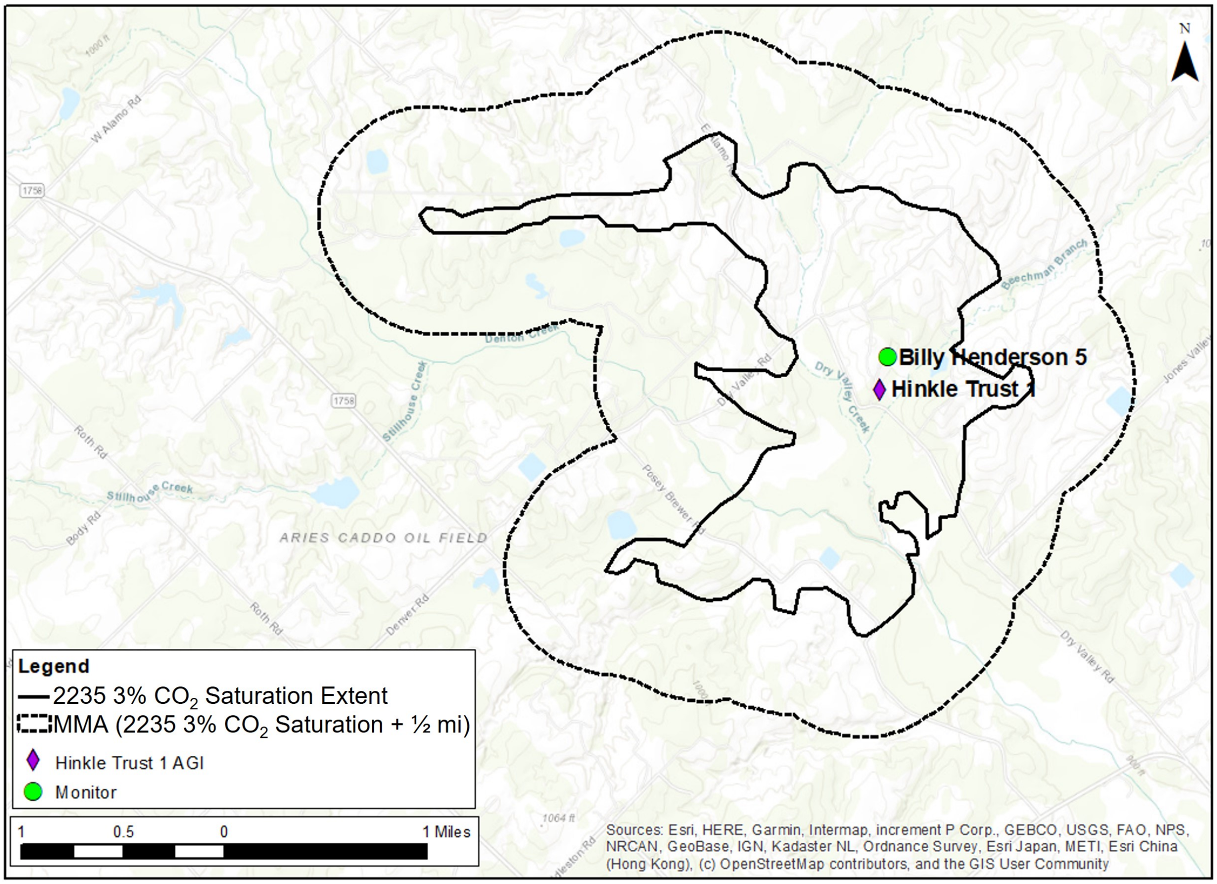

Figure 23: Maximum monitoring area for Bowie project.

3.4 Active Monitoring Area (AMA)

To define the active monitoring area (AMA), the initial monitoring period of 12 years was chosen based on the expected injection duration for the project. As a result, the separate phase CO_2 at the end of injection in year 2035 (i.e., “t”) - assuming the same 3% CO_2 saturation threshold - plus the required half-mile buffer was defined (blue dashed contour in Figure 24). Per the definition of the AMA in Subpart RR, this area was superimposed against the projected plume outline in the year 2040 (i.e.,“t + 5”) - the green outline in Figure 24. Since the green outline lies entirely within the blue dashed outline, the AMA is defined by the plume outline in the year 2035 plus the half-mile buffer.

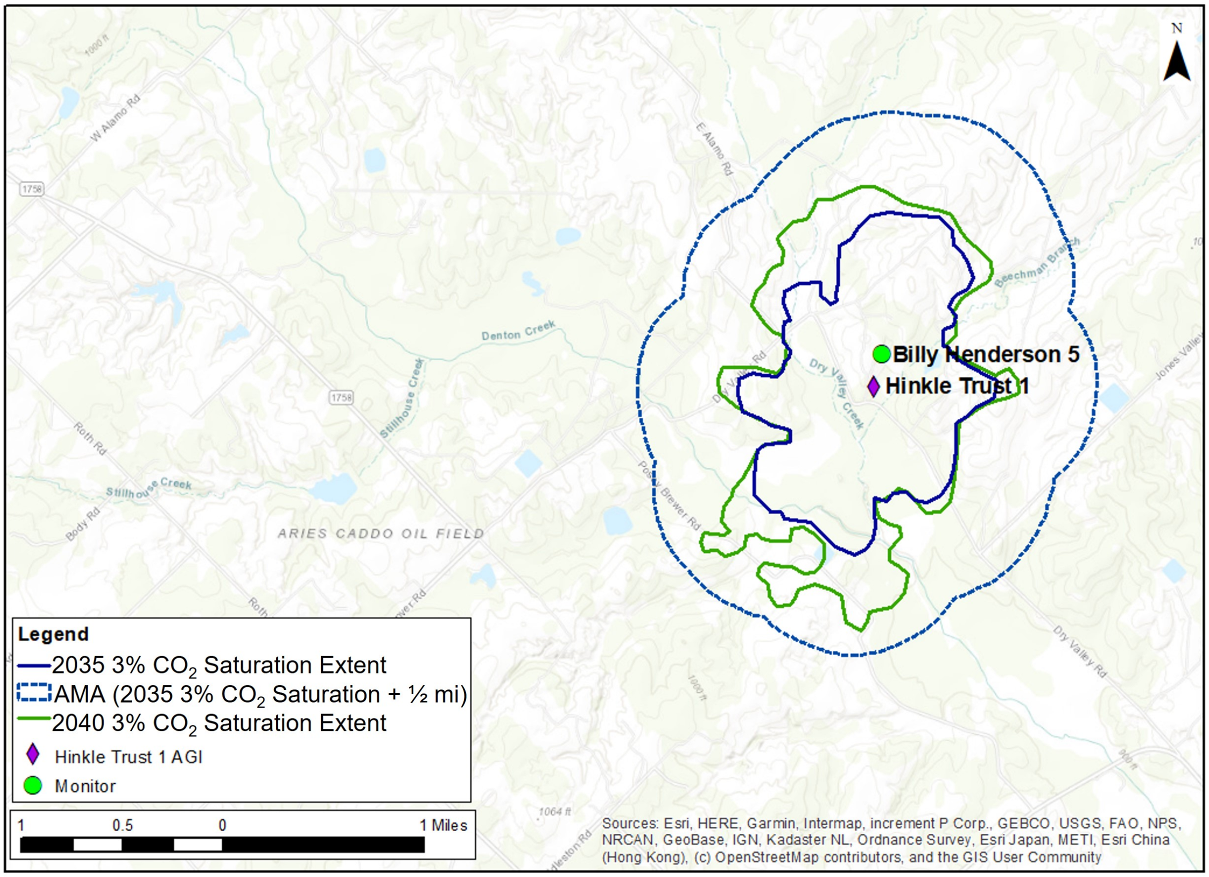

Figure 24: Active monitoring area for Bowie project.

3.5 Potential Surface Leakage Pathways

Per Subpart RR requirements, SPG has addressed the potential surface leakage pathways in the project area associated with surfaces facilities, faults and fractures, wellbores, and the confining system in a two-part approach. Part one de-risks the project site through various characterization methods, taking into account both static character and dynamic performance of the system through injection scenario modeling. This first part is addressed in the document subsections immediately below. Part two presents the required plan for detection, verification, and quantification of potential leaks and is addressed in subsection 3.6.

3.5.1 Surface Facilities

Leakage from surface facilities downstream of the injection meter is unlikely. The high pressure injection meter is placed near the high pressure compressor outlet and less than 210 ft upstream of the wellhead (Figure 3), minimizing potential leakage points between the metering of the stream and downhole injection point. Furthermore, the piping and flanges between the injection meter and the wellhead are Class 2500 rated by the American National Standards Institute and all welds are certified by x-ray inspection. If leakage from surface equipment is detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release in accordance with 40 CFR §98.448(5).

3.5.2 Wellbores

Dedicated Project Wellbores

The only wellbores that penetrate the injection zone in the AMA and MMA are those that were constructed specifically for this project. Both the Billy Henderson #5 and Hinkle Trust #1 were constructed 1) to mitigate leakage risks from CO_2 injection and 2) to provide for monitoring of near-wellbore conditions prior to, during, and after injection operations.

The Billy Henderson #5 monitor was designed to mitigate the risk of CO_2 migration out of the injection zone. A CO_2-resistant cement blend, EverCrete [SLB (2021)], was used to bond the long string casing in place. The top of cement sits above the top of the upper confining system defined for the project. In addition, pressure-temperature gauges and fiber monitoring instrumentation were installed across the injection zone (gauges and fiber), below the injection zone (fiber only) and above the injection zone (gauges and fiber) to allow for monitoring of pressure and temperature responses across the wellbore (Figure 25).

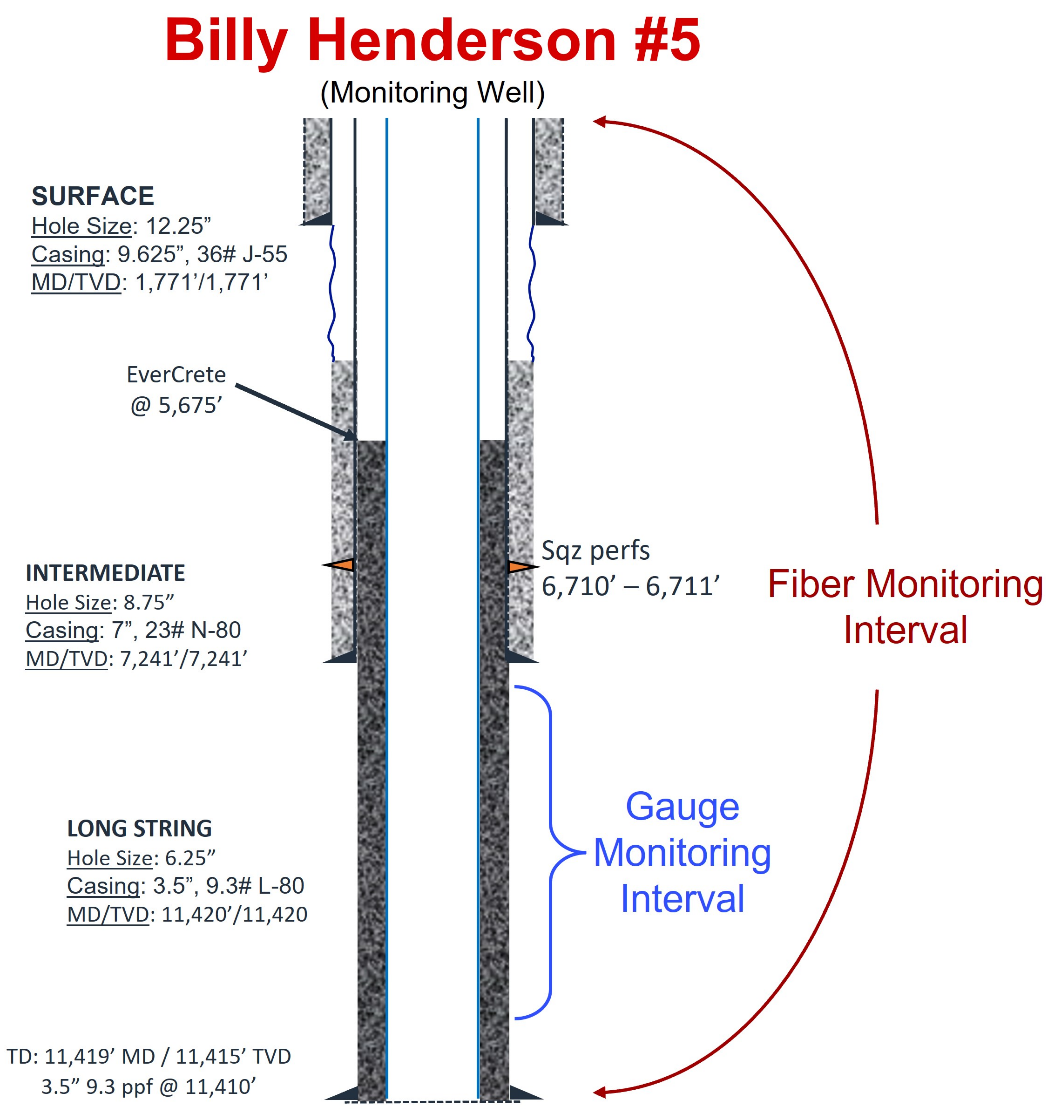

Figure 25: Billy Henderson #5 wellbore diagram.

The Hinkle Trust #1 injection well was also designed to mitigate the risk of CO_2 migration out of the injection zone. All strings of casing were cemented to surface and a CO_2-resistant resin product, WellLock [Halliburton (2017)], was used to cement the liner section of the long string casing sitting directly above the open hole injection interval. In addition, pressure-temperature gauges and fiber monitoring instrumentation were installed on the intermediate casing above the injection zone and on the injection tubing to allow for monitoring of pressure and temperature responses in the tubing, long string annular space, and above the injection zone (Figure 26).

Data from downhole instrumentation is collected and archived continuously across both wells. Aggradation and analysis of this data will allow SPG to quickly detect any leakage present within the wellbore. In addition, an annual mechanical integrity test (MIT) will be conducted in the injection well as prescribed in the Class II Underground Injection Control (UIC) permit (see Appendix A). The first MIT has already been conducted during the initial completion of the well. If leakage is detected, EOG will use the recorded operating conditions at the time of the leak to estimate the volume of CO_2 released and then take appropriate corrective action.

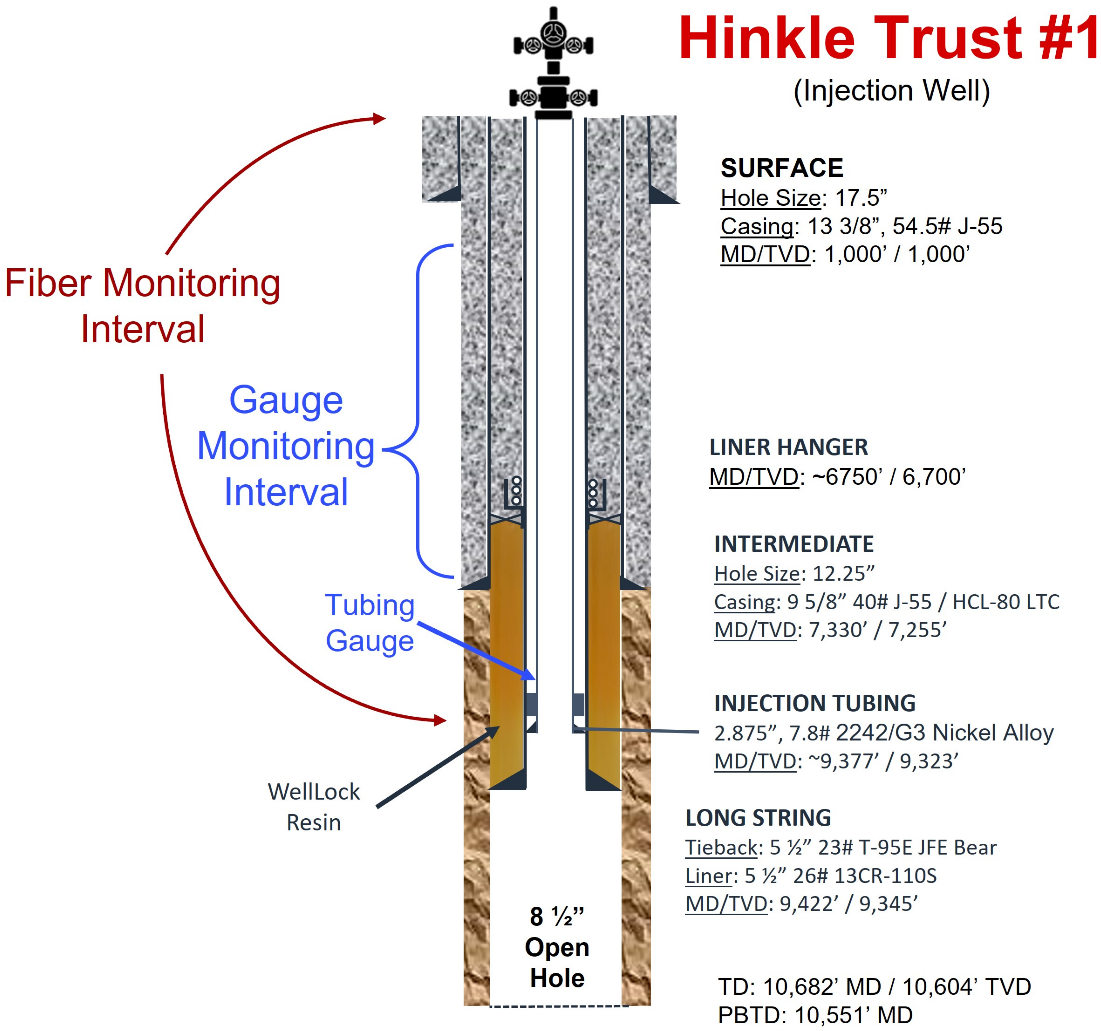

Figure 26: Hinkle Trust #1 wellbore diagram.

Other Existing and Potential Future Wellbores

There are additional wellbores present in the AMA and MMA, but they do not penetrate the injection zone. Texas Railroad Commission records, including completion reports, well plugging reports, drilling permits, and injection permits, as well as any available digital and raster log data, were analyzed for these wells. Table 7 and Figure 27 provide a high-level summary of the existing wells and location permits within or intersecting the MMA, with a more detailed tabulation of the records provided in Appendix C.

Table 7: Summary of existing wells within the MMA.

Entity	Quantity
Total well- or permit-level records analyzed	125
Plugged wells	54
Open (non-plugged) wells	56
Expired permits	14
Active permits	1

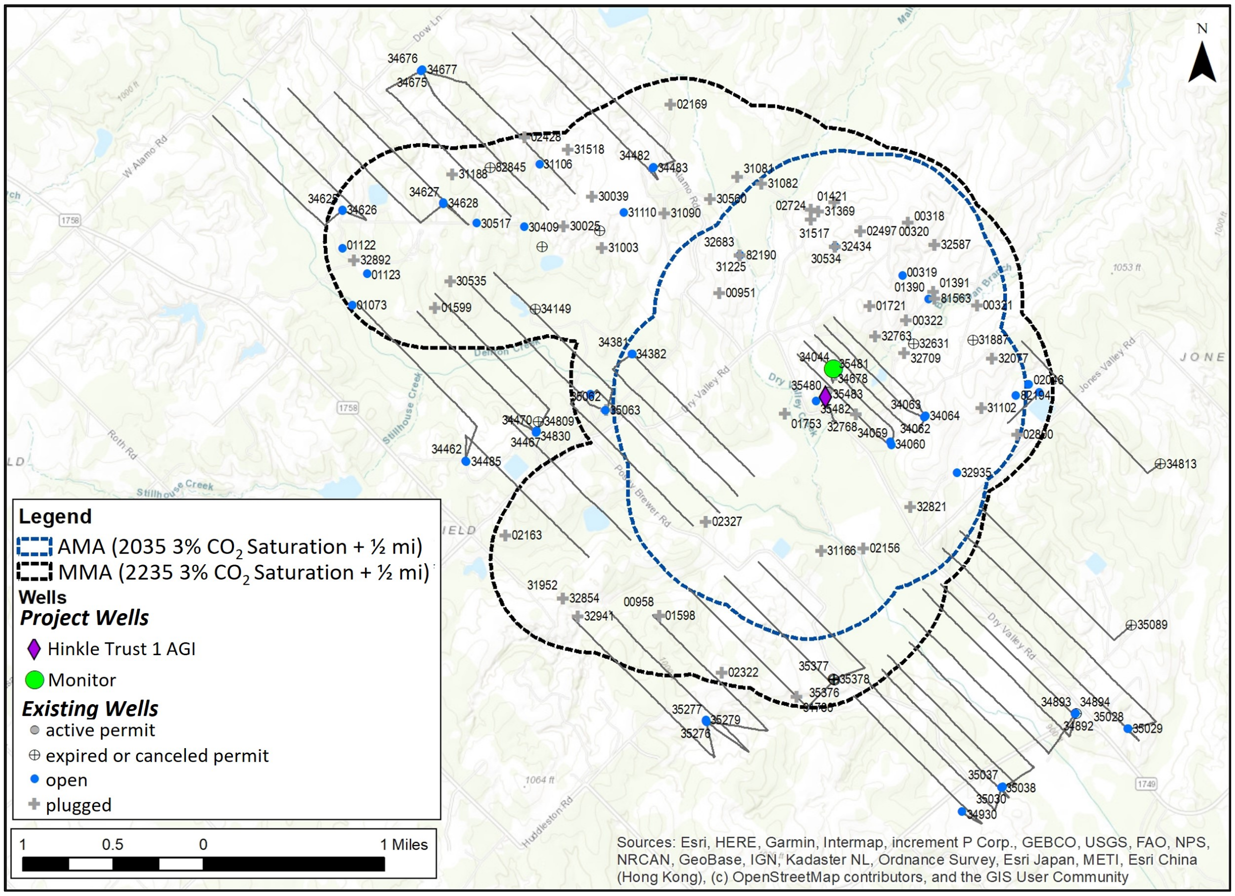

Figure 27: Existing wells and all previously permitted locations within the AMA and MMA symbolized by well and permit status.

Figure 28 shows the distribution of existing well maximum true vertical depth and Figure 29 shows the distribution of vertical separation in feet between the existing wellbores and top of the injection zone within the MMA. The minimum vertical separation between the injection zone and any overlying well within the MMA is over 1,400 feet. The majority of existing wellbores are 2,000 to 3,500 feet above the middle Ellenburger injection zone.

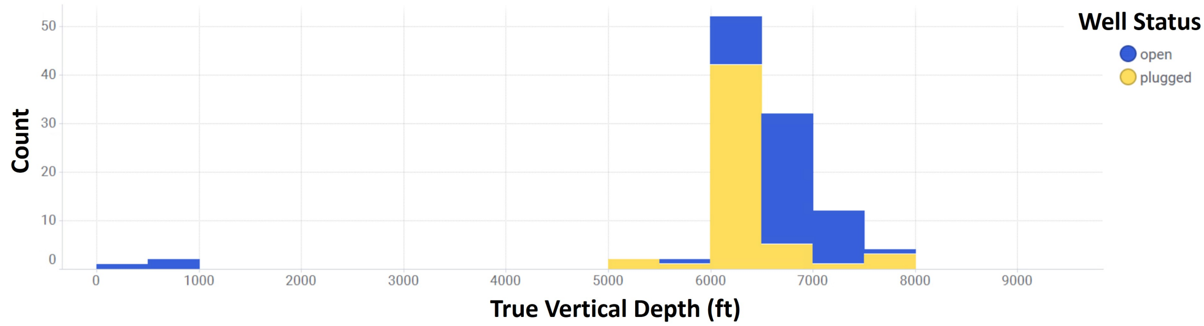

Figure 28: Distribution of maximum true vertical depth of existing wells in the MMA. Data is binned in 500 foot intervals.

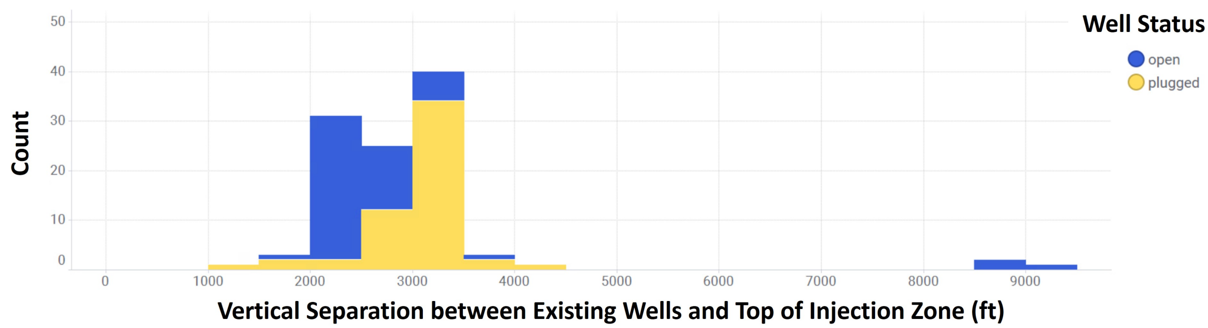

Figure 29: Distribution of vertical separation between maximum true vertical depth of existing wells and the top of the injection zone in the MMA. Seismic structure mapping was used to constrain the top of the injection zone. Data is binned in 500 foot intervals.

With regard to future drilling in the MMA, SPG does not anticipate new wellbores to penetrate the injection zone as the formation does not contain commercial hydrocarbon accumulations within the vicinity of the project site. This was one of the key criteria for siting the project in this area. In addition, the single existing active permit within the MMA is currently permitted to 675 feet total depth, which if drilled, would be over 8,000 feet above the injection zone.

If new wells were to be permitted and drilled within one-quarter mile of the Hinkle Trust #1 injection well, operators would be subject to TXRRC Rule 13 compliance on wellbore construction since the Ellenburger is identified in the drilling permit as one of the formations requiring such compliance (see Appendix B). Rule 13 requires operators to set steel casing and cement across and above all formations permitted for injection (under TXRRC Rules 9 or 46) as well as across and above all zones with the potential for flow or containing corrosive formation fluids [Texas Administrative Code (2023)]. Furthermore, SPG intends to monitor permitting activity across the entire project area on a quarterly basis and take appropriate action if any proposed wells present a potential risk for leakage within the MMA. In the case that any new wells are drilled within the MMA and create a material change to the surface leakage risk, the MRV plan would be updated to reflect this change and the potential risk for leakage presented by these wells would be evaluated based on the most current operational and monitoring data. Any additional monitoring activities deemed necessary to enhance the surveillance in the areas of these new wells would also be included in an updated version of the MRV plan at that time.

In summary, the potential for surface leakage through existing or future wells in the project area is highly unlikely. However, if it were suspected that CO_2 had migrated from the primary injection zone and was leaking into an existing or future wellbore within the MMA, SPG would first estimate the likelihood of the proposed leak against the latest operational data, monitoring data, and reservoir simulation projections. If these data and interpretations confirm the potential relationship between the Bowie injection project and the leak, SPG would then coordinate efforts with the owner(s) of the well to 1) characterize the change in gas composition against historical baselines (if available); 2) estimate the point in time when the composition changed from the historical baseline; 3) measure the approximate flow rate associated with the leak (if possible); 4) quantify the incremental CO_2 mass associated with this leakage pathway over the effective time period; and 5) develop and implement an appropriate wellbore remediation design and a supplementary monitoring program to ensure the leak has been permanently eliminated. Any CO_2 mass associated with this unlikely leakage scenario would be noted in the annual monitoring report and reflected in the total mass of CO_2 sequestered per the procedure documented in Section 3.8.5.

3.5.3 Faults and Fractures

The Ellenburger and underlying basement at the injection site are characterized by large scale strike-slip faults and prevalent natural fracturing. The propensity for each of these characteristics to serve as surface leakage pathways is discussed below.

To assess the risk of leakage through faults, a Fault Slip Potential (FSP) analysis [Walsh et al. (2017)] was performed on large-scale basement-rooted faults traversing the proposed injection area and interval. The FSP analysis probabilistically evaluates the likelihood of excess pressure generated by fluid injection to trigger shear slip on pre-existing faults. As faults which are able to slip in shear in the present-day stress field with minor excess pressure (critically-stressed) tend to be those which are hydraulically-conductive [Barton et al. (1995)], the FSP analysis simultaneously assesses both induced seismicity and fault leakage likelihood. The FSP analysis includes faults mapped from 3D seismic data, directly measured reservoir and fluid properties from logs and core, and the planned CO_2 injection schedule. FSP results are shown in Figure 30, and indicate all major faults within the planned injection area and interval exhibit a very low (<10%) fault slip likelihood over the CO_2 injection timeline. In other words, the major faults are not critically-stressed in the present-day stress field and are, therefore, not expected to be hydraulically-conductive leakage pathways during CO_2 injection. Nevertheless, downhole pressure instruments installed in the project wells (described in the previous section) will be continuously monitored via the project's real-time data acquisition system. Appropriate alarms and operational set points for surface equipment will be established to ensure that downhole conditions do not exceed the safety thresholds which could potentially trigger a fault-slip event in the most conservative case.

Only one earthquake in Montague County has been recorded in the last 100 years [U.S. Geological Survey (2023)] despite significant SWD injection within the Ellenburger. The FSP results are consistent with generally stable fault behavior in larger Montague County - and within the proposed injection area - as evident by the lack of detectable seismicity despite the presence of numerous Ellenburger SWD injection wells within the county (Figure 31).

Cross-fault leakage is also unlikely due to fault sense-of-slip and displacement. The dominant strike-slip sense of motion on major faults in the area decreases the likelihood of vertically juxtaposing injection intervals with containment intervals. In addition, cross-fault leakage is also likely inhibited by development of a thick, a low-permeability fault core due to significant fault displacement [Torabi et al. (2019), Caine et al. (1996)].

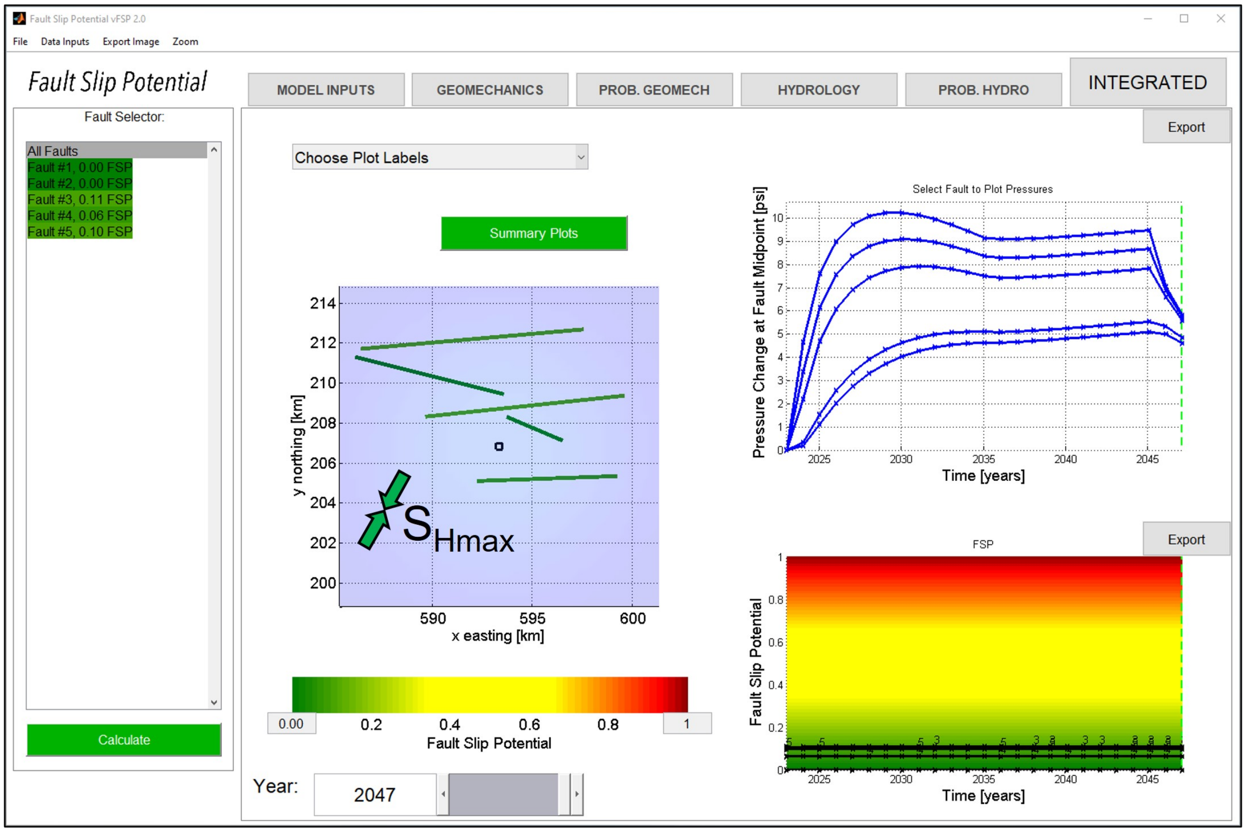

Figure 30: Fault slip potential analysis results.

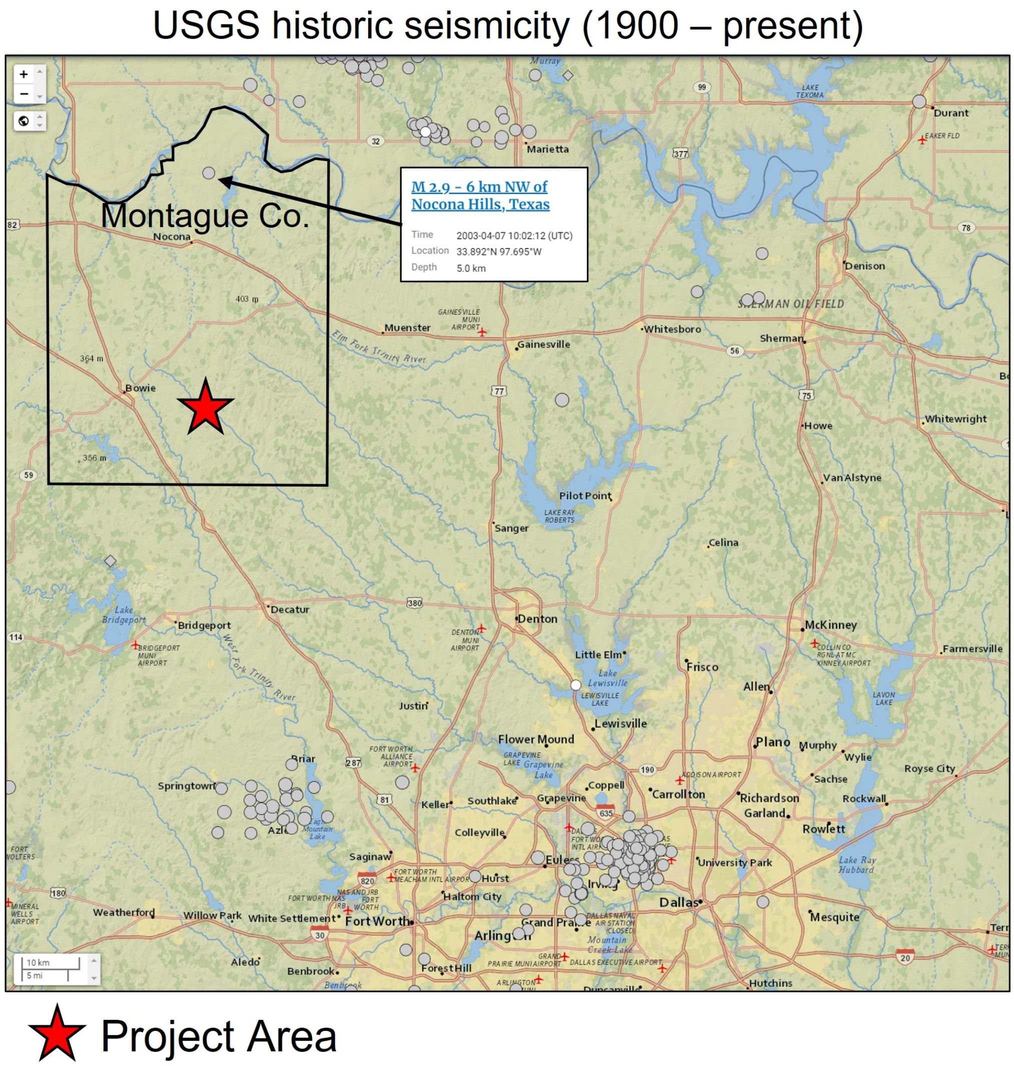

Figure 31: Historical records of regional seismicity from the United States Geological Survey (USGS).

To assess potential fracture leakage, fracture characteristics (orientation, density) as inferred from wellbore image logs in the proposed injection well are compared with various indicators of fluid conductivity (e.g., temperature anomalies, injection testing) in the proposed injection well. Natural fracture orientation and density do not correlate with either temperature reductions or primary permeability pathways inferred from injection testing, suggesting natural fractures are not the dominant transport (i.e., permeability) mechanisms within the injection interval (Figure 32) and therefore pose minor leakage risk.

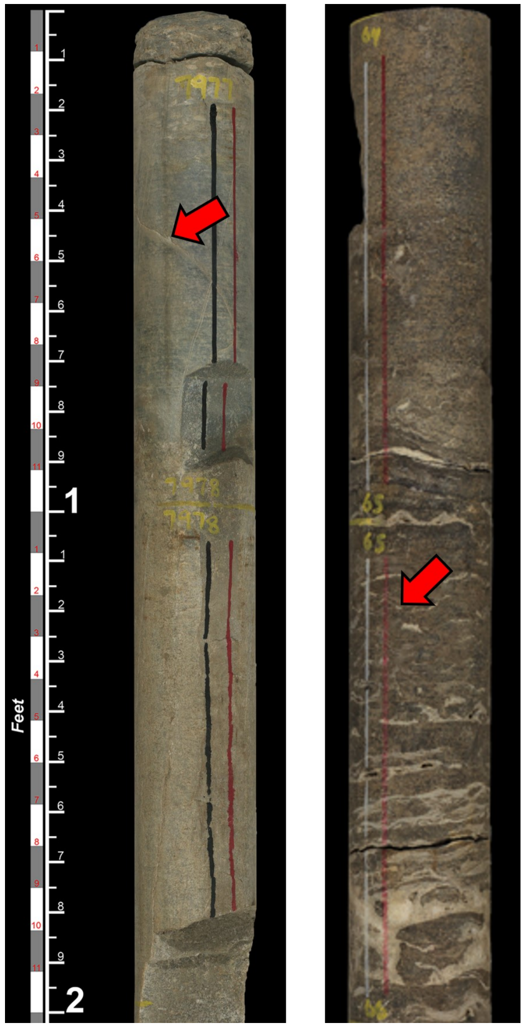

Figure 32: Representative whole core examples of confining (left) and injection (right) zones illustrating natural fractures (generally cemented, red arrows).

3.5.4 Confining System

To assess potential leakage from an excess pressure (i.e., hydraulic fracturing) perspective, injection tests to measure pore pressure and the minimum horizontal stress (S_{hmin}) were conducted in the overlying seal interval. The tests yielded a pore pressure estimate of 0.49 psi/ft and S_{hmin} estimate of 0.69 psi/ft, or roughly 4,900 psi and 6,900 psi bottomhole, respectively, when extrapolated to the injection interval around 10,000 ft TVD. Thus, ~2,000 psi downhole excess pressure is required to generate and propagate hydraulic fractures. Plume injection modeling and offset Ellenburger SWD injection data all indicate maximum bottomhole pressure buildups on the order of 10s of psi for comparable injection volumes and rates - nearly two orders of magnitude lower than would be required to generate a hydraulic fracture. CO_2 leakage through hydraulic fracture generation/propagation is therefore highly unlikely. Furthermore, as CO_2 is anticipated to be the buoyant phase relative to the *in situ* brine within the Ellenburger injection interval, CO_2 migration and excess pressure buildup downward toward the lower confining and basement intervals is not anticipated.

With regard to the risk of diffuse displacement of fluids from the injection zone through the confining system, the 2,200 foot-thick geologic sequence including the upper Ellenburger, Simpson, Viola, and lower Barnett shale (as discussed in section 2.7.2) is expected to provide excellent long-term containment. This general assessment is attributable to 1) the low matrix porosities and permeabilities measured in core samples taken throughout this interval (Table 3); 2) the lack of pervasive karsting or conductive fractures observed in core and image log data; and 3) the absence of flow observed

in this interval during dynamic injection testing and surveys conducted in the project wells. Furthermore, results from reservoir simulation of the proposed injection volumes show no appreciable pressure change or fluid migration in the model layers immediately above the middle Ellenburger injection zone. Thus, surface leakage through the confining system is expected to be extremely unlikely.

3.6 Detection, Verification, and Quantification of Potential Leaks

This subsection addresses the detection, verification and quantification of potential leaks associated with surfaces facilities, faults and fractures, wellbores, and the confining system.

3.6.1 Detection of Leaks

Table 8 summarizes the methods and procedures SPG plans to employ to detect potential leaks across the various potential pathways previously discussed.

Table 8: Leakage detection methodologies to be employed for the Bowie Project.

Leakage Pathway	Monitoring Activity	Frequency	Coverage
Surface facilities	Wellhead pressure monitoring	Continuous	Flowmeter to injection wellhead
	Visual inspection	Weekly	
	Personal H_2S monitors	Weekly	
In-Zone Wellbores	P/T* gauges & fiber on casing/tubing	Continuous	Surface through injection zone
	Annulus pressure monitoring	Continuous	
	Integrity testing (MIT) per Class II permit	Yearly	
	Periodic corrosion monitoring surveys	Yearly	
Faults/fractures	Pressure monitoring	Continuous	Project site/plume extent
	Pressure transient analysis	Yearly	
Confining system	Pressure monitoring	Continuous	Project site/plume extent
	P/T gauges & fiber on casing	Continuous	
	Pressure transient analysis	Yearly	
	Time-lapse saturation surveys	Yearly	

*P/T = Pressure and temperature

3.6.2 Verification of Leaks

If the detection methods described above indicate a leak through one of the potential leakage pathways, SPG would take the actions summarized in Table 9 to verify its presence or confirm a potential “false positive”.

Table 9: Leakage verification actions to be taken for the Bowie Project.

Leakage Pathway	**Verification Action**
Surface facilities	Auditory, Visual, and Olfactory (AVO) Inspection
	Forward Looking Infrared (FLIR) camera inspection
	Enhanced gas monitoring
In-Zone Wellbores	Validation of calibration & functionality of downhole sensors
	Deployment of additional wireline sensors
	Additional saturation logging survey
	Additional MIT and corrosion logging survey
Faults/fractures	Extended pressure transient analysis
	Additional saturation logging survey
	Enhanced surveillance on nearby wells operated by EOG
Confining system	Validation of calibration & functionality of downhole sensors
	Deployment of additional wireline sensors
	Additional saturation logging survey
	Extended pressure transient analysis
	Enhanced surveillance on nearby wells operated by EOG

3.6.3 Quantification of Leaks

If leakage through one of the identified pathways is verified, SPG would implement the methodologies summarized in Table 10 in an effort to quantify the mass of CO_2 that has leaked to shallow aquifers or to the surface. Because CO_2 leakage through several of the pathways cannot be directly measured or visualized but must be indirectly inferred, reservoir simulation will likely be an essential tool to quantify the magnitude of the leak in those cases. For example, while the precise pathway of a CO_2 leak may not be known, it may be possible to measure the pressure or saturation change created along the leakage pathway in the subsurface (e.g., the Billy Henderson #5 monitoring well or a nearby production well operated by EOG). Through the iterative history matching process, it is possible to replicate the observed subsurface response by invoking some potential leakage mechanism(s) in the reservoir model. The resulting volume or mass of CO_2 that yields the best match to the observed data is likely to be a reasonable estimate of the magnitude of the leak. Furthermore, by considering several different plausible leakage cases with the model, the magnitude of the leak can be quantified across a range of potential outcomes. Due to the non-unique nature of numerical simulations, however, SPG will also consider conducting additional appropriate geophysical imaging surveys or drilling additional monitoring wells in strategic locations to further constrain and refine the leakage quantification estimates yielded by the models.

Table 10: Leakage quantification methodologies for the Bowie Project.

Leakage Pathway	Quantification Method*	Qualitative Accuracy
Surface facilities	Calculation based on process conditions at time of leakage and dimensions of leakage pathway	High
	Comparison & calculation against recent historical trends	High
	Direct measurement of leakage (if accessible and safe)	Very High
In-Zone Wellbores	Calculation against recent historical injection trends (using surface & downhole P/T data)	High
	Estimation from change in saturation profile within reservoir and/or confining zones in project wells	Moderately High
	Enhanced surveillance (e.g., saturation surveys) on nearby wells operated by EOG	Moderately High
Faults/fractures	Use reservoir model to simulate the CO_2 leakage required to generate the observed pressure transient behavior	Moderate
	Use reservoir model to simulate the CO_2 leakage required to generate the observed nearby well surveillance response	Moderate
	Enhanced surveillance (e.g., saturation surveys) on multiple nearby wells operated by EOG	Moderately High
	Conduct additional geophysical imaging surveys near potential leak pathways	Moderately High
	Drill additional monitoring wells in strategic locations	High
Confining system	Use reservoir model to simulate the CO_2 leakage required to generate the observed pressure transient behavior	Moderate
	Use reservoir model to simulate the CO_2 leakage required to generate the observed nearby well surveillance response	Moderate
	Enhanced surveillance (e.g., saturation surveys) on multiple nearby wells operated by EOG	Moderately High
	Conduct additional geophysical imaging surveys near potential leak pathways	Moderately High
	Drill additional monitoring wells in strategic locations	High

*Quantification methods presented in order of practical implementation.

3.7 Baseline Determination

SPG has developed a strategy to establish baselines for monitoring CO_2 surface leakage that is in agreement with 40 CFR §98.448(a)(4). "Expected baseline" is defined as the anticipated value of a monitored parameter that is compared to the measured monitored parameter. SPG has existing automated continuous data collection systems in place that allow for aggradation and analysis of operations data to 1) establish trends in operational performance parameters and 2) identify deviations from these trends. Non-continuous data will also be collected periodically to augment and enhance the analysis of continuous data throughout the project. Baseline surveys for non-continuous data have already been collected as described below. Baselines for operational performance parameters are expected to be completed by July 17th, 2023, which will provide for several weeks of data collection with the entire system operational.

AVO Inspections: Field personnel will conduct daily to weekly inspections at the injection site pre-, during, and post-injection. Any indications of surface leakage of CO_2 will be addressed via appropriate corrective action in a timely manner. Personnel will wear personal H_2S monitors calibrated to OSHA standards with a detection sensitivity of 0.5 ppm and a low-level alarm threshold of 10 ppm. Indications of H_2S present will serve as a proxy for CO_2 presence as the injection stream contains both components.

Continuous Monitoring: Continuous monitoring systems are in place for both the surface process facilities and wells. Pressure and temperature gauges installed on both casing and tubing strings, DTS fiber-based data, and surface pressures on all strings of casing is collected continuously in both wells. Operational baselines will be determined from analysis of this data over a reasonable period once the system is fully operational (see comments on timing above). Any deviations from these operational baselines will be investigated to determine if the deviation is a leakage signal.

Well Integrity Testing: EOG will conduct an annual MIT on the Hinkle Trust #1 as required by the Class II permit issued by TXRRC. Subsequent MIT results will be compared to initial MIT results and TXRRC standards to establish a baseline. An initial MIT and subsequent interpretation of test results has already been performed on the Hinkle Trust #1 as part of the Class II permit requirements.

Pressure Transient Analysis: EOG has conducted initial pressure transient analyses using injection test data. Subsequent pressure transient analyses are in progress and will continue to be performed when operationally feasible to establish and re-establish expected baseline reservoir behavior throughout the project. Comparison of these analyses over time will aid in diagnosing consistency in the long-term behavior of the injection and confining zones.

Wellbore Surveys: The Billy Henderson #5 and Hinkle Trust #1 are both constructed to allow for time-lapse saturation and mechanical integrity logging. Initial pre-injection surveys have been conducted for both saturation and mechanical integrity and will serve to establish baselines for comparison of future logging datasets.

3.8 Site Specific Modifications to the Mass Balance Equation

3.8.1 Mass of CO_2 Received

Following the Subpart RR requirements under §98.444(a)(4), equation RR-4 (Figure 33) will be used for calculating the mass of CO_2 received since the CO_2 stream received via the gathering pipeline will be wholly injected and not mixed. The mass flow rate measured at the coriolis meter immediately downstream of the high pressure injection compressor (Figure 2) will be used as input to equation RR-4. This measurement will account for the concentration of CO_2 in the injection stream using the measurement from the gas chromatograph immediately upstream of the high pressure compressor, which will be validated quarterly via gas sample analysis as per the requirements under §98.444(b).

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

where:
$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.
$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).
$C_{CO2,p,u}$ = 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.

Figure 33: Equation RR-4 as defined in 40 CFR §98 Subpart RR.

3.8.2 Mass of CO_2 Injected

The annual mass of CO_2 injected will be calculated using equation RR-4 as per Subpart RR §98.443(c)(1) since a high pressure coriolis meter will be used to measure the mass flow rate as described in the previous section 3.8.1. The high pressure coriolis mass meter used in the system has an accuracy of ±0.15% and concentration inputs to the calculation will be provided by the gas chromatograph immediately upstream of the high pressure compressor which will be validated quarterly in accordance with §98.444(b).

3.8.3 Mass of CO_2 Produced

Mass of CO_2 produced is not applicable to this project as no CO_2 will be produced.

3.8.4 Mass of CO_2 Emitted

Equipment Leaks and Vented Emissions

The likelihood of any fugitive CO_2 emissions between the injection meter and the injection wellhead is expected to be extremely low due to the material specifications of the installed equipment and the minimal number of components along this flow path (Figure 2). Any intentional venting of CO_2 emissions - in the case of a planned compressor blow-down before maintenance, for example - would occur upstream of the injection meter used to measure the injection quantity and therefore would not need to be subtracted from the total mass injected. Nevertheless, this equipment will still be subject to regular AVO inspections and H_2S monitoring. If the determination is made that CO_2 has leaked between the injection meter used to measure injection quantity and the injection wellhead, the methods outlined in 40 CFR §98 subpart W will be used to quantify those amounts.

Since CO_2 will not be produced in the scope of this proposed injection project, the consideration of leaks from production-related equipment is not applicable.

Surface Leakage

If it were determined that surface leakage had occurred or is actively occurring through any of the identified pathways, the quantification methodology described in Section 3.6.3 would be used to estimate the mass emitted from each pathway and summed using equation RR-10 (Figure 34).

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

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

Figure 34: Equation RR-10 as defined in 40 CFR §98 Subpart RR.

3.8.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated using equation RR-12 (Figure 35) since this project will not actively produce oil, natural gas, or any other fluids.

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{(Eq. RR-12)}$$

where:

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

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

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

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

Figure 35: Equation RR-12 as defined in 40 CFR §98 Subpart RR.

In accordance with §98.448(a)(7), the date to begin collecting data for calculating the total amount sequestered shall be after 1) expected baselines are established and 2) implementation of the leakage detection and quantification strategy within the initial AMA. SPG proposes the date of July 17th, 2023 as the date to begin collecting data for calculating the total amount sequestered for the SPG CO_2 Bowie Facility.

3.9 Implementation Schedule For MRV Plan

The final MRV plan will be implemented upon receiving approval from the EPA, and no later than the day after the day on which the plan becomes final, as described in §98.448(c). The Hinkle Trust #1 is currently permitted to inject under a TXRRC Class II UIC permit (see Appendix A) and the SPG CO_2 Bowie Facility is expected to operate for 12 years. Once approved, the MRV plan will be implemented throughout the 12-year operational period in accordance with 40 CFR §98 Subpart RR and for an additional 5-year post-injection monitoring period.

3.10 Quality Assurance

3.10.1 Monitoring QA/QC

SPG will implement quality assurance procedures that are in compliance with requirements stated in 40 CFR §98.444 as detailed below.

CO_2 Injected:

- The flow rate of the CO_2 injection stream is measured continuously with a high pressure mass flow meter that has an accuracy of ±0.15%.
- The composition of the CO_2 injection stream is measured with a high accuracy gas chromatograph upstream of the flow meter.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer recommendations.

CO_2 Emissions from Leaks and Vented Emissions:

- Calculation methods from 40 CFR §98 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.

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).

3.10.2 Missing Data

Missing data will be estimated as prescribed by 40 CFR §98.445 if SPG is unable to collect the data required 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 and venting from facility surface equipment will be estimated and reported per the procedures specified in 40 CFR §98 subpart W.

3.10.3 MRV Plan Revisions

If any of the changes outlined in 40 CFR §98.448(d) occur, SPG will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

3.11 Records Retention

SPG will retain all records as required by 40 CFR §98.3(g). Records will be retained for at least three years, and will include, but will not be limited to:

- Quarterly records of injected CO_2 including mass flow rate at standard conditions, mass flow rate at operating conditions, operating temperature and pressure, and concentration of the injected CO_2 stream.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

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A Class II UIC Permit for Hinkle Trust #1

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. 17041

EOG SPG HOLDINGS, INC.
ATTN SETH WOODARD
PO BOX 4362
HOUSTON TX 77210

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 April 01, 2022, for the permitted interval(s) of the ELLENBURGER formation(s) and subject to the following terms and special conditions:

HINKLE TRUST (00000) LEASE
BARNABUS (ELLENBURGER) FIELD
MONTAGUE 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	33700000	000125307	Carbon Dioxide (CO_2); Hydrogen Sulfide (H_2S); Natural Gas	7,300	13,000		12,000		4,100

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	33700000	**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. An annual annulus pressure test must be performed and the test results submitted in accordance with the instructions of Form H-5. 3. The tubing-casing annulus pressure must be monitored at least weekly and reported annually on Form H-10 to the Commission's Austin Offices. 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. 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. 6. 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. 7. 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.**

Note: This document will only be distributed electronically.

		8. NOTE: Per operator email dated on June 01, 2022, the four plants are operated by EOG Resources, Inc. They are permitted under Pecan Pipeline Company (P-5 #648675) and Pecan Pipeline is EOG Resources. **Below are the names and RRC Serial Numbers for each plant:** **Bowie South – 09-0415** **St. Jo – 09-0406** **Henderson – 09-0405** **Kripple Kreek – 09-0401**

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 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.

Note: This document will only be distributed electronically.

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 July 18, 2022.

Sean Avitt, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

B Drilling Permit for Hinkle Trust #1

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 (*<u>other than diesel fuels</u>*) 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 879709	DATE PERMIT ISSUED OR AMENDED May 10, 2022	DISTRICT * 09
API NUMBER 42-337-35480	FORM W-1 RECEIVED May 03, 2022	COUNTY MONTAGUE
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 682.83
OPERATOR 100178 EOG SPG HOLDINGS, INC. ATTN SETH WOODARD PO BOX 4362 HOUSTON, TX 77210		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 HINKLE TRUST		WELL NUMBER 1
LOCATION 9.4 miles SE direction from MONTAGUE, TX		TOTAL DEPTH 15000
Section, Block and/or Survey SECTION SURVEY MC DONALD, J	BLOCK	ABSTRACT 538
DISTANCE TO SURVEY LINES 1150 ft. NE 277 ft. SE		DISTANCE TO NEAREST LEASE LINE ft.
DISTANCE TO LEASE LINES 604 ft. SW 204 ft. SE		DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
BARNABUS (ELLENBURGER) HINKLE TRUST	682.83 0	13,000	1	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

MONTAGUE (337) County

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

C Existing Wellbores in the AMA and MMA

Table 11: Details of existing wellbores in the MMA

API	Latitude[d]	Longitude[d]	Type[e]	Measured Depth (ft)	True Vertical Depth[f] (ft)	Vertical Separation[g] (ft)	Status	Plugging Date
4233700318	33.5476473	-97.6680356	V	6,316	6,316	3,281	plugged	8/23/1948
4233700319	33.5433524	-97.6685669	V	6,185	6,185	3,239	open	-
4233700320	33.54584	-97.6654879	V	6,150	6,150	3,359	plugged	9/26/2003
4233700321	33.5409871	-97.6613966	V	6,185	6,185	3,295	plugged	9/9/1949
4233700322	33.5397595	-97.6682099	V	6,075	6,075	3,332	plugged	11/30/1949
4233700331	33.5492584	-97.6751192	V	6,180	6,180	3,290	plugged	6/23/1952
4233700951	33.5419592	-97.6861446	V	6,200	6,200	3,209	plugged	8/9/1974
4233700958	33.5160018	-97.6918485	V	6,350	6,350	3,085	plugged	9/6/1952
4233701073	33.5409088	-97.7213681	V	6,023	6,023	3,127	open	-
4233701122	33.5454835	-97.7223205	V	6,033	6,033	3,086	open	-
4233701123	33.5434121	-97.7199676	V	6,200	6,200	2,950	open	-
4233701390	33.5414571	-97.666039	V	6,930	6,930	2,497	open	-
4233701391	33.5420799	-97.6656006	V	6,185	6,185	3,254	plugged	4/30/1958
4233701421	33.5486792	-97.6773436	V	6,330	6,330	3,065	plugged	6/23/1952
4233701598	33.5160018	-97.6918485	V	6,263	6,263	2,919	plugged	7/10/1951
4233701599	33.5407157	-97.7134382	V	6,391	6,388	2,864	plugged	3/21/2017
4233701721	33.5409308	-97.6717112	V	6,233	6,233	3,178	plugged	12/8/1953
4233701753	33.5322683	-97.6798167	V	6,215	6,215	3,190	plugged	5/8/1958
4233702046	33.5346366	-97.6564126	V	6,292	6,292	3,270	open	-
4233702156	33.5214402	-97.6722279	V	6,197	6,197	3,179	plugged	6/2/1955
4233702163	33.5224329	-97.7066105	V	6,215	6,215	3,207	plugged	4/19/1955
4233702169	33.5570792	-97.6908437	V	6,460	6,460	2,981	plugged	7/12/1954
4233702322	33.5114096	-97.6858321	V	6,287	6,287	3,223	plugged	5/24/1955
4233702327	33.5235695	-97.6873659	V	7,703	7,703	1,658	plugged	10/2/1953
4233702428	33.5544365	-97.704817	V	6,510	6,510	2,804	plugged	11/20/2001
4233702497	33.5469321	-97.6726204	V	6,300	6,300	3,184	plugged	9/22/2003
4233702720	33.5449729	-97.6841474	V	6,235	6,235	3,073	open	-
4233702724	33.5478849	-97.6773222	V	6,322	6,322	3,063	plugged	12/4/2007
4233702800	33.5306035	-97.6575182	V	6,265	6,265	3,315	plugged	9/3/1964
4233730025	33.5472796	-97.7010957	V	6,650	6,650	2,640	plugged	9/19/2006
4233730039	33.549693	-97.698387	V	6,350	6,350	3,016	plugged	10/23/2008
4233730409	33.5472133	-97.7049151	V	7,500	7,500	1,754	open	-
4233730500	33.5456717	-97.6750313	V	6,250	6,250	3,138	plugged	8/4/1976
4233730517	33.5475022	-97.7094562	V	6,290	6,290	2,984	open	-
4233730534	33.5456717	-97.6750313	V	6,280	6,280	3,170	open	-
4233730535	33.5428675	-97.7119696	V	6,198	6,198	3,056	plugged	10/10/2012
4233730560	33.5494984	-97.6870224	V	6,300	6,300	3,031	plugged	11/21/2018
4233731003	33.5455463	-97.697421	V	6,409	6,409	2,879	plugged	7/28/2006
4233731081	33.5513089	-97.6844319	V	6,397	6,397	2,950	plugged	4/12/1996
4233731082	33.5507531	-97.6820947	V	6,500	6,500	2,878	plugged	12/4/2006
4233731090	33.548335	-97.691426	V	6,400	6,400	2,950	plugged	5/19/2023
4233731102	33.5327209	-97.6609319	V	6,269	6,269	3,228	plugged	11/1/1984
4233731106	33.5522614	-97.7034382	V	6,460	6,460	2,827	open	-
4233731110	33.548384	-97.69536	V	6,397	6,397	2,963	open	-
4233731166	33.5212553	-97.6762734	V	6,338	6,338	3,041	plugged	12/19/1978
4233731188	33.551443	-97.7117592	V	6,502	6,502	2,838	plugged	12/28/2020
4233731225	33.5449729	-97.6841474	V	7,336	7,336	2,013	open	-
4233731369	33.5485133	-97.6766576	V	6,370	6,370	3,038	plugged	8/9/2022
4233731481	33.5339855	-97.6554106	V	985	985	8,593	open	-
4233731517	33.5456717	-97.6750313	V	7,673	7,673	1,794	plugged	4/8/1981
4233731518	33.5534751	-97.7007102	V	7,880	7,880	1,474	plugged	3/5/1988

Continued on next page

Table 11 – continued from previous page

API	Latitude[d]	Longitude[d]	Type[e]	Measured Depth (ft)	True Vertical Depth[f] (ft)	Vertical Separation[g] (ft)	Status	Plugging Date
4233731786	33.5094884	-97.6786147	V	6,317	6,317	3,141	plugged	2/11/1983
4233731952	33.5173691	-97.7010647	V	6,300	6,300	3,087	plugged	8/14/1982
4233732077	33.5367212	-97.6599446	V	7,200	7,200	2,323	plugged	7/25/1983
4233732434	33.5456717	-97.6750313	V	6,300	6,300	3,138	plugged	9/28/1998
4233732570	33.5354122	-97.6749735	V	6,300	6,300	3,087	plugged	3/4/1998
4233732587	33.54584	-97.6654879	V	5,550	5,550	3,894	plugged	9/2/1998
4233732683	33.5449729	-97.6841474	V	6,400	6,400	2,927	plugged	1/14/1987
4233732709	33.5371514	-97.6683467	V	6,200	6,200	3,212	plugged	10/25/1998
4233732763	33.5384755	-97.6711482	V	6,300	6,300	3,073	plugged	9/25/2003
4233732768	33.5322426	-97.6729935	V	6,150	6,150	3,275	plugged	8/17/1988
4233732821	33.5247848	-97.6677227	V	6,226	6,226	3,206	plugged	3/18/1990
4233732854	33.5173691	-97.7010647	V	6,265	6,265	3,207	plugged	12/11/1990
4233732892	33.544519	-97.721225	V	6,410	6,410	2,721	plugged	10/10/2012
4233732935	33.5275003	-97.663315	V	7,190	7,190	2,276	open	-
4233732941	33.5159471	-97.6996498	V	5,380	5,380	3,992	plugged	5/12/1993
4233734044[h]	33.5358702	-97.6751655	V	11,419	11,415	-	open	-
4233734059	33.5297189	-97.669596	H	10,486	6,951	2,449	open	-
4233734060	33.5299917	-97.6696954	H	10,565	6,877	2,511	open	-
4233734062	33.5319777	-97.6664584	H	10,825	7,043	2,391	open	-
4233734063	33.5320278	-97.6664	H	10,643	6,884	2,528	open	-
4233734064	33.532075	-97.6663417	H	10,675	6,971	2,430	open	-
4233734381	33.53702	-97.69446	H	11,515	6,876	2,533	open	-
4233734382	33.53701	-97.69455	H	11,714	6,879	2,511	open	-
4233734383	33.53378	-97.6985	H	11,614	6,899	2,477	open	-
4233734384	33.53371	-97.69848	H	11,665	6,889	2,474	open	-
4233734462	33.5283945	-97.7104741	H	11,765	6,980	2,406	open	-
4233734467	33.5308216	-97.7036631	H	11,390	6,854	2,424	open	-
4233734470	33.530757	-97.7036925	H	11,408	6,856	2,419	open	-
4233734482	33.55202	-97.69247	H	12,428	6,691	2,633	open	-
4233734483	33.55198	-97.69253	H	12,492	6,705	2,593	open	-
4233734485	33.528352	-97.7104097	H	11,780	6,907	2,318	open	-
4233734625	33.5484861	-97.7223667	H	11,053	6,674	2,335	open	-
4233734626	33.5485528	-97.7223528	H	11,525	6,680	2,341	open	-
4233734627	33.54907	-97.71264	H	12,042	6,688	2,347	open	-
4233734628	33.54914	-97.71264	H	12,086	6,709	2,362	open	-
4233734675	33.5597583	-97.7148194	H	11,763	6,787	2,566	open	-
4233734676	33.5598	-97.71475	H	11,280	6,723	2,642	open	-
4233734677	33.55984	-97.71469	H	11,162	6,699	2,689	open	-
4233734813	33.52826	-97.6437701	-	-	-	-	expired permit	-
4233734830	33.5306885	-97.7037284	H	11,884	6,932	2,474	open	-
4233734892	33.5082164	-97.6518451	-	-	-	-	expired permit	-
4233734893	33.50816	-97.65192	H	13,083	7,145	2,341	open	-
4233734894	33.50819	-97.65188	H	12,952	7,083	2,396	open	-
4233734930	33.50028	-97.66277	H	12,250	7,103	2,393	open	-
4233735021	33.5022397	-97.6589206	H	12,220	7,071	2,374	open	-
4233735028	33.50694	-97.64689	H	14,965	6,992	2,460	open	-
4233735029	33.5069683	-97.6468561	H	15,080	5,779	3,678	open	-
4233735030	33.50221	-97.65896	H	12,220	7,154	2,283	open	-
4233735037	33.50226	-97.65889	H	12,165	7,125	2,327	open	-
4233735038	33.5022	-97.65899	H	12,225	7,143	2,288	open	-
4233735062	33.5325183	-97.6969905	H	11,512	6,772	2,439	plugged	8/22/2022
4233735063	33.532491	-97.6970572	H	11,642	6,915	2,298	open	-
4233735089	33.5152982	-97.6465287	-	-	-	-	expired permit	-
4233735276	33.5074642	-97.6873168	H	12,840	7,024	2,348	open	-

Continued on next page

Table 11 – continued from previous page

API	Latitude[d]	Longitude[d]	Type[e]	Measured Depth (ft)	True Vertical Depth[f] (ft)	Vertical Separation[g] (ft)	Status	Plugging Date
4233735277	33.5075236	-97.687336	H	12,870	6,938	2,484	open	-
4233735279	33.5075832	-97.6873554	H	11,945	6,976	2,456	open	-
4233735376	33.5108452	-97.6750413	-	-	-	-	expired permit	-
4233735377	33.5108847	-97.6750867	-	-	-	-	expired permit	-
4233735378	33.5109245	-97.6751324	-	-	-	-	expired permit	-
4233735480[h]	33.5335602	-97.6759106	V	10,682	10,604	-	open	-
4233781563	33.5415486	-97.6654882	V	5,223	5,223	4,204	plugged	5/18/1979
4233782190	33.5449729	-97.6841474	V	6,050	6,050	3,258	plugged	8/9/1974
4233782845	33.551994	-97.7081803	-	-	-	-	expired permit	-
-	33.5456338	-97.7031434	-	-	-	-	expired permit	-
-	33.5469238	-97.6976345	-	-	-	-	expired permit	-
4233734149	33.5406337	-97.7038043	-	-	-	-	expired permit	-
4233734809	33.5316025	-97.7035052	-	-	-	-	canceled permit	-
4233782194	33.5337573	-97.6576655	V	-	-	-	open	-
4233731887	33.5382044	-97.6617854	-	-	-	-	expired permit	-
4233732631	333.5379144	-97.6675013	-	-	-	-	expired permit	-
4233735482	33.5332824	-97.676859	V	840	840	8,565	open	-
4233735483	33.5340654	-97.675702	V	-	-	-	active permit[i]	-
4233734678	33.5359944	-97.675356	-	-	-	-	expired permit	-
4233735481	33.5362434	-97.675106	V	340	340	9,060	open	-

[d]Denotes surface hole location for both vertical and horizontal wells in North American Datum 1927 (NAD84).
[e]Denotes vertical (V) or horizontal (H) wellbores.
[f]Denotes total depth as specified for vertical wells or maximum TVD (true vertical depth) for horizontal wells using directional surveys.
[g]Denotes vertical separation in feet between existing wellbores and top of middle Ellenburger injection zone based on seismic structure mapping and maximum true vertical depth of wellbores from well records analyses.
[h]Denotes wellbore constructed for this project.
[i]Currently permitted to 675 ft depth.

Request for Additional Information: SPG CO_2 Bowie Facility
November 7, 2023

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	Please ensure that all acronyms are defined during the first use within the MRV plan. For example, "ANSI" is not defined within the text.	*All acronyms have been defined in this latest revision.*
2.	2.2	10	"Over the proposed 12-year project life injection rates will decline from an initial rate of approximately 10 MMSCFD (~520 MT-CO_2/day) down to 4 MMSCFD (~200 MT-CO_2/day), resulting in a total cumulative injected mass of approximately 1.45 million MT-CO_2." While a 200-year post-injection shut-in time is mentioned in the reservoir simulation model discussion, there is no mention of a post-injection monitoring period. Please clarify how long monitoring will occur post-injection.	*A post-injection monitoring period of five years has been proposed in the revised MRV plan under* **Section 3.9 Implementation Schedule For MRV Plan.**

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
3.	3.5.2	34	"There are additional wellbores present in the AMA/MMA, but they do not penetrate the injection zone. Because they do not penetrate the injection zone, they are not leakage risks to this project and are not discussed in detail within this document." Please provide more information about these additional wells and to explain the surface leakage characterization. For example, what is the distance/depth between these additional wells and the injection formation? How many are there? If it were determined that CO2 somehow migrated and did reach these wells, even if it is unlikely, would the facility include these leakage estimates in the subpart RR report?	*A summary overview characterizing the existing wells and location permits throughout the MMA is included in the revised MRV plan in* **Section 3.5.2 Wellbores** *and accompanied by a detailed table in* **Appendix C** *cataloging essential data about each record gathered from a thorough review of TX Railroad Commission documents.* *An additional paragraph in* **3.5.2 Wellbores** *addresses the approach SPG would take to quantify and mitigate any CO_2 leakage associated with a hypothetical CO_2 migration reaching the wells. In this unlikely leakage scenario, the volumes would be documented in the Subpart RR report and reflected in the total mass of CO_2 sequestered per the procedure documented in* **Section 3.8.5 Mass of CO_2 Sequestered.**

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	3.8.4	45	This section discusses "The mass of CO_2 emissions from equipment leaks or vented emissions from surface equipment located between the injection meter and the wellhead…" but then references equation RR-10, which is specific to surface leakage. Please note that these two types of leakage are different and are separate terms in equation RR-12. These variables are defined as: CO2E = Total annual CO2 mass emitted (metric tons) by surface leakage in the reporting year. CO2FI = Total annual CO2 mass emitted (metric tons) from equipment leaks and vented emissions of CO2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of this part. The CO2E term could encompass leakage estimates from any of the potential surface leakage pathways identified in the plan not covered by CO2FI. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	*The distinction between these two potential leakage sources and the methods for quantifying the annual total mass associated with each source have been addressed and clarified in the revised MRV plan in* **Section 3.8.4 Mass of CO_2 Emitted.**

EOG SPG Holdings, Inc.

Subpart RR Monitoring, Reporting, and Verification Plan for SPG CO_2 Bowie Facility

Montague County, TX

Version 2
September 2023

Contents

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List of Tables

1 Introduction

EOG SPG Holdings, Inc. (SPG), a subsidiary of EOG Resources, Inc. recently received authorization from the Railroad Commission of Texas (TXRRC) to drill and operate a Class II disposal well (Hinkle Trust #1) under Texas Administrative Code (TAC) Title 16, Part 1, § 3.9. Under this permit (No. 17041), SPG can inject up to 12 MMSCFD (million standard cubic feet per day) of acid gas waste - composed primarily of CO_2, N_2, H_2S, and other trace hydrocarbons - generated by four natural gas amine treatment facilities located in Montague County, TX and operated by EOG Resources, Inc. (EOG). These facilities separate the acid gas components from the natural gas stream produced from the Barnett Shale by approximately 1,100 wells across the Newark East Field, also operated by EOG. Historically, the separated CO_2 stream has been emitted to the atmosphere while the H_2S was incinerated by a thermal oxidizer with the resulting SO_2 emitted to the atmosphere. In 2022, the aggregate total reportable greenhouse gas (GHG) emissions from all four amine separation facilities were approximately 180,000 metric tons (MT) of CO_2.

EOG is submitting this Monitoring, Reporting, and Verification (MRV) plan to the EPA for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) in connection with qualifying for the tax credits in section 45Q of the Internal Revenue Code.

1.1 Document Organization

This MRV plan is organized into three main sections: 1) this introductory section; 2) project details; and 3) a description of the development and administration of the MRV plan.

Section 1 introduces the injection project. It provides a high-level overview of the existing natural gas amine treatment facilities that are the sources of the CO_2 emissions as well as the capture, compression, and pipeline gathering systems that have recently been constructed as part of the injection project infrastructure. The section concludes with a general description of the subsurface storage complex including the target storage reservoir, the confining system, and the operational history that is relevant to the planned injection operations.

Section 2 provides more detailed presentations of the regional geology in the project area and the operational infrastructure including:

- a more detailed review of the source of the CO_2 emissions and the capture, compression, and pipeline gathering systems that will be used to deliver the CO_2 to the injection site;
- a summary of the proposed injection volume rates and the projected cumulative mass of CO_2 to be stored over the expected project life;
- the stratigraphy of the underburden, storage reservoir, and confining system;
- the structural features and subsurface stress characteristics within the project area;
- a more detailed review of the Barnabus (Ellenburger) field history; and
- a description of the fluid transport characteristics of both the storage reservoir and the confining system;

Section 3 describes the specific technical elements of the proposed MRV plan and how the plan will be administered over the expected project life, including:

- a description of the geologic and reservoir models used to simulate the long-term injection performance and CO_2 plume behavior;
- the delineation of the Active and Maximum Monitoring Areas (AMA and MMA);
- a description and assessment of the potential surface leakage pathways in the project area;
- a discussion of the methods and techniques that will be used to detect, verify, and quantify potential surface leaks of the injected CO_2;
- a presentation of the routine and regular operational monitoring that will establish baseline operating conditions, against which future monitoring surveys and results will be compared;

- a description of the various measurement and mass balance accounting techniques that will be employed to quantify the mass of the various CO_2 streams;
- an explanation of how quality assurance will be maintained across all aspects of the project operations;
- an acknowledgment of the requirements to submit revisions to the MRV plan in the event of material changes to the project; and
- a summary of the records that will be retained throughout the expected project life.

1.2 Surface Infrastructure Overview

EOG operates four natural gas amine treatment facilities that provide CO_2 to the Hinkle Trust #1 injection well. Figure 1 shows the geographic location of these facilities as well as the pipeline network that delivers CO_2 to the injection site. The names, TXRRC serial numbers, EPA GHGRP site identification numbers, and the CO_2 emissions for the 2022 reporting year of each of these facilities are summarized in Table 1. Section 2.1 provides a more detailed description of the gas treatment process and the CO_2 delivery infrastructure associated with the project.

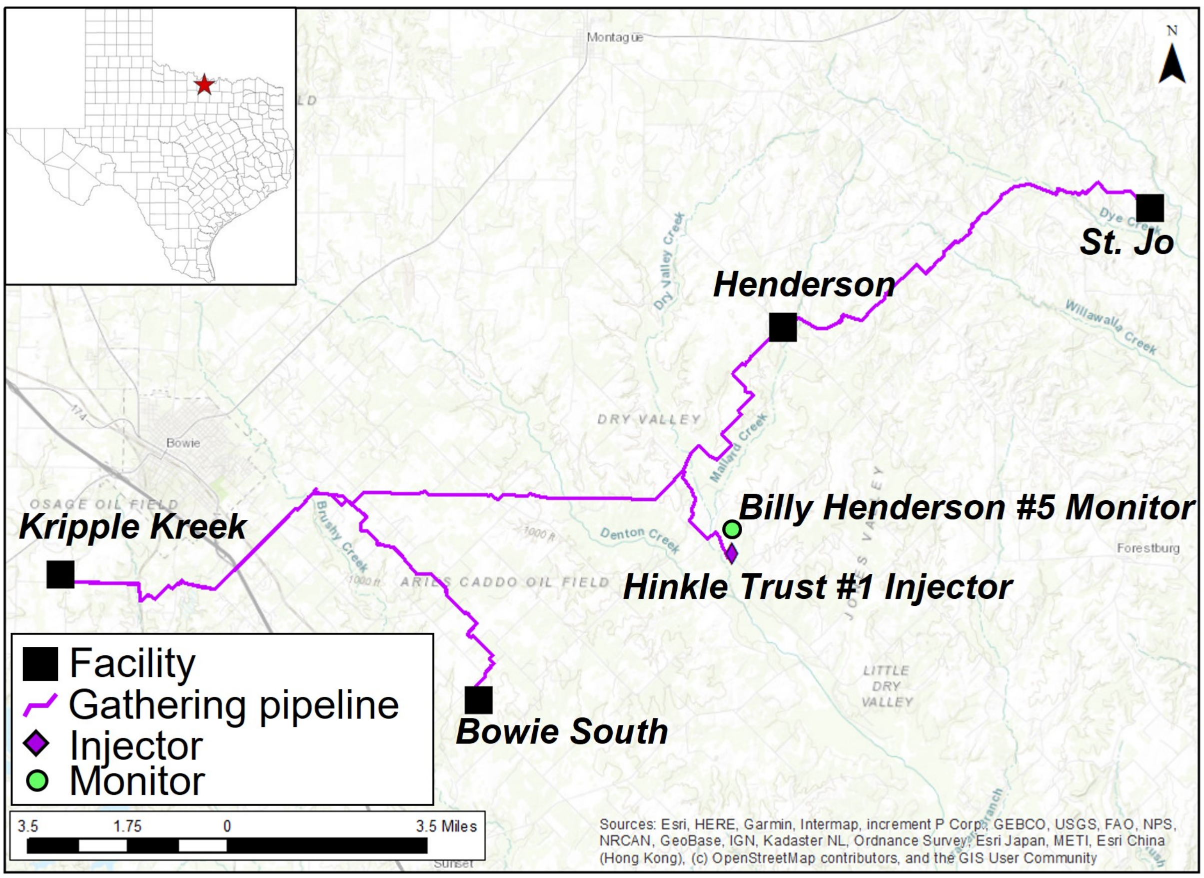


Figure 1: Project site map showing four gas amine treatment facilities providing CO_2 to the project, the pipeline network connecting processing facilities to the injection site, and the injection site well locations.

Table 1: Details and associated 2022 emissions for EOG gas amine treatment facilities.

Facility Name	TXRRC Serial No.	GHGRP ID	2022 Reported CO_2 Emissions (MT)
Bowie South[a]	09-0415	566952	54,352
Henderson[a]	09-0405	566952	20,584
Kripple Kreek	09-0401	528742	61,709
Saint Jo[a]	09-0406	566952	43,509
Total	—	—	**180,154**

[a]Previously reported as part of EOG Resources, Inc. 420 Fort Worth Syncline Basin Gathering & Boosting facility under Subpart W.

1.3 Subsurface Storage Complex Overview

The subsurface stratigraphy of interest for this project consists of the approximately four thousand feet of rock below the Barnett Shale formation, which is the primary hydrocarbon-producing interval within the project area. The middle Ellenburger formation is the main injection target for the project, which is an approximately one thousand foot thick dolomitic karst reservoir. Overlying the middle Ellenburger dolomite is over two thousand feet of mixed carbonates in the upper Ellenburger formation, mixed shale and limestone in the Simpson formation, and limestone in the Viola formation. These units contain ample footages of tight limestones, tight dolomites, and low permeability shales, and serve as the upper confining system for the project. Below the middle Ellenburger injection zone is about one thousand feet of tight limestone, which serves as the lower confining zone between the middle Ellenburger injection zone and the underlying granitic basement.

Two wells were drilled for this injection project. The Billy Henderson #5 is a vertical pilot and monitoring well that was drilled into granitic basement. This well provided project site-specific data across the injection and confining zones and was subsequently completed as a monitor well for the project. The Hinkle Trust #1 is the injection well for the project. This slightly-deviated well was drilled approximately 1,600 feet (ft) away from the Billy Henderson #5 monitor to a depth only a few hundred feet below the base of the injection zone. Evaluation data was also collected in this well for further subsurface characterization of the project site. The Hinkle Trust #1 was completed as an openhole injector into the middle Ellenburger dolomite.

2 Project Details

2.1 Source and Gathering of CO_2 for Injection

The Bowie Production Area has four central gas gathering sites that take produced gas from the field at low pressure (25-35 psig) and condition the gas to go through high pressure (750-900 psig) gathering lines to deliver the produced gas to a central gas treatment facility. Each of the gas gathering sites - Saint Jo, Henderson, Bowie South, and Bowie East Compressor Stations - have 3-stage compressors to increase the pressure of the gas before it goes through treatment to remove water and other impurities. Three of these gas gathering sites - Saint Jo, Henderson, and Bowie South - have amine treatment using Methyl-diethanolamine (MDEA) and Piperazine to remove CO_2 and H_2S from produced gas in the field down from 8%-15% CO_2 to 4% CO_2. The gas is then dehydrated using Triethylene Glycol (TEG) to remove water down to 7 pounds (lbs) per MMSCF (million standard cubic feet) before being sent to Kripple Kreek Gas Plant to go through final treatment. At the Kripple Kreek Gas Processing Plant, the remaining CO_2 in the high pressure produced gas is removed using MDEA and Piperazine from 4% CO_2 down to 100-200 parts per million (ppm) CO_2. The high pressure produced gas is dehydrated to a -300 °F dewpoint using TEG then mol sieve dehydration where the gas is then sent for final processing to separate the residue gas from the natural gas liquids (NGLs) for final sale. The residue gas is compressed and sold into a residue gas pipeline system, where the NGLs are subsequently sold and pumped into a y-grade NGL pipeline system.

The SPG CO_2 Bowie Facility (*aka* the injection facility; GHGRP ID 583201) gathers the CO_2 from each of the four existing amine treatment facilities (at Saint Jo, Henderson, Bowie South, and Kripple Kreek) using 4-stage booster compressors to increase the pressure of the CO_2-rich gas from low pressure (5 psig) off of the amine still to high pressure (750-850 psig). The CO_2-rich gas is then conditioned using a TEG dehydration unit to lower the dew point below 0 °F to ensure free water is not condensed during normal operations. The CO_2-rich gas is then sent through a measurement section to record the mass flowrate, composition, temperature, pressure, oxygen content, and water content before being introduced into the CO_2 gathering system. Based on routine measurements from the gas chromatograph (GC) installed at the injection facility, the CO_2-rich gas will be >98% CO_2 by weight with the remainder being a mixture of nitrogen, small amounts of various hydrocarbons, water and trace H_2S (see Table 2). As such, the injected gas stream is nominally described by its principal component (CO_2) throughout the MRV plan.

Table 2: Compositional analysis of gas stream to be injected at SPG CO2 Bowie Facility.

Component Name	**Normalized Mol %**	**Normalized Weight %**
Hydrogen Sulfide	0.0034	0.0027
Nitrogen	2.2536	1.4487
Carbon Dioxide	97.3991	98.3634
Methane	0.2207	0.0813
Ethane	0.0359	0.0247
Propane	0.0347	0.0351
i-Butane	0.0015	0.002
n-Butane	0.0061	0.008
i-Pentane	0.0021	0.0035
n-Pentane	0.0025	0.0041
C6+	0.0057	0.0122
Water	0.0347	0.0144
Total	100	

The gathering system consists of 36 miles of 6-inch nominal diameter Flexsteel composite pipe that collects the CO_2 streams from each of the four processing sites. The CO_2 is then sent to the injection facility where the gas enters the site and goes through an inlet heater for conditioning to ensure it is in the vapor phase before it goes through a measurement section to record the mass flowrate, composition, temperature, pressure, oxygen content, and water content before the gas is compressed from high pressure (750-850 psig) to supercritical (1,600-2,200 psig) in the final 2-stage unit. The supercritical CO_2 leaving the compressor is left hot to then be routed to the heater to cross exchange and provide heat for the inlet gas from the CO_2 gathering pipeline. The supercritical CO_2 is then sent through final measurement to collect the mass flowrate before the gas enters the wellhead and is injected in the subsurface. Figures 2 and 3 depict the general process flow that delivers conditioned CO_2 to the injection facility as well as the detailed plot plan of the injection well site. Both figures identify the location of the final coriolis meter (Meter ID: FW46045INJ) which will serve as the reference injection measurement used in the mass balance accounting under Subpart RR.

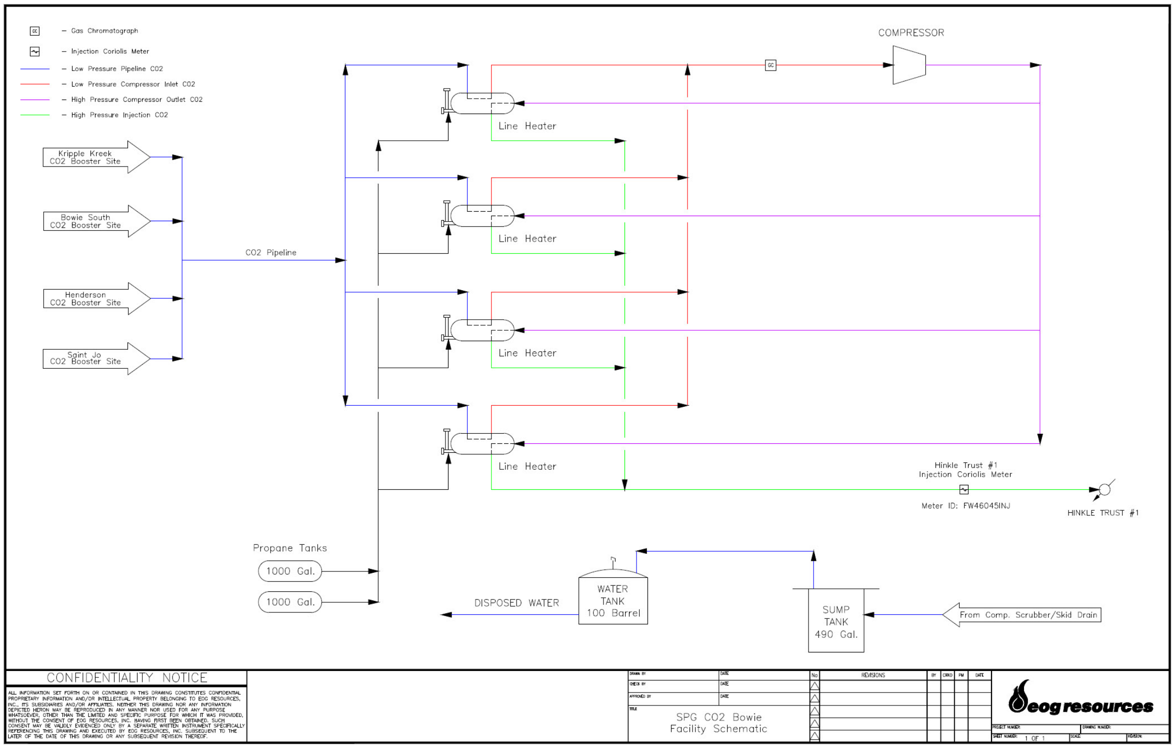


Figure 2: General flow diagram for SPG CO2 Bowie Facility.

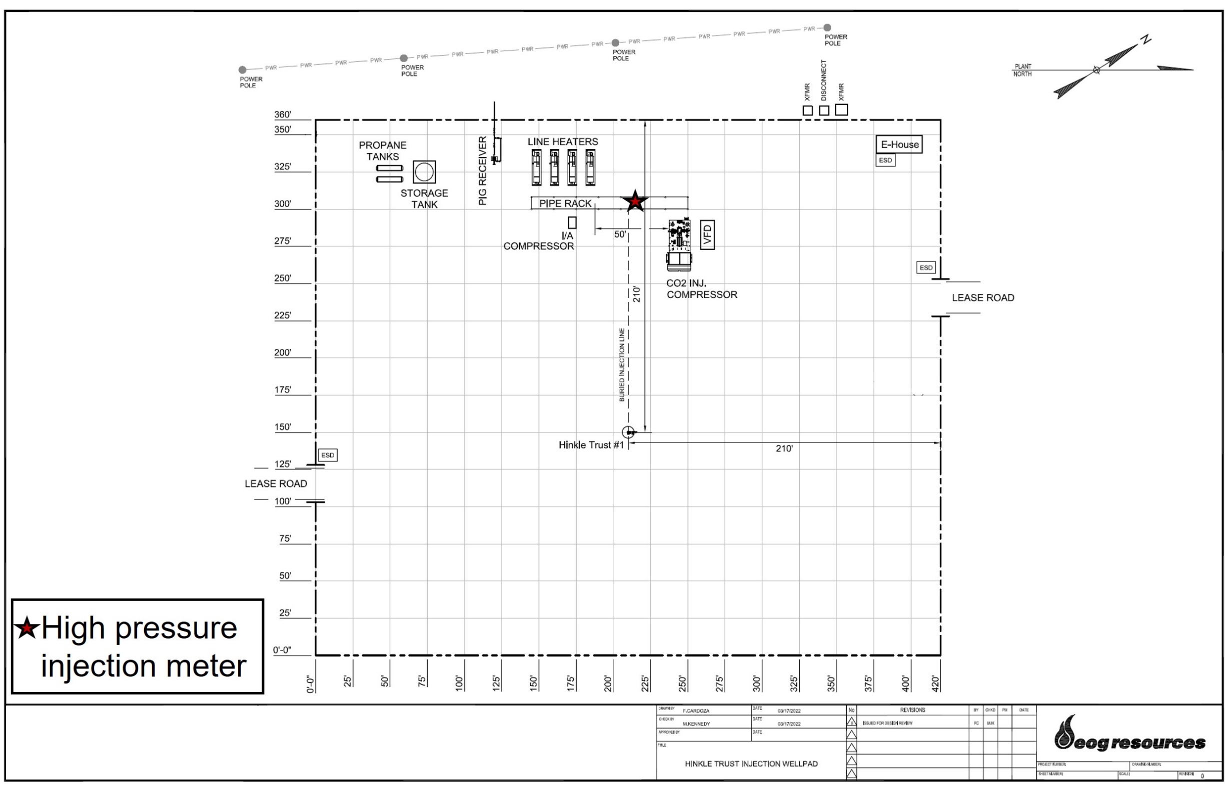


Figure 3: Plot plan for Hinkle Trust #1 injection pad.

2.2 Proposed Injection Volumes

The proposed CO_2 injection stream is separated from the natural gas produced by EOG's nearly 1,100 active Barnett wells in Montague County. Since these wells are on a natural depletion decline (and additional development drilling is not currently planned), the projected CO_2 volumes will follow a similar decline trend. Over the proposed 12-year project life, injection rates will decline from an initial rate of approximately 10 MMSCFD (~520 MT-CO_2/day) down to 4 MMSCFD (~200 MT-CO_2/day), resulting in a total cumulative injected mass of approximately 1.45 million MT-CO_2 (Figure 4). Injection operations began in February 2023 with CO_2 volumes supplied from the Henderson facility only. Injection operations from all four amine treatment facilities that will supply CO_2 to the gathering system commenced in June 2023, following completion of start-up and commissioning tests.

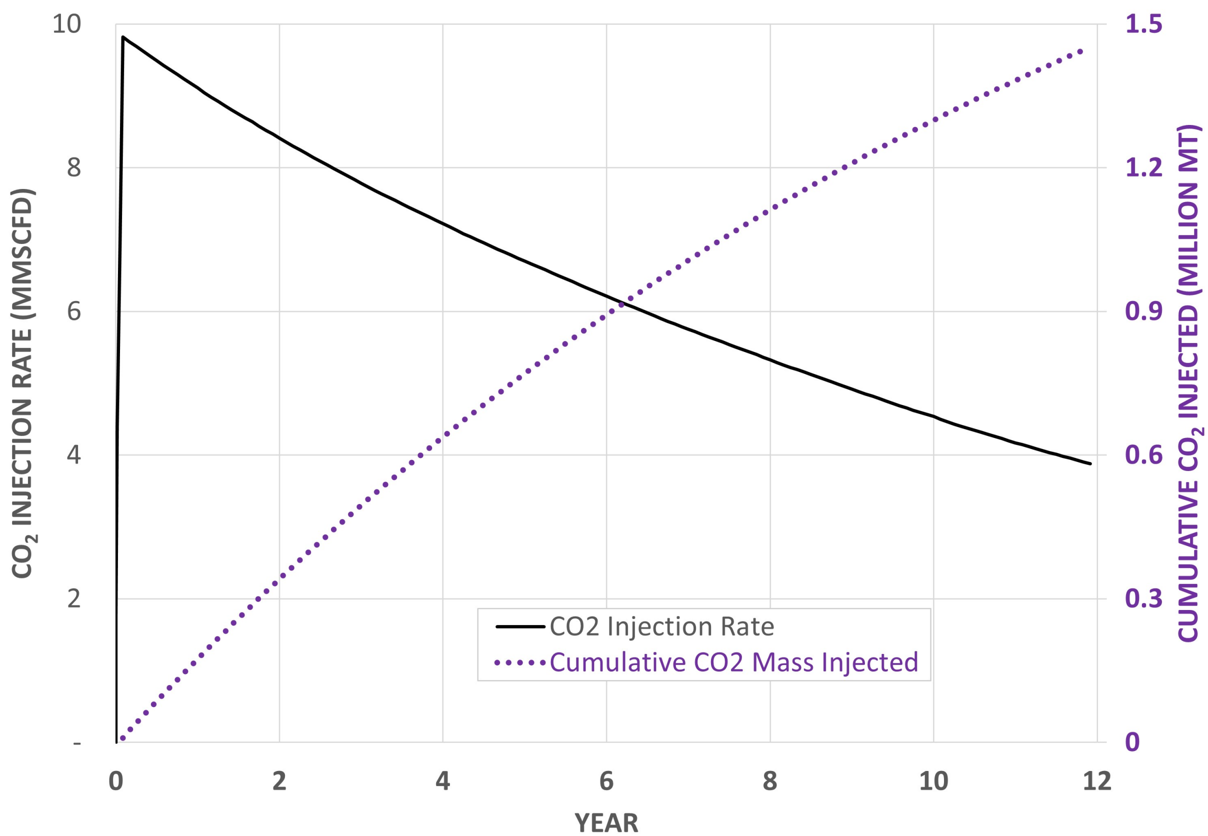


Figure 4: Projected CO_2 injection rate and cumulative mass injected over the proposed 12-year injection period.

2.3 Regional Geology

The project is located in the northern Fort Worth Basin which is a Paleozoic foreland basin associated with the Ouachita Orogenic belt (Figure 5). It exhibits stratigraphy similar to other Paleozoic structural basins found in North America [Meckel et al. (1992)]. The main hydrocarbon producing intervals are Mississippian to Pennsylvanian in age [Pollastro et al. (2007)]. The formations of interest for this injection project are pre-Mississippian-aged marine sediments, which sit below the major productive oil and gas intervals, and are separated from the underlying granitic basement by Cambrian aged sediments sitting below the injection zone (Figure 6) [Alsalem et al. (2018)]. The Ellenburger is the main formation of interest for this project, with secondary formations of interest being the overlying Simpson, Viola, and Barnett in stratigraphic order.

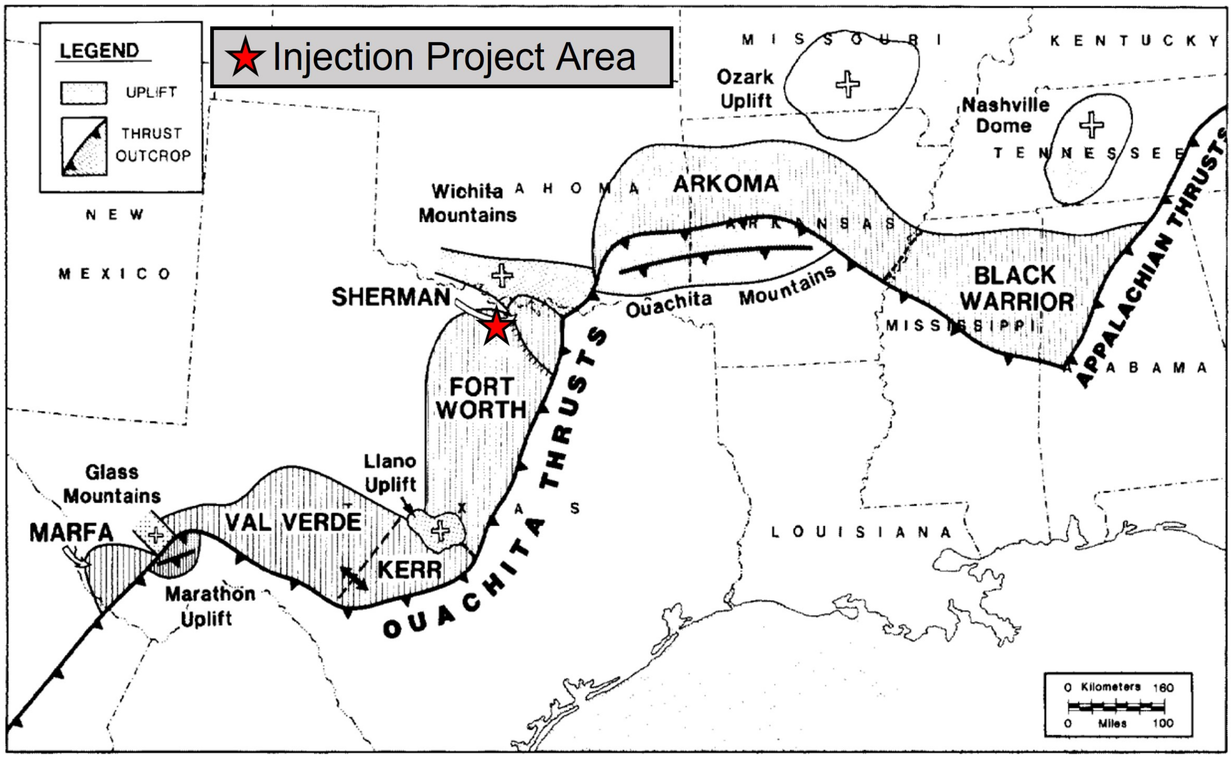


Figure 5: Location of Bowie injection project in northern Fort Worth Basin in reference to Ouachita front and related structural features. Figure modified from Meckel et al. (1992).

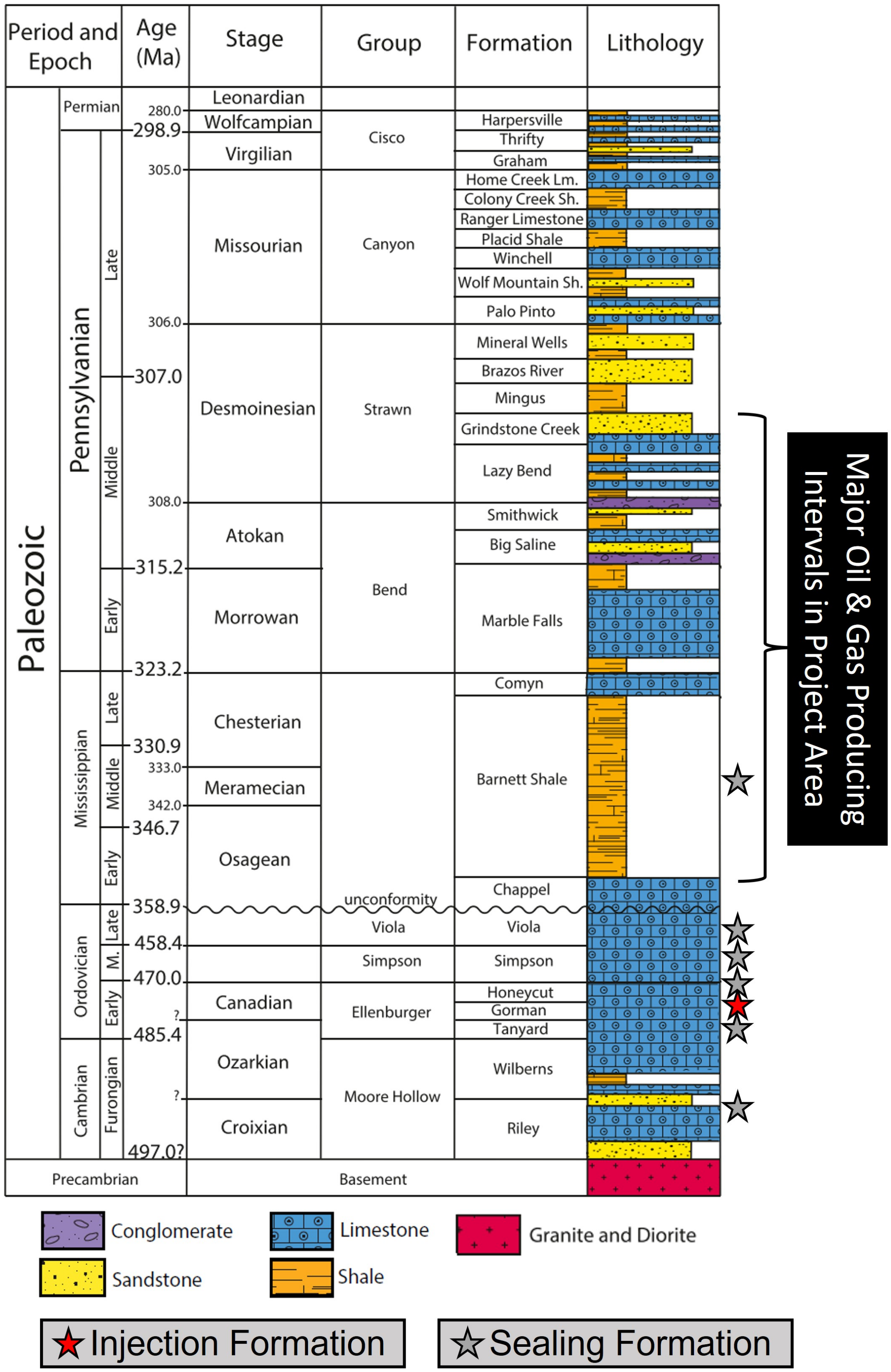


Figure 6: Generalized stratigraphic column of the Fort Worth Basin. Note that thicknesses of formations depicted within this illustration are not to scale for any particular location within the basin. Figure modified from Alsalem et al. (2018).

Prior to the formation of the Fort Worth structural basin in the project area, these Cambrian and Ordovician-aged sediments of interest were deposited on an epeiric carbonate platform developed on the Laurentian margin. This carbonate platform is commonly referred to as the Great American carbonate bank, which extended across the entirety of North America and rimmed the stable cratonic interior (Figure 7) [Derby et al. (2012)].

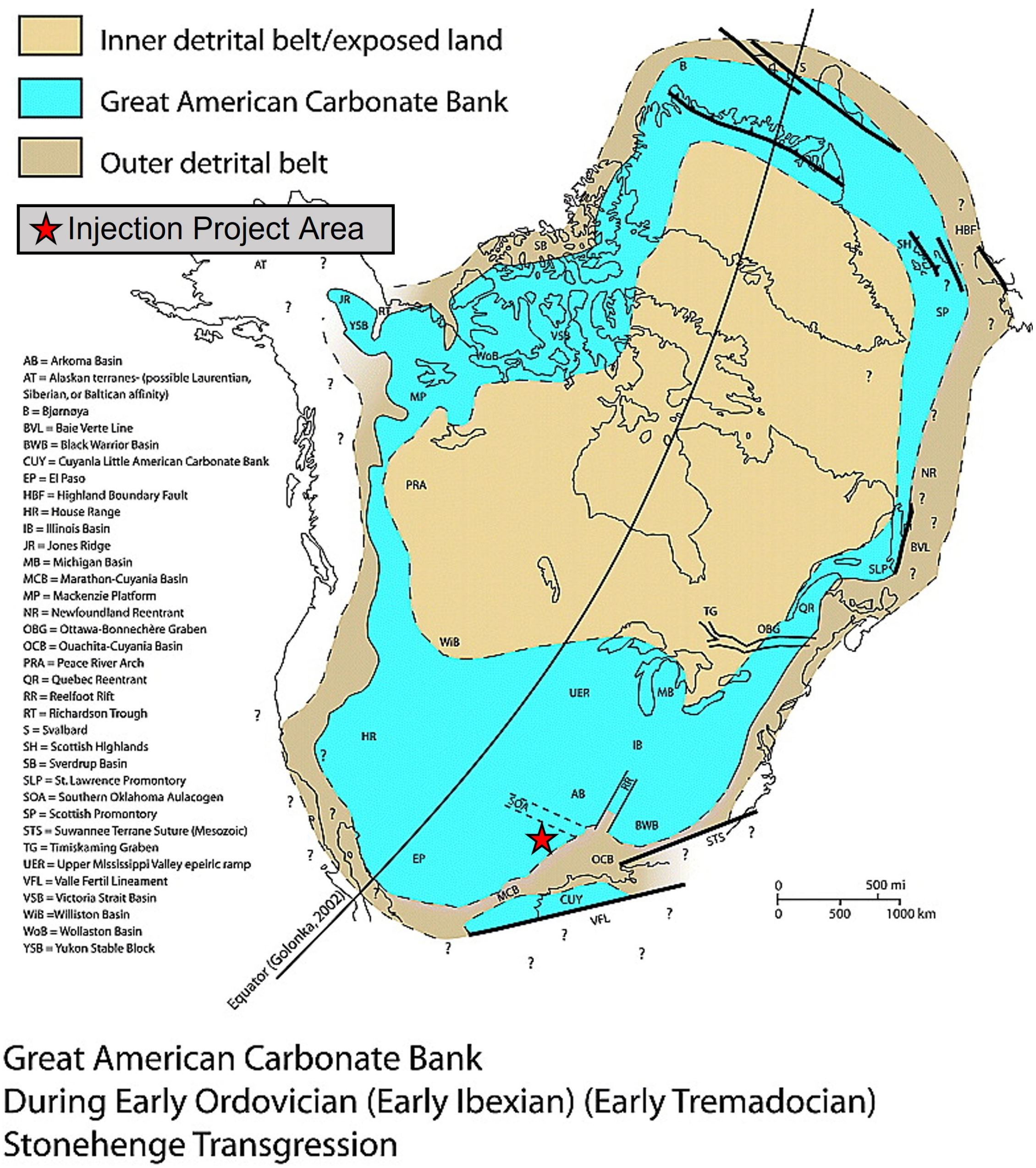


Figure 7: Location of Bowie injection project in reference to Great American carbonate bank paleogeography. Figure modified from Derby et al. (2012).

A large sea level change between the Ordovician and Mississippian resulted in an unconformity that removed any Silurian or Devonian rocks that may have been deposited. It was upon this unconformity that the Mississippian sediments, including the Barnett shale, were deposited. The late-Paleozoic Ouachita Orogeny formed the structural Fort Worth Basin and influenced sedimentation patterns through Permian time, with additional influence on the character

and thickness of sediments by local structure perturbations. In the northern Fort Worth Basin, these local structures include the Muenster Arch and Red River Arch. Pennsylvanian and early Permian sediments include both siliciclastics and carbonates, with siliciclastics being more dominant in the mid to late Pennsylvanian and Permian [Pollastro et al. (2007)]. In the eastern part of the Fort Worth Basin, the Cretaceous Trinity group rests unconformably on the Permian and Pennsylvanian-aged sediments [Fort Worth Geological Society (1955)]. The Trinity group contains the major freshwater aquifer units where present in the Fort Worth Basin, with no minor aquifers present (Figure 8) [George et al. (2011)].

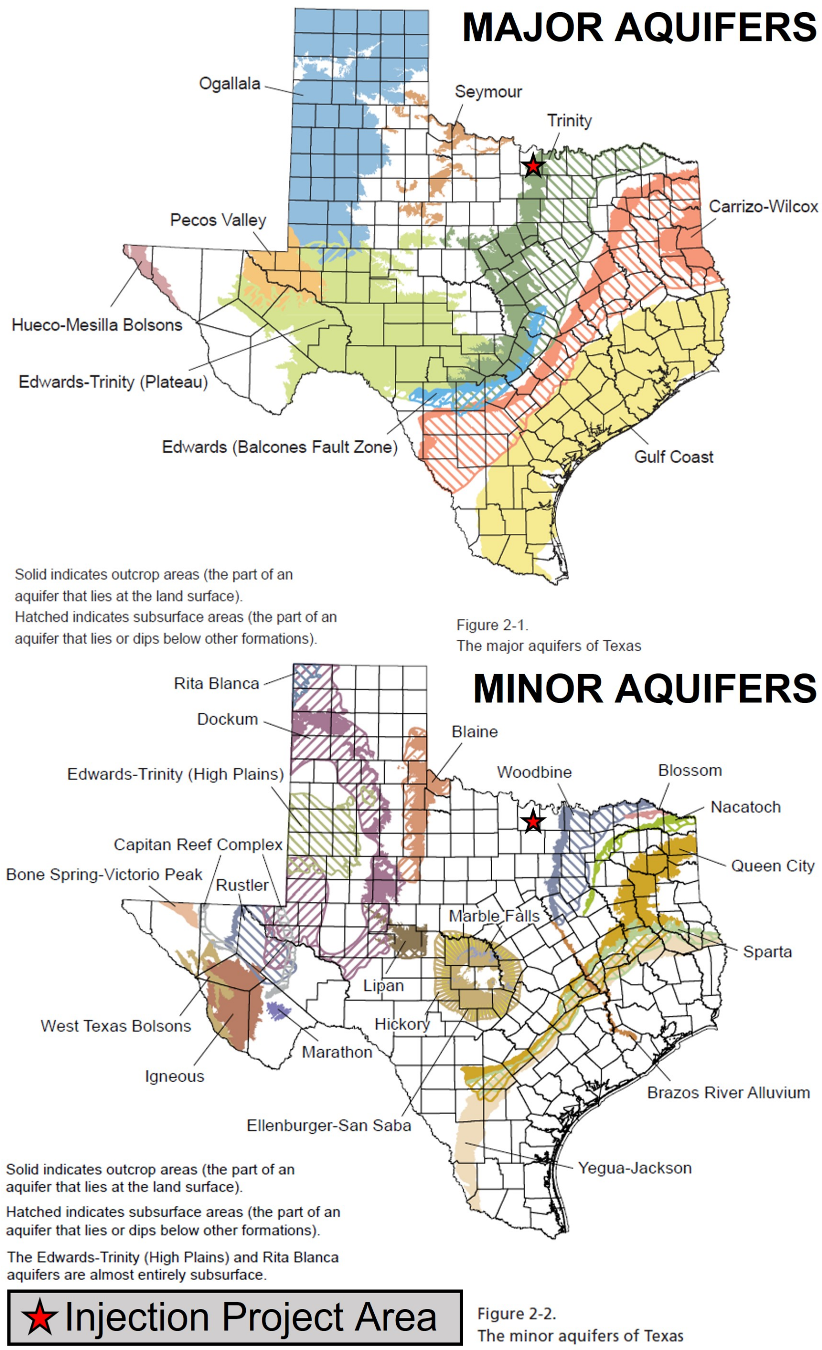


Figure 8: Project site referenced to Texas major and minor aquifers as identified by the Texas Water Development Board. Figure modified from George et al. (2011).

The injection project is located in Montague County, in the far northern part of Fort Worth Basin, in a structurally deep part of the basin adjacent to the Muenster Arch. Figure 9 shows the location of the project, structure contours on the top Ellenburger, and regional structural elements, including the Muenster Arch. The Muenster Arch has reactivated numerous times since the Precambrian, influencing local depositional patterns in Paleozoic strata.

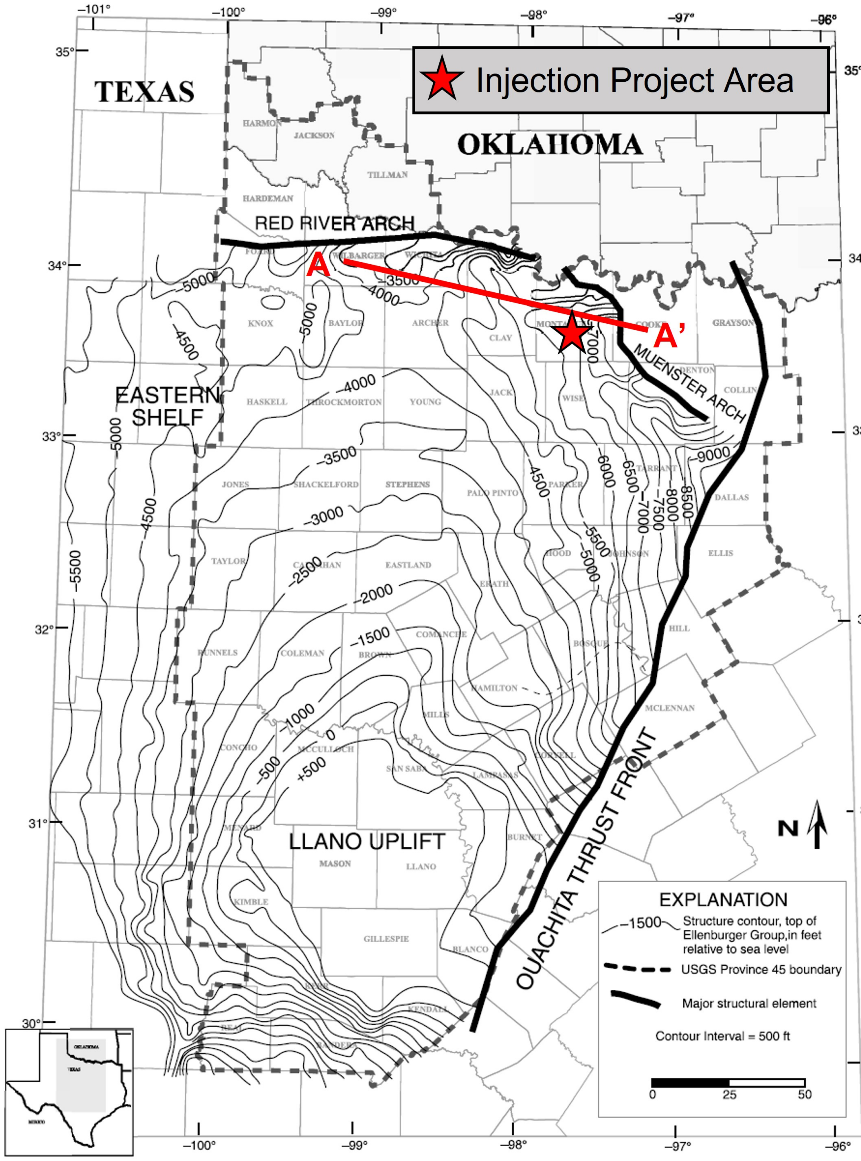


Figure 9: Location of Bowie injection project in Northern Fort Worth Basin, with top Ellenburger subsea true vertical depth (SSTVD) structure contours. Figure modified from Pollastro et al. (2007).

2.4 Stratigraphy of the Project Area

Figure 10 shows the general character of the stratigraphy in the vicinity of the project area in Montague County. Formations between the basement and lower Penn (labeled top "Caddo") thicken and deepen towards the Muenster Arch, showing its influence on both deposition and present-day structural position. The Muenster Arch is shown as a series of high angle thrusts that place Ordovician Ellenburger above younger Mississippian and Penn sediments. Penn and Permian sediments thicken towards the Ouachita front and Muenster Arch and are truncated by the base Cretaceous unconformity. The Cretaceous-age Trinity group is present in Montague County and sits above this unconformity.

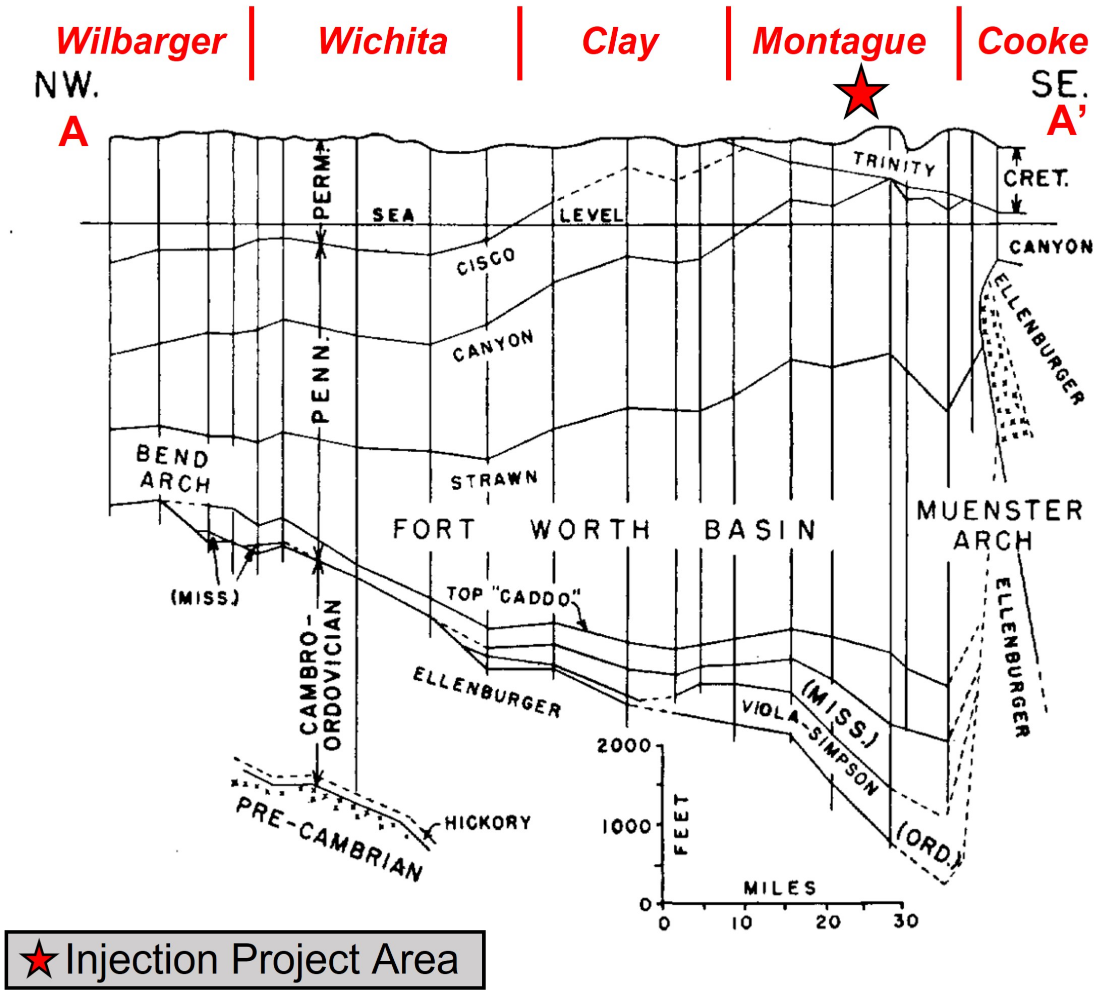


Figure 10: Generalized stratigraphic cross-section of North Fort Worth Basin with counties annotated on section. Figure modified from Fort Worth Geological Society (1955). Location of section shown in Figure 9.

Figure 11 shows the specific stratigraphic units present in the project area which are described below. Geologic descriptions are based on literature and internal EOG data collected across the stratigraphy for this project and others. The Precambrian basement within the project site is granitic and is variably cut by mafic intrusives. The carbonate section from the basement to the top of the Ellenburger has been broken in three units that can be correlated across Montague County. These three units are the basal carbonate (from basement to Base M. Ellenburger in typelog), middle Ellenburger, and upper Ellenburger. Above these units, the Simpson, Viola, and Barnett Shale are observed to be present within the project site [Pollastro et al. (2007)]. More detail will be presented on the lower carbonate through lower Barnett shale in the sections describing the injection and confining zones for the project (Section 2.7). The overlying Pennsylvanian stratigraphy has been broken out using both regional and local nomenclature for the stratigraphic units. At the top of the section is the base of the Trinity aquifer unit, which crops out within the project site (see Figure 12) [George et al. (2011)].

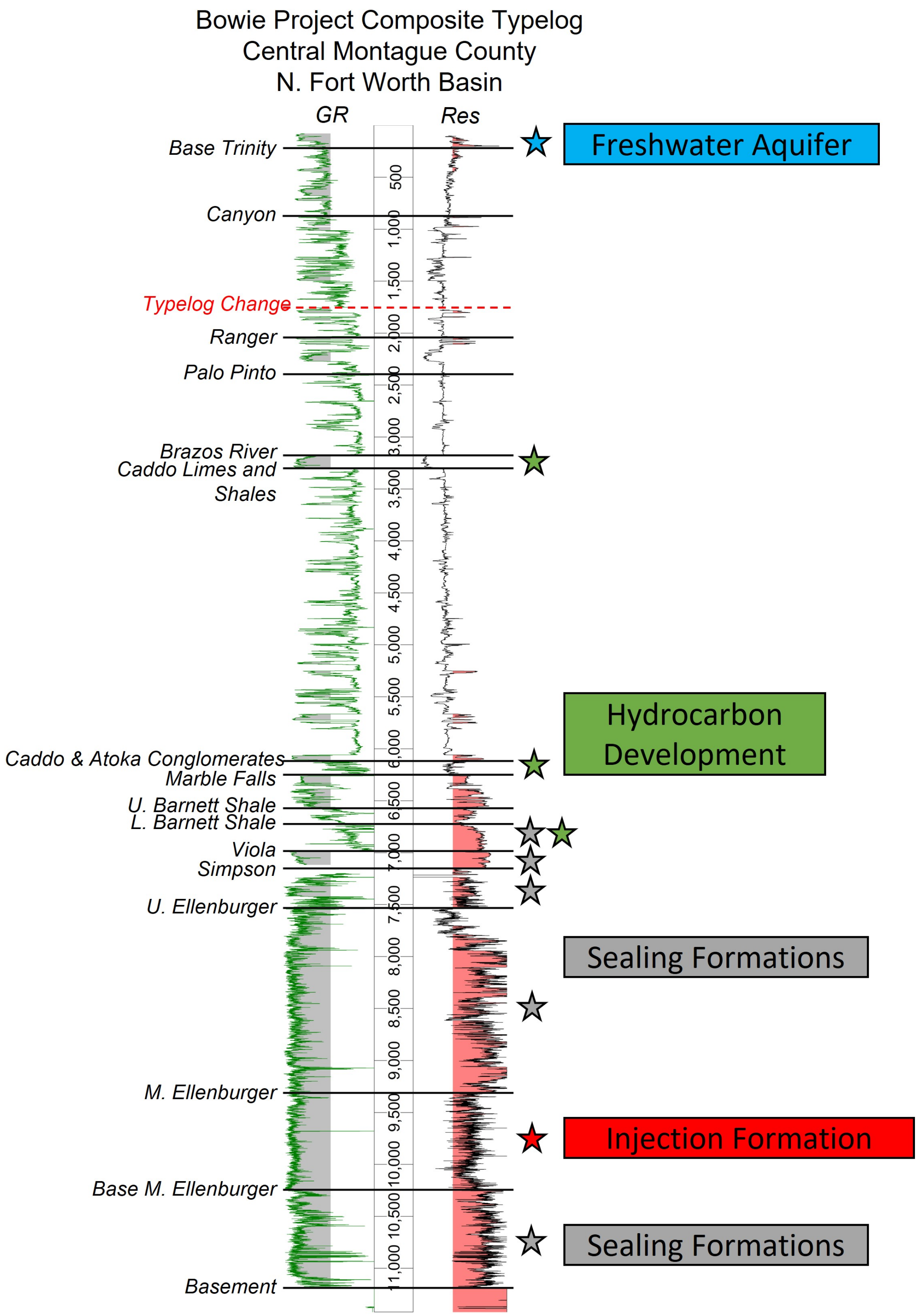


Figure 11: Project site-specific typelog utilizing well log data collected from the Billy Henderson #5 (lower Canyon to basement section) and Hinkle Trust #1 (surface to lower Canyon section).

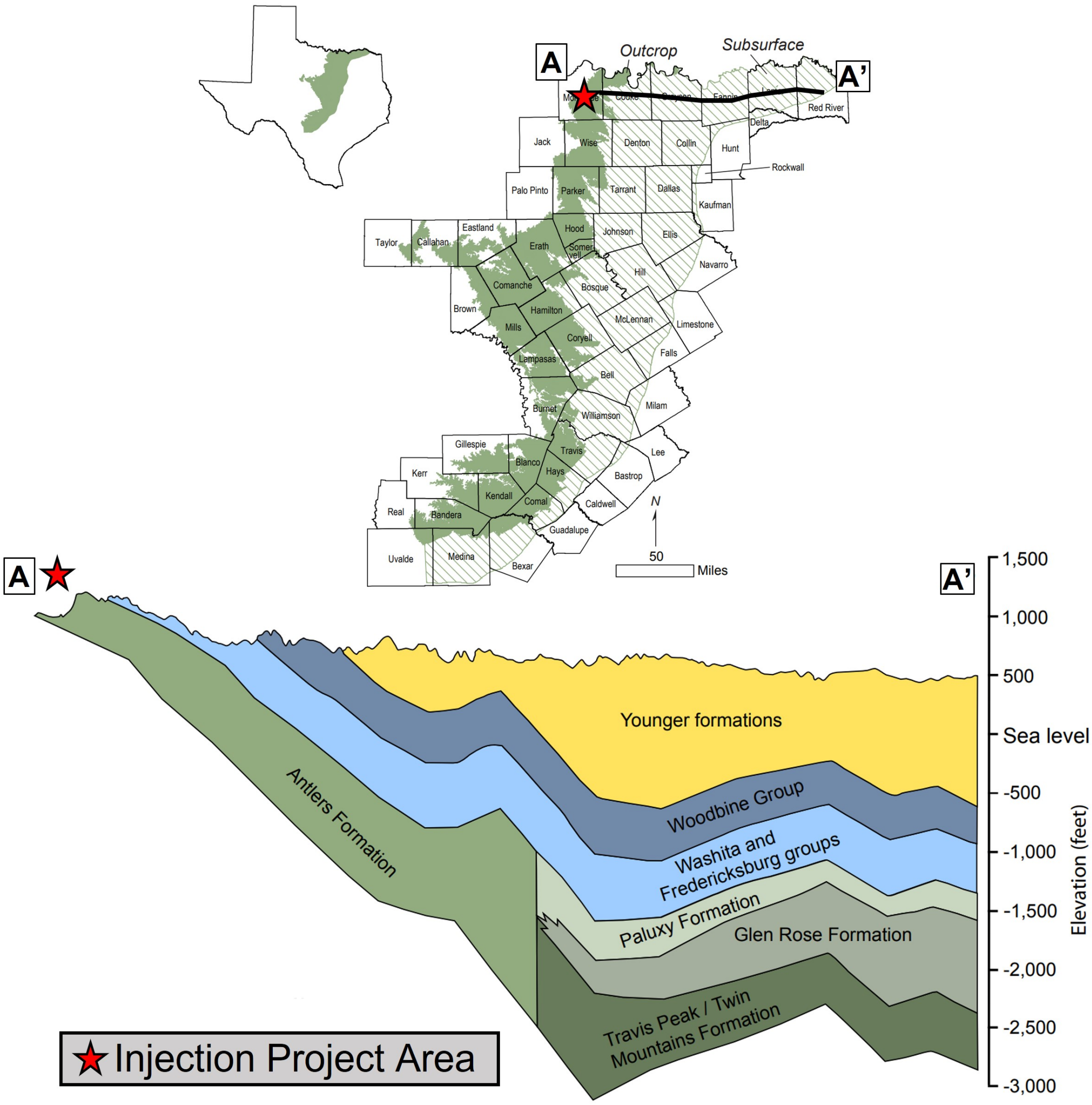


Figure 12: Trinity aquifer extent and geometry in the vicinity of the project area. Figure modified from George et al. (2011).

2.5 Structural Geology of the Project Area

The injection area is bounded by the Muenster Arch to the east and northeast and the Red River Arch to the north, both of which are positive, basement-rooted structural features formed during the Paleozoic Oklahoma aulacogen and were reactivated during Ouachita orogenic compression [Walper (1982)]. The injection area is characterized by three key structural components: basement-rooted faulting, natural fracturing, and, specifically within the Ellenburger, extensive karst formation. Within the injection area, these structural components are characterized with 3D seismic data, core, and well log data, and are discussed in further detail below.

Basement faulting: The injection area is characterized by a variety of fault orientations and styles reflecting multiple tectonic episodes during Fort Worth Basin evolution. Prominent basement faults generally strike east-west, largely exhibit strike-slip characteristics including extensive flower structures, and were likely formed during the Oklahoma aulacogen [Walper (1982), Pollastro et al. (2007)]. Most prominent basement faults either truncate within the basement or splay into smaller faults upon entering the Ellenburger, though some larger faults may extend up to Pennsylvanian

Strawn or Bend groups (Figure 13). A secondary basement fault set strikes NNE-SSW, paralleling present-day Ellenburger structural strike, though is less prevalent and does not extend above the basement within the injection area. Several basement-level faults intersect the injection interval (Figure 13), and are discussed as potential leakage pathways in section 3.5.3.

Natural fracturing: Ellenburger natural fractures, characterized by wellbore image logs and core data in the injection and monitoring wells, exhibit highly variable strike and dip, and likely originated from a combination of tectonic forces and intra-karst collapse and brecciation [Kerans (1988), Ijirigho and Schreiber Jr (1988)]. Natural fractures also generally appear cemented (Figure 29). The karst features themselves appear to be restricted to the injection zone, and do not appear to extend into the confining zone within the project area. Therefore, the fracturing associated with the karsts is not interpreted to be present across the confining zone.

Karsting: Ordovician Ellenburger group carbonates were deposited on a carbonate platform on a stable cratonic shelf. Sea level drops during and following Ellenburger deposition yielded subareal platform exposure and complex, extensive karsting, which was subsequently filled with Simpson Group clastics [Kerans (1988)]. Karst features are present within the proposed injection area and likely provide the primary Ellenburger storage (i.e., pore space) within the proposed injection interval.

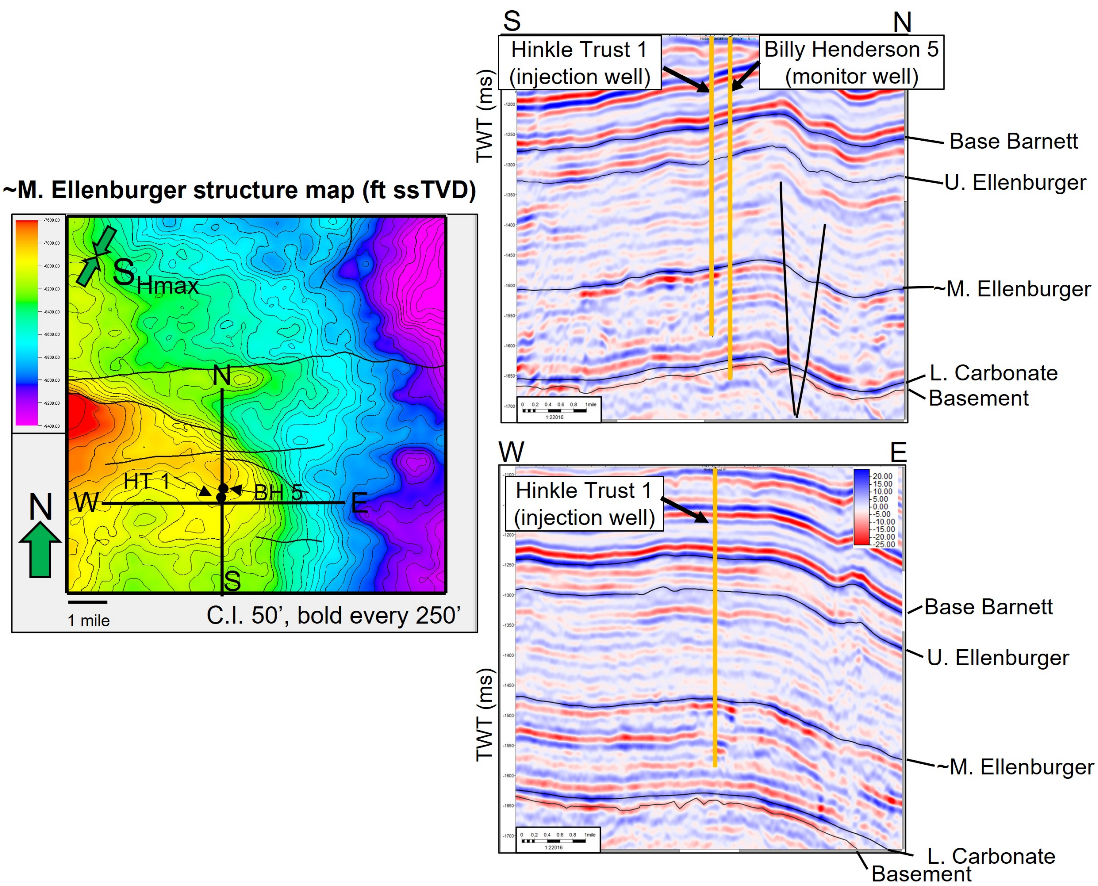


Figure 13: Middle Ellenburger structure map (top injection zone) and seismic cross-sections over proposed injection area. Black lines denote major faults.

2.6 Barnabus Ellenburger Field History

The Hinkle Trust #1 is permitted as an acid gas injector (AGI) within the TXRRC-defined field known as the Barnabus Ellenburger field. Across EOG's productive Barnett acreage in Montague County, this zone has historically been used

extensively for the disposal of produced water (i.e., SWD, or saltwater disposal). Of the six wells drilled into the Ellenburger for SWD by EOG, only four penetrated the middle Ellenburger - the zone intended for long-term CO_2 injection and storage. These four wells are shown on the map in Figure 14 in relation to the Hinkle Trust #1 and Billy Henderson #5, the injection and monitoring wells drilled for this project. Only two of these wells - the Cox and the Davenport - are still active SWD injectors while the other two have been permanently plugged and abandoned. Of the remaining active injectors, the Cox is the closest to the project area, located approximately 6 miles to the north.

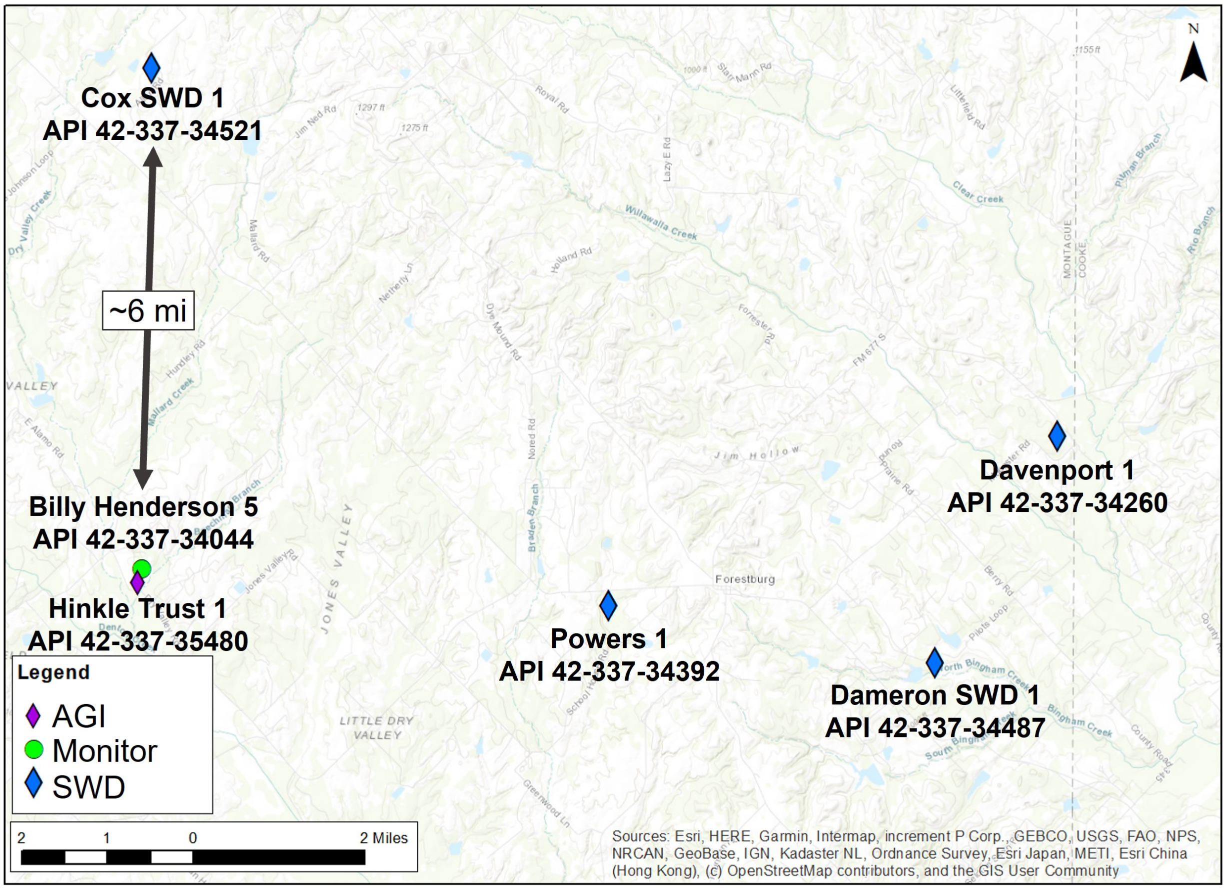


Figure 14: Map of SWD wells drilled into the middle Ellenburger in relation to the CO_2 injection project area.

Figure 15 shows the historical combined monthly injection rates and total cumulative volume injected from all four deep SWD wells from 2010 to 2022. What is notable in these injection trends are the very high rates from 2010 to 2014, when EOG's Barnett development was at its peak. During those years, the SWD wells were each injecting nearly 500,000 barrels (BBL) per month - indicating good injection characteristics in the middle Ellenburger. Over time, as development drilling and field production declined, so did the volume of produced water, which explains the tapering off in the use of the SWD wells from 2014 to 2022. During the entire active period, the four SWD wells injected nearly 90 MM BBL into the middle Ellenburger - suggestive of a large reservoir storage capacity. A relatively small amount of SWD injection is presently active in the Cox and Davenport wells at average rates of 4,200 and 3,700 BBL/day, respectively, with both wells showing stable and consistent injection pressure trends.

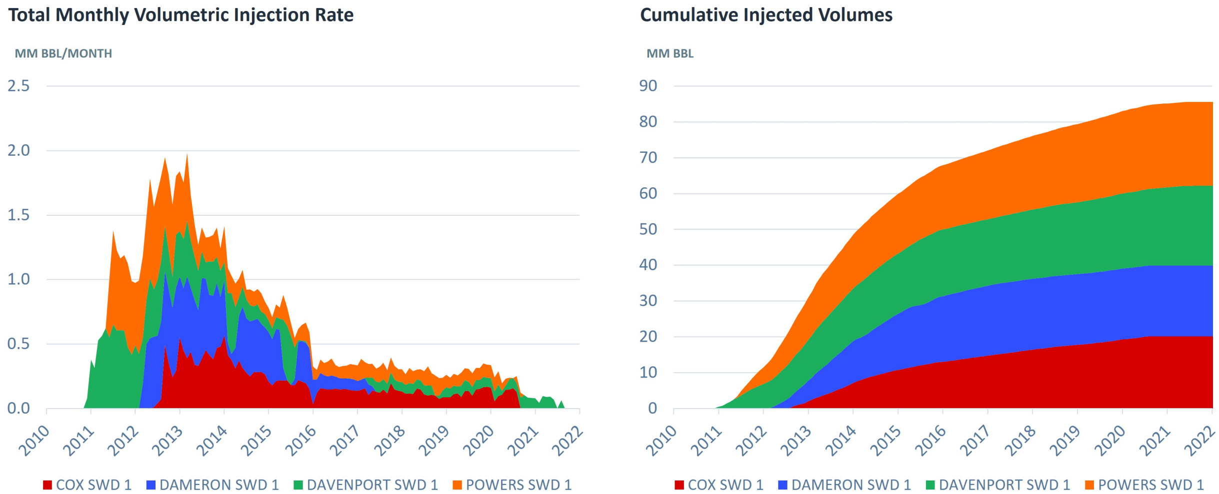


Figure 15: Combined monthly SWD injection rate (left) and cumulative injected water volumes (right) of deep Ellenburger SWD wells from 2010 to 2022.

2.7 Injection and Confining Zone Details

This section provides both quantitative and qualitative descriptions of the injection and confining zones. Observations presented are based on core, petrophysical well log, and 3D seismic data sets that have been integrated across appropriate scales. Petrophysical logs for the injection, upper confining, and lower confining zones were chosen to represent the character and thicknesses observed in the subsequent sections (Figures 16-18). Raw petrophysical logs are shown with the exception of a modeled lithology, which is calibrated to x-ray diffraction mineralogical measurements from core plugs. Core and seismic data are consistent with the characteristics exemplified by the petrophysical logs shown across the injection and confining zones.

2.7.1 Injection Zone

The injection zone for this project is the middle Ellenburger, which is a karsted carbonate reservoir. The injection zone is approximately one thousand feet thick in the project area. The lithology is primarily dolomite, with minor interbedded limestones (Figure 16). The limestones within the injection zone are nonporous and have low permeability based on log and core measurements. The dolomites within in the injection zone host the observed porosity and favorable permeability and range in texture from nonporous, overdolomitized to mesoscale vuggy sucrosic to karst breccias with significant macroscale pore networks. Pervasive dolomitization and karsting is associated with a shallow marine carbonate depositional setting and post-depositional sea level fluctuations allowing for formation of repeated unconformities and karst development across the section.

Qualitative and quantitative descriptive methods were tailored to capture relevant data across this range of textures. Multiscale core measurements and detailed borehole image log analyses were combined with traditional petrophysical modeling to provide the best quantitative interpretation of the injection section for modeling purposes. Matrix scale measurements were made using routine core analysis on plugs taken from a conventional core cut within the injection zone and from rotary sidewall cores collected off wireline in the Billy Henderson #5. These measurements illustrate the range in matrix porosity and permeability observed within the injection zone. Observed porosity and permeability ranges were less than 1% to over 15% and microdarcy to millidarcy, respectively (Table 3).

Matrix scale measurements were combined with methods more suited to measure porosity and permeability within mesoscale karst textures. Two methods were employed: full-diameter, whole core porosity and permeability mechanical measurements and high-resolution computed tomography (CT) scan digital modeling and measurements. A series of whole core porosity and permeability measurements were made on approximately 6-inch long pieces of whole (unslabbed) core sections. Samples were also CT-scanned and then the images were interpreted to create a 3D model of the pore network within the samples. The 3D digital model was then used to generate a set of high resolution poros-

ity curves for each sample. Quantitative data from these mesoscale measurements shows the wide range of values expected for this karst system (Table 4).

The permeabilities measured within the mesoscale to macroscale karst textures were observed to be significantly higher than that of the matrix rock. Interpretation of these observations combined with dynamic injection testing and flow allocation surveys suggests that fluid flow is significantly impacted by the presence or absence of these karst textures. Therefore, methods employed in the creation of a representative geomodel and reservoir simulation for the project incorporate all scales of measurement, which is discussed in detail in subsequent sections of this document.

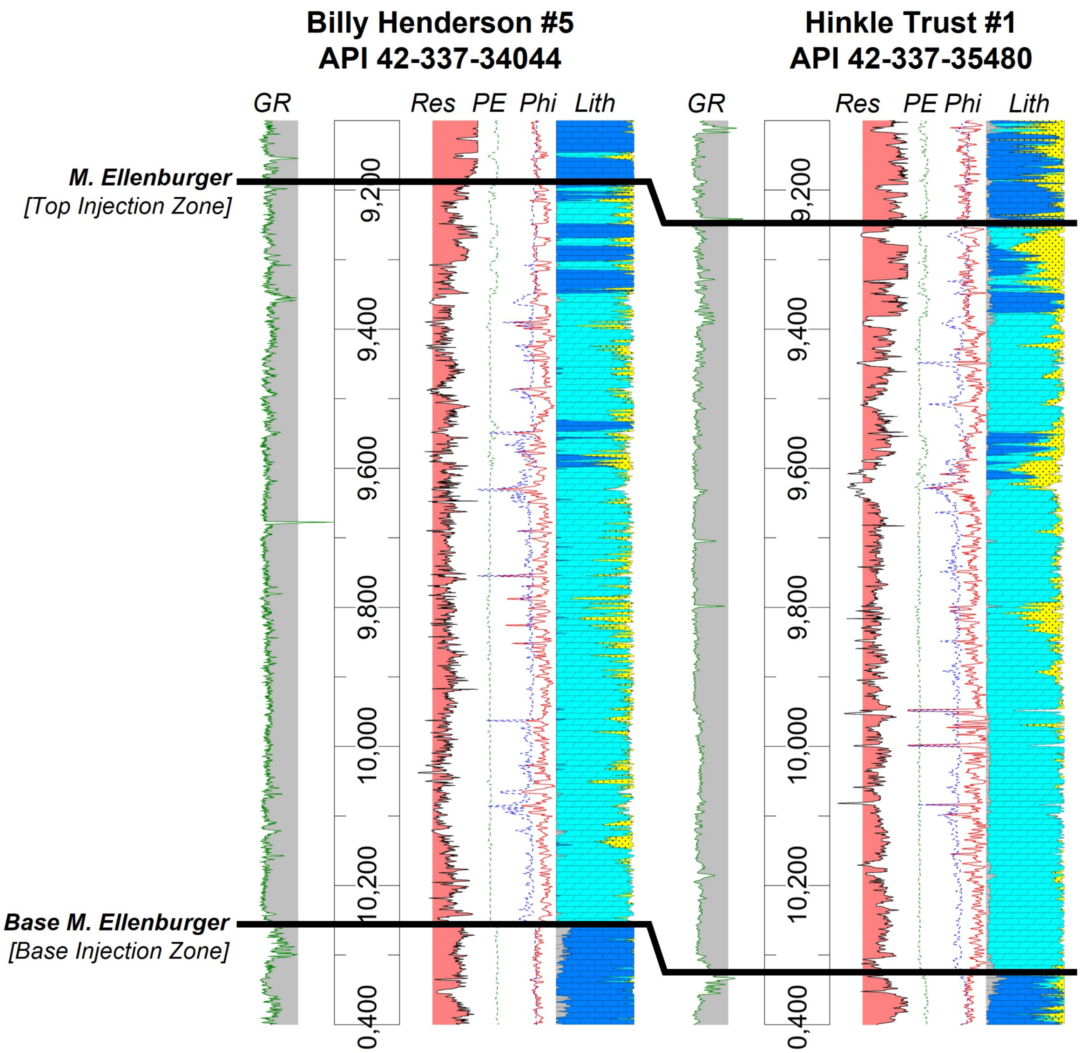


Figure 16: Petrophysical log interpretation in true vertical depth (TVD) for the Middle Ellenburger injection zone at the Bowie project site. Lithologic model presented includes dolomite (cyan), limestone (blue), silica (yellow), clay (gray), and organics (green).

2.7.2 Upper Confining Zone

The upper confining zone for this project is defined as the upper Ellenburger, Simpson, Viola, and base of Barnett shale. The upper confining zone is approximately 2,200 ft thick within the project site. A significant portion of the confining zone consists of sealing tight limestones and dolomites with varying amounts of clay and clay-rich shale. Other rock types present include variably-porous dolomites and limestones (Figure 17). The units within the upper

confining zone appear present and of similar thickness and character across the project site based on 3D seismic and well log interpretation.

The base of the upper Ellenburger consists of approximately 600 ft of mostly tight limestone with a few low porosity dolomite stringers directly overlying the injection zone. This contact is interpreted as a significant unconformity due to the sharp contrasts observed above and below the surface. Petrographic and petrophysical modeling of this zone indicates the presence of tightly-cemented, fine-grained mudstones and wackestones.

Above the lower blocky, tight limestone is interbedded tight limestone and variably porous dolomite. The interbedded lithologies and variable porosities observed are interpreted as coarsening upward depositional cycles with tight limestones at the base grading to variably porous dolomites that cap the cycles. Tight limestones here are similar to those observed in the base of the upper Ellenburger. Depositional textures within the dolomites are more difficult to ascertain due to dolomitization, but it is probable that some of these facies were coarser packstones and grainstones as well as muddier carbonate facies.

At the top of the upper Ellenburger, a blocky porous dolomite section is observed. The top of the Ellenburger likely represents another significant unconformity, but does not show the pervasive karst textures observed within the middle Ellenburger. Minor karst textures are observed, but most porosity in this part of the section seems to be associated with the matrix of the rock.

The Simpson formation is primarily limestone with minor to moderate clay content. It consists of an upper and lower section with higher clay content and a cleaner limestone facies in the middle of the section. Within the project area, the Simpson is approximately 400 ft thick. The upper and lower sections consist of fine-grained, muddy carbonate facies with varying amounts of fine-grained siliciclastics. The clean limestones contain coarser carbonate facies with minor preserved porosity. The Viola within the project area is approximately 180 ft of tight limestone. Observations from a nearby proprietary core just outside the project site suggest the Viola consists mainly of nonporous carbonate mudstones and wackestones within the project area.

At the top of the confining zone is the lower Barnett shale. The lower Barnett is the main hydrocarbon development horizon within the project site. As such, the main focus on the lower Barnett for confinement is restricted to the base of the section below the horizontally-drilled development target. The rock volume within the Barnett that has not been stimulated by hydraulic fracturing, however, likely contributes to confinement within the project area as well.

Matrix scale measurements were made using routine core analysis on plugs taken from several sources. Data for the upper Ellenburger and Simpson comes from plugs from a conventional core cut within the upper Ellenburger and from rotary sidewall cores collected via wireline in the Billy Henderson #5 well. Data for the Simpson and the Barnett come from plugs cut from analog cores near the project site. Quantitative measurements indicate the low porosity, low permeability nature of the pervasive sealing facies within the upper Ellenburger, Simpson, Viola, and lower Barnett shale (Table 3).

The quantitative data presented here were incorporated into the geomodel for the confining zone. In contrast to the injection zone, no pervasive karst textures were observed within the confining zone in the project area. Image log analysis and dynamic injection testing and surveys also indicate an apparent lack of karst features, as well as a lack of transmissive fractures and faults within the upper confining zone at the injection site. As such, the upper confining system as described above is expected to provide excellent long-term sealing capacity.

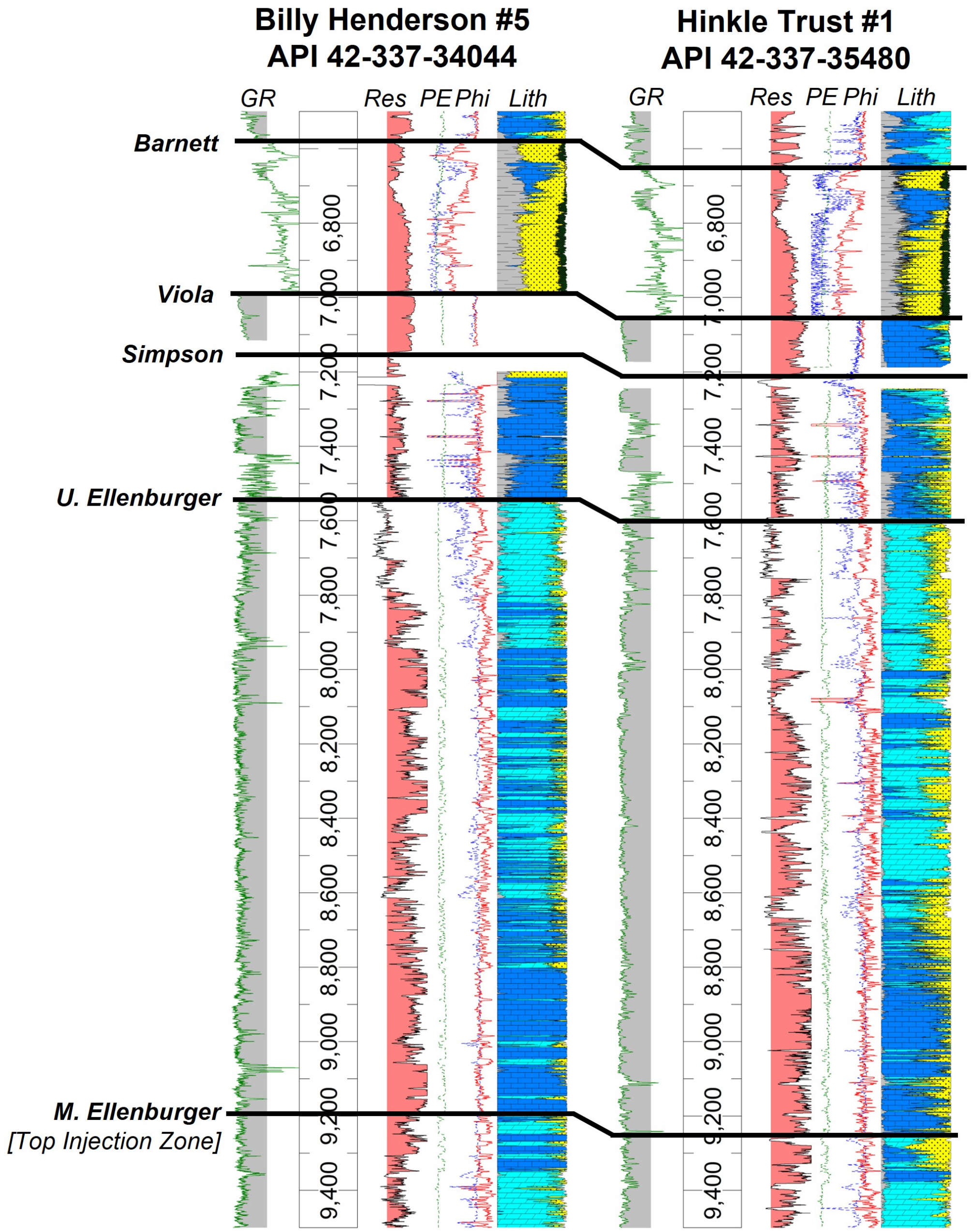


Figure 17: Petrophysical log interpretation in true vertical depth (TVD) for the upper Ellenburger to Barnett upper confining zone within the Bowie project site. Lithologic model presented includes dolomite (cyan), limestone (blue), silica (yellow), clay (gray), and organics (green).

2.7.3 Lower Confining Zone

The lower confining zone consists of the section between the granitic basement and the base of the middle Ellenburger injection zone. This zone consists of approximately 1,000 ft of primarily tight limestone with minor clay within the limestones and a few clay stringers in the project area (Figure 18). Petrographic analysis indicates the presence of heavily cemented limestone facies ranging from mudstones to packstones. A few porous limestone beds are preserved near the clay-rich stringers, but porous limestones are relatively rare across the entirety of the section.

Quantitative routine core analysis data confirms the presence of low porosity, low permeability limestone facies across much of the section. As with the upper confining zone, these matrix scale measurements were used in the geomodel and subsequent reservoir simulation for the lower confining zone. Image log analysis, dynamic injection testing, and injection surveys also indicate a lack of karst features within the lower confining zone, as well as an apparent lack of transmissive fractures and faults within the lower confining zone at the injection site.

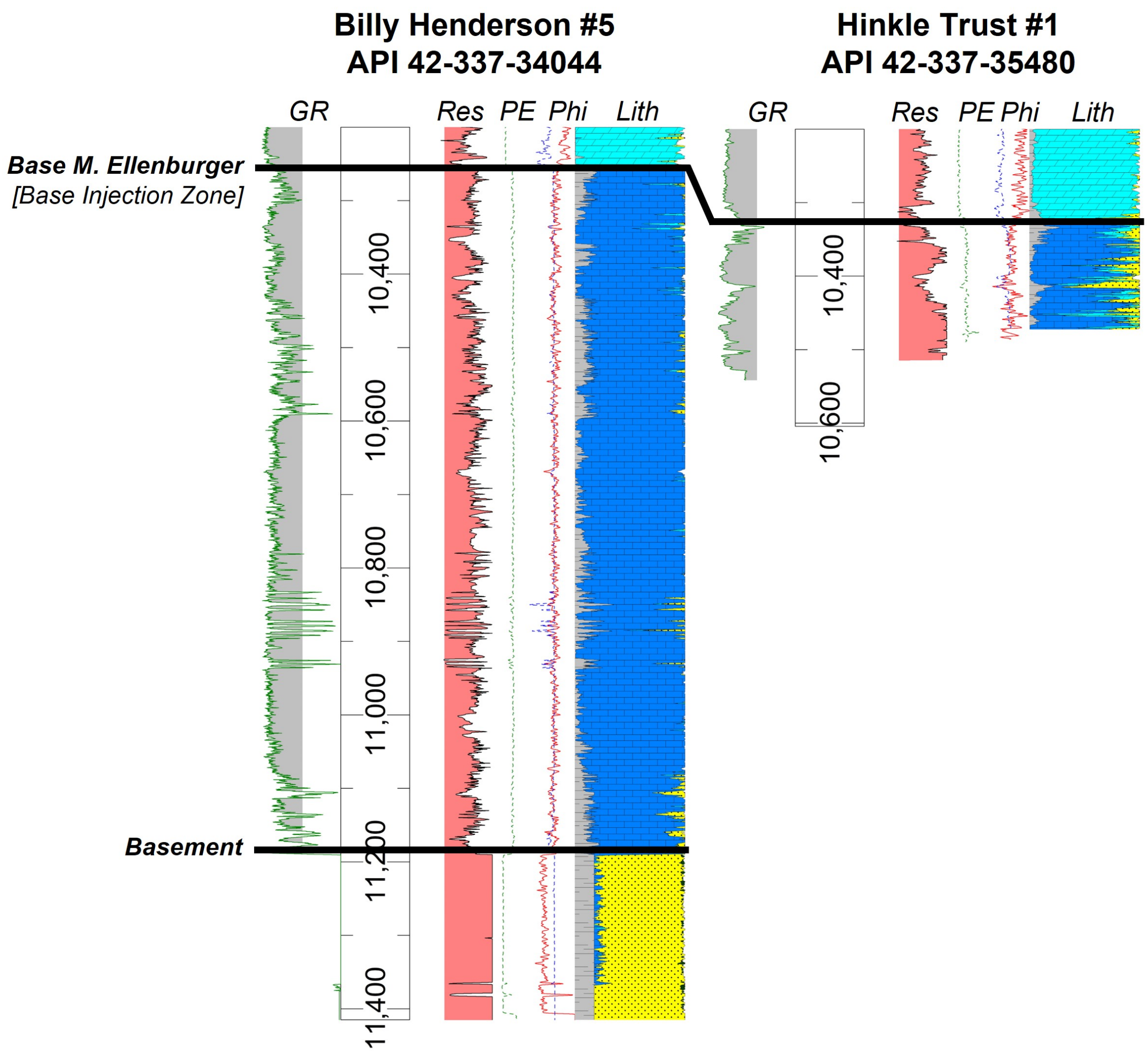


Figure 18: Petrophysical log interpretation in true vertical depth (TVD) for the base Ellenburger to middle Ellenburger lower confining zone within the Bowie project site. Lithologic model presented includes dolomite (cyan), limestone (blue), silica (yellow), clay (gray), and organics (green).

Table 3: Summary of routine core analysis (RCA) data collected for the project by system and formation.

System	Formation	Porosity Minimum %	Porosity Maximum %	Permeability Minimum md	Permeability Maximum md
Upper Confining	L. Barnett	1.29	8.29	3.02E-06[b]	7.24E-04[b]
	Viola	1.68	6.59	5.00E-04	1.60E-02
	Simpson	1.60	4.32	4.90E-03	6.34E-01
	U. Ellenburger	0.36	13.85	<1.00E-03[c]	5.58E00
Injection	M. Ellenburger	0.29	15.96	<1.00E-03[c]	1.68E00
Lower Confining	L. Carbonate	0.35	15.87	<1.00E-03[c]	9.40E00

[b]Denotes permeability measurements made using pressure decay methods.
[c]Denotes permeability values were below the measurement threshold of the routine core analysis technique. Therefore, the value presented represents an upper limit of minimum permeability. Minimum permeabilities could be significantly lower than the values presented.

Table 4: Summary of full diameter core mesoscale data over the injection interval collected for the project.

	Test Method	
Measurement	Full Diameter Mechanical	Computed Tomography (CT) Digital
Porosity Minimum (%)	2.2	<0.01
Porosity Maximum (%)	6.3	51.9
Horizontal Permeability Minimum (md)	6.96E-02	—
Horizontal Permeability Maximum (md)	1.86E04	—
Vertical Permeability Minimum (md)	1.64E-04	—
Vertical Permeability Maximum (md)	2.83E00	—
Ratio Vert./Horiz. Perm. (Minimum)	4.0E-07	—
Ratio Vert./Horiz. Perm. (Maximum)	7.5E-01	—
Ratio Vert./Horiz. Perm. (Median)	1.0E-03	—

3 Development and Administration of the MRV Plan

As required under §98.448(a)(1)-(2) of Subpart RR, the MRV plan is developed around and tailored to the potential surface leakage pathways within the active and maximum monitoring areas (AMA and MMA, respectively) defined in §98.449. Since the AMA and MMA are both dependent on the expected long-term behavior of CO_2 in the subsurface, numerical reservoir simulation is the generally-accepted best practice to represent the dynamic behavior and complex fluid interactions that influence the CO_2 plume extent and shape during and after injection operations. The next two sections describe the development of a detailed geologic model using the available regional and site-specific data that serves as the basis for predictive numerical reservoir simulations to delineate the AMA and MMA extents for the proposed injection volumes.

3.1 Geologic Model

A geologic model was developed with the proposed injection project at the approximate center of the gridded region. The general grid properties are summarized in Table 5 and the overall grid geometry and structure is depicted in Figure 19. Major stratigraphic surfaces - from the Lower Barnett through the upper Granitic Basement - and regional structure were interpreted from EOG's in-house 3D seismic data and depth-tied to well log correlations from the deep penetrations in the project area. Although faulting and fracturing is generally present within the proposed injection

area, injection testing and geomechanical modeling suggests faults and fractures are not primary permeability pathways. Consequently, they are not included in the initial simulation model. Grid layer thicknesses in the over- and under-burden horizons are generally coarse (ranging from 70 to more than 700 feet) since little change is expected in these regions, whereas the layers in the primary injection horizon (i.e., the middle Ellenburger) were selectively refined (ranging from 15 to ~50 feet) to capture the geologic heterogeneity that is likely to influence the CO_2 flow distribution within the storage reservoir.

Table 5: Summary of geologic model grid properties

	i-dir	**j-dir**	**k-dir**
Increment (ft)	200	200	variable
Layer Count	126	126	35
Total Length (ft)	26,200	26,200	~5,400
Total Cell Count		555,660	

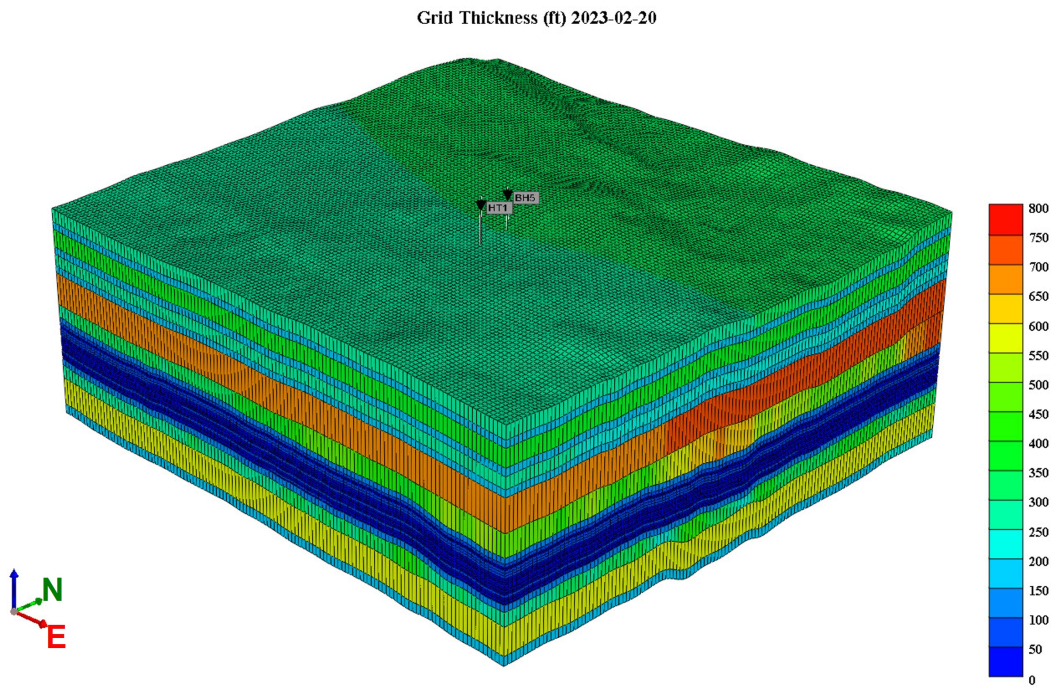


Figure 19: Northwest-looking 3D-view of the overall model grid structure; grid cell thickness property displayed.

Petrophysical transport properties (e.g., porosity and permeability) for each geologic horizon were subsequently propagated throughout the grid framework based on the rigorous integration and characterization of the core, log, and seismic data sets available in the project area (and described in the previous Section 2.7). The statistical range and spatial variability of all geologic intervals included in the model were considered in this multiscale analysis, with particular emphasis on representing the extreme heterogeneity observed in the karsted, dolomitized injection interval of the middle Ellenburger. The iterative property modeling workflow adopted for this project is summarized by the following general steps:

1. comparison and calibration of log response to measured core values (plug and full-diameter samples);
2. identification of key facies associated with injection/storage versus baffling/containment at well scale;

3. development of porosity-permeability transforms and net-to-gross (NTG) relationships for each facies type at well scale;
4. development of independent ties between well-scale porosity and NTG to seismic-scale attributes;
5. probabilistic spatial modeling of porosity and NTG via collocated co-kriging with associated seismic attributes;
6. calculation of permeability properties (i.e., vertical and horizontal) based on established porosity transforms for each geologic horizon.

Figure 20 depicts a representative layer from the resulting baseline realization of the geologic model which was used in the subsequent reservoir simulation forecasts. Of particular note is the heterogeneous nature in the spatial distribution of both the porosity and permeability properties in the middle Ellenburger, which is guided by amplitudes and patterns in the seismic data interpreted to be associated with large-scale karst features. The transport characteristics associated with these features are expected to have a first-order influence on the CO_2 plume growth over time and the workflow described above incorporates the available data - at the appropriate scales - to rigorously represent them in the model.

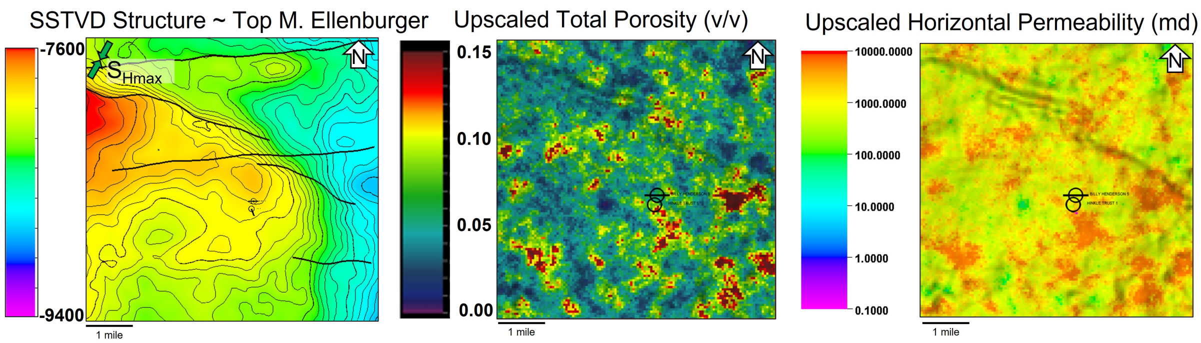


Figure 20: Example character of geomodel structural inputs in subsea true vertical depth (SSTVD) and property distributions (total porosity and horizontal permeability) within the middle Ellenburger storage zone. Note the varied distribution of high porosity and permeability representative of a karst reservoir.

Due to the limited availability of vertical permeability data in the project area, a simpler deterministic approach was taken to distribute vertical permeability throughout the model grid. For the main injection zone - the middle Ellenburger - the median value of the measured vertical-to-horizontal permeability ratios of 1.0E-03 was used (see Table 4). This choice captures the extremely heterogeneous nature of the injection interval, which is characterized by high permeability karst features interspersed with low porosity and very low permeability host rock. In the underlying and overlying confining zones, a vertical-to-horizontal permeability ratio of 1.0 was applied due to the more homogeneous nature of these intervals, which are characterized by low permeability matrix rock with little secondary enhancement.

3.2 Reservoir Simulation Model

With a representative static geologic model established, the grid and associated properties were then imported into Computer Modeling Group's (CMG) GEM v2022.30 compositional reservoir simulation software to forecast the long-term CO_2 plume behavior. GEM is a state-of-the-art finite difference solver which uses a compositional equation-of-state (EOS) methodology to represent the complex, multi-component thermodynamic interactions of fluid components during transport in porous media [Computer Modeling Group, LTD. (2021)]. As noted in other MRV plans recently approved by the EPA [Stakeholder Midstream Gas Services, LLC (2022)], GEM has become a generally-accepted software package for technical evaluation of geologic sequestration projects and is cited as such in the EPA's area of review guidance document for Class VI injection permits [US EPA (2013)].

Initialization of the reservoir model conditions was based on data acquired during the drilling and characterization of the project wells. Table 6 summarizes key inputs for the main injection interval in the middle Ellenburger, including

reference subsea true vertical depth (SSTVD), pressure, temperature, water saturation (S_w), and total dissolved solids (TDS) of the native formation brine in ppm. These data were obtained from wireline-conveyed dynamic testing and sampling tools deployed during logging operations on the Billy Henderson #5 and are representative of the reservoir throughout the project area. Pressure and temperature gradients were extended from the reference depth through all grid layers based on fluid density measurements and stabilized fiber-optic distributed temperature sensor (DTS) measurements, respectively.

Table 6: Basic middle Ellenburger Reservoir conditions

Depth SSTVD ft	**Pressure** psia	**Temperature** °F	$\mathbf{S_w}$ v/v	**TDS** ppm
-9,275	4,993	195	1	211,961

Other key transport parameters and dynamic fluid processes for both the injection and confining horizons represented in the simulation include:

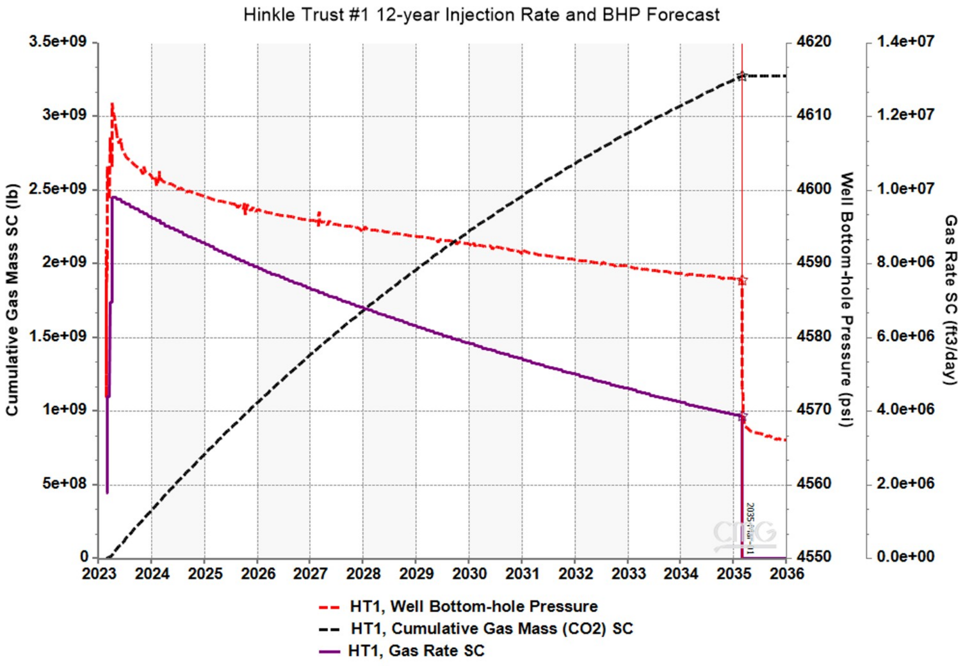
1. Drainage and imbibition capillary pressure functions for the CO_2-brine system derived from intrusion and extrusion mercury injection capillary pressure measurements (MICP) on core samples;
2. Porosity- and permeability-scaling of capillary pressure according to the Leverett J-function [Leverett (1941)];
3. Drainage and imbibition relative permeability functions calculated from the corresponding capillary pressure profiles;
4. Hysteresis trapping of the phases between drainage and imbibition cycles; and
5. Salinity concentration in the water (i.e., brine) phase and solubility between CO_2 and brine phases.

Before CO_2 injection forecast simulations were run, the model was rigorously history-matched to the water injection step-rate and pressure interference testing that was conducted between the Hinkle Trust #1 injection well and the Billy Henderson #5 monitoring well. Transient analysis of the pressure fall-off and interference test data revealed a single-porosity reservoir response with no apparent far-field boundary influence (i.e., an infinite-acting reservoir). In addition, pressure data obtained during the test from multiple gauges installed in both wells provided a robust data set against which to further calibrate and adjust the porosity, permeability, rock compressibility, and boundary conditions of the simulation model. This crucial step provides additional confidence in the simulated injection performance and long-term CO_2 plume development projections.

Another important constraint to consider when evaluating the simulated injection performance and long-term storage integrity is the fracture pressure of the injection and confining zones. As discussed later in section 3.5, the minimum horizontal stress gradient of the upper confining system was demonstrated via discrete micro-frac injection test to be 0.69 psi/ft, which equates to an absolute pressure of approximately ~5,500 psia at 7,980 ft - the TVD of the measurement. A continuous geomechanical earth model was subsequently constructed and calibrated to this measured data to assess the minimum horizontal stress profile in the injection zone, since it was impractical to initiate a fracture in this zone due to the extremely high permeability/injectivity. The resulting estimate of the minimum horizontal stress at the top of the injection zone (~9,350 ft TVD; see Figure 26) is approximately ~5,890 psia or an effective gradient of 0.63 psi/ft. Applying a 90% safety factor to that estimate yields an effective gradient of approximately ~0.57 psi/ft or 5,300 psia.

A base case injection forecast was run using the calibrated reservoir model and the proposed 12-year CO_2 volumes schedule in Figure 4. An additional 200 years of post-injection shut-in time was simulated to observe the long-term reservoir response and predict the stabilized extent and shape of the separate phase CO_2 plume after buoyant migration has ceased. Simulated bottom-hole pressure (BHP) at the Hinkle Trust #1 injection well and CO_2 saturation (S_g) maps at the top of the middle Ellenburger injection zone - for both the 12-year injection and 212-year total simulation periods - are shown in Figures 21 and 22, respectively. Of particular note in Figure 21 is the relatively low BHP increase above the initial static pressure of ~4,550 psia: at the maximum injection rate of ~10 MMSCFD, the BHP reaches a maximum value slightly above 4,610 psia or 60 psi above initial static conditions. This pressure increase is well below the safe operational threshold of 5,300 psia discussed above. Over the proposed 12-year injection schedule, the risk of over-pressurization in the injection zone decreases since the BHP gradually declines with the declining CO_2 injection rate. At the end of the 12-year injection period, the BHP drops to within 20 psi of initial static conditions instantly due to the high system permeability/injectivity of the middle Ellenburger. The period of pressure decline observed at the injection well through the year 2060 is a result of the natural decompression of the infinite-acting reservoir system in combination with the gradual buoyant equilibration of the compressible CO_2 plume.

Inspection of the CO_2 saturation maps (Figure 22) reveals the influence of reservoir heterogeneity and structure in the distribution, shape, and migrational path of the separate phase plume over time. After 12 years of CO_2 injection - or ~1.45 million MT-CO_2 injected - the plume takes on an amorphous elliptical shape that is ~9,000 ft in length and ~6,000 ft in width and roughly centered on the injection well. When comparing the example porosity and permeability distributions in the middle Ellenburger (Figure 20) and the 12-year CO_2 saturation map, similar patterns can be seen between the tortuous edges of the plume footprint and the high porosity/permeability regions where the CO_2 has found preferable pathways during injection. During the 200-year post-injection simulated period, geologic structure in the middle Ellenburger is observed to have more influence in the buoyant growth of the plume over time as evidenced by the expansion of the plume to the north (up structural dip) and the extension of a narrow "limb" of CO_2 to the west along a structural ridge in the middle of the grid. This ridge can be identified on the map of structural contours in the left panel of Figure 20. Overall the plume grows by roughly 33% during the 200-year post-injection simulated period and completely stabilizes around year 2225 (190 years after injection stops), showing no visible areal expansion thereafter.



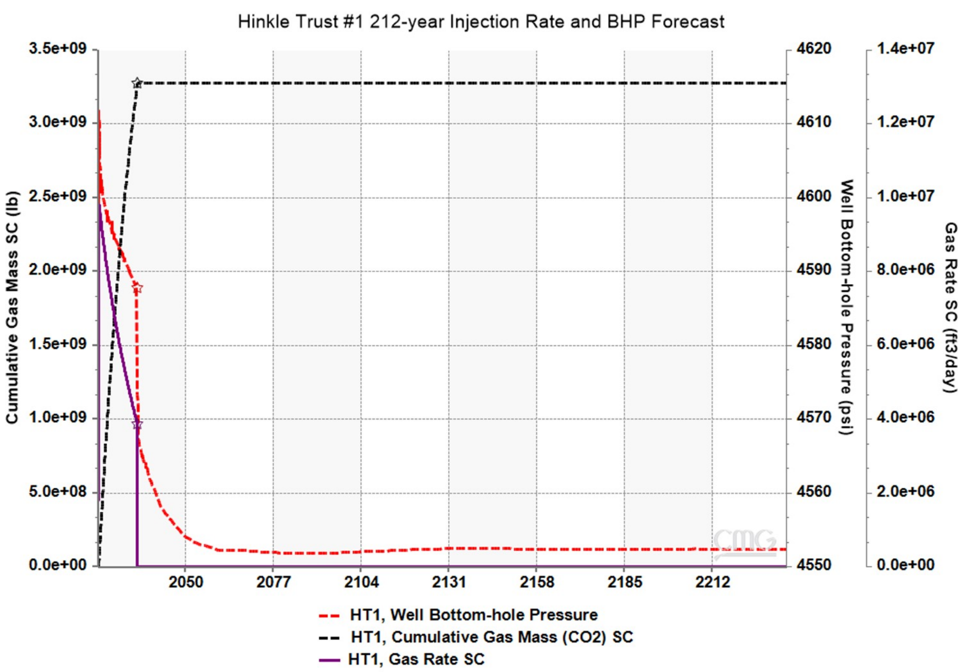


Figure 21: Modeled CO_2 rates, pressures, and cumulative volume for 12-year (top) and 212-year (bottom) time steps.

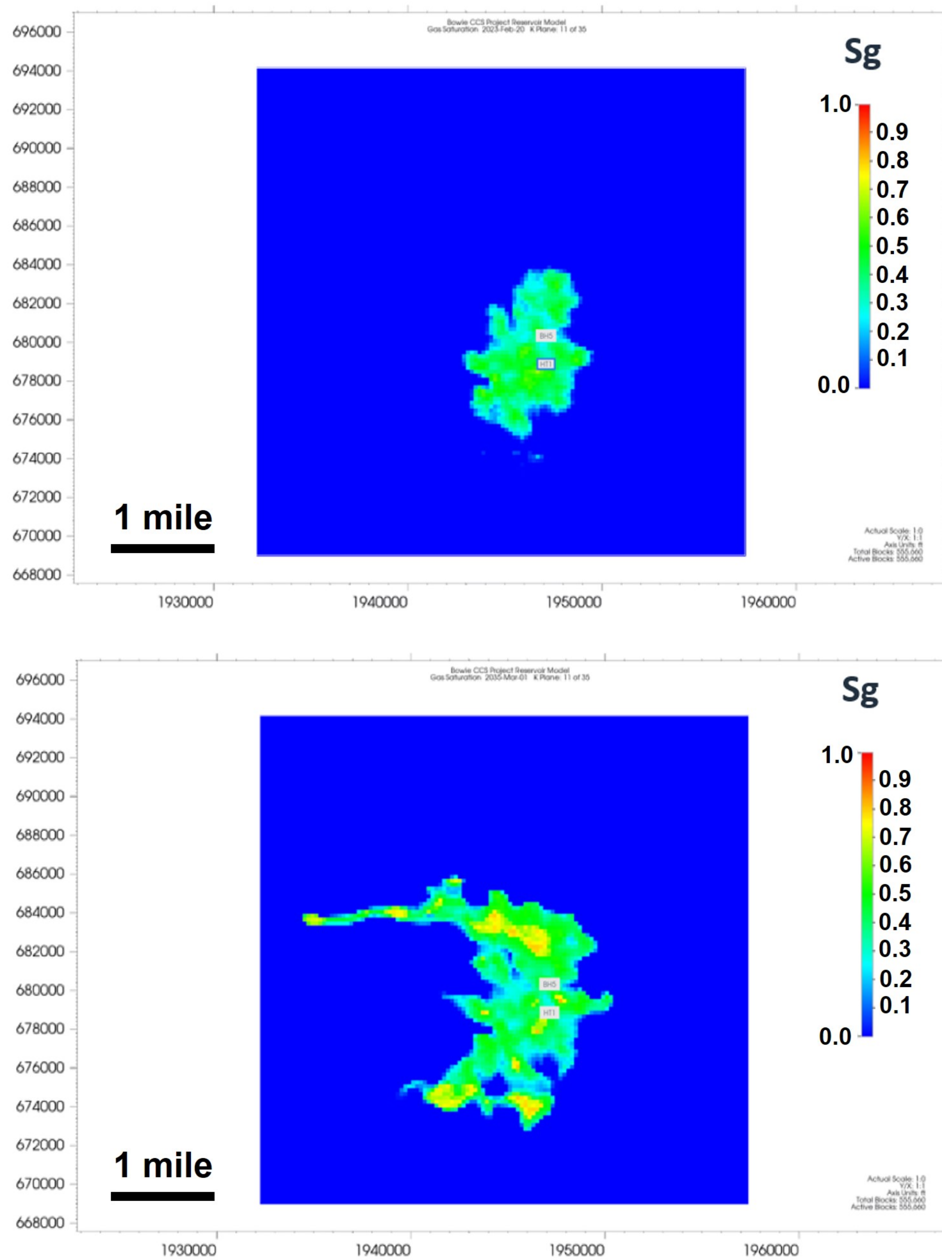


Figure 22: Modeled CO_2 saturation distribution for 12-year (top) and 212-year (bottom) time steps. Note that the Hinkle Trust #1 injector is labeled "HT1" and Billy Henderson #5 monitor is labeled "BH5" on the saturation maps.

3.3 Maximum Monitoring Area (MMA)

In Subpart RR, the maximum monitoring area (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. Using a 3% CO_2 saturation threshold - the estimated saturation of gas breakthrough from mercury injection capillary pressure (MICP) measurements - the boundary of the stabilized, separate phase plume was determined from the simulation results in Figure 22. This boundary, plus the required half-mile buffer, is depicted in Figure 23 with the injection and monitoring wells for context.

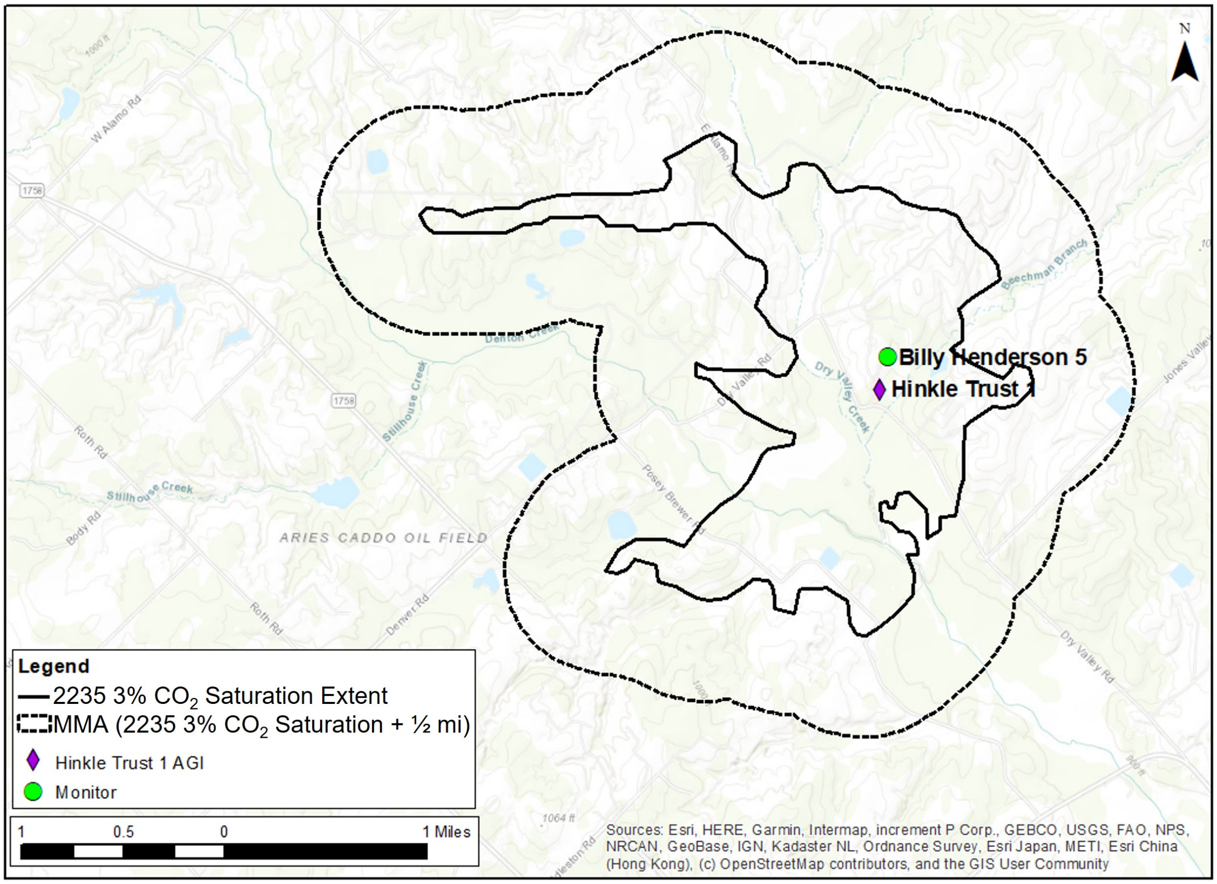


Figure 23: Maximum monitoring area for Bowie project.

3.4 Active Monitoring Area (AMA)

To define the active monitoring area (AMA), the initial monitoring period of 12 years was chosen based on the expected injection duration for the project. As a result, the separate phase CO_2 at the end of injection in year 2035 (i.e., “t”) - assuming the same 3% CO_2 saturation threshold - plus the required half-mile buffer was defined (blue dashed contour in Figure 24). Per the definition of the AMA in Subpart RR, this area was superimposed against the projected plume outline in the year 2040 (i.e.,“t + 5”) - the green outline in Figure 24. Since the green outline lies entirely within the blue dashed outline, the AMA is defined by the plume outline in the year 2035 plus the half-mile buffer.

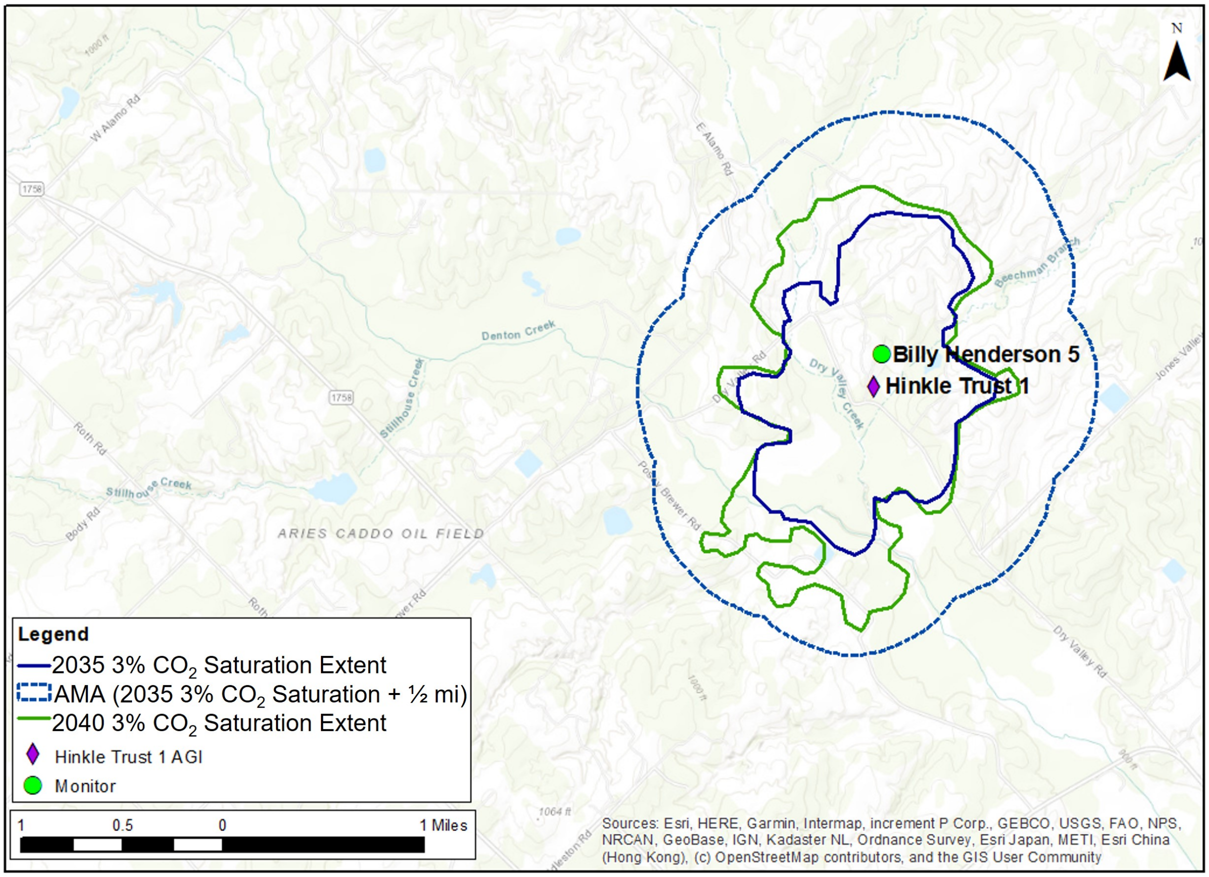


Figure 24: Active monitoring area for Bowie project.

3.5 Potential Surface Leakage Pathways

Per Subpart RR requirements, SPG has addressed the potential surface leakage pathways in the project area associated with surfaces facilities, faults and fractures, wellbores, and the confining system in a two-part approach. Part one de-risks the project site through various characterization methods, taking into account both static character and dynamic performance of the system through injection scenario modeling. This first part is addressed in the document subsections immediately below. Part two presents the required plan for detection, verification, and quantification of potential leaks and is addressed in subsection 3.6.

3.5.1 Surface Facilities

Leakage from surface facilities downstream of the injection meter is unlikely. The high pressure injection meter is placed near the high pressure compressor outlet and less than 210 ft upstream of the wellhead (Figure 3), minimizing potential leakage points between the metering of the stream and downhole injection point. Furthermore, the piping and flanges between the injection meter and the wellhead are ANSI 2500 rated, and all welds are certified by x-ray inspection. If leakage from surface equipment is detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release in accordance with 40 CFR §98.448(5).

3.5.2 Wellbores

The only wellbores that penetrate the injection zone in the AMA and MMA are those that were constructed specifically for this project. Both the Billy Henderson #5 and Hinkle Trust #1 were constructed 1) to mitigate leakage risks from CO_2 injection and 2) to provide for monitoring of near-wellbore conditions prior to, during, and after injection operations. There are additional wellbores present in the AMA/MMA, but they do not penetrate the injection zone.

Because they do not penetrate the injection zone, they are not leakage risks to this project and are not discussed in detail within this document.

The Billy Henderson #5 monitor was designed to mitigate the risk of CO_2 migration out of the injection zone. A CO_2-resistant cement blend, EverCrete [SLB (2021)], was used to bond the long string casing in place. The top of cement sits above the top of the upper confining system defined for the project. In addition, pressure-temperature gauges and fiber monitoring instrumentation were installed across the injection zone (gauges and fiber), below the injection zone (fiber only) and above the injection zone (gauges and fiber) to allow for monitoring of pressure and temperature responses across the wellbore (Figure 25).

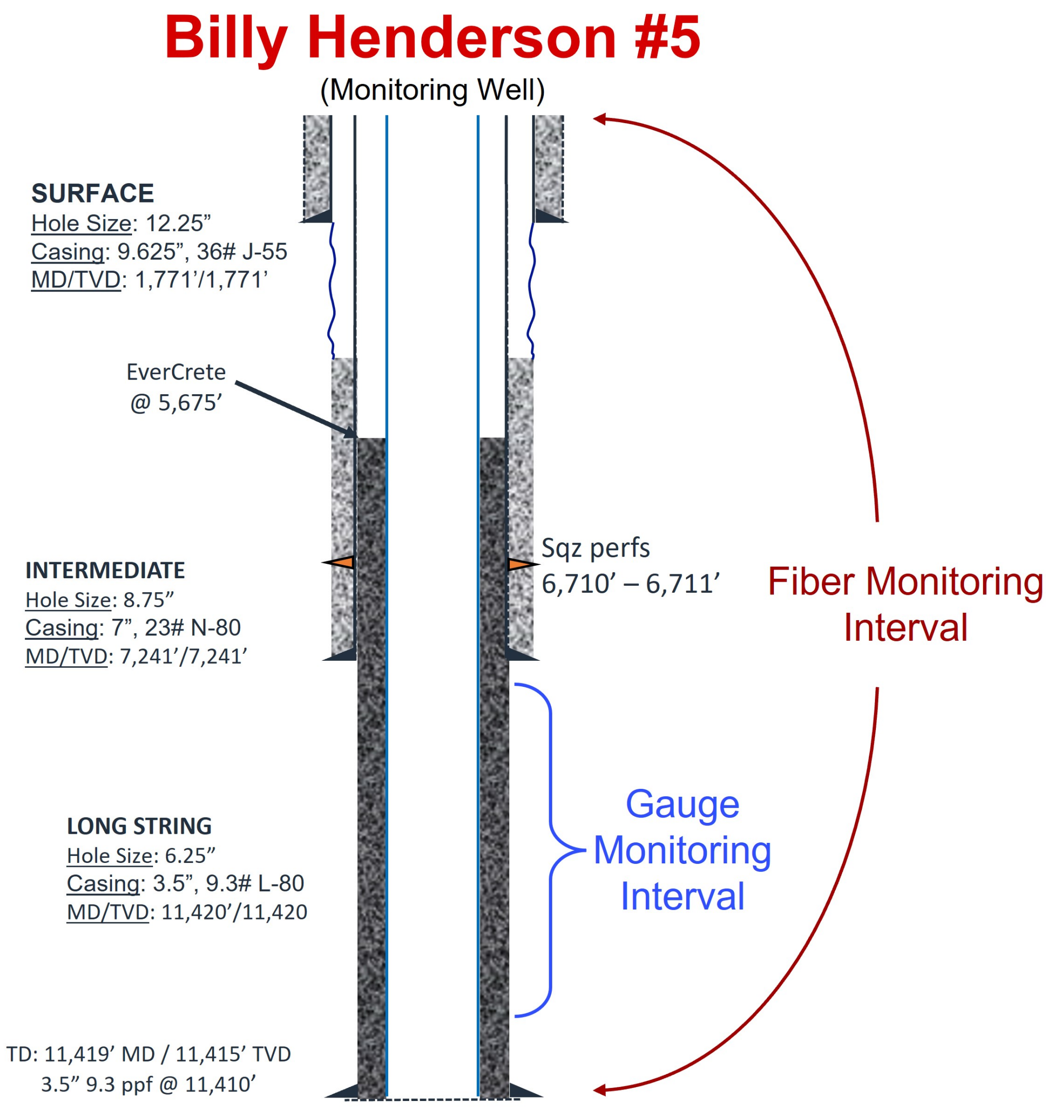


Figure 25: Billy Henderson #5 wellbore diagram.

The Hinkle Trust #1 injection well was also designed to mitigate the risk of CO_2 migration out of the injection zone. All strings of casing were cemented to surface and a CO_2-resistant resin product, WellLock [Halliburton (2017)], was used to cement the liner section of the long string casing sitting directly above the open hole injection interval. In addition, pressure-temperature gauges and fiber monitoring instrumentation were installed on the intermediate casing above the injection zone and on the injection tubing to allow for monitoring of pressure and temperature responses in the tubing, long string annular space, and above the injection zone (Figure 26).

Data from downhole instrumentation is collected and archived continuously across both wells. Aggradation and analysis of this data will allow SPG to quickly detect any leakage present within the wellbore. In addition, an annual mechanical integrity test (MIT) will be conducted in the injection well as prescribed in the Class II Underground Injection Control (UIC) permit (see Appendix A). The first MIT has already been conducted. If leakage is detected, EOG will use the recorded operating conditions at the time of the leak to estimate the volume of CO_2 released and then take appropriate corrective action.

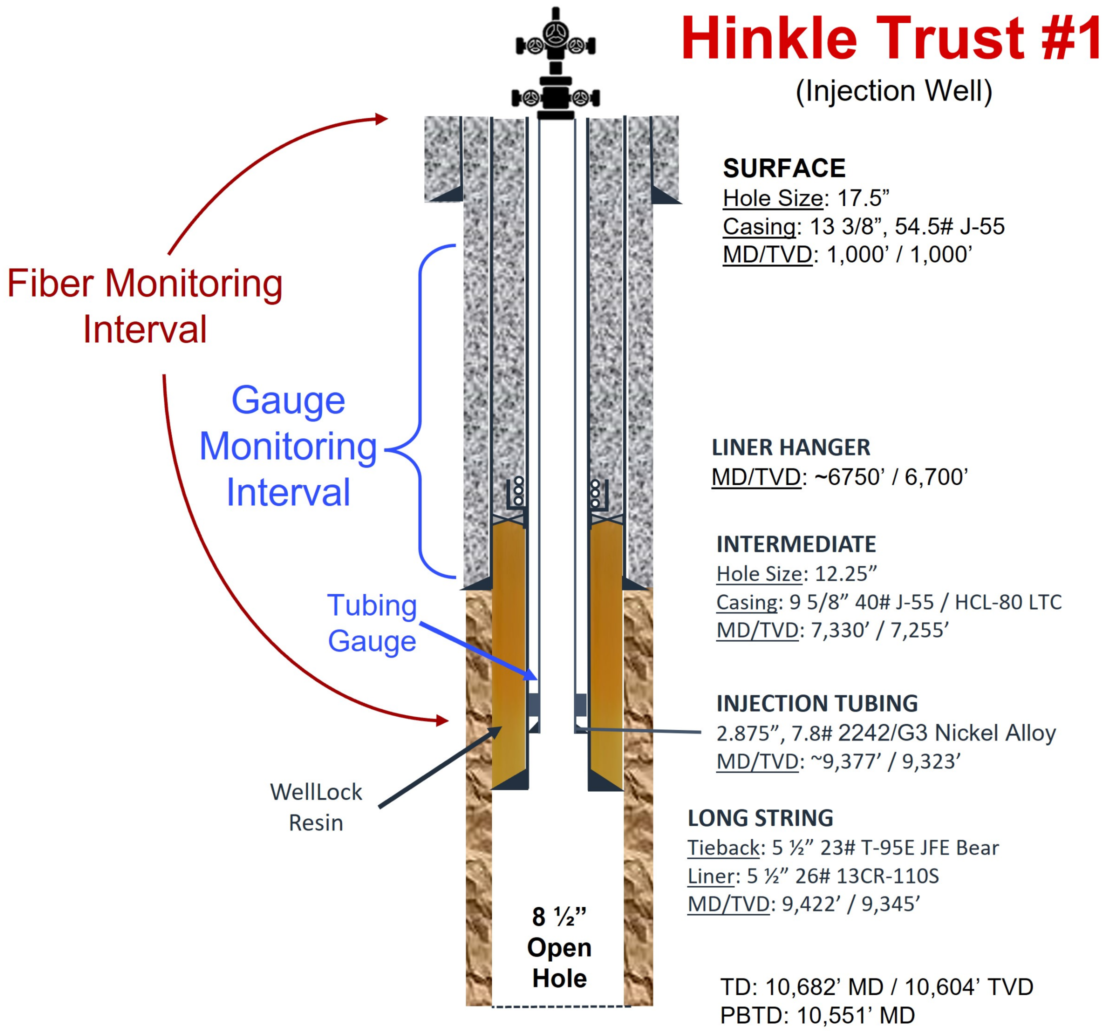


Figure 26: Hinkle Trust #1 wellbore diagram.

With regard to future drilling in the MMA, SPG does not anticipate new wellbores to penetrate the injection zone as the formation does not contain commercial hydrocarbon accumulations within the vicinity of the project site. This was one of the key criteria for siting the project in this area. If new wells were to be permitted and drilled within one-quarter mile of the Hinkle Trust #1 injection well, operators would be subject to TXRRC Rule 13 compliance on wellbore construction since the Ellenburger is identified in the drilling permit as one of the formations requiring such compliance (see Appendix B). Rule 13 requires operators to set steel casing and cement across and above all formations permitted for injection (under TXRRC Rules 9 or 46) [Texas Administrative Code (2023)]. Furthermore, Rule 13 requires operators to set casing and cement across and above all zones with the potential for flow or containing corrosive formation fluids. As such, the potential for surface leakage through existing or future wells in the project area is highly unlikely.

3.5.3 Faults and Fractures

The Ellenburger and underlying basement at the injection site are characterized by large scale strike-slip faults and prevalent natural fracturing. The propensity for each of these characteristics to serve as surface leakage pathways is discussed below.

To assess the risk of leakage through faults, a Fault Slip Potential (FSP) analysis [Walsh et al. (2017)] was performed on large-scale basement-rooted faults traversing the proposed injection area and interval. The FSP analysis probabilistically evaluates the likelihood of excess pressure generated by fluid injection to trigger shear slip on pre-existing faults. As faults which are able to slip in shear in the present-day stress field with minor excess pressure (critically-stressed) tend to be those which are hydraulically-conductive [Barton et al. (1995)], the FSP analysis simultaneously assesses both induced seismicity and fault leakage likelihood. The FSP analysis includes faults mapped from 3D seismic data, directly measured reservoir and fluid properties from logs and core, and the planned CO_2 injection schedule. FSP results are shown in Figure 27, and indicate all major faults within the planned injection area and interval exhibit a very low (<10%) fault slip likelihood over the CO_2 injection timeline. In other words, the major faults are not critically-stressed in the present-day stress field and are, therefore, not expected to be hydraulically-conductive leakage pathways during CO_2 injection. Nevertheless, downhole pressure instruments installed in the project wells (described in the previous section) will be continuously monitored via the project's real-time data acquisition system. Appropriate alarms and operational set points for surface equipment will be established to ensure that downhole conditions do not exceed the safety thresholds which could potentially trigger a fault-slip event in the most conservative case.

Only one earthquake in Montague County has been recorded in the last 100 years [U.S. Geological Survey (2023)] despite significant SWD injection within the Ellenburger. The FSP results are consistent with generally stable fault behavior in larger Montague County - and within the proposed injection area - as evident by the lack of detectable seismicity despite the presence of numerous Ellenburger SWD injection wells within the county (Figure 28).

Cross-fault leakage is also unlikely due to fault sense-of-slip and displacement. The dominant strike-slip sense of motion on major faults in the area decreases the likelihood of vertically juxtaposing injection intervals with containment intervals. In addition, cross-fault leakage is also likely inhibited by development of a thick, a low-permeability fault core due to significant fault displacement [Torabi et al. (2019), Caine et al. (1996)].

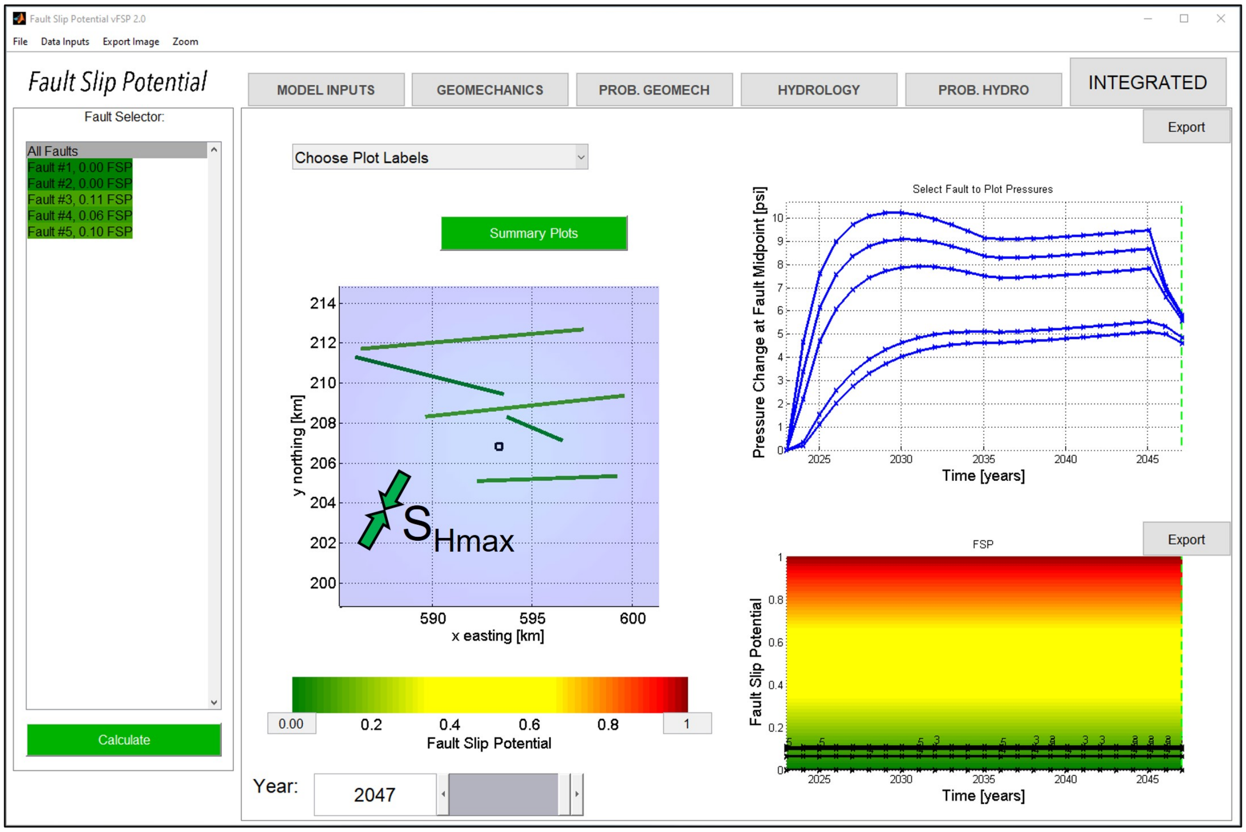


Figure 27: Fault slip potential analysis results.

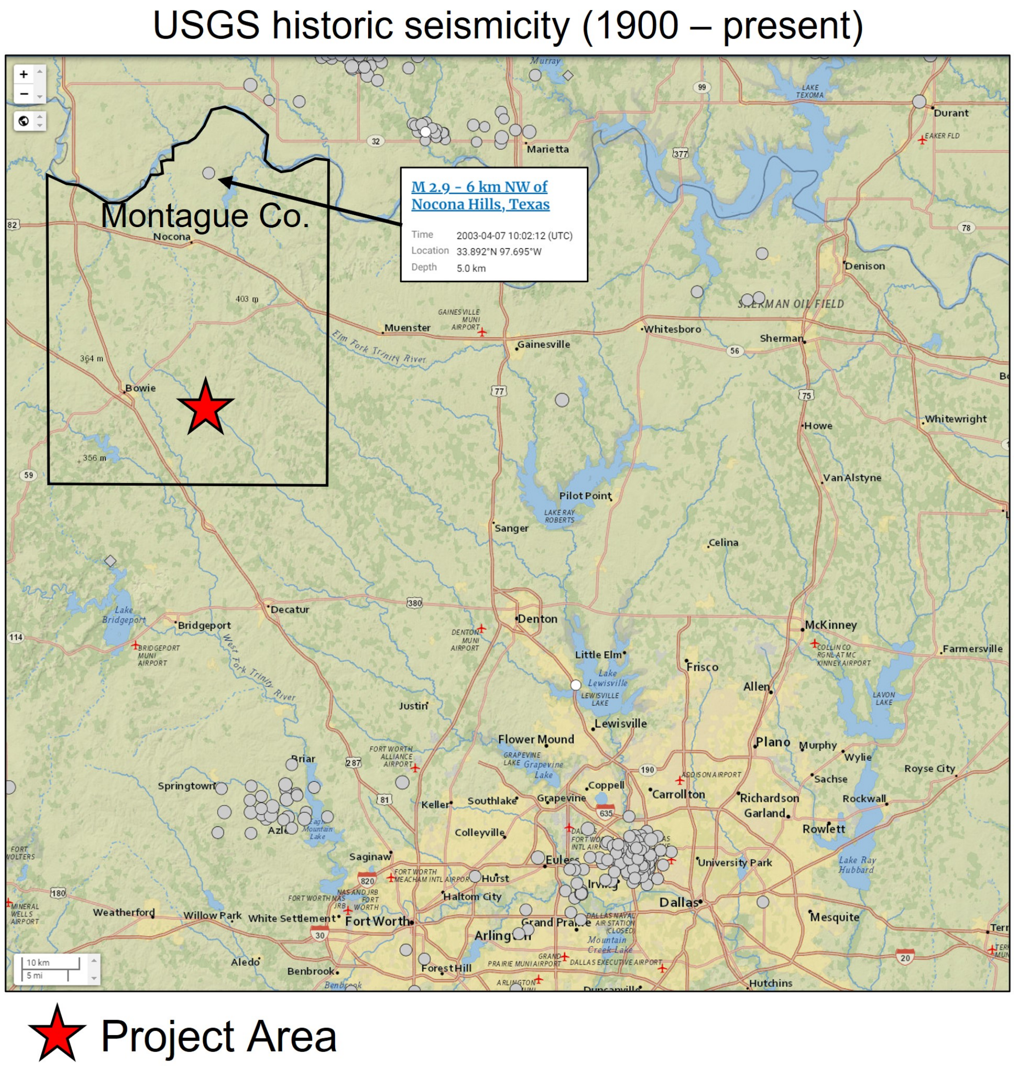


Figure 28: Historical records of regional seismicity from the United States Geological Survey (USGS).

To assess potential fracture leakage, fracture characteristics (orientation, density) as inferred from wellbore image logs in the proposed injection well are compared with various indicators of fluid conductivity (e.g., temperature anomalies, injection testing) in the proposed injection well. Natural fracture orientation and density do not correlate with either temperature reductions or primary permeability pathways inferred from injection testing, suggesting natural fractures are not the dominant transport (i.e., permeability) mechanisms within the injection interval (Figure 29) and therefore pose minor leakage risk.

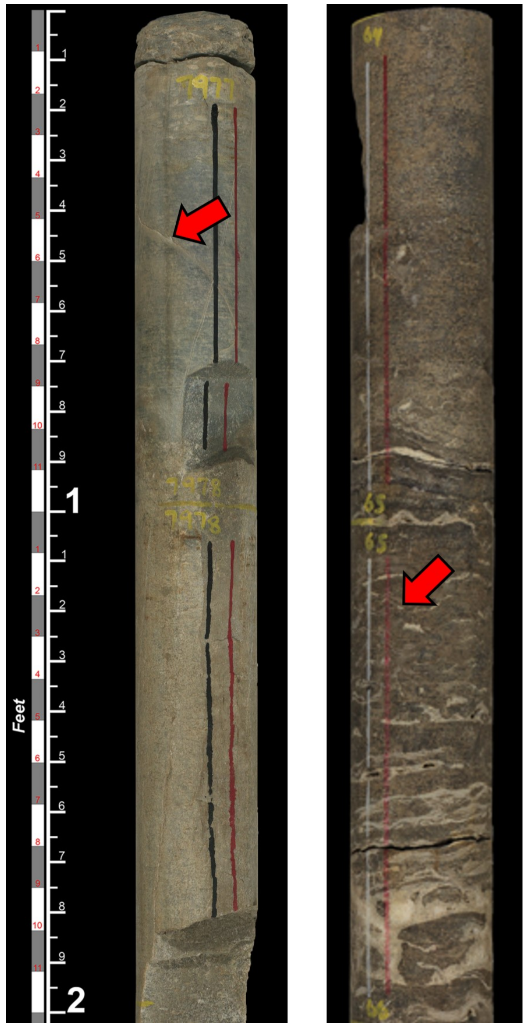


Figure 29: Representative whole core examples of confining (left) and injection (right) zones illustrating natural fractures (generally cemented, red arrows).

3.5.4 Confining System

To assess potential leakage from an excess pressure (i.e., hydraulic fracturing) perspective, injection tests to measure pore pressure and the minimum horizontal stress (S_{hmin}) were conducted in the overlying seal interval. The tests yielded a pore pressure estimate of 0.49 psi/ft and S_{hmin} estimate of 0.69 psi/ft, or roughly 4,900 psi and 6,900 psi bottomhole, respectively, when extrapolated to the injection interval around 10,000 ft TVD. Thus, ~2,000 psi downhole excess pressure is required to generate and propagate hydraulic fractures. Plume injection modeling and offset Ellenburger SWD injection data all indicate maximum bottomhole pressure buildups on the order of 10s of psi for comparable injection volumes and rates - nearly two orders of magnitude lower than would be required to generate a hydraulic fracture. CO_2 leakage through hydraulic fracture generation/propagation is therefore highly unlikely. Furthermore, as CO_2 is anticipated to be the buoyant phase relative to the *in situ* brine within the Ellenburger injection interval, CO_2 migration and excess pressure buildup downward toward the lower confining and basement intervals is not anticipated.

With regard to the risk of diffuse displacement of fluids from the injection zone through the confining system, the 2,200 foot-thick geologic sequence including the upper Ellenburger, Simpson, Viola, and lower Barnett shale (as discussed in section 2.7.2) is expected to provide excellent long-term containment. This general assessment is attributable to 1) the low matrix porosities and permeabilities measured in core samples taken throughout this interval (Table 3); 2) the lack of pervasive karsting or conductive fractures observed in core and image log data; and 3) the absence of flow observed

in this interval during dynamic injection testing and surveys conducted in the project wells. Furthermore, results from reservoir simulation of the proposed injection volumes show no appreciable pressure change or fluid migration in the model layers immediately above the middle Ellenburger injection zone. Thus, surface leakage through the confining system is expected to be extremely unlikely.

3.6 Detection, Verification, and Quantification of Potential Leaks

This subsection addresses the detection, verification and quantification of potential leaks associated with surfaces facilities, faults and fractures, wellbores, and the confining system.

3.6.1 Detection of Leaks

Table 7 summarizes the methods and procedures SPG plans to employ to detect potential leaks across the various potential pathways previously discussed.

Table 7: Leakage detection methodologies to be employed for the Bowie Project.

Leakage Pathway	**Monitoring Activity**	**Frequency**	**Coverage**
Surface facilities	Wellhead pressure monitoring	Continuous	Flowmeter to injection wellhead
	Visual inspection	Weekly	
	Personal H_2S monitors	Weekly	
Wellbores	P-T gauges & fiber on casing/tubing	Continuous	Surface through injection zone
	Annulus pressure monitoring	Continuous	
	Integrity testing (MIT) per Class II permit	Yearly	
	Periodic corrosion monitoring surveys	Yearly	
Faults/fractures	Pressure monitoring	Continuous	Project site/plume extent
	Pressure transient analysis	Yearly	
Confining system	Pressure monitoring	Continuous	Project site/plume extent
	P-T gauges & fiber on casing	Continuous	
	Pressure transient analysis	Yearly	
	Time-lapse saturation surveys	Yearly	

3.6.2 Verification of Leaks

If the detection methods described above indicate a leak through one of the potential leakage pathways, SPG would take the actions summarized in Table 8 to verify its presence or confirm a potential “false positive”.

Table 8: Leakage verification actions to be taken for the Bowie Project.

Leakage Pathway	Verification Action
Surface facilities	Auditory, Visual, and Olfactory (AVO) Inspection
	Forward Looking Infrared (FLIR) camera inspection
	Enhanced gas monitoring
Wellbores	Validation of calibration & functionality of downhole sensors
	Deployment of additional wireline sensors
	Additional saturation logging survey
	Additional MIT and corrosion logging survey
Faults/fractures	Extended pressure transient analysis
	Additional saturation logging survey
	Enhanced surveillance on nearby wells operated by EOG
Confining system	Validation of calibration & functionality of downhole sensors
	Deployment of additional wireline sensors
	Additional saturation logging survey
	Extended pressure transient analysis
	Enhanced surveillance on nearby wells operated by EOG

3.6.3 Quantification of Leaks

If leakage through one of the identified pathways is verified, SPG would implement the methodologies summarized in Table 9 in an effort to quantify the mass of CO_2 that has leaked to shallow aquifers or to the surface. Because CO_2 leakage through several of the pathways cannot be directly measured or visualized but must be indirectly inferred, reservoir simulation will likely be an essential tool to quantify the magnitude of the leak in those cases. For example, while the precise pathway of a CO_2 leak may not be known, it may be possible to measure the pressure or saturation change created along the leakage pathway in the subsurface (e.g., the Billy Henderson #5 monitoring well or a nearby production well operated by EOG). Through the iterative history matching process, it is possible to replicate the observed subsurface response by invoking some potential leakage mechanism(s) in the reservoir model. The resulting volume or mass of CO_2 that yields the best match to the observed data is likely to be a reasonable estimate of the magnitude of the leak. Furthermore, by considering several different plausible leakage cases with the model, the magnitude of the leak can be quantified across a range of potential outcomes. Due to the non-unique nature of numerical simulations, however, SPG will also consider conducting additional appropriate geophysical imaging surveys or drilling additional monitoring wells in strategic locations to further constrain and refine the leakage quantification estimates yielded by the models.

Table 9: Leakage quantification methodologies for the Bowie Project.

Leakage Pathway	Quantification Method*	Qualitative Accuracy
Surface facilities	Calculation based on process conditions at time of leakage and dimensions of leakage pathway	High
	Comparison & calculation against recent historical trends	High
	Direct measurement of leakage (if accessible and safe)	Very High
Wellbores	Calculation against recent historical injection trends (using surface & downhole P-T data)	High
	Estimation from change in saturation profile within reservoir and/or confining zones in project wells	Moderately High
	Enhanced surveillance (e.g., saturation surveys) on nearby wells operated by EOG	Moderately High
Faults/fractures	Use reservoir model to simulate the CO_2 leakage required to generate the observed pressure transient behavior	Moderate
	Use reservoir model to simulate the CO_2 leakage required to generate the observed nearby well surveillance response	Moderate
	Enhanced surveillance (e.g., saturation surveys) on multiple nearby wells operated by EOG	Moderately High
	Conduct additional geophysical imaging surveys near potential leak pathways	Moderately High
	Drill additional monitoring wells in strategic locations	High
Confining system	Use reservoir model to simulate the CO_2 leakage required to generate the observed pressure transient behavior	Moderate
	Use reservoir model to simulate the CO_2 leakage required to generate the observed nearby well surveillance response	Moderate
	Enhanced surveillance (e.g., saturation surveys) on multiple nearby wells operated by EOG	Moderately High
	Conduct additional geophysical imaging surveys near potential leak pathways	Moderately High
	Drill additional monitoring wells in strategic locations	High

*Quantification methods presented in order of practical implementation.

3.7 Baseline Determination

SPG has developed a strategy to establish baselines for monitoring CO_2 surface leakage that is in agreement with 40 CFR §98.448(a)(4). "Expected baseline" is defined as the anticipated value of a monitored parameter that is compared to the measured monitored parameter. SPG has existing automated continuous data collection systems in place that allow for aggradation and analysis of operations data to: 1) establish trends in operational performance parameters and 2) identify deviations from these trends. Non-continuous data will also be collected periodically to augment and enhance the analysis of continuous data throughout the project. Baseline surveys for non-continuous data have already been collected as described below. Baselines for operational performance parameters are expected to be completed by July 17th, 2023, which will provide for several weeks of data collection with the entire system operational.

AVO (Audio, Visual, Olfactory) Inspections: Field personnel will conduct daily to weekly inspections at the injection site pre-, during, and post-injection. Any indications of surface leakage of CO_2 will be addressed via appropriate corrective action in a timely manner. Personnel will wear personal H_2S monitors calibrated to OSHA standards with a detection sensitivity of 0.5 ppm and a low-level alarm threshold of 10 ppm. Indications of H_2S present will serve as a proxy for CO_2 presence as the injection stream contains both components.

Continuous Monitoring: Continuous monitoring systems are in place for both the surface process facilities and wells. Pressure and temperature gauges installed on both casing and tubing strings, DTS fiber-based data, and surface pressures on all strings of casing is collected continuously in both wells. Operational baselines will be determined from analysis of this data over a reasonable period once the system is fully operational (see comments on timing above). Any deviations from these operational baselines will be investigated to determine if the deviation is a leakage signal.

Well Integrity Testing: EOG will conduct an annual MIT on the Hinkle Trust #1 as required by the Class II permit issued by TXRRC. Subsequent MIT results will be compared to initial MIT results and TXRRC standards to establish a baseline. An initial MIT and subsequent interpretation of test results has already been performed on the Hinkle Trust #1 as part of the Class II permit requirements.

Pressure Transient Analysis: EOG has conducted initial pressure transient analyses using injection test data. Subsequent pressure transient analyses are in progress and will continue to be performed when operationally feasible to establish and re-establish expected baseline reservoir behavior throughout the project. Comparison of these analyses over time will aid in diagnosing consistency in the long-term behavior of the injection and confining zones.

Wellbore Surveys: The Billy Henderson #5 and Hinkle Trust #1 are both constructed to allow for time-lapse saturation and mechanical integrity logging. Initial pre-injection surveys have been conducted for both saturation and mechanical integrity and will serve to establish baselines for comparison of future logging datasets.

3.8 Site Specific Modifications to the Mass Balance Equation

3.8.1 Mass of CO_2 Received

Following the Subpart RR requirements under §98.444(a)(4), equation RR-4 (Figure 30) will be used for calculating the mass of CO_2 received since the CO_2 stream received via the gathering pipeline will be wholly injected and not mixed. The mass flow rate measured at the coriolis meter immediately downstream of the high pressure injection compressor will be used (refer to Figure 2) as input to equation RR-4. This measurement will account for the concentration of CO_2 in the injection stream using the measurement from the gas chromatograph immediately upstream of the high pressure compressor, which will be validated quarterly via gas sample analysis as per the requirements under §98.444(b).

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

where:
$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.
$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).
$C_{CO2,p,u}$ = 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.

Figure 30: Equation RR-4 as defined in 40 CFR §98 Subpart RR.

3.8.2 Mass of CO_2 Injected

The annual mass of CO_2 injected will be calculated using equation RR-4 as per Subpart RR §98.443(c)(1) since a high pressure coriolis meter will be used to measure the mass flow rate as described in the previous section 3.8.1. The high pressure coriolis mass meter used in the system has an accuracy of ±0.15% and concentration inputs to the calculation will be provided by the gas chromatograph immediately upstream of the high pressure compressor which will be validated quarterly in accordance with §98.444(b).

3.8.3 Mass of CO_2 Produced

Mass of CO_2 produced is not applicable to this project as no CO_2 will be produced.

3.8.4 Mass of CO_2 Emitted

The mass of CO_2 emissions from equipment leaks or vented emissions from surface equipment located between the injection meter and the wellhead is expected to be zero or exceedingly small. Nevertheless, this equipment will still be subject to regular AVO inspections and H_2S monitoring. Any leakage source(s) found will be quantified based on process conditions at the time of the leak and corrected in volumes reporting using equation RR-10 (Figure 31). Since CO_2 will not be produced in the scope of this proposed injection project, the consideration of leakage from production-related equipment is not applicable.

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

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

Figure 31: Equation RR-10 as defined in 40 CFR §98 Subpart RR.

3.8.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated using equation RR-12 (Figure 32) since this project will not actively produce oil, natural gas, or any other fluids.

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{(Eq. RR-12)}$$

where:
CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.
CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.
CO_{2E}= Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.
CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of this part.

Figure 32: Equation RR-12 as defined in 40 CFR §98 Subpart RR.

In accordance with §98.448(a)(7), the date to begin collecting data for calculating the total amount sequestered shall be after 1) expected baselines are established and 2) implementation of the leakage detection and quantification strategy within the initial AMA. SPG proposes the date of July 17th, 2023 as the date to begin collecting data for calculating the total amount sequestered for the SPG CO_2 Bowie Facility.

3.9 Implementation Schedule For MRV Plan

The final MRV plan will be implemented upon receiving approval from the EPA, and no later than the day after the day on which the plan becomes final, as described in §98.448(c). The Hinkle Trust #1 is currently permitted to inject under a TXRRC Class II UIC permit (see Appendix A).

3.10 Quality Assurance

3.10.1 Monitoring QA/QC

SPG will implement quality assurance procedures that are in compliance with requirements stated in 40 CFR §98.444 as detailed below.

CO_2 Injected:

- The flow rate of the CO_2 injection stream is measured continuously with a high pressure mass flow meter that has an accuracy of ±0.15%.
- The composition of the CO_2 injection stream is measured with a high accuracy gas chromatograph upstream of the flow meter.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer recommendations.

CO_2 Emissions from Leaks and Vented Emissions:

- Calculation methods from 40 CFR §98 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.

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).

3.10.2 Missing Data

Missing data will be estimated as prescribed by 40 CFR §98.445 if SPG is unable to collect the data required 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 and venting from facility surface equipment will be estimated and reported per the procedures specified in 40 CFR §98 subpart W.

3.10.3 MRV Plan Revisions

If any of the changes outlined in 40 CFR §98.448(d) occur, SPG will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

3.11 Records Retention

SPG will retain all records as required by 40 CFR §98.3(g). Records will be retained for at least three years, and will include, but will not be limited to:

- Quarterly records of injected CO_2 including mass flow rate at standard conditions, mass flow rate at operating conditions, operating temperature and pressure, and concentration of the injected CO_2 stream.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

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A Class II UIC Permit for Hinkle Trust #1

WAYNE CHRISTIAN, CHAIRMAN
CHRISTI CRADDICK, COMMISSIONER
JIM WRIGHT, COMMISSIONER

DANNY SORRELLS
ASSISTANT EXECUTIVE DIRECTOR
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. 17041

EOG SPG HOLDINGS, INC.
ATTN SETH WOODARD
PO BOX 4362
HOUSTON TX 77210

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 April 01, 2022, for the permitted interval(s) of the ELLENBURGER formation(s) and subject to the following terms and special conditions:

HINKLE TRUST (00000) LEASE
BARNABUS (ELLENBURGER) FIELD
MONTAGUE 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	33700000	000125307	Carbon Dioxide (CO2); Hydrogen Sulfide (H2S); Natural Gas	7,300	13,000		12,000		4,100

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	33700000	**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. An annual annulus pressure test must be performed and the test results submitted in accordance with the instructions of Form H-5.** **3. The tubing-casing annulus pressure must be monitored at least weekly and reported annually on Form H-10 to the Commission's Austin Offices.** **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. 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.** **6. 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.** **7. 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.**

Note: This document will only be distributed electronically.

		8. NOTE: Per operator email dated on June 01, 2022, the four plants are operated by EOG Resources, Inc. They are permitted under Pecan Pipeline Company (P-5 #648675) and Pecan Pipeline is EOG Resources. **Below are the names and RRC Serial Numbers for each plant:** **Bowie South – 09-0415** **St. Jo – 09-0406** **Henderson – 09-0405** **Kripple Kreek – 09-0401**

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 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.

Note: This document will only be distributed electronically.

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 July 18, 2022.

Sean Avitt, Manager
Injection-Storage Permits Unit

Note: This document will only be distributed electronically.

B Drilling Permit for Hinkle Trust #1

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 (*<u>other than diesel fuels</u>*) 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 879709	DATE PERMIT ISSUED OR AMENDED May 10, 2022	DISTRICT * 09
API NUMBER 42-337-35480	FORM W-1 RECEIVED May 03, 2022	COUNTY MONTAGUE
TYPE OF OPERATION NEW DRILL	WELLBORE PROFILE(S) Vertical	ACRES 682.83
OPERATOR 100178 EOG SPG HOLDINGS, INC. ATTN SETH WOODARD PO BOX 4362 HOUSTON, TX 77210		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 HINKLE TRUST		WELL NUMBER 1
LOCATION 9.4 miles SE direction from MONTAGUE, TX		TOTAL DEPTH 15000
Section, Block and/or Survey SECTION SURVEY MC DONALD, J	BLOCK	ABSTRACT 538
DISTANCE TO SURVEY LINES 1150 ft. NE 277 ft. SE		DISTANCE TO NEAREST LEASE LINE ft.
DISTANCE TO LEASE LINES 604 ft. SW 204 ft. SE		DISTANCE TO NEAREST WELL ON LEASE See FIELD(s) Below

FIELD(s) and LIMITATIONS:

* SEE FIELD DISTRICT FOR REPORTING PURPOSES *

FIELD NAME LEASE NAME	ACRES NEAREST LEASE	DEPTH	WELL # NEAREST WE	DIST
BARNABUS (ELLENBURGER) HINKLE TRUST	682.83	13,000	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

MONTAGUE (337) County

Formation	Remarks	Geological Order	Effective Date
TRINITY WATER SANDS	high wash-out factor	1	12/17/2013
SPANISH FORT		2	12/17/2013
PERMIAN		3	12/17/2013
CISCO		4	12/17/2013
CANYON SAND		5	12/17/2013
PALO PINTO		6	12/17/2013
STRAWN		7	12/17/2013
UNDETERMINED	gas producing zones	8	12/17/2013
BRAZOS RIVER		9	12/17/2013
BRYSON SAND		10	12/17/2013
CADDO		11	12/17/2013
ATOKA CONGLOMERATE		12	12/17/2013
CONGLOMERATE		13	12/17/2013
MARBLE FALLS		14	12/17/2013
BARNETT SHALE		15	12/17/2013
MISSISSIPPIAN		16	12/17/2013
VIOLA LIME		17	12/17/2013
GRANITE WASH		18	12/17/2013
ELLENBURGER		19	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

Request for Additional Information: SPG CO_2 Bowie Facility
August 15, 2023

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	We recommend doing an additional review for spelling, grammar, etc. Examples include but are not limited to: Oauchita vs Ouachita Initial vs Inital	***These issues have been corrected.***
2.	N/A	N/A	The "Hinkle Trust Injection Facility" is mentioned on page 7 of the MRV plan. However, the facility under which this MRV plan was submitted is called "SPG CO2 Bowie Facility". Please clarify how these different facility names relate to the MRV plan and the overall project. Furthermore, we recommend specifying the GHGRP ID associated with the injection facility, in addition to those provided in Table 1.	***"SPG CO2 Bowie Facility" is the formal name of injection site registered under GHGRP ID 583201 and is referred to as "the injection facility" in the revised MRV plan. References to "Hinkle Trust Injection Facility" have been removed.***
3.	N/A	N/A	Please ensure that all acronyms are defined during the first use within the MRV plan. For example, "MMSCFD" is not defined within the text.	***Acronyms used throughout the document have been reviewed and are defined in context after their first use. "MMSCFD", for example, is defined in the first paragraph of the introduction.***
4.	N/A	N/A	We recommend including a clear process flow diagram to help with the indicate where meters relevant to subpart RR calculations are located on site.	***A general process flow diagram has been added to section 2.1 in addition to the injection well site plot plan that was previously included. The final Subpart RR measurement meter is annotated on both figures for clarity.***

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	2.1	7	This section mentions that composition is measured, please explain why process modelling is being used if the gas composition is being measured.	***Real-time gas chromatography will be used to analyze the injected gas composition. Location of this device is annotated on the process flow diagram in section 2.1. References to process modeling have been removed to avoid confusion.***
6.	2.1	7	"Based on the results of process modeling, the CO_2 rich gas will be >95% CO_2 with the remainder being a mixture of N_2, $H2_S$, and trace hydrocarbons from methane (C1) up to hexanes (C7)." We recommend including estimates or measurements of the remaining mole fractions of the injected gas. It is also stated in this section that the CO_2 is pure, which seems to contradict the percentage mentioned here. Please clarify.	***A table summarizing the compositional analysis has been included in section 2.1 to clarify the narrative. Because the composition of the injected gas stream is >98% CO_2, the gas will be referred to by is principal component: CO_2. Use of the descriptor "pure" has been removed.***
7.	2.3	10	The MRV plan states that the Middle Ellenburger is the main injection target injection zone and the Upper Ellenburger is one of the upper confining units. The red star denoting the injection formation in Figure 5 appears to be on the lower end of the Ellenburger formation. We recommend ensuring that the text and figure are consistent.	***The red star adjacent to the stratigraphic column in Figure 6 has been adjusted to more clearly indicate that the intended injection zone is the Middle Ellenburger.***

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
8.	2.7.2	21	The mention of karst textures in this section seems to indicate that the porosity and permeability of the upper confining interval may allow CO_2 migration. Please provide more explanation regarding whether the formations discussed in the MRV plan reliably prevent the migration of CO_2. Please also clarify what the vertical permeability input into the reservoir simulation was. If karsting is a potential leakage pathway, please include it in the discussion in section 3.5.	***Please reference the last paragraph of section 2.7.2 stating the lack of evidence for pervasive karsting in the upper confining interval as observed across multiple datasets.*** ***Details regarding measured vertical-to-horizontal permeability relationships of the injection interval from full diameter core analysis have been included in Table 4. Additional wording was added in section 3.1 (Geologic Model) to clarify treatment of vertical permeability throughout the simulation model.*** ***Karsting is not considered to be a potential leakage pathway in the project area and language to this effect has been added to section 3.5.4.***
9.	3.5	31	"The only wellbores that penetrate the injection zone in the AMA and MMA are those that were constructed specifically for this project." In the MRV plan, please clarify whether there are wellbores in the AMA/MMA that do not penetrate the injection zone, and provide information as to whether they are potential leakage pathways (if applicable). Furthermore, does the facility anticipate future drilling in the project area that might create new leakage pathways?	***Within the MRV plan, additional statements have been added to clarify that there are other wells drilled in the AMA/MMA, but they do not penetrate the injection zone, therefore, they are not applicable.*** ***SPG does not anticipate future drilling into the main injection zone in the project area – the text at the end of section 3.5.2 has been enhanced to clarify this point and to explain why the overall risk of wellbore leakage is very low.***
10.	3.5	N/A	Please include additional detail on possible leakage through induced and natural seismic activity. E.g., will the facility take operational steps to ensure that seismicity is not induced?	***As detailed in section 3.5.3, FSP modeling results and existing earthquake catalogs suggest a low fault slip, leakage, and seismicity (induced or natural) likelihood. However, additional discussion has been included in section 3.5 to describe how the downhole monitoring instrumentation will be used to guide operational parameters to minimize the risk of triggering a potential fault-slip event throughout the project duration.***

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
11.	3.6	39	Table 8 describes the quantification methods for the faults/fractures and confining systems leakage pathways as moderately accurate. Please elaborate on how these estimation methods might be verified if they are used.	***Additional quantification methods have been added to Table 9 (previously Table 8) to clarify the progressive measures that will be taken to further constrain and refine the leakage estimates should one be suspected.***
12.	3.7	39	"Personnel will wear personal H_2S monitors set to OSHA standards. Indications of H_2S present will serve as a proxy for CO_2 presence as the injection stream contains both components." Please clarify the detection limit of the H_2S monitors and at what point they would trigger.	***Personal H_2S monitors have a detection sensitivity of 0.5 ppm and a low-level alarm threshold of 10 ppm. These details have been added to the text in section 3.7.***
13.	3.8	40	"Equation RR-4 will be used for calculating the mass of CO2 received." Equation RR-4 is used to calculate the mass of CO_2 injected, not received. Per 40 CFR 98.433, you must calculate the mass of CO2 received using CO2 received equations (Equations RR–1 to RR–3 of this section), unless you follow the procedures in § 98.444(a)(4). Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	***The text in section 3.8 has been revised to clarify that equation RR-4 will be used to report the mass of CO_2 received and injected per the requirements in § 98.444(a)(4) of the Subpart RR regulations.***
14.	3.8.4	40	"Mass of CO_2 emitted from surface leakage of any kind is assumed to be zero per the MRV plan." Mass of CO2 emitted must be calculated according to Equation RR-10. Please revise this section and ensure that all equations required by 40 CFR 98.443 are included in the MRV plan, accounting for the possibility that there could be leakage from the identified surface leakage pathways.	***Section 3.8.4 has been revised to consider the possibility of leakage or vented emissions from surface equipment and reference to equation RR-10 has been included.***

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
15.			". The CO2E and CO2FI terms will drop out in most cases since the mass of CO2 emitted from surface leakage is assumed to be zero except in rare cases where leakage is identified." Per 40 CFR 98.443(f)(2), CO2FI must be calculated according to the procedures provided in subpart W. Please revise this section to ensure it is consistent with the requirements in 40 CFR 98.443, accounting for the possibility that there could be leakage from the equipment leaks and vented emissions.	***Section 3.8.5 has been revised to be consistent with the requirements of §98.443(f)(2).***

EOG SPG Holdings, Inc.

Subpart RR Monitoring, Reporting, and Verification Plan for SPG CO_2 Bowie Facility

Montague County, TX

Version 1
June 2023

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1 Introduction

EOG SPG Holdings, Inc. (SPG), a subsidiary of EOG Resources, Inc. recently received authorization from the Railroad Commission of Texas (TXRRC) to drill and operate a Class II disposal well (Hinkle Trust #1) under Texas Administrative Code (TAC) Title 16, Part 1, § 3.9. Under this permit (No. 17041), SPG can inject up to 12 MMSCFD (million standard cubic feet per day) of acid gas waste - comprised primarily of CO_2, N_2, H_2S, and other trace hydrocarbons - generated by four natural gas amine treatment facilities located in Montague County, TX and operated by EOG Resources, Inc. (EOG). These facilities separate the acid gas components from the natural gas stream produced from the Barnett Shale by approximately 1,100 wells across the Newark East Field, also operated by EOG. Historically, the separated CO_2 stream has been emitted to the atmosphere while the H_2S was incinerated by a thermal oxidizer with the resulting SO_2 emitted to the atmosphere. In 2022, the aggregate total reportable greenhouse gas (GHG) emissions from all four amine separation facilities were approximately 180,000 metric tons (MT) of CO_2.

EOG is submitting this Monitoring, Reporting, and Verification (MRV) plan to the EPA for approval according to 40 CFR 98.440 (c)(1), Subpart RR of the Greenhouse Gas Reporting Program (GHGRP) in connection with qualifying for the tax credits in section 45Q of the Internal Revenue Code.

1.1 Document Organization

This MRV plan is organized into three main sections: 1) this introductory section; 2) project details; and 3) a description of the development and administration of the MRV plan.

Section 1 introduces the injection project. It provides a high-level overview of the existing natural gas amine treatment facilities that are the sources of the CO_2 emissions as well as the capture, compression, and pipeline gathering systems that have recently been constructed as part of the injection project infrastructure. The section concludes with a general description of the subsurface storage complex including the target storage reservoir, the confining system, and the operational history that is relevant to the planned injection operations.

Section 2 provides more detailed presentations of the regional geology in the project area and the operational infrastructure including:

- a more detailed review of the source of the CO_2 emissions and the capture, compression, and pipeline gathering systems that will be used to deliver the CO_2 to the injection site;
- a summary of the proposed injection volume rates and the projected cumulative mass of CO_2 to be stored over the expected project life;
- the stratigraphy of the underburden, storage reservoir, and confining system;
- the structural features and subsurface stress characteristics within the project area;
- a more detailed review of the Barnabus (Ellenburger) field history; and
- a description of the fluid transport characteristics of both the storage reservoir and the confining system;

Section 3 describes the specific technical elements of the proposed MRV plan and how the plan will be administered over the expected project life, including:

- a description of the geologic and reservoir models used to simulate the long-term injection performance and CO_2 plume behavior;
- the delineation of the Active and Maximum Monitoring Areas (AMA and MMA);
- a description and assessment of the potential surface leakage pathways in the project area;
- a discussion of the methods and techniques that will be used to detect, verify, and quantify potential surface leaks of the injected CO_2;
- a presentation of the routine and regular operational monitoring that will establish baseline operating conditions, against which future monitoring surveys and results will be compared;

- a description of the various measurement and mass balance accounting techniques that will be employed to quantify the mass of the various CO_2 streams;
- an explanation of how quality assurance will be maintained across all aspects of the project operations;
- an acknowledgment of the requirements to submit revisions to the MRV plan in the event of material changes to the project; and
- a summary of the records that will be retained throughout the expected project life.

1.2 Surface Infrastructure Overview

EOG operates four natural gas amine treatment facilities that provide CO_2 to the Hinkle Trust #1 injection well. Figure 1 shows the geographic location of these facilities as well as the pipeline network that delivers CO_2 to the injection site. The names, TXRRC serial numbers, EPA GHGRP site identification numbers, and the CO_2 emissions for the 2022 reporting year of each of these facilities are summarized in Table 1. Section 2.1 provides a more detailed description of the gas treatment process and the CO_2 delivery infrastructure associated with the project.

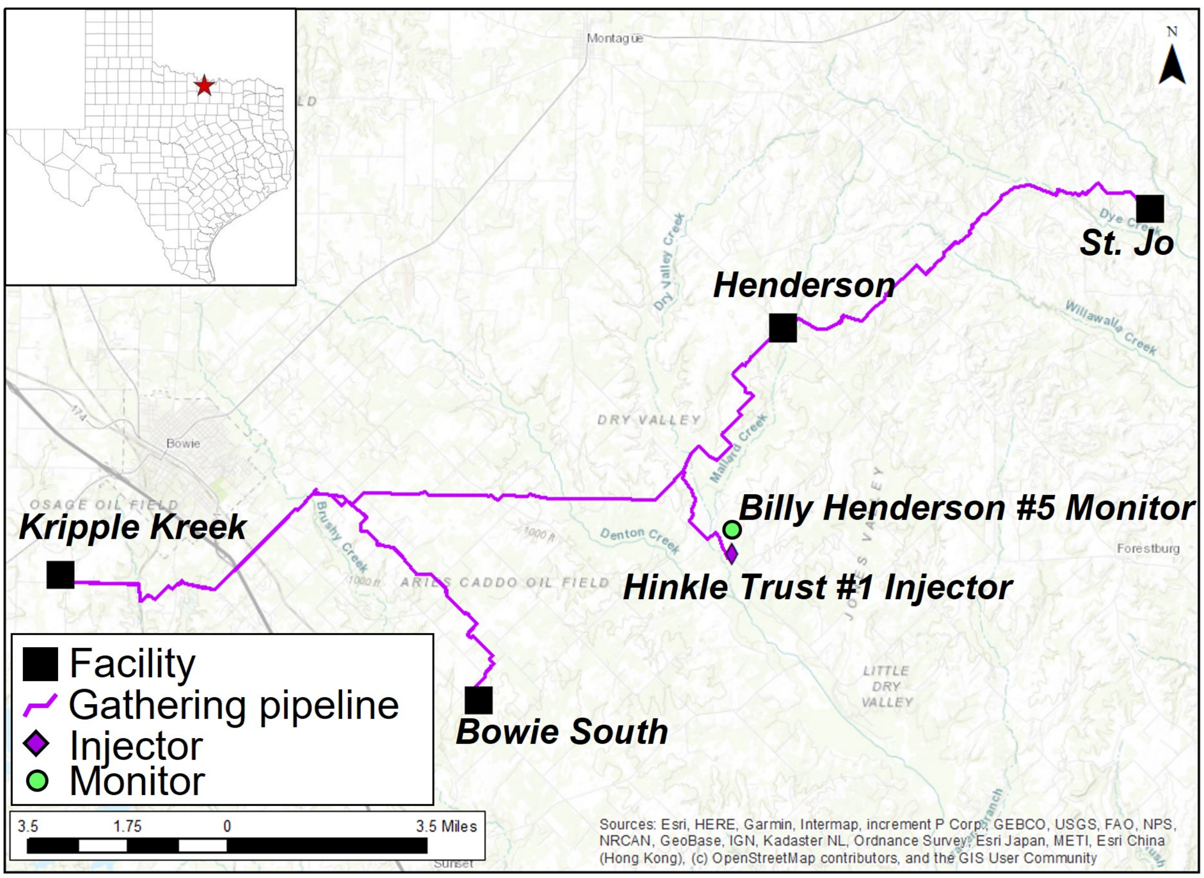

Figure 1: Project site map showing four gas amine treatment facilities providing CO_2 to the project, the pipeline network connecting processing facilities to the injection site, and the injection site well locations.

Table 1: Details and associated 2022 emissions for EOG gas amine treatment facilities.

Facility Name	TXRRC Serial No.	GHGRP ID	2022 Reported CO_2 Emissions (MT)
Bowie South[a]	09-0415	566952	54,352
Henderson[a]	09-0405	566952	20,584
Kripple Kreek	09-0401	528742	61,709
St. Jo[a]	09-0406	566952	43,509
Total	—	—	**180,154**

[a]Previously reported as part of EOG Resources, Inc. 420 Fort Worth Syncline Basin Gathering & Boosting facility under Subpart W.

1.3 Subsurface Storage Complex Overview

The subsurface stratigraphy of interest for this project consists of the approximately four thousand feet of rock below the Barnett Shale formation, which is the primary hydrocarbon-producing interval within the project area. The middle Ellenburger formation is the main injection target for the project, which is an approximately one thousand foot thick dolomitic karst reservoir. Overlying the middle Ellenburger dolomite is over two thousand feet of mixed carbonates in the upper Ellenburger formation, mixed shale and limestone in the Simpson formation, and limestone in the Viola formation. These units contain ample footages of tight limestones, tight dolomites, and low permeability shales, and serve as the upper confining system for the project. Below the middle Ellenburger injection zone is about one thousand feet of tight limestone, which serves as the lower confining zone between the middle Ellenburger injection zone and the underlying granitic basement.

Two wells were drilled for this injection project. The Billy Henderson #5 is a vertical pilot and monitoring well that was drilled into granitic basement. This well provided project site-specific data across the injection and confining zones and was subsequently completed as a monitor well for the project. The Hinkle Trust #1 is the injection well for the project. This slightly-deviated well was drilled approximately 1,600 ft away from the Billy Henderson #5 monitor to a depth only a few hundred feet below the base of the injection zone. Evaluation data was also collected in this well for further subsurface characterization of the project site. The Hinkle Trust #1 was completed as an openhole injector into the middle Ellenburger dolomite.

2 Project Details

2.1 Source and Gathering of CO_2 for Injection

The Bowie Production Area has four central gas gathering sites that take produced gas from the field at low pressure (25-35 PSIG) and condition the gas to go through high pressure (750-900 PSIG) gathering lines to deliver the produced gas to a central gas treatment facility. Each of the gas gathering sites - Saint Jo, Henderson, Bowie South, and Bowie East Compressor Stations - have 3-stage compressors to increase the pressure of the gas before it goes through treatment to remove water and other impurities. Three of these gas gathering sites - Saint Jo, Henderson, and Bowie South - have amine treatment using Methyl-diethanolamine (MDEA) and Piperazine to remove CO_2 and H_2S from produced gas in the field down from 8%-15% CO_2 to 4% CO_2. The gas is then dehydrated using Triethylene Glycol (TEG) to remove water down to 7 pounds (lbs) per MMSCF before being sent to Kripple Kreek Gas Plant to go through final treatment. At the Kripple Kreek Gas Processing Plant, the remaining CO_2 in the high pressure produced gas is removed using MDEA and Piperazine from 4% CO_2 down to 100-200 ppm CO_2. The high pressure produced gas is dehydrated to a -300 °F dewpoint using TEG then mol sieve dehydration where the gas is then sent for final processing to separate the residue gas from the natural gas liquids (NGLs) for final sale. The residue gas is compressed and sold into a residue gas pipeline system, where the NGLs are subsequently sold and pumped into a y-grade NGL pipeline system.

The Bowie CCS project gathers the CO_2 from each of the four existing amine treatment facilities (at Saint Jo, Henderson, Bowie South, and Kripple Kreek) using CO_2 compressors to increase the pressure of the CO_2 rich gas from low pressure (5 PSIG) off of the amine still to high pressure (750-850 PSIG) using a 4-stage compressor. The CO_2 rich gas is then conditioned using a TEG dehydration unit to lower the dew point below 0 °F to ensure free water is not condensed during normal operations. The CO_2 rich gas is then sent through a measurement section to record the mass flowrate, composition, temperature, pressure, oxygen content, and water content before being introduced into the CO_2 gathering system. Based on the results of process modeling, the CO_2 rich gas will be >95% CO_2 with the remainder being a mixture of N_2, H_2S, and trace hydrocarbons from methane (C1) up to hexanes (C7).

The gathering system consists of 36 miles of 6-inch nominal diameter Flexsteel composite pipe that collects the pure CO_2 streams from each of the four processing sites. The CO_2 is then sent to the Hinkle Trust Injection Facility where the gas enters the site and goes through an inlet heater for conditioning to ensure it is in the vapor phase before it goes through a measurement section to record the mass flowrate, composition, temperature, pressure, oxygen content, and water content before the gas is compressed from high pressure (750-850 PSIG) to supercritical (1,600-2,200 PSIG) in the final 2-stage unit. The supercritical CO_2 leaving the compressor is left hot to then be routed to the heater to cross exchange and provide heat for the inlet gas from the CO_2 gathering pipeline. The supercritical CO_2 is then sent through final measurement to collect the mass flowrate before the gas enters the wellhead and is injected in the subsurface (Figure 2).

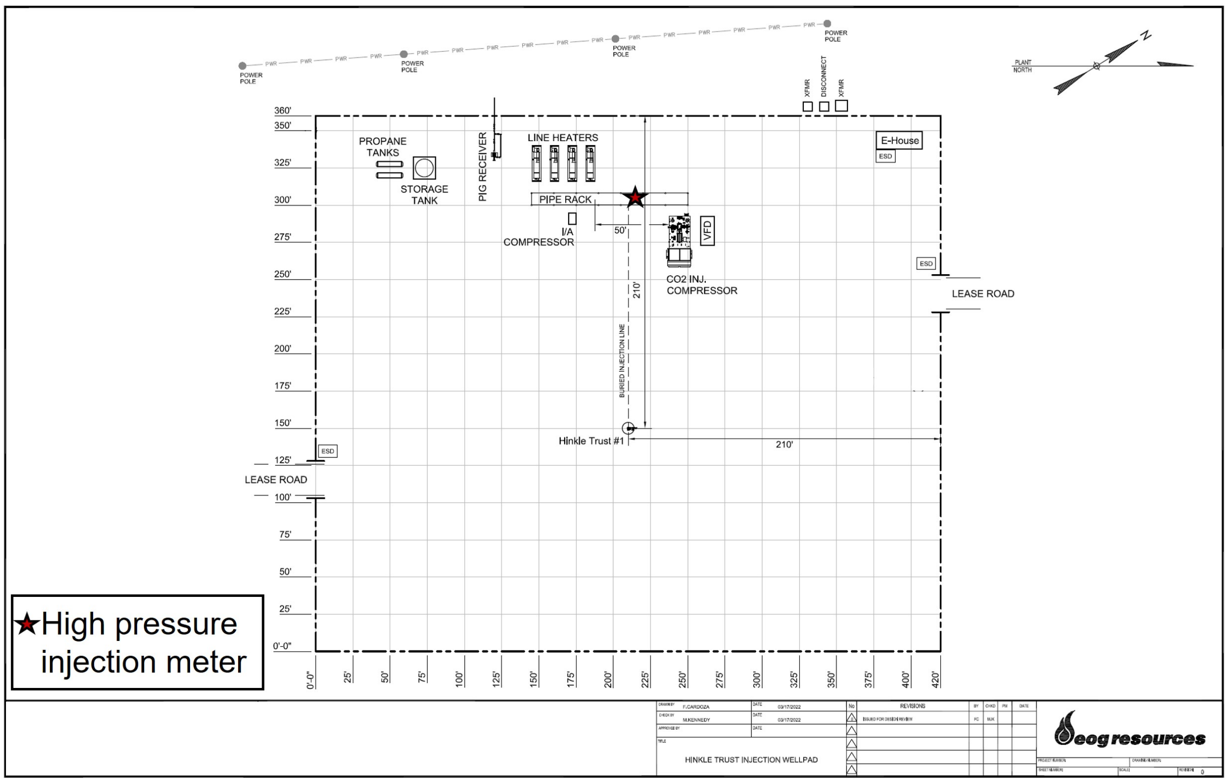

Figure 2: Plot plan for Hinkle Trust #1 injection pad.

2.2 Proposed Injection Volumes

The proposed CO_2 injection stream is separated from the natural gas produced by EOG's nearly 1,100 active Barnett wells in Montague County. Since these wells are on a natural depletion decline (and additional development drilling is not currently planned), the projected CO_2 volumes will follow a similar decline trend. Over the proposed 12-year project life, injection rates will decline from an inital rate of approximately 10 MMSCFD (~520 MT-CO_2/day) down to 4 MMSCFD (~200 MT-CO_2/day), resulting in a total cumulative injected mass of approximately 1.45 million MT-CO_2 (Figure 3). Injection operations began in February 2023 with CO_2 volumes supplied from the Henderson facility only. Injection operations from all four amine treatment facilities that will supply CO_2 to the gathering system commenced in June 2023, following completion of start-up and commissioning tests.

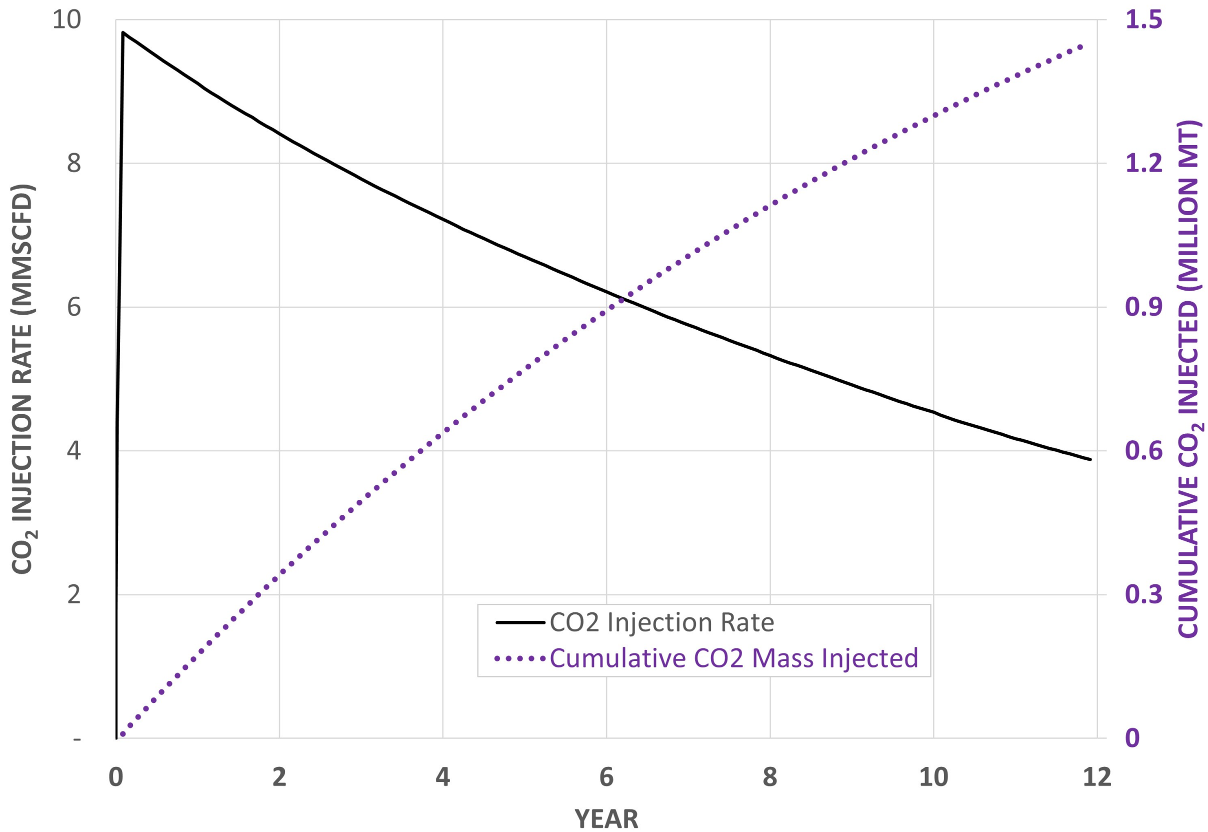

Figure 3: Projected CO_2 injection rate and cumulative mass injected over the proposed 12-year injection period.

2.3 Regional Geology

The project is located in the northern Fort Worth Basin which is a Paleozoic foreland basin associated with the Oauchita Orogenic belt (Figure 4). It exhibits stratigraphy similar to other Paleozoic structural basins found in North America [Meckel et al. (1992)]. The main hydrocarbon producing intervals are Mississippian to Pennsylvanian in age [Pollastro et al. (2007)]. The formations of interest for this injection project are pre-Mississippian-aged marine sediments, which sit below the major productive oil and gas intervals, and are separated from the underlying granitic basement by Cambrian aged sediments sitting below the injection zone (Figure 5) [Alsalem et al. (2018)]. The Ellenburger is the main formation of interest for this project, with secondary formations of interest being the overlying Simpson, Viola, and Barnett in stratigraphic order.

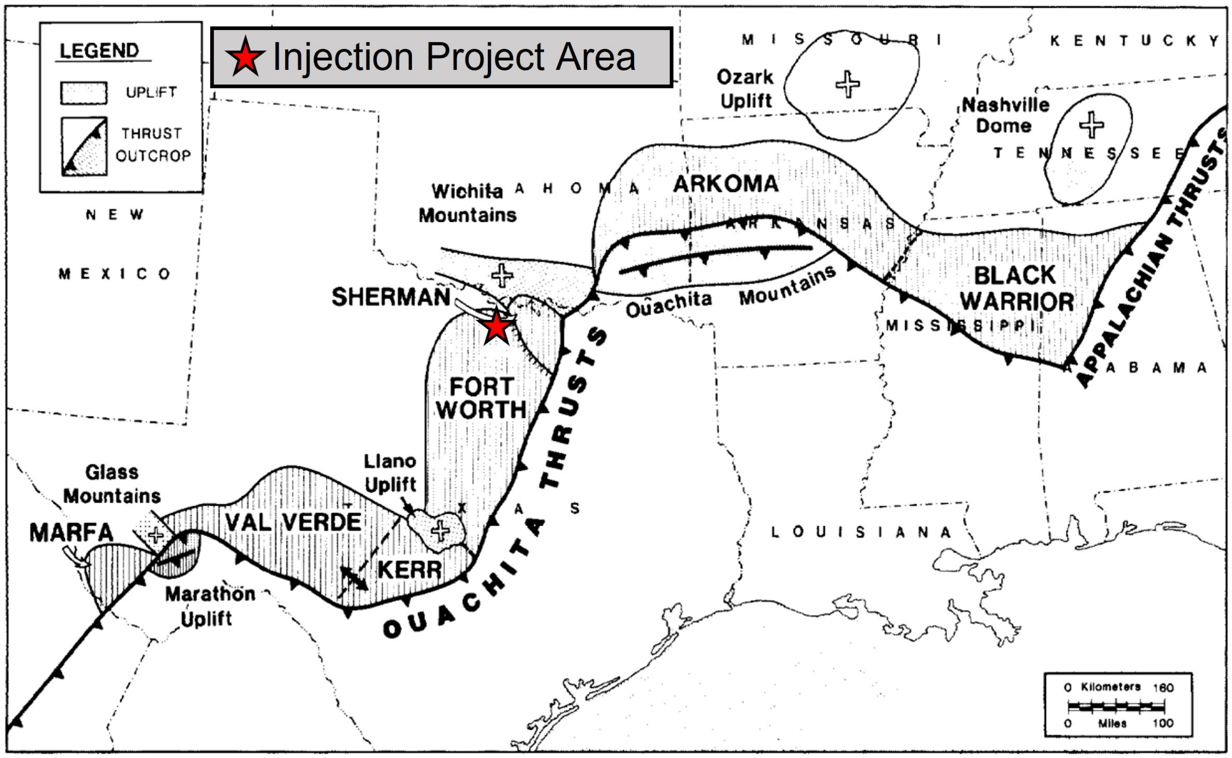

Figure 4: Location of Bowie injection project in northern Fort Worth Basin in reference to Oauchita front and related structural features. Figure modified from Meckel et al. (1992).

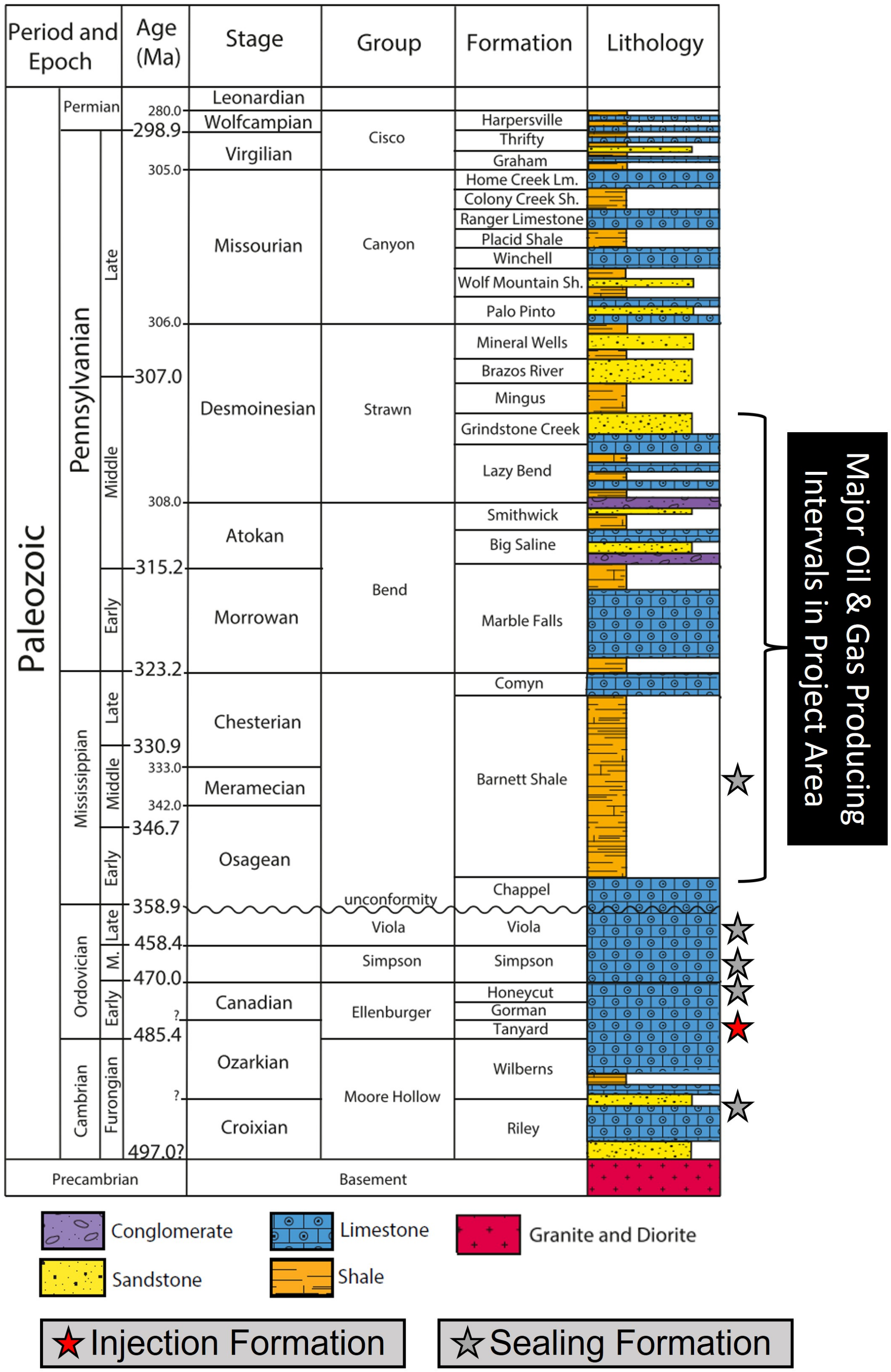

Figure 5: Generalized stratigraphic column of the Fort Worth Basin. Figure modified from Alsalem et al. (2018).

Prior to the formation of the Fort Worth structural basin in the project area, these Cambrian and Ordovician-aged sediments of interest were deposited on an epeiric carbonate platform developed on the Laurentian margin. This carbonate platform is commonly referred to as the Great American carbonate bank, which extended across the entirety of North America and rimmed the stable cratonic interior (Figure 6) [Derby et al. (2012)].

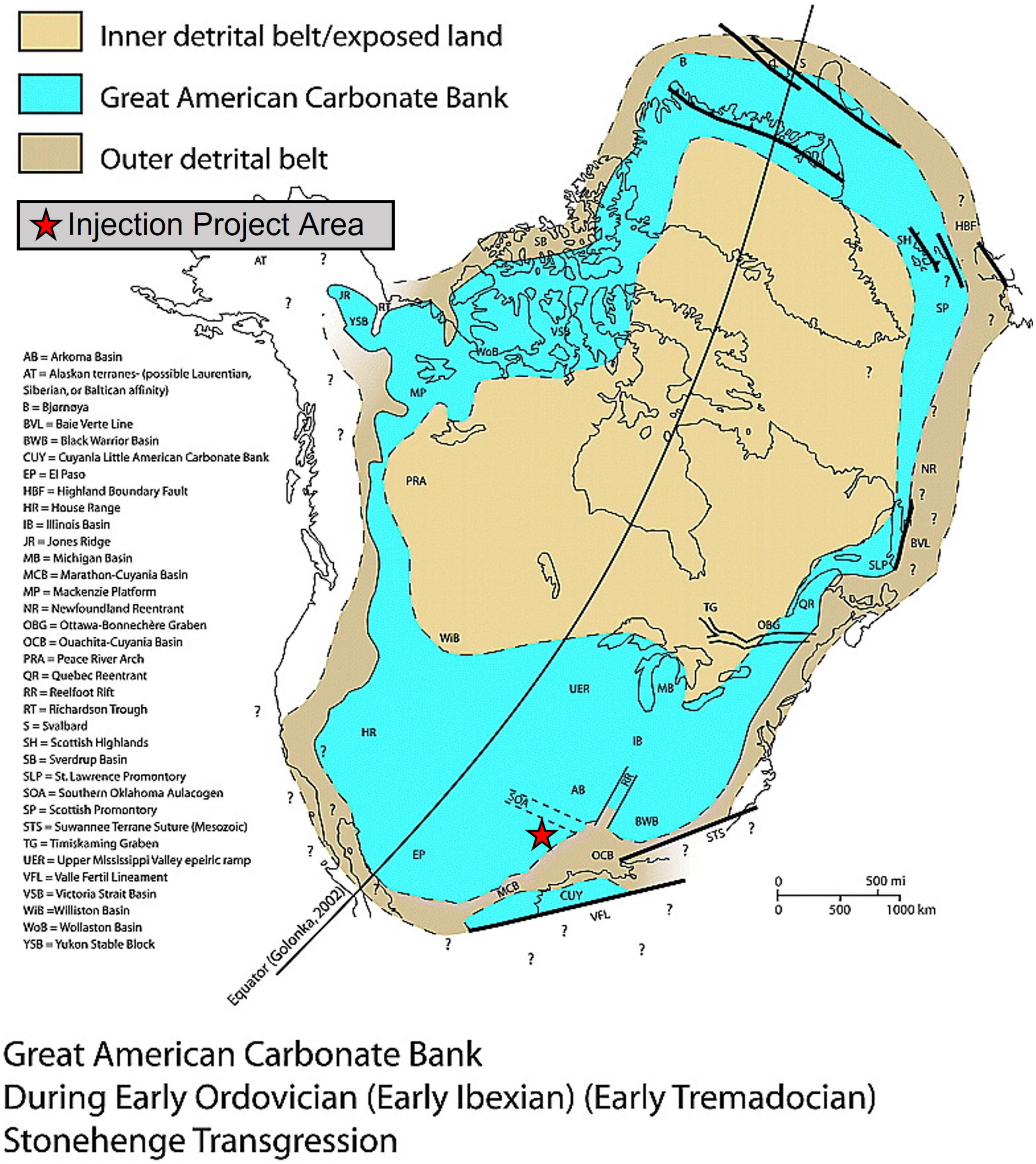

Figure 6: Location of Bowie injection project in reference to Great American carbonate bank paleogeography. Figure modified from Derby et al. (2012).

A large sea level change between the Ordovician and Mississippian resulted in an unconformity that removed any Silurian or Devonian rocks that may have been deposited. It was upon this unconformity that the Mississippian sediments, including the Barnett shale, were deposited. The late-Paleozoic Oauchita Orogeny formed the structural Fort Worth Basin and influenced sedimentation patterns through Permian time, with additional influence on the character

and thickness of sediments by local structure perturbations. In the northern Fort Worth Basin, these local structures include the Muenster Arch and Red River Arch. Pennsylvanian and early Permian sediments include both siliciclastics and carbonates, with siliciclastics being more dominant in the mid to late Pennsylvanian and Permian [Pollastro et al. (2007)]. In the eastern part of the Fort Worth Basin, the Cretaceous Trinity group rests unconformably on the Permian and Pennsylvanian-aged sediments [Fort Worth Geological Society (1955)]. The Trinity group contains the major freshwater aquifer units where present in the Fort Worth Basin, with no minor aquifers present (Figure 7) [George et al. (2011)].

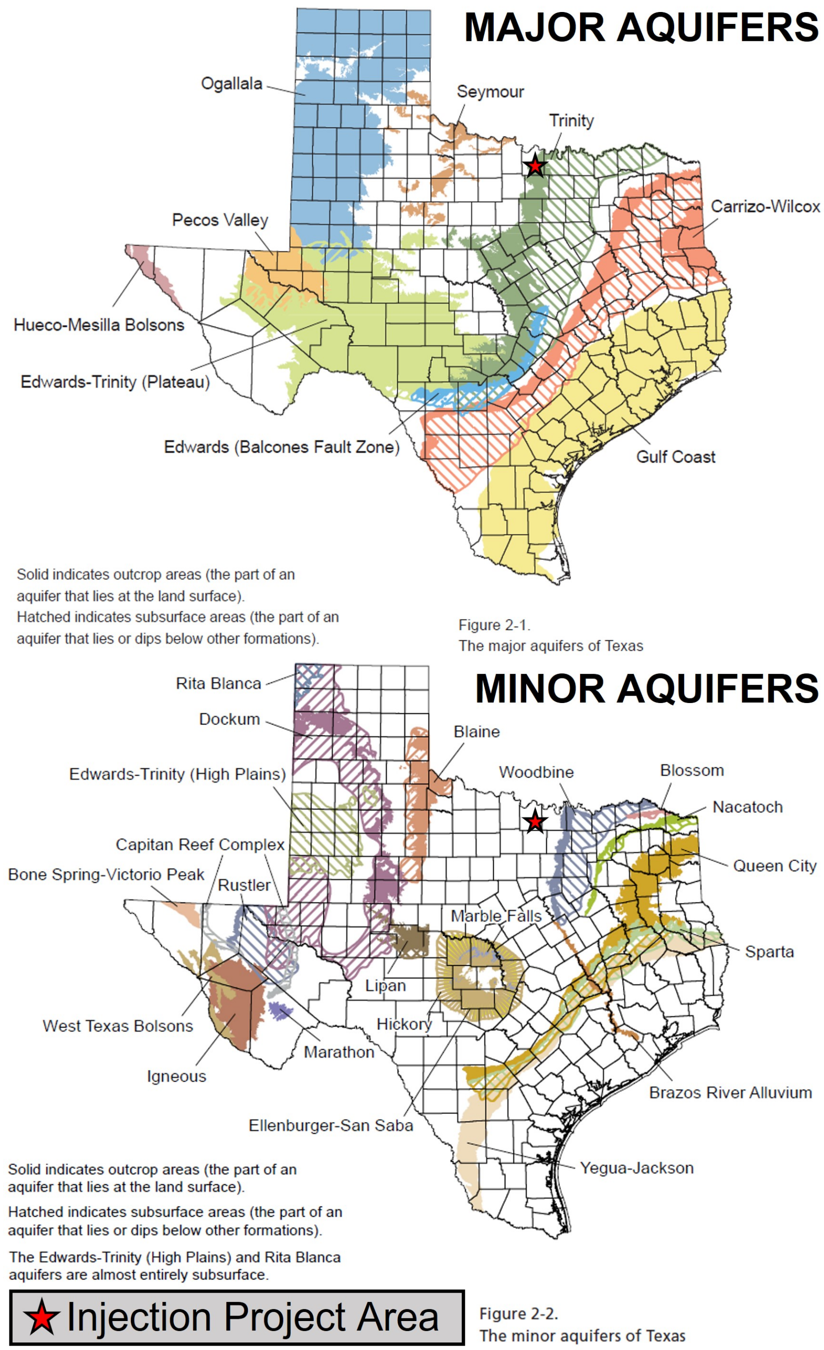

Figure 7: Project site referenced to Texas major and minor aquifers as identified by the Texas Water Development Board. Figure modified from George et al. (2011).

The injection project is located in Montague County, in the far northern part of Fort Worth Basin, in a structurally deep part of the basin adjacent to the Muenster Arch. Figure 8 shows the location of the project, structure contours on the top Ellenburger, and regional structural elements, including the Muenster Arch. The Muenster Arch has reactivated numerous times since the Precambrian, influencing local depositional patterns in Paleozoic strata.

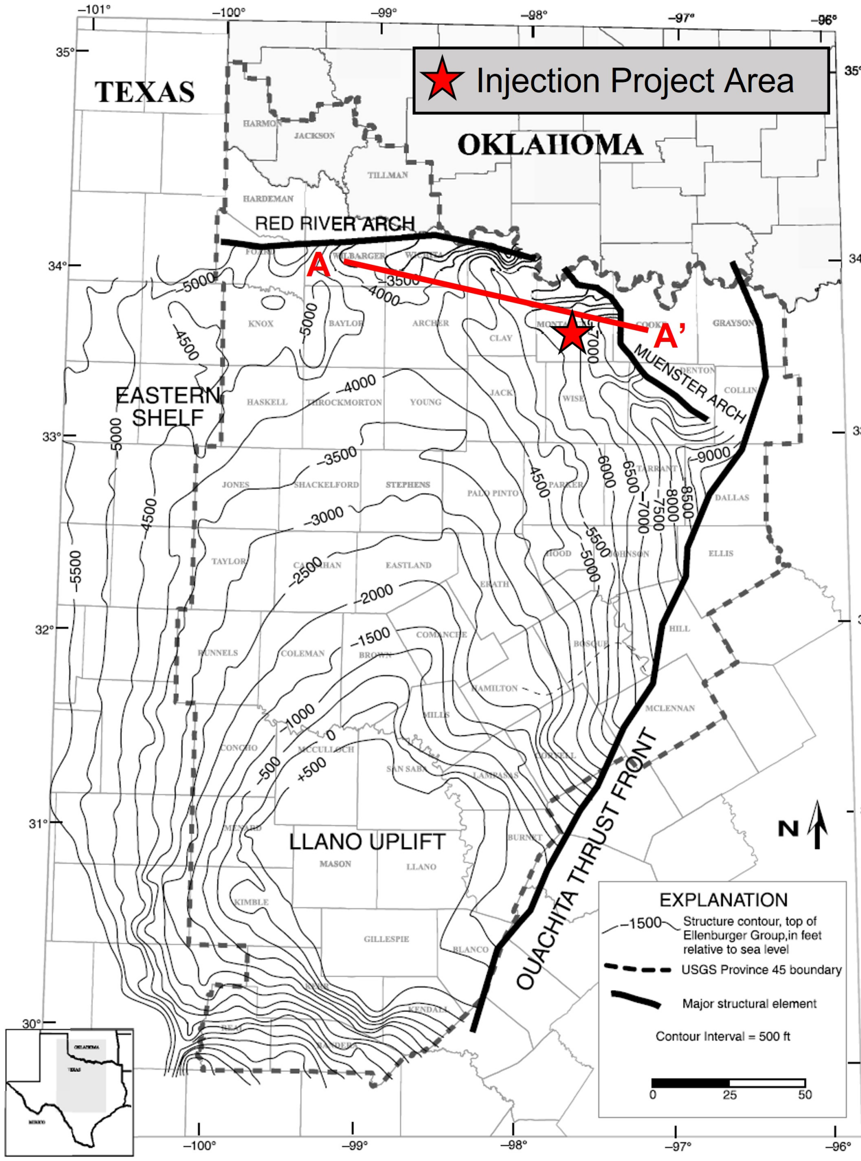

Figure 8: Location of Bowie injection project in Northern Fort Worth Basin, with top Ellenburger subsea true vertical depth (SSTVD) structure contours. Figure modified from Pollastro et al. (2007).

2.4 Stratigraphy of the Project Area

Figure 9 shows the general character of the stratigraphy in the vicinity of the project area in Montague County. Formations between the basement and lower Penn (labeled top "Caddo") thicken and deepen towards the Muenster Arch, showing its influence on both deposition and present-day structural position. The Muenster Arch is shown as a series of high angle thrusts that place Ordovican Ellenburger above younger Mississippian and Penn sediments. Penn and Permian sediments thicken towards the Oauchita front and Muenster Arch and are truncated by the base Cretaceous unconformity. The Cretaceous-age Trinity group is present in Montague County and sits above this unconformity.

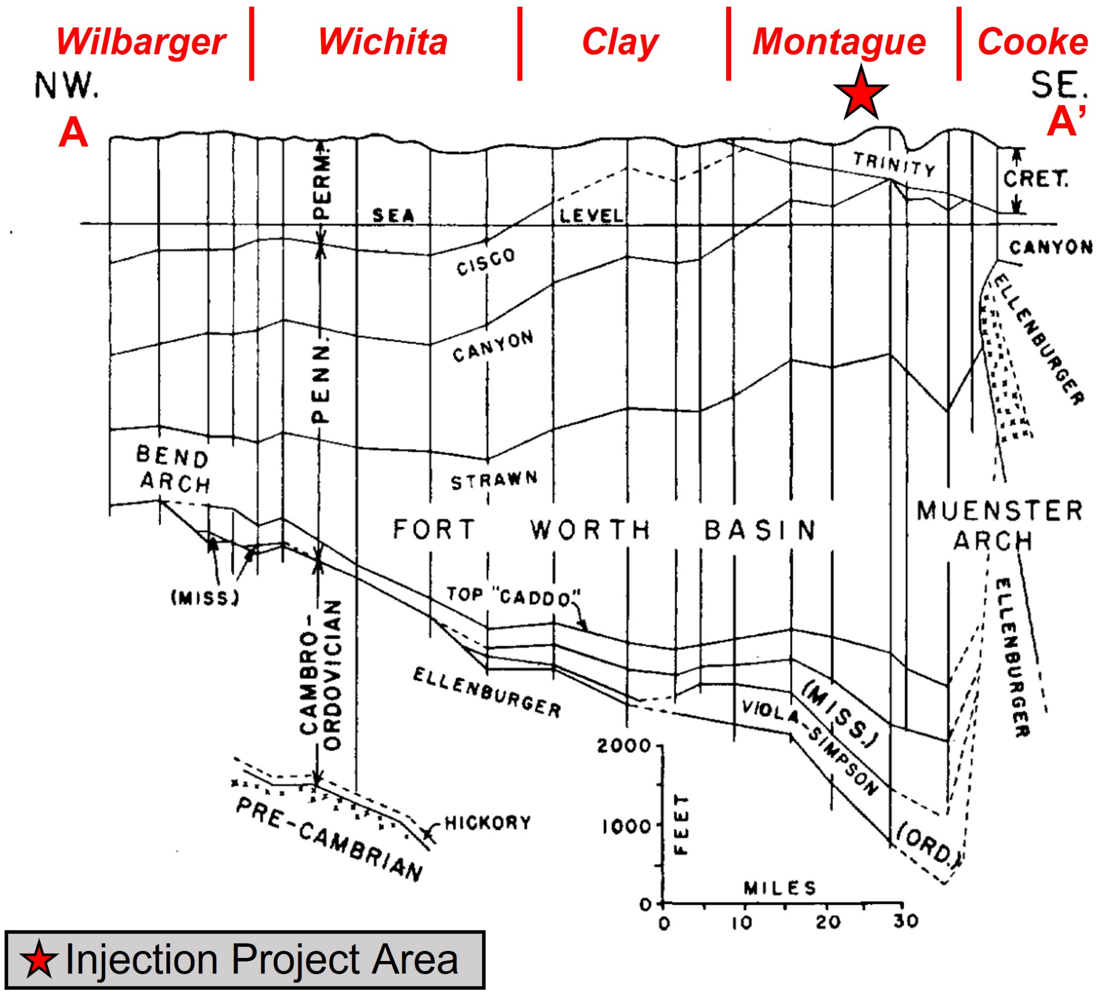

Figure 9: Generalized stratigraphic cross-section of North Fort Worth Basin with counties annotated on section. Figure modified from Fort Worth Geological Society (1955). Location of section shown in Figure 8.

Figure 10 shows the specific stratigraphic units present in the project area which are described below. Geologic descriptions are based on literature and internal EOG data collected across the stratigraphy for this project and others. The Precambrian basement within the project site is granitic and is variably cut by mafic intrusives. The carbonate section from the basement to the top of the Ellenburger has been broken in three units that can be correlated across Montague County. These three units are the basal carbonate (from basement to Base M. Ellenburger in typelog), middle Ellenburger, and upper Ellenburger. Above these units, the Simpson, Viola, and Barnett Shale are observed to be present within the project site [Pollastro et al. (2007)]. More detail will be presented on the lower carbonate through lower Barnett shale in the sections describing the injection and confining zones for the project (Section 2.7). The overlying Pennsylvanian stratigraphy has been broken out using both regional and local nomenclature for the stratigraphic units. At the top of the section is the base of the Trinity aquifer unit, which crops out within the project site (see Figure 11) [George et al. (2011)].

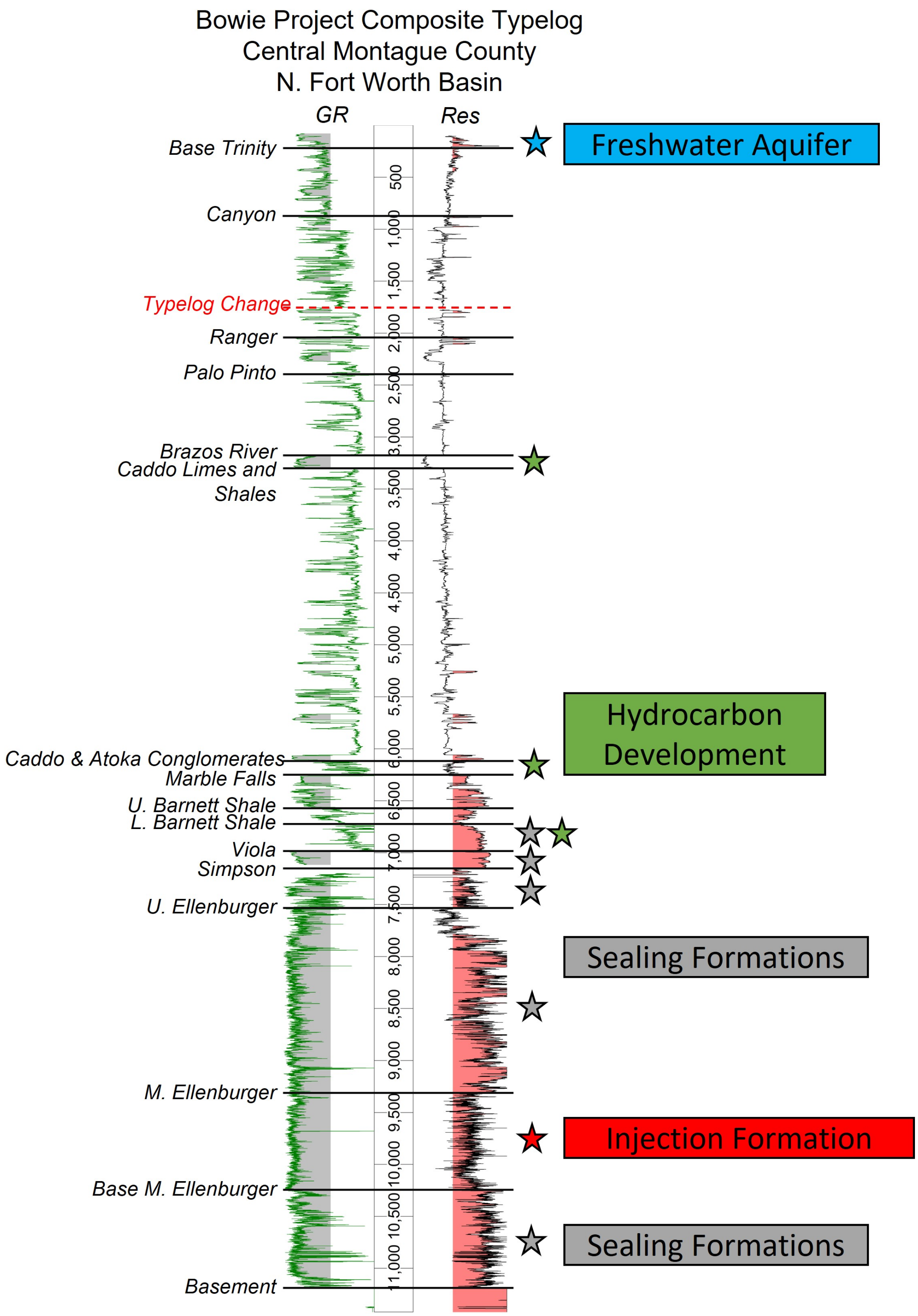

Figure 10: Project site-specific typelog utilizing well log data collected from the Billy Henderson #5 (lower Canyon to basement section) and Hinkle Trust #1 (surface to lower Canyon section).

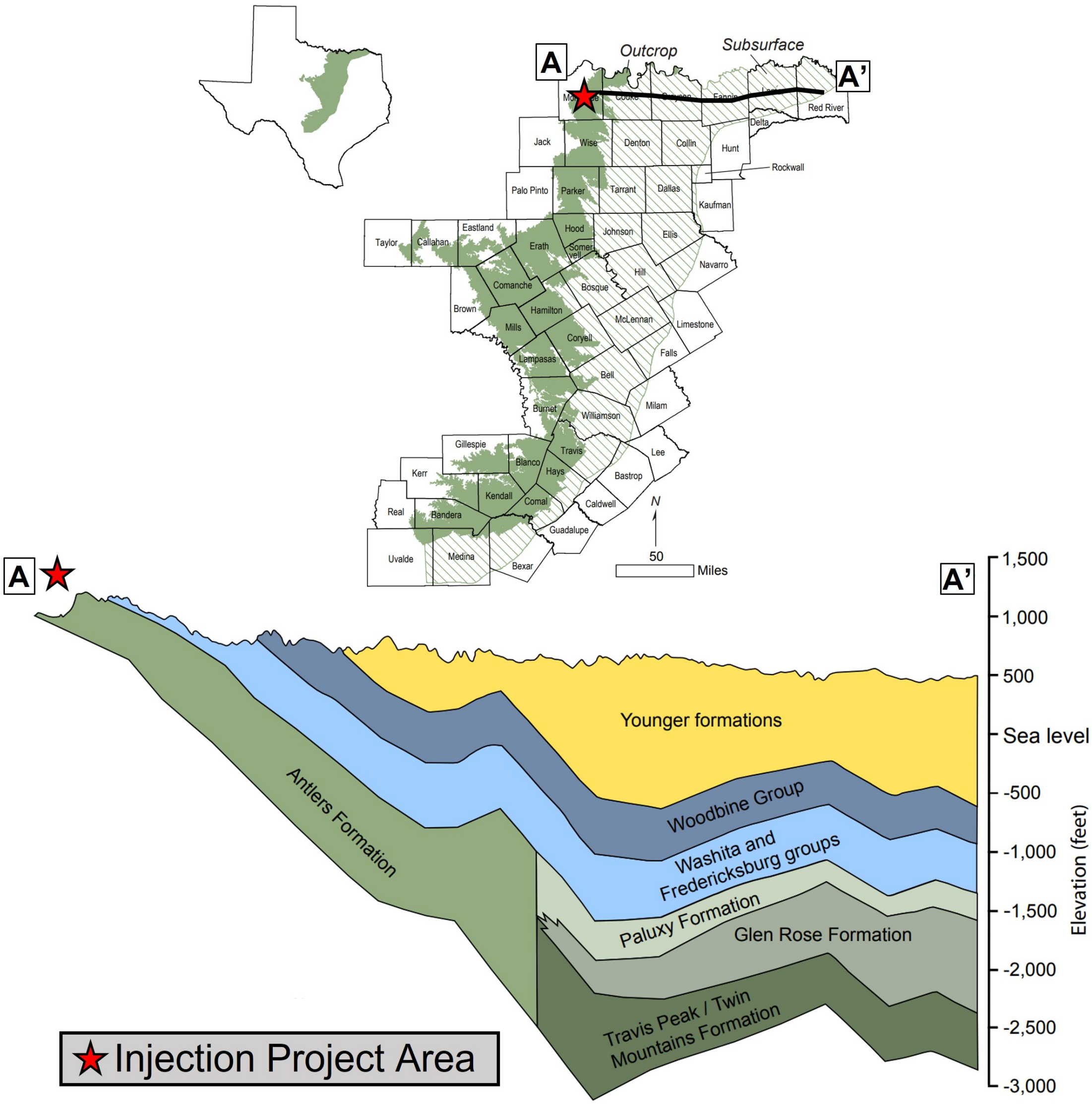

Figure 11: Trinity aquifer extent and geometry in the vicinity of the project area. Figure modified from George et al. (2011).

2.5 Structural Geology of the Project Area

The injection area is bounded by the Muenster Arch to the east and northeast and the Red River Arch to the north, both of which are positive, basement-rooted structural features formed during the Paleozoic Oklahoma aulacogen and were reactivated during Ouachita orogenic compression [Walper (1982)]. The injection area is characterized by three key structural components: basement-rooted faulting, natural fracturing, and, specifically within the Ellenburger, extensive karst formation. Within the injection area, these structural components are characterized with 3D seismic data, core, and well log data, and are discussed in further detail below.

Basement faulting: The injection area is characterized by a variety of fault orientations and styles reflecting multiple tectonic episodes during Fort Worth Basin evolution. Prominent basement faults generally strike east-west, largely exhibit strike-slip characteristics including extensive flower structures, and were likely formed during the Oklahoma aulacogen [Walper (1982), Pollastro et al. (2007)]. Most prominent basement faults either truncate within the basement or splay into smaller faults upon entering the Ellenburger, though some larger faults may extend up to Pennsylvanian

Strawn or Bend groups (Figure 12). A secondary basement fault set strikes NNE-SSW, paralleling present-day Ellenburger structural strike, though is less prevalent and does not extend above the basement within the injection area. Several basement-level faults intersect the injection interval (Figure 12), and are discussed as potential leakage pathways in section 3.5.3.

Natural fracturing: Ellenburger natural fractures, characterized by wellbore image logs and core data in the injection and monitoring wells, exhibit highly variable strike and dip, and likely originated from a combination of tectonic forces and intra-karst collapse and brecciation [Kerans (1988), Ijirigho and Schreiber Jr (1988)]. Natural fractures also generally appear cemented (Figure 28). The karst features themselves appear to be restricted to the injection zone, and do not appear to extend into the confining zone within the project area. Therefore, the fracturing associated with the karsts is not interpreted to be present across the confining zone.

Karsting: Ordovician Ellenburger group carbonates were deposited on a carbonate platform on a stable cratonic shelf. Sea level drops during and following Ellenburger deposition yielded subareal platform exposure and complex, extensive karsting, which was subsequently filled with Simpson Group clastics [Kerans (1988)]. Karst features are present within the proposed injection area and likely provide the primary Ellenburger storage (i.e., pore space) within the proposed injection interval.

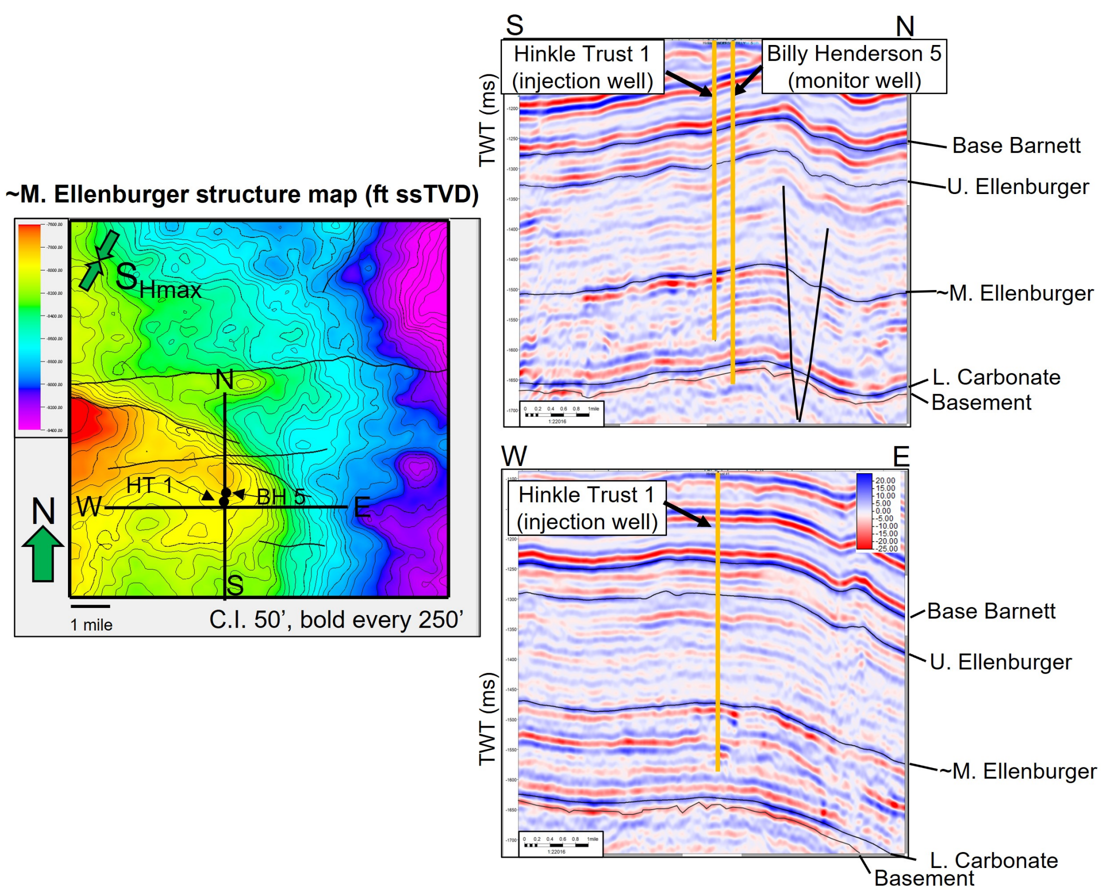

Figure 12: Middle Ellenburger structure map (top injection zone) and seismic cross-sections over proposed injection area. Black lines denote major faults.

2.6 Barnabus Ellenburger Field History

The Hinkle Trust #1 is permitted as an acid gas injector (AGI) within the TXRRC-defined field known as the Barnabus Ellenburger field. Across EOG's productive Barnett acreage in Montague County, this zone has historically been used

extensively for the disposal of produced water (i.e., SWD, or saltwater disposal). Of the six wells drilled into the Ellenburger for SWD by EOG, only four penetrated the middle Ellenburger - the zone intended for long-term CO_2 injection and storage. These four wells are shown on the map in Figure 13 in relation to the Hinkle Trust #1 and Billy Henderson #5, the injection and monitoring wells drilled for this project. Only two of these wells - the Cox and the Davenport - are still active SWD injectors while the other two have been permanently plugged and abandoned. Of the remaining active injectors, the Cox is the closest to the project area, located approximately 6 miles to the north.

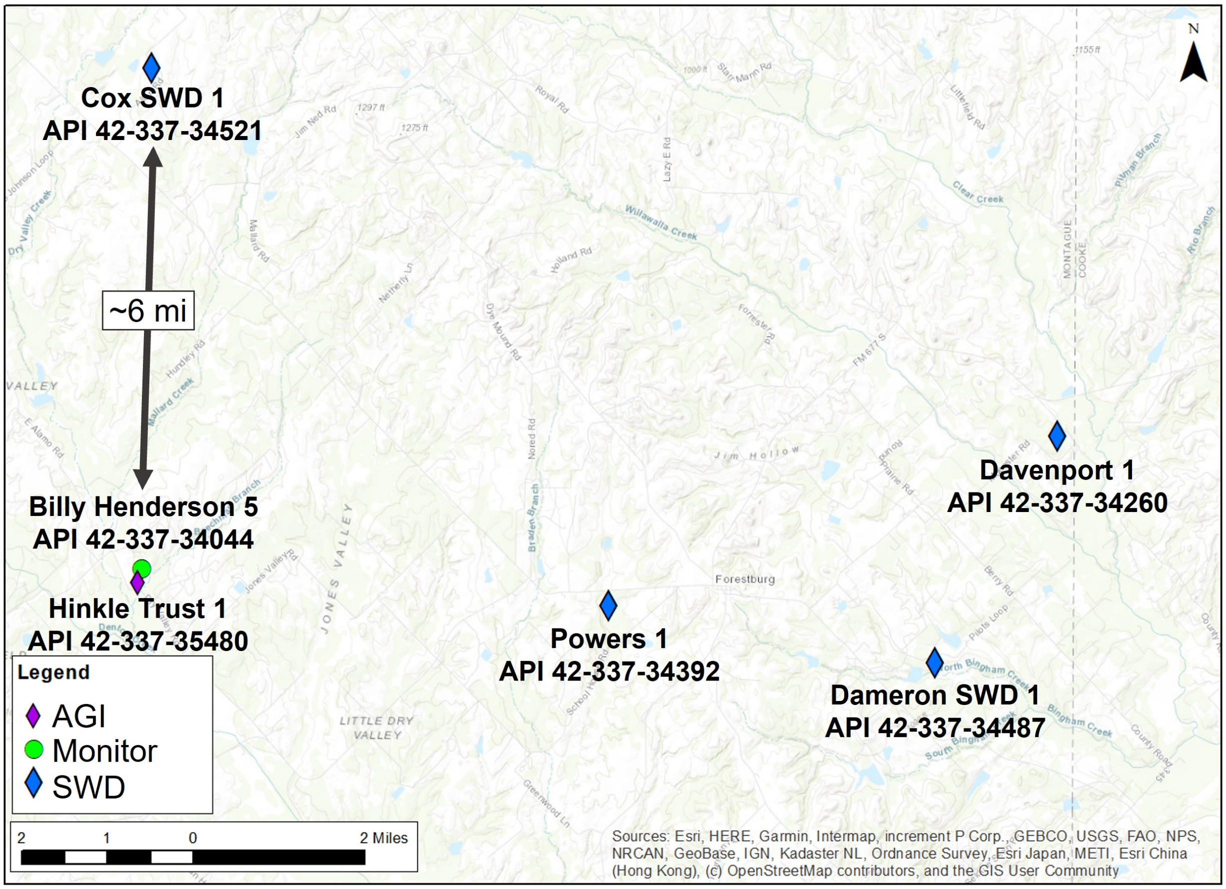

Figure 13: Map of SWD wells drilled into the middle Ellenburger in relation to the CO_2 injection project area.

Figure 14 shows the historical combined monthly injection rates and total cumulative volume injected from all four deep SWD wells from 2010 to 2022. What is notable in these injection trends are the very high rates from 2010 to 2014, when EOG's Barnett development was at its peak. During those years, the SWD wells were each injecting nearly 500,000 barrels (BBL) per month - indicating good injection characteristics in the middle Ellenburger. Over time, as development drilling and field production declined, so did the volume of produced water, which explains the tapering off in the use of the SWD wells from 2014 to 2022. During the entire active period, the four SWD wells injected nearly 90 MM BBL into the middle Ellenburger - suggestive of a large reservoir storage capacity. A relatively small amount of SWD injection is presently active in the Cox and Davenport wells at average rates of 4,200 and 3,700 BBL/day, respectively, with both wells showing stable and consistent injection pressure trends.

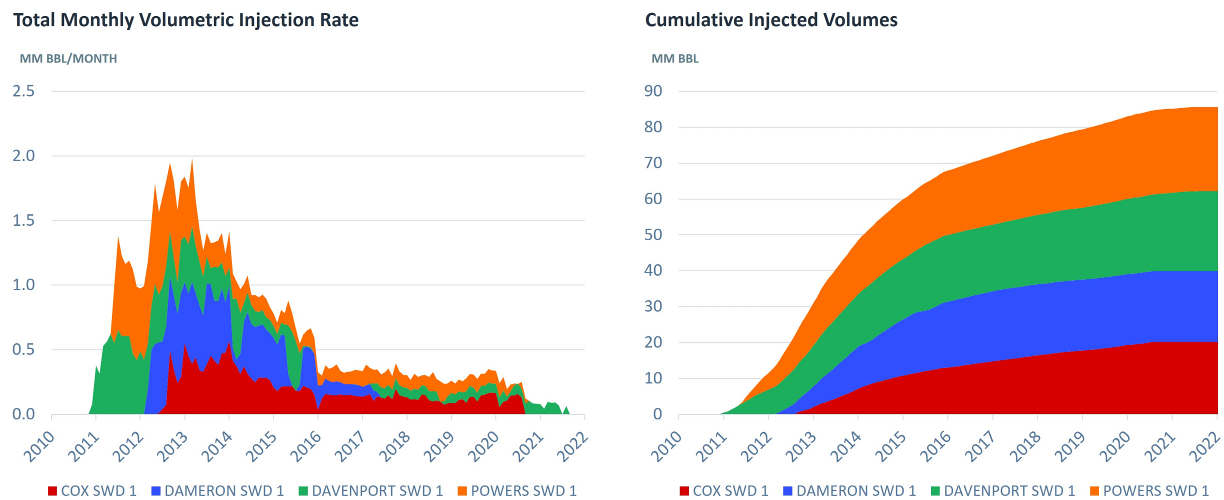

Figure 14: Combined monthly SWD injection rate (left) and cumulative injected water volumes (right) of deep Ellenburger SWD wells from 2010 to 2022.

2.7 Injection and Confining Zone Details

This section provides both quantitative and qualitative descriptions of the injection and confining zones. Observations presented are based on core, petrophysical well log, and 3D seismic data sets that have been integrated across appropriate scales. Petrophysical logs for the injection, upper confining, and lower confining zones were chosen to represent the character and thicknesses observed in the subsequent sections (Figures 15-17). Raw petrophysical logs are shown with the exception of a modeled lithology, which is calibrated to x-ray diffraction mineralogical measurements from core plugs. Core and seismic data are consistent with the characteristics exemplified by the petrophysical logs shown across the injection and confining zones.

2.7.1 Injection Zone

The injection zone for this project is the middle Ellenburger, which is a karsted carbonate reservoir. The injection zone is approximately one thousand feet thick in the project area. The lithology is primarily dolomite, with minor interbedded limestones (Figure 15). The limestones within the injection zone are nonporous and have low permeability based on log and core measurements. The dolomites within in the injection zone host the observed porosity and favorable permeability and range in texture from nonporous, overdolomitized to mesoscale vuggy sucrosic to karst breccias with significant macroscale pore networks. Pervasive dolomitization and karsting is associated with a shallow marine carbonate depositional setting and post-depositional sea level fluctuations allowing for formation of repeated unconformities and karst development across the section.

Qualitative and quantitative descriptive methods were tailored to capture relevant data across this range of textures. Multiscale core measurements and detailed borehole image log analyses were combined with traditional petrophysical modeling to provide the best quantitative interpretation of the injection section for modeling purposes. Matrix scale measurements were made using routine core analysis on plugs taken from a conventional core cut within the injection zone and from rotary sidewall cores collected off wireline in the Billy Henderson #5. These measurements illustrate the range in matrix porosity and permeability observed within the injection zone. Observed porosity and permeability ranges were less than 1% to over 15% and microdarcy to millidarcy, respectively (Table 2).

Matrix scale measurements were combined with methods more suited to measure porosity and permeability within mesoscale karst textures. Two methods were employed: full-diameter, whole core porosity and permeability mechanical measurements and high-resolution computed tomography (CT) scan digital modeling and measurements. A series of whole core porosity and permeability measurements were made on approximately 6-inch long pieces of whole (unslabbed) core sections. Samples were also CT-scanned and then the images were interpreted to create a 3D model of the pore network within the samples. The 3D digital model was then used to generate a set of high resolution poros-

ity curves for each sample. Quantitative data from these mesoscale measurements shows the wide range of values expected for this karst system (Table 3).

The permeabilities measured within the mesoscale to macroscale karst textures were observed to be significantly higher than that of the matrix rock. Interpretation of these observations combined with dynamic injection testing and flow allocation surveys suggests that fluid flow is significantly impacted by the presence or absence of these karst textures. Therefore, methods employed in the creation of a representative geomodel and reservoir simulation for the project incorporate all scales of measurement, which is discussed in detail in subsequent sections of this document.

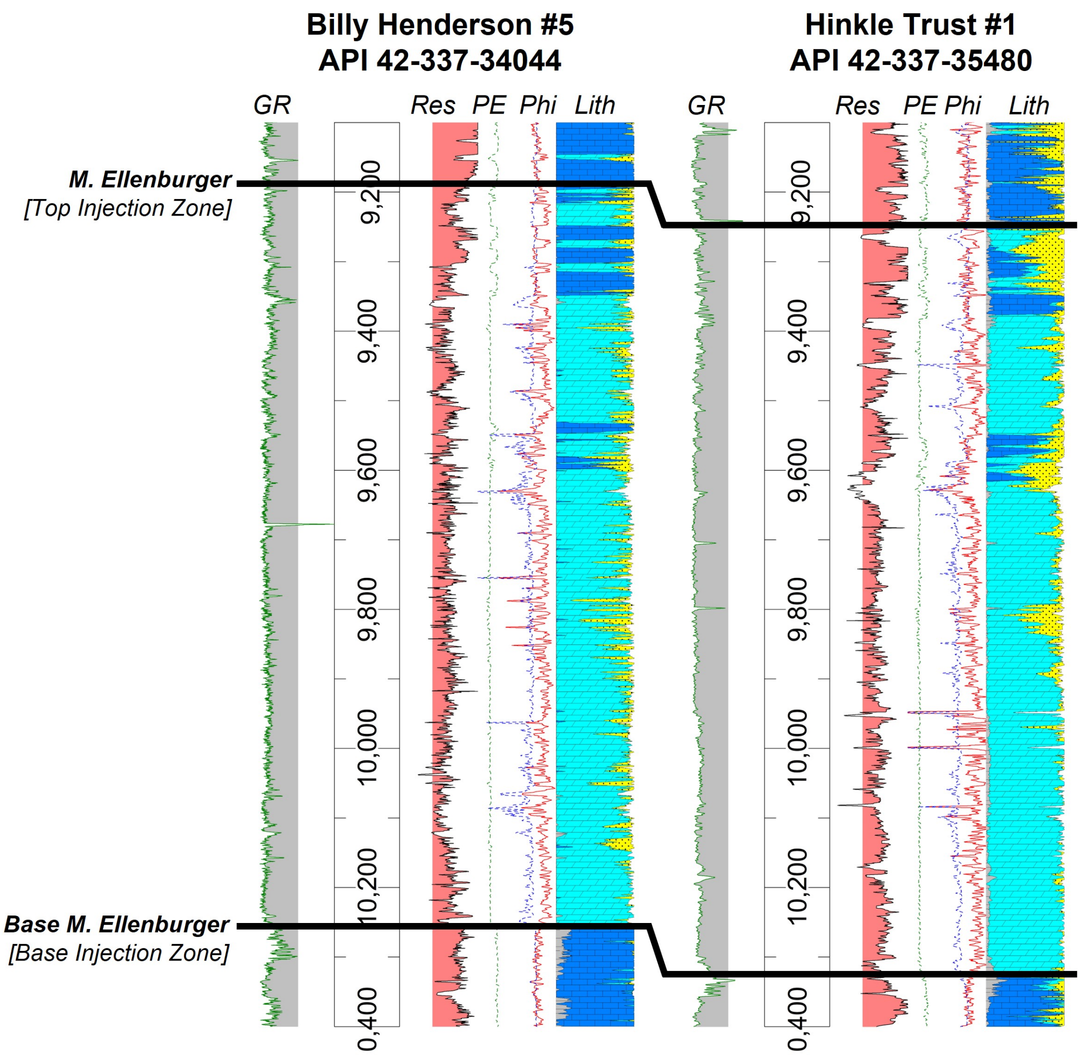

Figure 15: Petrophysical log interpretation in true vertical depth (TVD) for the Middle Ellenburger injection zone at the Bowie project site. Lithologic model presented includes dolomite (cyan), limestone (blue), silica (yellow), clay (gray), and organics (green).

2.7.2 Upper Confining Zone

The upper confining zone for this project is defined as the Upper Ellenburger, Simpson, Viola, and base of Barnett shale. The upper confining zone is approximately 2,200 ft thick within the project site. A significant portion of the confining zone consists of sealing tight limestones and dolomites with varying amounts of clay and clay-rich shale. Other rock types present include variably-porous dolomites and limestones (Figure 16). The units within the upper

confining zone appear present and of similar thickness and character across the project site based on 3D seismic and well log interpretation.

The base of the upper Ellenburger consists of approximately 600 ft of mostly tight limestone with a few low porosity dolomite stringers directly overlying the injection zone. This contact is interpreted as a significant unconformity due to the sharp contrasts observed above and below the surface. Petrographic and petrophysical modeling of this zone indicates the presence of tightly-cemented, fine-grained mudstones and wackestones.

Above the lower blocky, tight limestone is interbedded tight limestone and variably porous dolomite. The interbedded lithologies and variable porosities observed are interpreted as coarsening upward depositional cycles with tight limestones at the base grading to variably porous dolomites that cap the cycles. Tight limestones here are similar to those observed in the base of the upper Ellenburger. Depositional textures within the dolomites are more difficult to ascertain due to dolomitization, but it is probable that some of these facies were coarser packstones and grainstones as well as muddier carbonate facies.

At the top of the upper Ellenburger, a blocky porous dolomite section is observed. The top of the Ellenburger likely represents another significant unconformity, but does not show the pervasive karst textures observed within the middle Ellenburger. Minor karst textures are observed, but most porosity in this part of the section seems to be associated with the matrix of the rock.

The Simpson formation is primarily limestone with minor to moderate clay content. It consists of an upper and lower section with higher clay content and a cleaner limestone facies in the middle of the section. Within the project area, the Simpson is approximately 400 ft thick. The upper and lower sections consist of fine-grained, muddy carbonate facies with varying amounts of fine-grained siliciclastics. The clean limestones contain coarser carbonate facies with minor preserved porosity. The Viola within the project area is approximately 180 ft of tight limestone. Observations from a nearby proprietary core just outside the project site suggest the Viola consists mainly of nonporous carbonate mudstones and wackestones within the project area.

At the top of the confining zone is the lower Barnett shale. The lower Barnett is the main hydrocarbon development horizon within the project site. As such, the main focus on the lower Barnett for confinement is restricted to the base of the section below the horizontally-drilled development target. The rock volume within the Barnett that has not been stimulated by hydraulic fracturing, however, likely contributes to confinement within the project area as well.

Matrix scale measurements were made using routine core analysis on plugs taken from several sources. Data for the upper Ellenburger and Simpson comes from plugs from a conventional core cut within the upper Ellenburger and from rotary sidewall cores collected via wireline in the Billy Henderson #5 well. Data for the Simpson and the Barnett come from plugs cut from analog cores near the project site. Quantitative measurements indicate the low porosity, low permeability nature of the pervasive sealing facies within the upper Ellenburger, Simpson, Viola, and lower Barnett shale (Table 2).

The quantitative data presented here were incorporated into the geomodel for the confining zone. In contrast to the injection zone, no pervasive karst textures were observed within the confining zone in the project area. Image log analysis and dynamic injection testing and surveys also indicate an apparent lack of karst features, as well as a lack of transmissive fractures and faults within the upper confining zone at the injection site.

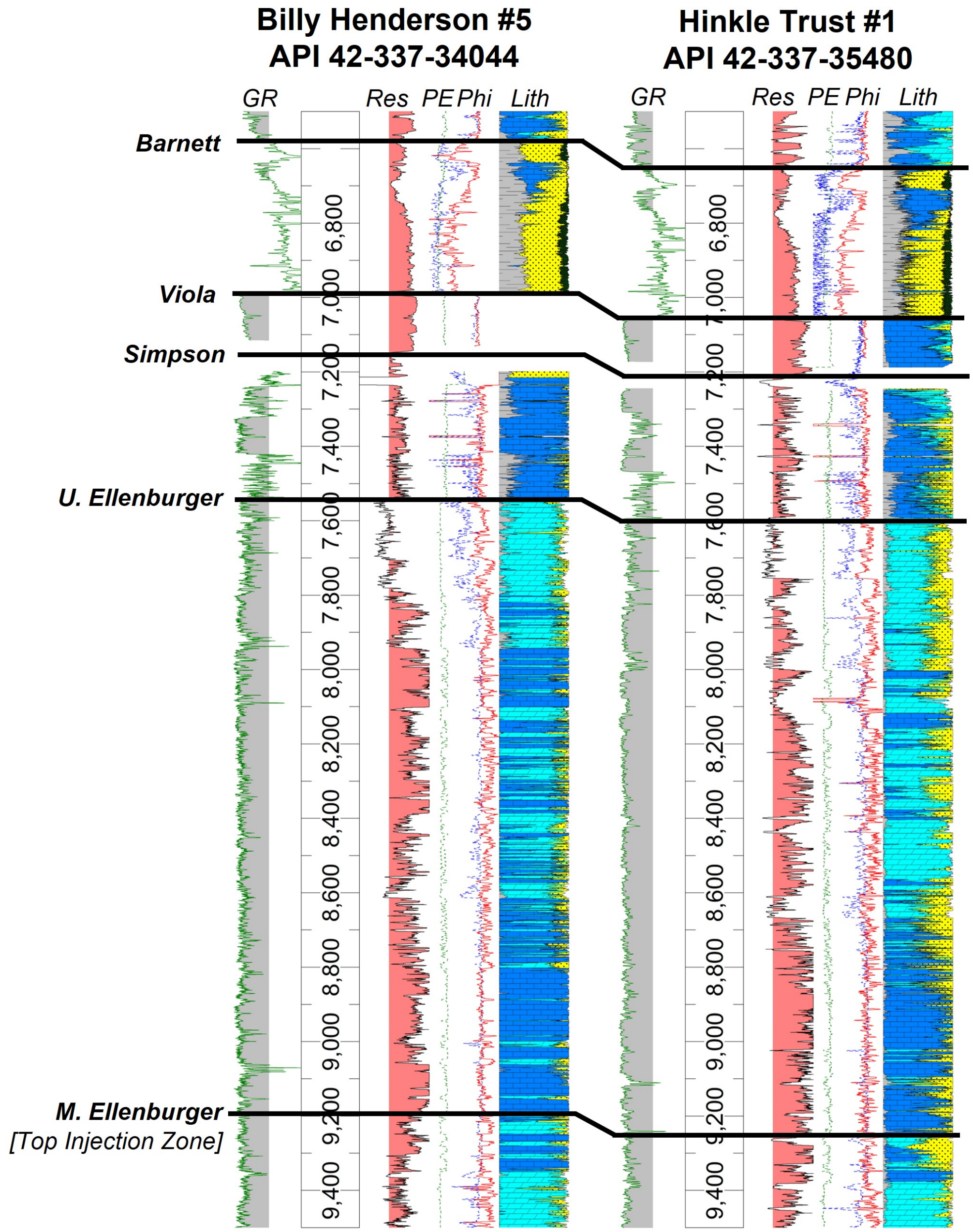

Figure 16: Petrophysical log interpretation in true vertical depth (TVD) for the Upper Ellenburger to Barnett upper confining zone within the Bowie project site. Lithologic model presented includes dolomite (cyan), limestone (blue), silica (yellow), clay (gray), and organics (green).

2.7.3 Lower Confining Zone

The lower confining zone consists of the section between the granitic basement and the base of the middle Ellenburger injection zone. This zone consists of approximately 1,000 ft of primarily tight limestone with minor clay within the limestones and a few clay stringers in the project area (Figure 17). Petrographic analysis indicates the presence of heavily cemented limestone facies ranging from mudstones to packstones. A few porous limestone beds are preserved near the clay-rich stringers, but porous limestones are relatively rare across the entirety of the section.

Quantitative routine core analysis data confirms the presence of low porosity, low permeability limestone facies across much of the section. As with the upper confining zone, these matrix scale measurements were used in the geomodel and subsequent reservoir simulation for the lower confining zone. Image log analysis, dynamic injection testing, and injection surveys also indicate a lack of karst features within the lower confining zone, as well as an apparent lack of transmissive fractures and faults within the lower confining zone at the injection site.

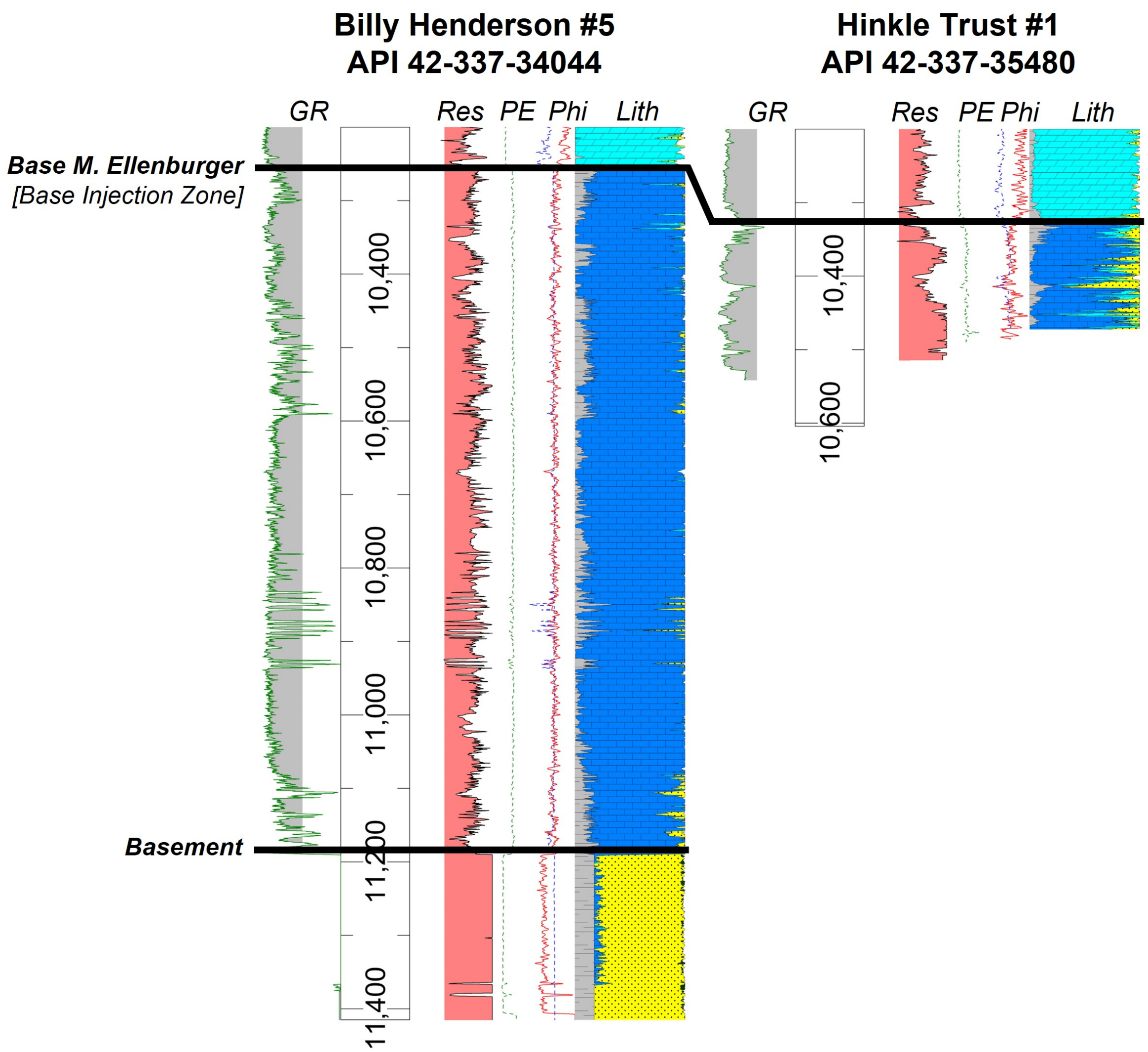

Figure 17: Petrophysical log interpretation in true vertical depth (TVD) for the base Ellenburger to middle Ellenburger lower confining zone within the Bowie project site. Lithologic model presented includes dolomite (cyan), limestone (blue), silica (yellow), clay (gray), and organics (green).

Table 2: Summary of routine core analysis (RCA) data collected for the project by system and formation.

System	**Formation**	**Porosity Minimum** %	**Porosity Maximum** %	**Permeability Minimum** md	**Permeability Maximum** md
Upper Confining	L. Barnett	1.29	8.29	3.02E-06[b]	7.24E-04[b]
	Viola	1.68	6.59	5.00E-04	1.60E-02
	Simpson	1.60	4.32	4.90E-03	6.34E-01
	U. Ellenburger	0.36	13.85	<1.00E-03[c]	5.58E00
Injection	M. Ellenburger	0.29	15.96	<1.00E-03[c]	1.68E00
Lower Confining	L. Carbonate	0.35	15.87	<1.00E-03[c]	9.40E00

[b]Denotes permeability measurements made using permeability decay methods.
[c]Denotes permeability values were below the measurement threshold of the routine core analysis technique. Therefore, the value presented represents an upper limit of minimum permeability. Minimum permeabilities could be significantly lower than the values presented.

Table 3: Summary of full diameter core mesoscale data over the injection interval collected for the project.

	Test Method	
Measurement	Full Diameter Mechanical	Computed Tomography (CT) Digital
Porosity Minimum (%)	2.2	<0.01
Porosity Maximum (%)	6.3	51.9
Horizontal Permeability Minimum (md)	6.96E-02	—
Horizontal Permeability Maximum (md)	1.86E04	—
Vertical Permeability Minimum (md)	1.64E-04	—
Vertical Permeability Maximum (md)	2.83E00	—

3 Development and Administration of the MRV Plan

As required under §98.448(a)(1)-(2) of Subpart RR, the MRV plan is developed around and tailored to the potential surface leakage pathways within the active and maximum monitoring areas (AMA and MMA, respectively) defined in §98.449. Since the AMA and MMA are both dependent on the expected long-term behavior of CO_2 in the subsurface, numerical reservoir simulation is the generally-accepted best practice to represent the dynamic behavior and complex fluid interactions that influence the CO_2 plume extent and shape during and after injection operations. The next two sections describe the development of a detailed geologic model using the available regional and site-specific data that serves as the basis for predictive numerical reservoir simulations to delineate the AMA and MMA extents for the proposed injection volumes.

3.1 Geologic Model

A geologic model was developed with the proposed injection project at the approximate center of the gridded region. The general grid properties are summarized in Table 4 and the overall grid geometry and structure is depicted in Figure 18. Major stratigraphic surfaces - from the Lower Barnett through the upper Granitic Basement - and regional structure were interpreted from EOG's in-house 3D seismic data and depth-tied to well log correlations from the deep penetrations in the project area. Although faulting and fracturing is generally present within the proposed injection area, injection testing and geomechanical modeling suggests faults and fractures are not primary permeability pathways. Consequently, they are not included in the initial simulation model. Grid layer thicknesses in the over- and under-burden horizons are generally coarse (ranging from 70 to more than 700 feet) since little change is expected in these regions, whereas the layers in the primary injection horizon (i.e., the middle Ellenburger) were selectively refined (ranging from 15 to ~50 feet) to capture the geologic heterogeneity that is likely to influence the CO_2 flow distribution within the storage reservoir.

Table 4: Summary of geologic model grid properties

	i-dir	j-dir	k-dir
Increment (ft)	200	200	variable
Layer Count	126	126	35
Total Length (ft)	26,200	26,200	~5,400
Total Cell Count		555,660	

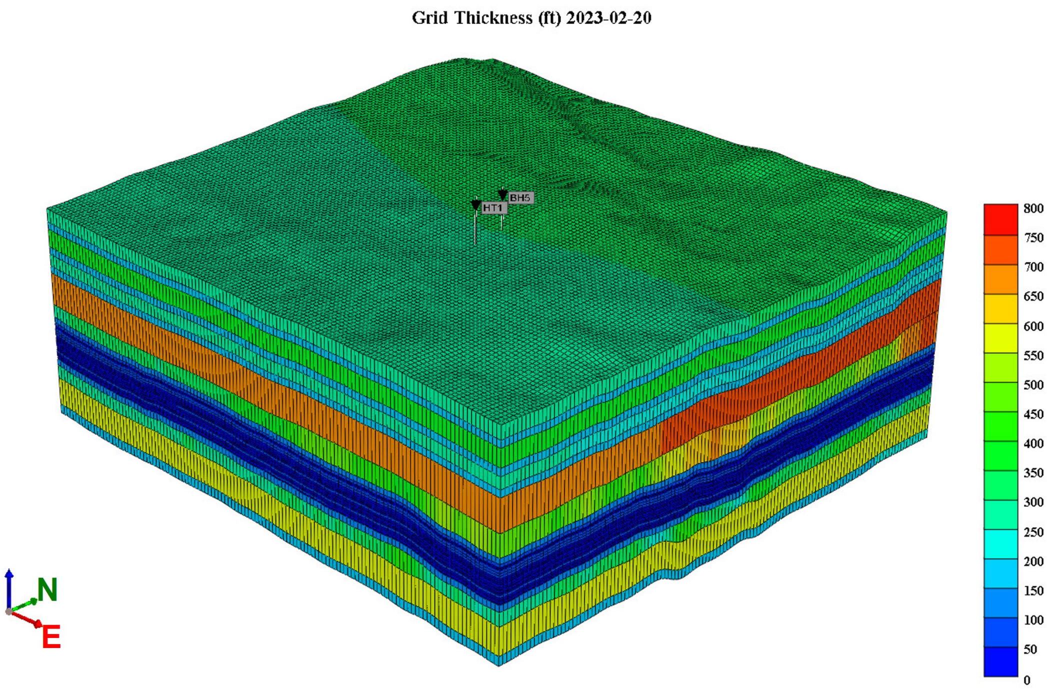

Figure 18: Northwest-looking 3D-view of the overall model grid structure; grid cell thickness property displayed.

Petrophysical transport properties (e.g., porosity and permeability) for each geologic horizon were subsequently propagated throughout the grid framework based on the rigorous integration and characterization of the core, log, and seismic data sets available in the project area (and described in the previous Section 2.7). The statistical range and spatial variability of all geologic intervals included in the model were considered in this multiscale analysis, with particular emphasis on representing the extreme heterogeneity observed in the karsted, dolomitized injection interval of the middle Ellenburger. The iterative property modeling workflow adopted for this project is summarized by the following general steps:

1. comparison and calibration of log response to measured core values (plug and full-diameter samples);
2. identification of key facies associated with injection/storage versus baffling/containment at well scale;
3. development of porosity-permeability transforms and net-to-gross (NTG) relationships for each facies type at well scale;
4. development of independent ties between well-scale porosity and NTG to seismic-scale attributes;
5. probabilistic spatial modeling of porosity and NTG via collocated co-kriging with associated seismic attributes;

6. calculation of permeability properties (i.e., vertical and horizontal) based on established porosity transforms for each geologic horizon.

Figure 19 depicts a representative layer from the resulting baseline realization of the geologic model which was used in the subsequent reservoir simulation forecasts. Of particular note is the heterogeneous nature in the spatial distribution of both the porosity and permeability properties in the middle Ellenburger, which is guided by amplitudes and patterns in the seismic data interpreted to be associated with large-scale karst features. The transport characteristics associated with these features are expected to have a first-order influence on the CO_2 plume growth over time and the workflow described above incorporates the available data - at the appropriate scales - to rigorously represent them in the model.

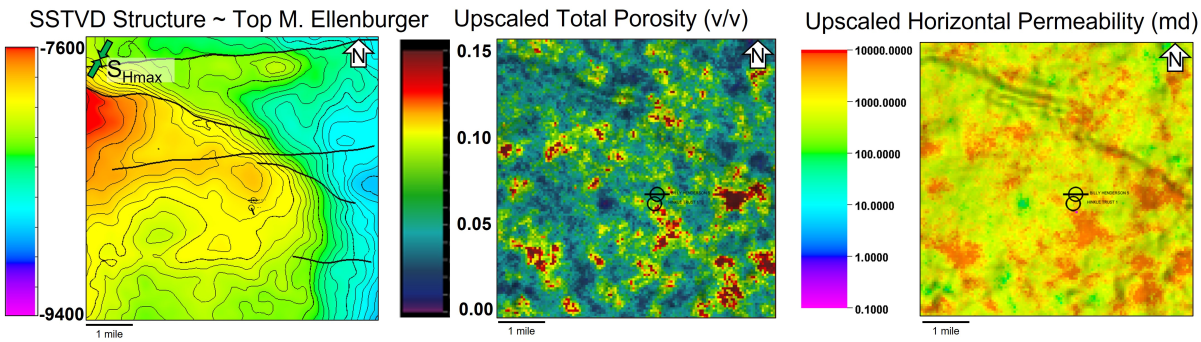

Figure 19: Example character of geomodel structural inputs in subsea true vertical depth (SSTVD) and property distributions (total porosity and horizontal permeability) within the middle Ellenburger storage zone. Note the varied distribution of high porosity and permeability representative of a karst reservoir.

3.2 Reservoir Simulation Model

With a representative static geologic model established, the grid and associated properties were then imported into Computer Modeling Group's (CMG) GEM v2022.30 compositional reservoir simulation software to forecast the long-term CO_2 plume behavior. GEM is a state-of-the-art finite difference solver which uses a compositional equation-of-state (EOS) methodology to represent the complex, multi-component thermodynamic interactions of fluid components during transport in porous media [Computer Modeling Group, LTD. (2021)]. As noted in other MRV plans recently approved by the EPA [Stakeholder Midstream Gas Services, LLC (2022)], GEM has become a generally-accepted software package for technical evaluation of geologic sequestration projects and is cited as such in the EPA's area of review guidance document for Class VI injection permits [US EPA (2013)].

Initialization of the reservoir model conditions was based on data acquired during the drilling and characterization of the project wells. Table 5 summarizes key inputs for the main injection interval in the middle Ellenburger, including reference subsea true vertical depth (SSTVD), pressure, temperature, water saturation (S_w), and total dissolved solids (TDS) of the native formation brine in parts per million (ppm). These data were obtained from wireline-conveyed dynamic testing and sampling tools deployed during logging operations on the Billy Henderson #5 and are representative of the reservoir throughout the project area. Pressure and temperature gradients were extended from the reference depth through all grid layers based on fluid density measurements and stabilized fiber-optic distributed temperature sensor (DTS) measurements, respectively.

Table 5: Basic middle Ellenburger Reservoir conditions

Depth SSTVD ft	**Pressure** psia	**Temperature** °F	**S_w** v/v	**TDS** ppm
-9,275	4,993	195	1	211,961

Other key transport parameters and dynamic fluid processes for both the injection and confining horizons represented in the simulation include:

1. Drainage and imbibition capillary pressure functions for the CO_2-brine system derived from intrusion and extrusion mercury injection capillary pressure measurements (MICP) on core samples;
2. Porosity- and permeability-scaling of capillary pressure according to the Leverett J-function [Leverett (1941)];
3. Drainage and imbibition relative permeability functions calculated from the corresponding capillary pressure profiles;
4. Hysteresis trapping of the phases between drainage and imbibition cycles; and
5. Salinity concentration in the water (i.e., brine) phase and solubility between CO_2 and brine phases.

Before CO_2 injection forecast simulations were run, the model was rigorously history-matched to the water injection step-rate and pressure interference testing that was conducted between the Hinkle Trust #1 injection well and the Billy Henderson #5 monitoring well. Transient analysis of the pressure fall-off and interference test data revealed a single-porosity reservoir response with no apparent far-field boundary influence (i.e., an infinite-acting reservoir). In addition, pressure data obtained during the test from multiple gauges installed in both wells provided a robust data set against which to further calibrate and adjust the porosity, permeability, rock compressibility, and boundary conditions of the simulation model. This crucial step provides additional confidence in the simulated injection performance and long-term CO_2 plume development projections.

Another important constraint to consider when evaluating the simulated injection performance and long-term storage integrity is the fracture pressure of the injection and confining zones. As discussed later in section 3.5, the minimum horizontal stress gradient of the upper confining system was demonstrated via discrete micro-frac injection test to be 0.69 psi/ft, which equates to an absolute pressure of approximately ~5,500 psia at 7,980 ft - the TVD of the measurement. A continuous geomechanical earth model was subsequently constructed and calibrated to this measured data to assess the minimum horizontal stress profile in the injection zone, since it was impractical to initiate a fracture in this zone due to the extremely high permeability/injectivity. The resulting estimate of the minimum horizontal stress at the top of the injection zone (~9,350 ft TVD; see Figure 25) is approximately ~5,890 psia or an effective gradient of 0.63 psi/ft. Applying a 90% safety factor to that estimate yields an effective gradient of approximately ~0.57 psi/ft or 5,300 psia.

A base case injection forecast was run using the calibrated reservoir model and the proposed 12-year CO_2 volumes schedule in Figure 3. An additional 200 years of post-injection shut-in time was simulated to observe the long-term reservoir response and predict the stabilized extent and shape of the separate phase CO_2 plume after buoyant migration has ceased. Simulated bottom-hole pressure (BHP) at the Hinkle Trust #1 injection well and CO_2 saturation (S_g) maps at the top of the middle Ellenburger injection zone - for both the 12-year injection and 212-year total simulation periods - are shown in Figures 20 and 21, respectively. Of particular note in Figure 20 is the relatively low BHP increase above the initial static pressure of ~4,550 psia: at the maximum injection rate of ~10 MMSCFD, the BHP reaches a maximum value slightly above 4,610 psia or 60 psi above initial static conditions. This pressure increase is well below the safe operational threshold of 5,300 psia discussed above. Over the proposed 12-year injection schedule, the risk of over-pressurization in the injection zone decreases since the BHP gradually declines with the declining CO_2 injection rate. At the end of the 12-year injection period, the BHP drops to within 20 psi of initial static conditions instantly due to the high system permeability/injectivity of the middle Ellenburger. The period of pressure decline observed at the injection well through the year 2060 is a result of the natural decompression of the infinite-acting reservoir system in combination with the gradual buoyant equilibration of the compressible CO_2 plume.

Inspection of the CO_2 saturation maps (Figure 21) reveals the influence of reservoir heterogeneity and structure in the distribution, shape, and migrational path of the separate phase plume over time. After 12 years of CO_2 injection - or ~1.45 million MT-CO_2 injected - the plume takes on an amorphous elliptical shape that is ~9,000 ft in length and ~6,000 ft in width and roughly centered on the injection well. When comparing the example porosity and permeability distributions in the middle Ellenburger (Figure 19) and the 12-year CO_2 saturation map, similar patterns can be seen between the tortuous edges of the plume footprint and the high porosity/permeability regions where the CO_2 has found preferable pathways during injection. During the 200-year post-injection simulated period, geologic structure in the middle Ellenburger is observed to have more influence in the buoyant growth of the plume over time as evidenced by the expansion of the plume to the north (up structural dip) and the extension of a narrow “limb” of CO_2 to the west along a structural ridge in the middle of the grid. This ridge can be identified on the map of structural contours in the left panel of Figure 19. Overall the plume grows by roughly 33% during the 200-year post-injection simulated period and completely stabilizes around year 2225 (190 years after injection stops), showing no visible areal expansion thereafter.

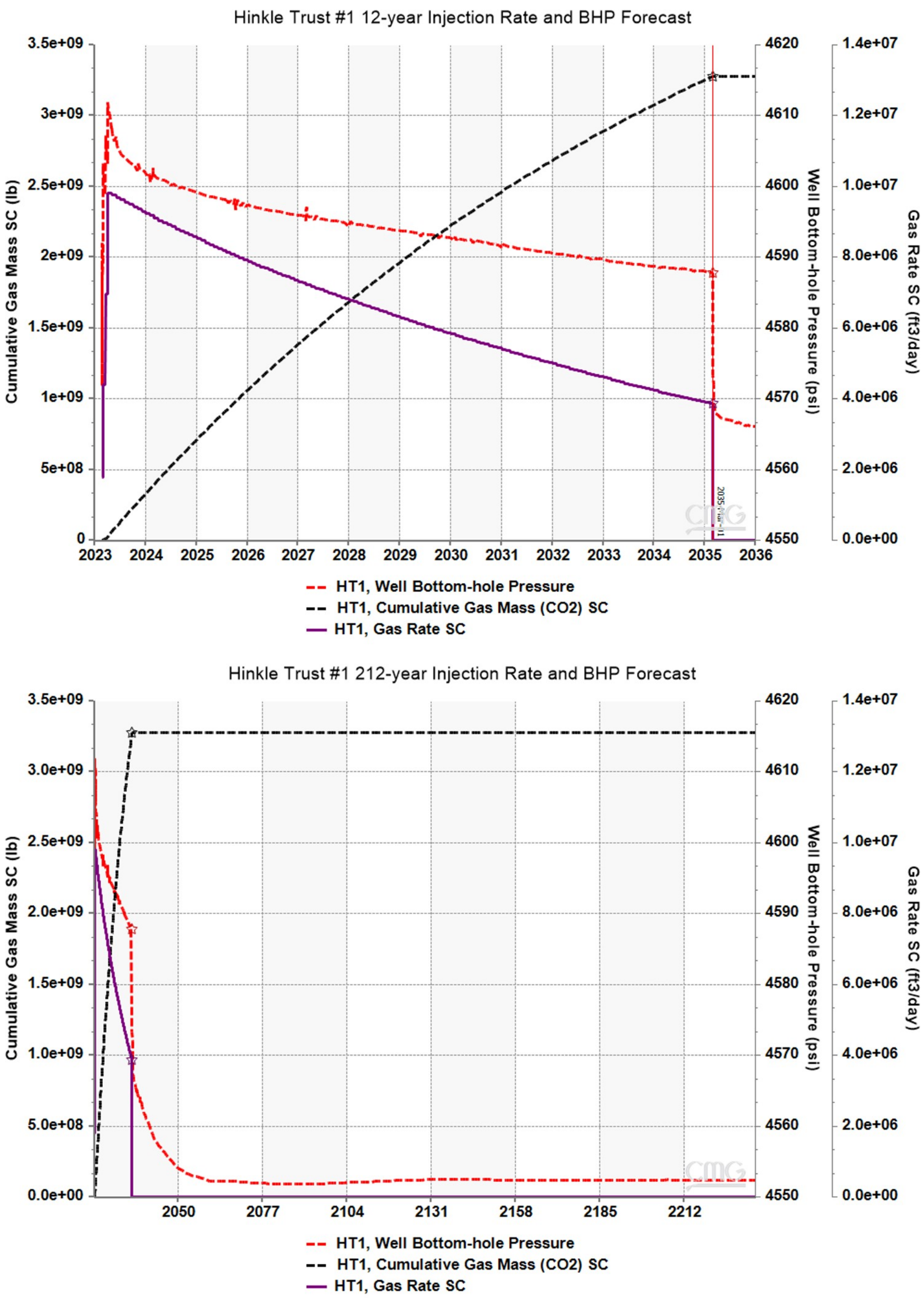

Figure 20: Modeled CO_2 rates, pressures, and cumulative volume for 12-year (top) and 212-year (bottom) time steps.

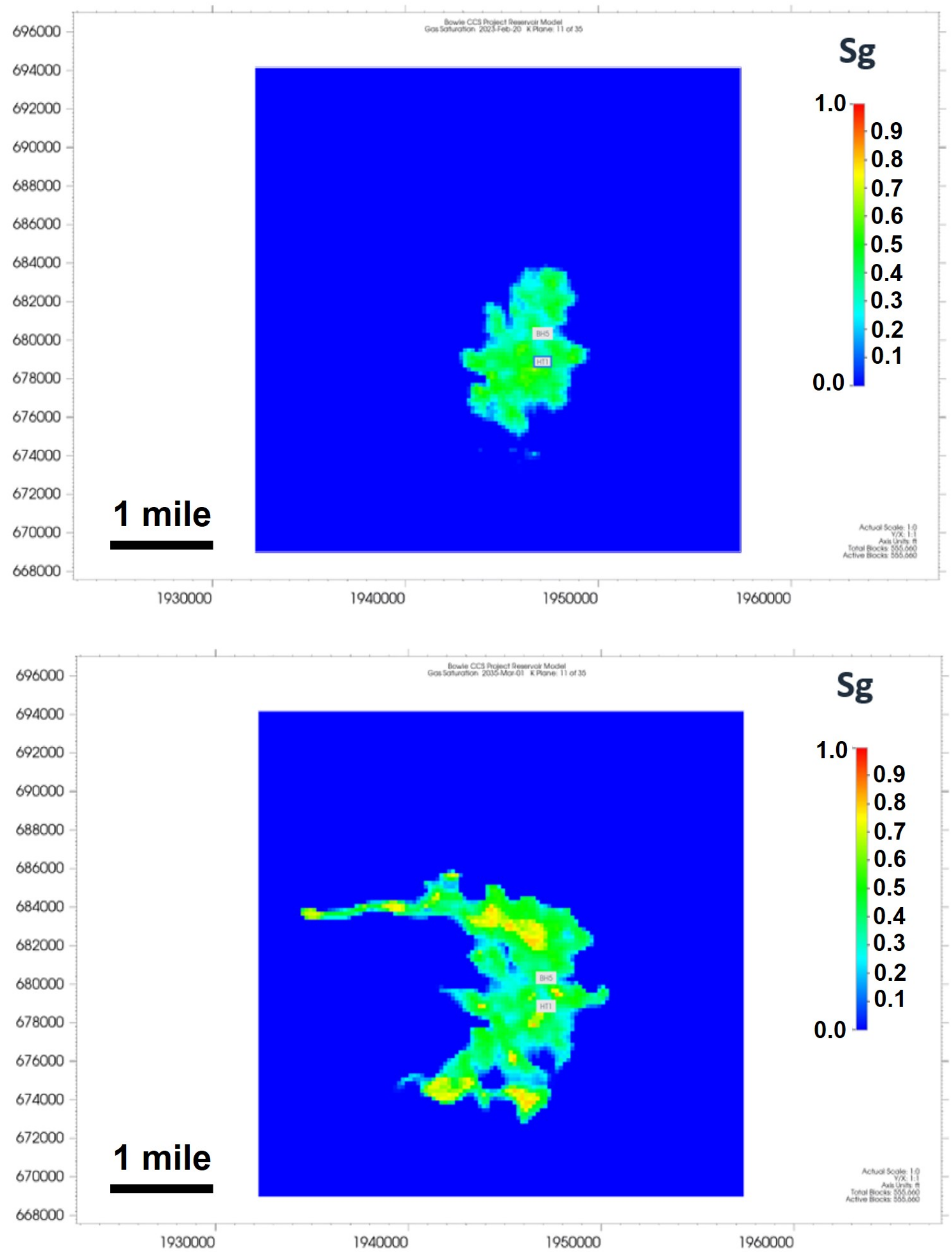

Figure 21: Modeled CO_2 saturation distribution for 12-year (top) and 212-year (bottom) time steps. Note that the Hinkle Trust #1 injector is labeled "HT1" and Billy Henderson #5 monitor is labeled "BH5" on the saturation maps.

3.3 Maximum Monitoring Area (MMA)

In Subpart RR, the maximum monitoring area (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. Using a 3% CO_2 saturation threshold - the estimated saturation of gas breakthrough from mercury injection capillary pressure (MICP) measurements - the boundary of the stabilized, separate phase plume was determined from the simulation results in Figure 21. This boundary, plus the required half-mile buffer, is depicted in Figure 22 with the injection and monitoring wells for context.

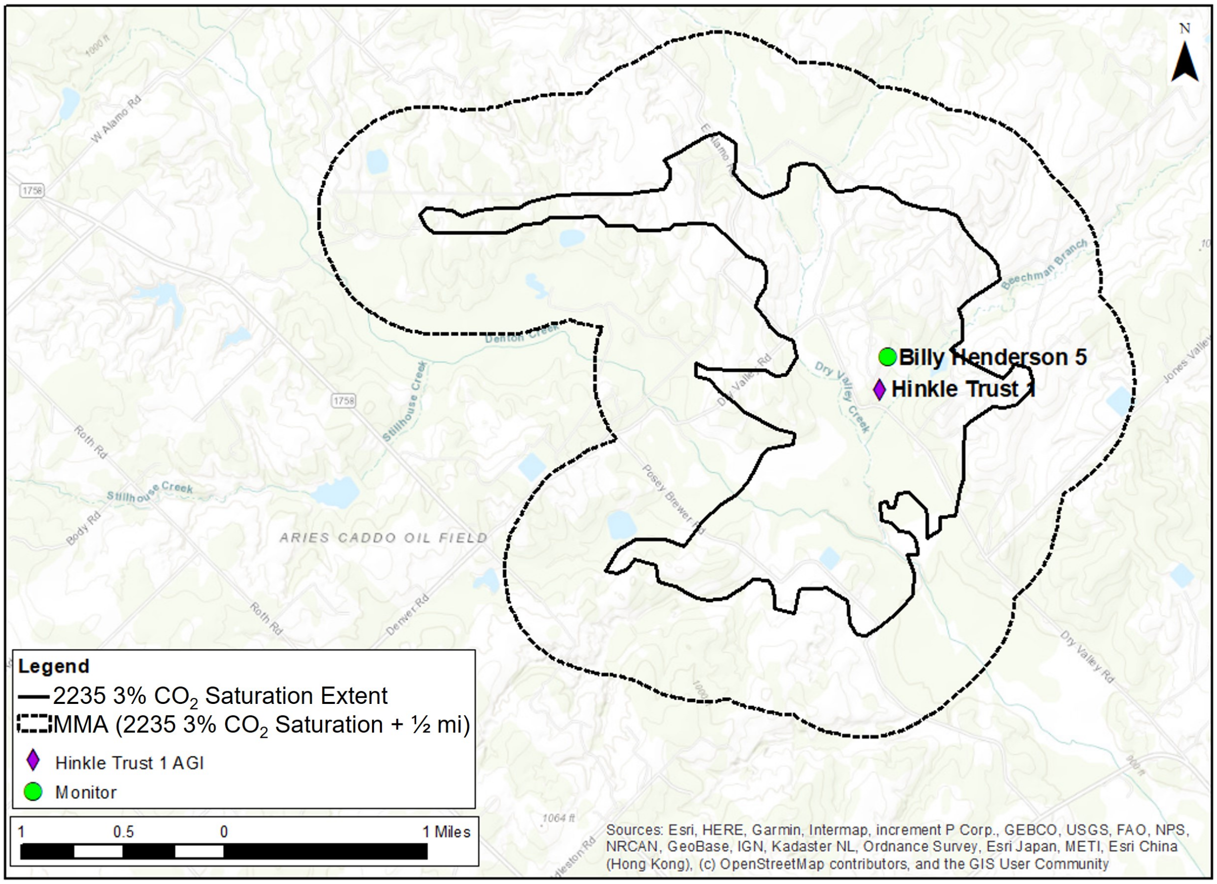

Figure 22: Maximum monitoring area for Bowie project.

3.4 Active Monitoring Area (AMA)

To define the active monitoring area (AMA), the initial monitoring period of 12 years was chosen based on the expected injection duration for the project. As a result, the separate phase CO_2 at the end of injection in year 2035 (i.e., “t”) - assuming the same 3% CO_2 saturation threshold - plus the required half-mile buffer was defined (blue dashed contour in Figure 23). Per the definition of the AMA in Subpart RR, this area was superimposed against the projected plume outline in the year 2040 (i.e.,“t + 5”) - the green outline in Figure 23. Since the green outline lies entirely within the blue dashed outline, the AMA is defined by the plume outline in the year 2035 plus the half-mile buffer.

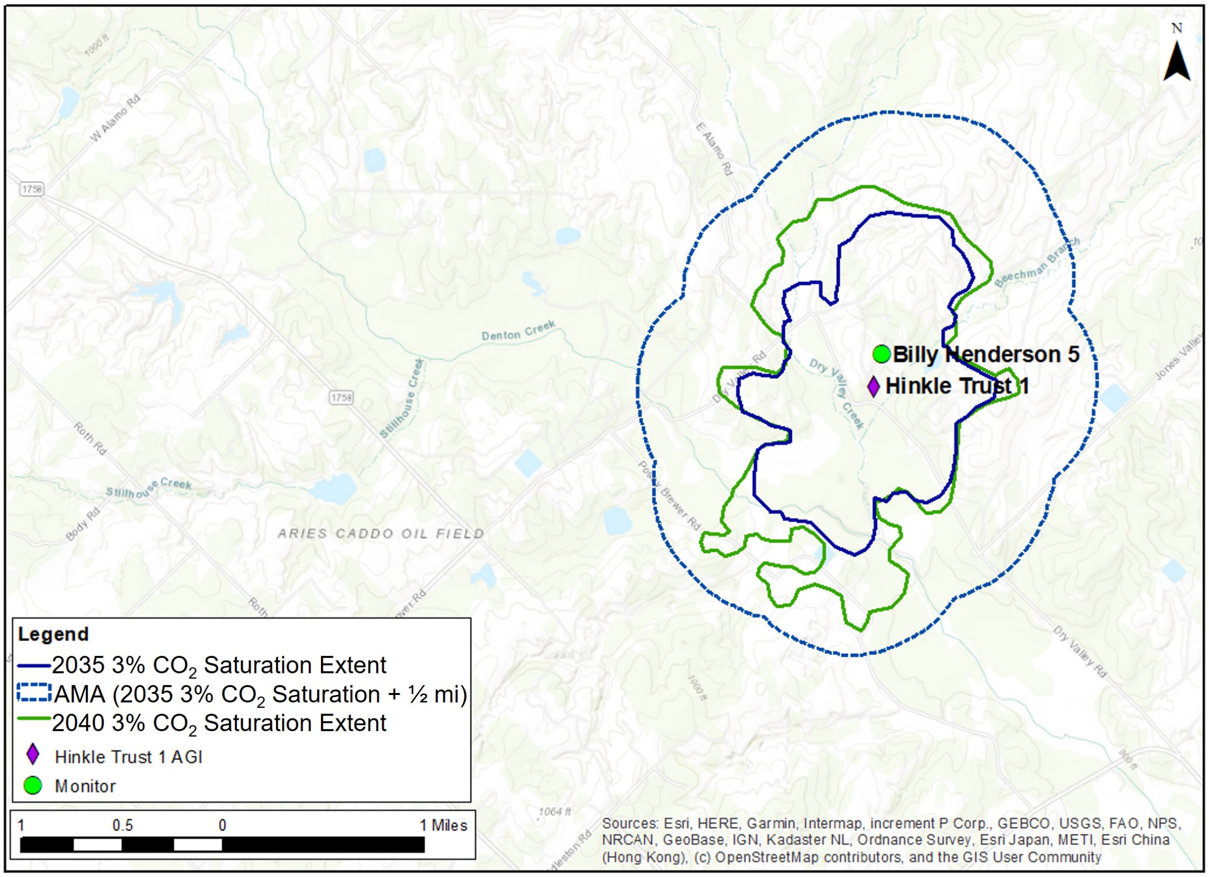

Figure 23: Active monitoring area for Bowie project.

3.5 Potential Surface Leakage Pathways

Per Subpart RR requirements, SPG has addressed the potential surface leakage pathways in the project area associated with surfaces facilities, faults and fractures, wellbores, and the confining system in a two-part approach. Part one de-risks the project site through various characterization methods, taking into account both static character and dynamic performance of the system through injection scenario modeling. This first part is addressed in the document subsections immediately below. Part two presents the required plan for detection, verification, and quantification of potential leaks and is addressed in subsection 3.6.

3.5.1 Surface Facilities

Leakage from surface facilities downstream of the injection meter is unlikely. The high pressure injection meter is placed near the high pressure compressor outlet and less than 210 ft upstream of the wellhead (Figure 2), minimizing potential leakage points between the metering of the stream and downhole injection point. Furthermore, the piping and flanges between the injection meter and the wellhead are ANSI 2500 rated, and all welds are certified by x-ray inspection. If leakage from surface equipment is detected, the volume of CO_2 released will be quantified based on the operating conditions at the time of release in accordance with 40 CFR §98.448(5).

3.5.2 Wellbores

The only wellbores that penetrate the injection zone in the AMA and MMA are those that were constructed specifically for this project. Both the Billy Henderson #5 and Hinkle Trust #1 were constructed 1) to mitigate leakage risks from CO_2 injection and 2) to provide for monitoring of near-wellbore conditions prior to, during, and after injection operations.

The Billy Henderson #5 monitor was designed to mitigate the risk of CO_2 migration out of the injection zone. A CO_2-resistant cement blend, EverCrete [SLB (2021)], was used to bond the long string casing in place. The top of cement sits above the top of the upper confining system defined for the project. In addition, pressure-temperature gauges and fiber monitoring instrumentation were installed across the injection zone (gauges and fiber), below the injection zone (fiber only) and above the injection zone (gauges and fiber) to allow for monitoring of pressure and temperature responses across the wellbore (Figure 24).

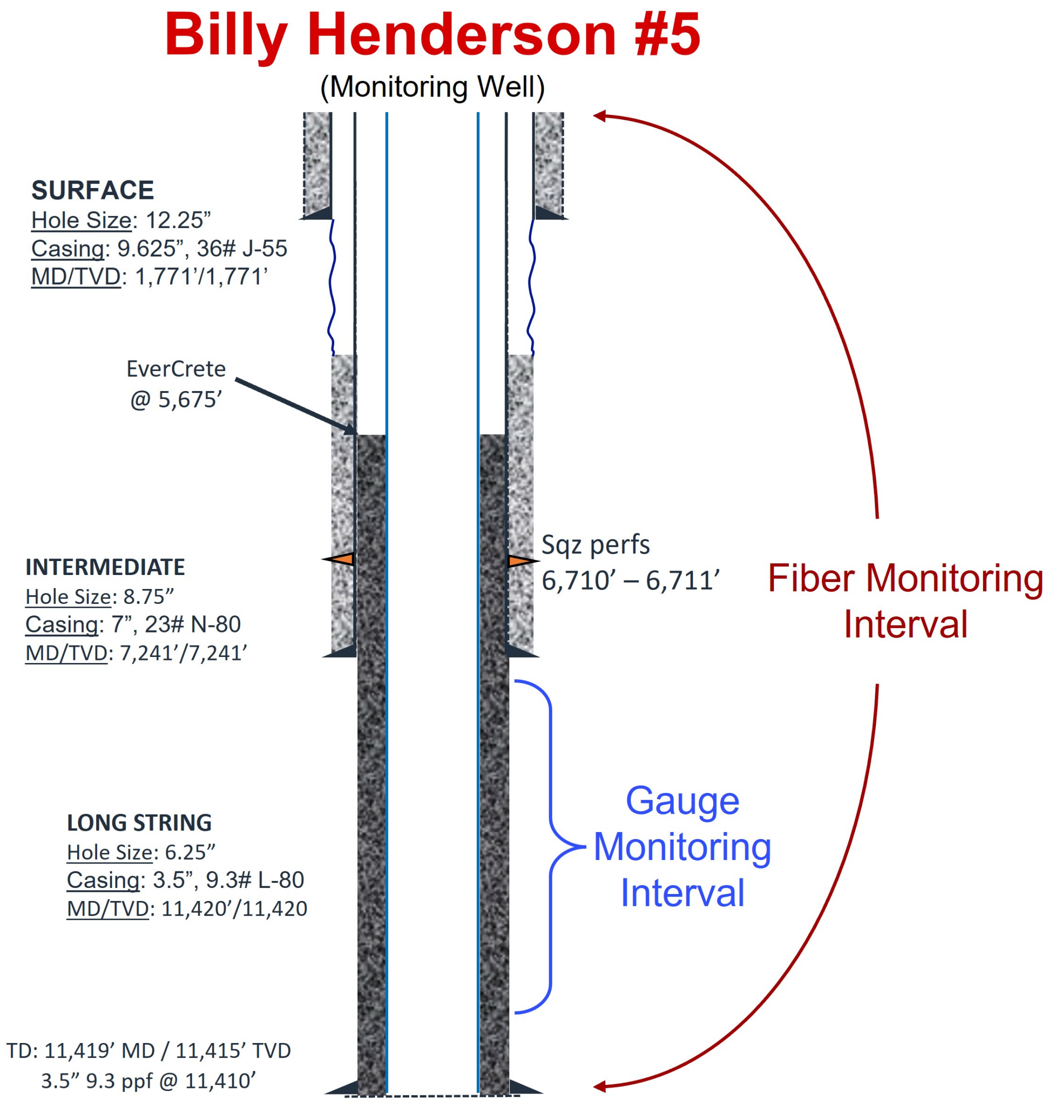

Figure 24: Billy Henderson #5 wellbore diagram.

The Hinkle Trust #1 injection well was also designed to mitigate the risk of CO_2 migration out of the injection zone. All strings of casing were cemented to surface and a CO_2-resistant resin product, WellLock [Halliburton (2017)], was used to cement the liner section of the long string casing sitting directly above the open hole injection interval. In addition, pressure-temperature gauges and fiber monitoring instrumentation were installed on the intermediate casing above the injection zone and on the injection tubing to allow for monitoring of pressure and temperature responses in the tubing, long string annular space, and above the injection zone (Figure 25).

Data from downhole instrumentation is collected and archived continuously across both wells. Aggradation and analysis of this data will allow SPG to quickly detect any leakage present within the wellbore. In addition, an annual mechanical integrity test (MIT) will be conducted in the injection well as prescribed in the Class II Underground Injection Control (UIC) permit (see Appendix A). The first MIT has already been conducted. If leakage is detected, EOG will use the recorded operating conditions at the time of the leak to estimate the volume of CO_2 released and then take appropriate corrective action.

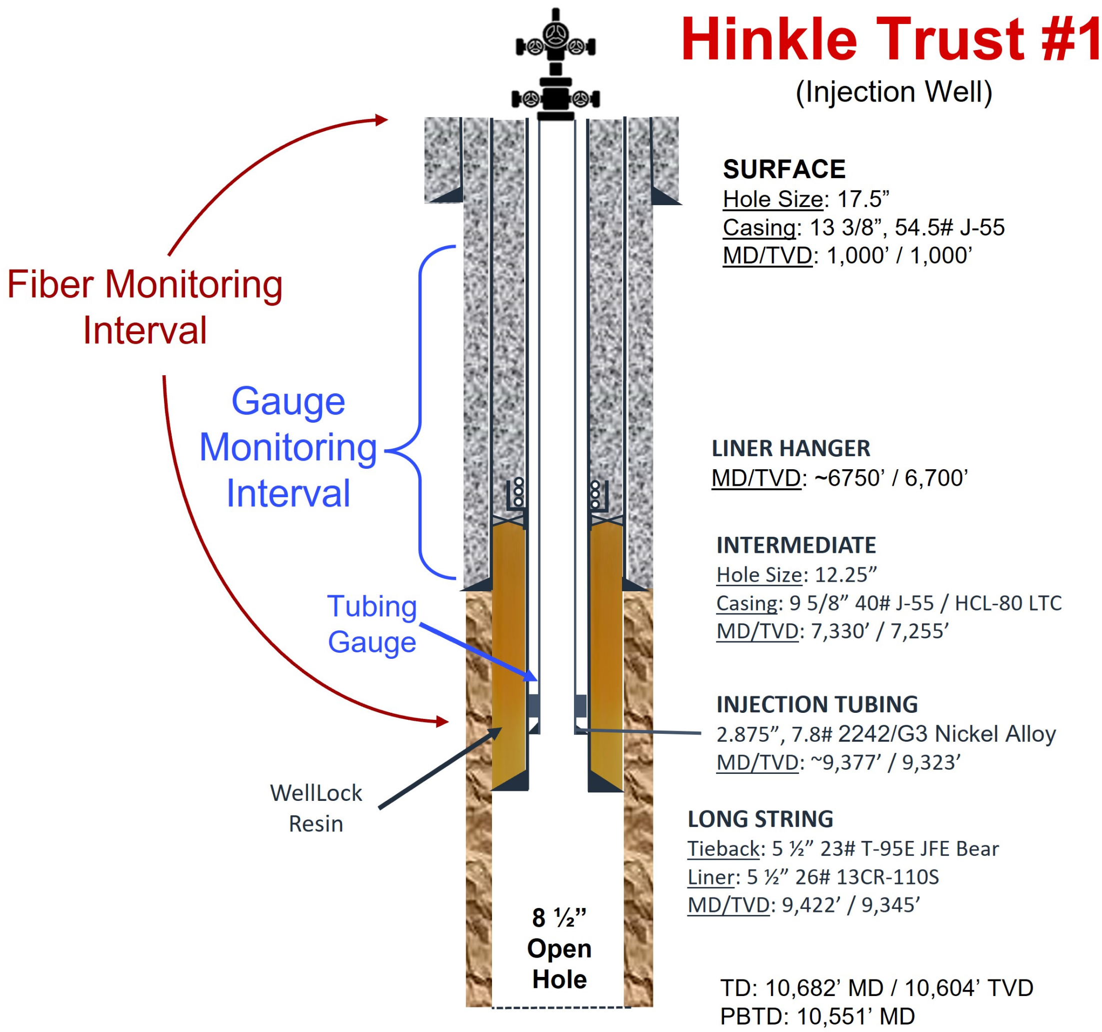

Figure 25: Hinkle Trust #1 wellbore diagram.

SPG does not anticipate future wellbores to penetrate the injection zone as the zone does not contain commercial hydrocarbon accumulations within the project site. If wells were to be permitted and drilled within the project site, operators constructing the wells would be subject to the TXRRC rules on wellbore construction which require wellbore construction designs that would mitigate risk of leakage.

3.5.3 Faults and Fractures

The Ellenburger and underlying basement at the injection site are characterized by large scale strike-slip faults and prevalent natural fracturing. The propensity for each of these characteristics to serve as surface leakage pathways is discussed below.

To assess the risk of leakage through faults, a Fault Slip Potential (FSP) analysis [Walsh et al. (2017)] was performed on large-scale basement-rooted faults traversing the proposed injection area and interval. The FSP analysis probabilistically evaluates the likelihood of excess pressure generated by fluid injection to trigger shear slip on pre-existing faults. As faults which are able to slip in shear in the present-day stress field with minor excess pressure (critically-stressed) tend to be those which are hydraulically-conductive [Barton et al. (1995)], the FSP analysis simultaneously assesses both induced seismicity and fault leakage likelihood. The FSP analysis includes faults mapped from 3D seismic data, directly measured reservoir and fluid properties from logs and core, and the planned CO_2 injection schedule. FSP results are shown in Figure 26, and indicate all major faults within the planned injection area and interval exhibit a very low (<10%) fault slip likelihood over the CO_2 injection timeline. In other words, the major faults are not critically-stressed in the present-day stress field and are, therefore, not expected to be hydraulically-conductive leakage pathways during CO_2 injection.

Only one earthquake in Montague County has been recorded in the last 100 years [U.S. Geological Survey (2023)] despite significant SWD injection within the Ellenburger. The FSP results are consistent with generally stable fault behavior in larger Montague County - and within the proposed injection area - as evident by the lack of detectable seismicity despite the presence of numerous Ellenburger SWD injection wells within the county (Figure 27).

Cross-fault leakage is also unlikely due to fault sense-of-slip and displacement. The dominant strike-slip sense of motion on major faults in the area decreases the likelihood of vertically juxtaposing injection intervals with containment intervals. In addition, cross-fault leakage is also likely inhibited by development of a thick, a low-permeability fault core due to significant fault displacement [Torabi et al. (2019), Caine et al. (1996)].

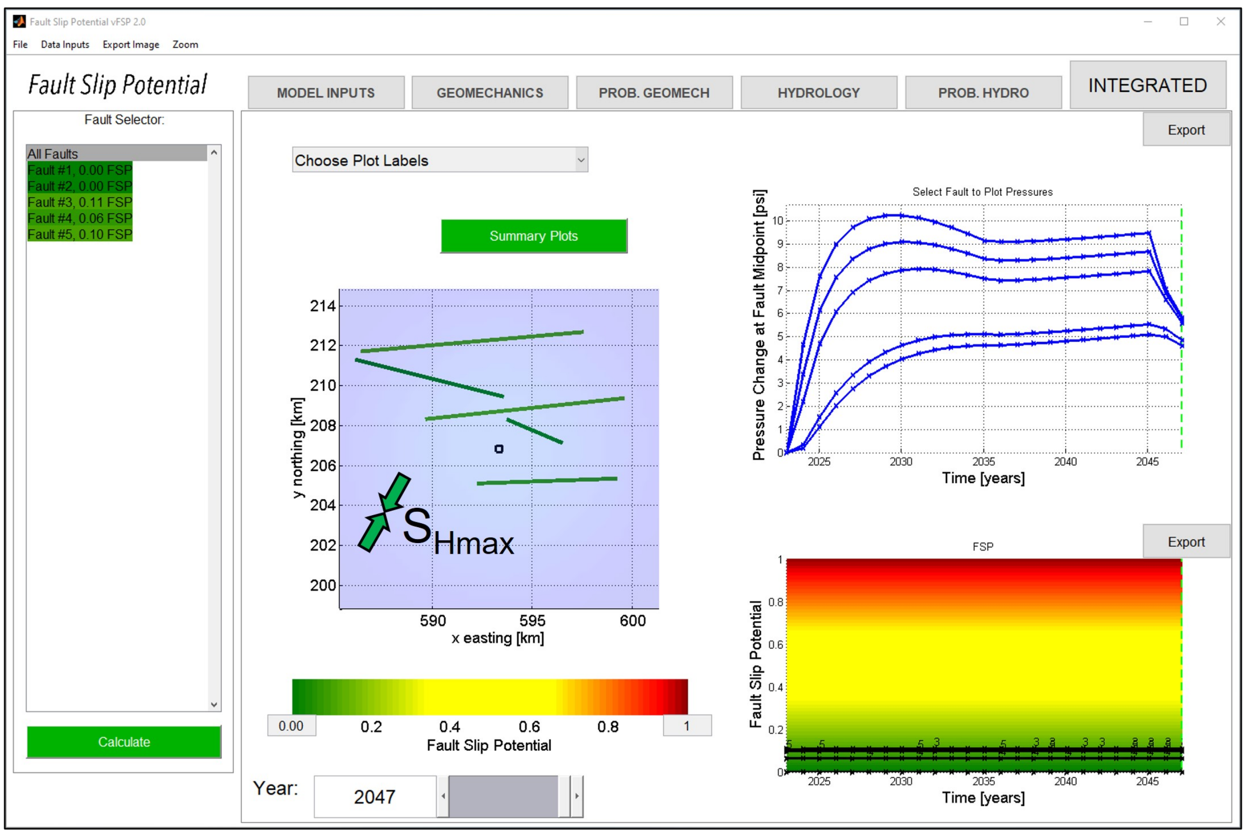

Figure 26: Fault slip potential analysis results.

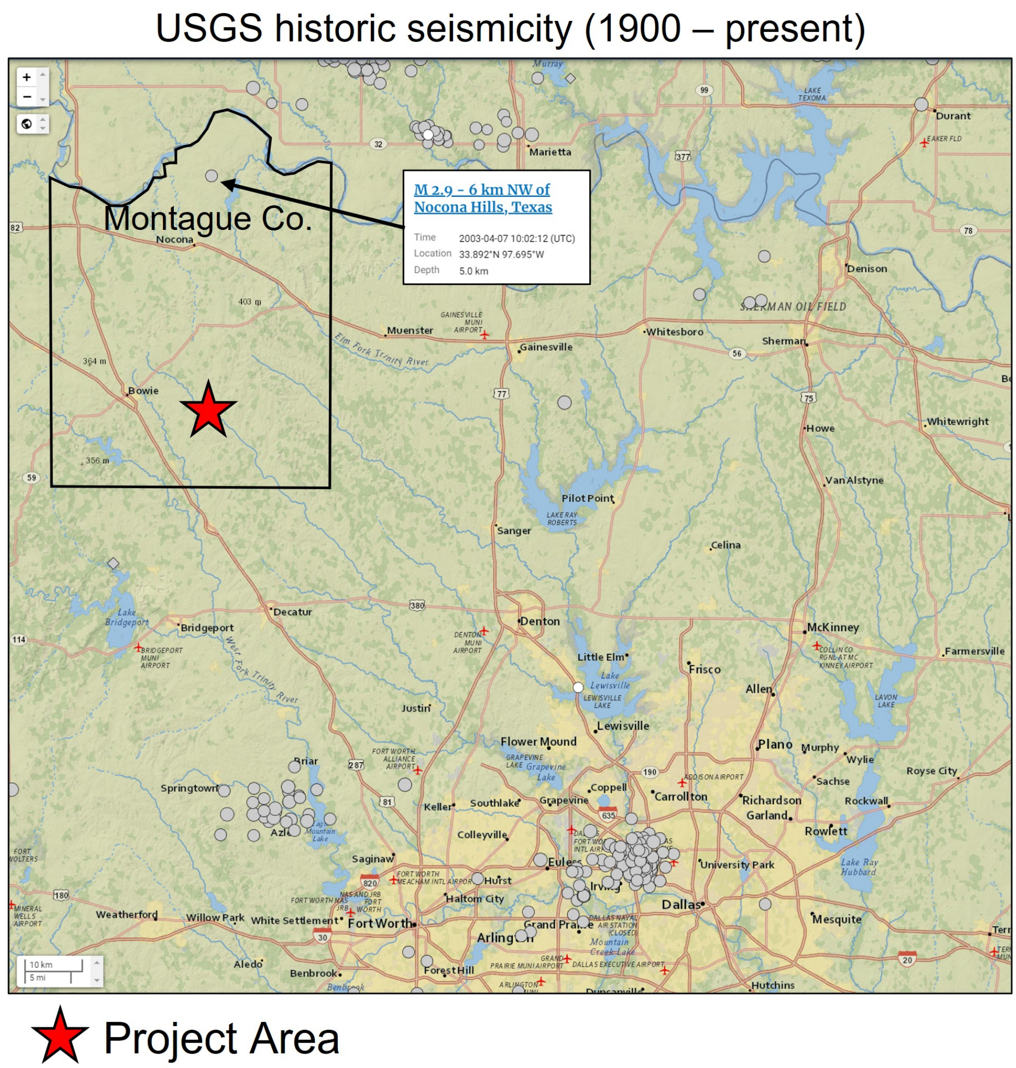

Figure 27: Historical records of regional seismicity from the United States Geological Survey (USGS).

To assess potential fracture leakage, fracture characteristics (orientation, density) as inferred from wellbore image logs in the proposed injection well are compared with various indicators of fluid conductivity (e.g., temperature anomalies, injection testing) in the proposed injection well. Natural fracture orientation and density do not correlate with either temperature reductions or primary permeability pathways inferred from injection testing, suggesting natural fractures are not the dominant transport (i.e., permeability) mechanisms within the injection interval (Figure 28) and therefore pose minor leakage risk.

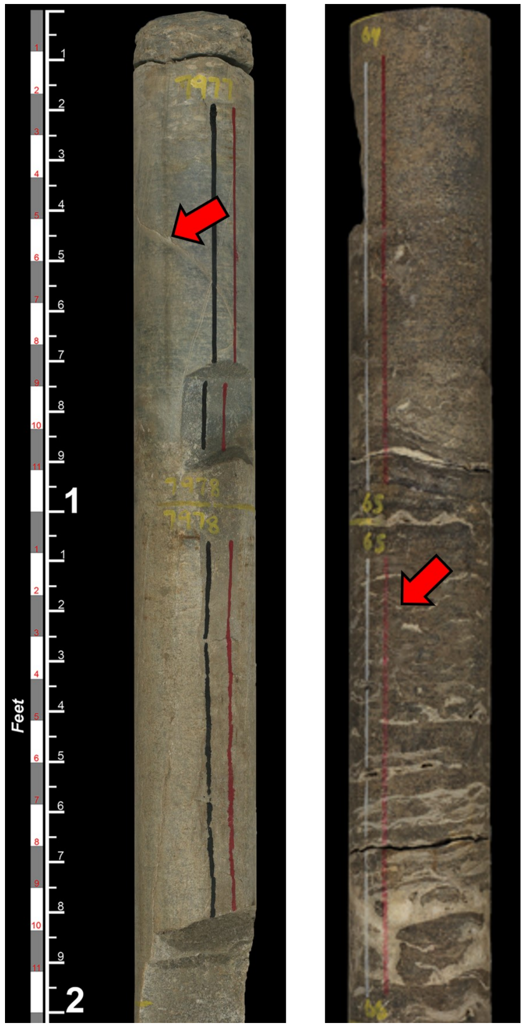

Figure 28: Representative whole core examples of confining (left) and injection (right) zones illustrating natural fractures (generally cemented, red arrows).

3.5.4 Confining System

To assess potential leakage from an excess pressure (i.e., hydraulic fracturing) perspective, injection tests to measure pore pressure and the minimum horizontal stress (S_{hmin}) were conducted in the overlying seal interval. The tests yielded a pore pressure estimate of 0.49 psi/ft and S_{hmin} estimate of 0.69 psi/ft, or roughly 4,900 psi and 6,900 psi bottomhole, respectively, when extrapolated to the injection interval around 10,000 ft TVD. Thus, 2,000 psi downhole excess pressure is required to generate and propagate hydraulic fractures. Plume injection modeling and offset Ellenburger SWD injection data all indicate maximum bottomhole pressure buildups on the order of 10s of psi for comparable injection volumes and rates, nearly two orders of magnitude lower than would be required to generate a hydraulic fracture. CO_2 leakage through hydraulic fracture generation/propagation is therefore unlikely. Furthermore, as CO_2 is anticipated to be the buoyant phase relative to the *in situ* brine within the Ellenburger injection interval, CO_2 migration and excess pressure buildup downward toward the lower confining and basement intervals is not anticipated.

3.6 Detection, Verification, and Quantification of Potential Leaks

This subsection addresses the detection, verification and quantification of potential leaks associated with surfaces facilities, faults and fractures, wellbores, and the confining system.

3.6.1 Detection of Leaks

Table 6 summarizes the methods and procedures SPG plans to employ to detect potential leaks across the various potential pathways previously discussed.

Table 6: Leakage detection methodologies to be employed for the Bowie Project.

Leakage Pathway	Monitoring Activity	Frequency	Coverage
Surface facilities	Wellhead pressure monitoring	Continuous	Flowmeter to injection wellhead
	Visual inspection	Weekly	
	Personal H_2S monitors	Weekly	
Wellbores	P-T gauges & fiber on casing/tubing	Continuous	Surface through injection zone
	Annulus pressure monitoring	Continuous	
	Integrity testing (MIT) per Class II permit	Yearly	
	Periodic corrosion monitoring surveys	Yearly	
Faults/fractures	Pressure monitoring	Continuous	Project site/plume extent
	Pressure transient analysis	Yearly	
Confining system	Pressure monitoring	Continuous	Project site/plume extent
	P-T gauges & fiber on casing	Continuous	
	Pressure transient analysis	Yearly	
	Time-lapse saturation surveys	Yearly	

3.6.2 Verification of Leaks

If the detection methods described above indicate a leak through one of the potential leakage pathways, SPG would take the actions summarized in Table 7 to verify its presence or confirm a potential "false positive".

Table 7: Leakage verification actions to be taken for the Bowie Project.

Leakage Pathway	Verification Action
Surface facilities	Auditory, Visual, and Olfactory (AVO) Inspection
	Forward Looking Infrared (FLIR) camera inspection
	Enhanced gas monitoring
Wellbores	Validation of calibration & functionality of downhole sensors
	Deployment of additional wireline sensors
	Additional saturation logging survey
	Additional MIT and corrosion logging survey
Faults/fractures	Extended pressure transient analysis
	Additional saturation logging survey
	Enhanced surveillance on nearby wells operated by EOG
Confining system	Validation of calibration & functionality of downhole sensors
	Deployment of additional wireline sensors
	Additional saturation logging survey
	Extended pressure transient analysis
	Enhanced surveillance on nearby wells operated by EOG

3.6.3 Quantification of Leaks

If leakage through one of the identified pathways is verified, SPG would implement the methodologies summarized in Table 8 in an effort to quantify the mass of CO_2 that has leaked to shallow aquifers or to the surface. Because CO_2 leakage through several of the pathways cannot be directly measured or visualized but must be indirectly inferred, reservoir simulation will likely be an essential tool to quantify the magnitude of the leak in those cases. For example, while the precise pathway of a CO_2 leak may not be known, it may be possible to measure the pressure or saturation change created by the leak at some point in the subsurface. Through the iterative history matching process, it is possible to replicate the observed subsurface response by invoking some potential leakage mechanism(s) in the reservoir model. The resulting volume or mass of CO_2 that yields the best match to the observed data is likely to be a reasonable estimate of the magnitude of the leak. Furthermore, by considering several different plausible leakage cases with the model, the magnitude of the leak can be quantified across a range of potential outcomes.

Table 8: Leakage quantification methodologies for the Bowie Project.

Leakage Pathway	Quantification Method	Qualitative Accuracy
Surface facilities	Calculation based on process conditions at time of leakage and dimensions of leakage pathway	High
	Comparison & calculation against recent historical trends	High
	Direct measurement of leakage (if accessible and safe)	Very High
Wellbores	Calculation against recent historical injection trends (using surface & downhole P-T data)	High
	Estimation from change in saturation profile within reservoir and/or confining zones	Moderately High
Faults/fractures	Use reservoir model to simulate the CO_2 leakage required to generate the observed pressure transient behavior	Moderate
	Use reservoir model to simulate the CO_2 leakage required to generate the observed nearby well surveillance response	Moderate
Confining system	Use reservoir model to simulate the CO_2 leakage required to generate the observed pressure transient behavior	Moderate
	Use reservoir model to simulate the CO_2 leakage required to generate the observed nearby well surveillance response	Moderate

3.7 Baseline Determination

SPG has developed a strategy to establish baselines for monitoring CO_2 surface leakage that is in agreement with 40 CFR §98.448(a)(4). "Expected baseline" is defined as the anticipated value of a monitored parameter that is compared to the measured monitored parameter. SPG has existing automated continuous data collection systems in place that allow for aggradation and analysis of operations data to: 1) establish trends in operational performance parameters and 2) identify deviations from these trends. Non-continuous data will also be collected periodically to augment and enhance the analysis of continuous data throughout the project. Baseline surveys for non-continuous data have already been collected as described below. Baselines for operational performance parameters are expected to be completed by July 17th, 2023, which will provide for several weeks of data collection with the entire system operational.

AVO (Audio, Visual, Olfactory) Inspections: Field personnel will conduct daily to weekly inspections at the injection site pre-, during, and post-injection. Any indications of surface leakage of CO_2 will be addressed via appropriate corrective action in a timely manner. Personnel will wear personal H_2S monitors set to OSHA standards. Indications of H_2S present will serve as a proxy for CO_2 presence as the injection stream contains both components.

Continuous Monitoring: Continuous monitoring systems are in place for both the surface process facilities and wells. Pressure and temperature gauges installed on both casing and tubing strings, DTS fiber-based data, and surface pressures on all strings of casing is collected continuously in both wells. Operational baselines will be determined from analysis of this data over a reasonable period once the system is fully operational (see comments on timing above). Any deviations from these operational baselines will be investigated to determine if the deviation is a leakage signal.

Well Integrity Testing: EOG will conduct an annual MIT on the Hinkle Trust #1 as required by the Class II permit issued by TXRRC. Subsequent MIT results will be compared to initial MIT results and TXRRC standards to establish a baseline. An initial MIT and subsequent interpretation of test results has already been performed on the Hinkle Trust #1 as part of the Class II permit requirements.

Pressure Transient Analysis: EOG has conducted initial pressure transient analyses using injection test data. Subsequent pressure transient analyses are in progress and will continue to be performed when operationally feasible to establish and re-establish expected baseline reservoir behavior throughout the project. Comparison of these analyses over time will aid in diagnosing consistency in the long-term behavior of the injection and confining zones.

Wellbore Surveys: The Billy Henderson #5 and Hinkle Trust #1 are both constructed to allow for time-lapse saturation and mechanical integrity logging. Initial pre-injection surveys have been conducted for both saturation and mechanical integrity and will serve to establish baselines for comparison of future logging datasets.

3.8 Site Specific Modifications to the Mass Balance Equation

3.8.1 Mass of CO_2 Received

Equation RR-4 will be used for calculating the mass of CO_2 received. The CO_2 stream received will be wholly injected and not mixed.

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

where:
$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.
$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).
$C_{CO2,p,u}$ = 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.

Figure 29: Equation RR-4 as defined in 40 CFR §98 Subpart RR.

3.8.2 Mass of CO_2 Injected

The mass of CO_2 injected is equivalent to the mass of CO_2 received. The high pressure meter used in the system has an accuracy of ±0.15%.

3.8.3 Mass of CO_2 Produced

Mass of CO_2 produced is not applicable to this project as no CO_2 will be produced.

3.8.4 Mass of CO_2 Emitted

Mass of CO_2 emitted from surface leakage of any kind is assumed to be zero per the MRV plan. Mass of CO_2 emissions from equipment leaks and vented emissions from surface equipment located between injection meter and wellhead is assumed to be zero and will be subject to AVO inspection and H_2S monitoring. Any leakage found will be quantified and corrected in volumes reporting based on process conditions. Since CO_2 will not be produced in the scope of this proposed injection project, the consideration of leakage from production-related equipment is not applicable.

3.8.5 Mass of CO_2 Sequestered

Mass of CO_2 sequestered in subsurface geologic formations will be calculated using equation RR-12. The CO_{2E} and CO_{2FI} terms will drop out in most cases since the mass of CO_2 emitted from surface leakage is assumed to be zero except in rare cases where leakage is identified. Therefore, the CO_2 mass sequestered will normally equate to the CO_2 mass injected. The cumulative mass of CO_2 reported per year will be the summation of equation RR-4 over all reporting quarters (Figure 30).

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \qquad \text{(Eq. RR-12)}$$

where:

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

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

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

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

Figure 30: Equation RR-12 as defined in 40 CFR §98 Subpart RR.

In accordance with §98.448(a)(7), the date to begin collecting data for calculating the total amount sequestered shall be after 1) expected baselines are established and 2) implementation of the leakage detection and quantification strategy within the initial AMA. SPG proposes the date of July 17th, 2023 as the date to begin collecting data for calculating the total amount sequestered for the SPG CO_2 Bowie Facility.

3.9 Implementation Schedule For MRV Plan

The final MRV plan will be implemented upon receiving approval from the EPA, and no later than the day after the day on which the plan becomes final, as described in §98.448(c). The Hinkle Trust #1 is currently permitted to inject under a TXRRC Class II UIC permit (see Appendix A).

3.10 Quality Assurance

3.10.1 Monitoring QA/QC

SPG will implement quality assurance procedures that are in compliance with requirements stated in 40 CFR §98.444 as detailed below.

CO_2 Injected:

- The flow rate of the CO_2 injection stream is measured continuously with a high pressure mass flow meter that has an accuracy of ±0.15%.
- The composition of the CO_2 injection stream is measured with a high accuracy gas chromatograph upstream of the flow meter.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated according to manufacturer recommendations.

CO_2 Emissions from Leaks and Vented Emissions:

- Calculation methods from 40 CFR §98 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.

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).

3.10.2 Missing Data

Missing data will be estimated as prescribed by 40 CFR §98.445 if SPG is unable to collect the data required 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 and venting from facility surface equipment will be estimated and reported per the procedures specified in 40 CFR §98 subpart W.

3.10.3 MRV Plan Revisions

If any of the changes outlined in 40 CFR §98.448(d) occur, SPG will revise and submit an amended MRV plan within 180 days to the Administrator for approval.

3.11 Records Retention

SPG will retain all records as required by 40 CFR §98.3(g). Records will be retained for at least three years, and will include, but will not be limited to:

- Quarterly records of injected CO_2 including mass flow rate at standard conditions, mass flow rate at operating conditions, operating temperature and pressure, and concentration of the injected CO_2 stream.
- Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.
- Annual records of information used to calculate the CO_2 emitted from equipment leaks of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

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A Class II UIC Permit for Hinkle Trust #1

WAYNE CHRISTIAN, CHAIRMAN
CHRISTI CRADDICK, COMMISSIONER
JIM WRIGHT, COMMISSIONER

DANNY SORRELLS
ASSISTANT EXECUTIVE DIRECTOR
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. 17041

EOG SPG HOLDINGS, INC.
ATTN SETH WOODARD
PO BOX 4362
HOUSTON TX 77210

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 April 01, 2022, for the permitted interval(s) of the ELLENBURGER formation(s) and subject to the following terms and special conditions:

HINKLE TRUST (00000) LEASE
BARNABUS (ELLENBURGER) FIELD
MONTAGUE 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	33700000	000125307	Carbon Dioxide (CO_2); Hydrogen Sulfide (H_2S); Natural Gas	7,300	13,000		12,000		4,100

SPECIAL CONDITIONS:

Well No.	API No.	Special Conditions
1	33700000	**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. An annual annulus pressure test must be performed and the test results submitted in accordance with the instructions of Form H-5.** **3. The tubing-casing annulus pressure must be monitored at least weekly and reported annually on Form H-10 to the Commission's Austin Offices.** **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. 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.** **6. 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.** **7. 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.**

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		8. NOTE: Per operator email dated on June 01, 2022, the four plants are operated by EOG Resources, Inc. They are permitted under Pecan Pipeline Company (P-5 #648675) and Pecan Pipeline is EOG Resources. Below are the names and RRC Serial Numbers for each plant: Bowie South – 09-0415 St. Jo – 09-0406 Henderson – 09-0405 Kripple Kreek – 09-0401

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 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.

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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 July 18, 2022.

Sean Avitt, Manager
Injection-Storage Permits Unit

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