UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

OFFICE OF ATMOSPHERIC PROTECTION

WASHINGTON, D.C. 20460

October 28, 2024

Mr. Richard Adams
Ozona CCS, LLC
19026 Ridgewood Pkwy
Suite 200
San Antonio, TX 78259

Re: Monitoring, Reporting and Verification (MRV) Plan for O'Neal Gas Unit Well No. 4

Dear Mr. Adams:

The United States Environmental Protection Agency (EPA) has reviewed the Monitoring, Reporting and Verification (MRV) Plan submitted for O'Neal Gas Unit Well No. 4, as required by 40 CFR Part 98, Subpart RR of the Greenhouse Gas Reporting Program. The EPA is approving the MRV Plan submitted by O'Neal Gas Unit Well No. 4 on August 26, 2024, as the final MRV plan. The MRV Plan Approval Number is 1014786-1. This decision is effective October 29, 2024 and is appealable to the EPA's Environmental Appeals Board under 40 CFR Part 78. In conjunction with this MRV plan approval, we recommend reviewing the Subpart PP regulations to determine whether your facility is required to report data as a supplier of carbon dioxide. Furthermore, this decision is applicable only to the MRV plan and does not constitute an EPA endorsement of the project, technologies, or parties involved.

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

Sincerely,

Julius Banks
Supervisor, Greenhouse Gas Reporting Branch

Technical Review of Subpart RR MRV Plan for the O’Neal Gas Unit Well No. 4

October 2024

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Appendix A: Final MRV Plan
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This document summarizes the U.S. Environmental Protection Agency's (EPA's) technical evaluation of the Greenhouse Gas Reporting Program (GHGRP) subpart RR Monitoring, Reporting, and Verification (MRV) plan submitted by Ozona CCS, LLC (O'Neal) for its O'Neal Gas Unit Well No. 4 (O'Neal No. 4 well) treated acid gas (TAG) injection project, which injects into the Sligo Formation. Note that this evaluation pertains only to the subpart RR MRV plan for O'Neal No. 4, 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

Section 1 of the MRV plan states that O'Neal No. 4 well currently has a pending Class II disposal permit that will be issued by the Texas Railroad Commission (TRRC) for the O'Neal No. 4 well (API No. 42-025-32658, UIC No. 56819). The permit application was submitted in September of 2023. This permit would authorize O'Neal to inject up to 1.5 million standard cubic feet per day (MMscf/D) into the Sligo formation at a depth of 15,874 ft to 16,056 ft with a maximum allowable surface pressure of 7,920 pounds per square inch gauge (psig). This injection of treated acid gas will occur for approximately 12 years. The source of the injected TAG is the Pawnee Treating Plant (Plant) in Bee County, Texas. The O'Neal No. 4 well is located about 2 miles south of the Pawnee Gas Plant.

The MRV plan states that the facility and the well design of the O'Neal No. 4 well are planned to protect against the migration of carbon dioxide (CO_2) out of the injection interval, protect against contamination of subsurface formations, and most importantly, to prevent surface releases. The MRV plan states that the injection interval for the O'Neal No. 4 well, the Sligo formation, is located approximately 14,924 ft below the base of the Underground Source of Drinking Water (USDW). As stated in the MRV plan, the O'Neal No. 4 well will inject a CO_2 stream containing 98.2% CO_2, 0.4% H_2S, 1.03% hydrocarbons, and 0.37% Nitrogen.

Section 2 of the MRV plan describes the geologic setting and injection process for the O'Neal No. 4 well. The MRV plan states that the target injection interval is the lower Cretaceous-age Sligo Formation. As stated in the MRV plan, the Sligo Formation is predominately composed of shelf-edge limestones that were deposited along the lower Cretaceous platform. According to the MRV plan primary porosity and permeability of the upper Sligo Formation tends to develop in high-energy sequences with normal marine conditions that are dominated by the deposition of oolitic and skeletal grainstones. As explained in the MRV plan, the lithologic and petrophysical characteristics of the Sligo Formation at the O'Neal No. 4 well's location indicate that the reservoir contains the necessary thickness, porosity, and permeability to receive the proposed injection stream.

The MRV plan states that the Pearsall Formation will serve as the upper confining interval. The MRV plan states that following the deposition of the Sligo Formation, the Lower Cretaceous shelf was drowned by eustatic sea-level rise and deposition of the deep-water Pine Island Shale Member of the Pearsall Formation throughout the region. The Pine Island Shale consists of alternating beds of pelagic mudstone, hemipelagic mudstone, and iron-rich dolomitic mudstone interpreted to have been deposited along the outer ramp. According to the MRV plan, the 2012 U.S. Geological Survey (USGS) *CO_2 Storage Resource Assessment* suggests the Pine Island Shale Member contains the physical properties required to act as a regional seal and noted it is a sufficient regional seal with as little as 50 feet of contiguous shale development.

As stated in the MRV plan, the Lower Sligo and Hosston Formations serve as the lower confining interval. The Hosston to lower Sligo "contact" represents a gradational package with a decrease in terrigenous sediments, an increase in carbonate sediments, and an increase in burrows of marine organisms working up-section into the lower Sligo. The MRV plan also states that the porosity of the Lower Sligo formation ranges from 0 to 2% and permeability is consistently near 0 millidarcies (mD).

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, the reservoir modeling calculated that, after 12 years of injection followed by 10 additional years of density drift, the areal extent of the projected plume will be 303 acres. The reservoir is stated to be at hydrostatic equilibrium. Given the geological formation in which this well is located and its previous history as a gas producer, the model is assumed to be primarily saturated with gas. More precisely, the reservoir is assumed to be 80% gas saturated and 20% brine saturated, as deduced from the well log data. O'Neal No. 4 well found that the maximum distance from the wellbore to the edge of the forecasted plume to be approximately 0.45 miles (mi) after the 30-year post-injection period. The MMA boundary represents the stabilized plume boundary after 10 years of density drift plus an all-around buffer zone of one-half mile.

The MRV plan states that O'Neal No. 4 well initially established the AMA boundary by setting it equal to the expected total injection period of 12 years. The AMA was analyzed by super imposing the area based on a one-half mile buffer around the anticipated plume location after 12 years of injection (2037), with the area of the projected free-phase CO_2 plume after 5 additional years (2042). Due to the AMA boundary being only slightly smaller than the MMA boundary, O'Neal No. 4 well defined the AMA as equal to the MMA. The MRV plan also states that the facility will submit a revised MRV plan by 2037 to provide an updated AMA and MMA.

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). O'Neal No. 4 well identified the following as potential leakage pathways in Section 4 of their MRV plan that required consideration:

- Leakage from surface equipment
- Leakage through existing and future wells within the MMA
- Leakage through faults and fractures
- Leakage through the upper confining layer
- Leakage from natural or induced seismicity

A summary table of O'Neal No. 4 well's evaluation of the likelihood, magnitude, and timing of any potential CO_2 leakage can be found in Table 7 of the MRV plan and is reproduced below.

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. One artificial penetration was drilled into the injection interval. This well has been plugged and abandoned.	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Faults and fractures	Unlikely. There is over 14,000 ft of impermeable rock between the injection zone and the base of the USDW.	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.

Upper confining layer	Unlikely. The lateral continuity of the UCZ consisting primarily of the Pearsall Formation which is 500 ft thick is recognized as a very competent seal.	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Natural or induced seismicity	Unlikely. There is over 14,000 ft of impermeable rock between the injection zone and the base of the USDW.	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.

Magnitude Assessment Description
Low - categorized as little to no impact to safety, health and the environment and the costs to mitigate are minimal.
Medium - potential risks to the USDW and for surface releases does exist, but circumstances can be easily remediated.
High - danger to the USDW and significant surface release may exist, and if occurs this would require significant costs to remediate.

3.1 Leakage from Surface Equipment

Section 4.1 of the MRV plan states the Plant and the O'Neal No. 4 well are designed for separating transporting, and injecting TAG, primarily consisting of CO_2, in a manner to ensure safety to the public, the employees, and the environment. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) standards and practices. As the TAG stream contains H_2S, monitors installed for H_2S detection will also indicate the presence of CO_2. These monitors will be installed at key locations around the Plant and the O'Neal No. 4 well. These devices will be continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alert at set points at set points determined by the Plant's Health, Safety, and Environment (HS&E) Director, consistent with Occupational Safety and Health Administration (OSHA) requirements. The Plant will set the detection and alarm states for personnel at 10 ppm and at 40 ppm for initiating Emergency Shutdown. Key monitoring points and parameters are also provided in Table 8 of the MRV plan.

The MRV plan states facilities will incorporate important safety equipment to ensure reliable and safe operations. In addition to the H_2S monitors, emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant, the O'Neal No. 4 well, and other components, StarTex has a flare stack to safely handle the TAG when a depressuring event occurs. These facilities will be constructed in the coming months. The exact location of this equipment is not yet known, but it will be installed in accordance with applicable engineering and safety standards.

With continuous air monitoring at the Plant and the O'Neal No. 4 well site, a release of CO_2 would be quickly identified, and the safety systems and protocols would effectuate an orderly shutdown to ensure safety and minimize the release volume. The CO_2 injected into the O'Neal No. 4 well is from the amine unit at the Plant. O'Neal No. 4 well concludes that the leakage of CO_2 through the surface equipment is unlikely.

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

3.2 Leakage through Existing and Future Wells Within the MMA

Oil and Gas Operations within the Monitoring Area

Section 4.2 of the MRV plan states that the O'Neal No. 4 well is engineered to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 32 of the MRV plan. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) §3.46 [40 CFR §146.23 (b)(3)], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If an MIT were to indicate a leak, the well would be isolated, and the leak mitigated to prevent leakage of the injectate to the atmosphere.

According to the MRV plan, a map of all oil and gas wells within the MMA is shown in Figure 33. Figure 34 is a map of all the oil and gas wells that penetrate the MMA's gross injection zone. Only one well penetrates the MMA's gross injection zone. This well is non-productive and has been plugged and abandoned in accordance with TRRC requirements. A summary table of all oil and gas wells within the MMA is provided in Appendix B-1. This table in Appendix B-1 provides the total depth (TD) of all wells within the MMA. The wells that are shallower and do not penetrate the injection zone are separated by the Pearsall Formation with a gross thickness of 535 ft. The Pine Island Shale comprises approximately 130 ft of this interval and provides a competent regional seal—making vertical migration of fluids above the injection zone unlikely.

The MRV plan states the shallower offset hydrocarbon wells within the MMA will also serve as above zone monitoring wells. Should any of the sequestered volumes migrate vertically, they would potentially enter the shallower hydrocarbon reservoir. Regular sampling and analysis are performed on the produced hydrocarbons. O'Neal No. 4 well states if a material difference in the quantity of CO_2 in the sample occurs indicating a potential migration of injectate from the Sligo Formation, then it would investigate and develop a mitigation plan.

Future Drilling

The MRV plan states potential leakage pathways caused by future drilling in the area are not expected to occur. The deeper formations have proven to date to be nonproductive in this area, and therefore the facility does not see this as a risk. This is supported by a review of the TRRC Rule 13 (Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC §3.13. The Sligo is not among the formations listed for which operators in Bee County and District 2 (where the O'Neal No. 4 well is located) are required to comply with TRCC Rule 13; therefore, the TRRC does not believe there are productive horizons below the Sligo. The O'Neal No. 4 well drilling permit is provided in Appendix A-2.

Groundwater Wells

The MRV plan states that a groundwater well search resulted in five groundwater wells found within the MMA, as identified by the Texas Water Development Board. The surface and intermediate casings of the O'Neal No. 4 well, as shown in Figure 35 of the MRV plan, are designed to protect the shallow freshwater aquifers consistent with applicable TRRC regulations and the Groundwater Advisory Unit (GAU) letter issued for this location. The MRV plan also states that the wellbore casings and cements also prevent CO_2 leakage to the surface along the borehole. For these reasons, the O'Neal No. 4 well concludes that leakage of the sequestered CO_2 to groundwater is unlikely.

Thus, the MRV plan provides an acceptable characterization of CO_2 leakage that could be expected through existing wells within the MMA.

3.3 Leakage through Faults and Fractures

Section 4.3 of the MRV plan states detailed mapping of openhole logs surrounding the O'Neal No. 4 well did not identify any faulting within either the Pearsall or Sligo sections. However, there is a general lack of deep penetrators within the area that limits the amount of openhole coverage available.

According to the MRV plan, the majority of the published literature suggests that faulting near the project area is restricted to the shallower, overlying Cenozoic section, as shown in Figure 9 of the MRV plan, with shallow faults dying out before reaching the Pearsall Formation. One source interpreted the potential for faulting to the south. The potential fault is depicted in Figure 8 of the MRV plan relative to the location of the O'Neal No. 4 well. According to the map, the interpreted fault lies approximately 4.25 miles south-southeast of the well and approximately 3.9 mi south-southeast of the stabilized plume extent in the year 2047. O'Neal No. 4 well states in the unlikely scenario in which the injection plume or pressure front reaches the potential fault, and the potential fault was to act as a transmissive pathway, the upper confining Pearsall shale contains sufficient thickness and petrophysical properties required to confine and protect injectates from leaking outside of the permitted injection zone.

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

3.4 Leakage through the Confining Layer

Section 4.4 of the MRV plan states the Sligo injection zone has competent sealing intervals present above and below the targeted carbonate sequence of the Sligo section. The overlying Pine Island Shale Member of the Pearsall Formation is approximately 130 ft thick at the O'Neal No. 4 well. Above this confining unit, the Cow Creek Limestone, Cow Creek Shale, and Bexar Shale Members of the Pearsall Formation will act as additional confinement between the injection interval and the USDW. The MRV plan states that the USDW lies well above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. The MRV plan also states that the petrophysical properties of the lower Sligo and Hosston Formations make these ideal for lower confinement. The low porosity and permeability of these underlying formations minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injectate to the in-situ reservoir fluid makes migration below the lower confining layer unlikely

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

3.5 Leakage from Natural or Induced Seismicity

Section 4.5 of the MRV plan states that O'Neal No. 4 well is located in an area of the Gulf of Mexico considered to be active from a seismic perspective. Therefore, the Bureau of Economic Geology's TexNet (from 2017 to present) and USGS's Advanced National Seismic System (from 1971 to present) databases were reviewed to identify any recorded seismic events within 25 kilometers (km) of the O'Neal No. 4 well. The MRV plan states the investigation identified a multitude of seismic events within the 25-km search radius; however, the magnitude of most of the events was below 2.5. The nearest seismic event with a recorded magnitude of 3.0 or greater was measured approximately 5.6 km northwest of the O'Neal No. 4 well at a depth of 5 km. The results of the investigation are plotted on the map provided in Figure 36 of the MRV plan relative to the O'Neal No. 4 well and the 25-km search radius.

The MRV plan states the Plant will have operating procedures and set points programmed into the control and SCADA systems to ensure operating pressures are maintained within the injection and confining intervals' approved fracture gradients. Given the seismic activity in the area, O'Neal No. 4 well states it will closely monitor nearby TexNet station EF71 for activity and any corresponding irregularities in the operating pressures of the O'Neal No. 4 well.

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

Overall, the MRV plan provides an acceptable characterization of potential CO_2 leakage pathways as required by 40 CFR 98.448(a)(2).

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

40 CFR 98.448(a)(3) requires that an MRV plan contain a strategy for detecting and quantifying any surface leakage of CO_2, and 40 CFR 98.448(a)(4) requires that an MRV plan include a strategy for establishing the expected baselines for monitoring potential CO_2 leakage. Section 5 of the MRV plan discusses the strategy that O'Neal No. 4 well will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in Section 4, to meet the requirements of 40 CFR §98.448(a)(3).

As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Monitoring will occur during the planned 12-year injection period or cessation of injection operations, plus a proposed 10-year post-injection period until the plume has stabilized.

- Leakage from surface equipment
- Leakage through existing and future wells within the MMA
- Leakage through faults and fractures
- Leakage through confining seals
- Leakage from natural or induced seismicity

A summary table of O'Neal No. 4 well's strategy for monitoring any potential CO_2 leakage can be found in Table 9 of the MRV plan and is reproduced below.

Leakage Pathway	Monitoring Method
Surface equipment	Fixed H_2S monitors at the Plant and well site
	Visual inspections
	Monitor SCADA systems for the Plant and well site
Existing wells within the MMA	Monitor CO_2 levels in above zone producing wells
	Mechanical Integrity Tests (MIT) of O'Neal No. 4 well every 5 years
	Visual inspections
	Annual soil gas sampling near well locations that penetrate the Upper Confining Zone within the AMA
Leakage through groundwater wells	Annual groundwater samples from existing water well(s)
Leakage from future wells	Monitor drilling activity and compliance with TRRC Rule 13 Regulations
Faults and Fractures	SCADA continuous monitoring at the well site (volumes and pressures)
	Monitor CO_2 levels in above zone producing wells
Natural or induced seismicity	Monitor CO_2 levels in above zone producing wells
	Monitor existing TexNet station

4.1 Detection of Leakage from Surface Equipment

Section 5.1 of the MRV plan states the Plant and the O'Neal No. 4 well were designed to operate in a safe manner to minimize the risk of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established prior to commencing operation once facility construction has been completed. Ambient H_2S monitors will be located at the plant and near the O'Neal No. 4 well site for local alarm and are connected to the SCADA system for continuous monitoring.

According to the MRV plan, the plant and the O'Neal No. 4 well are continuously monitored through automated control systems. In addition, field personnel conduct routine visual field inspections of gauges and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow O'Neal No. 4 well to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. The MRV plan states should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR 98.448(a)(5) and 40 CFR 98.444(d).

The MRV plan states pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak.

Table 9 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected from surface equipment.

Thus, the MRV plan provides adequate characterization of the O'Neal No. 4 well's approach to detect potential leakage through surface equipment as required by 40 CFR 98.448(a)(3).

4.2 Detection of Leakage through Existing and Future Wells Within the MMA

Section 4.2 of the MRV plan states that O'Neal No. 4 well continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the O'Neal No. 4 well. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, O'Neal No. 4 well states MITs are performed every 5 years, as expected by the TRRC and UIC, and would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and investigated to develop a leak mitigation plan.

As discussed previously in the MRV plan, TRRC Rule 13 would ensure that new wells in the field would be constructed to prevent migration from the injection interval.

In addition to the fixed monitors described previously, the MRV plan states that the facility will also establish and operate an in- field monitoring program to detect CO_2 leakage within the AMA. This would include H_2S monitoring as a proxy for CO_2 at the well site and annual soil gas samples taken near any identified wells that penetrate the injection interval within the AMA. These samples will be analyzed by a qualified third party. Prior to commencing operation, and through the post-injection monitoring period, O'Neal No. 4 well states it will have these monitoring systems in place.

The MRV plan states that currently, there is only one well in the MMA identified that penetrates the injection interval. This well was plugged and abandoned in 2007. The TRRC records are provided in

Appendix A-4. O'Neal No. 4 well will take an annual soil gas sample from this area, which will be analyzed by a third-party lab. Additional monitoring will be added as the AMA is updated over time.

The MRV plan states O'Neal No. 4 well will also utilize shallower producing gas wells as proxies for above-zone monitoring wells. Production data from these wells is analyzed for monthly production statements, and therefore would be an early indicator of any possible subsurface issues. Should any material change from historical trends in the CO_2 concentration occur, O'Neal No. 4 well would investigate and develop a corrective action plan. Should any CO_2 migrate vertically from the Sligo, the magnitude risk of this event is very low, as the producing reservoir provides an ideal containment given the upper confining zone of this reservoir has proven competent.

Groundwater Quality Monitoring

According to the MRV plan, O'Neal No. 4 well will monitor the groundwater quality above the confining interval by sampling from groundwater wells near the O'Neal No. 4 well and analyzing the samples with a third-party laboratory on an annual basis. In the case of O'Neal No. 4 well, five existing groundwater wells have been identified within the AMA, as shown in Figure 38 of the MRV plan. Initial groundwater quality tests will be performed to establish a baseline prior to commencing operations.

Table 9 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected through existing and future wells within the MMA.

Thus, the MRV plan provides adequate characterization of O'Neal No. 4 well's approach to detect potential leakage through existing and future wells within the MMA as required by 40 CFR 98.448(a)(3).

4.3 Detection of Leakage through Faults, Fractures, or Confining Seals

Section 5.3 of the MRV plan states that the facility will continuously monitor the operations of the O'Neal No. 4 well through the automated controls and SCADA systems. Any deviation from normal operating volume and corresponding injection pressure could indicate movement into a potential leak pathway, such as a fault or breakthrough of the confining seal, and it would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

According to the MRV plan, the facility will also utilize shallower producing wells as proxies for above-zone monitoring wells. Production data is analyzed regularly for monthly production statements and therefore would be an early indicator of any possible subsurface issues. Should any material change from historical trends in the CO_2 concentration occur, O'Neal No. 4 well would investigate and develop a corrective action plan. The MRV plan also states should any CO_2 migrate vertically from the Sligo Formation, the magnitude risk of this event is very low, as the producing reservoir provides an ideal containment given the upper confining zone has proven competent.

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

Thus, the MRV plan provides adequate characterization of O'Neal No. 4 well's approach to detect potential leakage through faults, fractures, or confining seals as required by 40 CFR 98.448(a)(3).

4.4 Detection of Leakage from Natural or Induced Seismicity

The MRV plan states that while the likelihood of a natural or induced seismicity event is low, O'Neal No. 4 well plans to use the nearest TexNet seismic monitoring station, EF71, to monitor the area around the facility. The TexNet station is approximately 3 mi to the northwest, as shown in Figure 38 of the MRV plan. The MRV plan states that this is a sufficient distance to allow for accurate and detailed monitoring of the seismic activity in the area. O'Neal No. 4 well will monitor this station for any seismic activity, and if a seismic event of 3.0 magnitude or greater is detected, it will review the injection volumes and pressures of the O'Neal No. 4 well to determine if any significant changes have occurred that would indicate potential leakage.

The MRV plan also states O'Neal No. 4 well will continuously monitor operations through the SCADA system. Any deviation from normal operating pressure and volume set points would trigger an alarm for investigation by operations staff. Such a variance could indicate movement into a potential leak pathway, such as a fault or breakthrough of the confining seal. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Table 9 of the MRV plan provides a detailed characterization of detecting CO_2 leakage that could be expected from natural or induced seismicity.

Thus, the MRV plan provides adequate characterization of O'Neal No. 4 well's approach to detect potential leakage from natural or induced seismicity as required by 40 CFR 98.448(a)(3).

4.5 Quantification

Section 7.4 of the MRV plan states the potential for pathways for all previously mentioned forms of leakage is unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, O'Neal No. 4 well believes the most appropriate method to quantify the mass of CO_2 released will be determined on a case-by-case basis. Any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, in accordance with 40 CFR 98.448(a)(5).

4.6 Determination of Baselines

Section 6 of the MRV plan identifies the strategies that the facility will undertake to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR 98.448(a)(4). O'Neal No. 4 well will also use existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of CO_2. The MRV plan identifies the following strategies for determining baselines:

Visual Inspections

The MRV plan states regular inspections will be conducted by field personnel at the Plant and the O'Neal No. 4 well site. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken to address such issues.

CO_2/H_2S Detection

The MRV plan states that in addition to the fixed monitors in the Plant and at the wellsite, the facility will perform an annual in-field sampling program to monitor and detect any CO_2 leakage within the AMA. This will consist of soil gas sampling near any artificial penetrations of the injection zone and sampling of water wells. These probes have special membrane inserts that collect the gas samples over a 21-day period. These will be analyzed by a third-party lab to be analyzed for CO_2, H_2S, and trace contaminants typically found in a hydrocarbon gas stream. The lab results will be provided in the annual report should they indicate a material variance from the baseline. Initial samples will be taken and analyzed before the commencement of operations and will establish the baseline reference levels.

Operational Data

The MRV plan states upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of injectate and the corresponding component of CO_2.

Continuous Monitoring

The MRV plan states the total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is near the OSHA Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger alarms if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions, including pressure, flow rate, percentage of CO_2, size of the leak-point opening, and duration. This method is consistent with 40 CFR 98.448(a)(5) and 40 CFR 98.444(d), allowing the operator to calculate site-specific variables used in the mass balance equation.

The MRV plan also states in the case of a depressuring event, the acid gas stream will be sent to a flare stack to be safely processed and will be reported under reporting requirements for the plant. Any such events will be accounted for in the sequestered reporting volumes consistent with Section 7.4 of the MRV plan.

Groundwater Monitoring

The MRV plan states initial samples will be taken from groundwater wells in the area of the O'Neal No. 4 well upon approval of the MRV plan, and before commencement of CO_2 injection. These samples will be analyzed, and reports prepared by a third-party laboratory testing for pH, total dissolved solids (TDS), CO_2, and volatile organic compounds (VOC). Initial samples will be taken and analyzed before the commencement of operations and will establish the baseline reference levels. Sampling select wells will be performed annually. The MRV plan also states that in the event a material deviation in the sample analysis occurs, the results will be provided in the annual report.

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

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

5.1 Determining Mass of CO_2 Received

According to the MRV plan, the CO_2 received for the O'Neal No. 4 well is wholly injected and not mixed with any other supply. Therefore, the facility concludes that the annual mass of CO_2 injected will equal the amount received. The MRV plan states that any future streams would be metered separately before being combined into the calculated stream.

O'Neal No. 4 well 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 7.2 of the MRV plan states that the mass of CO_2 injected will be measured with a volumetric flow meter. The total annual mass of CO_2, in metric tons, will be calculated by multiplying the mass flow by the CO_2 concentration in the flow according to Equation RR-5:

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

Where:

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

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

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

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

p = Quarter of the year.

u = Flow meter.

O'Neal No. 4 well 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

The MRV plan states that O'Neal No. 4 well is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

5.4 Calculation of Mass of CO_2 Emitted by Surface Leakage

The MRV plan states that the mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly due to the H_2S concentration in the injection stream. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required, and those emissions would be sent to a flare stack and reported as a part of the required GHG reporting for the plant. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of H_2S and CO_2. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak point opening, and duration of the leak. This method is consistent with 40 CFR 98.448(a)(5).

Should CO_2 surface leakage occur, the MRV plan states that the mass emitted would be calculated for each surface pathway according to methods outlined in the plan and totaled using Equation RR-10 as

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

follows:

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.

Calculation methods using equations from subpart W will be used to calculate CO_2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

O'Neal No. 4 well 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 the mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Data collection for calculating the amount of CO_2 sequestered will begin once the subsurface recompletion and surface facilities construction has been completed, as well as the approval of this MRV plan. As this well will not actively produce oil or natural gas, or any other fluids, as follows:

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

Where:

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

The MRV plan states that CO_{2FI} will be calculated in accordance with subpart W reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required, and those emissions sent to flares and reported as part of the required GHG reporting for the gas plant.

O’Neal No. 4 well 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 the O’Neal Gas Unit Well No. 4 meets the requirements of 40 CFR 98.448. The regulatory provisions of 40 CFR 98.448(a), which specifies the requirements for MRV plans, are summarized below along with a summary of relevant provisions in the MRV plan.

Subpart RR MRV Plan Requirement	O’Neal Gas Unit Well No. 4 MRV Plan
40 CFR 98.448(a)(1): Delineation of the maximum monitoring area (MMA) and the active monitoring areas (AMA).	Section 3 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 (2037) with the area of the projected free-phase CO_2 plume at five additional years (2047). 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, and timing, of surface leakage of CO_2 through these pathways.	Section 4 of the MRV plan identifies and evaluates potential surface leakage pathways. The MRV plan identifies the following potential pathways: leakage from surface equipment; leakage through existing and future wells within the MMA; leakage through faults and fractures; leakage through the upper confining layer; and leakage from natural or induced seismicity. 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 5 and Section 7 of the MRV plan describe the 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 SCADA systems, MITs, groundwater sampling, and in-field monitors.
40 CFR 98.448(a)(4): A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.	Section 6 of the MRV plan describes the strategy for establishing baselines against which monitoring results will be compared to assess potential surface leakage.
40 CFR 98.448(a)(5): A summary of the considerations you intend to use to	Section 7 of the MRV plan describes O’Neal No. 4 well’s approach to determining the amount of CO_2

calculate site-specific variables for the mass balance equation.	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.	Section 1 of the MRV plan provides the well identification numbers for the O'Neal No. 4 well (API No. 42-025-32658, UIC No. 56819). The MRV plan specifies that the wells are pending a UIC Class II permit under TRRC Rule 9 and Rule 36.
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 8 of the MRV plan states that the mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12, assuming an expected injection start date of October 1, 2024.

Appendix A: Final MRV Plan

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
O'Neal Gas Unit Well No. 4

Bee County, TX

Prepared for *Ozona CCS, LLC*
San Antonio, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 4.0
August 2024

INTRODUCTION

Ozona CCS, LLC (Ozona) has a pending Class II acid gas injection (AGI) permit application with the Texas Railroad Commission (TRRC), which was submitted in September of 2023 for its O'Neal Gas Unit Well No. 4 (O'Neal No. 4), API No. 42-025-32658. Granting of this application would authorize Ozona to inject up to 1.5 million standard cubic feet per day (MMscf/D) of treated acid gas (TAG) into the Sligo Formation at a depth of 15,874 feet (ft) to 16,056 ft, with a maximum allowable surface pressure of 7,920 pounds per square inch gauge (psig). The TAG for this AGI well is associated with StarTex's Pawnee Treating Facility, located in a rural area of Bee County, Texas, approximately 2.0 miles (mi) south of Pawnee, Texas, as shown in Figure 1.

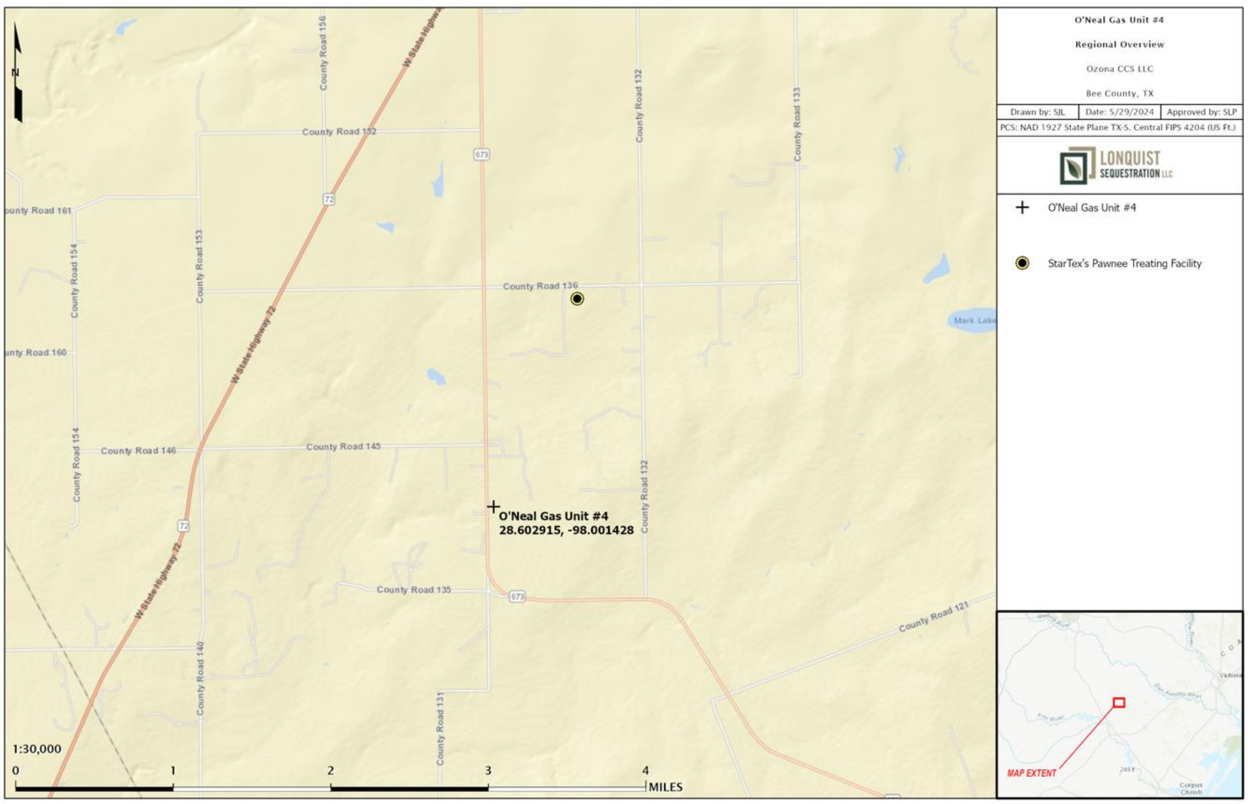

Figure 1 – Location of StarTex's Pawnee Treating Facility and the O'Neal No. 4

Ozona is submitting this Monitoring, Reporting, and Verification (MRV) plan to the EPA for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Ozona has applied to the TRRC for the O'Neal GU No. 4's Class II permit. Ozona plans to inject TAG for approximately 12 years. Table 1 shows the expected composition of the gas stream to be sequestered from the nearby treating facility.

Table 1 – Expected TAG Composition

Component	Mol Percent
Carbon Dioxide	98.2%
Hydrocarbons	1.03%
Hydrogen Sulfide	0.4%
Nitrogen	0.37%

ACRONYMS AND ABBREVIATIONS

AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group, Ltd.
CO_2	Carbon Dioxide (may also refer to other carbon oxides)
E	East
EOS	Equation of State
EPA	Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet

Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
PG	Pore Gradient
pH	Scale of Acidity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

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SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program. The TRRC classifies the O'Neal No. 4 as a UIC Class II well. Ozona has applied for a Class II permit for the O'Neal No. 4 under TRRC Rules 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas) and 46 (Fluid Injection into Productive Reservoirs).

1.2 UIC Well Identification Number

- O'Neal No. 4, API No. 42-025-32658, UIC No. 56819

1.3 Facility Address

- Facility Name: StarTex Pawnee Treating Facility
- Operator: StarTex Field Services, LLC
- Facility ID No. 568661
- Coordinates in North American Datum for 1983 (NAD 83) for this facility:
    - Latitude: 28.622211
    - Longitude: -97.992772
- Greenhouse Gas Reporting Program ID Information:
    - Ozona will report under GHGRP ID No. 587021 for this Monitoring, Reporting and Verification plan

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and reservoir and plume modeling performed for the O'Neal No. 4 well.

The O'Neal No. 4 will inject the TAG stream into the Sligo Formation at a depth of 15,874 ft to 16,056 ft, and approximately 14,924 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and—most critically—to prevent surface releases.

2.1 Regional Geology

The O'Neal No. 4 (API No. 42-025-32658) is located in south Texas within the Gulf of Mexico Basin. The onshore portion of the Gulf of Mexico basin spans approximately 148,049,000 acres and encompasses portions of Texas, Louisiana, Mississippi, Alabama, Arkansas, Missouri, Kentucky, Tennessee, Florida, and Georgia to the state-waters boundary of the United States (Roberts-Ashby et al., 2012). The location of the O'Neal No. 4 is designated by the red star in Figure 2, relative to the present coastal extent and major structural features of the basin.

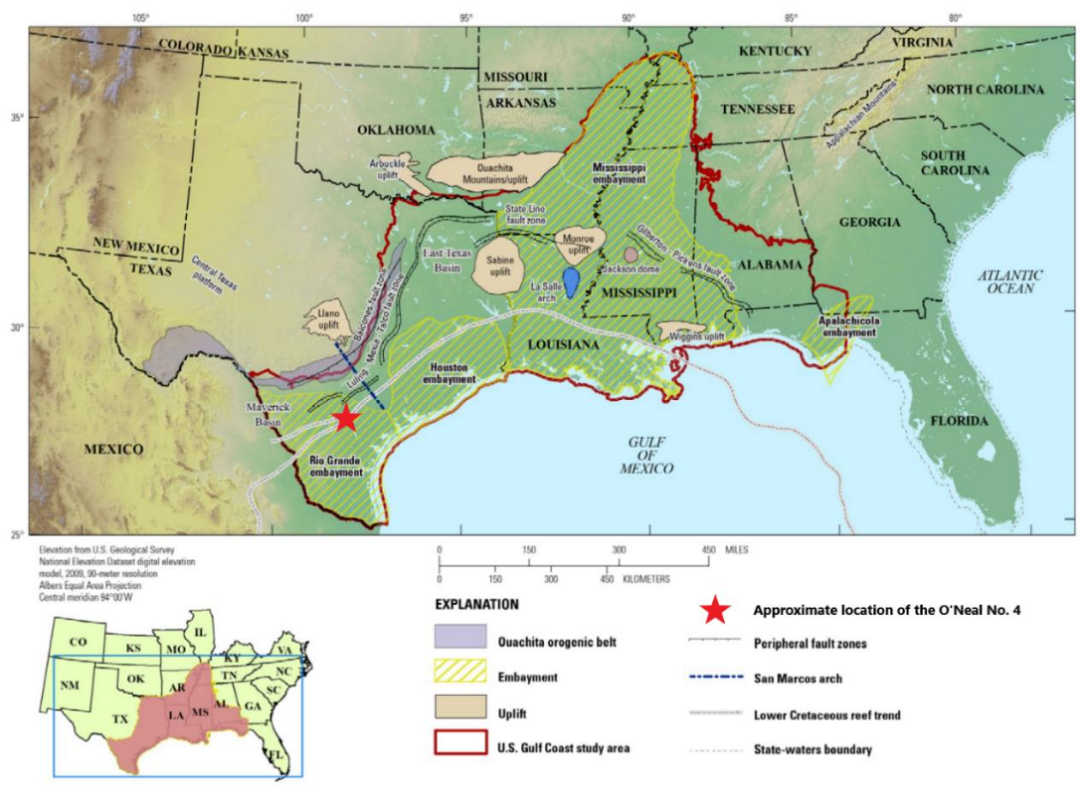

Figure 2 – Structural Features of the Gulf of Mexico and Locator Map (modified from Roberts-Ashby et al., 2012)

Figure 3 depicts a generalized stratigraphic column of the U.S. Gulf Coast, with light blue shading signifying the proposed injection interval and green stars indicating productive formations identified within 5 miles of the O'Neal No. 4. The injection interval is found within the Sligo Formation, with confinement provided by the overlying Pearsall Formation and tight underlying facies of the Lower Sligo and Hosston Formations.

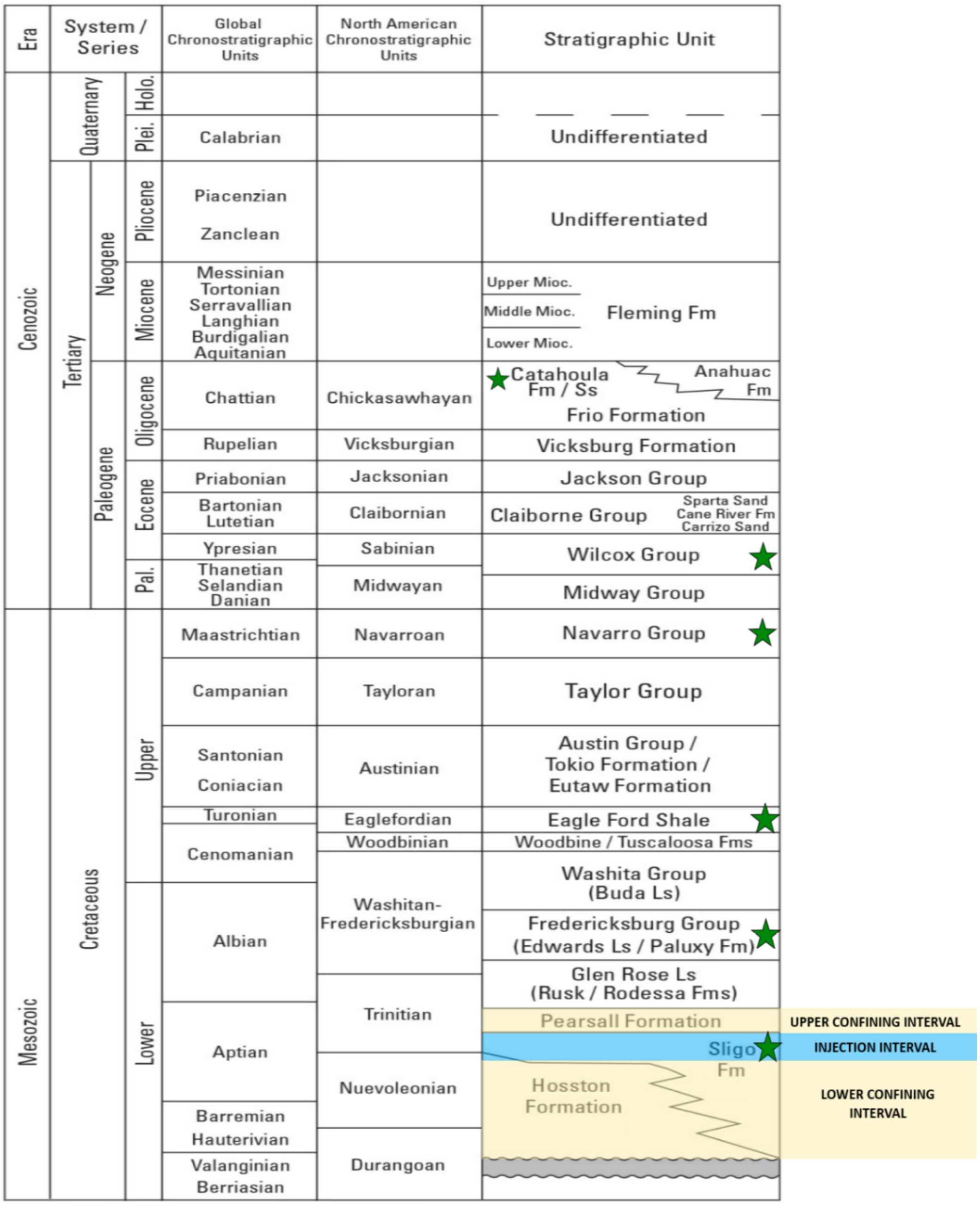

Figure 3 – Stratigraphic column of the U.S. Gulf Coast signifying proposed injection and confining intervals. Offset productive intervals are noted with a green star (modified from Roberts-Ashby et al., 2012).

The targeted formations of this study are located entirely within the Trinity Group, as clarified by the detailed stratigraphic column provided in Figure 4. During this time the area of interest was located along a broad, shallow marine carbonate platform that extended along the northern rim of the ancestral Gulf of Mexico. The Lower Cretaceous platform spanned approximately 870 mi from western Florida to northeastern Mexico, with a shoreline-to-basin margin that ranged between 45 to 125 mi wide (Yurewicz et al., 1993).

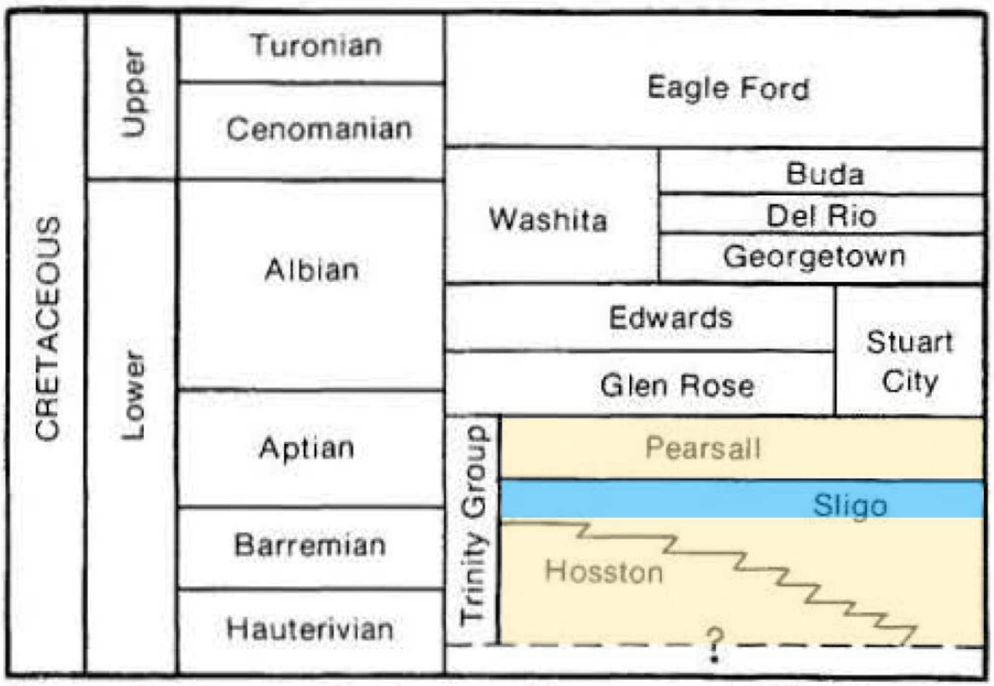

Figure 4 – Detailed stratigraphic column of Lower Cretaceous formations of south Texas. The proposed injection interval is shaded light blue and proposed confining intervals are shaded light yellow (modified from Bebout et al., 1981).

2.1.1 Geologic Setting and Depositional Environment

The depositional environment during the Lower Cretaceous generally consisted of a well-defined platform margin with a shallow marine platform interior or lagoon to the north, a shallow marine outer platform to the south, and a foreslope that gradually dipped southward towards the basin center. The platform margin remained stable for tens of millions of years during the Cretaceous but experienced episodic changes in sea level that resulted in cyclic deposition of several key facies that vary both spatially and within the geologic section. Facies distributions were heavily impacted by positioning relative to the margin, the height of the water column at any given time, and the degree of energy or wave action within the system (Galloway, 2008; Yurewicz et al., 1993).

In general, long stands of reef development and ooid shoaling developed primary porosity and permeability along the shallow, high-energy carbonate platform and represent reservoir quality

rock found within Cretaceous reef deposits. Deeper, basinward deposits tend to result in tighter petrophysical properties due to a relative increase in the amount of entrained clay associated with the heightening of the water column while moving downslope. Backreef deposits have the potential for porosity development but tend to have low permeability due to a general lack of wave action caused by restricted access to open water by the platform margin. Facies and petrophysical properties of the Lower Cretaceous section are anticipated to be relatively homogenous moving southwest-northwest along reef trend, with increased heterogeneity moving northwest-southeast due to the orientation of the carbonate rim and its effect on deposition and facies distributions (Yurewicz et al., 1993).

Figure 5 displays the paleogeography during deposition of the Lower Cretaceous section to visually demonstrate the position of the O'Neal No. 4 relative to the Sligo shelf margin and updip extents of Sligo deposition. A generalized schematic cross section of the Trinity Group is provided in Figure 6, which nearly intersects the project area from the northwest. The schematic illustrates the gross section thickening basinward, with primary reservoir development improving with proximity to the reef margin. Figure 7 displays a depositional model of the Lower Cretaceous carbonate platform to visually conceptualize depositional environments and anticipated petrophysical properties of facies introduced above.

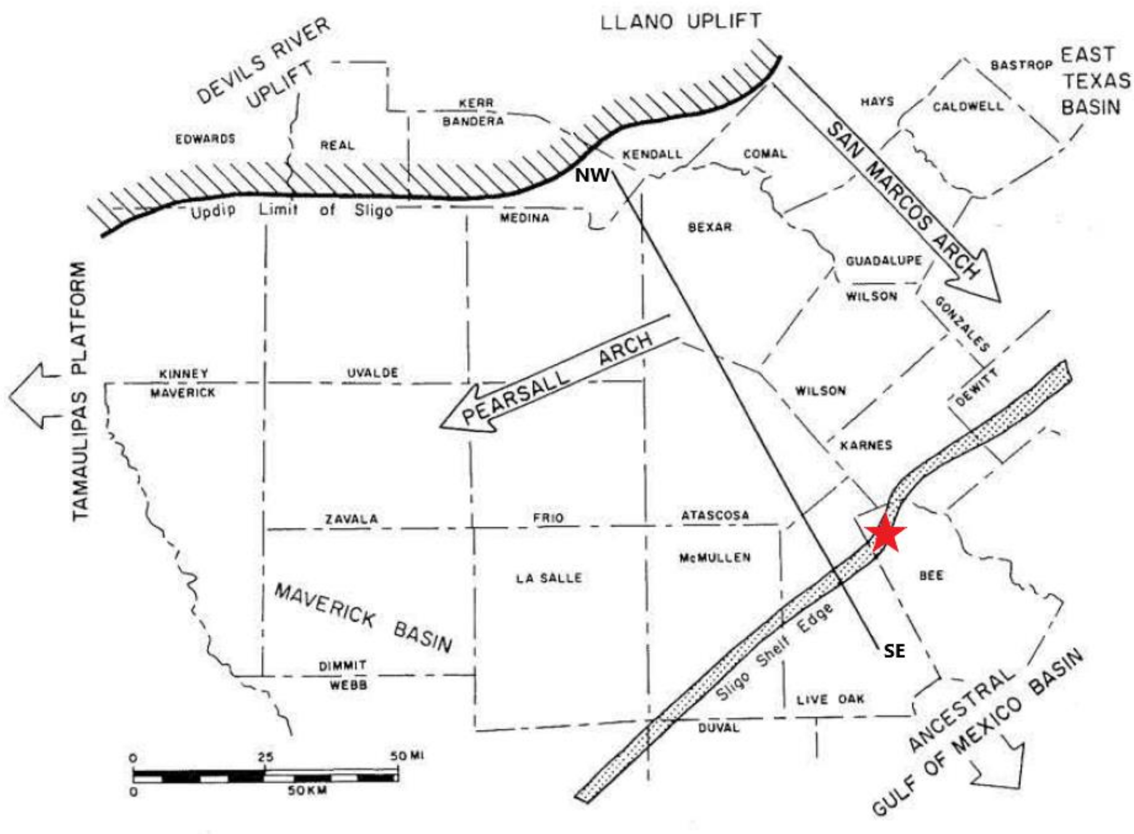

Figure 5 – Paleogeography of the Lower Cretaceous of south Texas. The red star represents the approximate location of the O'Neal No. 4 (modified from Bebout et al., 1981).

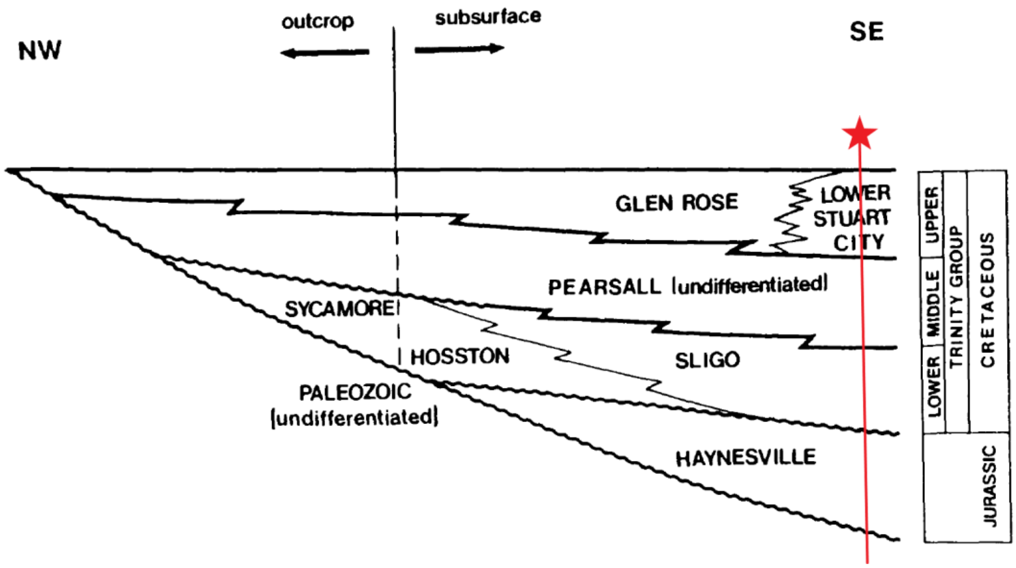

Figure 6 – Generalized northwest to southeast schematic cross section of the Trinity Group, south Texas (the line of section depicted in Figure 5). The red star and line represent the approximate location of the O'Neal No. 4 (modified from Kirkland et al., 1987)

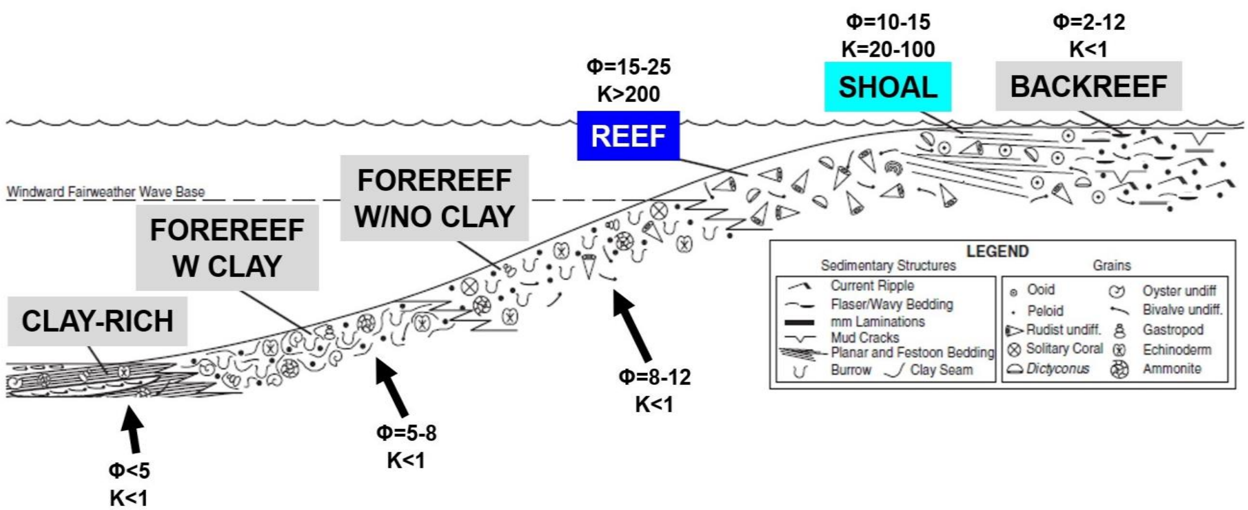

Figure 7 – Depositional model for the Lower Cretaceous carbonate platform with estimated porosity and permeability values of typical facies (modified from Talbert and Atchley, 2000).

2.1.2 Regional Structure and Faulting

The Gulf of Mexico basin was formed by crustal extension and sea-floor spreading associated with the Mesozoic breakup of Pangea. Rifting of northwest to southeast trending transfer faults during the Middle Jurassic lasted approximately 25 million years and resulted in variable thickness of the transcontinental crust underlying the region. By the Lower Cretaceous time, the general outline and morphology of the Gulf were similar to that of present-day (Galloway, 2008;

Yurewicz et al., 1993). Lower Cretaceous tectonic activity was limited to regional subsidence associated with areas of variable crustal thickness and local structuring caused by movement of Louann Salt (Yurewicz et al., 1993). The combination of these processes resulted in the structural development of regional arches, grabens, uplifts, embayments, salt domes, and salt basins around the northern edge of the basin (Dennen and Hackley, 2012; Galloway, 2008). The location of these structural features can be referenced in Figures 2 and 8 relative to the location of the O'Neal No. 4.

The schematic dip-oriented cross section displayed in Figure 9 presents a common interpretation of the current structural setting. Most of the published literature suggests that faulting near the project area is restricted to the shallower, overlying Cenozoic section, as displayed in Figure 9, with shallow faulting dying out before reaching the Pearsall Formation. However, one source did interpret the potential for faulting to the south (Swanson et al., 2016). The closest potential fault is depicted in Figure 8 relative to the location of the O'Neal No. 4. According to the map, the interpreted fault lies approximately 4.25 miles south-southeast of the well and approximately 3.9 miles south-southeast of the stabilized plume extent in the year 2047.

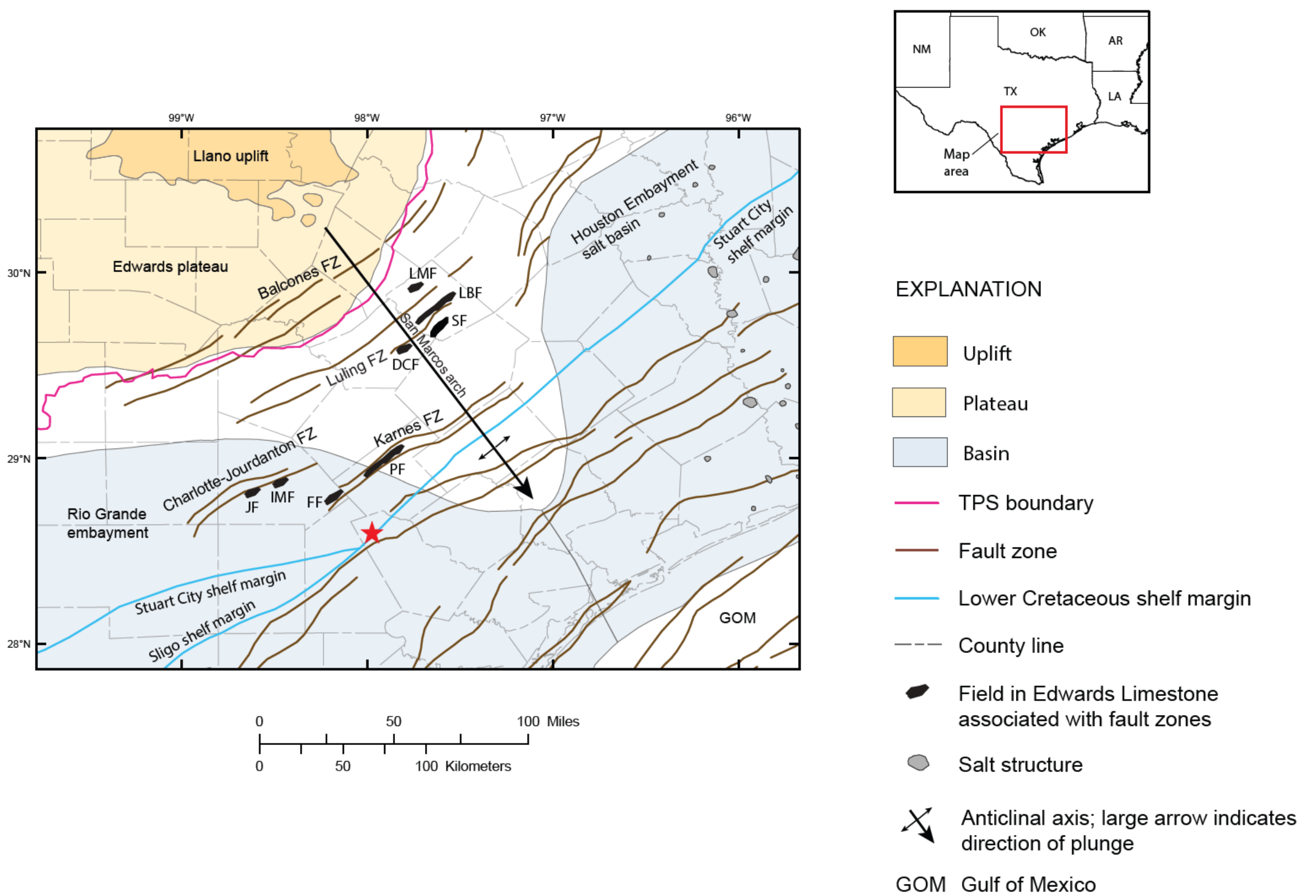

Figure 8 – Structural features and fault zones near the proposed injection site. The red star represents the approximate location of the O'Neal No. 4 (modified from Swanson et al., 2016).

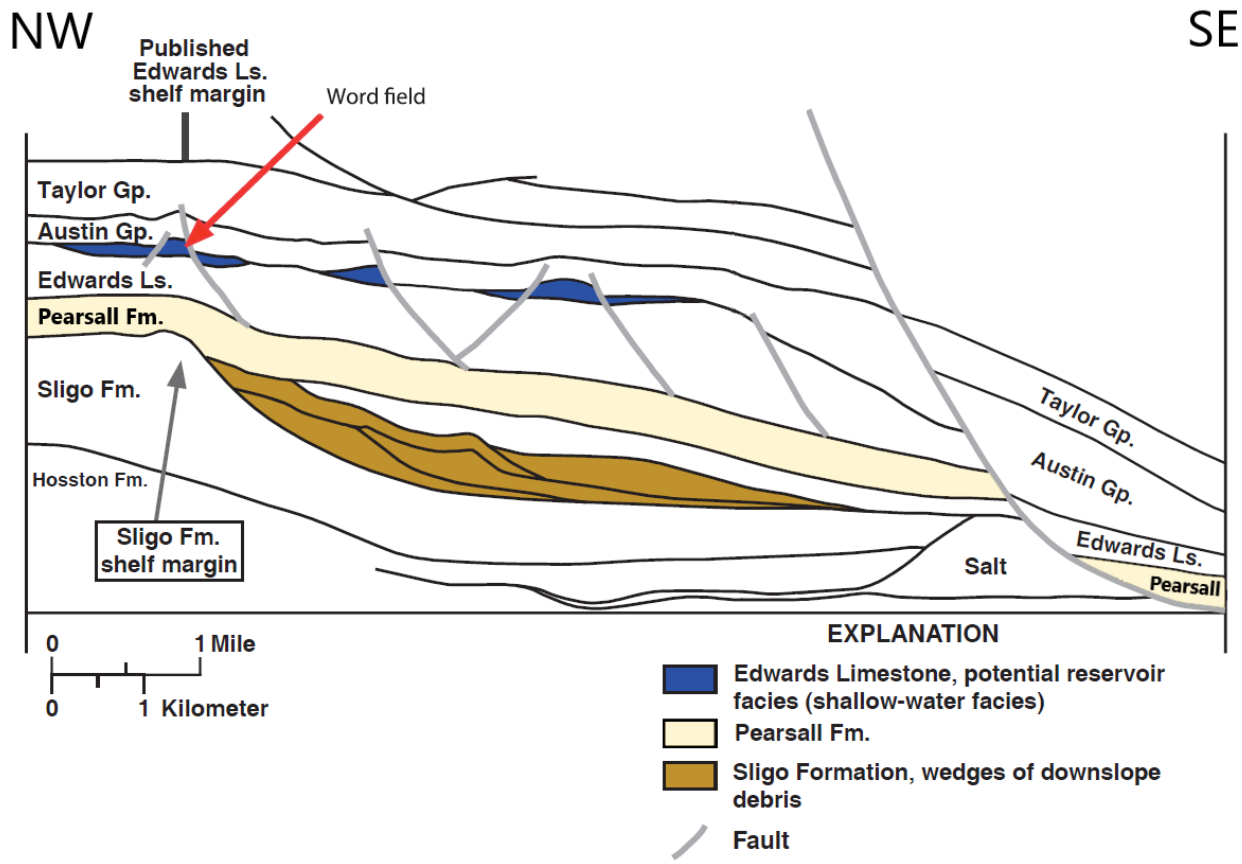

Figure 9 – Northwest to southeast schematic interpretation of the Edwards shelf margin through Word field, northeast of the O'Neal No. 4 project area (modified from Swanson et al., 2016).

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the O'Neal No. 4 well.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 depicts openhole logs from two offset wells (API No. 42-025-00473 and API No. 42-025-31892) to the O'Neal No. 4, indicating the injection and primary upper confining zones. The Tomasek No. 1 (API No. 42-025-00473) is located approximately 1 mi northeast of the O'Neal No. 4 and displays the shallow section from 0–8,200 ft. The Gordon No. 3 (API No. 42-025-31892) is located approximately 1.6 mi northeast of the O'Neal No. 4 and displays a shallow section from 8,200–16,400 ft.

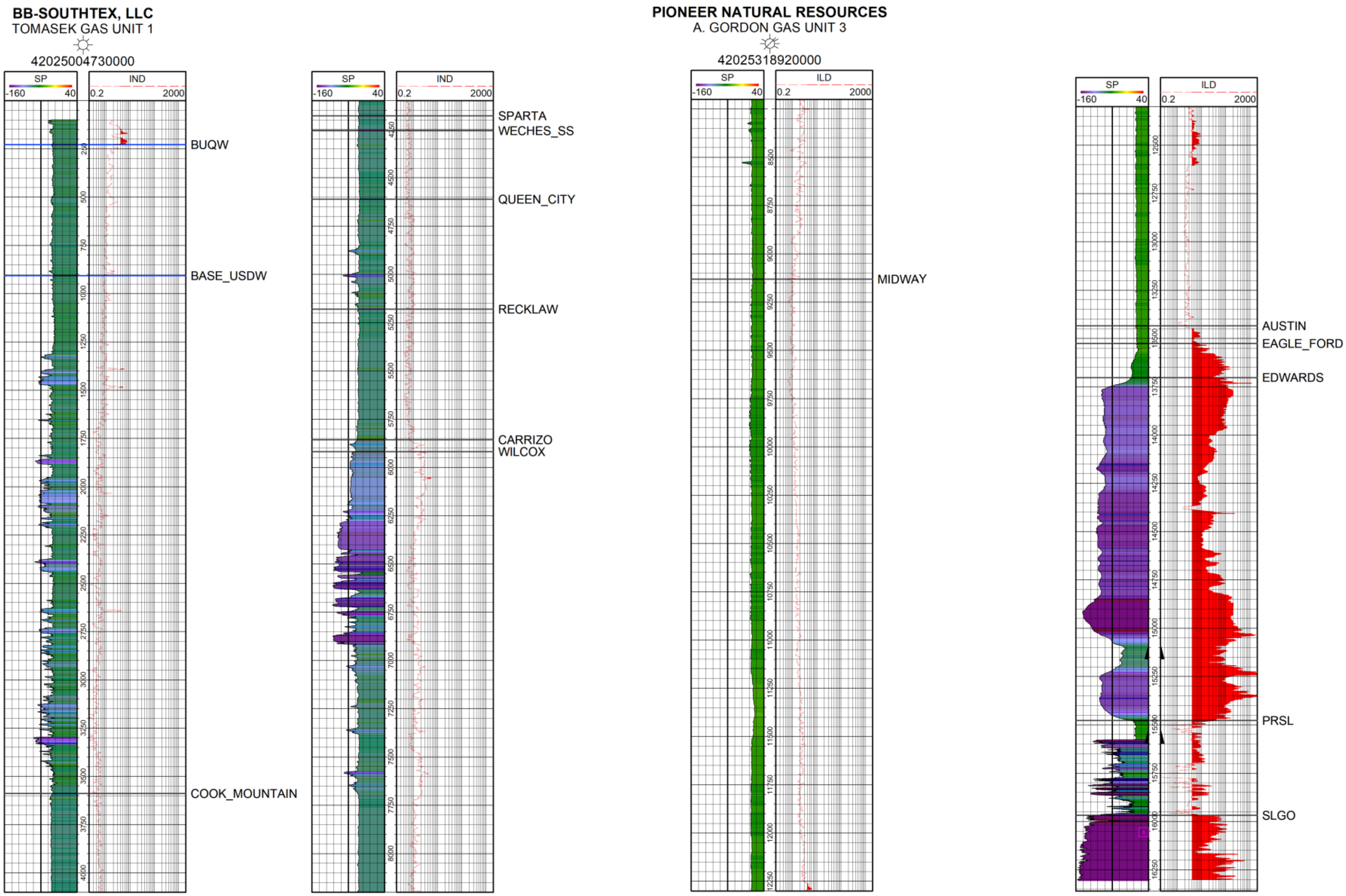

Figure 10 – Type Log with Tops, Confining, and Injection Intervals Depicted

2.2.2 Upper Confining Interval – Pearsall Formation

Following the deposition of the Sligo Formation, the Lower Cretaceous shelf was drowned by eustatic sea-level rise and deposition of the deep-water Pine Island Shale Member of the Pearsall Formation throughout the region (Roberts-Ashby et al., 2012). The Pine Island Shale consists of alternating beds of pelagic mudstone, hemipelagic mudstone, and Fe-rich dolomitic mudstone interpreted to have been deposited along the outer ramp. This is in agreement with core data published by Bebout and others (1981), and later by Swanson and others (2016), who identified the presence of *C. Margerelli*, a nannofossil indicative of anoxic conditions. The core-derived porosity-permeability relationship displayed in Figure 11 suggests that the permeability of the Pine Island Shale is incredibly low and stays below 0.0001 mD, regardless of porosity (Figure 11; Hull, 2011). This is further supported by the 2012 U.S. Geological Survey (USGS) *CO_2 Storage Resource Assessment*, which suggests that the Pine Island Shale contains the physical properties required to act as a regional seal and was chosen as the upward confining interval for their C50490108 Storage Assessment Unit (SAU) assessment of the Gulf Coast. The 2012 USGS report also noted that the Pine Island Shale is a sufficient regional seal with as little as 50 ft of contiguous shale development. The top of the Pearsall is encountered at a depth of 15,339 ft in the O'Neal No. 4, with a gross thickness of 535 ft (Figure 14). The Pine Island Shale member is approximately 130 ft thick at the O'Neal No. 4 location, with deposition of additional members of the overlying Pearsall Formation, which include the Cow Creek Limestone, Cow Creek shale, and Bexar Shale Members (Roberts-Ashby et al., 2012; Swanson et al., 2016).

The seismic line displayed in Figure 12 runs northwest to southeast across the Stuart City reef trend southwest of the project area. The top of the Buda, Pearsall, and Sligo Formation markers are depicted in color to demonstrate the lateral continuity of the section near the O'Neal No. 4. Seismic reflectors within the Pearsall Formation appear to lack deformation, suggesting consistent deposition over the reef margin. This is in agreement with reviewed published literature, which suggests deposition of the Pine Island Shale occurred during widespread marine transgression (Bebout et al., 1981; Hull, 2011.; Roberts-Ashby et al., 2012, Swanson et al., 2016).

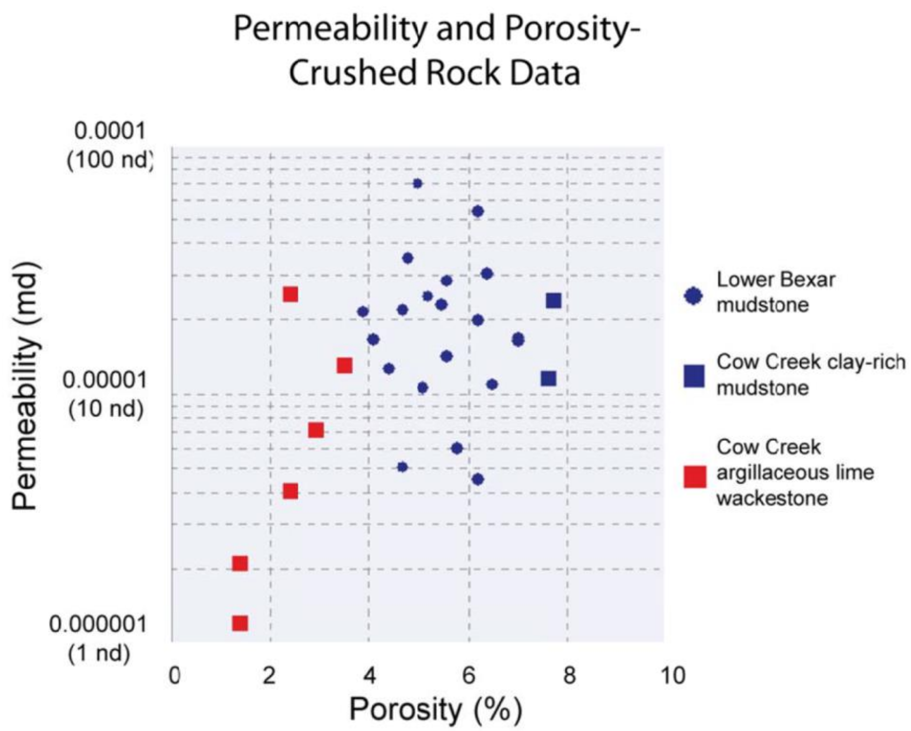

Figure 11 – Porosity-Permeability Crossplot of Pearsall Formation Crushed Rock Core Data (Swanson et al., 2016)

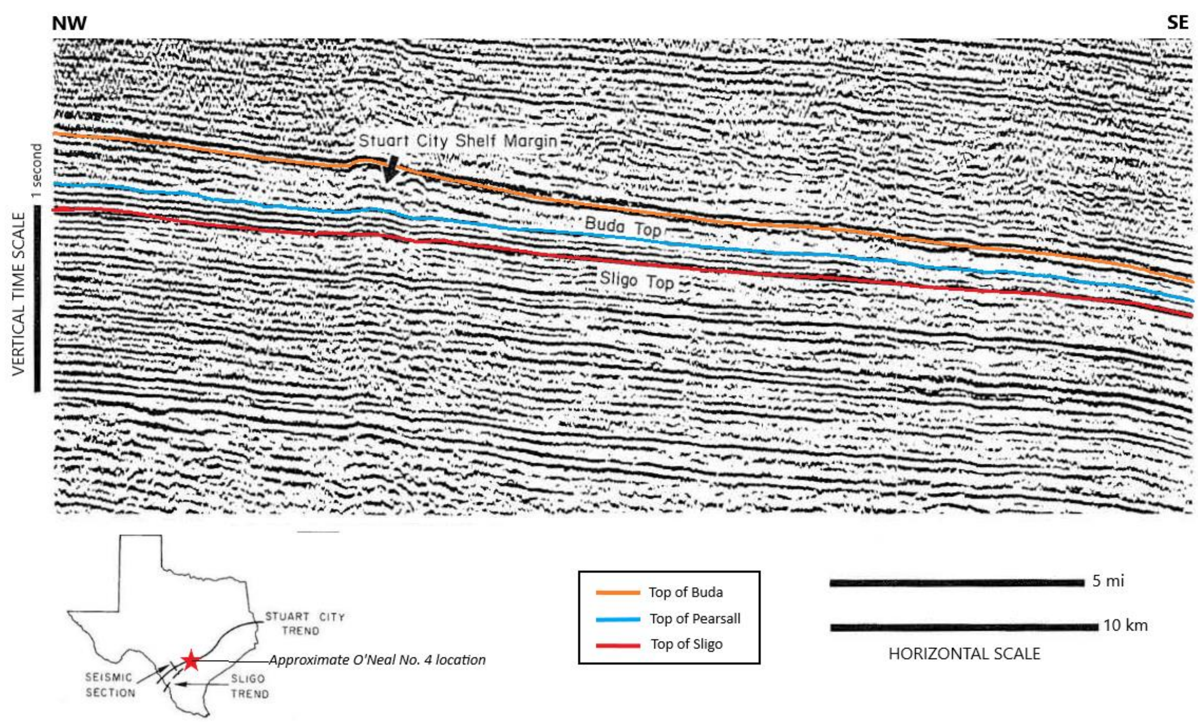

Figure 12 – Seismic line across the Stuart City (Edwards/Buda) shelf margin and locator map. The red star represents the approximate location of the O'Neal No. 4 (modified from Bebout et al., 1981).

2.2.3 Injection Interval – Upper Sligo Formation

The Sligo Formation underlies the Pearsall Formation and is predominately composed of shelf-edge limestones that were deposited along the Lower Cretaceous platform (Roberts-Ashby et al., 2012). However, the Cretaceous also experienced episodic changes in sea level that resulted in the deposition of cyclic Sligo facies that vary both spatially and within the geologic section. The overall Sligo interval is interpreted to be a transgressive sequence occasionally interrupted by progradational cycles that consists of porous shoaling-upward sequences that represent primary reservoir potential within the system (Bebout et al., 1981). Facies distributions of these reef complexes are heavily impacted by positioning relative to the margin, the height of the water column at any given time, and the degree of energy or wave action within the system (Galloway, 2008). Figure 13 depicts an idealized environmental setting of the Lower Cretaceous platform during deposition. Primary porosity and permeability of the upper Sligo Formation tends to develop in high-energy sequences with normal marine conditions that are dominated by the deposition of oolitic and skeletal grainstones.

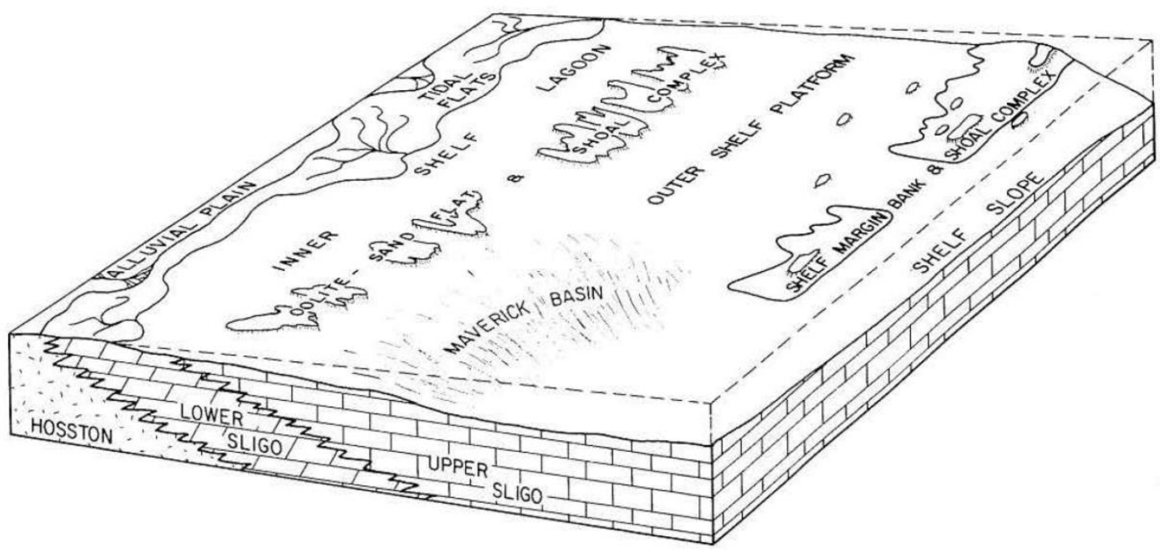

Figure 13 – Environmental Setting of Lower Cretaceous Platform (Bebout et al., 1981)

According to the 2012 USGS *CO_2 Storage Resource Assessment*, "the average porosity in the porous intervals of the storage reservoir decreases with depth from 9 to 16 percent" for their C50490108 DEEP SAU assessment of the Gulf Coast (>13,000 ft). The study also reported that "the average permeability in the storage reservoirs decreases with depth from 0.05 to 200 mD, with a most-likely value of 8 mD" for their C50490108 DEEP SAU assessment of the Gulf Coast (Roberts-Ashby et al., 2012).

The top of the upper Sligo is encountered at a depth of 15,874 ft in the O'Neal No. 4 with a gross thickness of 183 ft (Figure 14). The type log displayed in Figure 14 plots effective porosity for the confining interval and the total porosity of the injection interval, to account for the increased

volume of shale (Vshale) seen in the Pearsall Formation. The porosity data was compared to the analysis performed by Nutech to generate a permeability curve with a reasonable porosity-permeability relationship. The permeability curve was generated utilizing the Coates permeability equation, incorporated with a 20% irreducible brine saturation to match analysis provided by Nutech. Petrophysical analysis of the O'Neal No. 4 indicates an average porosity of 4.6%, a maximum porosity of 15%, an average permeability of 0.16 mD, and a maximum permeability of 3.3 mD. These curves have been extrapolated to the injection site and used to establish reservoir characteristics in the plume model.

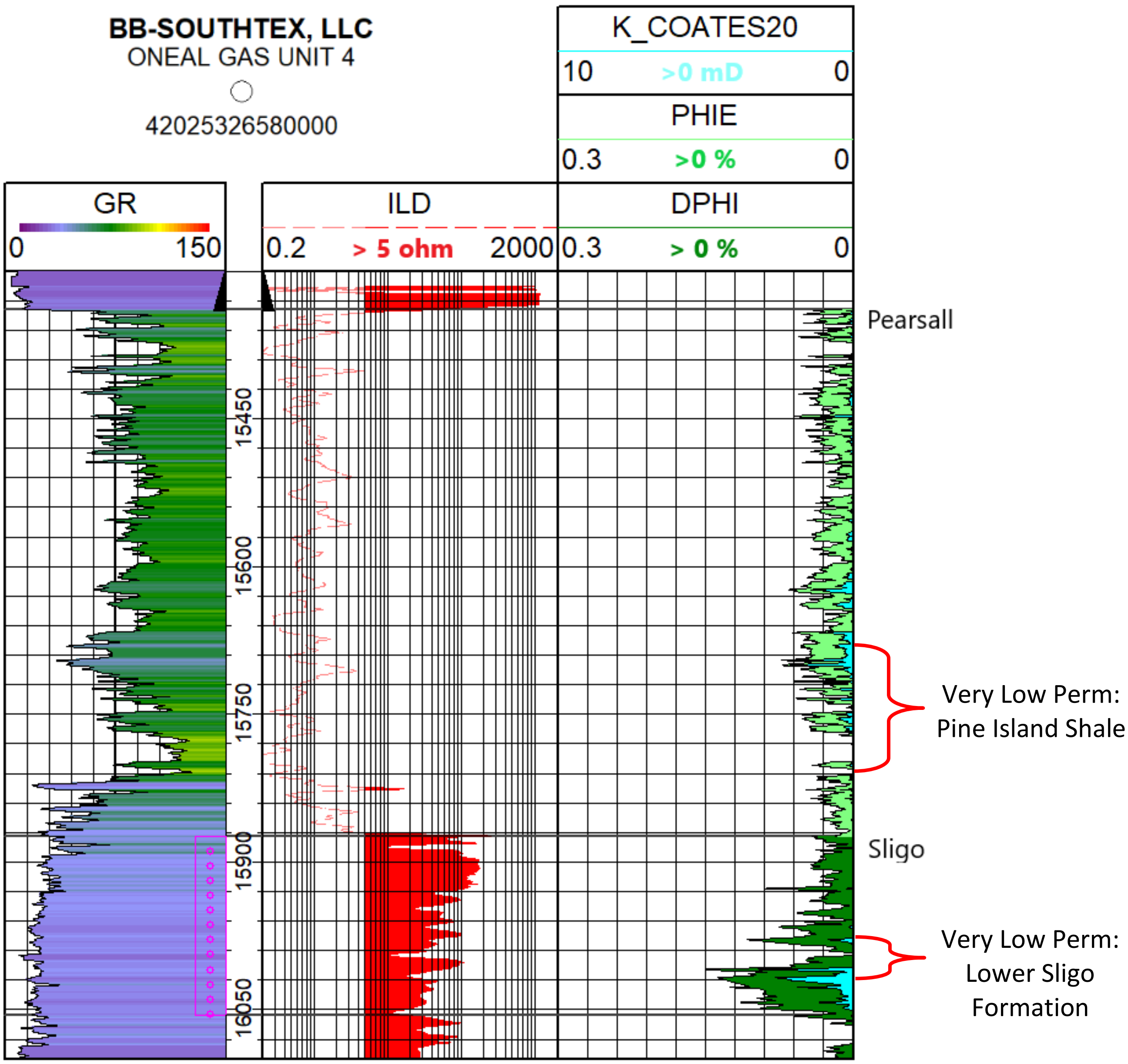

Figure 14 – Openhole log from O'Neal No. 4 (API No. 42-025-32658), with porosity curves shaded green >0%, permeability curve in blue >0 mD, and resistivity in red >5 ohms.

2.2.4 Formation Fluid

The USGS National Produced Waters Geochemical Database version 3.0 was reviewed for chemical analyses of Sligo oil-field brines within the state of Texas (Blondes et al., 2023). Only two samples were identified from the Sligo Formation: one located approximately 29 mi north-northeast in Karnes County and one located approximately 72 mi northeast in Gonzales County. The locations of these wells are shown in Figure 15 relative to the O'Neal No. 4. A summary of water chemistry analyses conducted on the two Texas Sligo oil-field brine samples is provided in Table 2 (page 25).

Averages from the samples were utilized for model assumptions due to the minimal Sligo sample availability and wide geographic spread of Sligo analysis. Total Dissolved Solids (TDS) of the samples contain a wide range of reported values but averaged 176,470 parts per million (ppm). Model sensitivities were established by running iterations with varying TDS values to understand the effect of brine concentrations on plume extents. The results suggested higher density brine values lead to smaller plumes; therefore, a value of 150,000 ppm was established in the model for a conservative approach. If the actual formation fluid sample that will be tested during the recompletion work produces a material difference in the plume, Ozona will submit an updated MRV plan.

Based on the results of the investigation, *in situ* Sligo reservoir fluid is anticipated to contain greater than 20,000 ppm TDS near the O'Neal No. 4, qualifying the aquifer as saline. These analyses indicate the *in situ* reservoir fluid of the Sligo Formation is compatible with the proposed injection fluids.

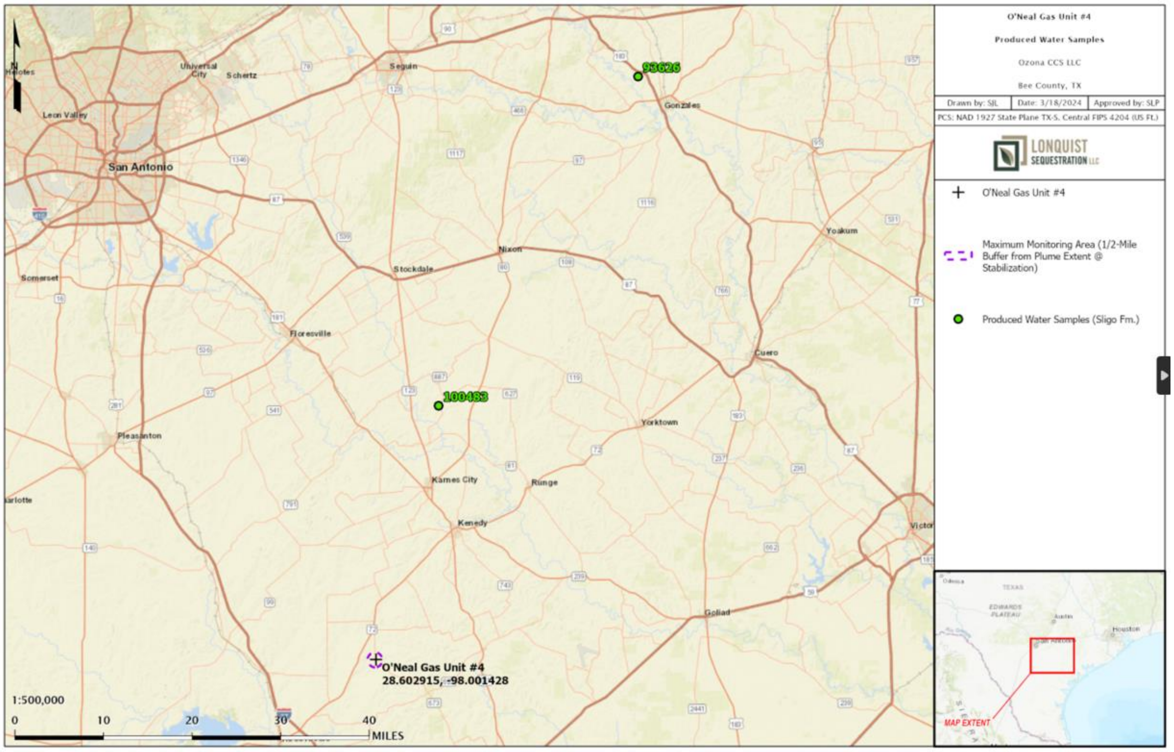

Figure 15 – Offset Wells Used for Formation Fluid Characterization

Table 2 – Analysis of Lower Cretaceous (Aptian) age formation fluids from the closest offset Sligo oil-field brine samples.

Measurement	Karnes County Sample	Gonzales County Sample	Average
Total Dissolved Solids (mg/L)	234,646	117,470	176,058
Sodium (mg/L)	51,168	27,909	39,539
Calcium (mg/L)	34,335	8,684	21,510
Chloride (mg/L)	146,500	57,811	102,156
Sample Depth (ft)	13,580 to 13,660	8,290-8,305	-
pH	5.9	8.2	7.05

2.2.5 Fracture Pressure Gradient

The fracture pressure gradient was obtained from a fracture report taken during the April 1993 completion of the Sligo interval in the O'Neal No. 4. The Sligo was perforated between the depths of 15,874 ft and 16,056 ft, with continuous monitoring during the minifrac job. The report noted a calculated fracture gradient of 0.954 psi/ft based on an initial shut-in pressure (ISIP) of 8,312 psi. A 10% safety factor was then applied to the calculated gradient, resulting in a maximum allowed bottomhole pressure of 0.86 psi/ft. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

2.2.6 Lower Confining Interval – Lower Sligo and Hosston Formations

The O'Neal No. 4 reaches its total depth in the lower Sligo Formation, directly below the upper Sligo proposed injection interval. The lower Sligo is interpreted by Bebout and others (1981) to represent the seaward extension of the low-energy lagoon and tidal-flat system of the underlying Hosston Formation, a sequence of siliciclastics, evaporites, and dolomitic mudstone (Figure 16). The Hosston to lower Sligo "contact" represents a gradational package with a decrease in terrigenous sediments, an increase in carbonate sediments, and an increase in burrows of marine organisms working up-section into the lower Sligo. The lower Sligo consists of numerous cycles of subtidal to supratidal carbonates deposited in a low-energy lagoon and tidal-flat system (Bebout et al., 1981). These low permeability facies of the lower Sligo and underlying Hosston Formation will provide lower confinement to the upper Sligo injection interval. Figure 16 illustrates the typical environmental setting for the deposition of tidal flat facies along the Lower Cretaceous margin. The type log displayed in Figure 14 (*Section 2.2.3*) illustrates that the porosity of the lower Sligo ranges between 0–2% with permeability staying close to 0 mD. Therefore, the petrophysical characteristics of the lower Sligo and Hosston are ideal for prohibiting the migration of the injection stream outside of the injection interval.

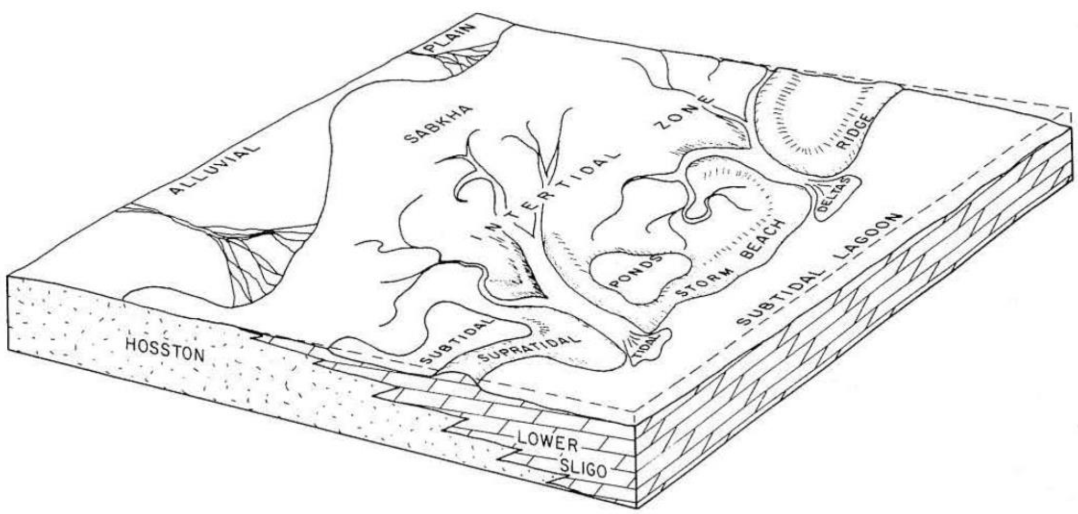

Figure 16 – Environmental Setting of Lower Cretaceous Tidal Flat Deposits (Bebout et al., 1981)

2.3 Local Structure

Structures surrounding the proposed sequestration site were influenced by regional arches, grabens, uplifts, embayments, movement of Louann Salt, and the development of carbonate reef complexes around the northern edge of the basin. However, one potential fault was identified in the literature within proximity and lies approximately 4.25 mi south-southeast of the well and

approximately 3.9 mi south-southeast of the stabilized plume extent in the year 2062 (Swanson et al., 2016). The location of these structural features can be referenced in Figures 2 and 8 relative to the location of the O'Neal No. 4.

A subsea true vertical depth (SSTVD) structure map on the top of the Sligo Formation is provided in Figure 17. The map illustrates the gentle basinward dip of the Sligo from the northwest to the southeast. The structural cross sections provided in Figures 18 and 19 (pages 28 and 29, respectively) illustrate the structural changes encountered in moving away from the O'Neal No. 4 site. The figures also demonstrate the laterally continuous nature of the Pearsall Formation that overlies the injection interval, with sufficient thickness and modeled petrophysical properties to alleviate the risk of upward migration of injected fluids. *Section 2.1.2*, discussing regional structure and faulting, presents a regional discussion pertinent to this topic.

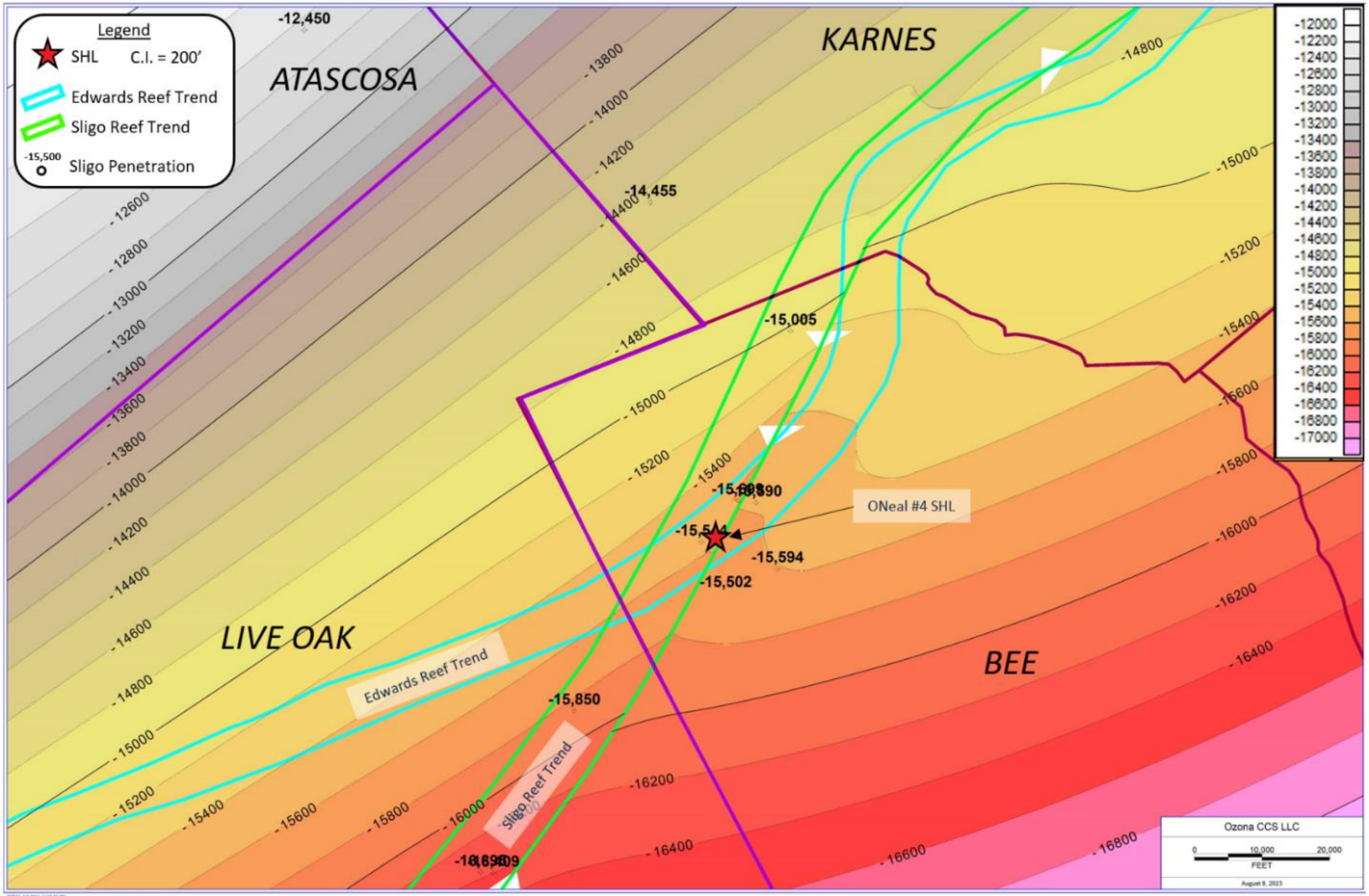

Figure 17 – Subsea Structure Map: Top of Sligo (injection interval). The red star signifies the location of the O'Neal No. 4.

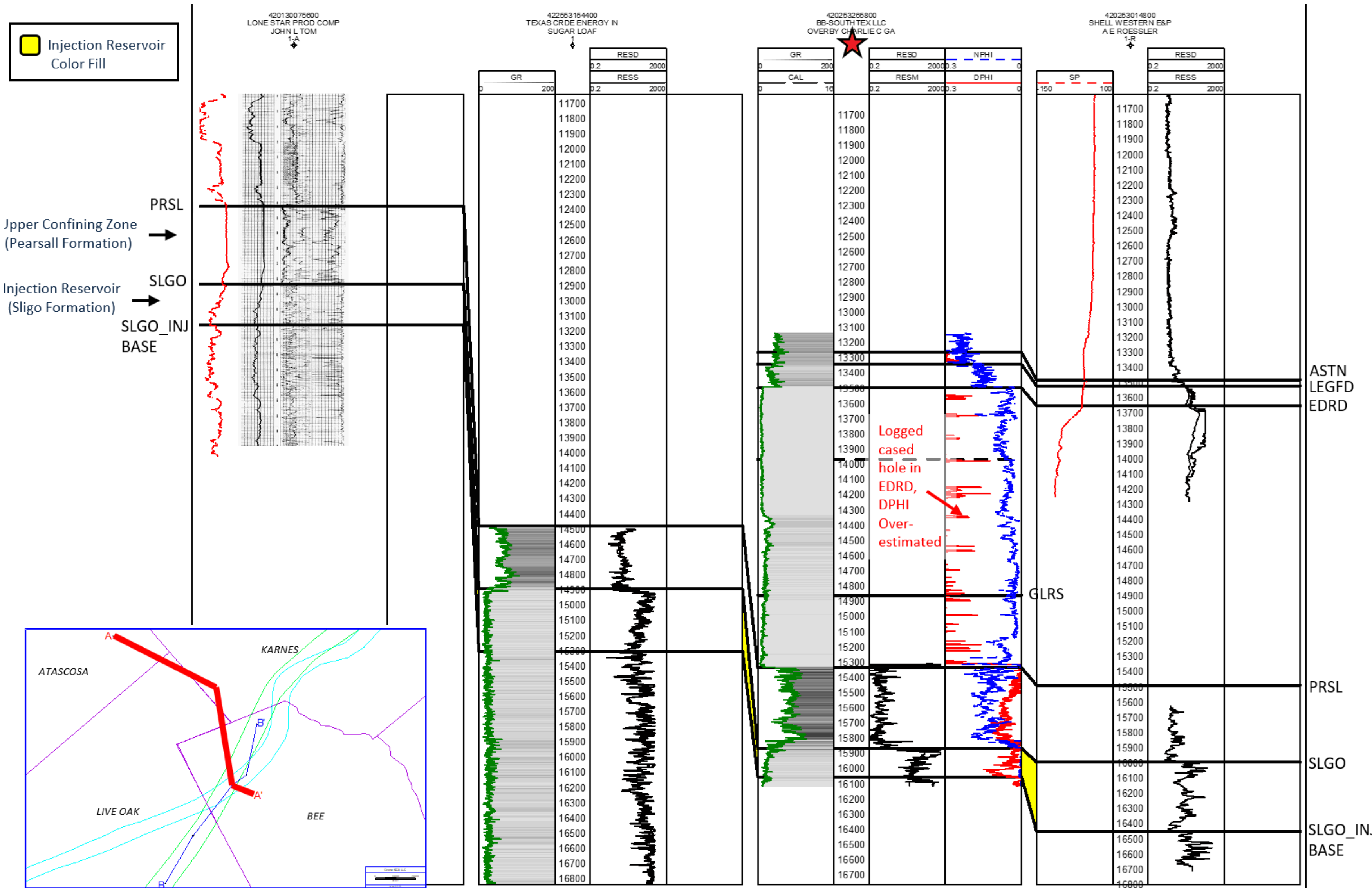

Figure 18 – Northwest to southeast structural cross section: A-A' Oriented along regional dip.
The red star signifies the location of the O'Neal No. 4, with the section line depicted in red on the locator map.

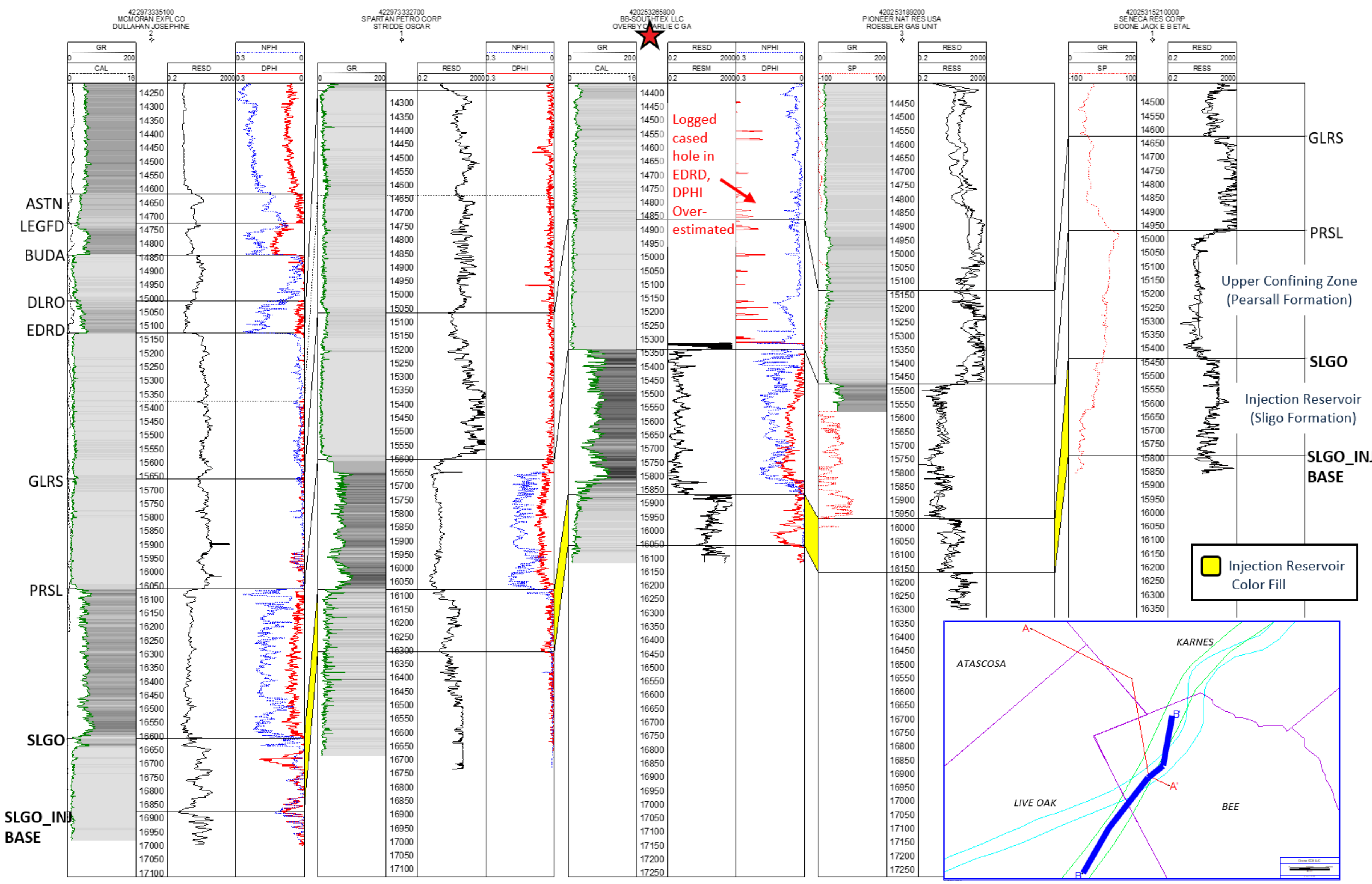

Figure 19 – Southwest to northeast structural cross section: B-B' oriented along regional strike.
The red star signifies the location of the O'Neal No. 4, with the section line depicted in blue on the locator map.

2.4 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Sligo Formation at the O'Neal No. 4 well location indicate that the reservoir contains the necessary thickness, porosity, and permeability to receive the proposed injection stream. The overlying Pearsall Formation is regionally extensive at the O'Neal No. 4 with low permeability and sufficient thickness to serve as the upper confining interval. Beneath the injection interval, the low permeability, low porosity facies tidal flat, and lagoonal facies of the lower Sligo and underlying Hosston Formation are unsuitable for fluid migration and serve as the lower confining interval.

2.5 Groundwater Hydrology

Bee County falls within the boundary of the Bee Groundwater Conservation District. Only one aquifer is identified by the Texas Water Development Board's Texas Aquifers Study near the O'Neal No. 4 well location, the unconfined to semi-confined Gulf Coast aquifer. The Gulf Coast aquifer parallels the Gulf of Mexico and extends across the state of Texas from the Mexican border to the border of Louisiana (Bruun et al., 2016). The extents of the Gulf Coast aquifer are provided in Figure 20 for reference.

The Gulf Coast aquifer is a major aquifer system comprised of several individual aquifers: the Jasper, Evangeline, and Chicot. These aquifers are composed of discontinuous clay, silt, sand, and gravel beds that range from Miocene to Holocene in age (Figure 21, page 32). Numerous interbedded lenses and layers of silt and clay are present within the aquifers, which can confine individual aquifers locally. The underlying Oligocene Catahoula tuff represents the lower confining interval, but it should be noted that the formation is prone to leaking along the base of the aquifer. However, the Burkeville confining interval provides isolation between Jasper and Evangeline aquifers which helps protect the shallower Evangeline and Chicot Aquifers (Bruun et al., 2016).

The schematic cross section provided in Figure 22 (page 32) runs south of the O'Neal No. 4, illustrating the structure and stratigraphy of the aquifer system. The thickness of individual sedimentary units within the Cenozoic section tends to thicken towards the Gulf of Mexico due to the presence of growth faults that allow additional loading of unconsolidated sediment. The total net sand thickness of the aquifer system ranges between 700 ft of sand in the south, to over 1,300 ft in the north, with the saturated freshwater thickness averaging 1,000 ft.

The water quality of the aquifer system varies with depth and locality but water quality generally improves towards the central to northeastern portions of the aquifer where TDS values are less than 500 milligrams per liter (mg/L). The salinity of the Gulf Coast aquifer increases to the south, where TDS ranges between 1,000 mg/L to more than 10,000 mg/L. The Texas Water Development Board's Texas Aquifers Study (2016) suggests that areas associated with higher salinities are possibly associated with saltwater intrusion likely "resulting from groundwater pumping or to brine migration in response to oil field operations and natural flows from salt domes intruding into the aquifer" (Bruun et al., 2016).

According to the TDS map of the Gulf Coast aquifer (Figure 23), the TDS in northern Bee County range between 500–3,000 mg/L near the O'Neal No. 4, categorizing the aquifer as fresh to slightly saline.

The TRRC's Groundwater Advisory Unit (GAU) identified the Base of Useable Quality water (BUQW) at a depth of 250 ft and the base of the USDW at a depth of 950 ft at the location of the O'Neal No. 4. Approximately 14,924 ft is therefore separating the base of the USDW and the injection interval. (A copy of the GAU's Groundwater Protection Determination letter issued by the TRRC as part of the Class II permitting process for the O'Neal No. 4 is provided in Exhibit A-1.) The base of the deepest aquifer is separated from the injection interval by more than 14,924 ft of rock, including 4,200 feet of Midway shale. Though unlikely for reasons outlined in the sections here on confinement and potential leaks, if the migration of injected fluid did occur above the Pearsall Formation, thousands of feet of tight sandstone, limestone, shale, and anhydrite beds occur between the injection interval and the lowest water-bearing aquifer.

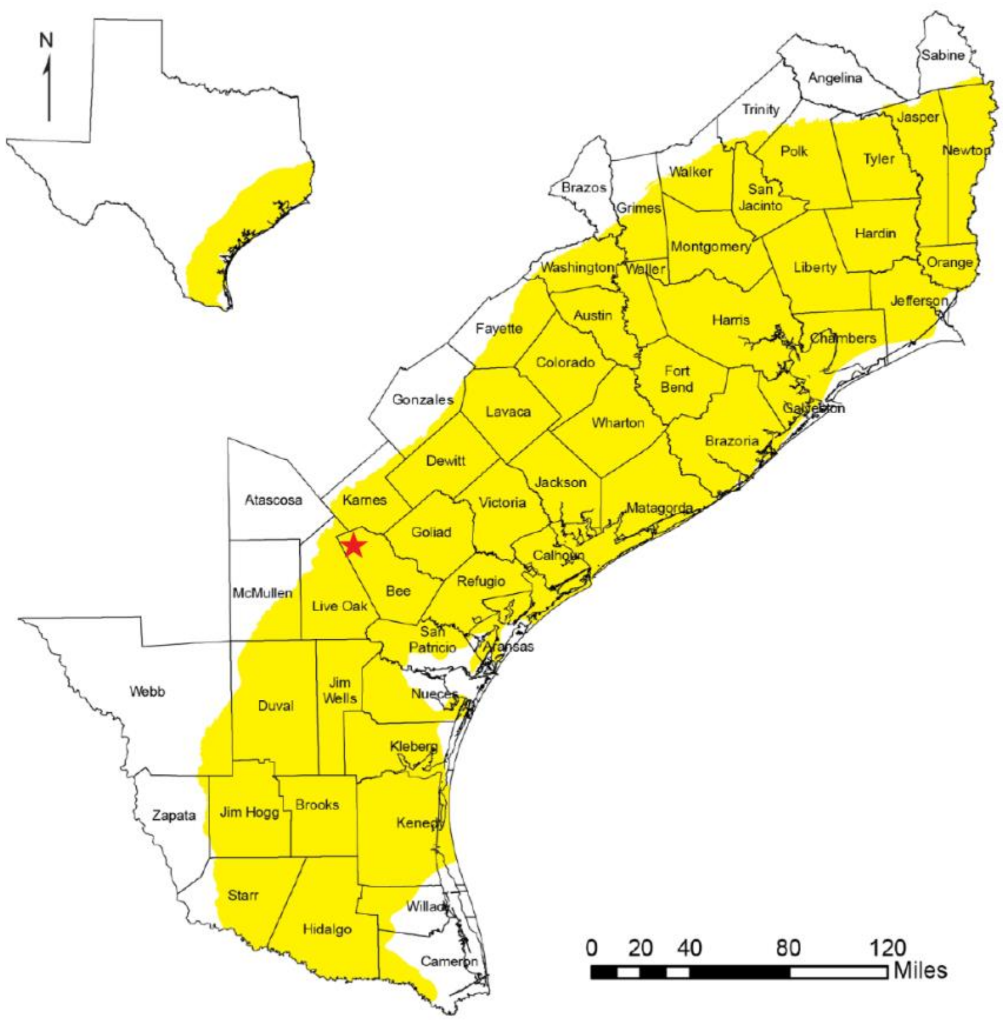

Figure 20 – Extent of the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun, B., et al., 2016)

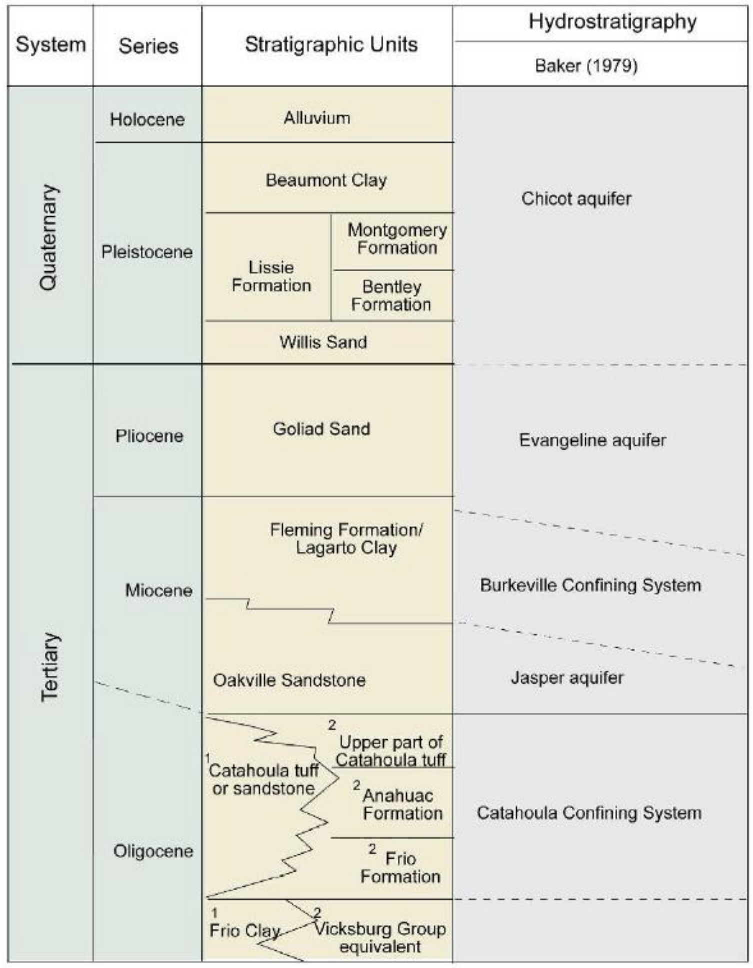

Figure 21 – Stratigraphic Column of the Gulf Coast Aquifer (Chowdhury and Turco, 2006)

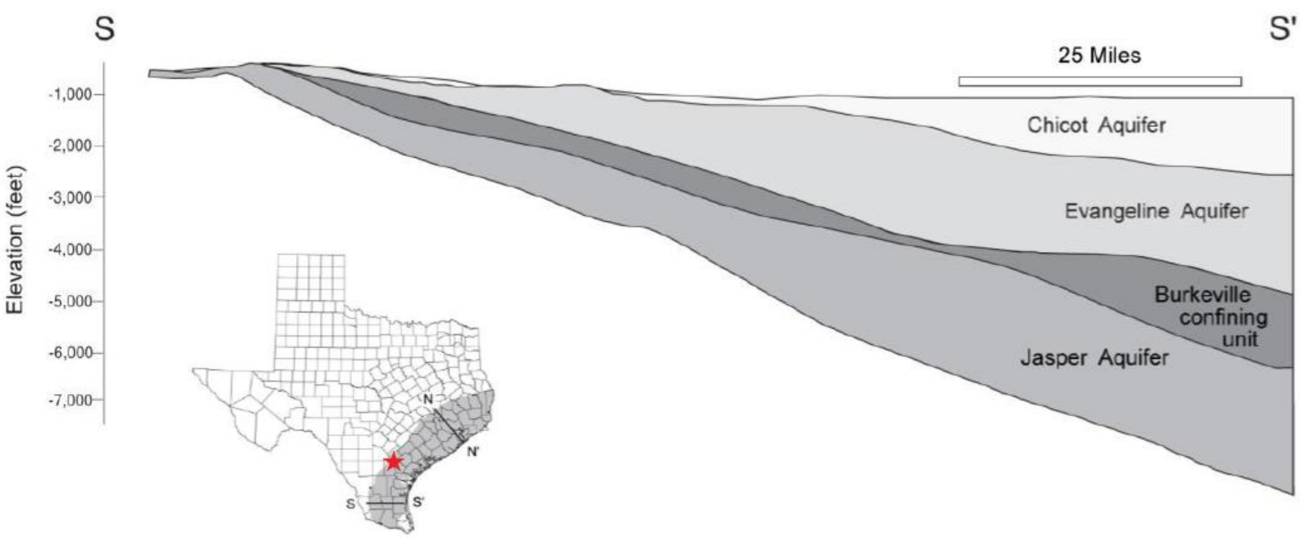

Figure 22 – Cross Section S-S' Across the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun et al., 2016)

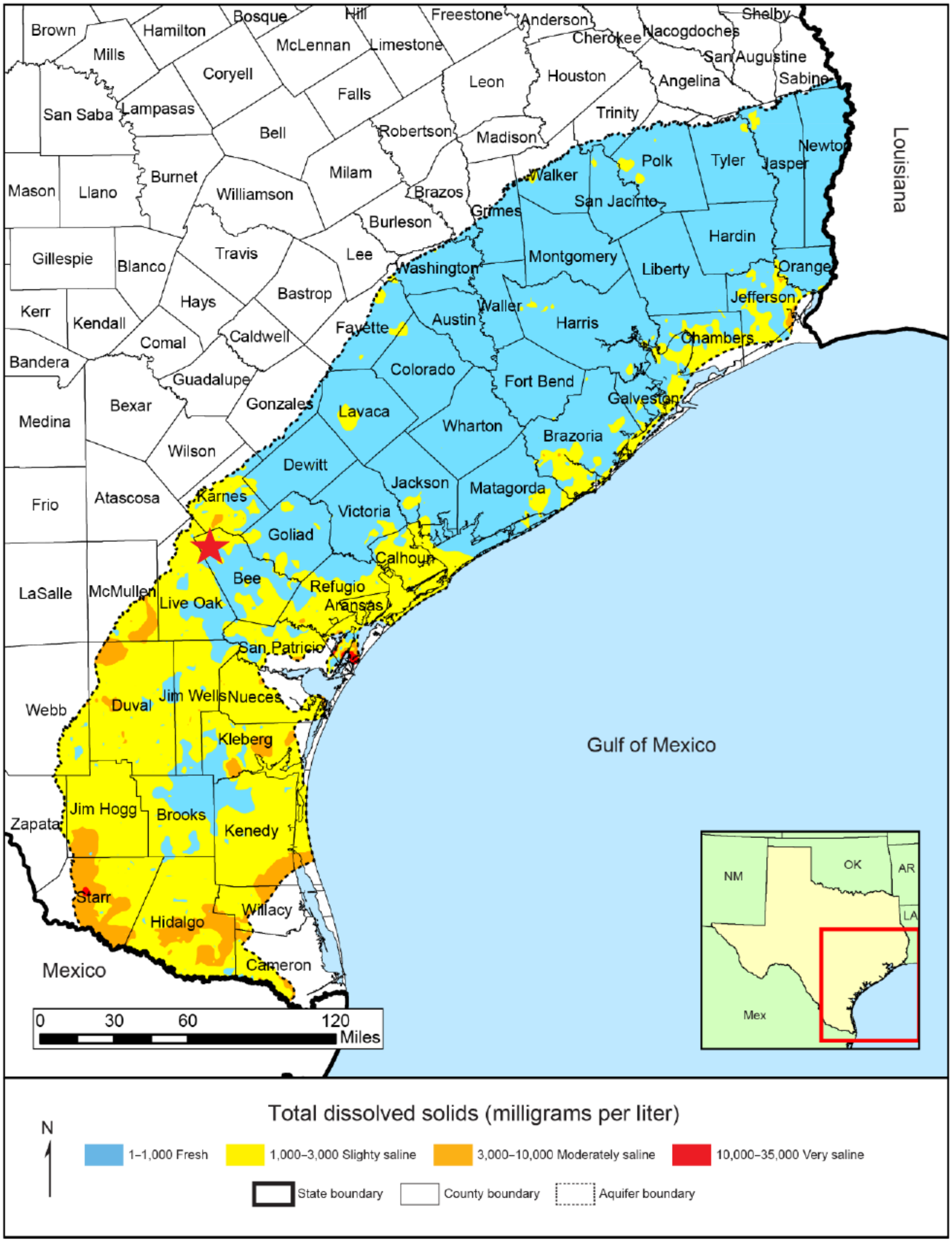

Figure 23 – Total Dissolved Solids (TDS) in the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun et al., 2016).

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2.7 Description of the Injection Process

2.7.1 Current Operations

The Pawnee Treating Facility and the O'Neal No. 4 are existing operating assets. The O'Neal No. 4 will be recompleted for acid gas injection service under the Class II permit process. Under the Class II application, the maximum injection rate is 28 MT/yr (1.5 MMscf/d). The TAG is 98.2% CO_2, which equates to 27.5 MT/yr of CO_2 each year. The current composition of the TAG stream is displayed in Table 3.

Table 3 – Gas Composition

Component	Mol Percent
Carbon Dioxide	98.2%
Hydrocarbons	1.03%
Hydrogen Sulfide	0.4%
Nitrogen	0.37%

The facility is designed to treat, dehydrate, and compress the natural gas produced from the surrounding acreage in Bee County. The facility uses an amine unit to remove the CO_2 and other constituents from the gas stream. The TAG stream is then dehydrated, compressed, and routed directly to the O'Neal No. 4 for injection. The remaining gas stream is processed to separate the natural gas liquids from the natural gas. The facility is monitored 24 hours per day, 7 days per week.

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group, Ltd.'s GEM 2023.2 (GEM) simulator, one of the most comprehensive reservoir simulation software packages for conventional, unconventional, and secondary recovery. The GEM utilizes equation-of-state (EOS) algorithms in conjunction with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics. This results in the creation of exceedingly precise and dependable simulation models for carbon injection and storage. The GEM model holds recognition from the EPA for its application in the delineation modeling aspect of the area of review, as outlined in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Sligo Formation serves as the target formation for the O'Neal No. 4 (API No. 42-025-32658). The Petra software package was utilized to construct the geological model for this target formation. Within Petra, formation top contours were generated and subsequently brought into GEM to outline the geological structure.

Porosity and permeability estimates were determined using the porosity log from the O'Neal No. 4. A petrophysical analysis was then conducted to establish a correlation between porosity values and permeability, employing the Coates equation. Both the porosity and permeability estimates from

the O'Neal No. 4 were incorporated into the model, with the assumption that they exhibit lateral homogeneity throughout the reservoir.

The reservoir is assumed to be at hydrostatic equilibrium. Given the geological formation in which this well is located and its previous history as a gas producer, the model is assumed to be primarily saturated with gas. More precisely, the reservoir is assumed to be 80% gas saturated and 20% brine saturated, as deduced from the well log data. The modeled injection interval exhibits an average permeability of 0.23 mD and an average porosity of 5%. All layers within the model have been perforated. An infinite-acting reservoir has been created to simulate the boundary conditions.

The gas injectate is composed predominantly of CO_2 as shown in Table 4. The modeled composition takes into consideration the carbon dioxide and other constituents of the total stream. As the facility has been in operation for many years, the gas composition for the proposed injection period is expected to remain constant.

Table 4 – Modeled Injectate Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Carbon Dioxide (CO_2)	98.2	98.2
Hydrocarbons	1.03	Hydrocarbons
Hydrogen Sulfide	0.4	Hydrogen Sulfide
Nitrogen	0.37	Nitrogen

Core data from the literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Sligo carbonates (Bennion and Bachu, 2010). A maximum residual gas saturation of 35% was assigned to the model based on core from the literature review. The Corey-Brooks method was used to create relative permeability curves. The key inputs used to create the relative permeability curves in the model include a Corey exponent for brine of 1.8, a Corey exponent for gas of 2.5, brine and gas relative permeability endpoints of 0.8 and 0.5, respectively, and an irreducible brine saturation of 20%. The relative permeability curves used for the GEM model are shown in Figure 24.

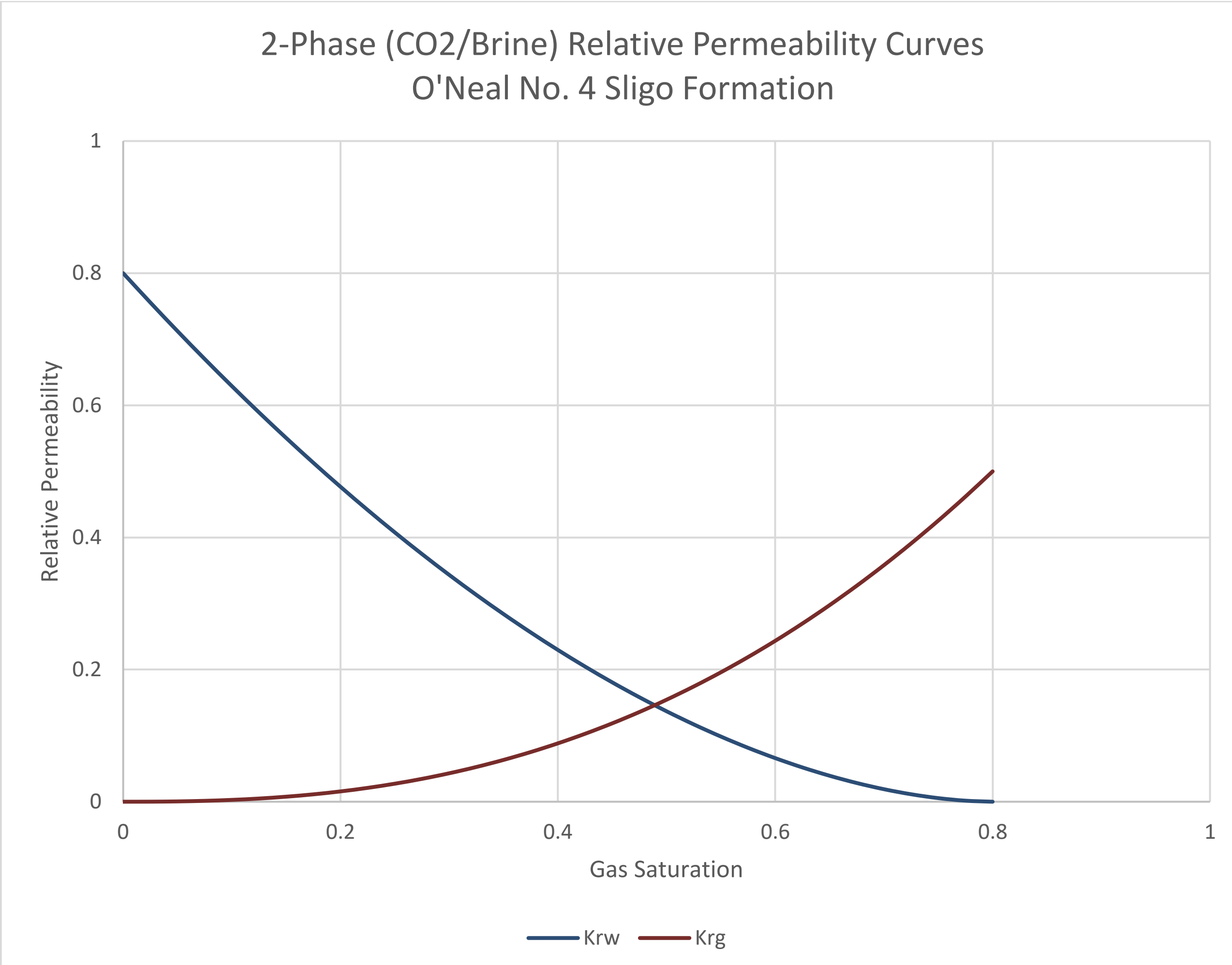


Figure 24 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 81 blocks in the x-direction (east-west) and 81 blocks in the y-direction (north-south), resulting in a total of 6,561 grid blocks per layer. Each grid block spans dimensions of 250 ft x 250 ft. This configuration yields a grid size measuring 20,250 ft x 20,250 ft, equating to just under 15 square miles in area. The grid cells in the vicinity of the O'Neal No. 4, within a radius of 0.5 mi, have been refined to dimensions of 83.333 ft x 83.333 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume and pressure effects near the wellbore.

In the model, each layer is characterized by homogeneous permeability and porosity values. These values are derived from the porosity log of the O'Neal No. 4. The model encompasses a total of 61 layers, each featuring a thickness of approximately 3 ft per layer. As previously mentioned, the model is perforated in each layer, with the top layer being the top of the injection interval and the bottom layer being the lowest portion of the injection interval. The summarized property values for each of these packages are displayed in Table 5.

Table 5 – GEM Model Layer Package Properties

Layer No.	Top (TVD ft)	Thickness	Perm. (mD)	Porosity (%)
1	15,874	3	0.004	3.75%
2	15,877	3	0.002	2.98%
3	15,880	3	0.001	1.62%
4	15,883	3	0.001	1.78%
5	15,886	3	0.002	2.32%
6	15,889	3	0.001	1.96%
7	15,892	3	0.002	3.10%
8	15,895	3	0.002	2.99%
9	15,898	3	0.003	3.52%
10	15,901	3	0.006	4.00%
11	15,904	3	0.005	3.93%
12	15,907	3	0.001	2.15%
13	15,910	3	0.001	1.99%
14	15,913	3	0.002	2.97%
15	15,916	3	0.001	2.22%
16	15,919	3	0.002	2.88%
17	15,922	3	0.001	2.38%
18	15,925	3	0.093	6.68%
19	15,928	3	0.005	2.62%
20	15,931	3	0.002	2.58%
21	15,934	3	0.003	3.07%
22	15,937	3	0.006	3.62%
23	15,940	3	0.002	2.68%
24	15,943	3	0.001	1.08%
25	15,946	3	0.002	1.87%
26	15,949	3	0.025	4.70%
27	15,952	3	0.024	4.37%
28	15,955	3	0.001	1.97%
29	15,958	3	0.003	2.27%
30	15,961	3	0.007	3.09%
31	15,964	3	0.110	6.75%
32	15,967	3	0.037	5.62%
33	15,970	3	0.011	4.41%
34	15,973	3	0.022	4.59%
35	15,976	3	0.297	7.88%
36	15,979	3	0.440	9.21%
37	15,982	3	0.060	5.90%
38	15,985	3	0.001	2.22%
39	15,988	3	0.001	2.21%

Layer No.	Top (TVD ft)	Thickness	Perm. (mD)	Porosity (%)
40	15,991	3	0.001	1.12%
41	15,994	3	0.003	2.05%
42	15,997	3	0.014	4.56%
43	16,000	3	0.007	4.15%
44	16,003	3	0.033	5.95%
45	16,006	3	1.233	10.25%
46	16,009	3	1.476	12.04%
47	16,012	3	0.566	10.08%
48	16,015	3	1.679	12.18%
49	16,018	3	2.194	13.08%
50	16,021	3	1.235	12.02%
51	16,024	3	0.788	11.22%
52	16,027	3	0.944	10.48%
53	16,030	3	0.424	9.05%
54	16,033	3	0.378	8.85%
55	16,036	3	0.378	8.81%
56	16,039	3	0.378	8.84%
57	16,042	3	0.736	9.91%
58	16,045	3	0.232	7.94%
59	16,048	3	0.238	7.97%
60	16,051	3	0.012	3.01%
61	16,054	3	0.038	4.30%

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

1. Estimate the maximum areal extent and density drift of the injectate plume after injection.
2. Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone.
3. Assess the likelihood of the injectate plume migrating into potential leak pathways.

The reservoir is assumed to have an irreducible brine saturation of 20%. The salinity of the brine within the formation is estimated to be 150,000 ppm (USGS National Produced Waters Geochemical Database, Ver. 2.3), typical for the region and formation. The injectate stream is primarily composed of CO_2 and H_2S as stated previously. Core data from the literature was used to help generate relative permeability curves. From the literature review, also as previously discussed, cores that most closely represent the carbonate rock formation of the Sligo seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low, conservative residual gas saturation based on the cores from the literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975).

The model is initialized with a reference pressure of 10,995 psig at a subsea depth of 15,740 ft. This, when a Kelly Bushing "KB" elevation of 334 ft is considered, correlates to a gradient of 0.684 psi/ft. This pressure gradient was determined from production data of the O'Neal No. 4. An initial reservoir pressure of 0.76 psi/ft was calculated before initial production. However, in 1997, after producing approximately 0.5 billion cubic feet (Bcf) of gas, the well was shut in. The last bottomhole pressure reading was calculated to be 0.480 psi/ft. This assumes the reservoir repressurizes after production ceases, but not fully back to in situ conditions. Therefore, a 10% safety factor was given to the initial reservoir pressure gradient of 0.76 psi/ft, and a gradient of 0.684 psi/ft was implemented into the model as a conservative estimate. A skin factor of -2 was applied to the well to simulate the stimulation of the O'Neal No. 4 for gas production from the Sligo Formation, which is based on the acid fracture report, provided in *Appendix A-3*.

The fracture gradient of the injection zone was estimated to be 0.954 psi/ft, which was determined from the acid fracture report. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.86 psi/ft, which is equivalent to 13,652 psig at the top of the Sligo injection interval.

The model, which begins in January 2025, runs for a total of 22 years, comprising 12 years of active injection, and is then succeeded by 10 years of density drift. Throughout the entire 12-year injection period, an injection rate of 1.5 MMscf/D is used to model the maximum available rate, yielding the largest estimate of the plume size. After the 12-year injection period, when the O'Neal No. 4 ceases injection, the density drift of the plume continues until the plume stabilizes 10 years later. The maximum plume extent during the 12-year injection period is shown in Figure 25. The final extent after 10 years of density drift after injection ceases is shown in Figure 26 (page 42).

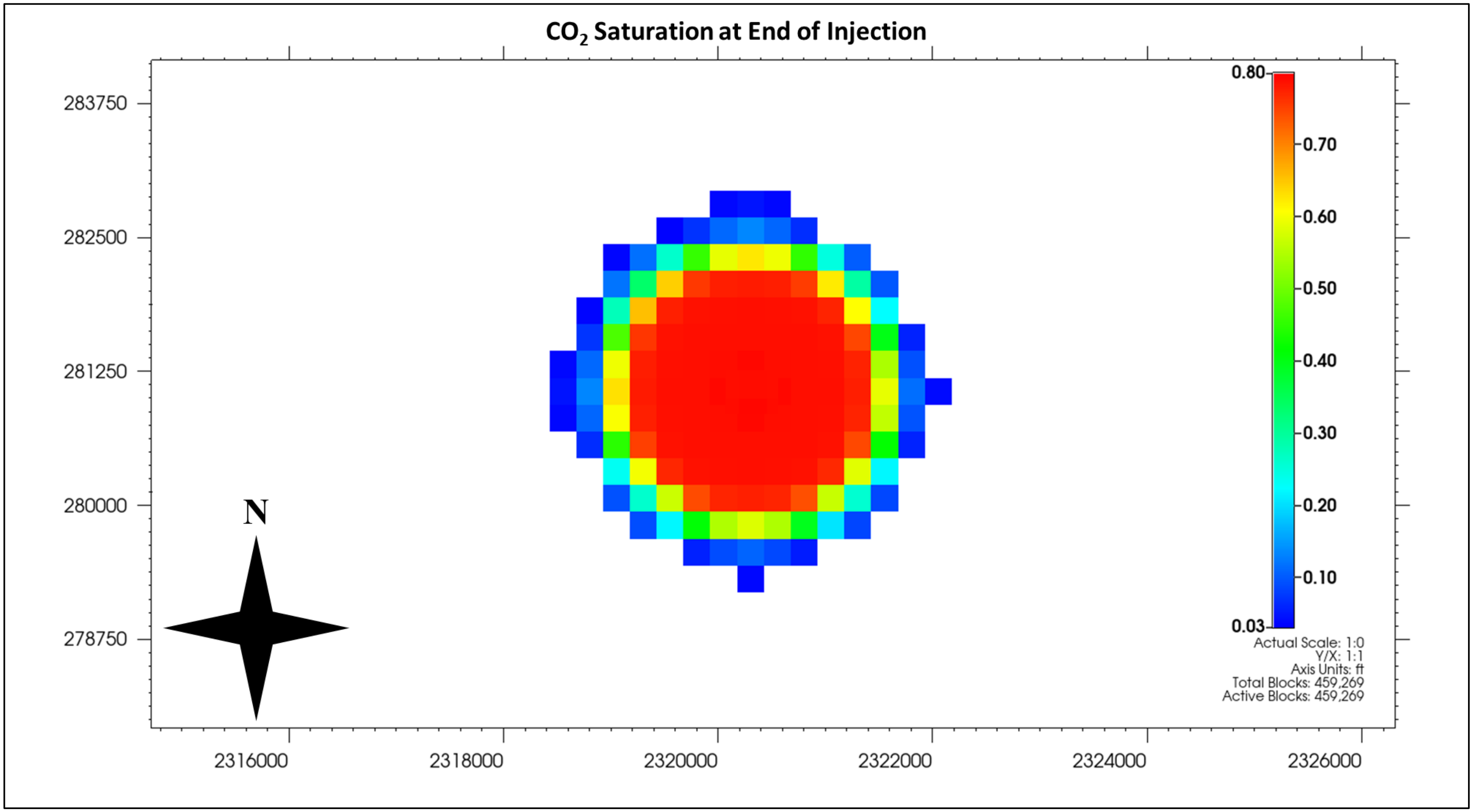


Figure 25 – Areal View of Saturation Plume at Shut-in (End of Injection)

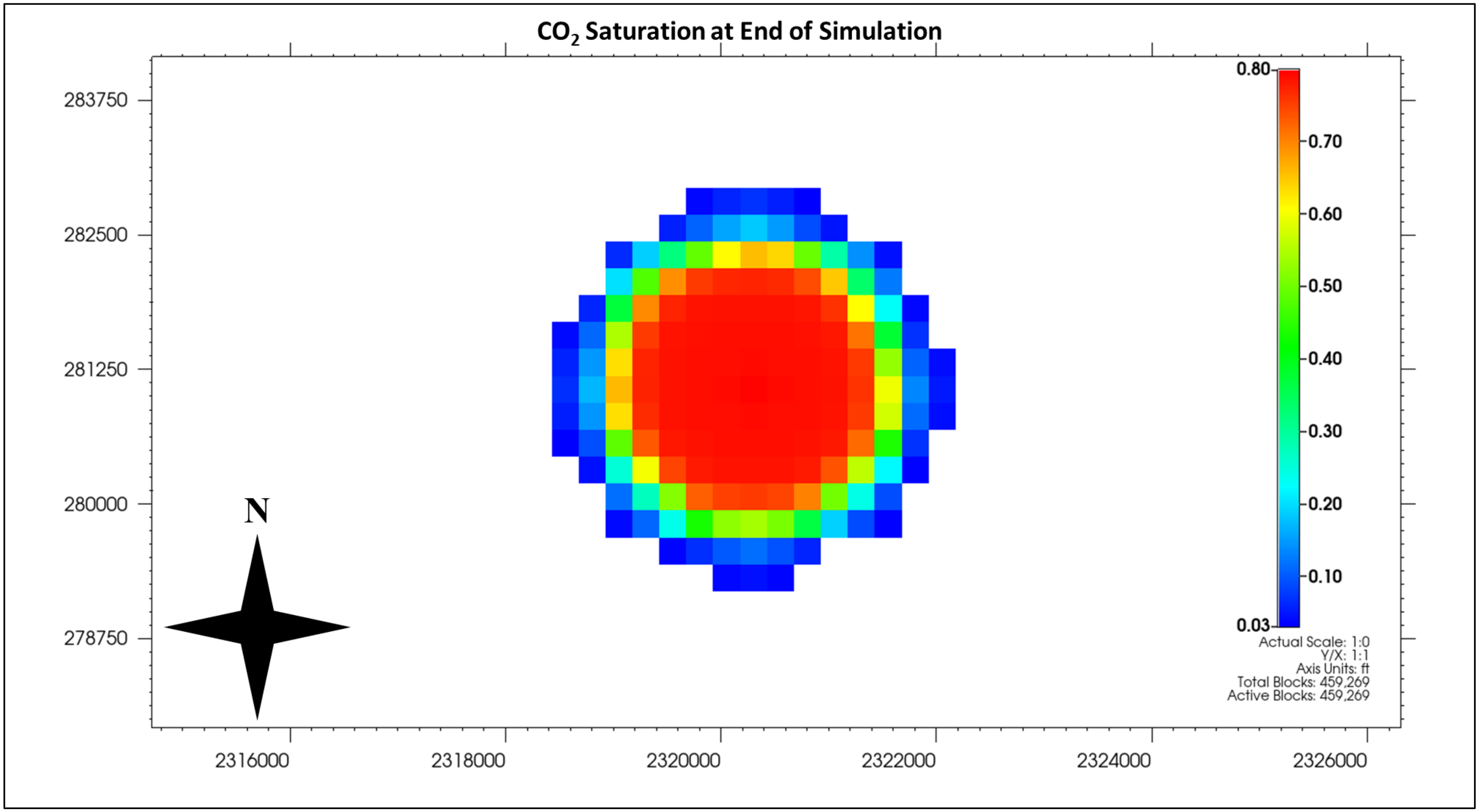


Figure 26 – Areal View of Gas Saturation Plume 10 Years After Shut-in (End of Simulation)

The cross-sectional view of the O'Neal No. 4 shows the extent of the plume from a side-view angle, cutting through the formation at the wellbore. Figure 27 shows the maximum plume extent during the 12-year injection period. During this time, gas from the injection well is injected into the permeable layers of the formation and predominantly travels laterally. Figure 28 (page 45) shows the final extent of the plume after 10 years of migration. Then, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 35% of injected gas that travels into each grid cell is trapped, as the gas travels mostly vertically—as it is less dense than the formation brine—until an impermeable layer is reached. Both figures are shown in an east-to-west view.

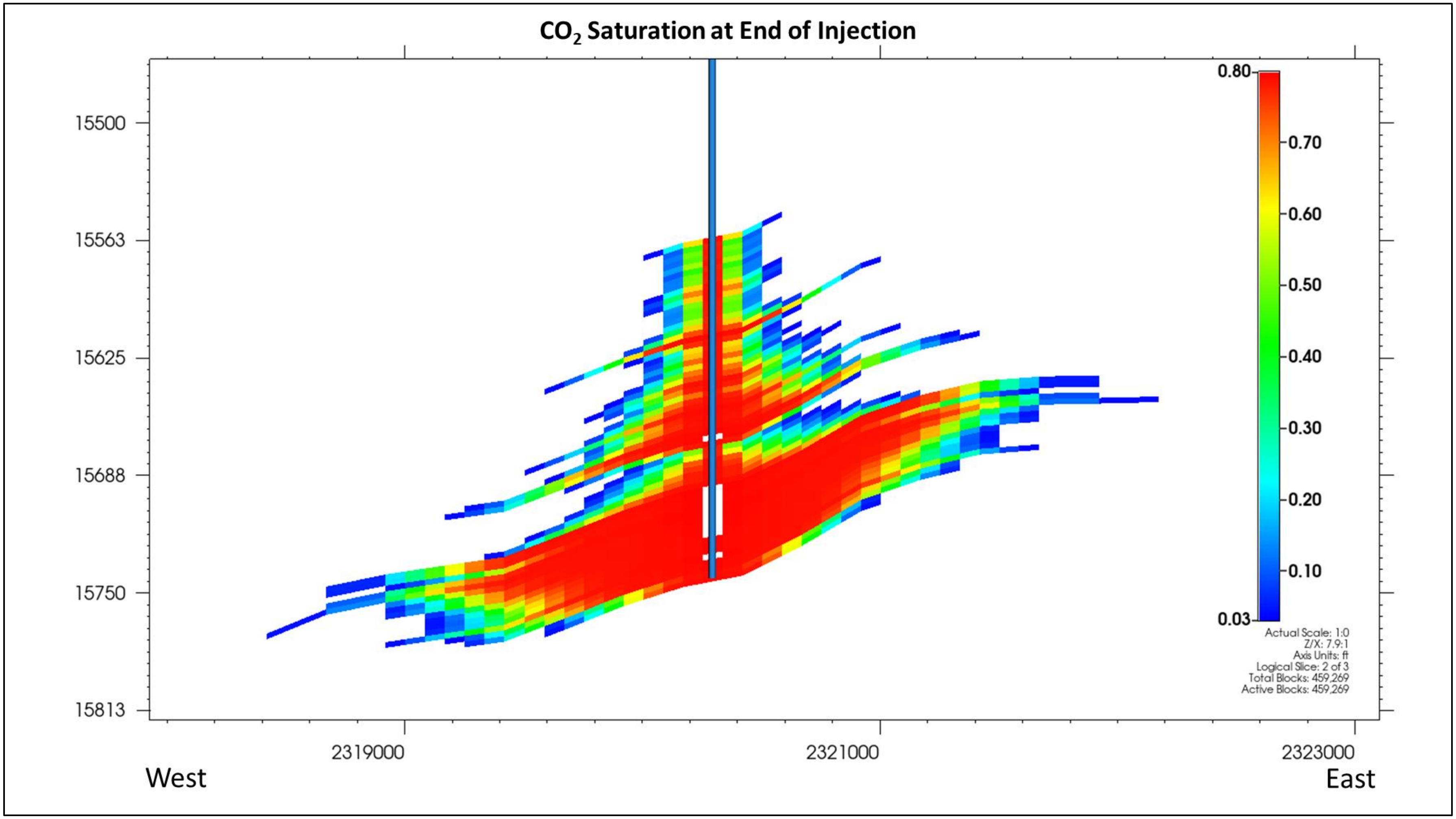


Figure 27 – East-West Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)

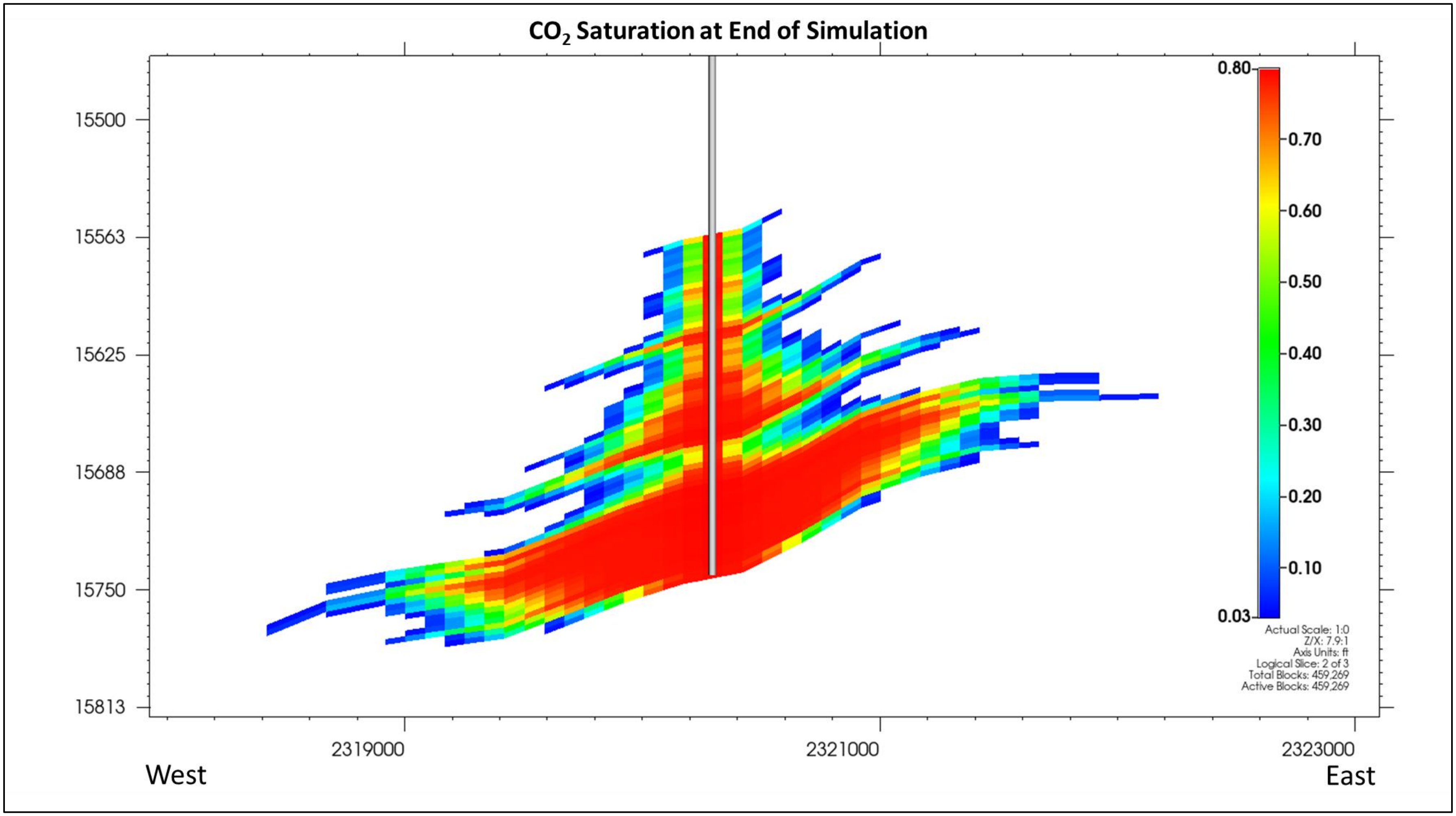


Figure 28 –East-West Cross-Sectional View of Gas Saturation Plume 10 Years After Shut-in (End of Simulation)

Figure 29 shows the surface injection rate, bottom hole pressures, and surface pressures over the injection period—and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate ends, reaching a maximum pressure of 13,337 psig, at the end of injection. This buildup of 2,362 psig keeps the bottomhole pressure below the fracture pressure of 13,652 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 6,095 psig, well below the maximum allowable 7,937 psig per the TRRC UIC permit application for this well. Bottomhole and wellhead pressures are provided in Table 6.

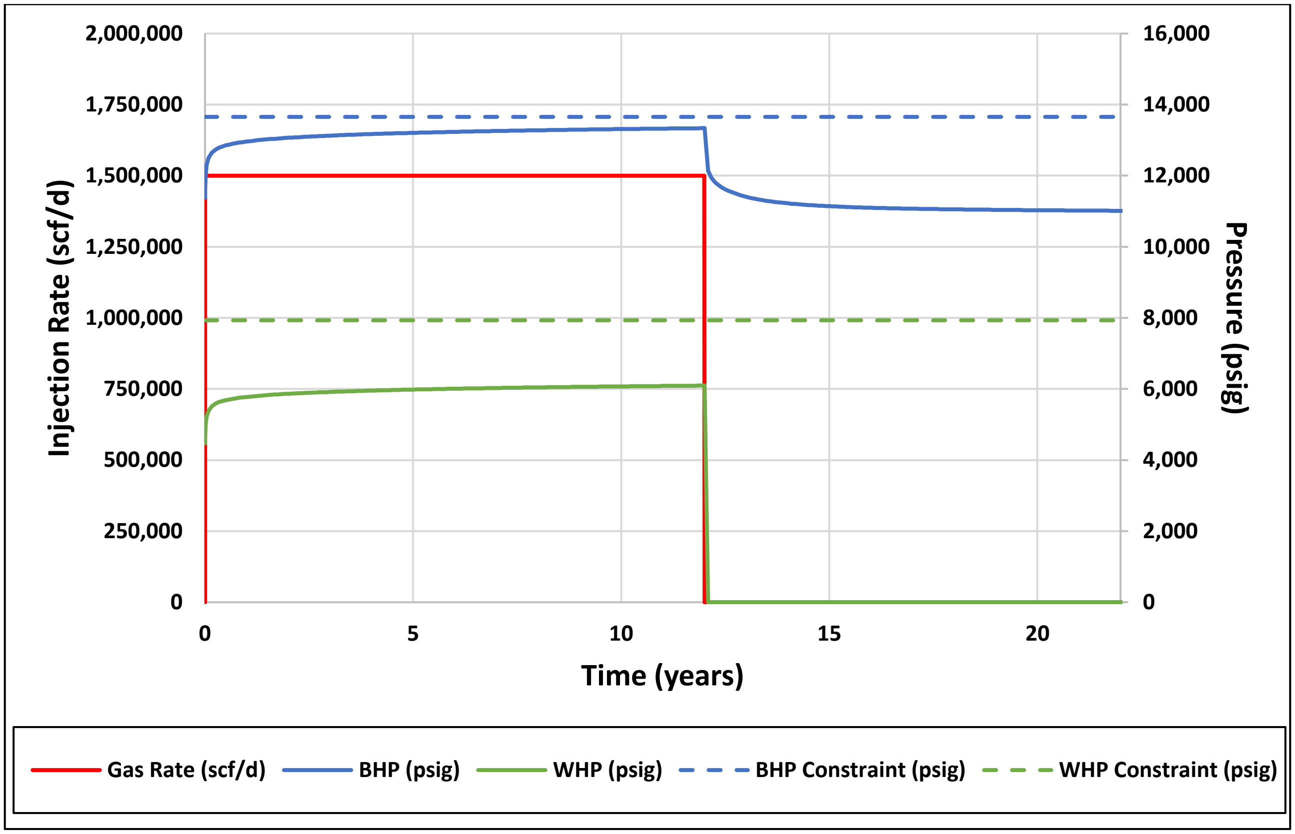


Figure 29 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 6 – Bottomhole and Wellhead Pressures from the Start of Injection

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	10,975	-
10	13,311	6,073
12 (End of Inj.)	13,337	6,095
20	11,029	-
22 (End of Model)	11,013	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in 40 CFR **§98.448(a)(1)**.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the plume has stabilized, plus an all-around buffer zone of at least one half mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

- Offset well logs to estimate geologic properties
- Petrophysical analysis to calculate the heterogeneity of the rock
- Geological interpretations to determine faulting and geologic structure
- Offset injection history to predict the density drift of the plume adequately

Ozona's expected gas composition was used in the model. The injectate is estimated at a molar composition of 98.2% CO_2 and 1.8% of other constituents. The StarTex Pawnee Treating Facility has been in stable operations for many years. Ozona believes the gas analysis provided in Table 1 is an accurate representation of the injectate. In the future, if the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be submitted to the GHGRP. As discussed in *Section 2*, the gas will be injected into the Sligo Formation. The geomodel was created based on the rock properties of the Sligo.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 12, the area expanse of the plume will be approximately 270 acres. The maximum distance between the wellbore and the edge of the plume is approximately 0.42 mi to the west. After 10 additional years of density drift, the areal extent of the plume is 303 acres with a maximum distance to the edge of the plume of approximately 0.45 mi to the west. Since the plume shape is relatively circular, the maximum distance from the injection well after density drift was used to define the circular boundary of the MMA. The AMA and the MMA have similar areas of influence, with the AMA being only marginally smaller than the MMA. Therefore, Ozona will set the AMA equal to the MMA as the basis for the area extent of the monitoring program.

This is shown in Figure 30 with the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA boundary represents the stabilized plume boundary after 10 years of density drift plus an all-around buffer zone of one half mile.

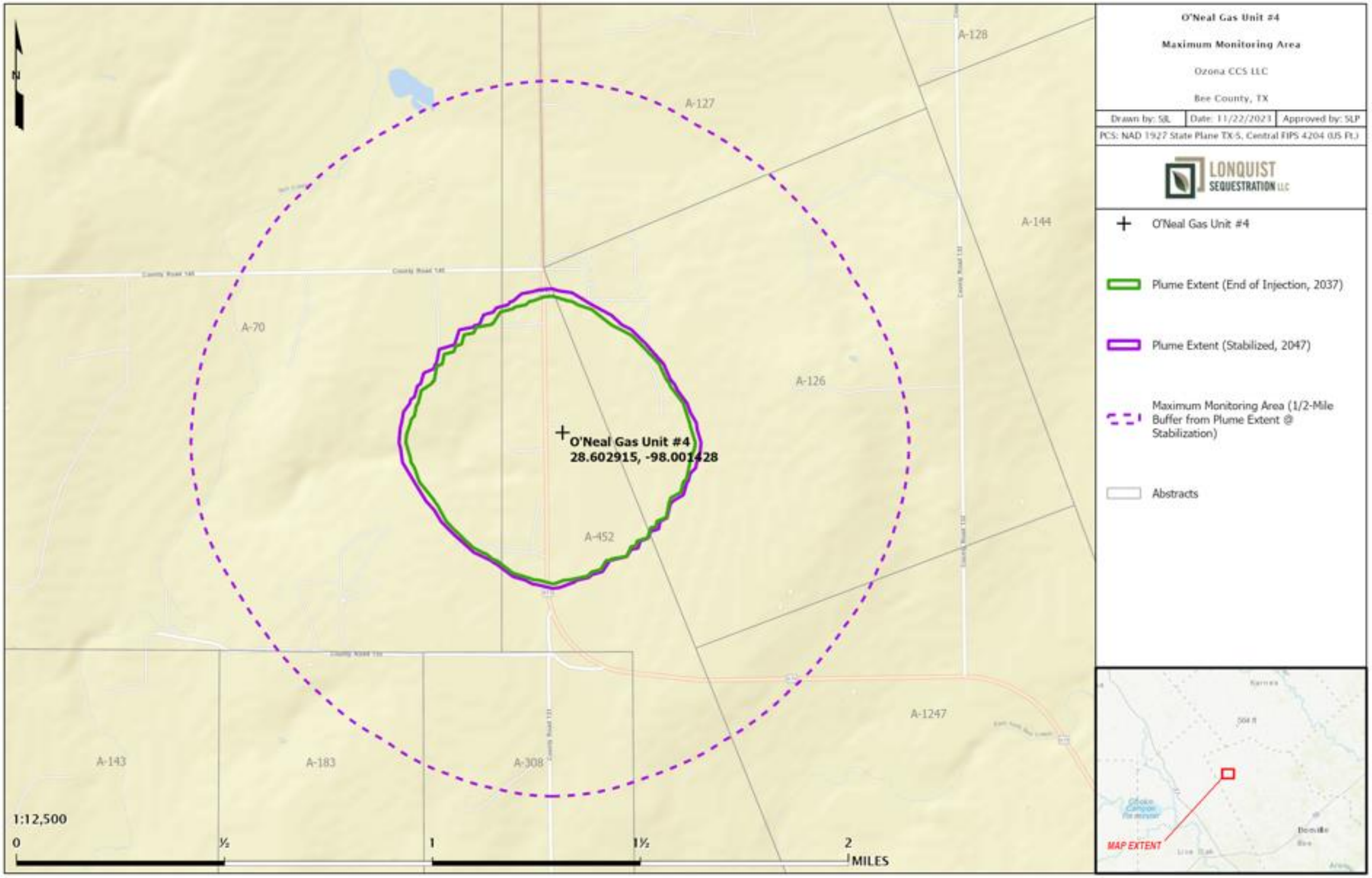


Figure 30 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The AMA was initially set equal to the expected total injection period of 12-years. The AMA was analyzed by superimposing the area based on a one-half mile buffer around the anticipated plume location after 12 years of injection (2037), with the area of the projected free-phase CO_2 plume at five additional years (2042). In this case, as shown in Figure 31, the plume boundary in 2042 is within the plume in 2037 plus the one-half mile buffer. Since the AMA boundary is only slightly smaller than the MMA boundary, Ozona will define the AMA to be equal to the MMA. By 2037, Ozona will submit a revised MRV plan to provide an updated AMA and MMA.

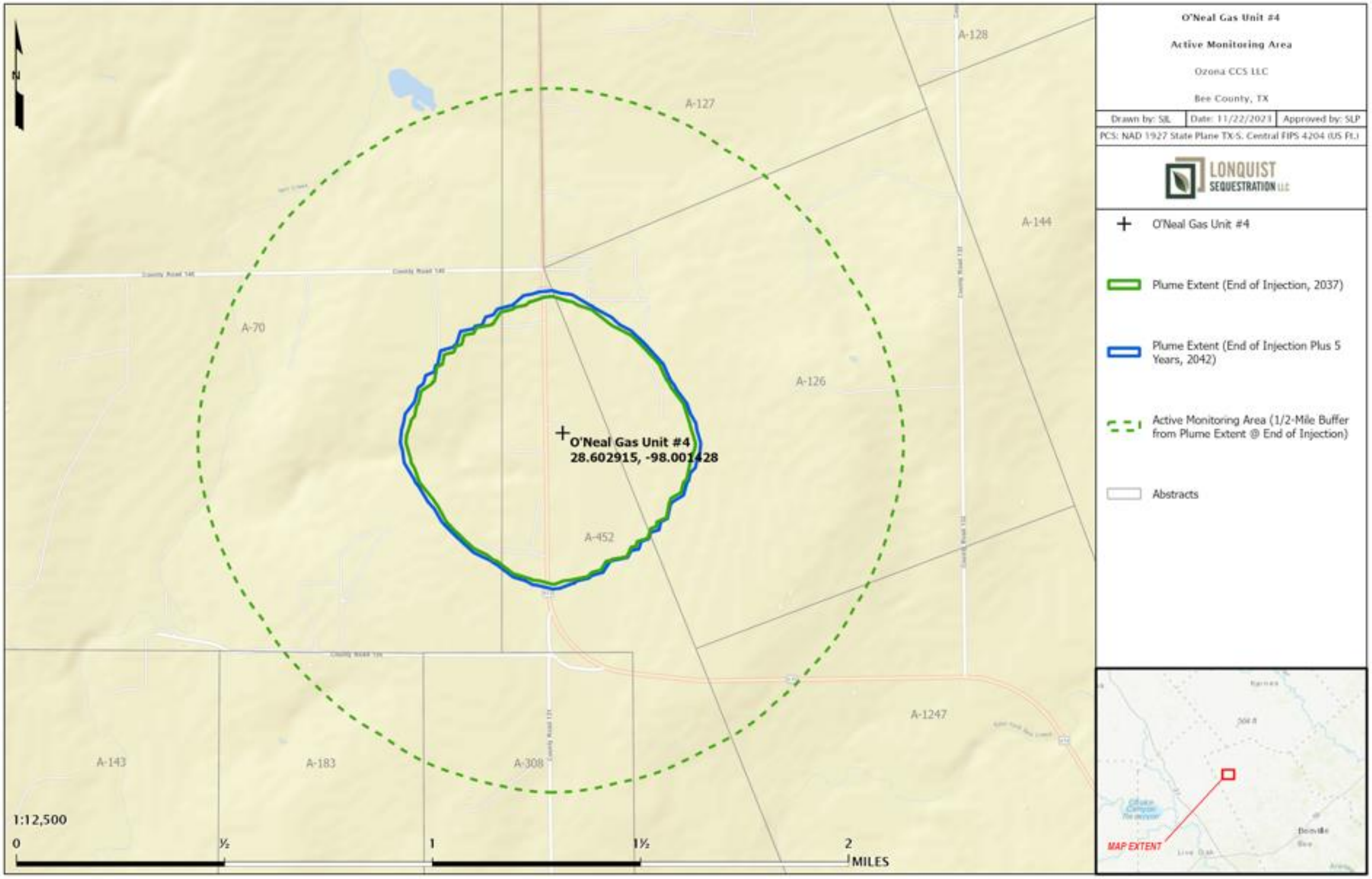


Figure 31 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies and discusses the potential pathways within the MMA for CO_2 to reach the surface and is summarized in Table 7. Also included are the likelihood, magnitude, and timing of such potential leakage. The potential leakage pathways are:

- Surface equipment
- Existing wells within the MMA
- Faults and fractures
- Upper confining layer
- Natural or induced seismicity

Table 7 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood		Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. One artificial penetration was drilled into the injection interval. This well has been properly plugged and abandoned.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Faults and fractures	Unlikely. There is over 14,000 ft of impermeable rock between the injection zone and the base of the USDW.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Upper confining zone	Unlikely. The lateral continuity of the UCZ consisting primarily of the Pearsall Formation which is over 500 ft thick is recognized as a very competent seal.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Natural or induced seismicity	Unlikely. There is over 14,000 ft of impermeable rock between the injection zone and the base of the USDW.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.

1 - UCZ is defined as the upper confining zone.

Magnitude Assessment Description
Low - catergorized as little to no impact to safety, health and the environment and the costs to mitigate are minimal.
Medium - potential risks to the USDW and for surface releases does exist, but circumstances can be easily remediated.
High - danger to the USDW and significant surface release may exist, and if occurs this would require significant costs to remediate.

4.1 Leakage from Surface Equipment

The Pawnee Treating Facility and O'Neal No. 4 are designed for separating, transporting, and injecting TAG, primarily consisting of CO_2, in a manner to ensure safety to the public, the employees, and the environment. The mechanical aspects of this are noted in Table 8 and Figure 32. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) applicable standards and practices. As the TAG stream contains H_2S, monitors installed for H_2S detection will also indicate the presence of CO_2. These monitors will be installed at key locations around the facility and the O'Neal No. 4 location. These devices will be continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points determined by the facility's Health, Safety and Environment (HS&E) Director, consistent with Occupational Safety and Health Administration (OSHA) requirements. The facility will set the detection and alarm states for personnel at 10 ppm and at 40 ppm for initiating Emergency Shutdown. Key monitoring points and parameters are also provided in Table 8.

The facilities will incorporate important safety equipment to ensure reliable and safe operations. In addition to the H_2S monitors, emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the facility, the O'Neal No. 4, and other components, StarTex has a flare stack to safely handle the TAG when a depressuring event occurs. These facilities will be constructed in the coming months. The exact location of this equipment is not yet known, but it will be installed in accordance with applicable engineering and safety standards.

Table 8 – Summary of TAG Monitors and Equipment

Device	Location	Set Point
H_2S Monitors (1-4)	O'Neal No. 4 wellsite	10 ppm High Alarm 40 ppm Emergency Shutdown
H_2S Monitors (5-8)	In-Plant Monitors	10 ppm High Alarm 40 ppm Emergency Shutdown
Flare Stack	Plant Site Perimeter	N/A
AGI Flowmeter	In-Plant (downstream of the Amine Unit)	Calibrated per API specifications
Emergency Shutdown	In-Plant Monitors	40 ppm Facility Shutdown
Emergency Shutdown	O'Neal No. 4 wellsite	40 ppm Facility Shutdown

With the continuous air monitoring at the facility and the well site, a release of CO_2 would be quickly identified, and the safety systems and protocols would effectuate an orderly shutdown to ensure safety and minimize the release volume. The CO_2 injected into the O'Neal No. 4 is from the amine unit at the Pawnee Treating Facility. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7*, in accordance with 40 CFR **§98.448(a)(5)**. Ozona concludes that the leakage of CO_2 through the surface equipment is unlikely.

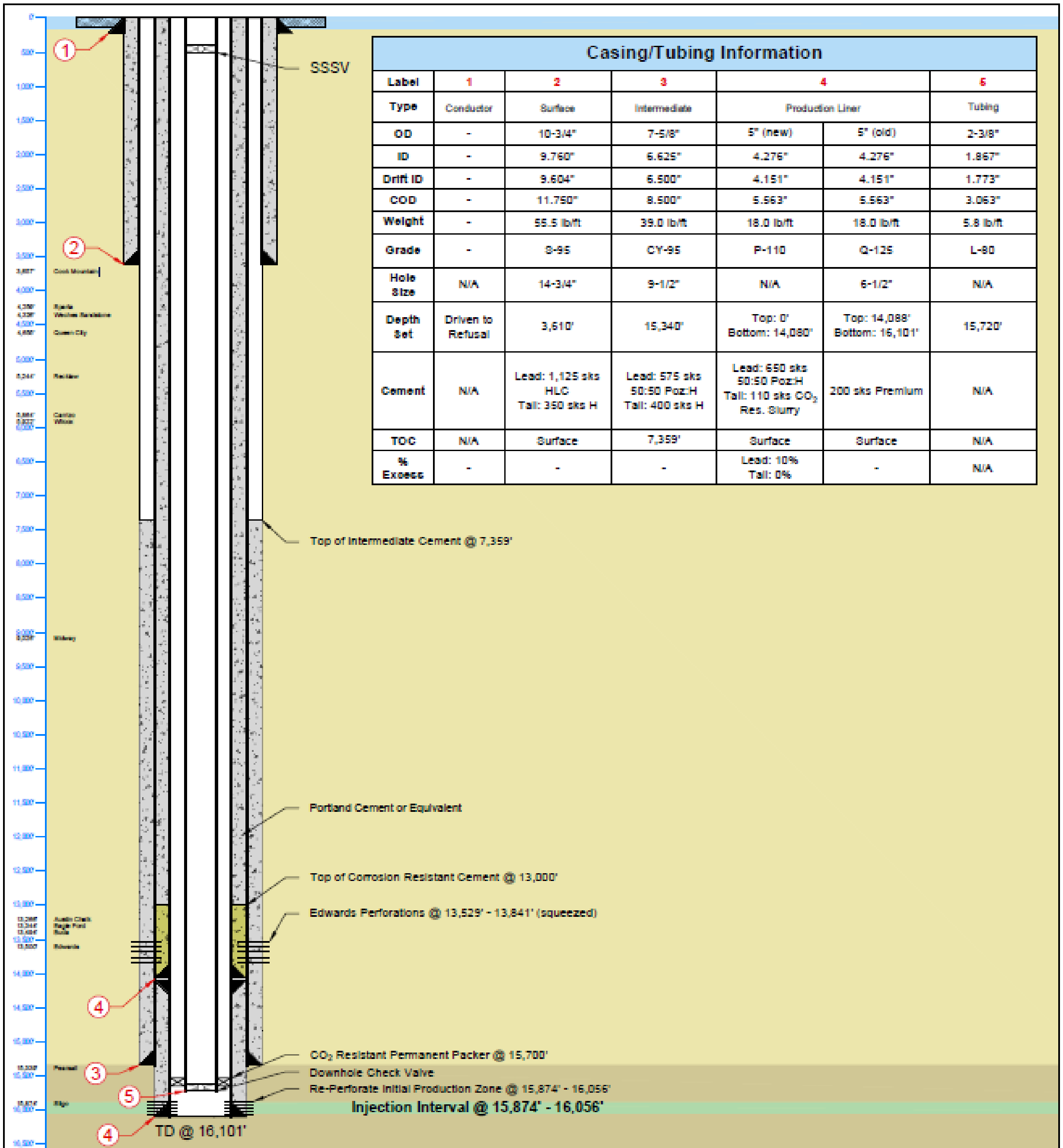
4.2 Leakage Through Existing Wells Within the MMA

The O'Neal No. 4 is engineered to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 32. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 33. Figure 34 is a map of all the oil and gas wells that penetrate the MMA's gross injection zone. Only one well penetrated the MMA's gross injection zone. This well was non-productive and has been plugged and abandoned in accordance with TRRC requirements. A summary table of all oil and gas wells within the MMA is provided in *Appendix B-1*.

This table in *Appendix B-1* provides the total depth (TD) of all wells within the MMA. The wells that are shallower and do not penetrate the injection zone are separated by the Pearsall Formation with a gross thickness of 535 ft. The Pine Island Shale comprises approximately 130 ft of this interval as discussed in *Section 2.2.2* and provides a competent regional seal—making vertical migration of fluids above the injection zone unlikely.

The shallower offset hydrocarbon wells within the MMA will also serve as above zone monitoring wells. Should any of the sequestered volumes migrate vertically, they would potentially enter the shallower hydrocarbon reservoir. Regular sampling and analysis is performed on the produced hydrocarbons. If a material difference in the quantity of CO_2 in the sample occurs indicating a potential migration of injectate from the Sligo Formation, Ozona would investigate and develop a mitigation plan. This may include reducing the injection rate or shutting in the well. Based on the investigation, the appropriate equation in *Section 7* would be used to make any adjustments to the reported volumes.



Casing/Tubing Information

Label	1	2	3	4		5
Type	Conductor	Surface	Intermediate	Production Liner		Tubing
OD	-	10-3/4"	7-5/8"	5" (new)	5" (old)	2-3/8"
ID	-	9.760"	6.625"	4.276"	4.276"	1.867"
Drift ID	-	9.604"	6.500"	4.151"	4.151"	1.773"
COD	-	11.750"	8.500"	5.563"	5.563"	3.063"
Weight	-	55.5 lb/ft	39.0 lb/ft	18.0 lb/ft	18.0 lb/ft	5.8 lb/ft
Grade	-	S-95	CY-95	P-110	Q-125	L-80
Hole Size	N/A	14-3/4"	9-1/2"	N/A	6-1/2"	N/A
Depth Set	Driven to Refusal	3,610'	15,340'	Top: 0' Bottom: 14,080'	Top: 14,088' Bottom: 16,101'	15,720'
Cement	N/A	Lead: 1,125 sks HLC Tail: 350 sks H	Lead: 575 sks 50:50 Poz:H Tail: 400 sks H	Lead: 650 sks 50:50 Poz:H Tail: 110 sks CO_2 Res. Slurry	200 sks Premium	N/A
TOC	N/A	Surface	7,359'	Surface	Surface	N/A
% Excess	-	-	-	Lead: 10% Tail: 0%	-	N/A

LONQUIST SEQUESTRATION LLC	Ozona CCS	CO_2 Injection Well Proposed Well Design - O'Neal Gas Unit No. 4	
	Country: USA	**State/Province:** Texas	**County/Parish:** Bee County
	API No: 42-025-32658	**Field:** TBD	**Well Type/Status:** Proposed
Texas License F-8652	**Location:** 28.6031807, -98.0017091	**Project No:** LS190	**Date:** 10/13/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Joseph Lovewell	**Reviewed:** David Lytle	**Approved:** David Lytle
	Rev No: 0	**Notes:**	

Figure 32 – O'Neal No. 4 Wellbore Schematic

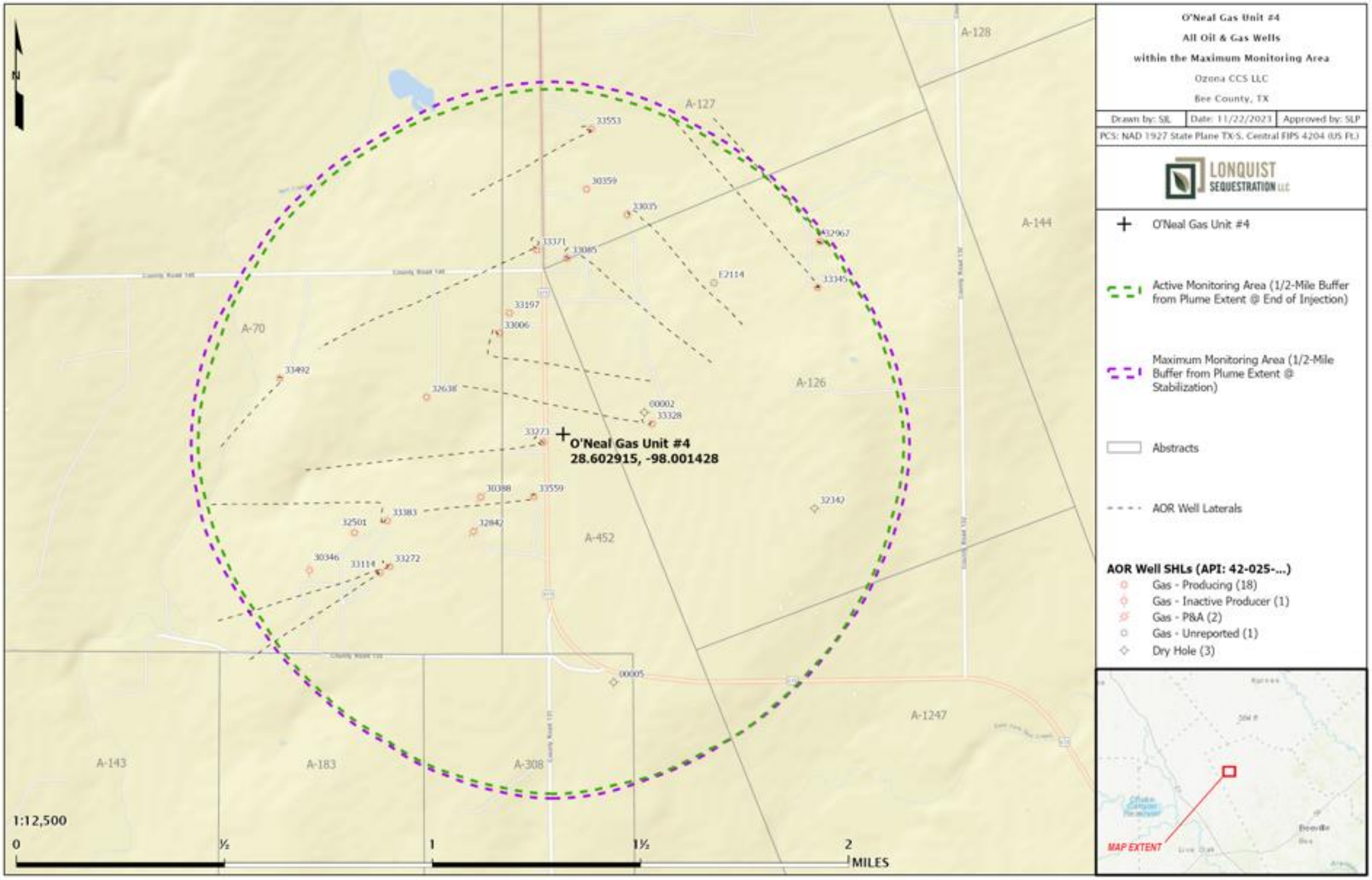


Figure 33 – All Oil and Gas Wells Within the MMA

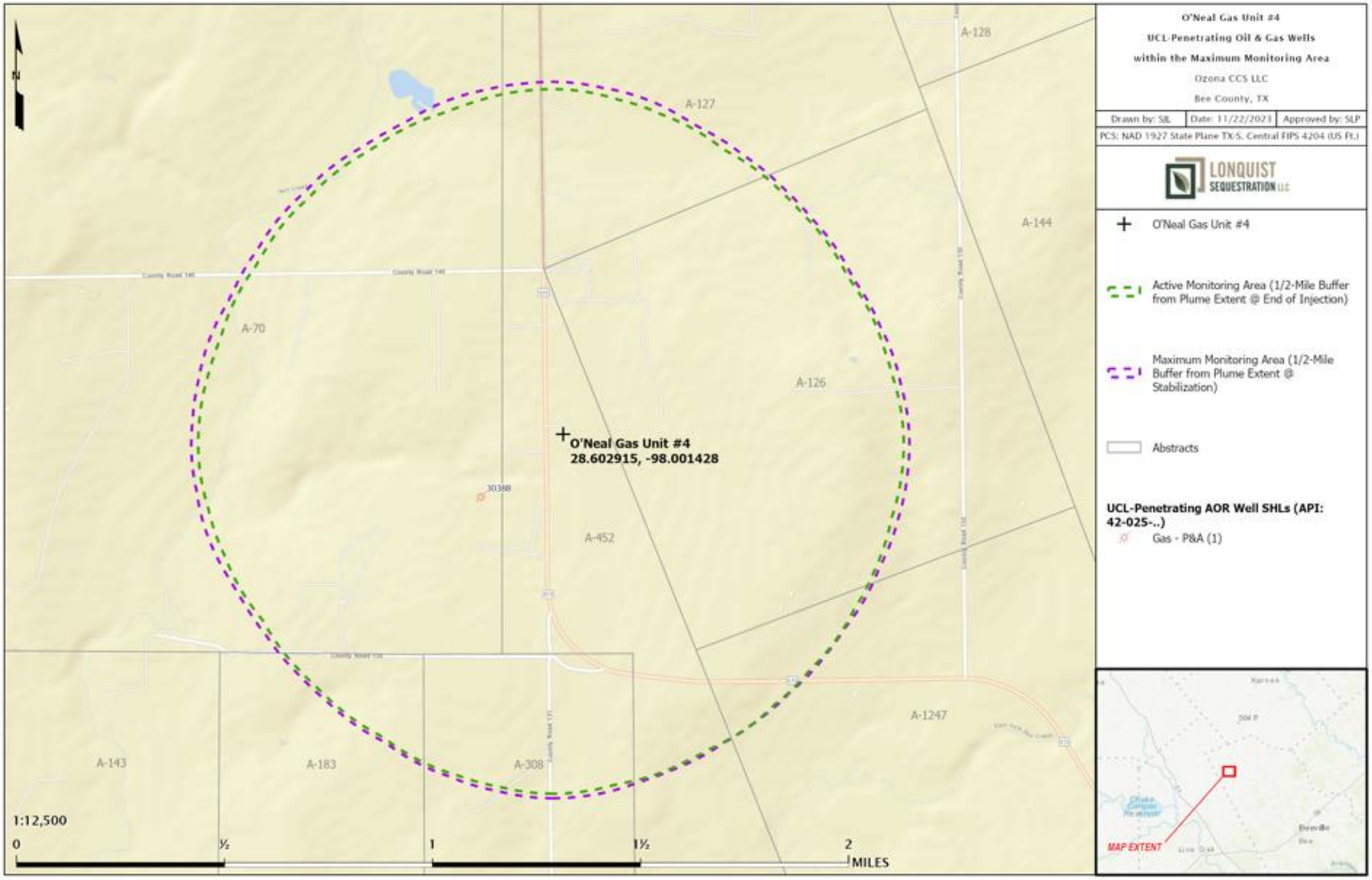


Figure 34 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations have proven to date to be nonproductive in this area, and therefore Ozona does not see this as a risk. This is supported by a review of the TRRC Rule 13 (Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC **§3.13**. The Sligo is not among the formations listed for which operators in Bee County and District 2 (where the O'Neal No. 4 is located) are required to comply with TRCC Rule 13; therefore, the TRRC does not believe there are productive horizons below the Sligo. The O'Neal No. 4 drilling permit is provided in *Appendix A-2*.

4.2.2 Groundwater Wells

The results of a groundwater well search found five wells within the MMA, as identified by the Texas Water Development Board as shown in Figure 35 and in tabular form in *Appendix B-2*.

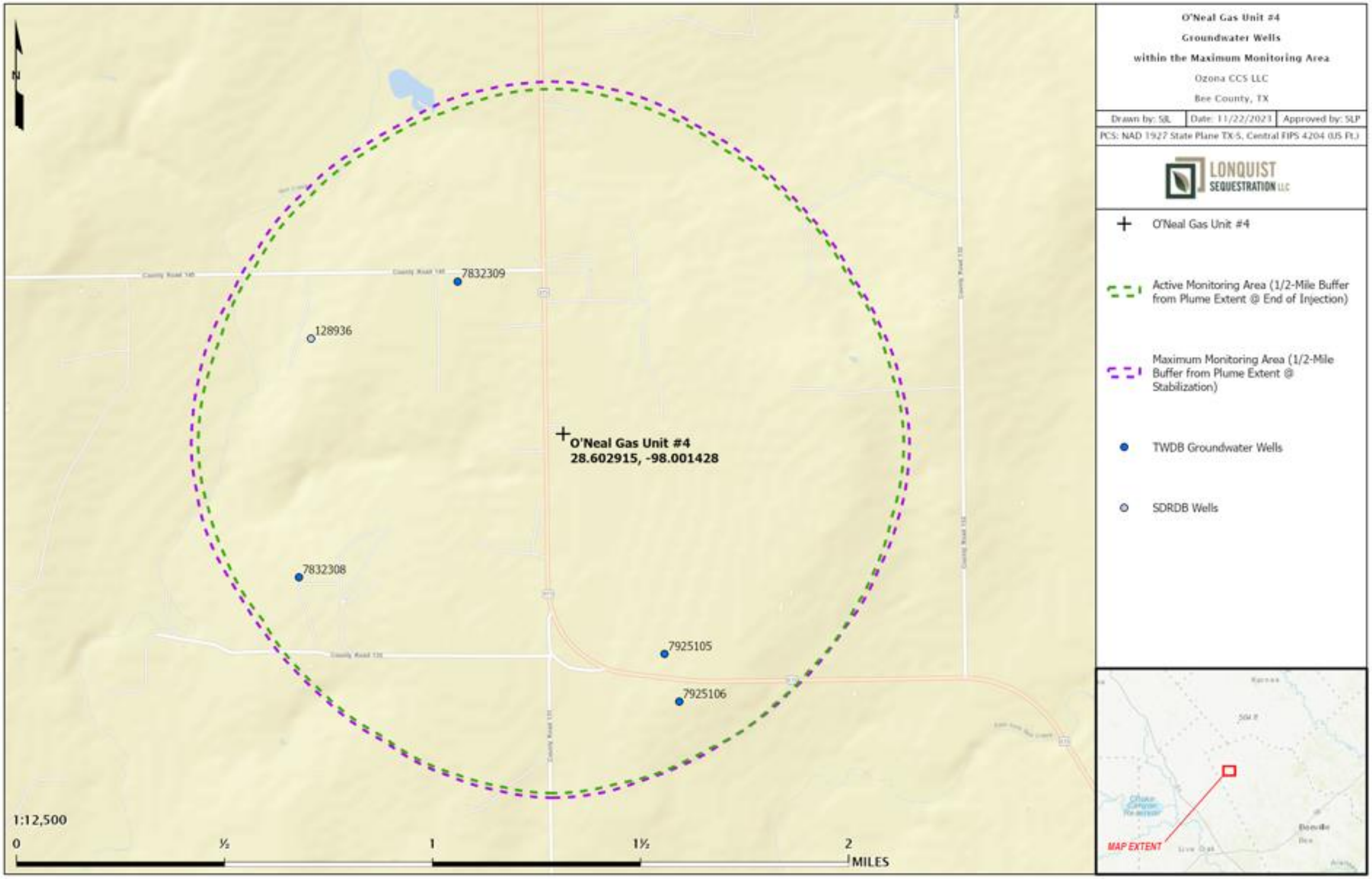


Figure 35 – Groundwater Wells Within the MMA

The surface, intermediate, and production casings of the O'Neal No. 4, as shown in Figure 32, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations, and the GAU letter issued for this location is provided in *Appendix A-1*. The wellbore casings and compatible cements prevent CO_2 leakage to the surface along the borehole. Ozona concludes that leakage of the sequestered CO_2 to the groundwater wells is unlikely.

4.3 Leakage Through Faults and Fractures

Detailed mapping of openhole logs surrounding the O'Neal No. 4 did not identify any faulting within either the Pearsall or Sligo sections. However, there is a general lack of deep penetrators within the area that limits the amount of openhole coverage available.

The majority of the published literature suggests that faulting near the project area is restricted to the shallower, overlying Cenozoic section, as shown in Figure 9, with shallow faults dying out before reaching the Pearsall Formation. One source interpreted the potential for faulting to the south (Swanson et al., 2016). The potential fault is depicted in Figure 8 relative to the location of the O'Neal No. 4. According to the map, the interpreted fault lies approximately 4.25 mi south-southeast of the well and approximately 3.9 mi south-southeast of the stabilized plume extent in the year 2047. In the unlikely scenario in which the injection plume or pressure front reaches the potential fault, and the potential fault was to act as a transmissive pathway, the upper confining Pearsall shale contains sufficient thickness and petrophysical properties required to confine and protect injectates from leaking outside of the permitted injection zone.

Section 2.1.2 discusses regional structure and faulting, and *Section 2.3* covers local structure, for additional material relevant to this topic.

4.4 Leakage Through the Upper Confining Zone

The Sligo injection zone has competent sealing intervals present above and below the targeted carbonate sequence of the Sligo section. The overlying Pine Island shale member of the Pearsall Formation is approximately 130 ft thick at the O'Neal No. 4. Above this confining unit, the Cow Creek Limestone, Cow Creek shale, and Bexar Shale Members of the Pearsall Formation will act as additional confinement between the injection interval and the USDW. The USDW lies well above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. The petrophysical properties of the lower Sligo and Hosston Formations make these ideal for lower confinement. The low porosity and permeability of these underlying formations minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injectate to the in situ reservoir fluid makes migration below the lower confining layer unlikely.

4.5 Leakage from Natural or Induced Seismicity

The O'Neal No. 4 is located in an area of the Gulf of Mexico considered to be active from a seismic perspective. Therefore, the Bureau of Economic Geology's TexNet (from 2017 to present) and USGS's Advanced National Seismic System (from 1971 to present) databases were reviewed to

identify any recorded seismic events within 25 kilometer (km) of the O'Neal No. 4.

The investigation identified a multitude of seismic events within the 25 km search radius; however, the magnitude of most of the events was below 2.5. The nearest seismic event with a recorded magnitude of 3.0 or greater was measured approximately 5.6 km northwest of the O'Neal No. 4 at a depth of 5 km. The results of the investigation are plotted on the map provided in Figure 36 relative to the O'Neal No. 4 and the 25-km search radius.

The Facility will have operating procedures and set points programmed into the control and SCADA systems to ensure operating pressures are maintained below the fracture gradient of the injection and confining intervals, thus avoiding the potential for inducing seismicity.

Given the seismic activity in the area, Ozona will closely monitor nearby TexNet station EF71 for activity and any corresponding irregularities in the operating pressures of O'Neal No. 4. If a seismic event of 3.0 or greater is recorded at Station EF71 or if anomalies are identified in the operating data, Ozona will review the data and determine if any changes occurred that indicate potential leakage. Ozona would take appropriate measures based on their findings, including limiting the injection pressure and reducing the injection rate.

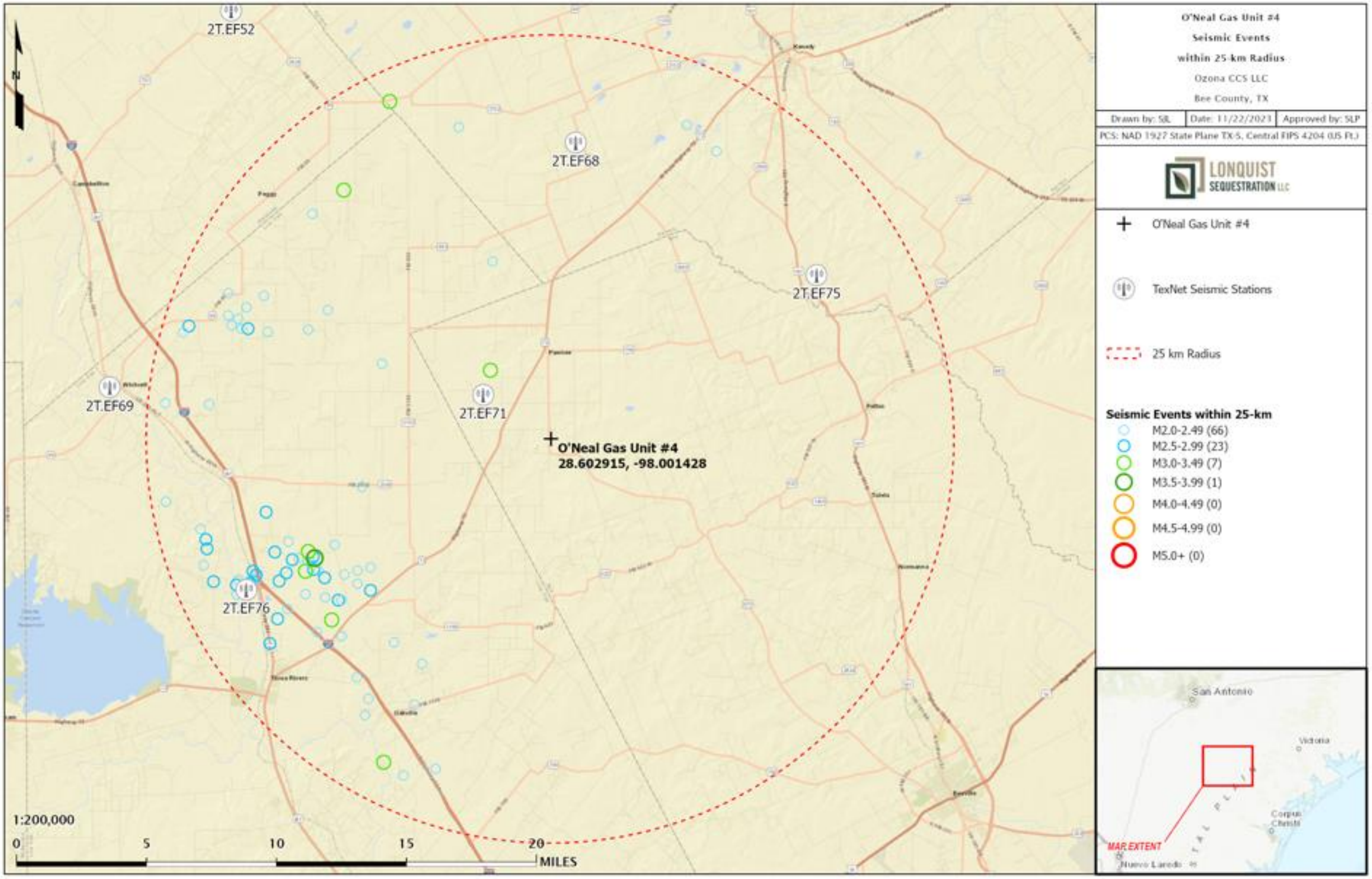


Figure 36 – 25-km Seismicity Review

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Ozona will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in *Section 4*, to meet the requirements of 40 CFR **§98.448(a)(3)**. As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 9 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 12-year injection period or cessation of injection operations, plus a proposed 10-year post-injection period until the plume has stabilized.

- Leakage from surface equipment
- Leakage through existing and future wells within the MMA
- Leakage through faults or fractures
- Leakage through confining seals
- Leakage through natural or induced seismicity

Table 9 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Surface equipment	Fixed H_2S monitors at the Plant and well site
	Visual inspections
	Monitor SCADA systems for the Plant and well site
Existing wells within the MMA	Monitor CO_2 levels in above zone producing wells
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Annual soil gas sampling near well locations that penetrate the Upper Confining Zone within the AMA
• Leakage through groundwater wells	Annual groundwater samples from existing water well(s)
• Leakage from future wells	Monitor drilling activity and compliance with TRRC Rule 13 Regulations
Faults and Fractures	SCADA continuous monitoring at the well site (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Upper confining zone	SCADA continuous monitoring at the well site (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Natural or induced seismicity	Monitor CO_2 levels in Above Zone producing wells
	Monitor existing TexNet station

|

5.1 Leakage from Surface Equipment

The facility depicted in Figure 37 and the O'Neal No. 4 were designed to operate in a safe manner to minimize the risk of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established prior to commencing operation once facility construction has been completed. Ambient H_2S monitors will be located at the facility and near the O'Neal No. 4 site for local alarm and are connected to the SCADA system for continuous monitoring.

The facility and the O'Neal No. 4 are continuously monitored through automated control systems. These monitoring points were discussed in *Section 4.1*. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Ozona to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

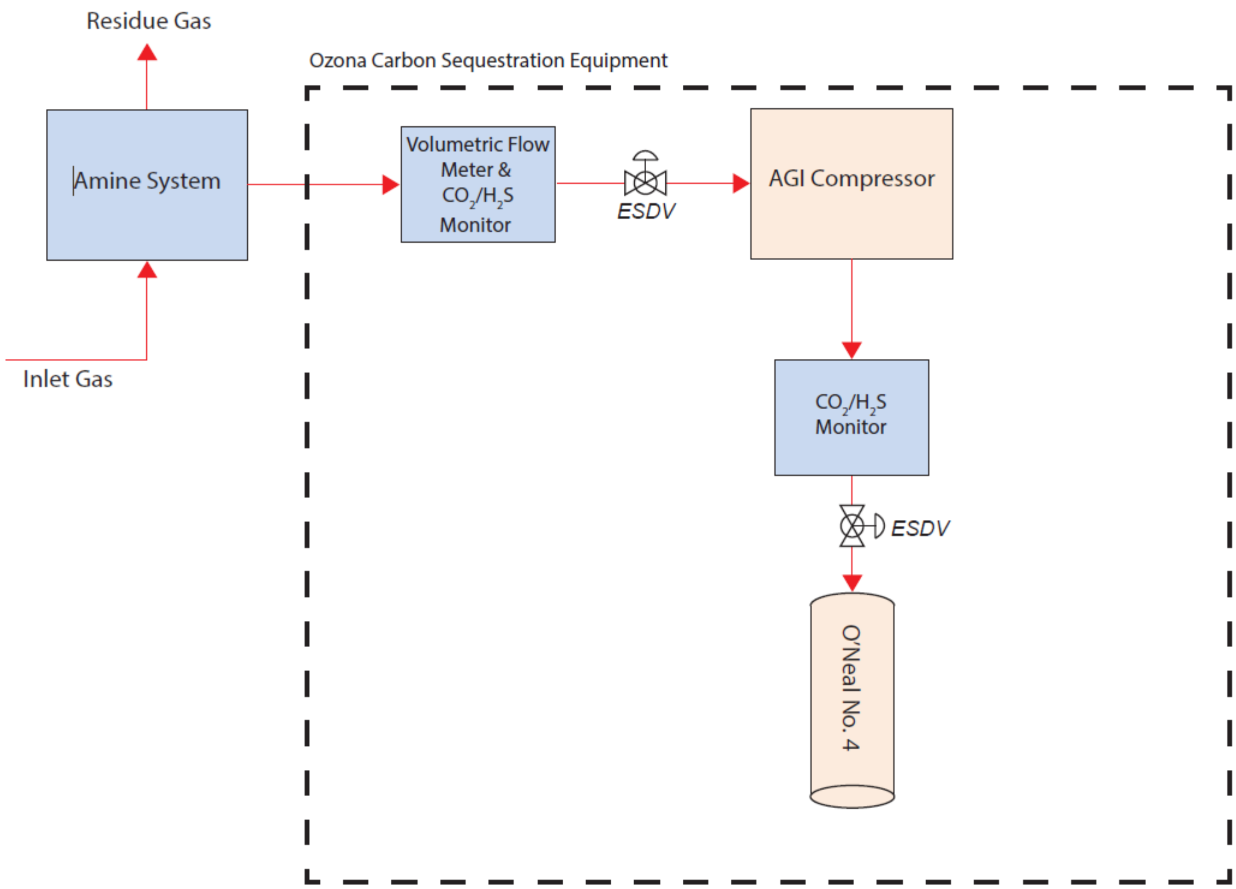


Figure 37 – O'Neal No. 4 Process Flow Diagram

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Ozona will quantify the leak per the strategies discussed in *Section 7*.

5.2 Leakage Through Existing and Future Wells Within the MMA

Ozona continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the O'Neal No. 4. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, MITs performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and investigated to develop a leak mitigation plan.

As discussed previously, TRRC Rule 13 ensures that new wells in the field are constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Ozona will also establish and operate an in-field monitoring program to detect CO_2 leakage within the AMA. This would include H_2S monitoring as a proxy for CO_2 at the well site and annual soil gas samples taken near any identified wells that penetrate the injection interval within the AMA. These samples will be analyzed by a qualified third party. Prior to commencing operation, and through the post-injection monitoring period, Ozona will have these monitoring systems in place.
Currently, there is only one well in the MMA identified that penetrates the injection interval. This well was plugged and abandoned in 2007. The TRRC records are provided in *Appendix A-4*. Ozona will take an annual soil gas sample from this area, which will be analyzed by a third-party lab. Additional monitoring will be added as the AMA is updated over time. In the unlikely event a leak occurs, Ozona will quantify the leak volumes by the methodologies discussed in *Section 7* and present these results and related activities in the annual report.

Ozona will also utilize shallower producing gas wells as proxies for above-zone monitoring wells. Production data from these wells is analyzed for monthly production statements, and therefore would be an early indicator of any possible subsurface issues. Should any material change from historical trends in the CO_2 concentration occur, Ozona would investigate and develop a corrective action plan. Should any CO_2 migrate vertically from the Sligo, the magnitude risk of this event is very low, as the producing reservoir provides an ideal containment given the upper confining zone of this reservoir has proven competent. In the unlikely event a leak occurs, Ozona would quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances and include these results in the annual report.

5.2.1 Groundwater Quality Monitoring

Ozona will monitor the groundwater quality above the confining interval by sampling from groundwater wells near the O'Neal No. 4 and analyzing the samples with a third-party laboratory on an annual basis. In the case of the O'Neal No. 4, 5 existing groundwater wells have been identified within the AMA (Figure 38). Initial groundwater quality tests will be performed to establish a baseline prior to commencing operations.

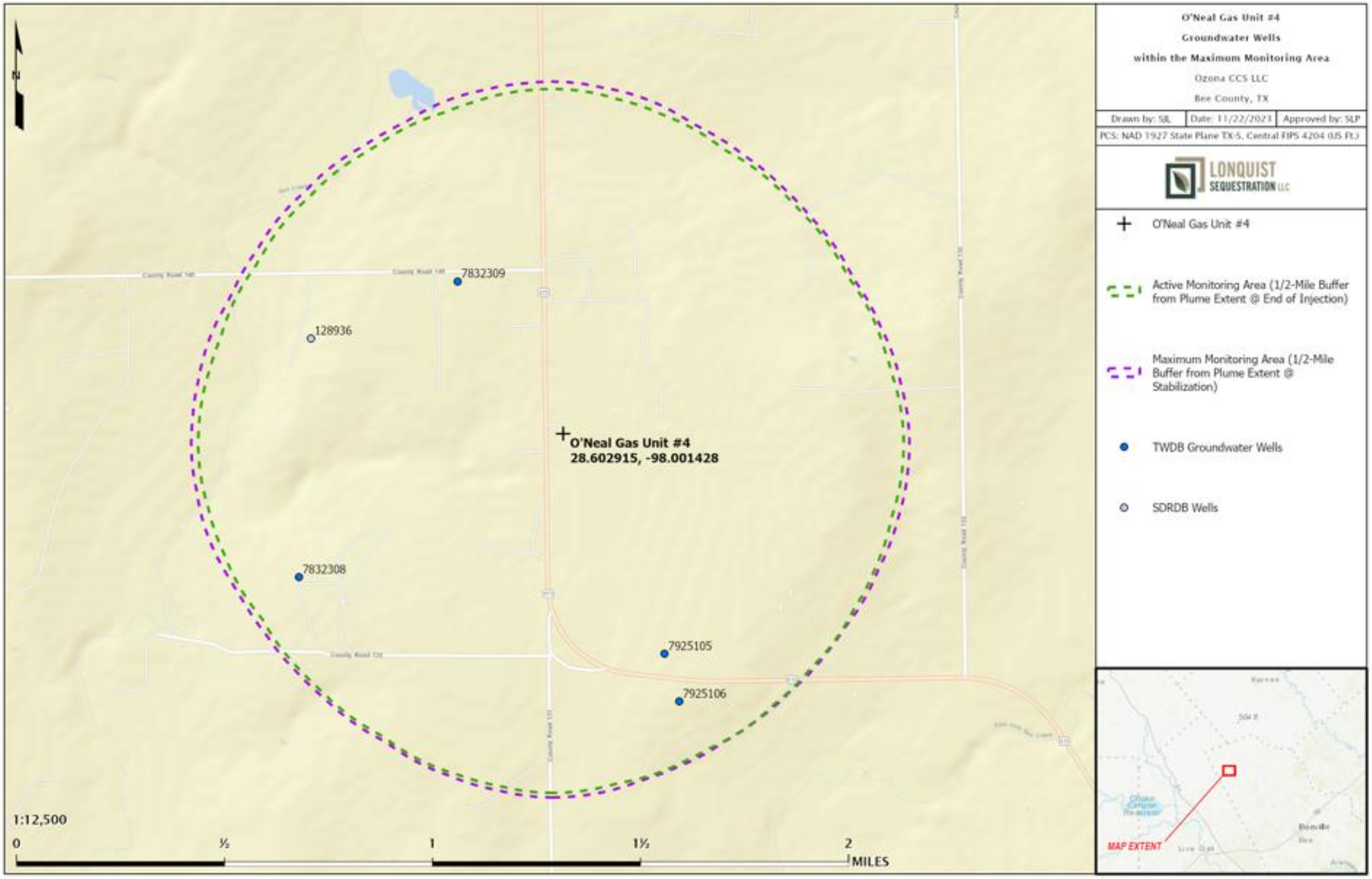


Figure 38 – Groundwater Wells

5.3 Leakage Through Faults, Fractures, or Confining Seals

Ozona will continuously monitor the operations of the O'Neal No. 4 through the automated controls and SCADA systems. Any deviation from normal operating volume and corresponding injection pressure could indicate movement into a potential leak pathway, such as a fault or breakthrough of the confining seal and would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Ozona will also utilize shallower producing wells as proxies for above-zone monitoring wells. Production data is analyzed regularly for monthly production statements and therefore would be an early indicator of any possible subsurface issues. Should any material change from historical trends in the CO_2 concentration occur, Ozona would investigate and develop a corrective action plan. Should any CO_2 migrate vertically from the Sligo Formation, the magnitude risk of this event is very low, as the producing reservoir provides an ideal containment given the upper confining zone has proven competent. In the unlikely event a leak occurs, Ozona would quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is low, Ozona plans to use the nearest TexNet seismic monitoring station, EF71, to monitor the area around the O'Neal No. 4. This station is approximately 3 mi to the northwest, as shown in Figure 38. This is sufficient distance to allow for accurate and detailed monitoring of the seismic activity in the area. Ozona will monitor this station for any seismic activity, and if a seismic event of 3.0 magnitude or greater is detected, Ozona will review the injection volumes and pressures of the O'Neal No. 4 to determine if any significant changes have occurred that would indicate potential leakage.

Ozona will also continuously monitor operations through the SCADA system. Any deviation from normal operating pressure and volume set points would trigger an alarm for investigation by operations staff. Such a variance could indicate movement into a potential leak pathway, such as a fault or breakthrough of the confining seal. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary

These are the two primary strategies for mitigating risks for induced seismicity. In the unlikely event a leak occurs, Ozona will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances.

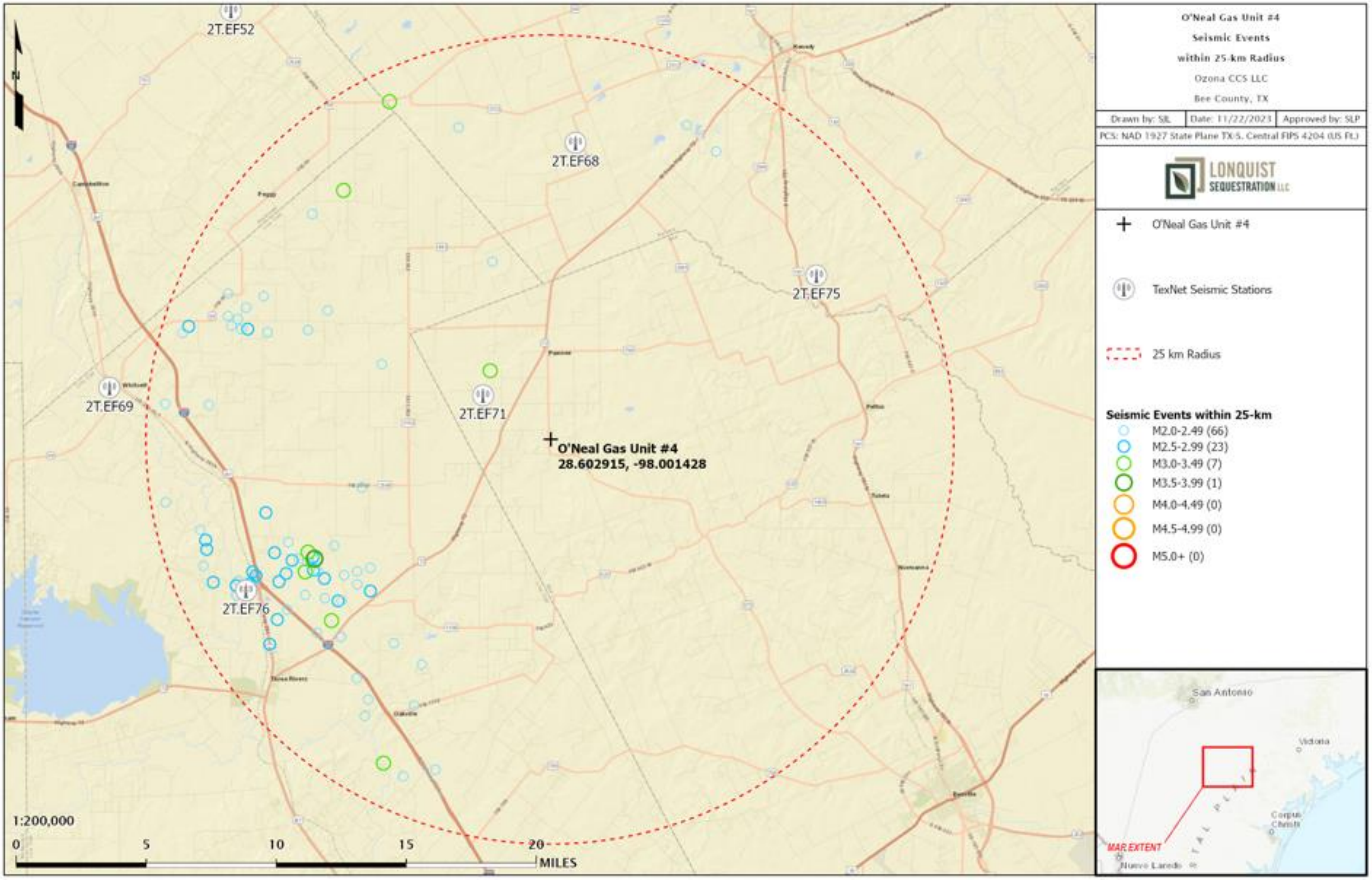


Figure 39 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

This section identifies the strategies Ozona will undertake to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR **§98.448(a)(4).** Ozona will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of injectate and calculate a corresponding amount of CO_2.

6.1 Visual Inspections

Regular inspections will be conducted by field personnel at the facility and O'Neal No. 4 site. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken prudently and safely to address such issues.

6.2 H_2S/ CO_2 Monitoring

In addition to the fixed monitors in the facility and at the wellsite, Ozona will establish and perform an annual in-field sampling program to monitor and detect any CO_2 leakage within the AMA. This will consist of soil gas sampling near any artificial penetrations of the injection zone and sampling of water wells. These probes have special membrane inserts that collect the gas samples over a 21-day period. These will be analyzed by a third-party lab to be analyzed for CO_2, H_2S, and trace contaminants typically found in a hydrocarbon gas stream. The lab results will be provided in the annual report should they indicate a material variance from the baseline. Initial samples will be taken and analyzed before the commencement of operations and will establish the baseline reference levels.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of injectate and the corresponding component of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is near the OSHA Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger alarms if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions, including pressure, flow rate, percentage of CO_2, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a depressuring event, the acid gas stream will be sent to a flare stack to be safely processed and will be reported under reporting requirements for the facility. Any such events will be accounted for in the sequestered reporting volumes consistent with *Section 7.*

6.5 <u>Groundwater Monitoring</u>

Initial samples will be taken from groundwater wells in the area of the O'Neal No. 4 upon approval of the MRV plan, and before commencement of CO_2 injection. These samples will be analyzed and reports prepared by a third-party laboratory testing for pH, total dissolved solids (TDS), CO_2, and volatile organic compounds (VOC). Initial samples will be taken and analyzed before the commencement of operations and will establish the baseline reference levels. Sampling select wells will be performed annually. In the event a material deviation in the sample analysis occurs, the results will be provided in the annual report.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO_2 Received

Per 40 CFR **§98.443**, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4**)." The 40 CFR **§98.444(a)(4)** states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." The CO_2 received for this injection well is injected and not mixed with any other supply; the annual mass of CO_2 injected will equal the amount received less any amounts calculated in accordance with the equations of this section. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO_2 Injected

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

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

Where:

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

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

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

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

The O'Neal No. 4 is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

7.4 Mass of CO_2 Emitted by Surface Leakage

The mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly due to the H_2S concentration in the injection stream. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions would be sent to a flare stack and reported as a part of the required GHG reporting for the facility. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of H_2S and CO_2. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak-point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

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

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

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

Calculation methods using equations from Subpart W will be used to calculate CO_2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage is unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Ozona believes the most appropriate method to quantify the mass of CO_2 released will be determined on a case-by-case basis. Any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. In the unlikely

event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events will be kept and stored as provided in *Section 10*.

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Data collection for calculating the amount of CO_2 sequestered in the O'Neal No. 4 will begin once the subsurface recompletion work, and the surface facilities construction has been completed, and subject to approval of the MRV plan. The calculation of sequestered volumes utilizes the following equation as the O'Neal No. 4 will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

CO_{2FI} will be calculated in accordance with Subpart W for reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a system blowdown event occurs. Those emissions would be sent to a flare stack and reported as part of the GHG reporting for the facility.

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The O'Neal Gas Unit No. 4 is an existing natural gas well that will be recompleted as a Class II well with corrosion-resistant materials. The Class II permit is still in process with the TRRC. Until this permit is issued, Ozona cannot specify a date to acquire the baseline testing data. Ozona is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan, including acquisition of baseline data, will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

Table 10 – Baseline Sampling Schedule

Sampling Location	Estimated Date	Comments
Fixed H_2S/CO_2 Monitors	Oct. 1, 2024	Baseline readings will be established during commissioning activities.
Soil gas sampling	Oct. 1, 2024	Baseline samples will be taken prior to commencement of injection.
Water well sampling	Oct. 1, 2024	Baseline samples will be taken prior to commencement of injection.

Notes:

- Above dates are estimates subject to adjustment based on actual regulatory approval dates and facilities construction timelines.
- All baseline sampling will be performed prior to the start of recording data for reporting under this MRV.
- Commissioning activities include installation of surface facilities, including flowline, compressors, manifolds, etc.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Ozona plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 Injected

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with API standards. These flow rates will be compiled quarterly.
- The composition of the injectate stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with API standards.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated per the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.

CO_2 Emissions from Leaks and Vented Emissions

- Gas monitors at the facility and O'Neal No. 4 will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.
- Calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR **§98.3(i).**
- Flow meters will be operated and maintained in accordance with applicable standards as published by a consensus-based standards organization.

All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60°F and an absolute pressure of 1 atmosphere.

9.2 Missing Data

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

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.

- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR **§98.**

9.3 MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Ozona will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least 3 years and include the following:

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

APPENDICES

APPENDIX A – O'Neal No. 4 TRRC FORMS

APPENDIX A-1: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-2: DRILLING PERMIT

- CHARLIE C. OVERBY API 42-025-32658
- O'NEAL GAS UNIT NO. 4 API 42-025-32658

APPENDIX A-3: COMPLETION REPORT

- CHARLIE C. OVERBY API 42-025-32658
- O'NEAL GAS UNIT NO. 4 API 42-025-32658
- MINI FRACTURE REPORT

APPENDIX A-4: API 42-025-30388 CHARLIE C. OVERBY GU PLUGGING RECORDS

<u>APPENDIX B – AREA OF REVIEW</u>

APPENDIX B-1: OIL AND GAS WELLS WITHIN THE MMA LIST

APPENDIX B-2: WATER WELLS WITHIN THE MMA LIST

Appendix B: Submissions and Responses to Requests for Additional Information

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
O'Neal Gas Unit Well No. 4

Bee County, TX

Prepared for *Ozona CCS, LLC*
San Antonio, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 4.0
August 2024

INTRODUCTION

Ozona CCS, LLC (Ozona) has a pending Class II acid gas injection (AGI) permit application with the Texas Railroad Commission (TRRC), which was submitted in September of 2023 for its O’Neal Gas Unit Well No. 4 (O’Neal No. 4), API No. 42-025-32658. Granting of this application would authorize Ozona to inject up to 1.5 million standard cubic feet per day (MMscf/D) of treated acid gas (TAG) into the Sligo Formation at a depth of 15,874 feet (ft) to 16,056 ft, with a maximum allowable surface pressure of 7,920 pounds per square inch gauge (psig). The TAG for this AGI well is associated with StarTex’s Pawnee Treating Facility, located in a rural area of Bee County, Texas, approximately 2.0 miles (mi) south of Pawnee, Texas, as shown in Figure 1.

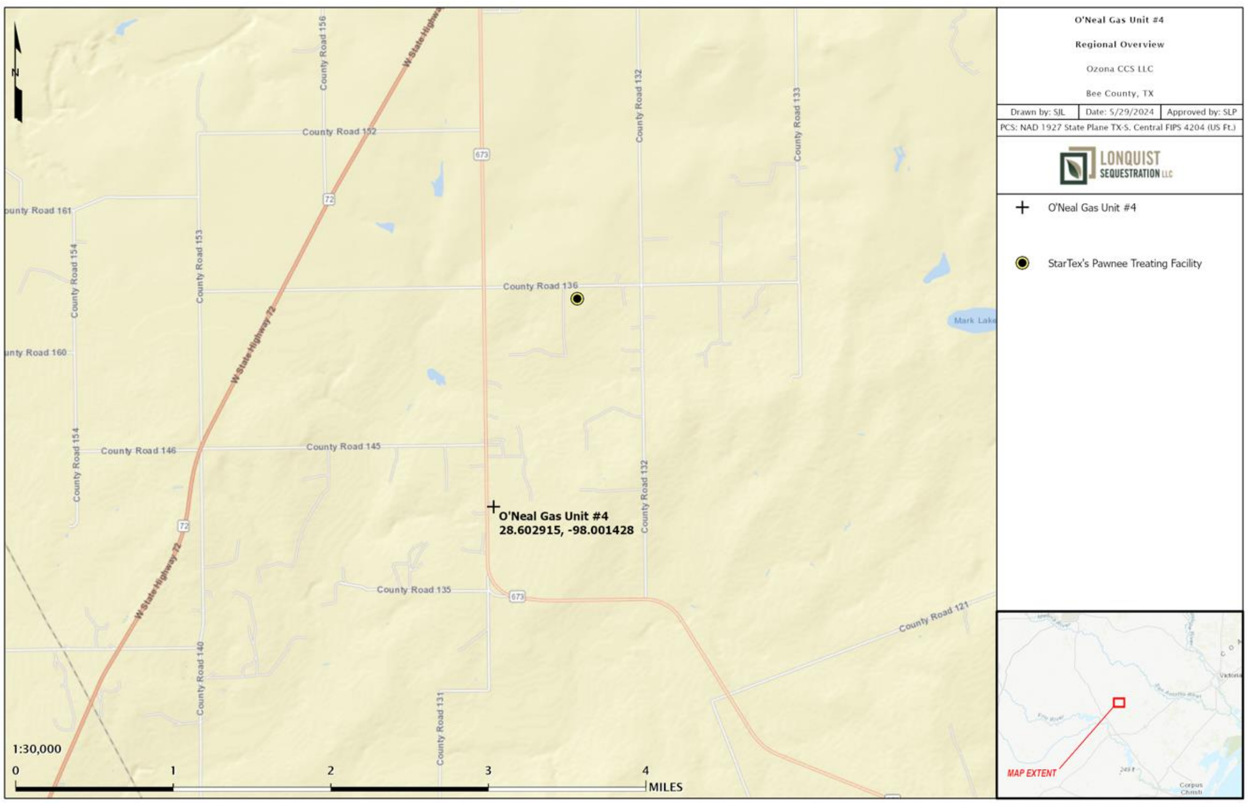


Figure 1 – Location of StarTex’s Pawnee Treating Facility and the O’Neal No. 4

Ozona is submitting this Monitoring, Reporting, and Verification (MRV) plan to the EPA for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Ozona has applied to the TRRC for the O'Neal GU No. 4's Class II permit. Ozona plans to inject TAG for approximately 12 years. Table 1 shows the expected composition of the gas stream to be sequestered from the nearby treating facility.

Table 1 – Expected TAG Composition

Component	Mol Percent
Carbon Dioxide	98.2%
Hydrocarbons	1.03%
Hydrogen Sulfide	0.4%
Nitrogen	0.37%

ACRONYMS AND ABBREVIATIONS

AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group, Ltd.
CO_2	Carbon Dioxide (may also refer to other carbon oxides)
E	East
EOS	Equation of State
EPA	Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet

Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
PG	Pore Gradient
pH	Scale of Acidity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

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SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program. The TRRC classifies the O'Neal No. 4 as a UIC Class II well. Ozona has applied for a Class II permit for the O'Neal No. 4 under TRRC Rules 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas) and 46 (Fluid Injection into Productive Reservoirs).

1.2 UIC Well Identification Number

- O'Neal No. 4, API No. 42-025-32658, UIC No. 56819

1.3 Facility Address

- Facility Name: StarTex Pawnee Treating Facility
- Operator: StarTex Field Services, LLC
- Facility ID No. 568661
- Coordinates in North American Datum for 1983 (NAD 83) for this facility:
    - Latitude: 28.622211
    - Longitude: -97.992772
- Greenhouse Gas Reporting Program ID Information:
    - Ozona will report under GHGRP ID No. 587021 for this Monitoring, Reporting and Verification plan

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and reservoir and plume modeling performed for the O'Neal No. 4 well.

The O'Neal No. 4 will inject the TAG stream into the Sligo Formation at a depth of 15,874 ft to 16,056 ft, and approximately 14,924 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and—most critically—to prevent surface releases.

2.1 Regional Geology

The O'Neal No. 4 (API No. 42-025-32658) is located in south Texas within the Gulf of Mexico Basin. The onshore portion of the Gulf of Mexico basin spans approximately 148,049,000 acres and encompasses portions of Texas, Louisiana, Mississippi, Alabama, Arkansas, Missouri, Kentucky, Tennessee, Florida, and Georgia to the state-waters boundary of the United States (Roberts-Ashby et al., 2012). The location of the O'Neal No. 4 is designated by the red star in Figure 2, relative to the present coastal extent and major structural features of the basin.

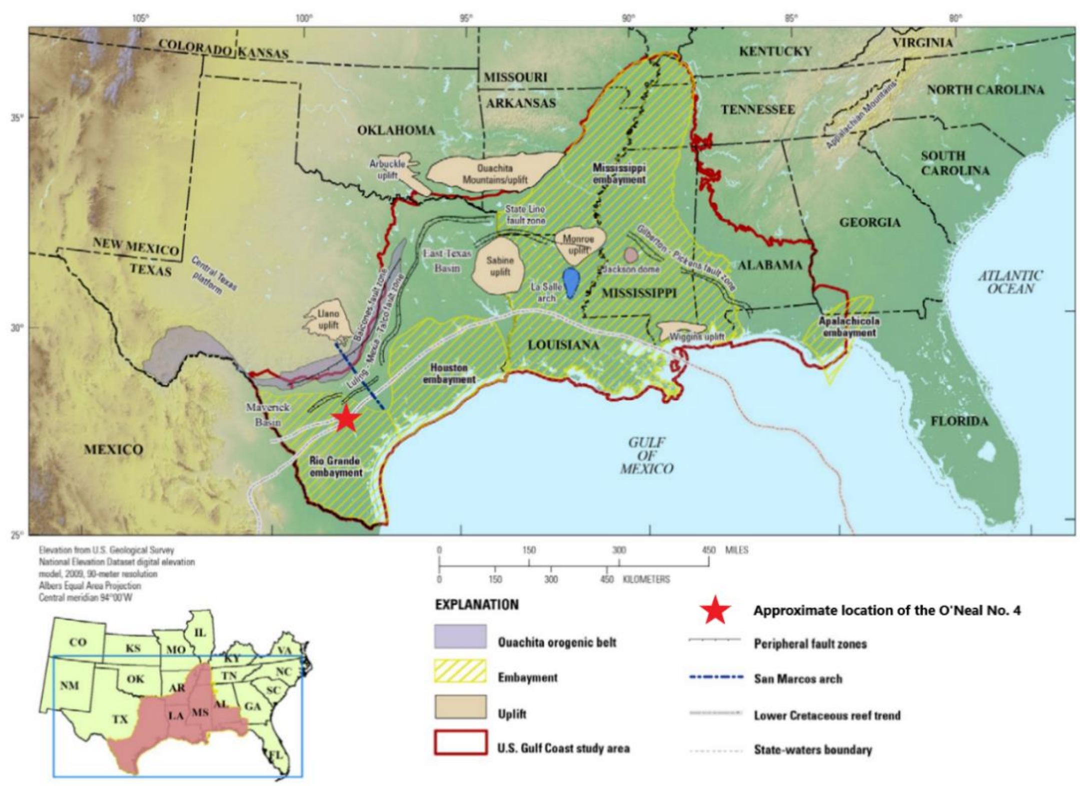

Figure 2 – Structural Features of the Gulf of Mexico and Locator Map (modified from Roberts-Ashby et al., 2012)

Figure 3 depicts a generalized stratigraphic column of the U.S. Gulf Coast, with light blue shading signifying the proposed injection interval and green stars indicating productive formations identified within 5 miles of the O'Neal No. 4. The injection interval is found within the Sligo Formation, with confinement provided by the overlying Pearsall Formation and tight underlying facies of the Lower Sligo and Hosston Formations.

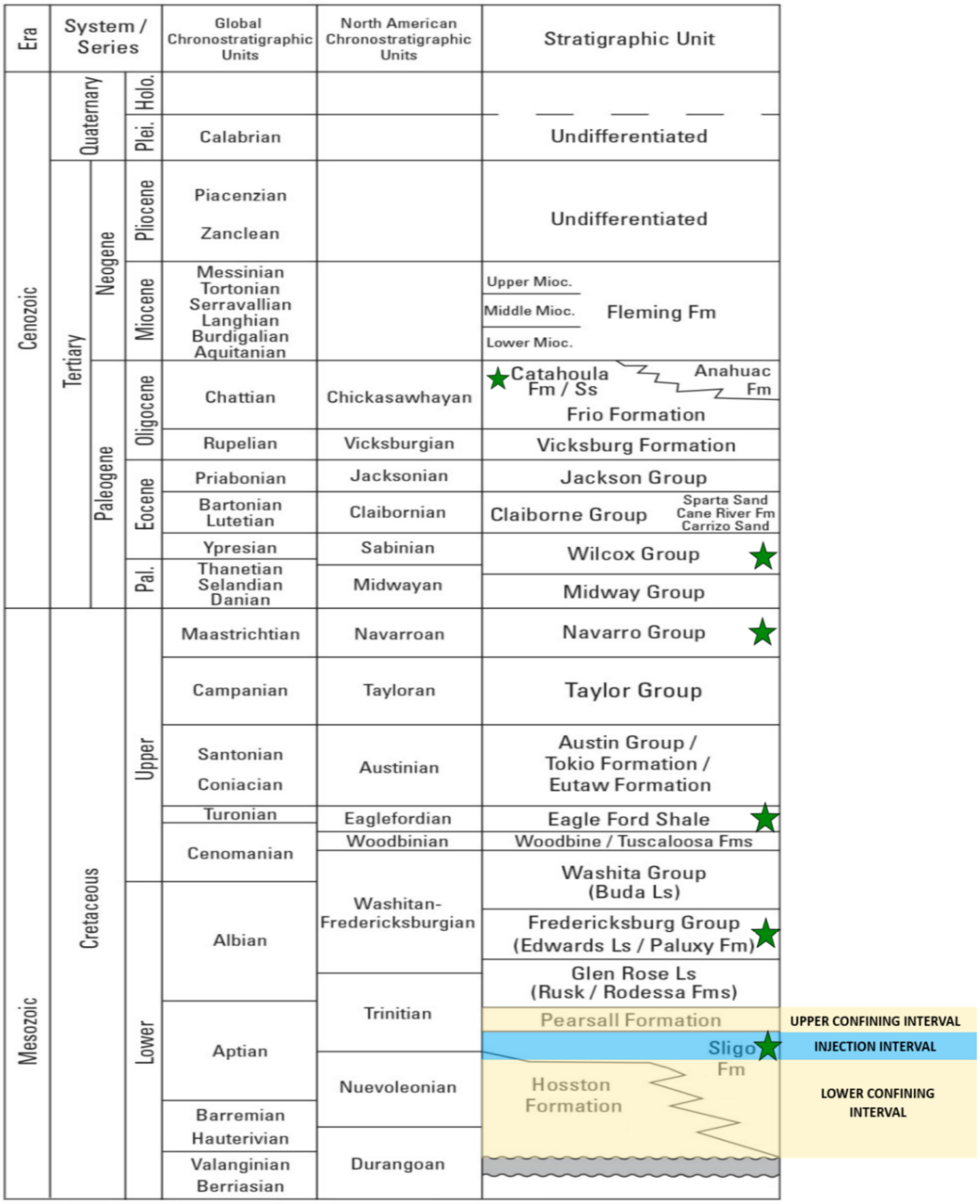

Figure 3 – Stratigraphic column of the U.S. Gulf Coast signifying proposed injection and confining intervals. Offset productive intervals are noted with a green star (modified from Roberts-Ashby et al., 2012).

The targeted formations of this study are located entirely within the Trinity Group, as clarified by the detailed stratigraphic column provided in Figure 4. During this time the area of interest was located along a broad, shallow marine carbonate platform that extended along the northern rim of the ancestral Gulf of Mexico. The Lower Cretaceous platform spanned approximately 870 mi from western Florida to northeastern Mexico, with a shoreline-to-basin margin that ranged between 45 to 125 mi wide (Yurewicz et al., 1993).

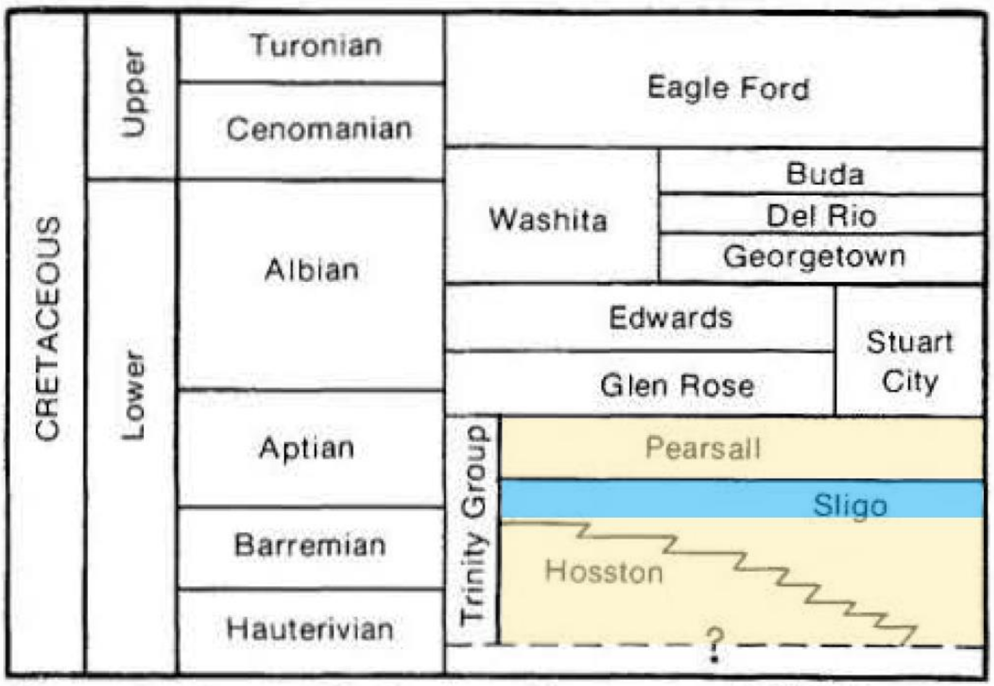

Figure 4 – Detailed stratigraphic column of Lower Cretaceous formations of south Texas. The proposed injection interval is shaded light blue and proposed confining intervals are shaded light yellow (modified from Bebout et al., 1981).

2.1.1 Geologic Setting and Depositional Environment

The depositional environment during the Lower Cretaceous generally consisted of a well-defined platform margin with a shallow marine platform interior or lagoon to the north, a shallow marine outer platform to the south, and a foreslope that gradually dipped southward towards the basin center. The platform margin remained stable for tens of millions of years during the Cretaceous but experienced episodic changes in sea level that resulted in cyclic deposition of several key facies that vary both spatially and within the geologic section. Facies distributions were heavily impacted by positioning relative to the margin, the height of the water column at any given time, and the degree of energy or wave action within the system (Galloway, 2008; Yurewicz et al., 1993).

In general, long stands of reef development and ooid shoaling developed primary porosity and permeability along the shallow, high-energy carbonate platform and represent reservoir quality

rock found within Cretaceous reef deposits. Deeper, basinward deposits tend to result in tighter petrophysical properties due to a relative increase in the amount of entrained clay associated with the heightening of the water column while moving downslope. Backreef deposits have the potential for porosity development but tend to have low permeability due to a general lack of wave action caused by restricted access to open water by the platform margin. Facies and petrophysical properties of the Lower Cretaceous section are anticipated to be relatively homogenous moving southwest-northwest along reef trend, with increased heterogeneity moving northwest-southeast due to the orientation of the carbonate rim and its effect on deposition and facies distributions (Yurewicz et al., 1993).

Figure 5 displays the paleogeography during deposition of the Lower Cretaceous section to visually demonstrate the position of the O'Neal No. 4 relative to the Sligo shelf margin and updip extents of Sligo deposition. A generalized schematic cross section of the Trinity Group is provided in Figure 6, which nearly intersects the project area from the northwest. The schematic illustrates the gross section thickening basinward, with primary reservoir development improving with proximity to the reef margin. Figure 7 displays a depositional model of the Lower Cretaceous carbonate platform to visually conceptualize depositional environments and anticipated petrophysical properties of facies introduced above.

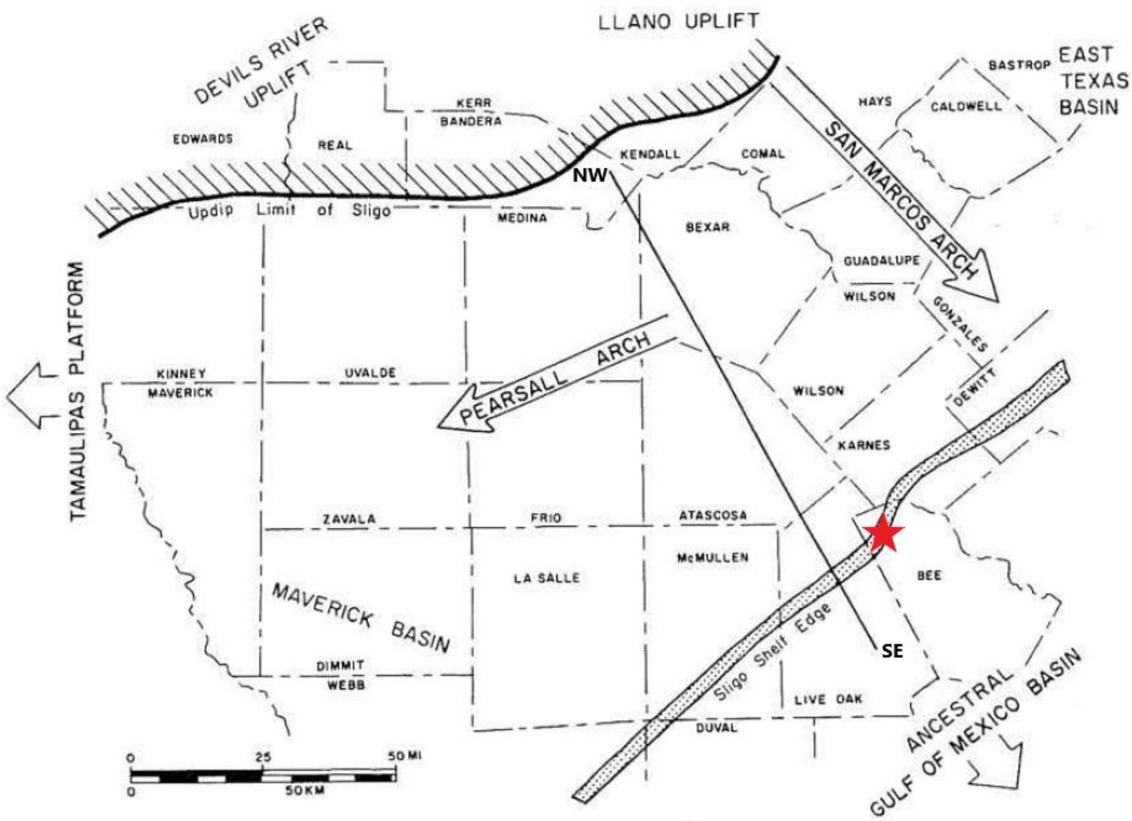

Figure 5 – Paleogeography of the Lower Cretaceous of south Texas. The red star represents the approximate location of the O'Neal No. 4 (modified from Bebout et al., 1981).

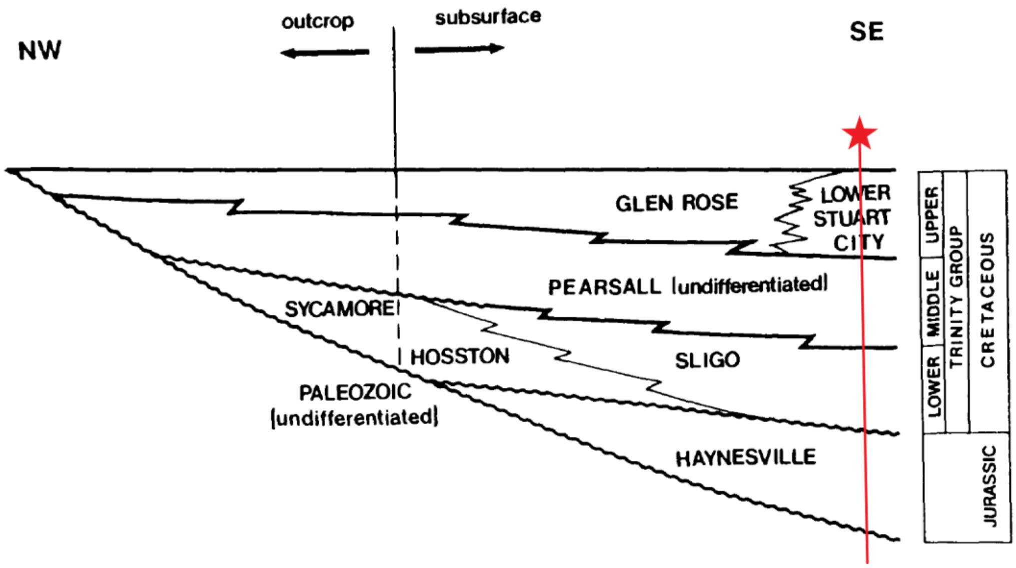

Figure 6 – Generalized northwest to southeast schematic cross section of the Trinity Group, south Texas (the line of section depicted in Figure 5). The red star and line represent the approximate location of the O'Neal No. 4 (modified from Kirkland et al., 1987)

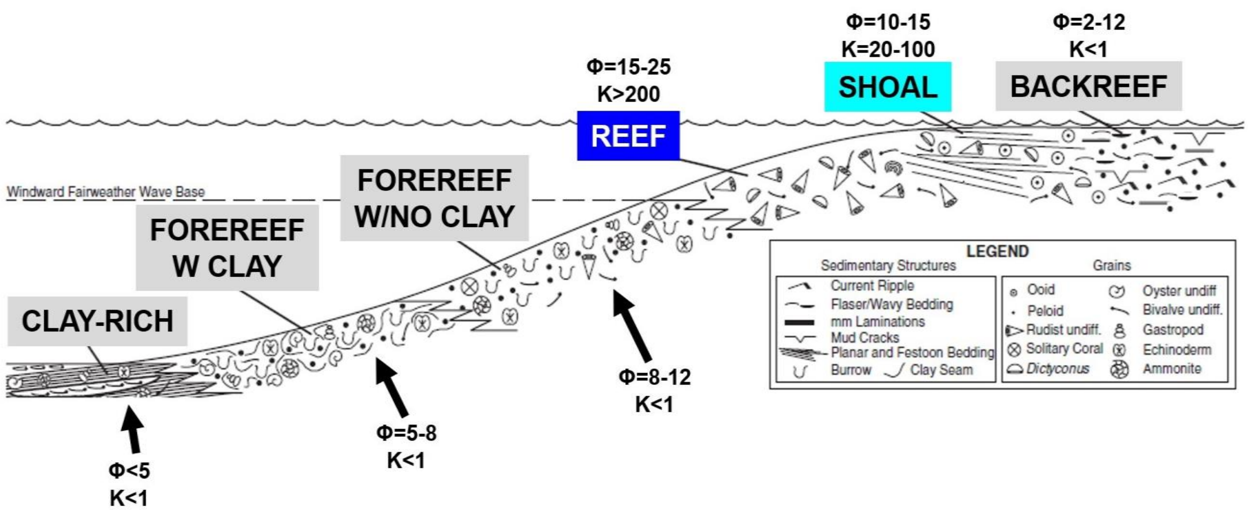

Figure 7 – Depositional model for the Lower Cretaceous carbonate platform with estimated porosity and permeability values of typical facies (modified from Talbert and Atchley, 2000).

2.1.2 Regional Structure and Faulting

The Gulf of Mexico basin was formed by crustal extension and sea-floor spreading associated with the Mesozoic breakup of Pangea. Rifting of northwest to southeast trending transfer faults during the Middle Jurassic lasted approximately 25 million years and resulted in variable thickness of the transcontinental crust underlying the region. By the Lower Cretaceous time, the general outline and morphology of the Gulf were similar to that of present-day (Galloway, 2008;

Yurewicz et al., 1993). Lower Cretaceous tectonic activity was limited to regional subsidence associated with areas of variable crustal thickness and local structuring caused by movement of Louann Salt (Yurewicz et al., 1993). The combination of these processes resulted in the structural development of regional arches, grabens, uplifts, embayments, salt domes, and salt basins around the northern edge of the basin (Dennen and Hackley, 2012; Galloway, 2008). The location of these structural features can be referenced in Figures 2 and 8 relative to the location of the O'Neal No. 4.

The schematic dip-oriented cross section displayed in Figure 9 presents a common interpretation of the current structural setting. Most of the published literature suggests that faulting near the project area is restricted to the shallower, overlying Cenozoic section, as displayed in Figure 9, with shallow faulting dying out before reaching the Pearsall Formation. However, one source did interpret the potential for faulting to the south (Swanson et al., 2016). The closest potential fault is depicted in Figure 8 relative to the location of the O'Neal No. 4. According to the map, the interpreted fault lies approximately 4.25 miles south-southeast of the well and approximately 3.9 miles south-southeast of the stabilized plume extent in the year 2047.

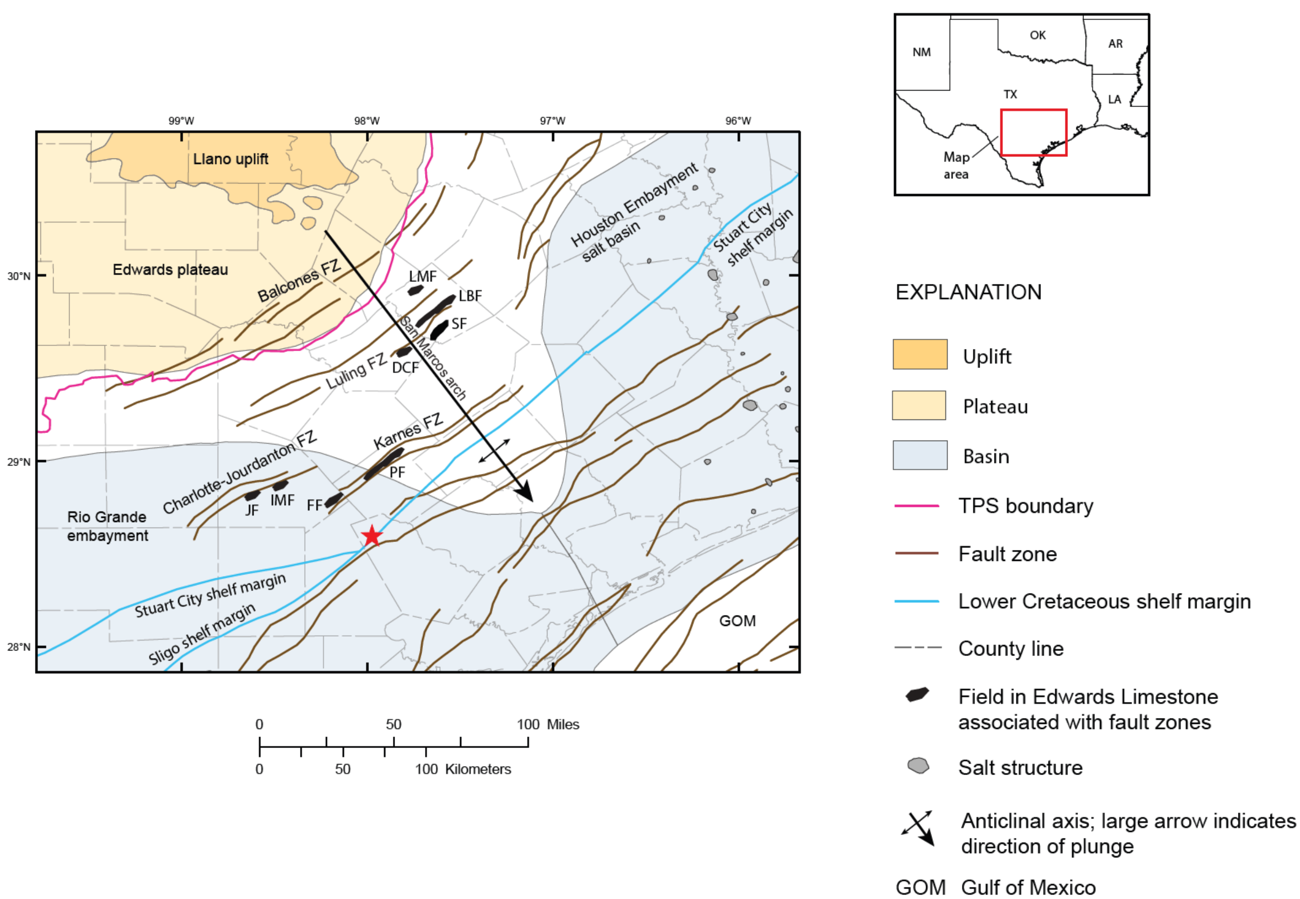

Figure 8 – Structural features and fault zones near the proposed injection site. The red star represents the approximate location of the O'Neal No. 4 (modified from Swanson et al., 2016).

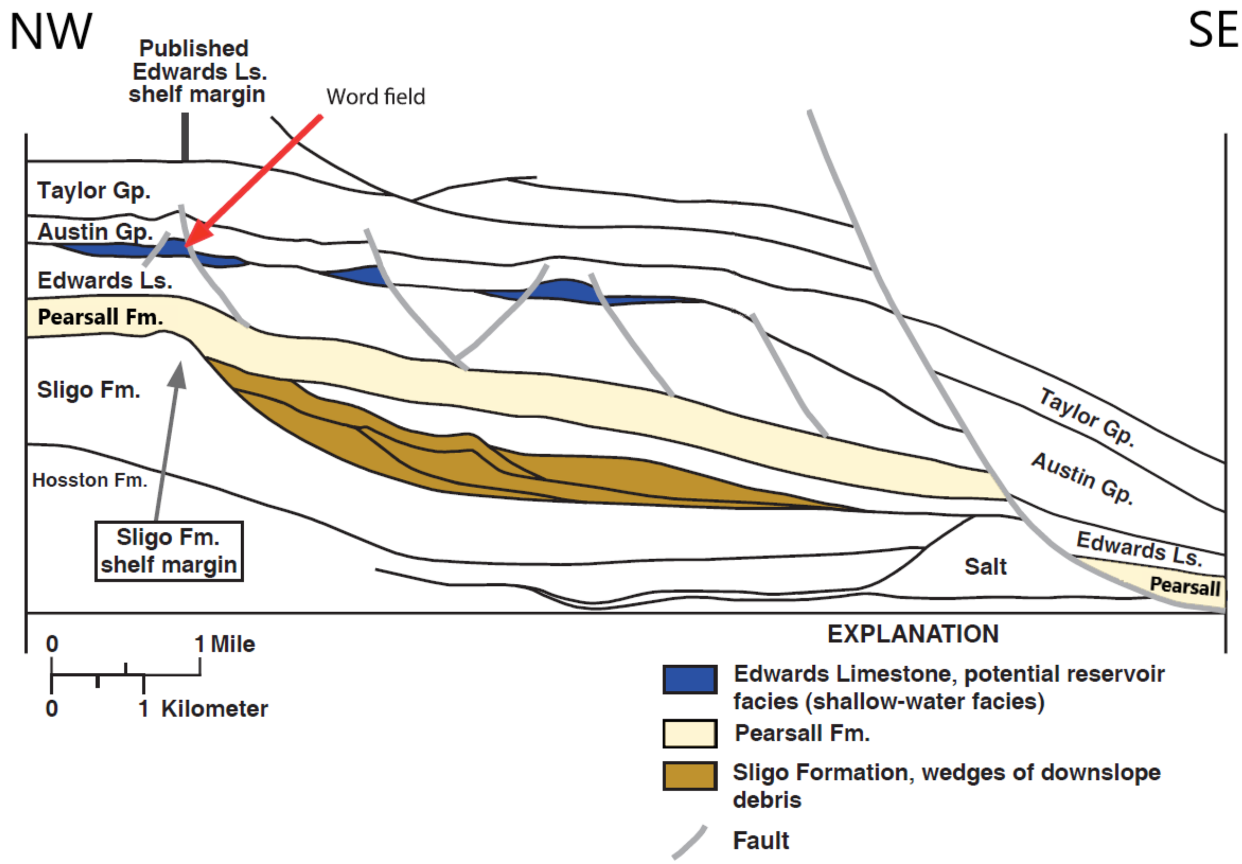

Figure 9 – Northwest to southeast schematic interpretation of the Edwards shelf margin through Word field, northeast of the O'Neal No. 4 project area (modified from Swanson et al., 2016).

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the O'Neal No. 4 well.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 depicts openhole logs from two offset wells (API No. 42-025-00473 and API No. 42-025-31892) to the O'Neal No. 4, indicating the injection and primary upper confining zones. The Tomasek No. 1 (API No. 42-025-00473) is located approximately 1 mi northeast of the O'Neal No. 4 and displays the shallow section from 0–8,200 ft. The Gordon No. 3 (API No. 42-025-31892) is located approximately 1.6 mi northeast of the O'Neal No. 4 and displays a shallow section from 8,200–16,400 ft.

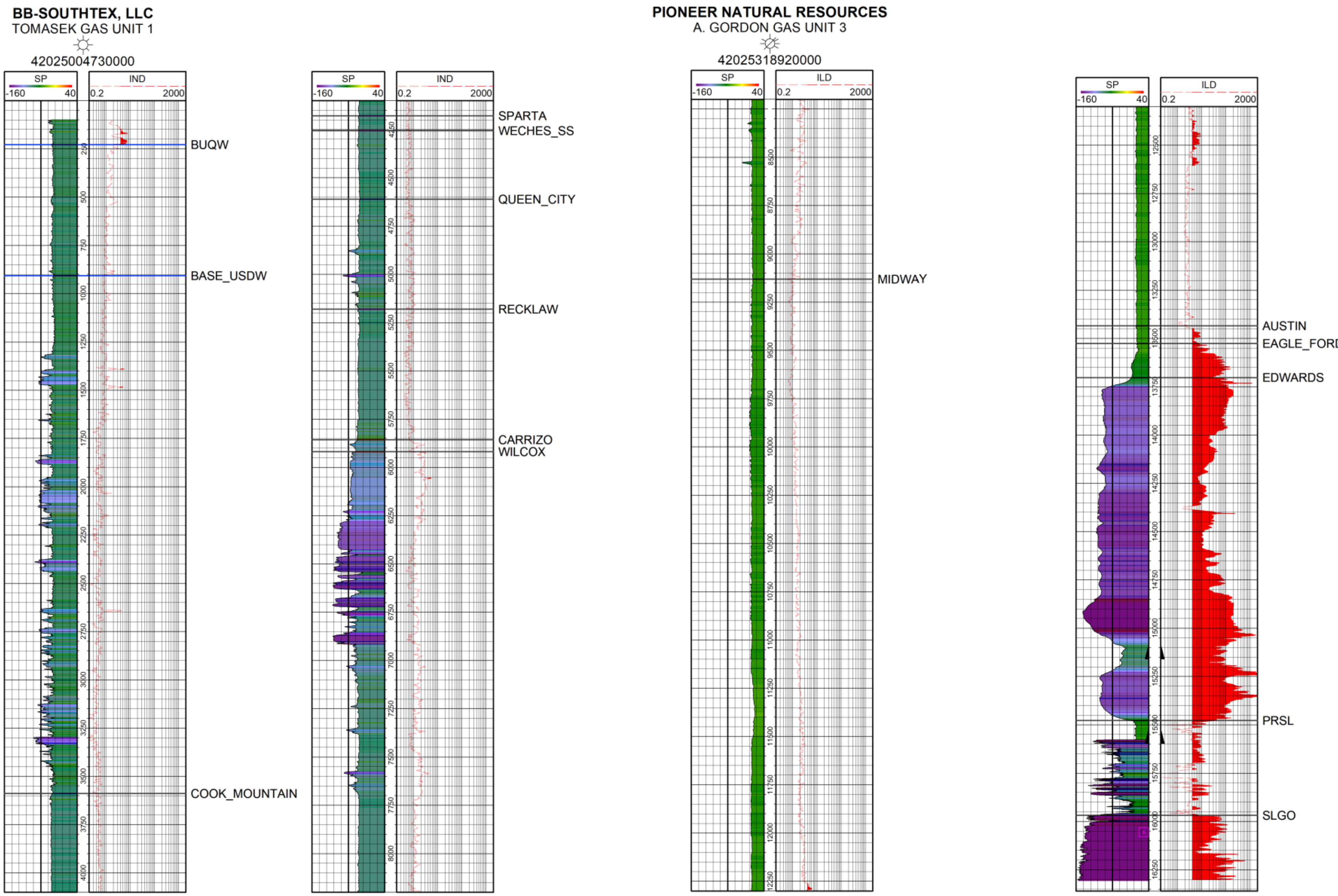

Figure 10 – Type Log with Tops, Confining, and Injection Intervals Depicted

2.2.2 Upper Confining Interval – Pearsall Formation

Following the deposition of the Sligo Formation, the Lower Cretaceous shelf was drowned by eustatic sea-level rise and deposition of the deep-water Pine Island Shale Member of the Pearsall Formation throughout the region (Roberts-Ashby et al., 2012). The Pine Island Shale consists of alternating beds of pelagic mudstone, hemipelagic mudstone, and Fe-rich dolomitic mudstone interpreted to have been deposited along the outer ramp. This is in agreement with core data published by Bebout and others (1981), and later by Swanson and others (2016), who identified the presence of *C. Margerelli*, a nannofossil indicative of anoxic conditions. The core-derived porosity-permeability relationship displayed in Figure 11 suggests that the permeability of the Pine Island Shale is incredibly low and stays below 0.0001 mD, regardless of porosity (Figure 11; Hull, 2011). This is further supported by the 2012 U.S. Geological Survey (USGS) *CO_2 Storage Resource Assessment*, which suggests that the Pine Island Shale contains the physical properties required to act as a regional seal and was chosen as the upward confining interval for their C50490108 Storage Assessment Unit (SAU) assessment of the Gulf Coast. The 2012 USGS report also noted that the Pine Island Shale is a sufficient regional seal with as little as 50 ft of contiguous shale development. The top of the Pearsall is encountered at a depth of 15,339 ft in the O'Neal No. 4, with a gross thickness of 535 ft (Figure 14). The Pine Island Shale member is approximately 130 ft thick at the O'Neal No. 4 location, with deposition of additional members of the overlying Pearsall Formation, which include the Cow Creek Limestone, Cow Creek shale, and Bexar Shale Members (Roberts-Ashby et al., 2012; Swanson et al., 2016).

The seismic line displayed in Figure 12 runs northwest to southeast across the Stuart City reef trend southwest of the project area. The top of the Buda, Pearsall, and Sligo Formation markers are depicted in color to demonstrate the lateral continuity of the section near the O'Neal No. 4. Seismic reflectors within the Pearsall Formation appear to lack deformation, suggesting consistent deposition over the reef margin. This is in agreement with reviewed published literature, which suggests deposition of the Pine Island Shale occurred during widespread marine transgression (Bebout et al., 1981; Hull, 2011.; Roberts-Ashby et al., 2012, Swanson et al., 2016).

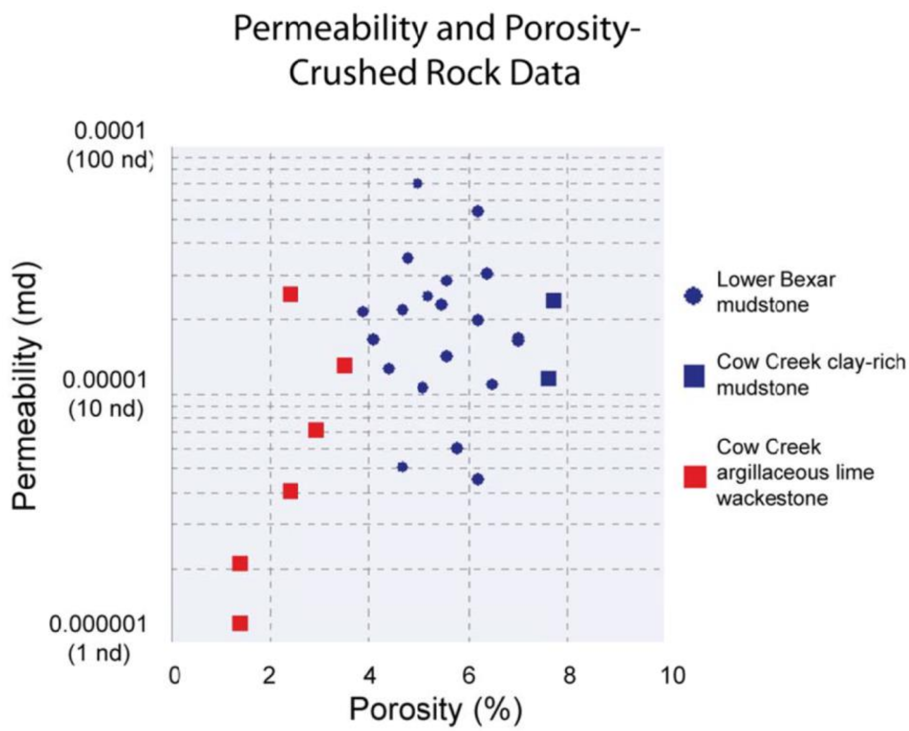

Figure 11 – Porosity-Permeability Crossplot of Pearsall Formation Crushed Rock Core Data (Swanson et al., 2016)

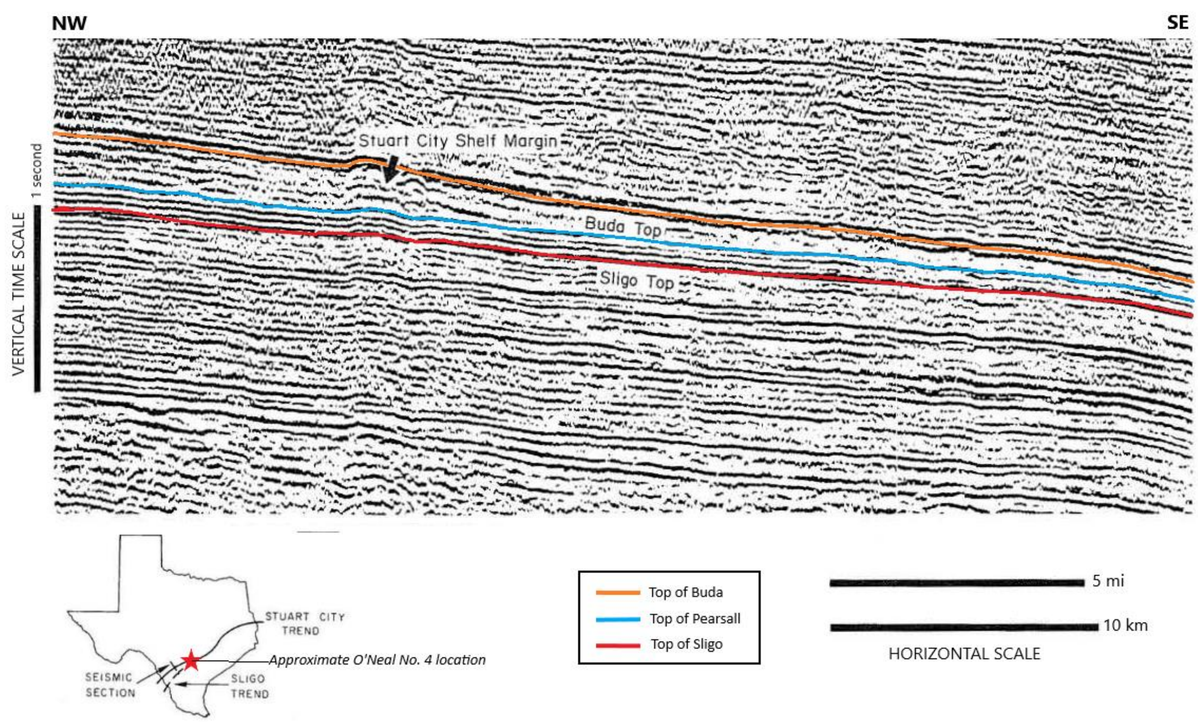

Figure 12 – Seismic line across the Stuart City (Edwards/Buda) shelf margin and locator map. The red star represents the approximate location of the O'Neal No. 4 (modified from Bebout et al., 1981).

2.2.3 Injection Interval – Upper Sligo Formation

The Sligo Formation underlies the Pearsall Formation and is predominately composed of shelf-edge limestones that were deposited along the Lower Cretaceous platform (Roberts-Ashby et al., 2012). However, the Cretaceous also experienced episodic changes in sea level that resulted in the deposition of cyclic Sligo facies that vary both spatially and within the geologic section. The overall Sligo interval is interpreted to be a transgressive sequence occasionally interrupted by progradational cycles that consists of porous shoaling-upward sequences that represent primary reservoir potential within the system (Bebout et al., 1981). Facies distributions of these reef complexes are heavily impacted by positioning relative to the margin, the height of the water column at any given time, and the degree of energy or wave action within the system (Galloway, 2008). Figure 13 depicts an idealized environmental setting of the Lower Cretaceous platform during deposition. Primary porosity and permeability of the upper Sligo Formation tends to develop in high-energy sequences with normal marine conditions that are dominated by the deposition of oolitic and skeletal grainstones.

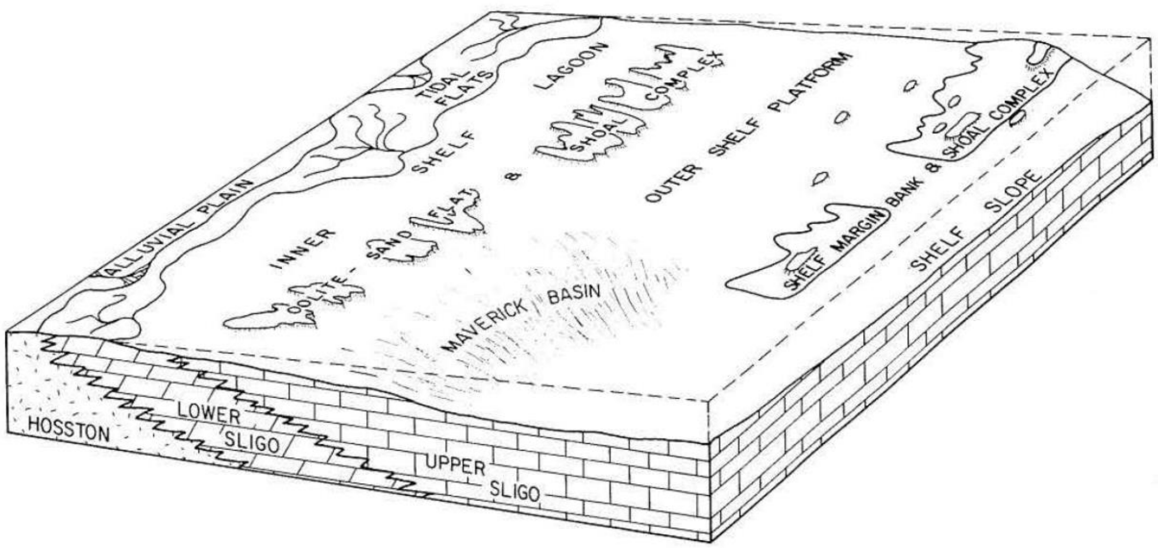

Figure 13 – Environmental Setting of Lower Cretaceous Platform (Bebout et al., 1981)

According to the 2012 USGS *CO_2 Storage Resource Assessment*, "the average porosity in the porous intervals of the storage reservoir decreases with depth from 9 to 16 percent" for their C50490108 DEEP SAU assessment of the Gulf Coast (>13,000 ft). The study also reported that "the average permeability in the storage reservoirs decreases with depth from 0.05 to 200 mD, with a most-likely value of 8 mD" for their C50490108 DEEP SAU assessment of the Gulf Coast (Roberts-Ashby et al., 2012).

The top of the upper Sligo is encountered at a depth of 15,874 ft in the O'Neal No. 4 with a gross thickness of 183 ft (Figure 14). The type log displayed in Figure 14 plots effective porosity for the confining interval and the total porosity of the injection interval, to account for the increased

volume of shale (Vshale) seen in the Pearsall Formation. The porosity data was compared to the analysis performed by Nutech to generate a permeability curve with a reasonable porosity-permeability relationship. The permeability curve was generated utilizing the Coates permeability equation, incorporated with a 20% irreducible brine saturation to match analysis provided by Nutech. Petrophysical analysis of the O'Neal No. 4 indicates an average porosity of 4.6%, a maximum porosity of 15%, an average permeability of 0.16 mD, and a maximum permeability of 3.3 mD. These curves have been extrapolated to the injection site and used to establish reservoir characteristics in the plume model.

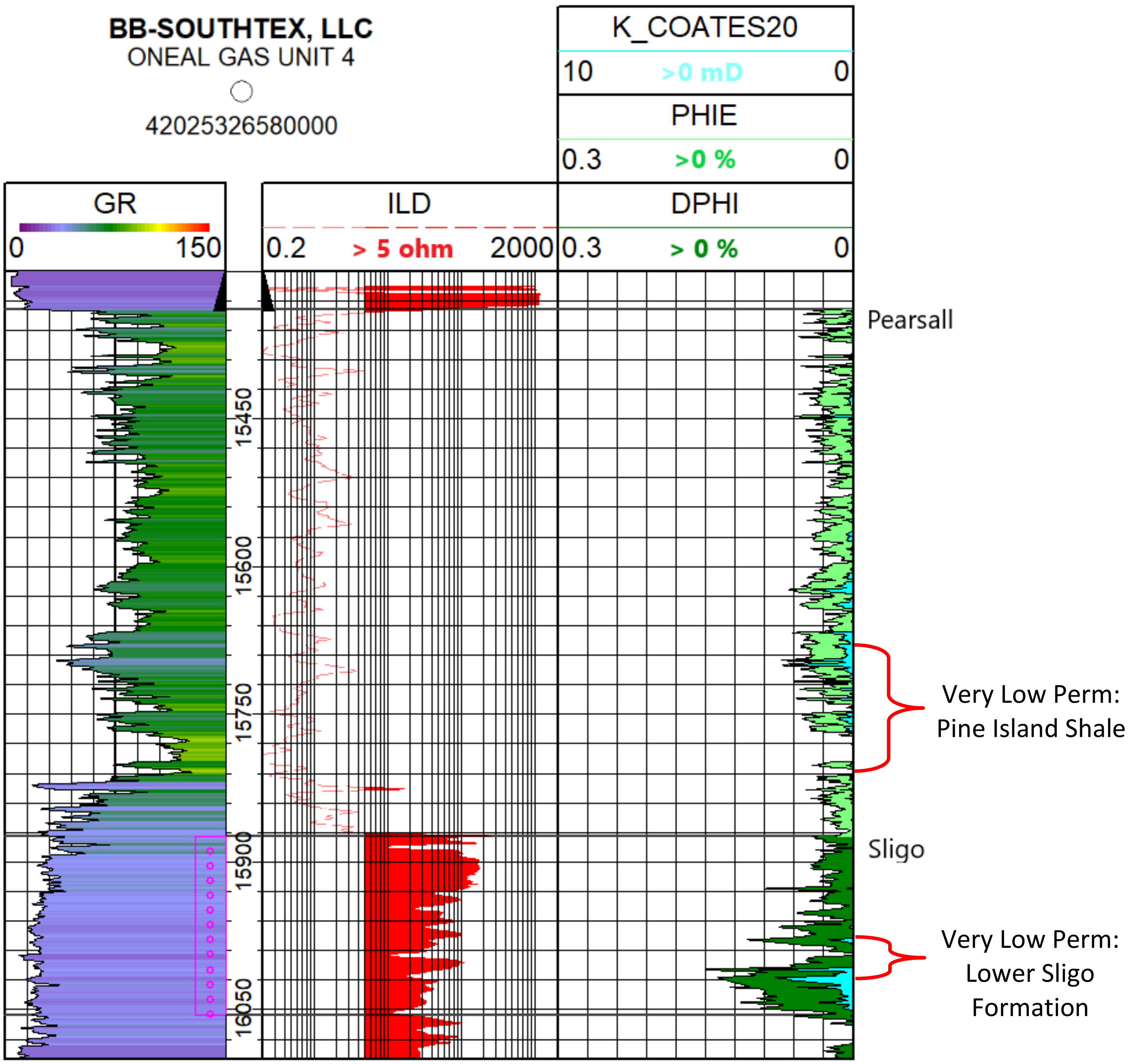

Figure 14 – Openhole log from O'Neal No. 4 (API No. 42-025-32658), with porosity curves shaded green >0%, permeability curve in blue >0 mD, and resistivity in red >5 ohms.

2.2.4 Formation Fluid

The USGS National Produced Waters Geochemical Database version 3.0 was reviewed for chemical analyses of Sligo oil-field brines within the state of Texas (Blondes et al., 2023). Only two samples were identified from the Sligo Formation: one located approximately 29 mi north-northeast in Karnes County and one located approximately 72 mi northeast in Gonzales County. The locations of these wells are shown in Figure 15 relative to the O'Neal No. 4. A summary of water chemistry analyses conducted on the two Texas Sligo oil-field brine samples is provided in Table 2 (page 25).

Averages from the samples were utilized for model assumptions due to the minimal Sligo sample availability and wide geographic spread of Sligo analysis. Total Dissolved Solids (TDS) of the samples contain a wide range of reported values but averaged 176,470 parts per million (ppm). Model sensitivities were established by running iterations with varying TDS values to understand the effect of brine concentrations on plume extents. The results suggested higher density brine values lead to smaller plumes; therefore, a value of 150,000 ppm was established in the model for a conservative approach. If the actual formation fluid sample that will be tested during the recompletion work produces a material difference in the plume, Ozona will submit an updated MRV plan.

Based on the results of the investigation, *in situ* Sligo reservoir fluid is anticipated to contain greater than 20,000 ppm TDS near the O'Neal No. 4, qualifying the aquifer as saline. These analyses indicate the *in situ* reservoir fluid of the Sligo Formation is compatible with the proposed injection fluids.

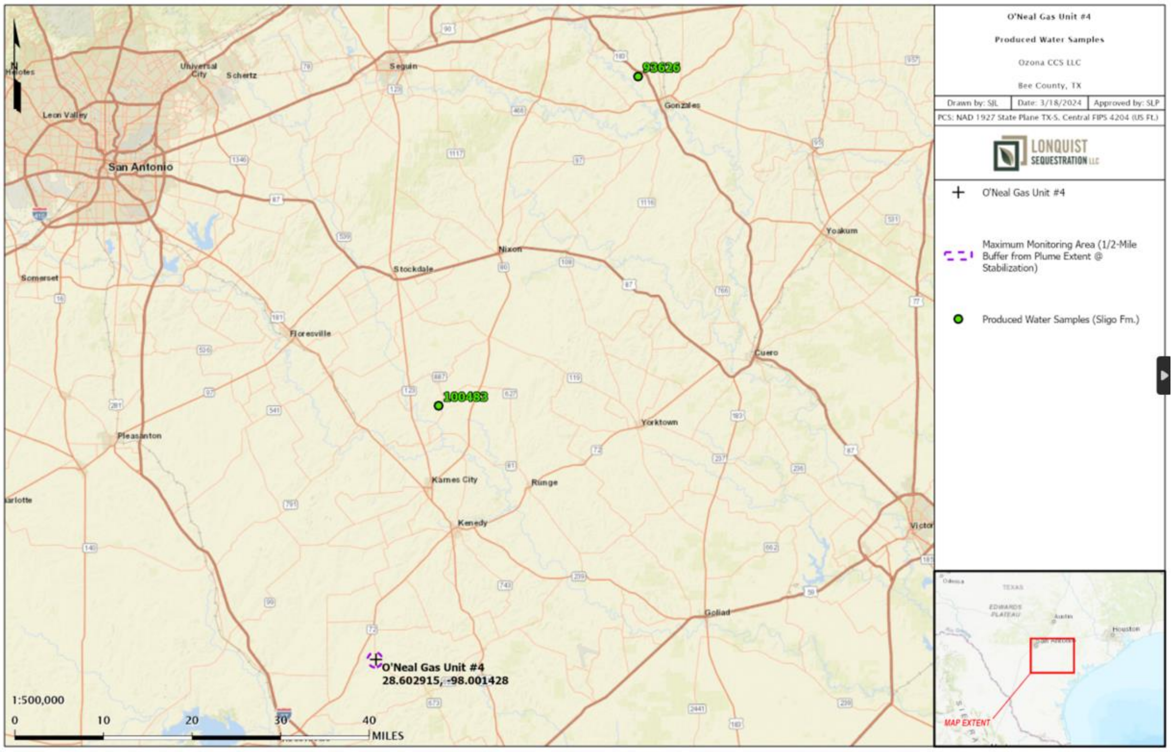

Figure 15 – Offset Wells Used for Formation Fluid Characterization

Table 2 – Analysis of Lower Cretaceous (Aptian) age formation fluids from the closest offset Sligo oil-field brine samples.

Measurement	Karnes County Sample	Gonzales County Sample	Average
Total Dissolved Solids (mg/L)	234,646	117,470	176,058
Sodium (mg/L)	51,168	27,909	39,539
Calcium (mg/L)	34,335	8,684	21,510
Chloride (mg/L)	146,500	57,811	102,156
Sample Depth (ft)	13,580 to 13,660	8,290-8,305	-
pH	5.9	8.2	7.05

2.2.5 Fracture Pressure Gradient

The fracture pressure gradient was obtained from a fracture report taken during the April 1993 completion of the Sligo interval in the O'Neal No. 4. The Sligo was perforated between the depths of 15,874 ft and 16,056 ft, with continuous monitoring during the minifrac job. The report noted a calculated fracture gradient of 0.954 psi/ft based on an initial shut-in pressure (ISIP) of 8,312 psi. A 10% safety factor was then applied to the calculated gradient, resulting in a maximum allowed bottomhole pressure of 0.86 psi/ft. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

2.2.6 Lower Confining Interval – Lower Sligo and Hosston Formations

The O'Neal No. 4 reaches its total depth in the lower Sligo Formation, directly below the upper Sligo proposed injection interval. The lower Sligo is interpreted by Bebout and others (1981) to represent the seaward extension of the low-energy lagoon and tidal-flat system of the underlying Hosston Formation, a sequence of siliciclastics, evaporites, and dolomitic mudstone (Figure 16). The Hosston to lower Sligo "contact" represents a gradational package with a decrease in terrigenous sediments, an increase in carbonate sediments, and an increase in burrows of marine organisms working up-section into the lower Sligo. The lower Sligo consists of numerous cycles of subtidal to supratidal carbonates deposited in a low-energy lagoon and tidal-flat system (Bebout et al., 1981). These low permeability facies of the lower Sligo and underlying Hosston Formation will provide lower confinement to the upper Sligo injection interval. Figure 16 illustrates the typical environmental setting for the deposition of tidal flat facies along the Lower Cretaceous margin. The type log displayed in Figure 14 (*Section 2.2.3*) illustrates that the porosity of the lower Sligo ranges between 0–2% with permeability staying close to 0 mD. Therefore, the petrophysical characteristics of the lower Sligo and Hosston are ideal for prohibiting the migration of the injection stream outside of the injection interval.

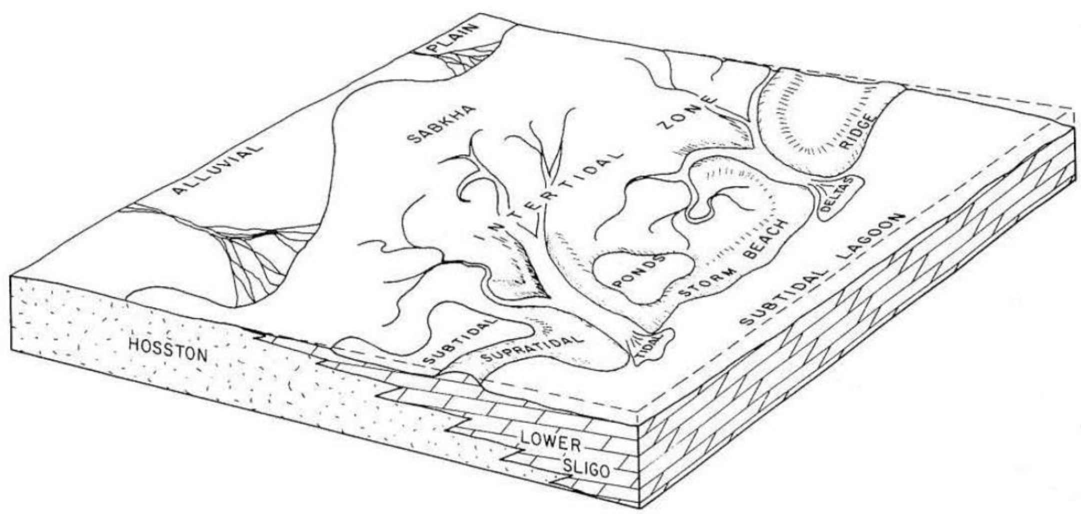

Figure 16 – Environmental Setting of Lower Cretaceous Tidal Flat Deposits (Bebout et al., 1981)

2.3 Local Structure

Structures surrounding the proposed sequestration site were influenced by regional arches, grabens, uplifts, embayments, movement of Louann Salt, and the development of carbonate reef complexes around the northern edge of the basin. However, one potential fault was identified in the literature within proximity and lies approximately 4.25 mi south-southeast of the well and

approximately 3.9 mi south-southeast of the stabilized plume extent in the year 2062 (Swanson et al., 2016). The location of these structural features can be referenced in Figures 2 and 8 relative to the location of the O'Neal No. 4.

A subsea true vertical depth (SSTVD) structure map on the top of the Sligo Formation is provided in Figure 17. The map illustrates the gentle basinward dip of the Sligo from the northwest to the southeast. The structural cross sections provided in Figures 18 and 19 (pages 28 and 29, respectively) illustrate the structural changes encountered in moving away from the O'Neal No. 4 site. The figures also demonstrate the laterally continuous nature of the Pearsall Formation that overlies the injection interval, with sufficient thickness and modeled petrophysical properties to alleviate the risk of upward migration of injected fluids. *Section 2.1.2*, discussing regional structure and faulting, presents a regional discussion pertinent to this topic.

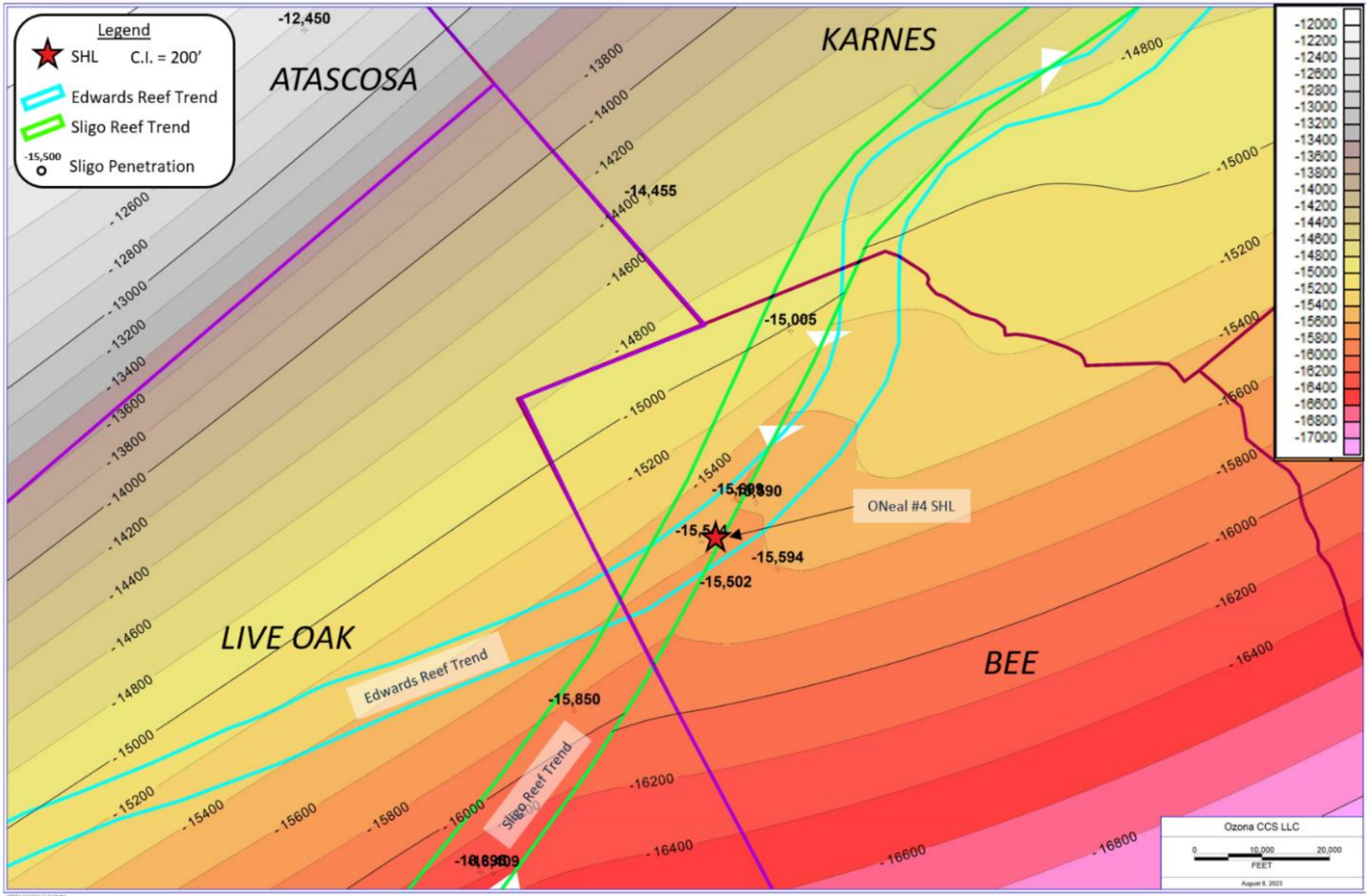

Figure 17 – Subsea Structure Map: Top of Sligo (injection interval). The red star signifies the location of the O'Neal No. 4.

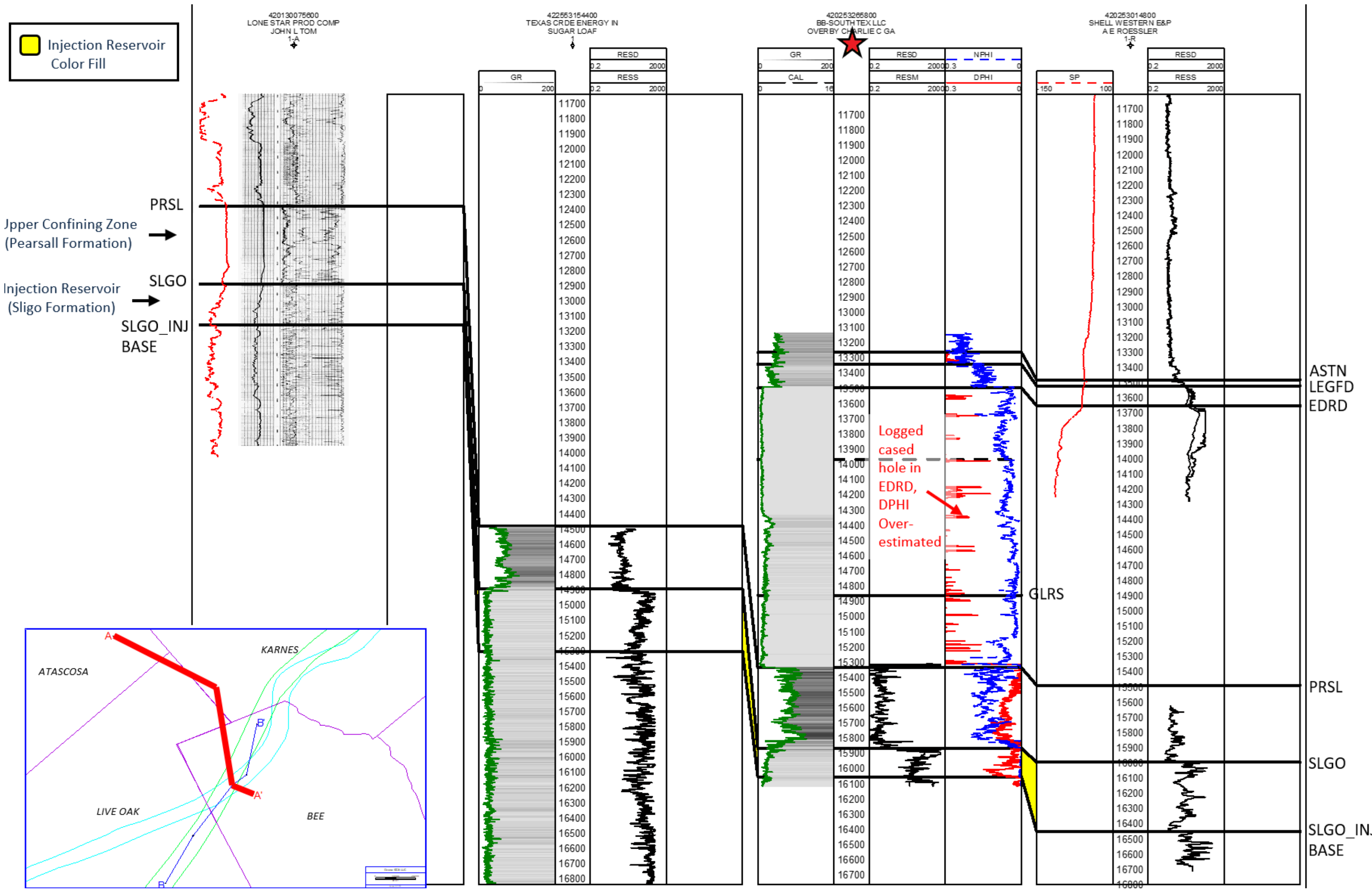

Figure 18 – Northwest to southeast structural cross section: A-A' Oriented along regional dip.
The red star signifies the location of the O'Neal No. 4, with the section line depicted in red on the locator map.

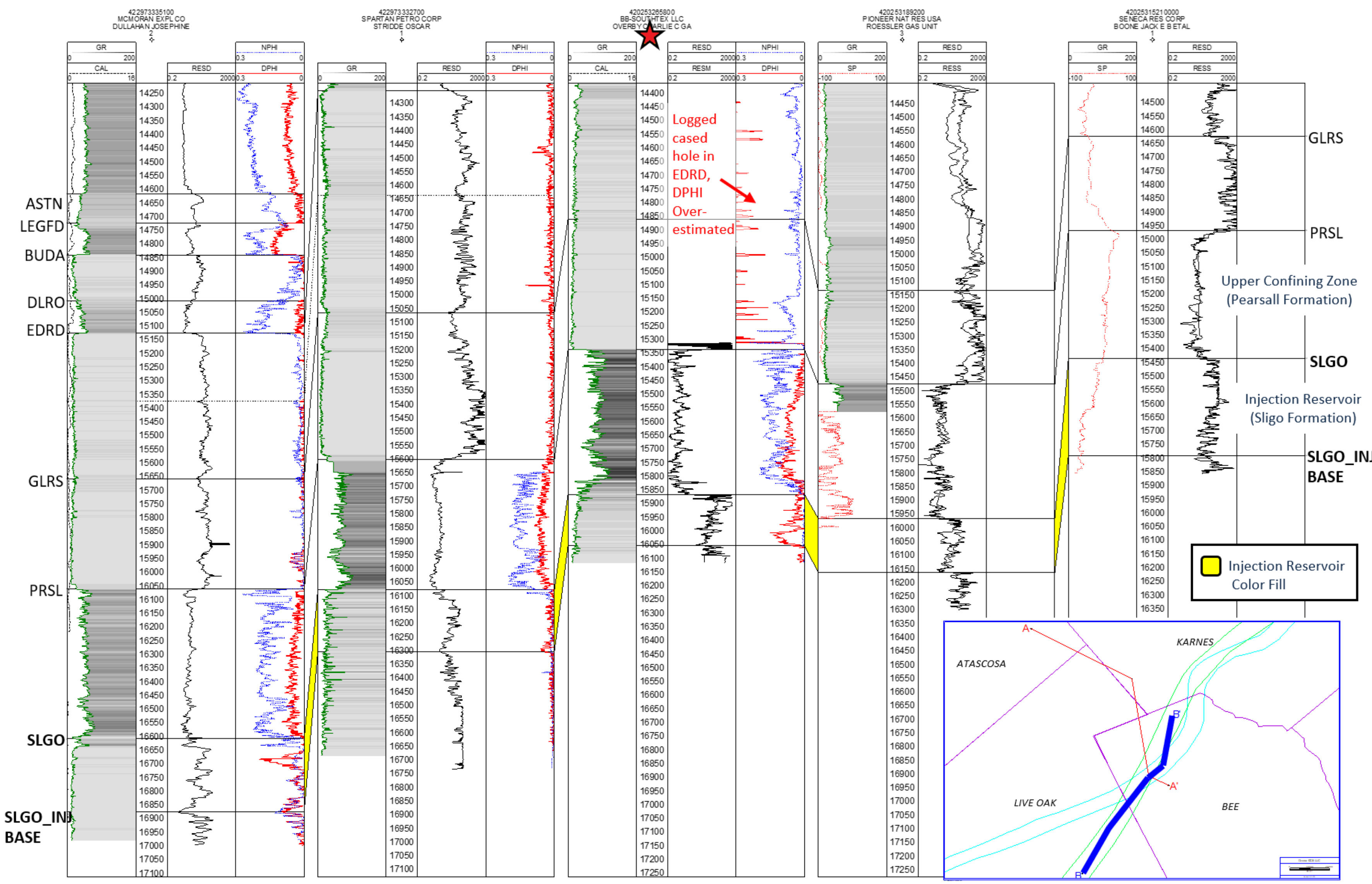

Figure 19 – Southwest to northeast structural cross section: B-B' oriented along regional strike.
The red star signifies the location of the O'Neal No. 4, with the section line depicted in blue on the locator map.

2.4 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Sligo Formation at the O'Neal No. 4 well location indicate that the reservoir contains the necessary thickness, porosity, and permeability to receive the proposed injection stream. The overlying Pearsall Formation is regionally extensive at the O'Neal No. 4 with low permeability and sufficient thickness to serve as the upper confining interval. Beneath the injection interval, the low permeability, low porosity facies tidal flat, and lagoonal facies of the lower Sligo and underlying Hosston Formation are unsuitable for fluid migration and serve as the lower confining interval.

2.5 Groundwater Hydrology

Bee County falls within the boundary of the Bee Groundwater Conservation District. Only one aquifer is identified by the Texas Water Development Board's Texas Aquifers Study near the O'Neal No. 4 well location, the unconfined to semi-confined Gulf Coast aquifer. The Gulf Coast aquifer parallels the Gulf of Mexico and extends across the state of Texas from the Mexican border to the border of Louisiana (Bruun et al., 2016). The extents of the Gulf Coast aquifer are provided in Figure 20 for reference.

The Gulf Coast aquifer is a major aquifer system comprised of several individual aquifers: the Jasper, Evangeline, and Chicot. These aquifers are composed of discontinuous clay, silt, sand, and gravel beds that range from Miocene to Holocene in age (Figure 21, page 32). Numerous interbedded lenses and layers of silt and clay are present within the aquifers, which can confine individual aquifers locally. The underlying Oligocene Catahoula tuff represents the lower confining interval, but it should be noted that the formation is prone to leaking along the base of the aquifer. However, the Burkeville confining interval provides isolation between Jasper and Evangeline aquifers which helps protect the shallower Evangeline and Chicot Aquifers (Bruun et al., 2016).

The schematic cross section provided in Figure 22 (page 32) runs south of the O'Neal No. 4, illustrating the structure and stratigraphy of the aquifer system. The thickness of individual sedimentary units within the Cenozoic section tends to thicken towards the Gulf of Mexico due to the presence of growth faults that allow additional loading of unconsolidated sediment. The total net sand thickness of the aquifer system ranges between 700 ft of sand in the south, to over 1,300 ft in the north, with the saturated freshwater thickness averaging 1,000 ft.

The water quality of the aquifer system varies with depth and locality but water quality generally improves towards the central to northeastern portions of the aquifer where TDS values are less than 500 milligrams per liter (mg/L). The salinity of the Gulf Coast aquifer increases to the south, where TDS ranges between 1,000 mg/L to more than 10,000 mg/L. The Texas Water Development Board's Texas Aquifers Study (2016) suggests that areas associated with higher salinities are possibly associated with saltwater intrusion likely "resulting from groundwater pumping or to brine migration in response to oil field operations and natural flows from salt domes intruding into the aquifer" (Bruun et al., 2016).

According to the TDS map of the Gulf Coast aquifer (Figure 23), the TDS in northern Bee County range between 500–3,000 mg/L near the O'Neal No. 4, categorizing the aquifer as fresh to slightly saline.

The TRRC's Groundwater Advisory Unit (GAU) identified the Base of Useable Quality water (BUQW) at a depth of 250 ft and the base of the USDW at a depth of 950 ft at the location of the O'Neal No. 4. Approximately 14,924 ft is therefore separating the base of the USDW and the injection interval. (A copy of the GAU's Groundwater Protection Determination letter issued by the TRRC as part of the Class II permitting process for the O'Neal No. 4 is provided in Exhibit A-1.) The base of the deepest aquifer is separated from the injection interval by more than 14,924 ft of rock, including 4,200 feet of Midway shale. Though unlikely for reasons outlined in the sections here on confinement and potential leaks, if the migration of injected fluid did occur above the Pearsall Formation, thousands of feet of tight sandstone, limestone, shale, and anhydrite beds occur between the injection interval and the lowest water-bearing aquifer.

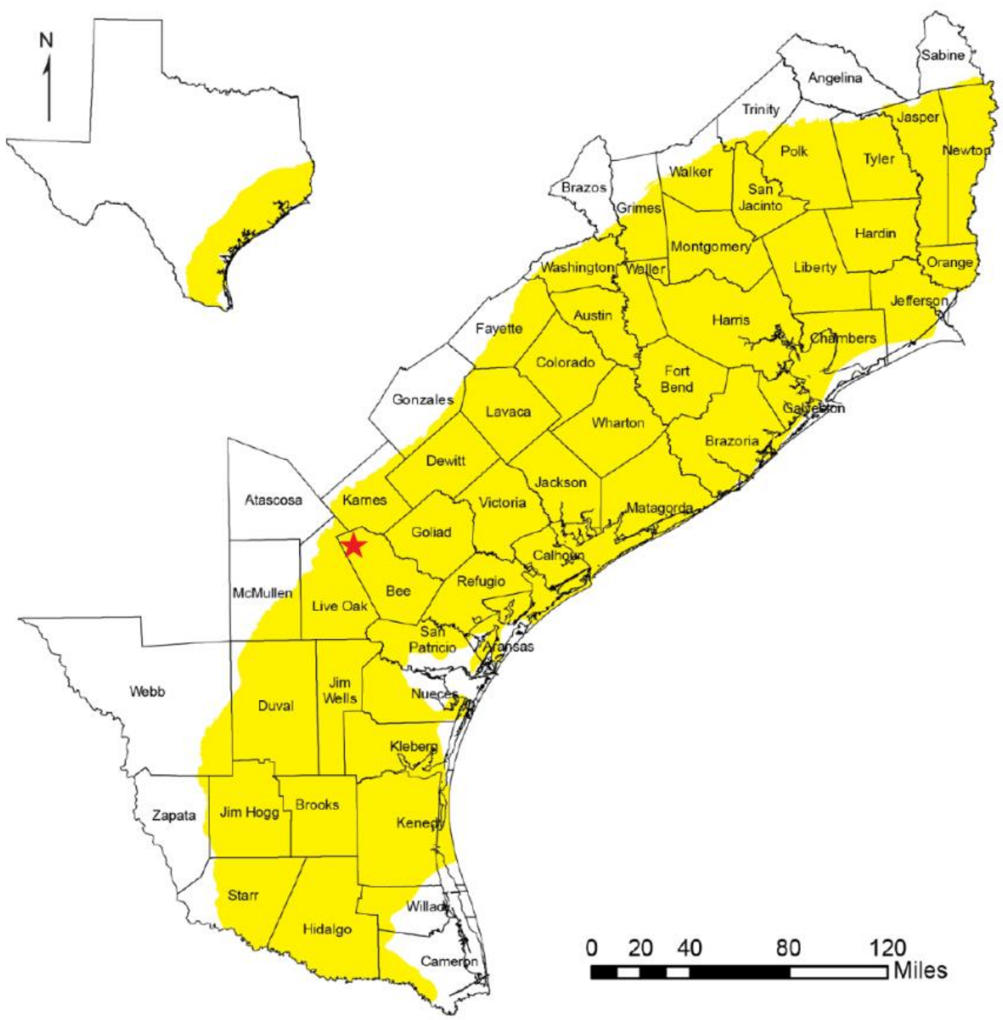

Figure 20 – Extent of the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun, B., et al., 2016)

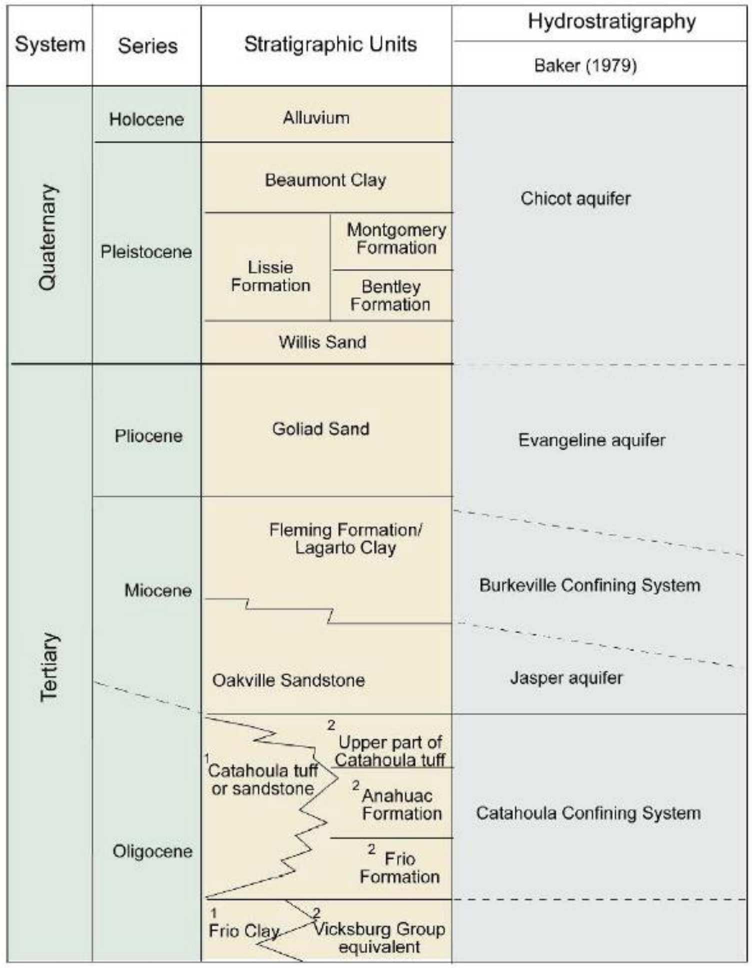

Figure 21 – Stratigraphic Column of the Gulf Coast Aquifer (Chowdhury and Turco, 2006)

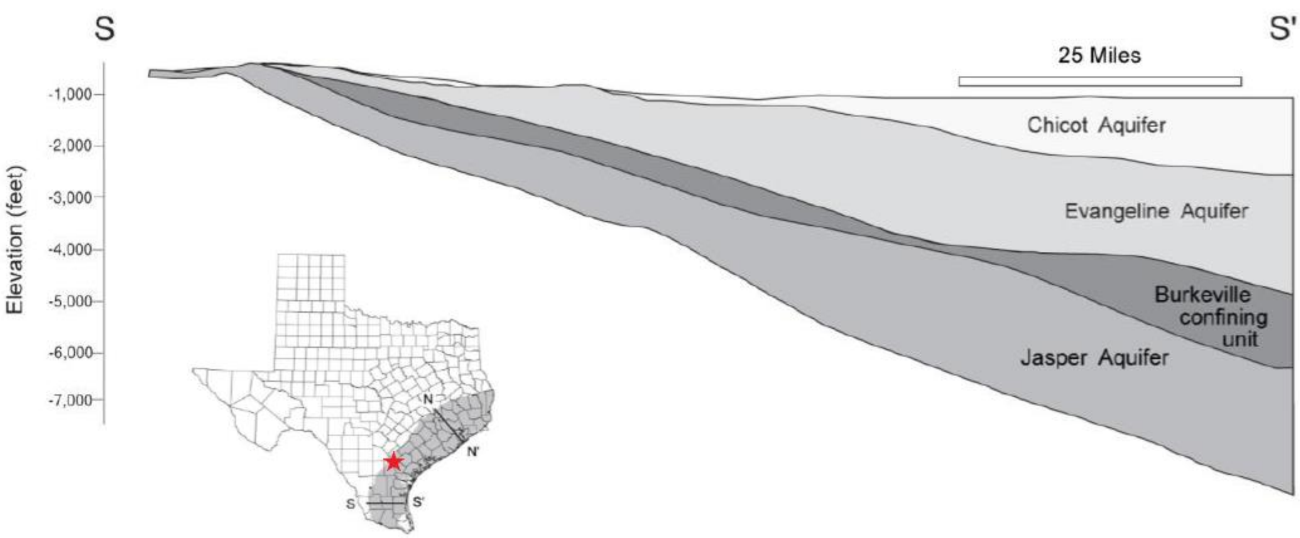

Figure 22 – Cross Section S-S' Across the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun et al., 2016)

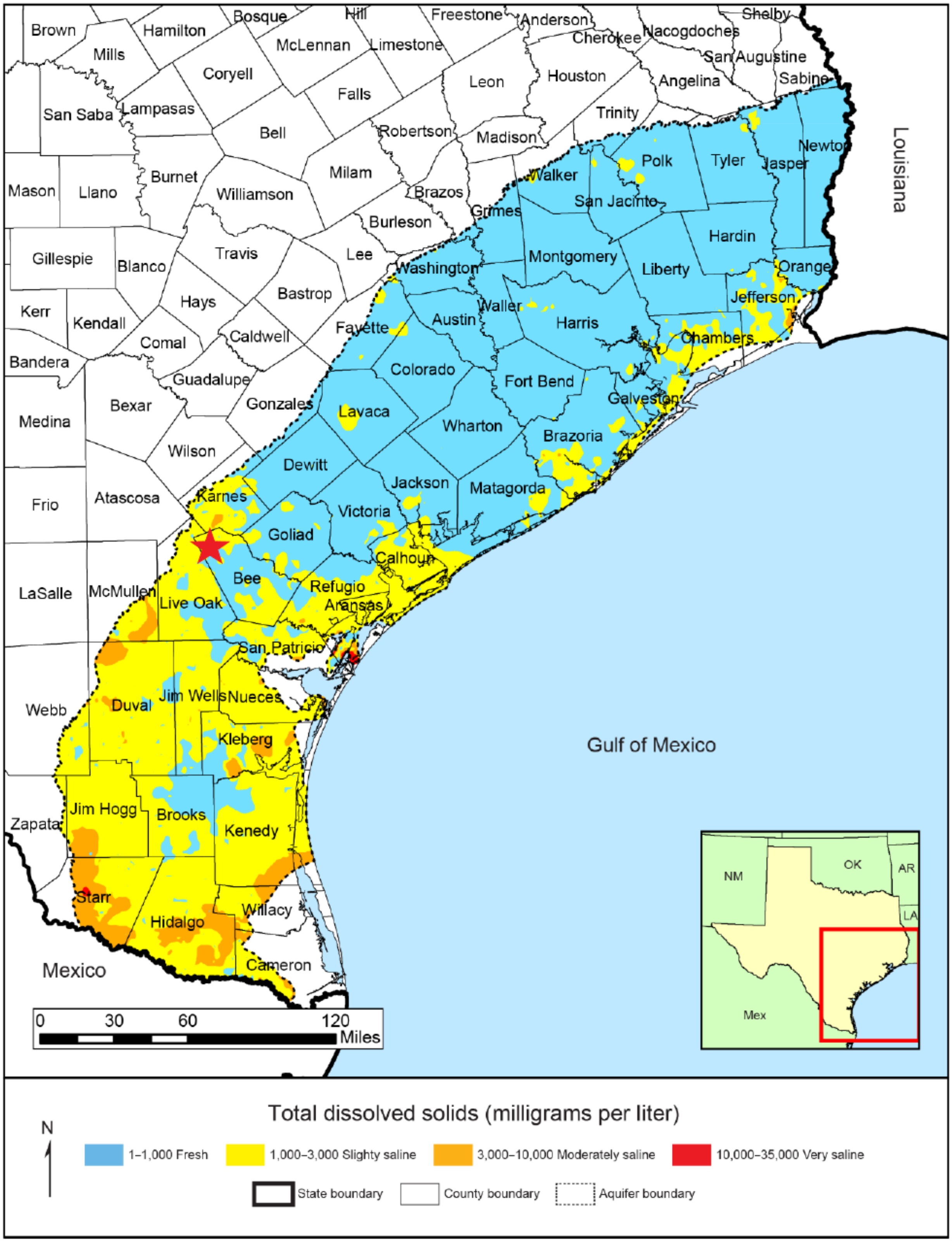

Figure 23 – Total Dissolved Solids (TDS) in the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun et al., 2016).

2.6 References

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2.7 Description of the Injection Process

2.7.1 Current Operations

The Pawnee Treating Facility and the O'Neal No. 4 are existing operating assets. The O'Neal No. 4 will be recompleted for acid gas injection service under the Class II permit process. Under the Class II application, the maximum injection rate is 28 MT/yr (1.5 MMscf/d). The TAG is 98.2% CO_2, which equates to 27.5 MT/yr of CO_2 each year. The current composition of the TAG stream is displayed in Table 3.

Table 3 – Gas Composition

Component	Mol Percent
Carbon Dioxide	98.2%
Hydrocarbons	1.03%
Hydrogen Sulfide	0.4%
Nitrogen	0.37%

The facility is designed to treat, dehydrate, and compress the natural gas produced from the surrounding acreage in Bee County. The facility uses an amine unit to remove the CO_2 and other constituents from the gas stream. The TAG stream is then dehydrated, compressed, and routed directly to the O'Neal No. 4 for injection. The remaining gas stream is processed to separate the natural gas liquids from the natural gas. The facility is monitored 24 hours per day, 7 days per week.

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group, Ltd.'s GEM 2023.2 (GEM) simulator, one of the most comprehensive reservoir simulation software packages for conventional, unconventional, and secondary recovery. The GEM utilizes equation-of-state (EOS) algorithms in conjunction with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics. This results in the creation of exceedingly precise and dependable simulation models for carbon injection and storage. The GEM model holds recognition from the EPA for its application in the delineation modeling aspect of the area of review, as outlined in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Sligo Formation serves as the target formation for the O'Neal No. 4 (API No. 42-025-32658). The Petra software package was utilized to construct the geological model for this target formation. Within Petra, formation top contours were generated and subsequently brought into GEM to outline the geological structure.

Porosity and permeability estimates were determined using the porosity log from the O'Neal No. 4. A petrophysical analysis was then conducted to establish a correlation between porosity values and permeability, employing the Coates equation. Both the porosity and permeability estimates from

the O'Neal No. 4 were incorporated into the model, with the assumption that they exhibit lateral homogeneity throughout the reservoir.

The reservoir is assumed to be at hydrostatic equilibrium. Given the geological formation in which this well is located and its previous history as a gas producer, the model is assumed to be primarily saturated with gas. More precisely, the reservoir is assumed to be 80% gas saturated and 20% brine saturated, as deduced from the well log data. The modeled injection interval exhibits an average permeability of 0.23 mD and an average porosity of 5%. All layers within the model have been perforated. An infinite-acting reservoir has been created to simulate the boundary conditions.

The gas injectate is composed predominantly of CO_2 as shown in Table 4. The modeled composition takes into consideration the carbon dioxide and other constituents of the total stream. As the facility has been in operation for many years, the gas composition for the proposed injection period is expected to remain constant.

Table 4 – Modeled Injectate Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Carbon Dioxide (CO_2)	98.2	98.2
Hydrocarbons	1.03	Hydrocarbons
Hydrogen Sulfide	0.4	Hydrogen Sulfide
Nitrogen	0.37	Nitrogen

Core data from the literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Sligo carbonates (Bennion and Bachu, 2010). A maximum residual gas saturation of 35% was assigned to the model based on core from the literature review. The Corey-Brooks method was used to create relative permeability curves. The key inputs used to create the relative permeability curves in the model include a Corey exponent for brine of 1.8, a Corey exponent for gas of 2.5, brine and gas relative permeability endpoints of 0.8 and 0.5, respectively, and an irreducible brine saturation of 20%. The relative permeability curves used for the GEM model are shown in Figure 24.

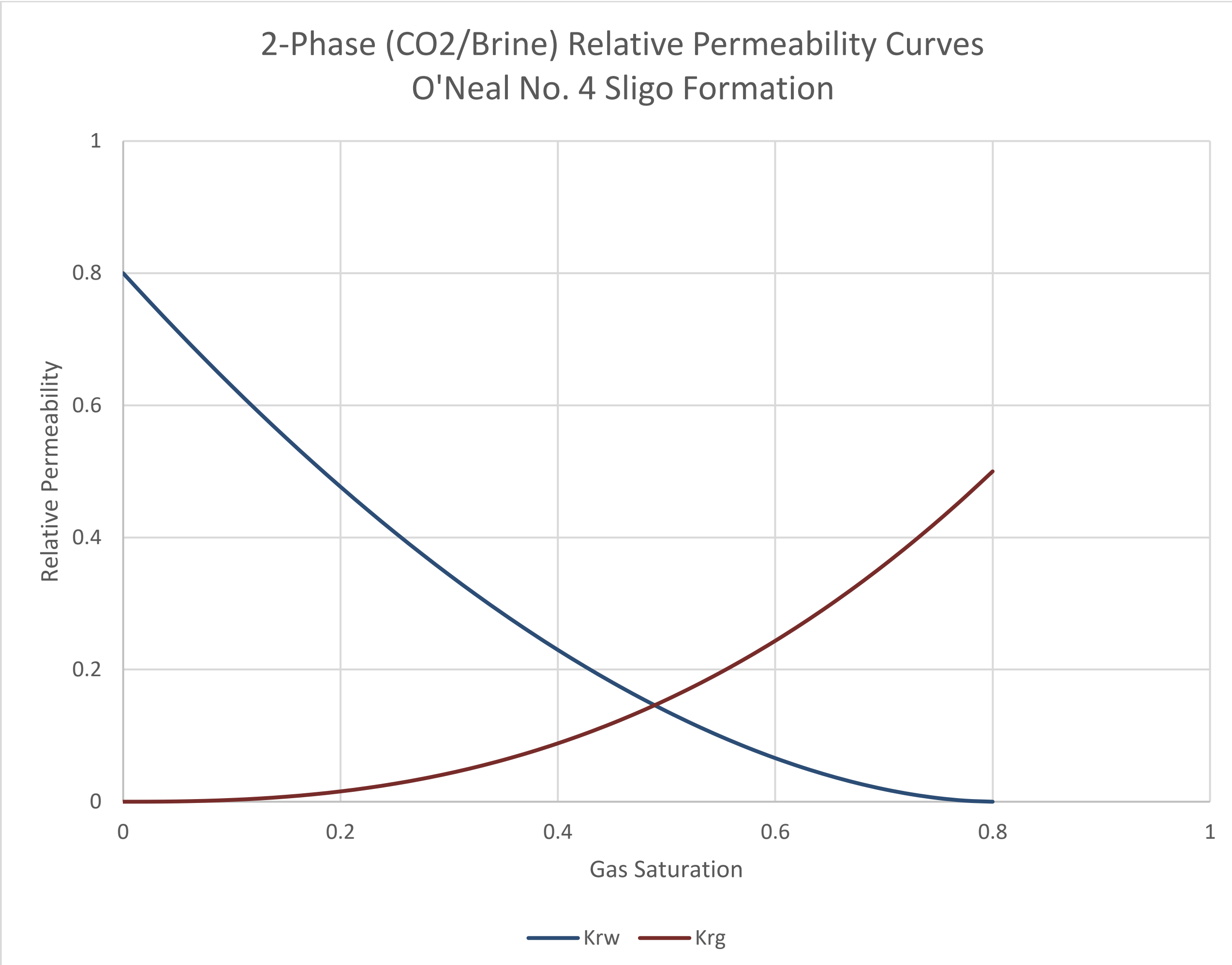


Figure 24 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 81 blocks in the x-direction (east-west) and 81 blocks in the y-direction (north-south), resulting in a total of 6,561 grid blocks per layer. Each grid block spans dimensions of 250 ft x 250 ft. This configuration yields a grid size measuring 20,250 ft x 20,250 ft, equating to just under 15 square miles in area. The grid cells in the vicinity of the O'Neal No. 4, within a radius of 0.5 mi, have been refined to dimensions of 83.333 ft x 83.333 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume and pressure effects near the wellbore.

In the model, each layer is characterized by homogeneous permeability and porosity values. These values are derived from the porosity log of the O'Neal No. 4. The model encompasses a total of 61 layers, each featuring a thickness of approximately 3 ft per layer. As previously mentioned, the model is perforated in each layer, with the top layer being the top of the injection interval and the bottom layer being the lowest portion of the injection interval. The summarized property values for each of these packages are displayed in Table 5.

Table 5 – GEM Model Layer Package Properties

Layer No.	Top (TVD ft)	Thickness	Perm. (mD)	Porosity (%)
1	15,874	3	0.004	3.75%
2	15,877	3	0.002	2.98%
3	15,880	3	0.001	1.62%
4	15,883	3	0.001	1.78%
5	15,886	3	0.002	2.32%
6	15,889	3	0.001	1.96%
7	15,892	3	0.002	3.10%
8	15,895	3	0.002	2.99%
9	15,898	3	0.003	3.52%
10	15,901	3	0.006	4.00%
11	15,904	3	0.005	3.93%
12	15,907	3	0.001	2.15%
13	15,910	3	0.001	1.99%
14	15,913	3	0.002	2.97%
15	15,916	3	0.001	2.22%
16	15,919	3	0.002	2.88%
17	15,922	3	0.001	2.38%
18	15,925	3	0.093	6.68%
19	15,928	3	0.005	2.62%
20	15,931	3	0.002	2.58%
21	15,934	3	0.003	3.07%
22	15,937	3	0.006	3.62%
23	15,940	3	0.002	2.68%
24	15,943	3	0.001	1.08%
25	15,946	3	0.002	1.87%
26	15,949	3	0.025	4.70%
27	15,952	3	0.024	4.37%
28	15,955	3	0.001	1.97%
29	15,958	3	0.003	2.27%
30	15,961	3	0.007	3.09%
31	15,964	3	0.110	6.75%
32	15,967	3	0.037	5.62%
33	15,970	3	0.011	4.41%
34	15,973	3	0.022	4.59%
35	15,976	3	0.297	7.88%
36	15,979	3	0.440	9.21%
37	15,982	3	0.060	5.90%
38	15,985	3	0.001	2.22%
39	15,988	3	0.001	2.21%

Layer No.	Top (TVD ft)	Thickness	Perm. (mD)	Porosity (%)
40	15,991	3	0.001	1.12%
41	15,994	3	0.003	2.05%
42	15,997	3	0.014	4.56%
43	16,000	3	0.007	4.15%
44	16,003	3	0.033	5.95%
45	16,006	3	1.233	10.25%
46	16,009	3	1.476	12.04%
47	16,012	3	0.566	10.08%
48	16,015	3	1.679	12.18%
49	16,018	3	2.194	13.08%
50	16,021	3	1.235	12.02%
51	16,024	3	0.788	11.22%
52	16,027	3	0.944	10.48%
53	16,030	3	0.424	9.05%
54	16,033	3	0.378	8.85%
55	16,036	3	0.378	8.81%
56	16,039	3	0.378	8.84%
57	16,042	3	0.736	9.91%
58	16,045	3	0.232	7.94%
59	16,048	3	0.238	7.97%
60	16,051	3	0.012	3.01%
61	16,054	3	0.038	4.30%

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

1. Estimate the maximum areal extent and density drift of the injectate plume after injection.
2. Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone.
3. Assess the likelihood of the injectate plume migrating into potential leak pathways.

The reservoir is assumed to have an irreducible brine saturation of 20%. The salinity of the brine within the formation is estimated to be 150,000 ppm (USGS National Produced Waters Geochemical Database, Ver. 2.3), typical for the region and formation. The injectate stream is primarily composed of CO_2 and H_2S as stated previously. Core data from the literature was used to help generate relative permeability curves. From the literature review, also as previously discussed, cores that most closely represent the carbonate rock formation of the Sligo seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low, conservative residual gas saturation based on the cores from the literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975).

The model is initialized with a reference pressure of 10,995 psig at a subsea depth of 15,740 ft. This, when a Kelly Bushing "KB" elevation of 334 ft is considered, correlates to a gradient of 0.684 psi/ft. This pressure gradient was determined from production data of the O'Neal No. 4. An initial reservoir pressure of 0.76 psi/ft was calculated before initial production. However, in 1997, after producing approximately 0.5 billion cubic feet (Bcf) of gas, the well was shut in. The last bottomhole pressure reading was calculated to be 0.480 psi/ft. This assumes the reservoir repressurizes after production ceases, but not fully back to in situ conditions. Therefore, a 10% safety factor was given to the initial reservoir pressure gradient of 0.76 psi/ft, and a gradient of 0.684 psi/ft was implemented into the model as a conservative estimate. A skin factor of -2 was applied to the well to simulate the stimulation of the O'Neal No. 4 for gas production from the Sligo Formation, which is based on the acid fracture report, provided in *Appendix A-3*.

The fracture gradient of the injection zone was estimated to be 0.954 psi/ft, which was determined from the acid fracture report. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.86 psi/ft, which is equivalent to 13,652 psig at the top of the Sligo injection interval.

The model, which begins in January 2025, runs for a total of 22 years, comprising 12 years of active injection, and is then succeeded by 10 years of density drift. Throughout the entire 12-year injection period, an injection rate of 1.5 MMscf/D is used to model the maximum available rate, yielding the largest estimate of the plume size. After the 12-year injection period, when the O'Neal No. 4 ceases injection, the density drift of the plume continues until the plume stabilizes 10 years later. The maximum plume extent during the 12-year injection period is shown in Figure 25. The final extent after 10 years of density drift after injection ceases is shown in Figure 26 (page 42).

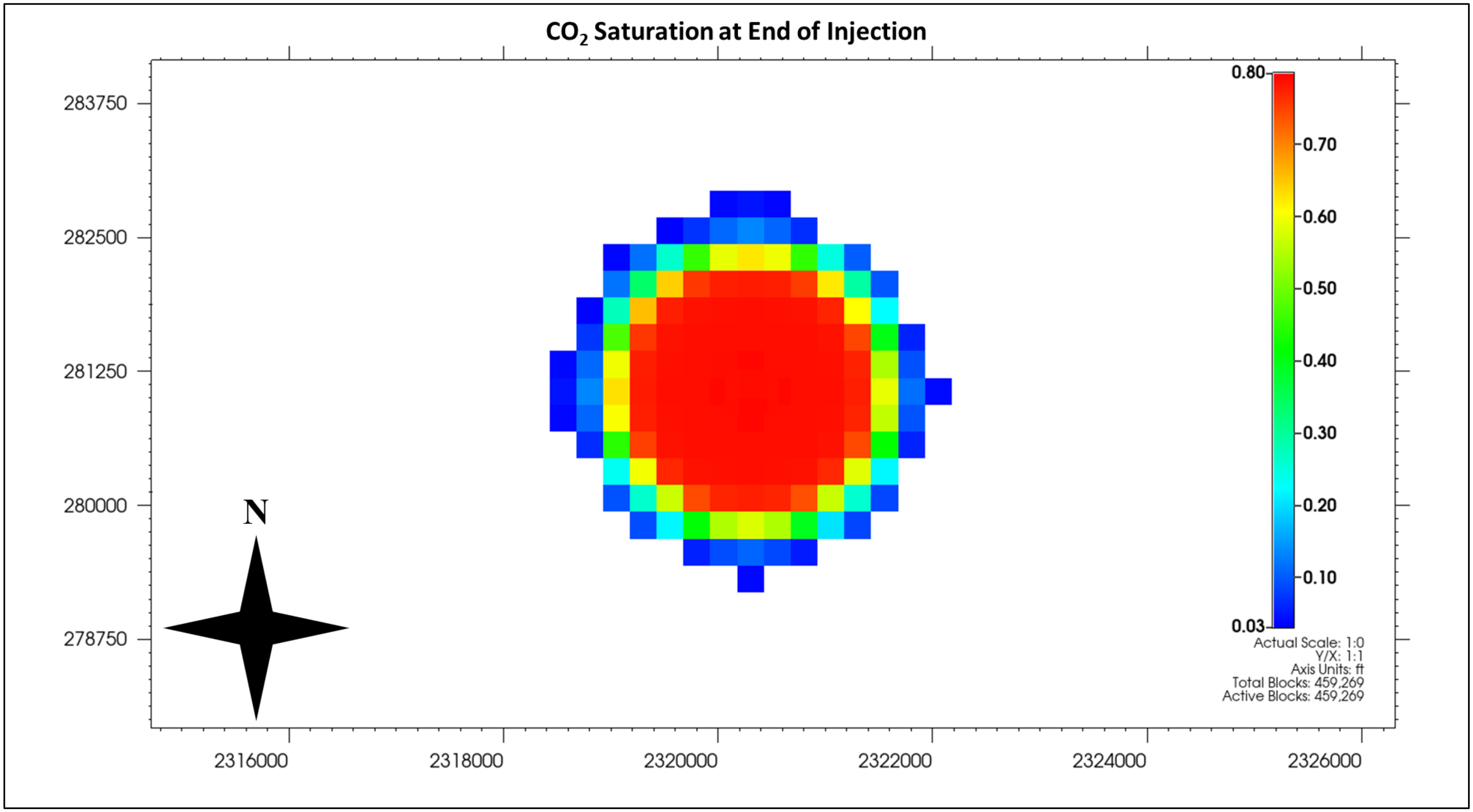


Figure 25 – Areal View of Saturation Plume at Shut-in (End of Injection)

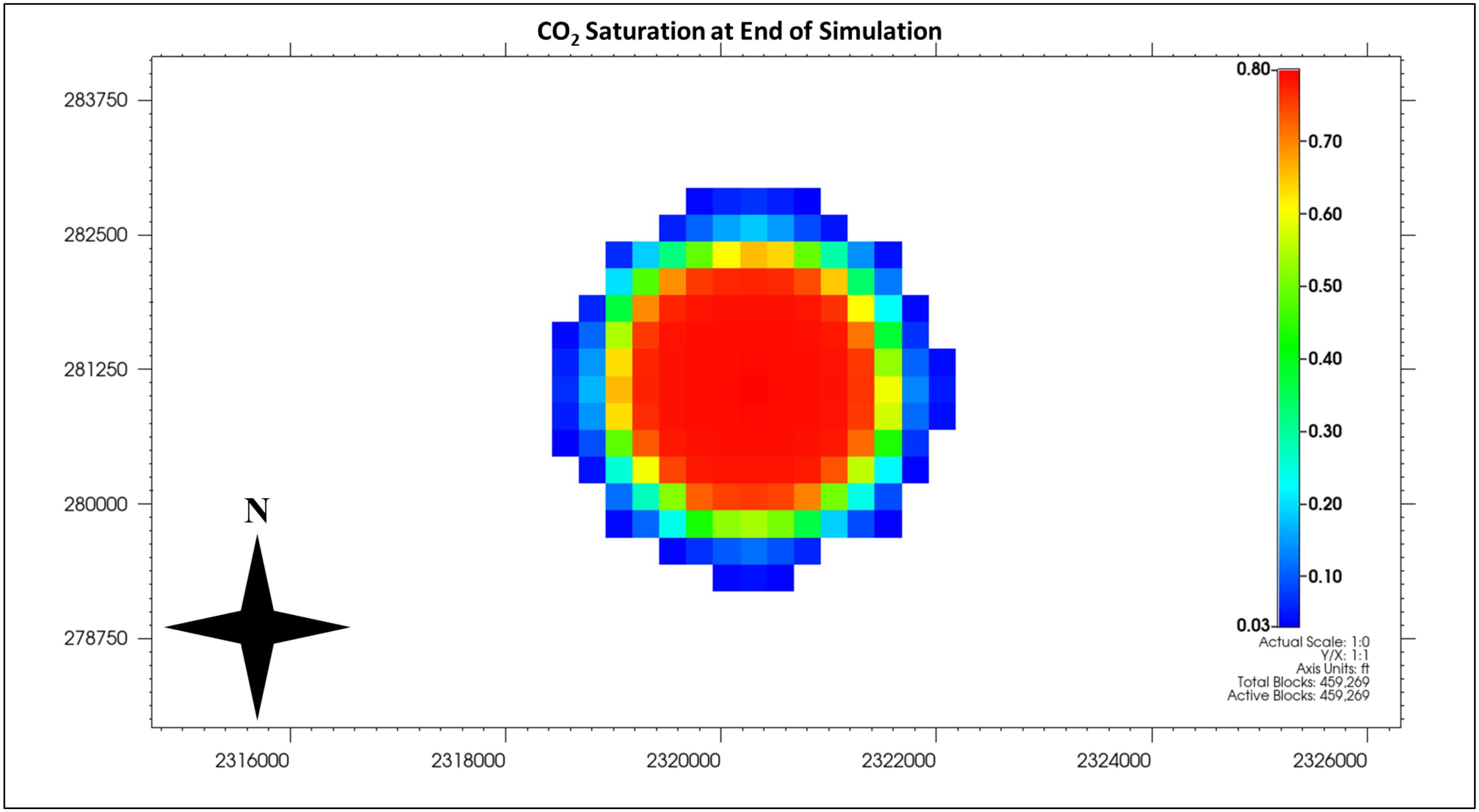


Figure 26 – Areal View of Gas Saturation Plume 10 Years After Shut-in (End of Simulation)

The cross-sectional view of the O'Neal No. 4 shows the extent of the plume from a side-view angle, cutting through the formation at the wellbore. Figure 27 shows the maximum plume extent during the 12-year injection period. During this time, gas from the injection well is injected into the permeable layers of the formation and predominantly travels laterally. Figure 28 (page 45) shows the final extent of the plume after 10 years of migration. Then, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 35% of injected gas that travels into each grid cell is trapped, as the gas travels mostly vertically—as it is less dense than the formation brine—until an impermeable layer is reached. Both figures are shown in an east-to-west view.

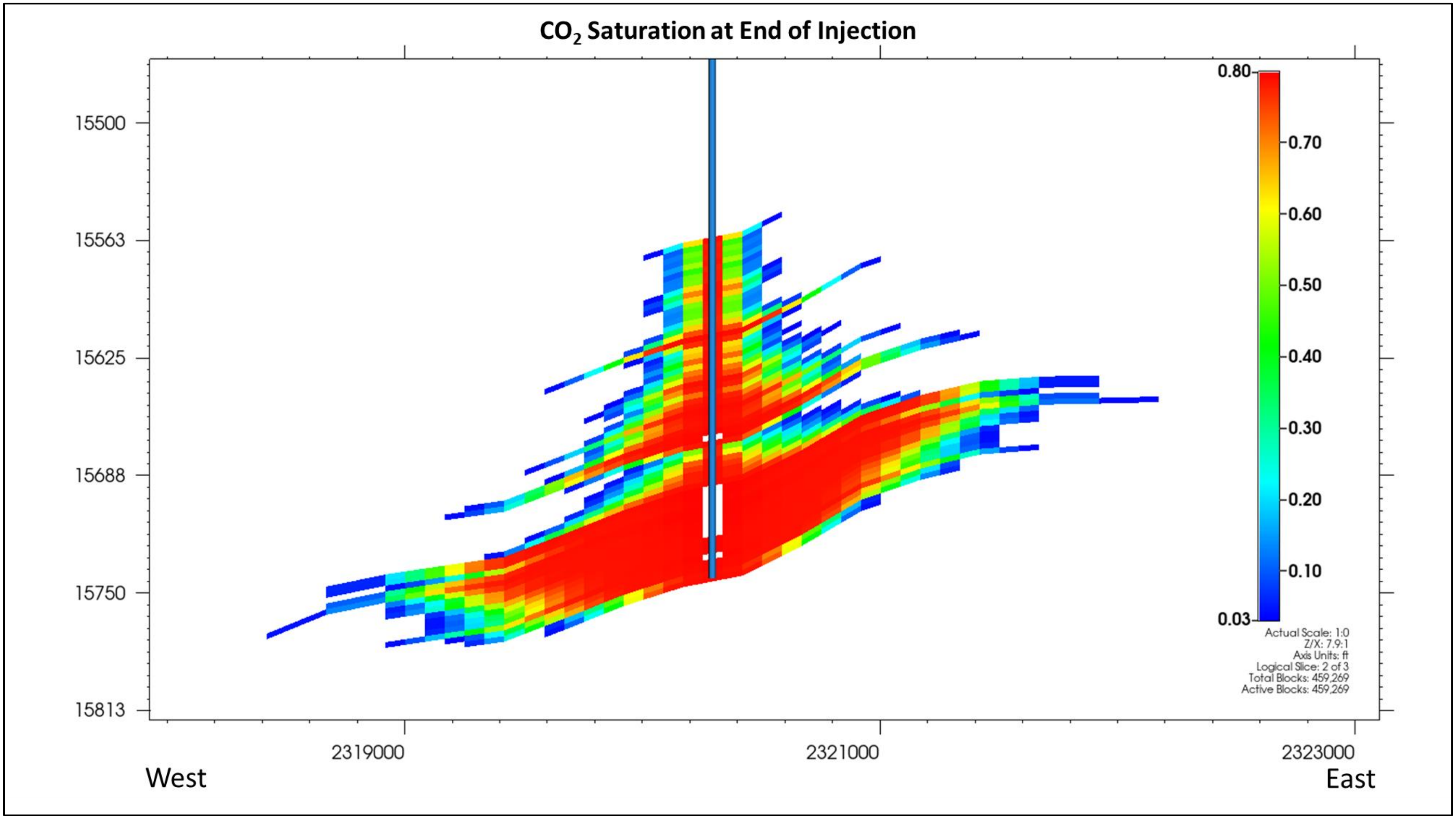


Figure 27 – East-West Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)

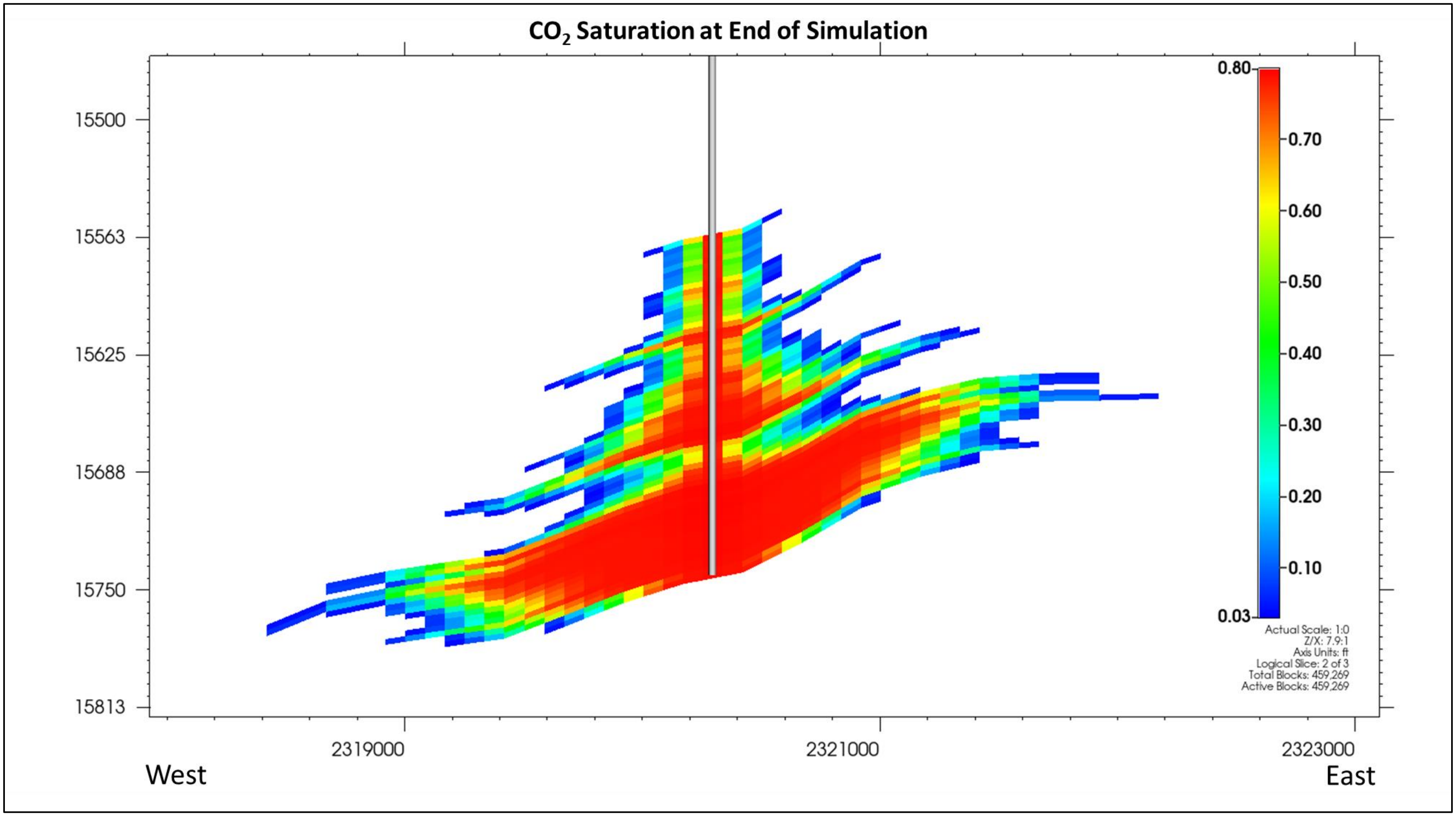


Figure 28 –East-West Cross-Sectional View of Gas Saturation Plume 10 Years After Shut-in (End of Simulation)

Figure 29 shows the surface injection rate, bottom hole pressures, and surface pressures over the injection period—and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate ends, reaching a maximum pressure of 13,337 psig, at the end of injection. This buildup of 2,362 psig keeps the bottomhole pressure below the fracture pressure of 13,652 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 6,095 psig, well below the maximum allowable 7,937 psig per the TRRC UIC permit application for this well. Bottomhole and wellhead pressures are provided in Table 6.

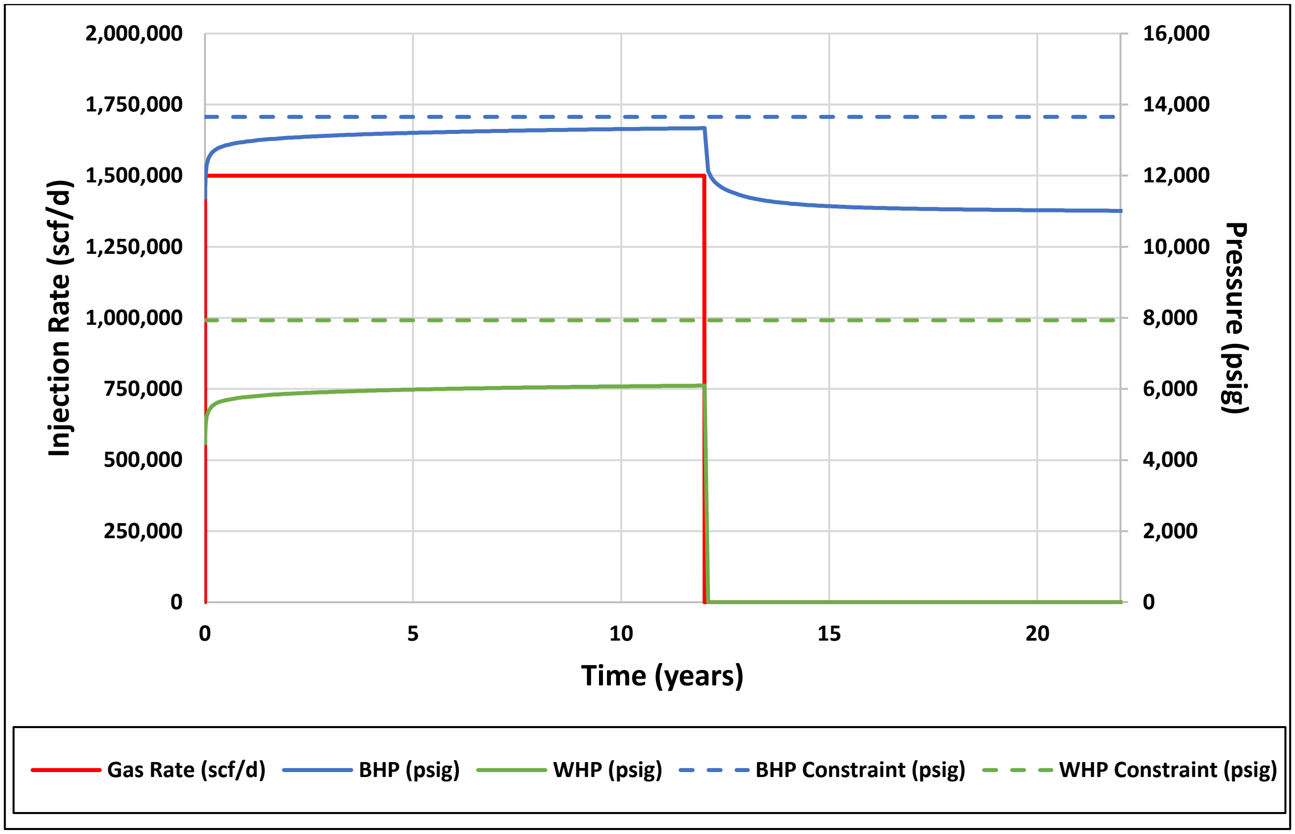


Figure 29 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 6 – Bottomhole and Wellhead Pressures from the Start of Injection

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	10,975	-
10	13,311	6,073
12 (End of Inj.)	13,337	6,095
20	11,029	-
22 (End of Model)	11,013	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in 40 CFR **§98.448(a)(1)**.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the plume has stabilized, plus an all-around buffer zone of at least one half mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

- Offset well logs to estimate geologic properties
- Petrophysical analysis to calculate the heterogeneity of the rock
- Geological interpretations to determine faulting and geologic structure
- Offset injection history to predict the density drift of the plume adequately

Ozona's expected gas composition was used in the model. The injectate is estimated at a molar composition of 98.2% CO_2 and 1.8% of other constituents. The StarTex Pawnee Treating Facility has been in stable operations for many years. Ozona believes the gas analysis provided in Table 1 is an accurate representation of the injectate. In the future, if the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be submitted to the GHGRP. As discussed in *Section 2*, the gas will be injected into the Sligo Formation. The geomodel was created based on the rock properties of the Sligo.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 12, the area expanse of the plume will be approximately 270 acres. The maximum distance between the wellbore and the edge of the plume is approximately 0.42 mi to the west. After 10 additional years of density drift, the areal extent of the plume is 303 acres with a maximum distance to the edge of the plume of approximately 0.45 mi to the west. Since the plume shape is relatively circular, the maximum distance from the injection well after density drift was used to define the circular boundary of the MMA. The AMA and the MMA have similar areas of influence, with the AMA being only marginally smaller than the MMA. Therefore, Ozona will set the AMA equal to the MMA as the basis for the area extent of the monitoring program.

This is shown in Figure 30 with the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA boundary represents the stabilized plume boundary after 10 years of density drift plus an all-around buffer zone of one half mile.

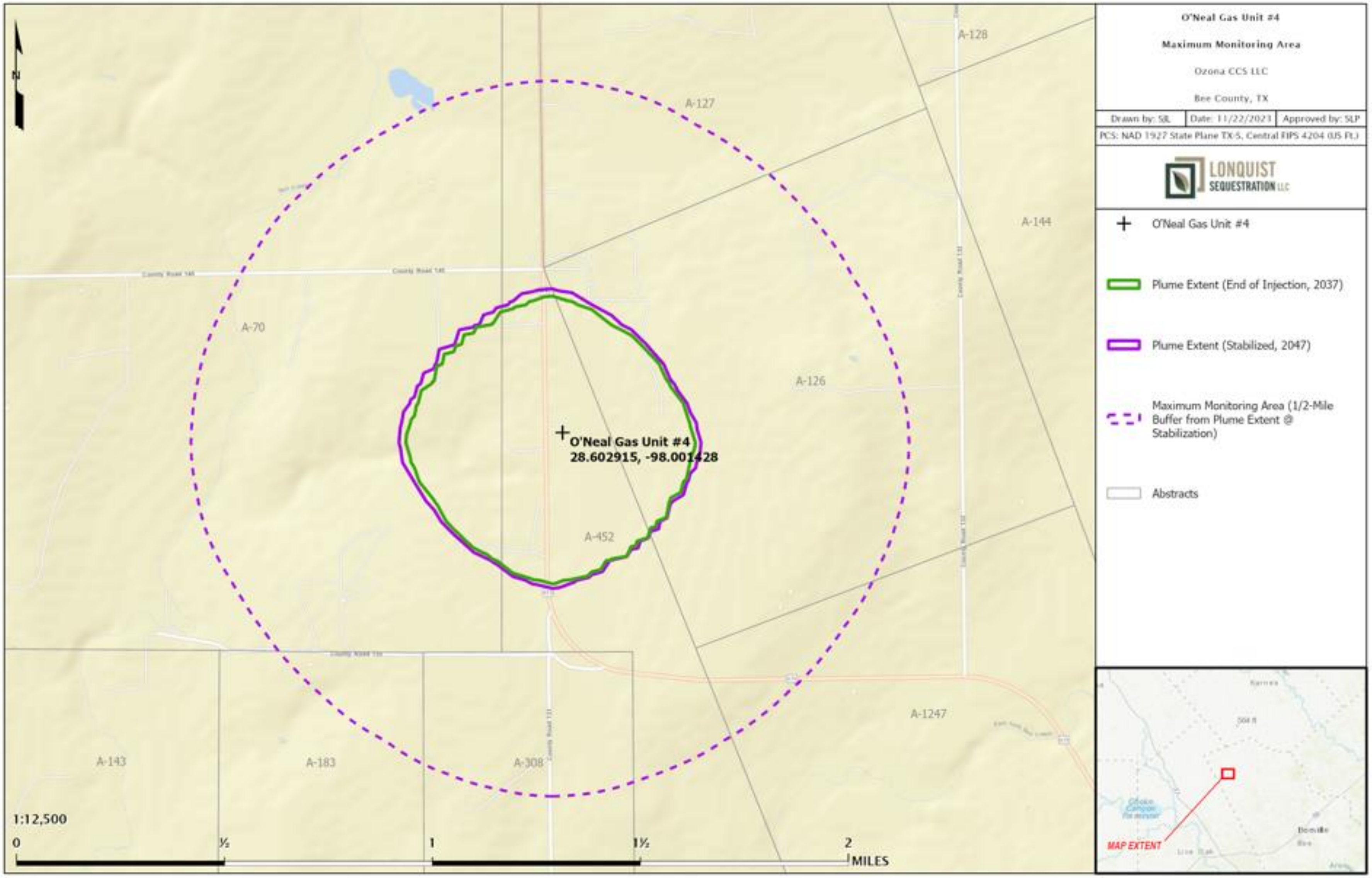


Figure 30 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The AMA was initially set equal to the expected total injection period of 12-years. The AMA was analyzed by superimposing the area based on a one-half mile buffer around the anticipated plume location after 12 years of injection (2037), with the area of the projected free-phase CO_2 plume at five additional years (2042). In this case, as shown in Figure 31, the plume boundary in 2042 is within the plume in 2037 plus the one-half mile buffer. Since the AMA boundary is only slightly smaller than the MMA boundary, Ozona will define the AMA to be equal to the MMA. By 2037, Ozona will submit a revised MRV plan to provide an updated AMA and MMA.

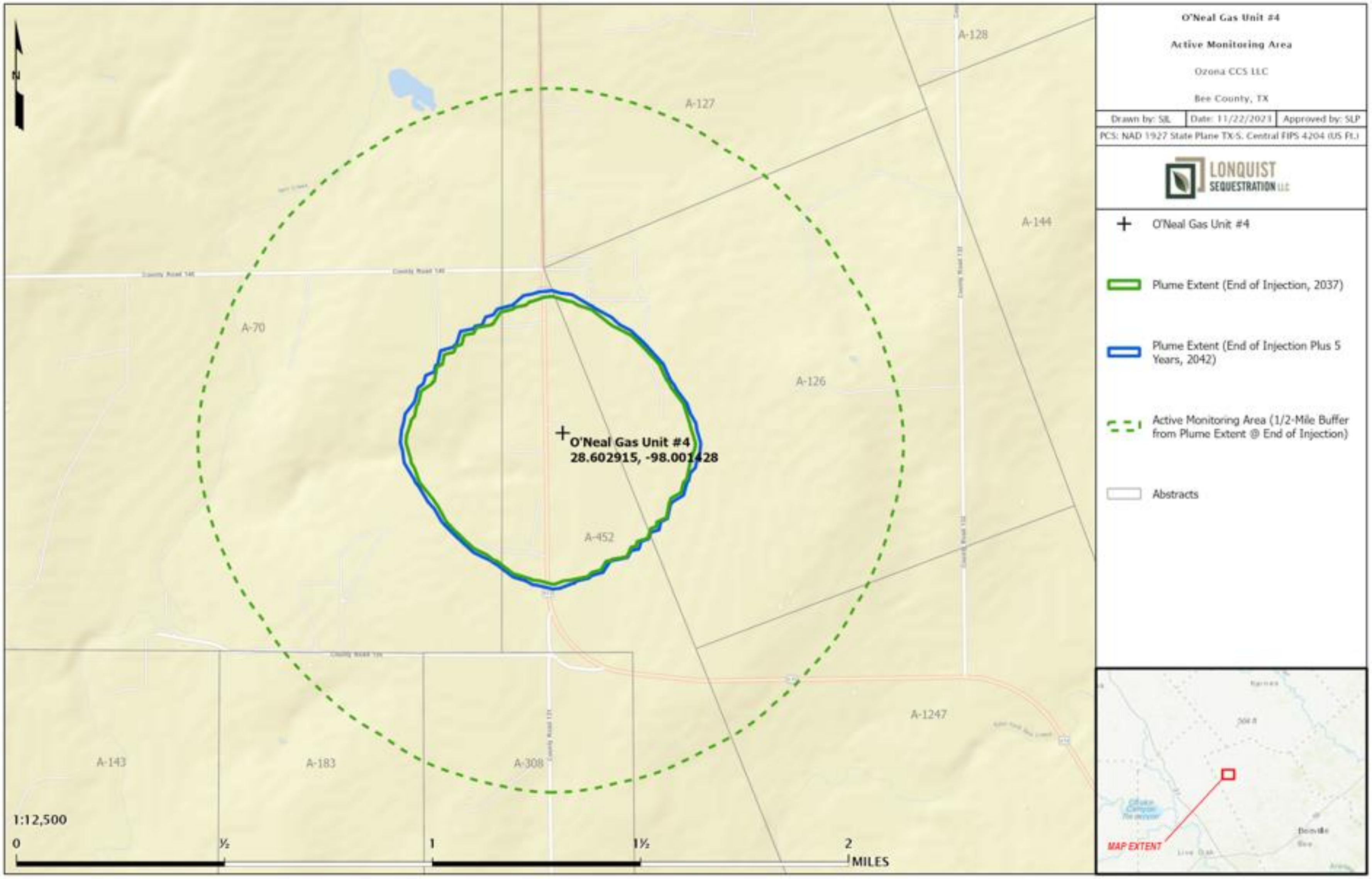


Figure 31 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies and discusses the potential pathways within the MMA for CO_2 to reach the surface and is summarized in Table 7. Also included are the likelihood, magnitude, and timing of such potential leakage. The potential leakage pathways are:

- Surface equipment
- Existing wells within the MMA
- Faults and fractures
- Upper confining layer
- Natural or induced seismicity

Table 7 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood		Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. One artificial penetration was drilled into the injection interval. This well has been properly plugged and abandoned.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Faults and fractures	Unlikely. There is over 14,000 ft of impermeable rock between the injection zone and the base of the USDW.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Upper confining zone	Unlikely. The lateral continuity of the UCZ consisting primarily of the Pearsall Formation which is over 500 ft thick is recognized as a very competent seal.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Natural or induced seismicity	Unlikely. There is over 14,000 ft of impermeable rock between the injection zone and the base of the USDW.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.

1 - UCZ is defined as the upper confining zone.

Magnitude Assessment Description
Low - catergorized as little to no impact to safety, health and the environment and the costs to mitigate are minimal.
Medium - potential risks to the USDW and for surface releases does exist, but circumstances can be easily remediated.
High - danger to the USDW and significant surface release may exist, and if occurs this would require significant costs to remediate.

4.1 Leakage from Surface Equipment

The Pawnee Treating Facility and O'Neal No. 4 are designed for separating, transporting, and injecting TAG, primarily consisting of CO_2, in a manner to ensure safety to the public, the employees, and the environment. The mechanical aspects of this are noted in Table 8 and Figure 32. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) applicable standards and practices. As the TAG stream contains H_2S, monitors installed for H_2S detection will also indicate the presence of CO_2. These monitors will be installed at key locations around the facility and the O'Neal No. 4 location. These devices will be continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points determined by the facility's Health, Safety and Environment (HS&E) Director, consistent with Occupational Safety and Health Administration (OSHA) requirements. The facility will set the detection and alarm states for personnel at 10 ppm and at 40 ppm for initiating Emergency Shutdown. Key monitoring points and parameters are also provided in Table 8.

The facilities will incorporate important safety equipment to ensure reliable and safe operations. In addition to the H_2S monitors, emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the facility, the O'Neal No. 4, and other components, StarTex has a flare stack to safely handle the TAG when a depressuring event occurs. These facilities will be constructed in the coming months. The exact location of this equipment is not yet known, but it will be installed in accordance with applicable engineering and safety standards.

Table 8 – Summary of TAG Monitors and Equipment

Device	Location	Set Point
H_2S Monitors (1-4)	O'Neal No. 4 wellsite	10 ppm High Alarm 40 ppm Emergency Shutdown
H_2S Monitors (5-8)	In-Plant Monitors	10 ppm High Alarm 40 ppm Emergency Shutdown
Flare Stack	Plant Site Perimeter	N/A
AGI Flowmeter	In-Plant (downstream of the Amine Unit)	Calibrated per API specifications
Emergency Shutdown	In-Plant Monitors	40 ppm Facility Shutdown
Emergency Shutdown	O'Neal No. 4 wellsite	40 ppm Facility Shutdown

With the continuous air monitoring at the facility and the well site, a release of CO_2 would be quickly identified, and the safety systems and protocols would effectuate an orderly shutdown to ensure safety and minimize the release volume. The CO_2 injected into the O'Neal No. 4 is from the amine unit at the Pawnee Treating Facility. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7*, in accordance with 40 CFR **§98.448(a)(5)**. Ozona concludes that the leakage of CO_2 through the surface equipment is unlikely.

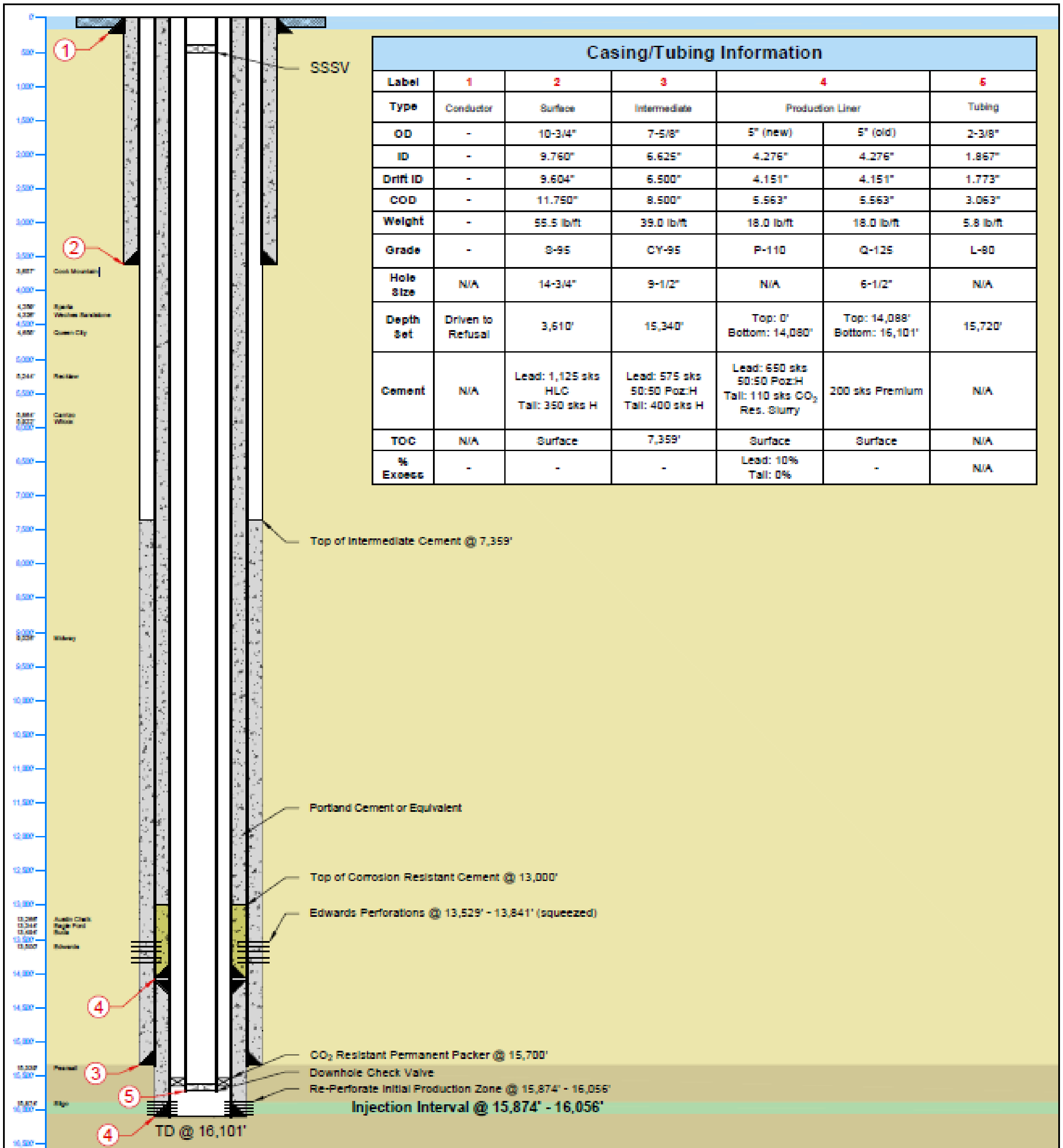
4.2 Leakage Through Existing Wells Within the MMA

The O'Neal No. 4 is engineered to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 32. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 33. Figure 34 is a map of all the oil and gas wells that penetrate the MMA's gross injection zone. Only one well penetrated the MMA's gross injection zone. This well was non-productive and has been plugged and abandoned in accordance with TRRC requirements. A summary table of all oil and gas wells within the MMA is provided in *Appendix B-1*.

This table in *Appendix B-1* provides the total depth (TD) of all wells within the MMA. The wells that are shallower and do not penetrate the injection zone are separated by the Pearsall Formation with a gross thickness of 535 ft. The Pine Island Shale comprises approximately 130 ft of this interval as discussed in *Section 2.2.2* and provides a competent regional seal—making vertical migration of fluids above the injection zone unlikely.

The shallower offset hydrocarbon wells within the MMA will also serve as above zone monitoring wells. Should any of the sequestered volumes migrate vertically, they would potentially enter the shallower hydrocarbon reservoir. Regular sampling and analysis is performed on the produced hydrocarbons. If a material difference in the quantity of CO_2 in the sample occurs indicating a potential migration of injectate from the Sligo Formation, Ozona would investigate and develop a mitigation plan. This may include reducing the injection rate or shutting in the well. Based on the investigation, the appropriate equation in *Section 7* would be used to make any adjustments to the reported volumes.



Casing/Tubing Information

Label	1	2	3	4		5
Type	Conductor	Surface	Intermediate	Production Liner		Tubing
OD	-	10-3/4"	7-5/8"	5" (new)	5" (old)	2-3/8"
ID	-	9.760"	6.625"	4.276"	4.276"	1.867"
Drift ID	-	9.604"	6.500"	4.151"	4.151"	1.773"
COD	-	11.750"	8.500"	5.563"	5.563"	3.063"
Weight	-	55.5 lb/ft	39.0 lb/ft	18.0 lb/ft	18.0 lb/ft	5.8 lb/ft
Grade	-	S-95	CY-95	P-110	Q-125	L-80
Hole Size	N/A	14-3/4"	9-1/2"	N/A	6-1/2"	N/A
Depth Set	Driven to Refusal	3,610'	15,340'	Top: 0' Bottom: 14,080'	Top: 14,088' Bottom: 16,101'	15,720'
Cement	N/A	Lead: 1,125 sks HLC Tail: 350 sks H	Lead: 575 sks 50:50 Poz:H Tail: 400 sks H	Lead: 650 sks 50:50 Poz:H Tail: 110 sks CO_2 Res. Slurry	200 sks Premium	N/A
TOC	N/A	Surface	7,359'	Surface	Surface	N/A
% Excess	-	-	-	Lead: 10% Tail: 0%	-	N/A

LONQUIST SEQUESTRATION LLC	Ozona CCS	CO_2 Injection Well Proposed Well Design - O'Neal Gas Unit No. 4	
	Country: USA	**State/Province:** Texas	**County/Parish:** Bee County
	API No: 42-025-32658	**Field:** TBD	**Well Type/Status:** Proposed
Texas License F-8652	**Location:** 28.6031807, -98.0017091	**Project No:** LS190	**Date:** 10/13/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	**Drawn:** Joseph Lovewell	**Reviewed:** David Lytle	**Approved:** David Lytle
	Rev No: 0	**Notes:**	

Figure 32 – O'Neal No. 4 Wellbore Schematic

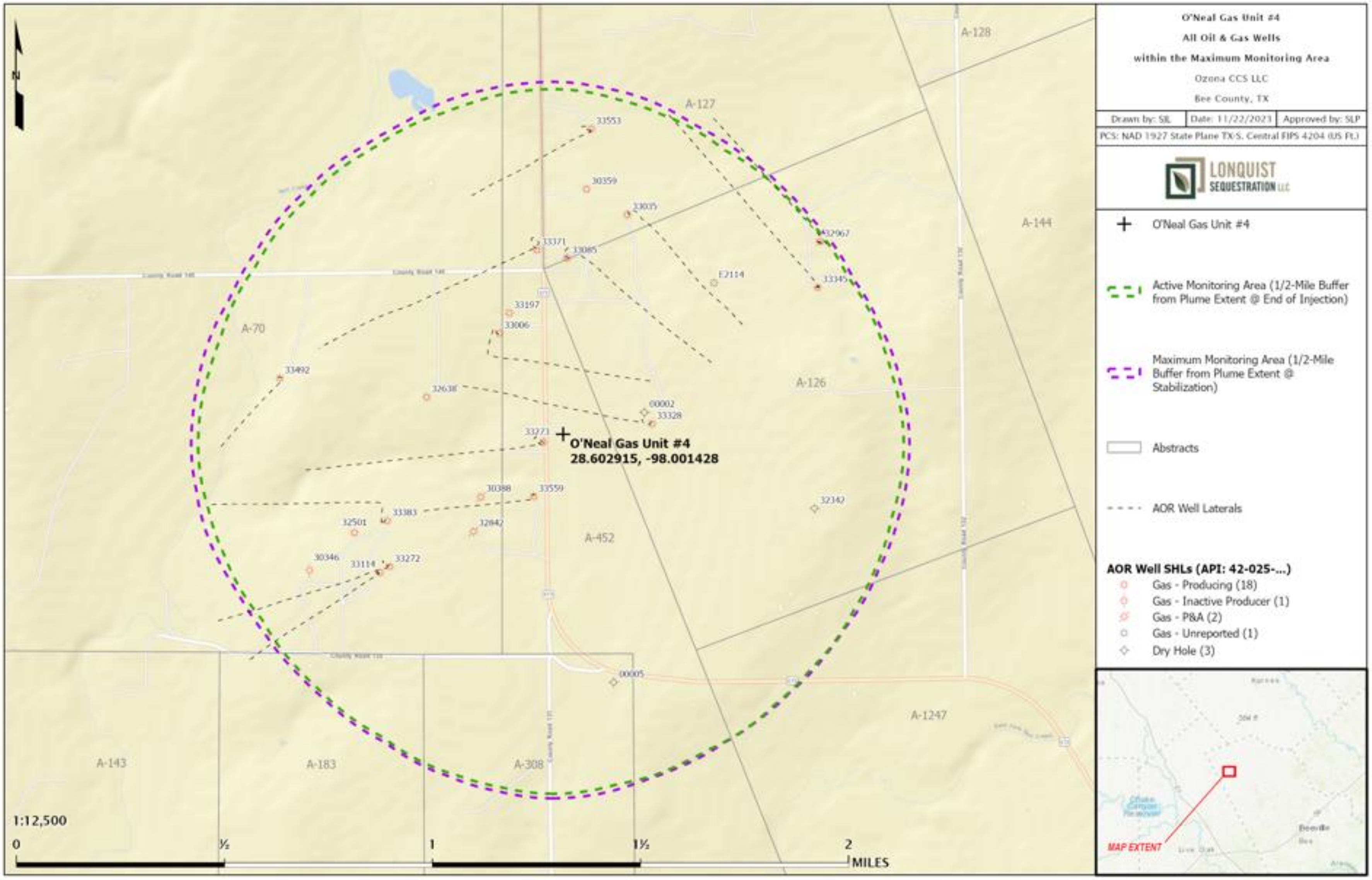


Figure 33 – All Oil and Gas Wells Within the MMA

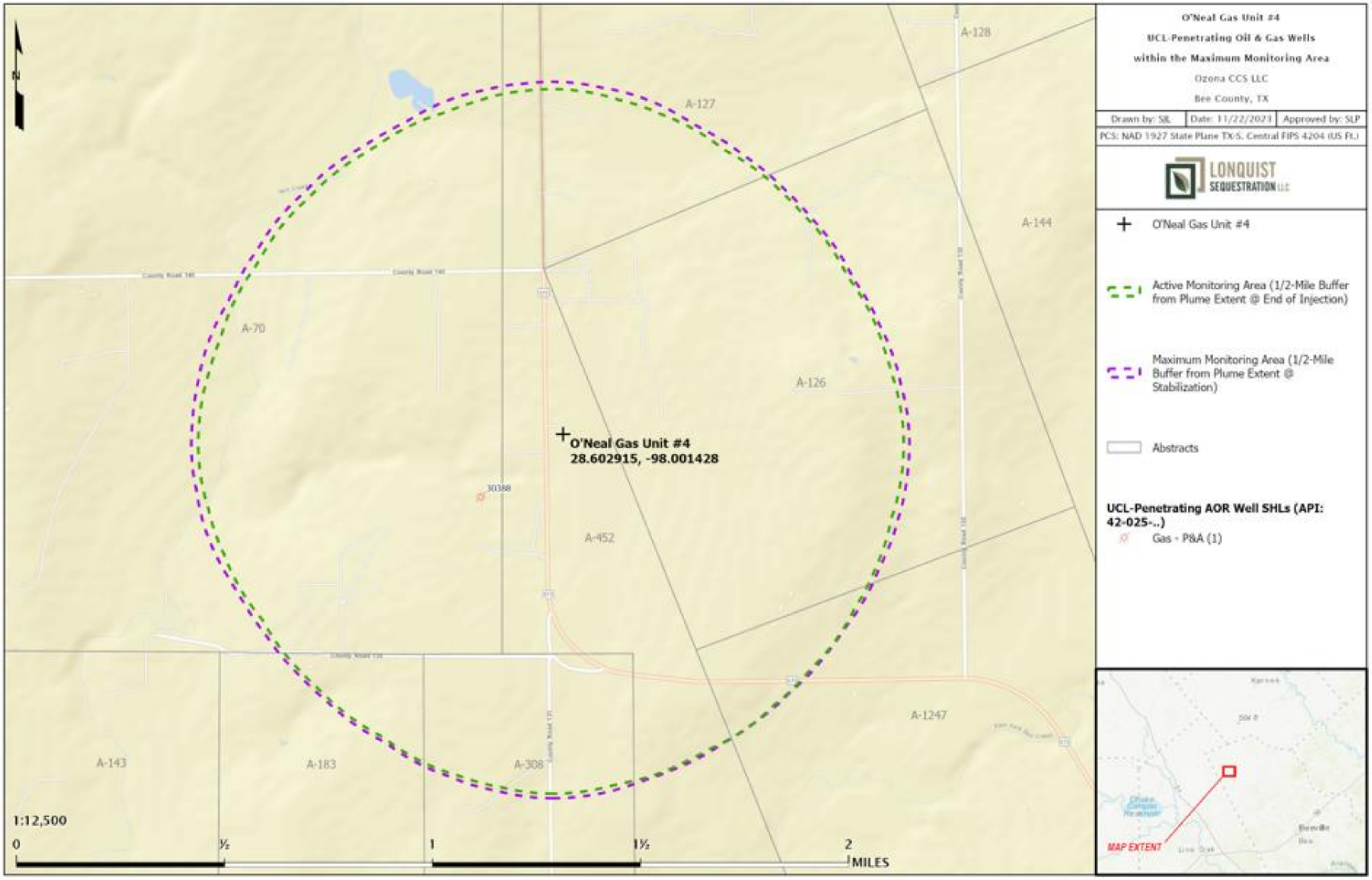


Figure 34 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations have proven to date to be nonproductive in this area, and therefore Ozona does not see this as a risk. This is supported by a review of the TRRC Rule 13 (Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC **§3.13**. The Sligo is not among the formations listed for which operators in Bee County and District 2 (where the O'Neal No. 4 is located) are required to comply with TRCC Rule 13; therefore, the TRRC does not believe there are productive horizons below the Sligo. The O'Neal No. 4 drilling permit is provided in *Appendix A-2*.

4.2.2 Groundwater Wells

The results of a groundwater well search found five wells within the MMA, as identified by the Texas Water Development Board as shown in Figure 35 and in tabular form in *Appendix B-2*.

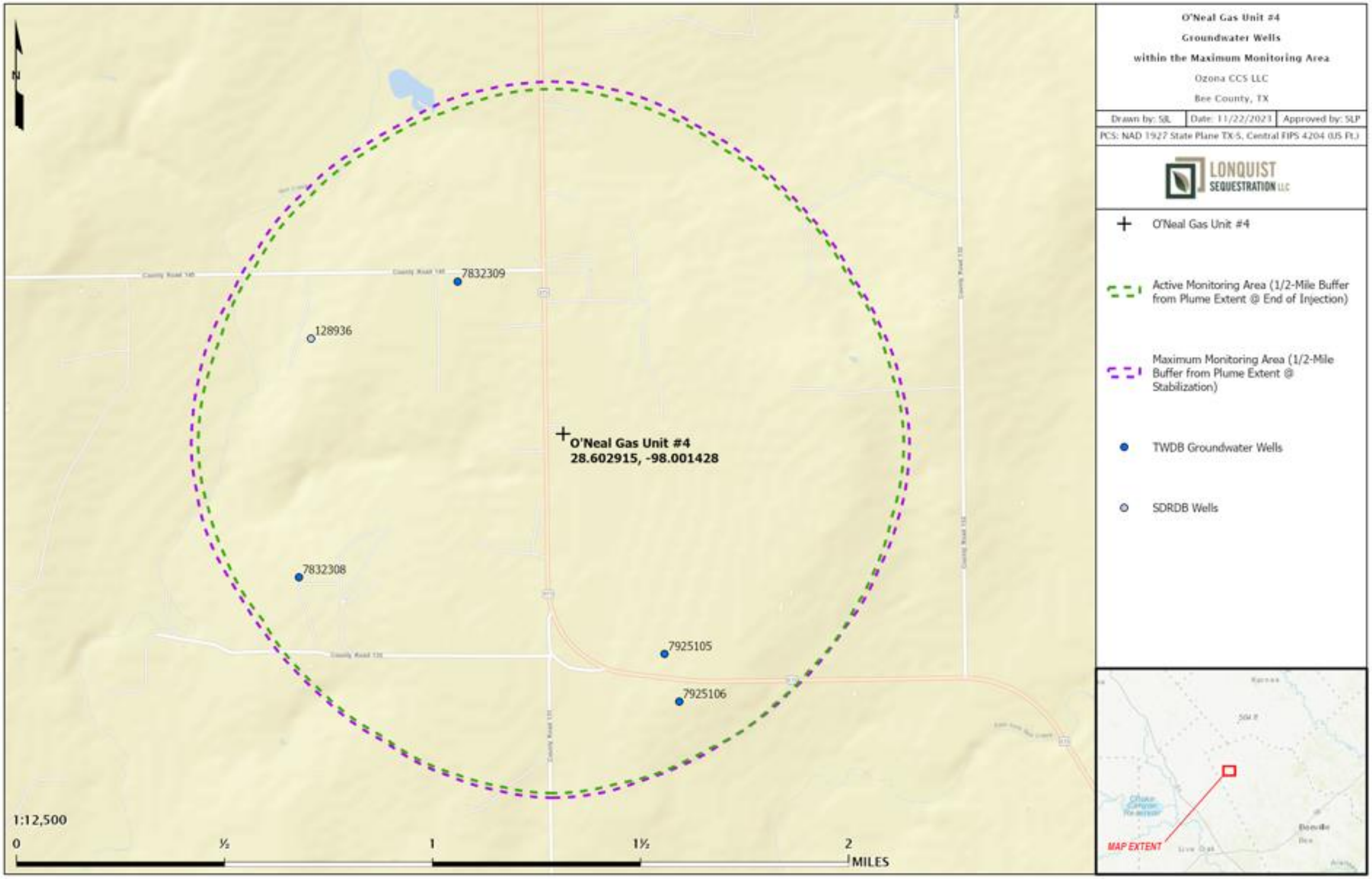


Figure 35 – Groundwater Wells Within the MMA

The surface, intermediate, and production casings of the O'Neal No. 4, as shown in Figure 32, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations, and the GAU letter issued for this location is provided in *Appendix A-1*. The wellbore casings and compatible cements prevent CO_2 leakage to the surface along the borehole. Ozona concludes that leakage of the sequestered CO_2 to the groundwater wells is unlikely.

4.3 Leakage Through Faults and Fractures

Detailed mapping of openhole logs surrounding the O'Neal No. 4 did not identify any faulting within either the Pearsall or Sligo sections. However, there is a general lack of deep penetrators within the area that limits the amount of openhole coverage available.

The majority of the published literature suggests that faulting near the project area is restricted to the shallower, overlying Cenozoic section, as shown in Figure 9, with shallow faults dying out before reaching the Pearsall Formation. One source interpreted the potential for faulting to the south (Swanson et al., 2016). The potential fault is depicted in Figure 8 relative to the location of the O'Neal No. 4. According to the map, the interpreted fault lies approximately 4.25 mi south-southeast of the well and approximately 3.9 mi south-southeast of the stabilized plume extent in the year 2047. In the unlikely scenario in which the injection plume or pressure front reaches the potential fault, and the potential fault was to act as a transmissive pathway, the upper confining Pearsall shale contains sufficient thickness and petrophysical properties required to confine and protect injectates from leaking outside of the permitted injection zone.

Section 2.1.2 discusses regional structure and faulting, and *Section 2.3* covers local structure, for additional material relevant to this topic.

4.4 Leakage Through the Upper Confining Zone

The Sligo injection zone has competent sealing intervals present above and below the targeted carbonate sequence of the Sligo section. The overlying Pine Island shale member of the Pearsall Formation is approximately 130 ft thick at the O'Neal No. 4. Above this confining unit, the Cow Creek Limestone, Cow Creek shale, and Bexar Shale Members of the Pearsall Formation will act as additional confinement between the injection interval and the USDW. The USDW lies well above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. The petrophysical properties of the lower Sligo and Hosston Formations make these ideal for lower confinement. The low porosity and permeability of these underlying formations minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injectate to the in situ reservoir fluid makes migration below the lower confining layer unlikely.

4.5 Leakage from Natural or Induced Seismicity

The O'Neal No. 4 is located in an area of the Gulf of Mexico considered to be active from a seismic perspective. Therefore, the Bureau of Economic Geology's TexNet (from 2017 to present) and USGS's Advanced National Seismic System (from 1971 to present) databases were reviewed to

identify any recorded seismic events within 25 kilometer (km) of the O’Neal No. 4.

The investigation identified a multitude of seismic events within the 25 km search radius; however, the magnitude of most of the events was below 2.5. The nearest seismic event with a recorded magnitude of 3.0 or greater was measured approximately 5.6 km northwest of the O’Neal No. 4 at a depth of 5 km. The results of the investigation are plotted on the map provided in Figure 36 relative to the O’Neal No. 4 and the 25-km search radius.

The Facility will have operating procedures and set points programmed into the control and SCADA systems to ensure operating pressures are maintained below the fracture gradient of the injection and confining intervals, thus avoiding the potential for inducing seismicity.

Given the seismic activity in the area, Ozona will closely monitor nearby TexNet station EF71 for activity and any corresponding irregularities in the operating pressures of O’Neal No. 4. If a seismic event of 3.0 or greater is recorded at Station EF71 or if anomalies are identified in the operating data, Ozona will review the data and determine if any changes occurred that indicate potential leakage. Ozona would take appropriate measures based on their findings, including limiting the injection pressure and reducing the injection rate.

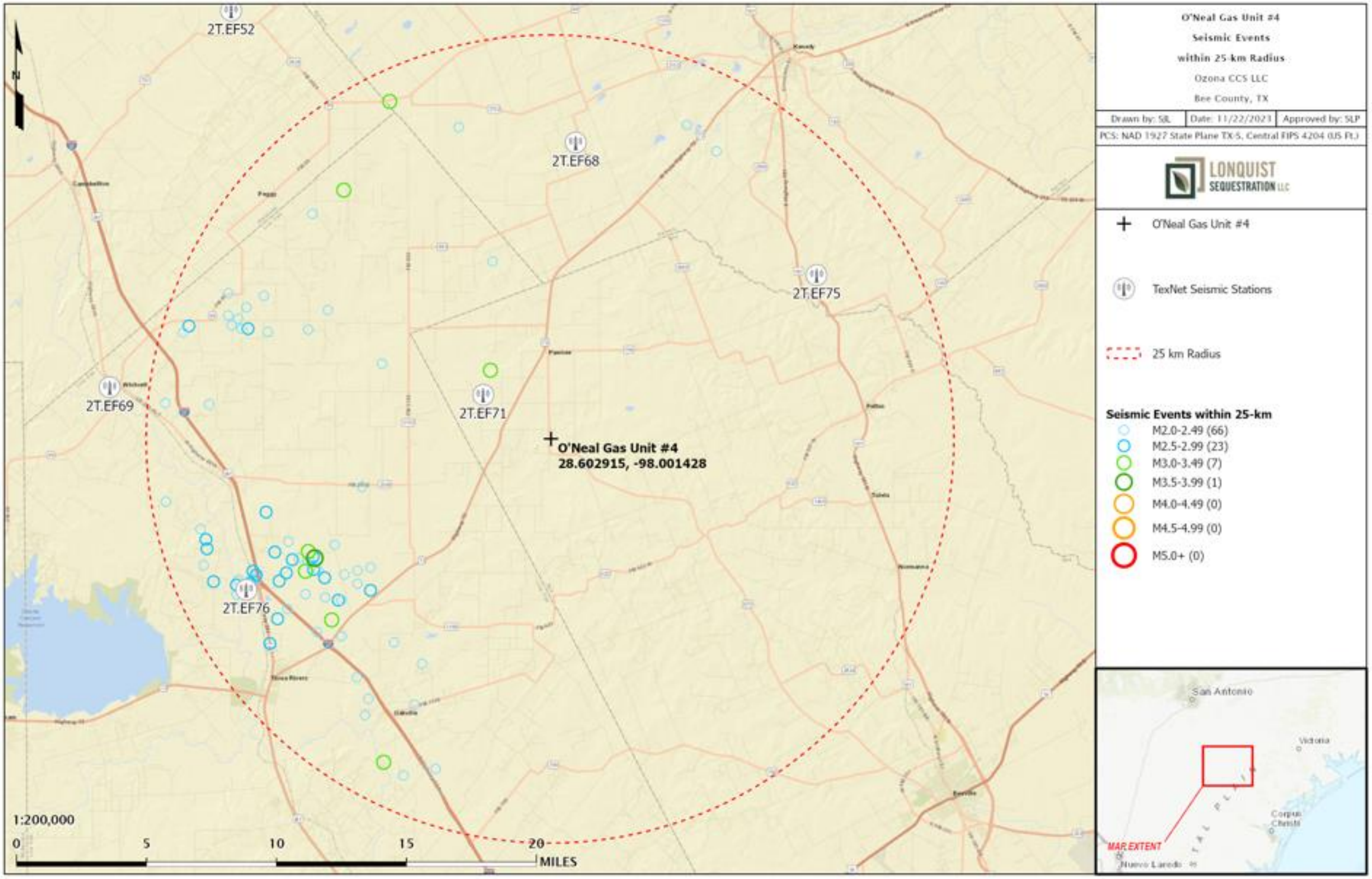


Figure 36 – 25-km Seismicity Review

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Ozona will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in *Section 4*, to meet the requirements of 40 CFR **§98.448(a)(3)**. As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 9 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 12-year injection period or cessation of injection operations, plus a proposed 10-year post-injection period until the plume has stabilized.

- Leakage from surface equipment
- Leakage through existing and future wells within the MMA
- Leakage through faults or fractures
- Leakage through confining seals
- Leakage through natural or induced seismicity

Table 9 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Surface equipment	Fixed H_2S monitors at the Plant and well site
	Visual inspections
	Monitor SCADA systems for the Plant and well site
Existing wells within the MMA	Monitor CO_2 levels in above zone producing wells
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Annual soil gas sampling near well locations that penetrate the Upper Confining Zone within the AMA
• Leakage through groundwater wells	Annual groundwater samples from existing water well(s)
• Leakage from future wells	Monitor drilling activity and compliance with TRRC Rule 13 Regulations
Faults and Fractures	SCADA continuous monitoring at the well site (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Upper confining zone	SCADA continuous monitoring at the well site (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Natural or induced seismicity	Monitor CO_2 levels in Above Zone producing wells
	Monitor existing TexNet station

5.1 Leakage from Surface Equipment

The facility depicted in Figure 37 and the O'Neal No. 4 were designed to operate in a safe manner to minimize the risk of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established prior to commencing operation once facility construction has been completed. Ambient H_2S monitors will be located at the facility and near the O'Neal No. 4 site for local alarm and are connected to the SCADA system for continuous monitoring.

The facility and the O'Neal No. 4 are continuously monitored through automated control systems. These monitoring points were discussed in *Section 4.1*. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Ozona to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

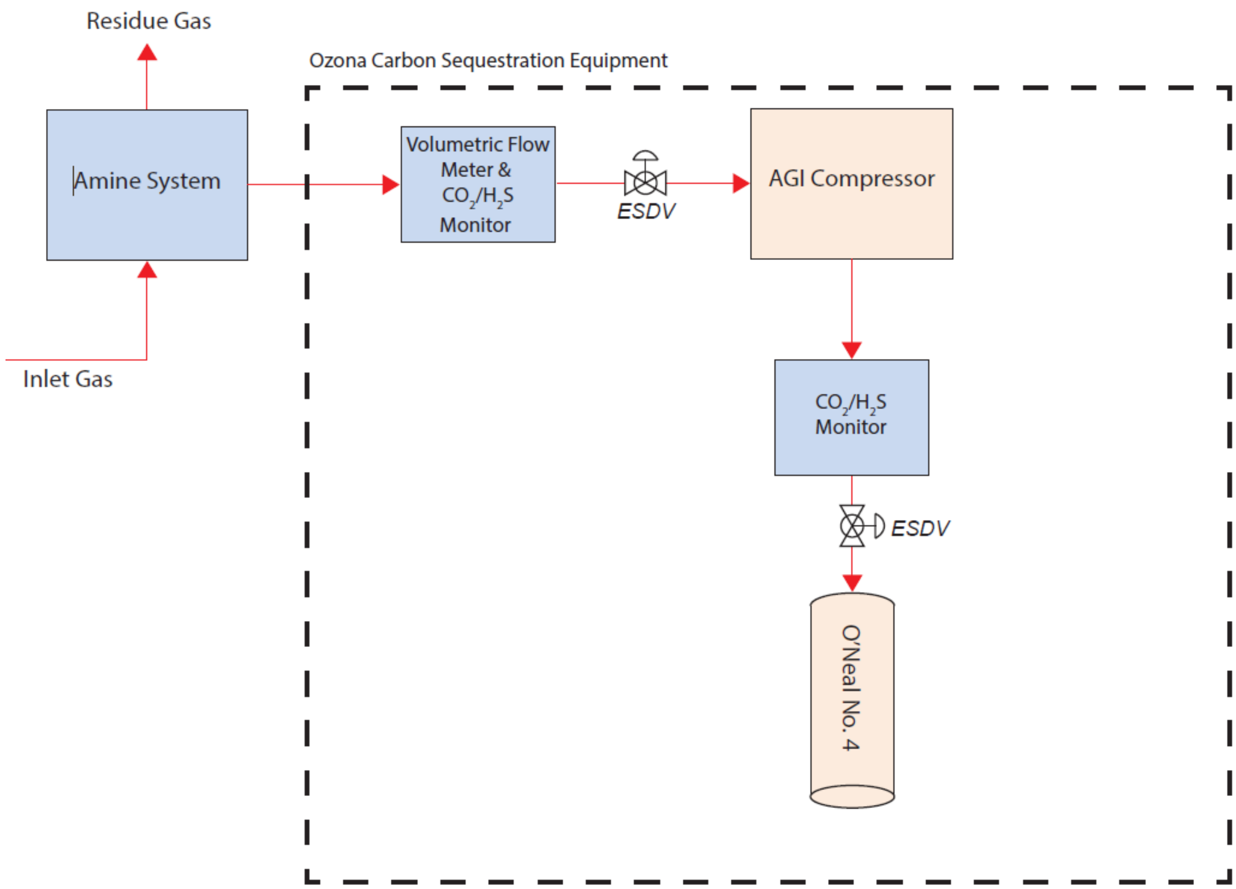


Figure 37 – O'Neal No. 4 Process Flow Diagram

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Ozona will quantify the leak per the strategies discussed in *Section 7*.

5.2 Leakage Through Existing and Future Wells Within the MMA

Ozona continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the O'Neal No. 4. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, MITs performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and investigated to develop a leak mitigation plan.

As discussed previously, TRRC Rule 13 ensures that new wells in the field are constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Ozona will also establish and operate an in-field monitoring program to detect CO_2 leakage within the AMA. This would include H_2S monitoring as a proxy for CO_2 at the well site and annual soil gas samples taken near any identified wells that penetrate the injection interval within the AMA. These samples will be analyzed by a qualified third party. Prior to commencing operation, and through the post-injection monitoring period, Ozona will have these monitoring systems in place.
Currently, there is only one well in the MMA identified that penetrates the injection interval. This well was plugged and abandoned in 2007. The TRRC records are provided in *Appendix A-4*. Ozona will take an annual soil gas sample from this area, which will be analyzed by a third-party lab. Additional monitoring will be added as the AMA is updated over time. In the unlikely event a leak occurs, Ozona will quantify the leak volumes by the methodologies discussed in *Section 7* and present these results and related activities in the annual report.

Ozona will also utilize shallower producing gas wells as proxies for above-zone monitoring wells. Production data from these wells is analyzed for monthly production statements, and therefore would be an early indicator of any possible subsurface issues. Should any material change from historical trends in the CO_2 concentration occur, Ozona would investigate and develop a corrective action plan. Should any CO_2 migrate vertically from the Sligo, the magnitude risk of this event is very low, as the producing reservoir provides an ideal containment given the upper confining zone of this reservoir has proven competent. In the unlikely event a leak occurs, Ozona would quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances and include these results in the annual report.

5.2.1 Groundwater Quality Monitoring

Ozona will monitor the groundwater quality above the confining interval by sampling from groundwater wells near the O'Neal No. 4 and analyzing the samples with a third-party laboratory on an annual basis. In the case of the O'Neal No. 4, 5 existing groundwater wells have been identified within the AMA (Figure 38). Initial groundwater quality tests will be performed to establish a baseline prior to commencing operations.

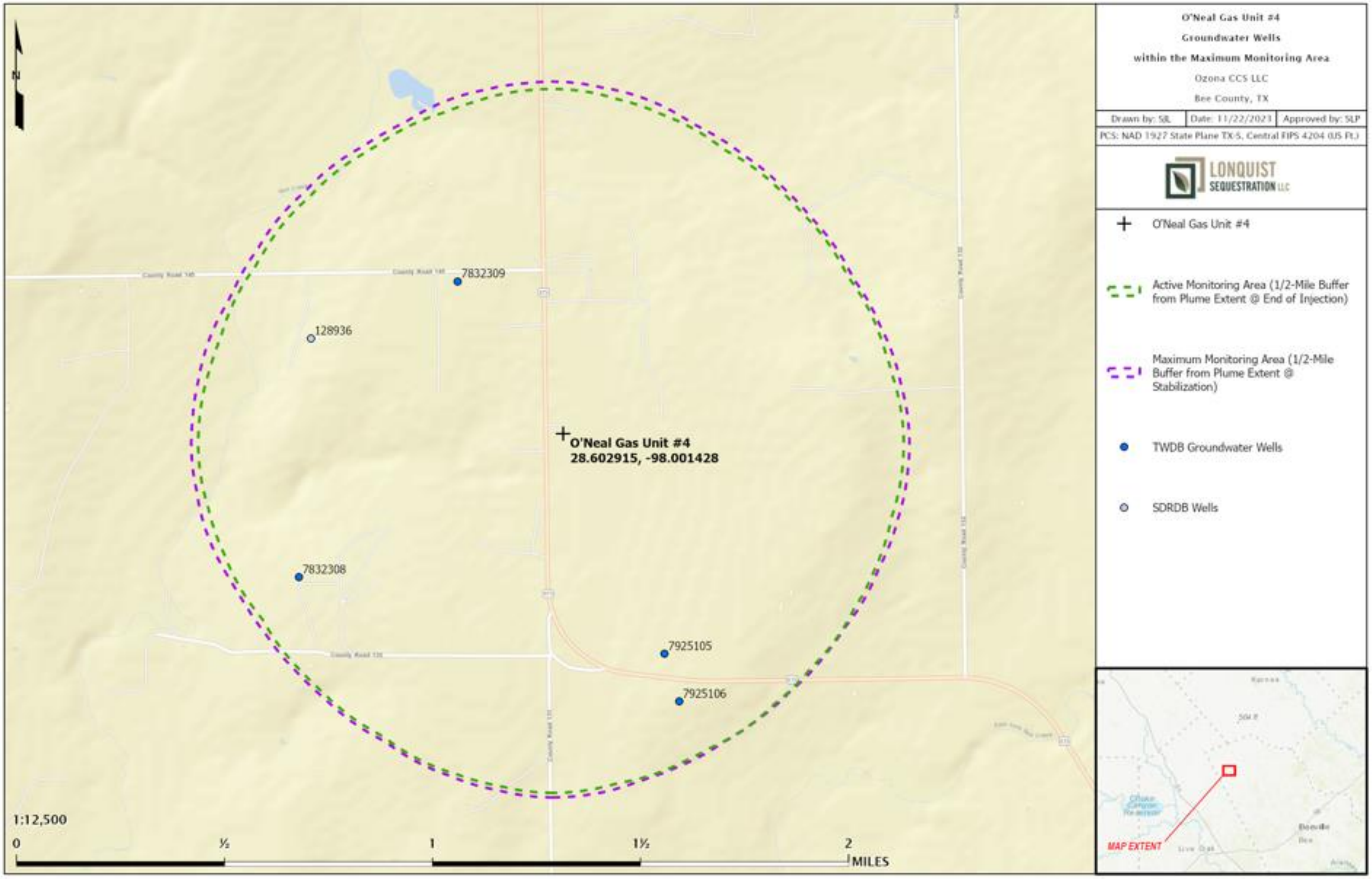


Figure 38 – Groundwater Wells

5.3 Leakage Through Faults, Fractures, or Confining Seals

Ozona will continuously monitor the operations of the O'Neal No. 4 through the automated controls and SCADA systems. Any deviation from normal operating volume and corresponding injection pressure could indicate movement into a potential leak pathway, such as a fault or breakthrough of the confining seal and would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Ozona will also utilize shallower producing wells as proxies for above-zone monitoring wells. Production data is analyzed regularly for monthly production statements and therefore would be an early indicator of any possible subsurface issues. Should any material change from historical trends in the CO_2 concentration occur, Ozona would investigate and develop a corrective action plan. Should any CO_2 migrate vertically from the Sligo Formation, the magnitude risk of this event is very low, as the producing reservoir provides an ideal containment given the upper confining zone has proven competent. In the unlikely event a leak occurs, Ozona would quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is low, Ozona plans to use the nearest TexNet seismic monitoring station, EF71, to monitor the area around the O'Neal No. 4. This station is approximately 3 mi to the northwest, as shown in Figure 38. This is sufficient distance to allow for accurate and detailed monitoring of the seismic activity in the area. Ozona will monitor this station for any seismic activity, and if a seismic event of 3.0 magnitude or greater is detected, Ozona will review the injection volumes and pressures of the O'Neal No. 4 to determine if any significant changes have occurred that would indicate potential leakage.

Ozona will also continuously monitor operations through the SCADA system. Any deviation from normal operating pressure and volume set points would trigger an alarm for investigation by operations staff. Such a variance could indicate movement into a potential leak pathway, such as a fault or breakthrough of the confining seal. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary

These are the two primary strategies for mitigating risks for induced seismicity. In the unlikely event a leak occurs, Ozona will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances.

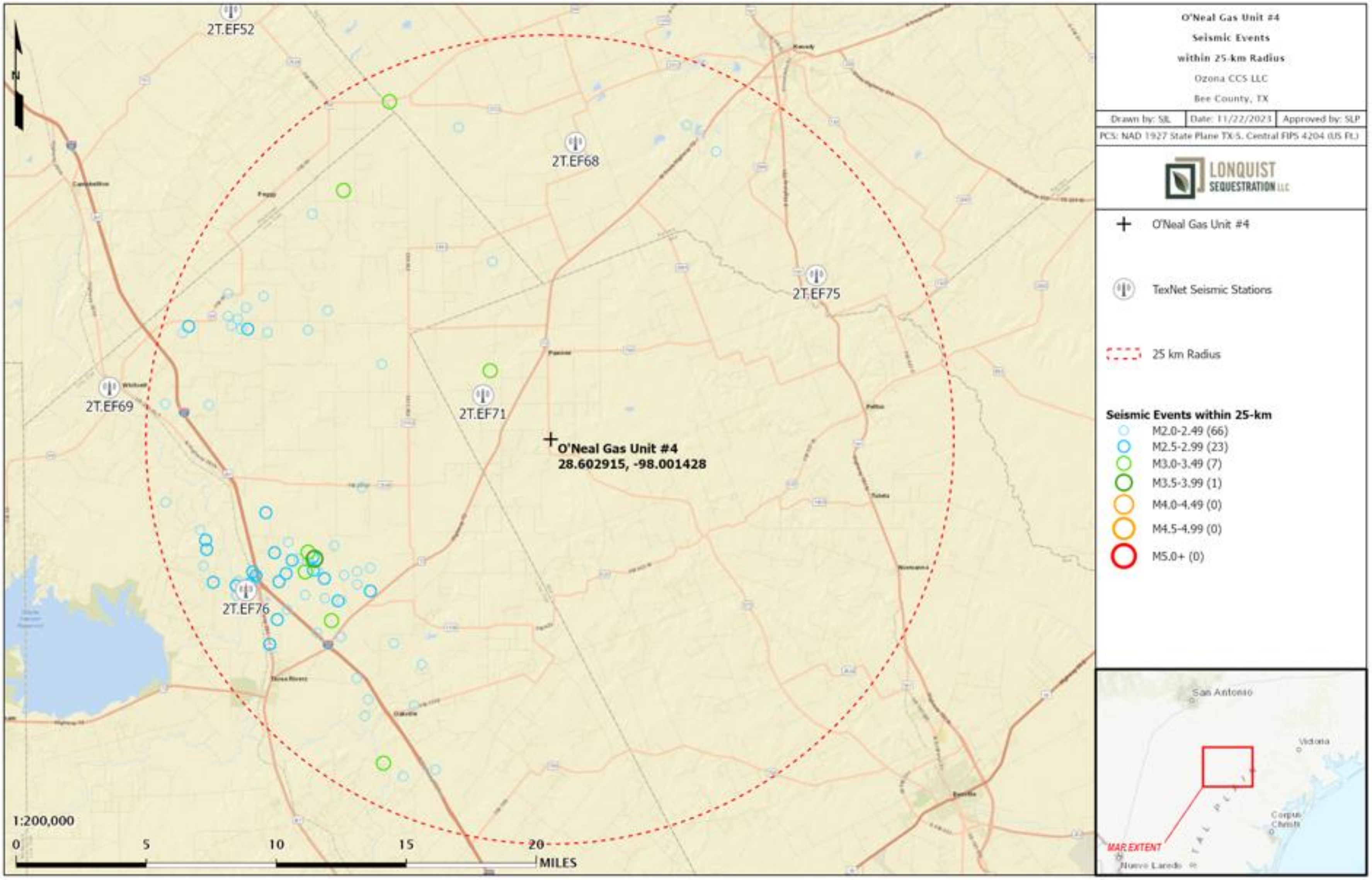


Figure 39 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

This section identifies the strategies Ozona will undertake to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR **§98.448(a)(4).** Ozona will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of injectate and calculate a corresponding amount of CO_2.

6.1 Visual Inspections

Regular inspections will be conducted by field personnel at the facility and O'Neal No. 4 site. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken prudently and safely to address such issues.

6.2 H_2S/ CO_2 Monitoring

In addition to the fixed monitors in the facility and at the wellsite, Ozona will establish and perform an annual in-field sampling program to monitor and detect any CO_2 leakage within the AMA. This will consist of soil gas sampling near any artificial penetrations of the injection zone and sampling of water wells. These probes have special membrane inserts that collect the gas samples over a 21-day period. These will be analyzed by a third-party lab to be analyzed for CO_2, H_2S, and trace contaminants typically found in a hydrocarbon gas stream. The lab results will be provided in the annual report should they indicate a material variance from the baseline. Initial samples will be taken and analyzed before the commencement of operations and will establish the baseline reference levels.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of injectate and the corresponding component of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is near the OSHA Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger alarms if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions, including pressure, flow rate, percentage of CO_2, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a depressuring event, the acid gas stream will be sent to a flare stack to be safely processed and will be reported under reporting requirements for the facility. Any such events will be accounted for in the sequestered reporting volumes consistent with *Section 7.*

6.5 Groundwater Monitoring

Initial samples will be taken from groundwater wells in the area of the O'Neal No. 4 upon approval of the MRV plan, and before commencement of CO_2 injection. These samples will be analyzed and reports prepared by a third-party laboratory testing for pH, total dissolved solids (TDS), CO_2, and volatile organic compounds (VOC). Initial samples will be taken and analyzed before the commencement of operations and will establish the baseline reference levels. Sampling select wells will be performed annually. In the event a material deviation in the sample analysis occurs, the results will be provided in the annual report.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO_2 Received

Per 40 CFR **§98.443**, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4**)." The 40 CFR **§98.444(a)(4)** states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." The CO_2 received for this injection well is injected and not mixed with any other supply; the annual mass of CO_2 injected will equal the amount received less any amounts calculated in accordance with the equations of this section. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO_2 Injected

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

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

Where:

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

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

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

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

The O'Neal No. 4 is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

7.4 Mass of CO_2 Emitted by Surface Leakage

The mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly due to the H_2S concentration in the injection stream. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions would be sent to a flare stack and reported as a part of the required GHG reporting for the facility. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of H_2S and CO_2. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak-point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

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

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

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

Calculation methods using equations from Subpart W will be used to calculate CO_2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage is unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Ozona believes the most appropriate method to quantify the mass of CO_2 released will be determined on a case-by-case basis. Any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. In the unlikely

event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events will be kept and stored as provided in *Section 10*.

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Data collection for calculating the amount of CO_2 sequestered in the O'Neal No. 4 will begin once the subsurface recompletion work, and the surface facilities construction has been completed, and subject to approval of the MRV plan. The calculation of sequestered volumes utilizes the following equation as the O'Neal No. 4 will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

CO_{2FI} will be calculated in accordance with Subpart W for reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a system blowdown event occurs. Those emissions would be sent to a flare stack and reported as part of the GHG reporting for the facility.

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The O'Neal Gas Unit No. 4 is an existing natural gas well that will be recompleted as a Class II well with corrosion-resistant materials. The Class II permit is still in process with the TRRC. Until this permit is issued, Ozona cannot specify a date to acquire the baseline testing data. Ozona is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan, including acquisition of baseline data, will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

Table 10 – Baseline Sampling Schedule

Sampling Location	Estimated Date	Comments
Fixed H_2S/CO_2 Monitors	Oct. 1, 2024	Baseline readings will be established during commissioning activities.
Soil gas sampling	Oct. 1, 2024	Baseline samples will be taken prior to commencement of injection.
Water well sampling	Oct. 1, 2024	Baseline samples will be taken prior to commencement of injection.

Notes:

- Above dates are estimates subject to adjustment based on actual regulatory approval dates and facilities construction timelines.
- All baseline sampling will be performed prior to the start of recording data for reporting under this MRV.
- Commissioning activities include installation of surface facilities, including flowline, compressors, manifolds, etc.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Ozona plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 Injected

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with API standards. These flow rates will be compiled quarterly.
- The composition of the injectate stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with API standards.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated per the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.

CO_2 Emissions from Leaks and Vented Emissions

- Gas monitors at the facility and O'Neal No. 4 will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.
- Calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR **§98.3(i).**
- Flow meters will be operated and maintained in accordance with applicable standards as published by a consensus-based standards organization.

All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60°F and an absolute pressure of 1 atmosphere.

9.2 Missing Data

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

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.

- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR **§98.**

9.3 MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Ozona will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least 3 years and include the following:

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

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APPENDIX A-3: COMPLETION REPORT

- CHARLIE C. OVERBY API 42-025-32658
- O'NEAL GAS UNIT NO. 4 API 42-025-32658
- MINI FRACTURE REPORT

APPENDIX A-4: API 42-025-30388 CHARLIE C. OVERBY GU PLUGGING RECORDS

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APPENDIX B-1: OIL AND GAS WELLS WITHIN THE MMA LIST

APPENDIX B-2: WATER WELLS WITHIN THE MMA LIST

Request for Additional Information: O'Neal Gas Unit Well No. 4
August 7, 2024

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	We recommend adding a process flow diagram (with locations of flow meters that will be used for subpart RR) to illustrate the path of CO_2 at the facility.	A process flow diagram has been added in Section 5.1.
2.	10		"Ozona will file an application for a separate Facility ID No. under Subpart RR for its sequestration assets." Please clarify this statement. E.g., does Ozona intend to change the facility ID number associated with this MRV plan, or is this referring to other sequestration?	This MRV plan is reporting under GHGRP ID No. 587021.
3.	7.2	72	"$CO_{CO2,p,u}$ = **Quarterly** CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction)" Per 40 CFR 98.443(C)(2), this variable should be "$CO_{CO2,p,u}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction)." Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	The definition has been edited to be consistent with 40 CFR 98.443(C)(2).

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
O'Neal Gas Unit Well No. 4

Bee County, TX

Prepared for *Ozona CCS, LLC*
San Antonio, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 2.0
January 2024

INTRODUCTION

Ozona CCS, LLC (Ozona) has a pending Class II acid gas injection (AGI) permit application with the Texas Railroad Commission (TRRC), which was submitted in September of 2023 for its O'Neal Gas Unit Well No. 4 (O'Neal No. 4), API No. 42-025-32658. Granting of this application would authorize Ozona to inject up to 1.5 million standard cubic feet per day (MMscf/D) of treated acid gas (TAG) into the Sligo Formation at a depth of 15,874 feet (ft) to 16,056 ft, with a maximum allowable surface pressure of 7,920 pounds per square inch gauge (psig). The TAG for this AGI well is associated with StarTex's Pawnee Treating Facility, located in a rural area of Bee County, Texas, approximately 2.0 miles (mi) south of Pawnee, Texas, as shown in Figure 1.

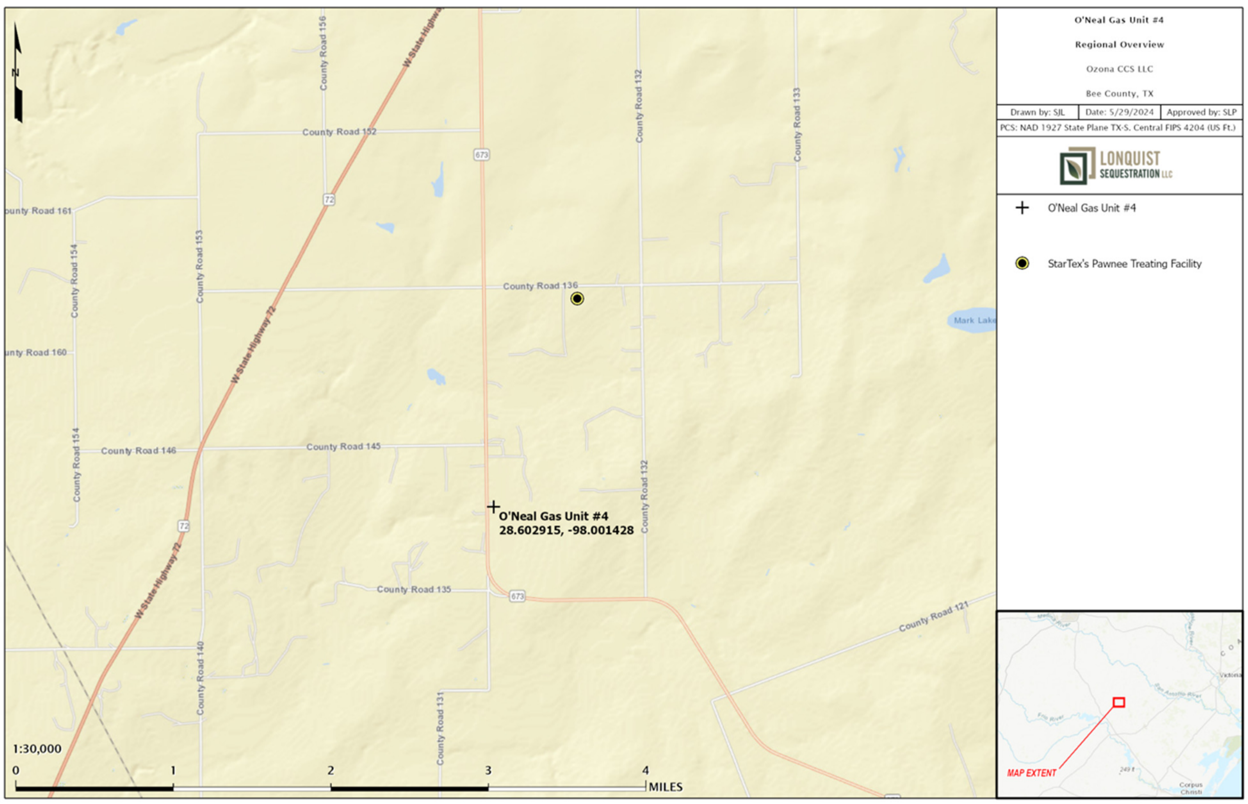

Figure 1 – Location of StarTex's Pawnee Treating Facility and the O'Neal No. 4

Ozona is submitting this Monitoring, Reporting, and Verification (MRV) plan to the EPA for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Ozona has applied to the TRRC for the O'Neal GU No. 4's Class II permit. Ozona plans to inject TAG for approximately 12 years. Table 1 shows the expected composition of the gas stream to be sequestered from the nearby treating facility.

Table 1 – Expected TAG Composition

Component	Mol Percent
Carbon Dioxide	98.2%
Hydrocarbons	1.03%
Hydrogen Sulfide	0.4%
Nitrogen	0.37%

ACRONYMS AND ABBREVIATIONS

AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group, Ltd.
CO_2	Carbon Dioxide (may also refer to other carbon oxides)
E	East
EOS	Equation of State
EPA	Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet

Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
PG	Pore Gradient
pH	Scale of Acidity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

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SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program. The TRRC classifies the O'Neal No. 4 as a UIC Class II well. Ozona has applied for a Class II permit for the O'Neal No. 4 under TRRC Rules 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas) and 46 (Fluid Injection into Productive Reservoirs).

1.2 UIC Well Identification Number

- O'Neal No. 4, API No. 42-025-32658, UIC No. 56819

1.3 Facility Address

- Facility Name: StarTex Pawnee Treating Facility
- Operator: StarTex Field Services, LLC
- Coordinates in North American Datum for 1983 (NAD 83) for this facility:
    - Latitude: 28.622211
    - Longitude: -97.992772
- Greenhouse Gas Reporting Program ID Information:
    - StarTex's gathering and boosting assets are currently reporting under Subpart W via Facility ID No. 568661.
    - Upon sequestration of CO_2 StarTex will also report in accordance with Subpart PP requirements using the same Facility ID No.
    - Ozona will file an application for a separate Facility ID No. under Subpart RR for its sequestration assets.

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and reservoir and plume modeling performed for the O'Neal No. 4 well.

The O'Neal No. 4 will inject the TAG stream into the Sligo Formation at a depth of 15,874 ft to 16,056 ft, and approximately 14,924 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and—most critically—to prevent surface releases.

2.1 Regional Geology

The O'Neal No. 4 (API No. 42-025-32658) is located in south Texas within the Gulf of Mexico Basin. The onshore portion of the Gulf of Mexico basin spans approximately 148,049,000 acres and encompasses portions of Texas, Louisiana, Mississippi, Alabama, Arkansas, Missouri, Kentucky, Tennessee, Florida, and Georgia to the state-waters boundary of the United States (Roberts-Ashby et al., 2012). The location of the O'Neal No. 4 is designated by the red star in Figure 2, relative to the present coastal extent and major structural features of the basin.

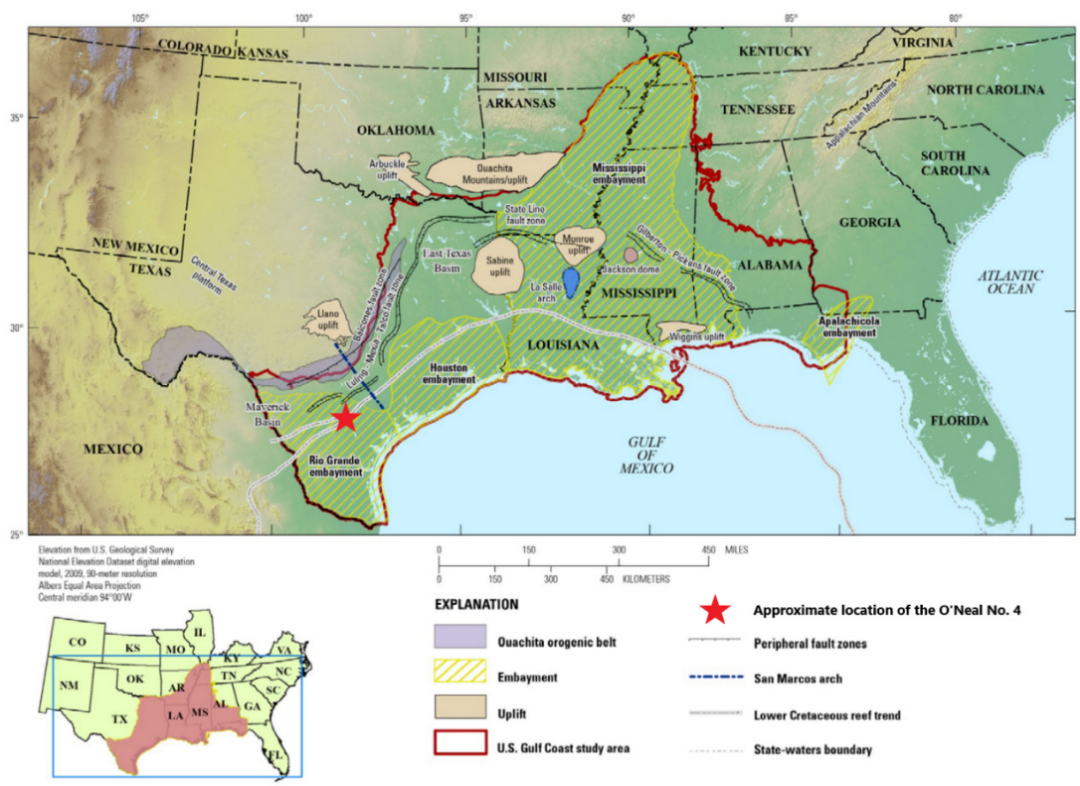

Figure 2 – Structural Features of the Gulf of Mexico and Locator Map (modified from Roberts-Ashby et al., 2012)

Figure 3 depicts a generalized stratigraphic column of the U.S. Gulf Coast, with light blue shading signifying the proposed injection interval and green stars indicating productive formations identified within 5 miles of the O'Neal No. 4. The injection interval is found within the Sligo Formation, with confinement provided by the overlying Pearsall Formation and tight underlying facies of the Lower Sligo and Hosston Formations.

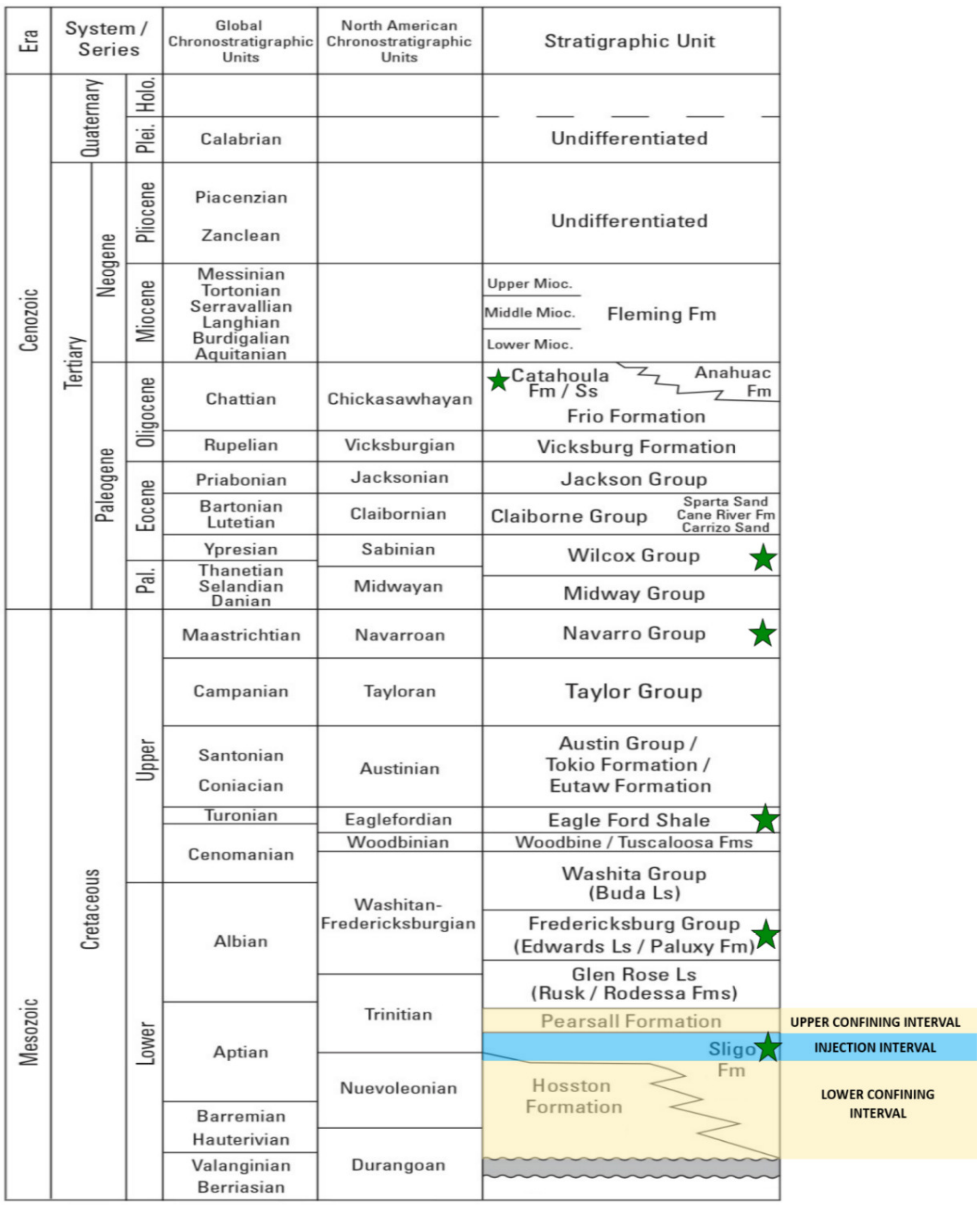

Figure 3 – Stratigraphic column of the U.S. Gulf Coast signifying proposed injection and confining intervals. Offset productive intervals are noted with a green star (modified from Roberts-Ashby et al., 2012).

The targeted formations of this study are located entirely within the Trinity Group, as clarified by the detailed stratigraphic column provided in Figure 4. During this time the area of interest was located along a broad, shallow marine carbonate platform that extended along the northern rim of the ancestral Gulf of Mexico. The Lower Cretaceous platform spanned approximately 870 mi from western Florida to northeastern Mexico, with a shoreline-to-basin margin that ranged between 45 to 125 mi wide (Yurewicz et al., 1993).

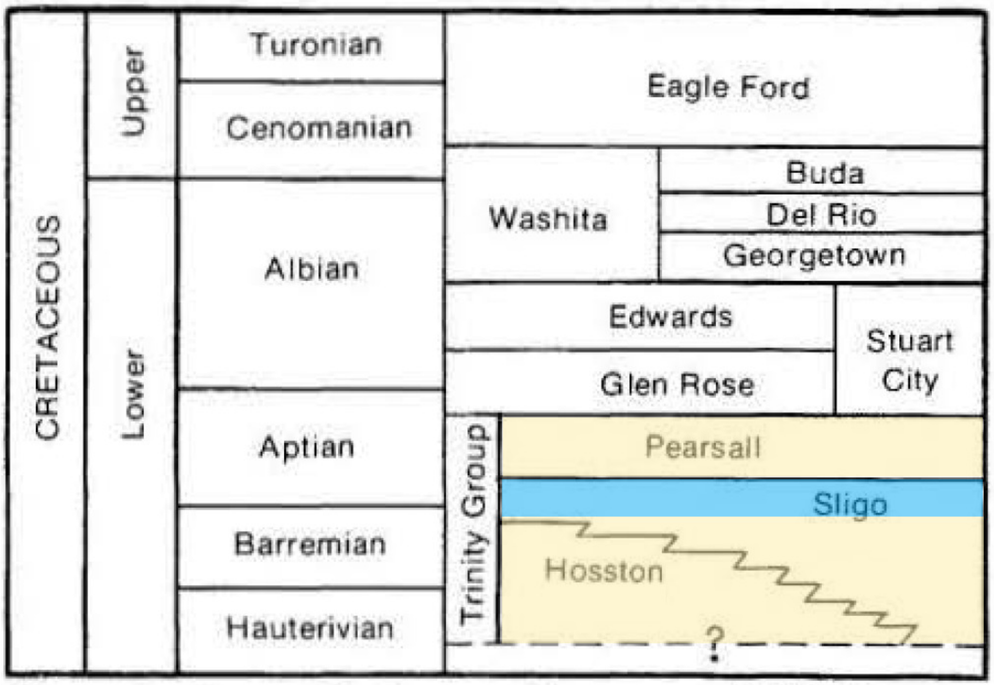

Figure 4 – Detailed stratigraphic column of Lower Cretaceous formations of south Texas. The proposed injection interval is shaded light blue and proposed confining intervals are shaded light yellow (modified from Bebout et al., 1981).

2.1.1 Geologic Setting and Depositional Environment

The depositional environment during the Lower Cretaceous generally consisted of a well-defined platform margin with a shallow marine platform interior or lagoon to the north, a shallow marine outer platform to the south, and a foreslope that gradually dipped southward towards the basin center. The platform margin remained stable for tens of millions of years during the Cretaceous but experienced episodic changes in sea level that resulted in cyclic deposition of several key facies that vary both spatially and within the geologic section. Facies distributions were heavily impacted by positioning relative to the margin, the height of the water column at any given time, and the degree of energy or wave action within the system (Galloway, 2008; Yurewicz et al., 1993).

In general, long stands of reef development and ooid shoaling developed primary porosity and permeability along the shallow, high-energy carbonate platform and represent reservoir quality

rock found within Cretaceous reef deposits. Deeper, basinward deposits tend to result in tighter petrophysical properties due to a relative increase in the amount of entrained clay associated with the heightening of the water column while moving downslope. Backreef deposits have the potential for porosity development but tend to have low permeability due to a general lack of wave action caused by restricted access to open water by the platform margin. Facies and petrophysical properties of the Lower Cretaceous section are anticipated to be relatively homogenous moving southwest-northwest along reef trend, with increased heterogeneity moving northwest-southeast due to the orientation of the carbonate rim and its effect on deposition and facies distributions (Yurewicz et al., 1993).

Figure 5 displays the paleogeography during deposition of the Lower Cretaceous section to visually demonstrate the position of the O'Neal No. 4 relative to the Sligo shelf margin and updip extents of Sligo deposition. A generalized schematic cross section of the Trinity Group is provided in Figure 6, which nearly intersects the project area from the northwest. The schematic illustrates the gross section thickening basinward, with primary reservoir development improving with proximity to the reef margin. Figure 7 displays a depositional model of the Lower Cretaceous carbonate platform to visually conceptualize depositional environments and anticipated petrophysical properties of facies introduced above.

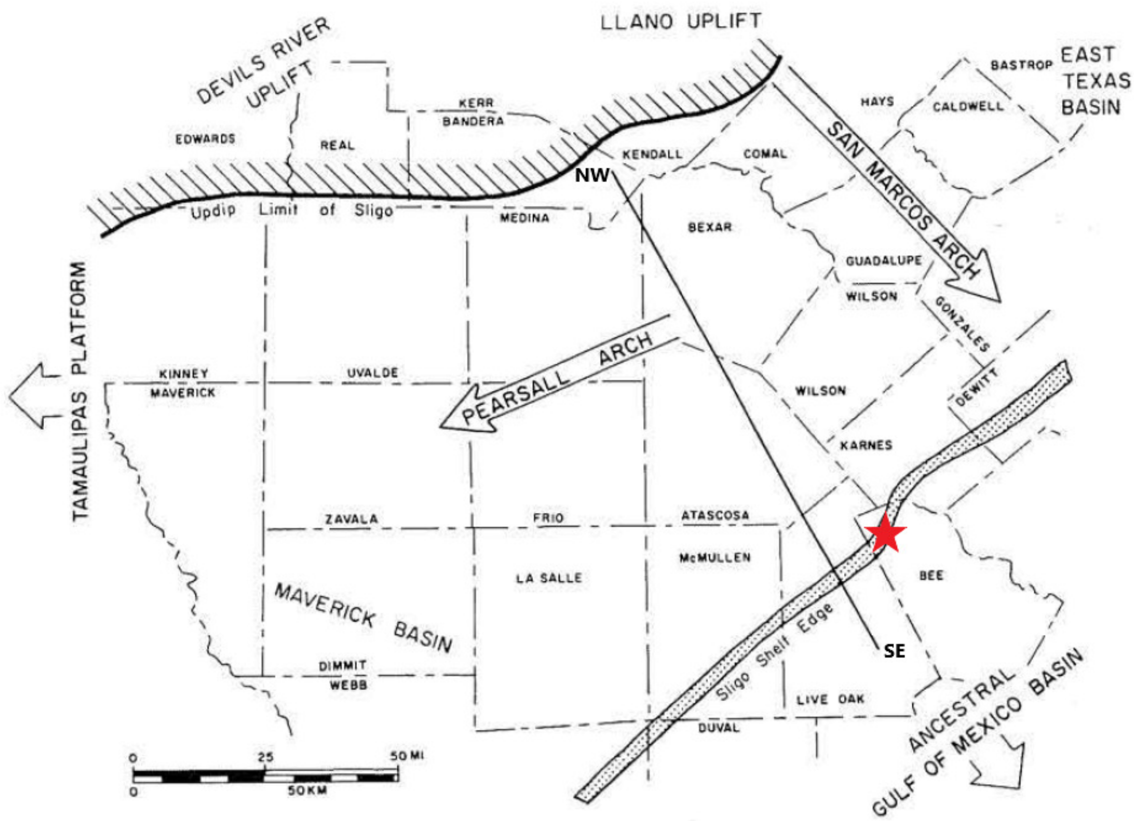

Figure 5 – Paleogeography of the Lower Cretaceous of south Texas. The red star represents the approximate location of the O'Neal No. 4 (modified from Bebout et al., 1981).

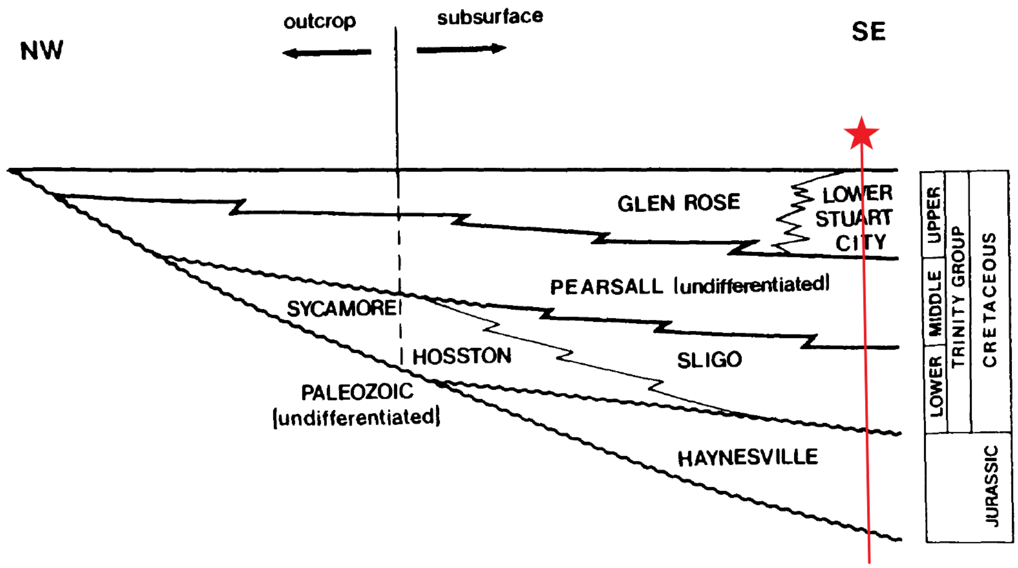

Figure 6 – Generalized northwest to southeast schematic cross section of the Trinity Group, south Texas (the line of section depicted in Figure 5). The red star and line represent the approximate location of the O'Neal No. 4 (modified from Kirkland et al., 1987)

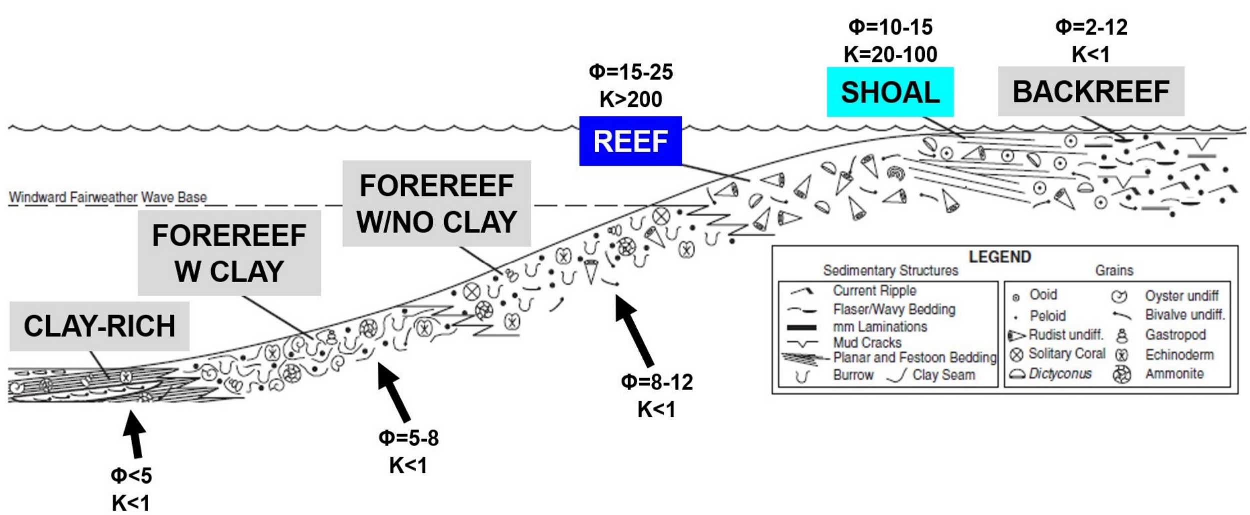

Figure 7 – Depositional model for the Lower Cretaceous carbonate platform with estimated porosity and permeability values of typical facies (modified from Talbert and Atchley, 2000).

2.1.2 Regional Structure and Faulting

The Gulf of Mexico basin was formed by crustal extension and sea-floor spreading associated with the Mesozoic breakup of Pangea. Rifting of northwest to southeast trending transfer faults during the Middle Jurassic lasted approximately 25 million years and resulted in variable thickness of the transcontinental crust underlying the region. By the Lower Cretaceous time, the general outline and morphology of the Gulf were similar to that of present-day (Galloway, 2008;

Yurewicz et al., 1993). Lower Cretaceous tectonic activity was limited to regional subsidence associated with areas of variable crustal thickness and local structuring caused by movement of Louann Salt (Yurewicz et al., 1993). The combination of these processes resulted in the structural development of regional arches, grabens, uplifts, embayments, salt domes, and salt basins around the northern edge of the basin (Dennen and Hackley, 2012; Galloway, 2008). The location of these structural features can be referenced in Figures 2 and 8 relative to the location of the O'Neal No. 4.

The schematic dip-oriented cross section displayed in Figure 9 presents a common interpretation of the current structural setting. Most of the published literature suggests that faulting near the project area is restricted to the shallower, overlying Cenozoic section, as displayed in Figure 9, with shallow faulting dying out before reaching the Pearsall Formation. However, one source did interpret the potential for faulting to the south (Swanson et al., 2016). The closest potential fault is depicted in Figure 8 relative to the location of the O'Neal No. 4. According to the map, the interpreted fault lies approximately 4.25 miles south-southeast of the well and approximately 3.9 miles south-southeast of the stabilized plume extent in the year 2047.

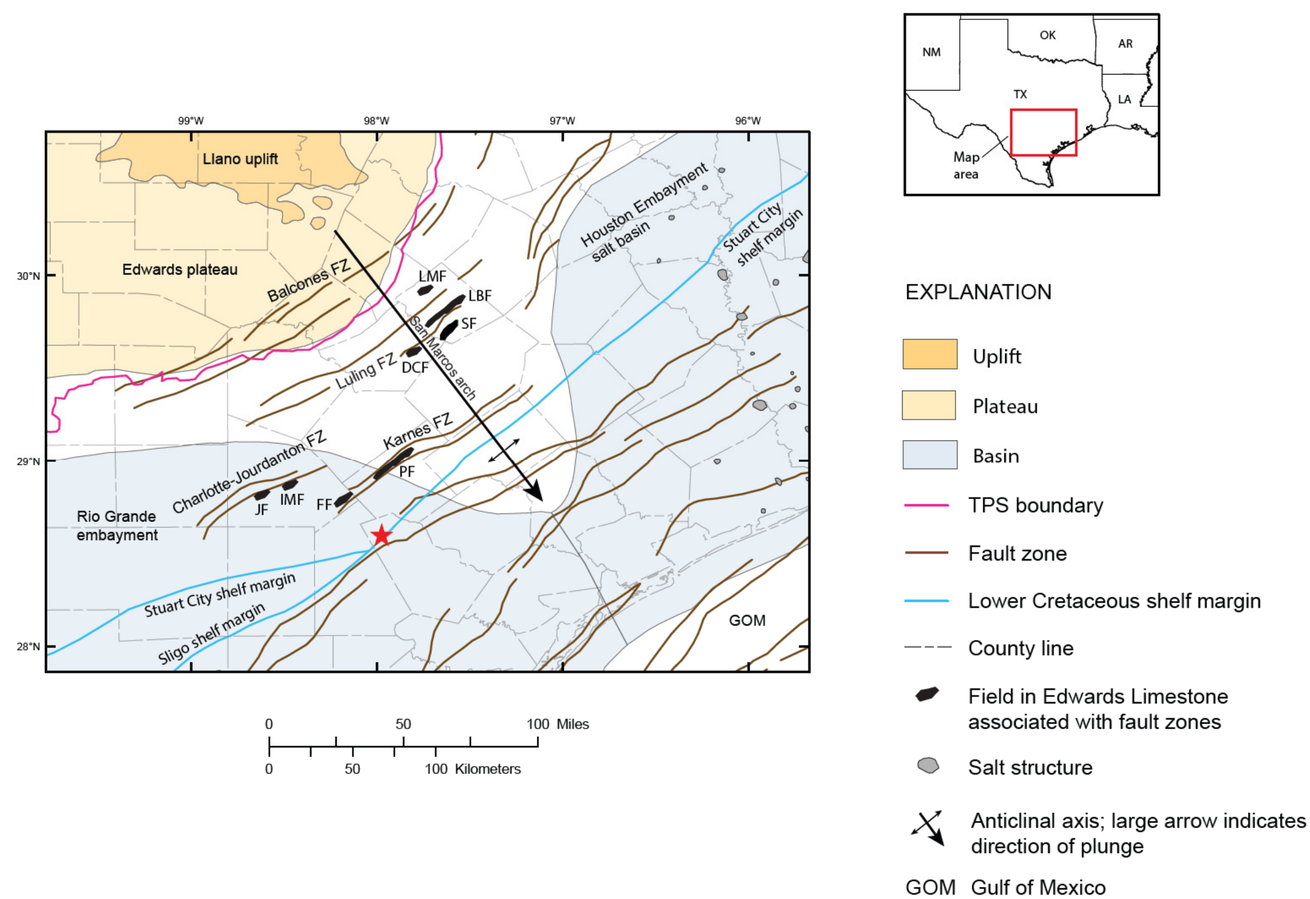

Figure 8 – Structural features and fault zones near the proposed injection site. The red star represents the approximate location of the O'Neal No. 4 (modified from Swanson et al., 2016).

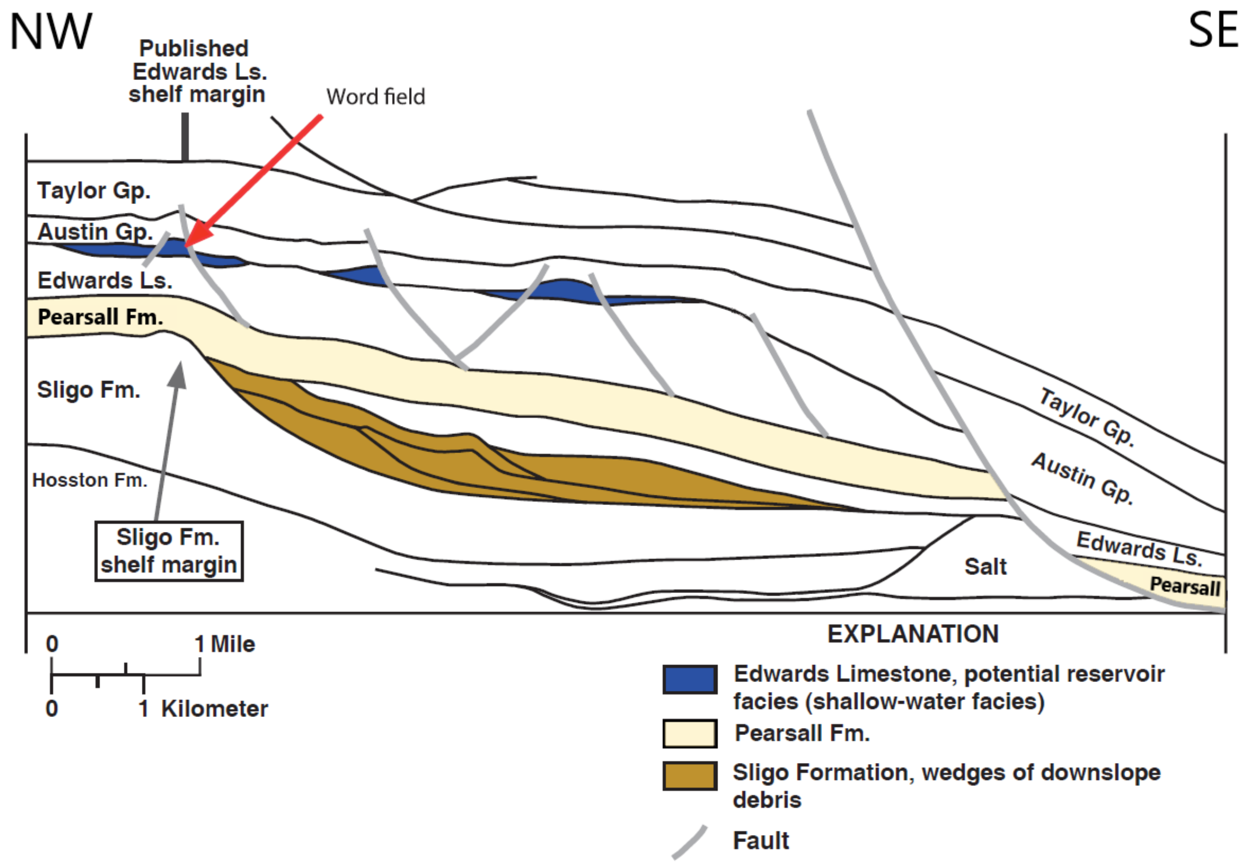

Figure 9 – Northwest to southeast schematic interpretation of the Edwards shelf margin through Word field, northeast of the O'Neal No. 4 project area (modified from Swanson et al., 2016).

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the O'Neal No. 4 well.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 depicts openhole logs from two offset wells (API No. 42-025-00473 and API No. 42-025-31892) to the O'Neal No. 4, indicating the injection and primary upper confining zones. The Tomasek No. 1 (API No. 42-025-00473) is located approximately 1 mi northeast of the O'Neal No. 4 and displays the shallow section from 0–8,200 ft. The Gordon No. 3 (API No. 42-025-31892) is located approximately 1.6 mi northeast of the O'Neal No. 4 and displays a shallow section from 8,200–16,400 ft.

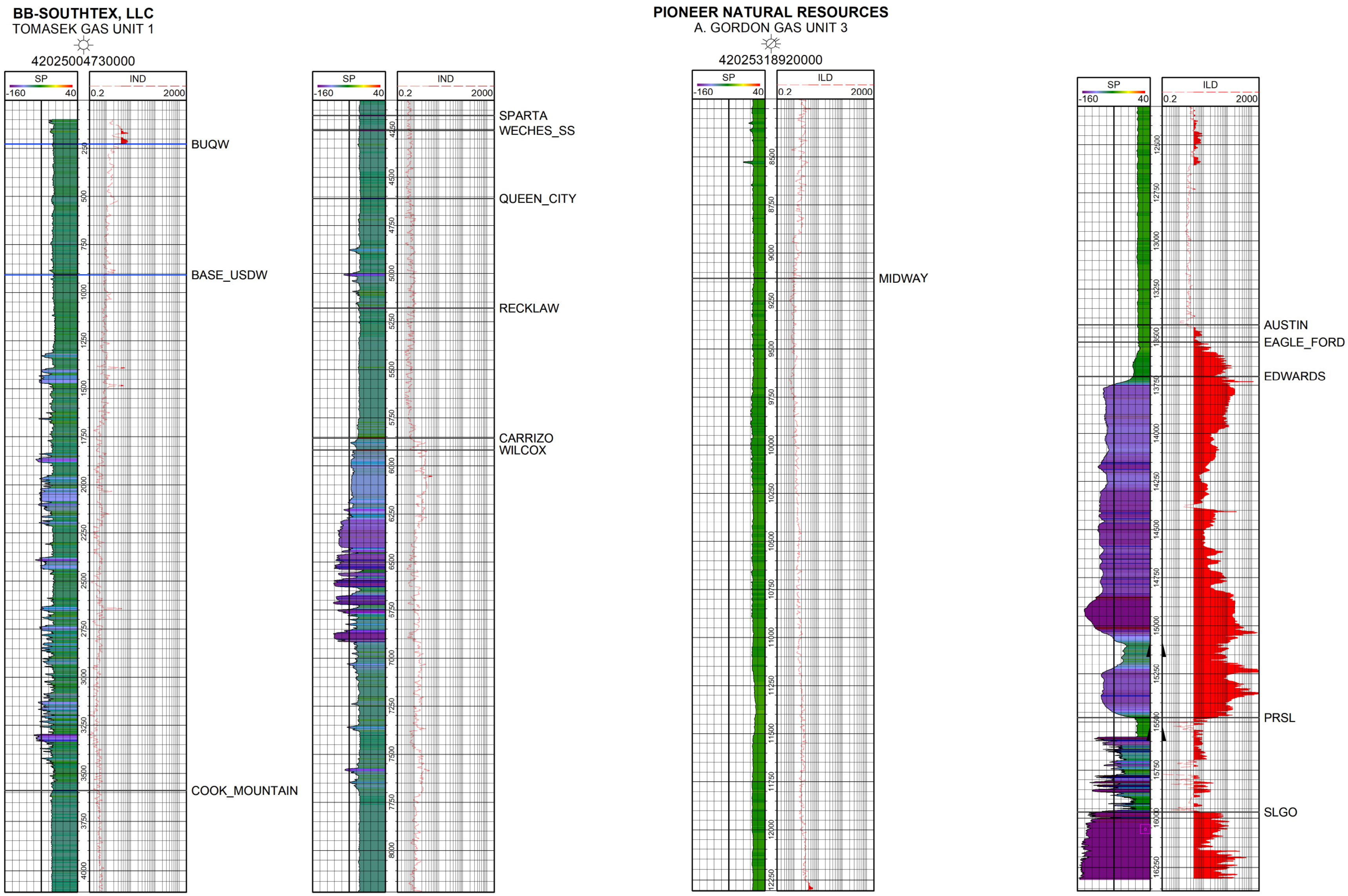

Figure 10 – Type Log with Tops, Confining, and Injection Intervals Depicted

2.2.2 Upper Confining Interval – Pearsall Formation

Following the deposition of the Sligo Formation, the Lower Cretaceous shelf was drowned by eustatic sea-level rise and deposition of the deep-water Pine Island Shale Member of the Pearsall Formation throughout the region (Roberts-Ashby et al., 2012). The Pine Island Shale consists of alternating beds of pelagic mudstone, hemipelagic mudstone, and Fe-rich dolomitic mudstone interpreted to have been deposited along the outer ramp. This is in agreement with core data published by Bebout and others (1981), and later by Swanson and others (2016), who identified the presence of *C. Margerelli*, a nannofossil indicative of anoxic conditions. The core-derived porosity-permeability relationship displayed in Figure 11 suggests that the permeability of the Pine Island Shale is incredibly low and stays below 0.0001 mD, regardless of porosity (Figure 11; Hull, 2011). This is further supported by the 2012 U.S. Geological Survey (USGS) *CO_2 Storage Resource Assessment*, which suggests that the Pine Island Shale contains the physical properties required to act as a regional seal and was chosen as the upward confining interval for their C50490108 Storage Assessment Unit (SAU) assessment of the Gulf Coast. The 2012 USGS report also noted that the Pine Island Shale is a sufficient regional seal with as little as 50 ft of contiguous shale development. The top of the Pearsall is encountered at a depth of 15,339 ft in the O'Neal No. 4, with a gross thickness of 535 ft (Figure 14). The Pine Island Shale member is approximately 130 ft thick at the O'Neal No. 4 location, with deposition of additional members of the overlying Pearsall Formation, which include the Cow Creek Limestone, Cow Creek shale, and Bexar Shale Members (Roberts-Ashby et al., 2012; Swanson et al., 2016).

The seismic line displayed in Figure 12 runs northwest to southeast across the Stuart City reef trend southwest of the project area. The top of the Buda, Pearsall, and Sligo Formation markers are depicted in color to demonstrate the lateral continuity of the section near the O'Neal No. 4. Seismic reflectors within the Pearsall Formation appear to lack deformation, suggesting consistent deposition over the reef margin. This is in agreement with reviewed published literature, which suggests deposition of the Pine Island Shale occurred during widespread marine transgression (Bebout et al., 1981; Hull, 2011.; Roberts-Ashby et al., 2012, Swanson et al., 2016).

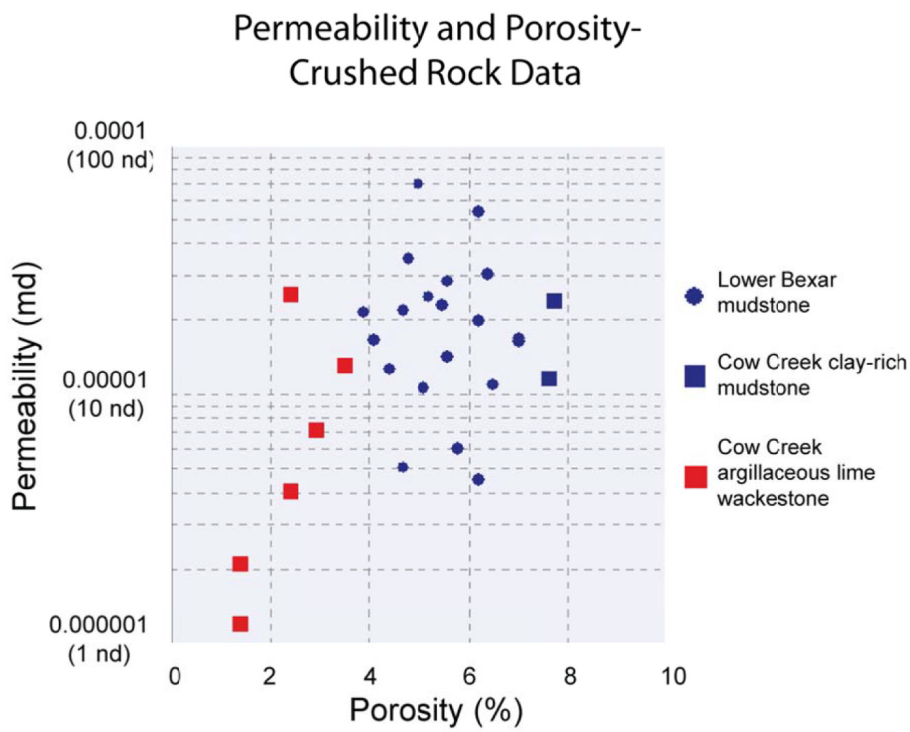

Figure 11 – Porosity-Permeability Crossplot of Pearsall Formation Crushed Rock Core Data (Swanson et al., 2016)

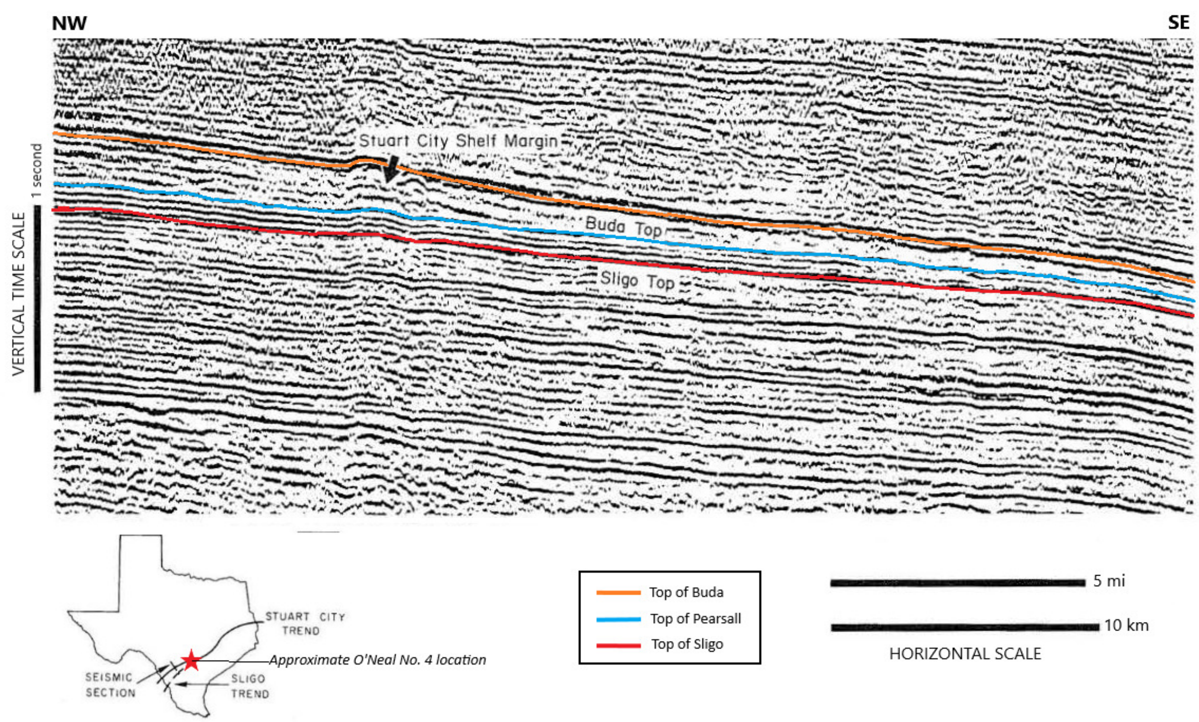

Figure 12 – Seismic line across the Stuart City (Edwards/Buda) shelf margin and locator map. The red star represents the approximate location of the O'Neal No. 4 (modified from Bebout et al., 1981).

2.2.3 Injection Interval – Upper Sligo Formation

The Sligo Formation underlies the Pearsall Formation and is predominately composed of shelf-edge limestones that were deposited along the Lower Cretaceous platform (Roberts-Ashby et al., 2012). However, the Cretaceous also experienced episodic changes in sea level that resulted in the deposition of cyclic Sligo facies that vary both spatially and within the geologic section. The overall Sligo interval is interpreted to be a transgressive sequence occasionally interrupted by progradational cycles that consists of porous shoaling-upward sequences that represent primary reservoir potential within the system (Bebout et al., 1981). Facies distributions of these reef complexes are heavily impacted by positioning relative to the margin, the height of the water column at any given time, and the degree of energy or wave action within the system (Galloway, 2008). Figure 13 depicts an idealized environmental setting of the Lower Cretaceous platform during deposition. Primary porosity and permeability of the upper Sligo Formation tends to develop in high-energy sequences with normal marine conditions that are dominated by the deposition of oolitic and skeletal grainstones.

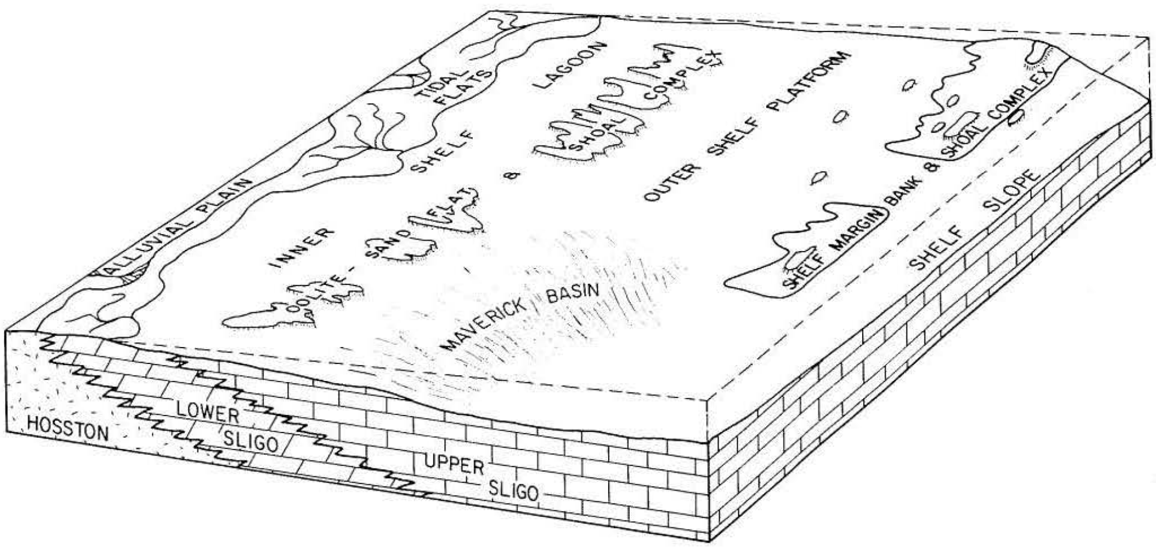

Figure 13 – Environmental Setting of Lower Cretaceous Platform (Bebout et al., 1981)

According to the 2012 USGS *CO_2 Storage Resource Assessment*, “the average porosity in the porous intervals of the storage reservoir decreases with depth from 9 to 16 percent” for their C50490108 DEEP SAU assessment of the Gulf Coast (>13,000 ft). The study also reported that “the average permeability in the storage reservoirs decreases with depth from 0.05 to 200 mD, with a most-likely value of 8 mD” for their C50490108 DEEP SAU assessment of the Gulf Coast (Roberts-Ashby et al., 2012).

The top of the upper Sligo is encountered at a depth of 15,874 ft in the O’Neal No. 4 with a gross thickness of 183 ft (Figure 14). The type log displayed in Figure 14 plots effective porosity for the confining interval and the total porosity of the injection interval, to account for the increased

volume of shale (Vshale) seen in the Pearsall Formation. The porosity data was compared to the analysis performed by Nutech to generate a permeability curve with a reasonable porosity-permeability relationship. The permeability curve was generated utilizing the Coates permeability equation, incorporated with a 20% irreducible brine saturation to match analysis provided by Nutech. Petrophysical analysis of the O'Neal No. 4 indicates an average porosity of 4.6%, a maximum porosity of 15%, an average permeability of 0.16 mD, and a maximum permeability of 3.3 mD. These curves have been extrapolated to the injection site and used to establish reservoir characteristics in the plume model.

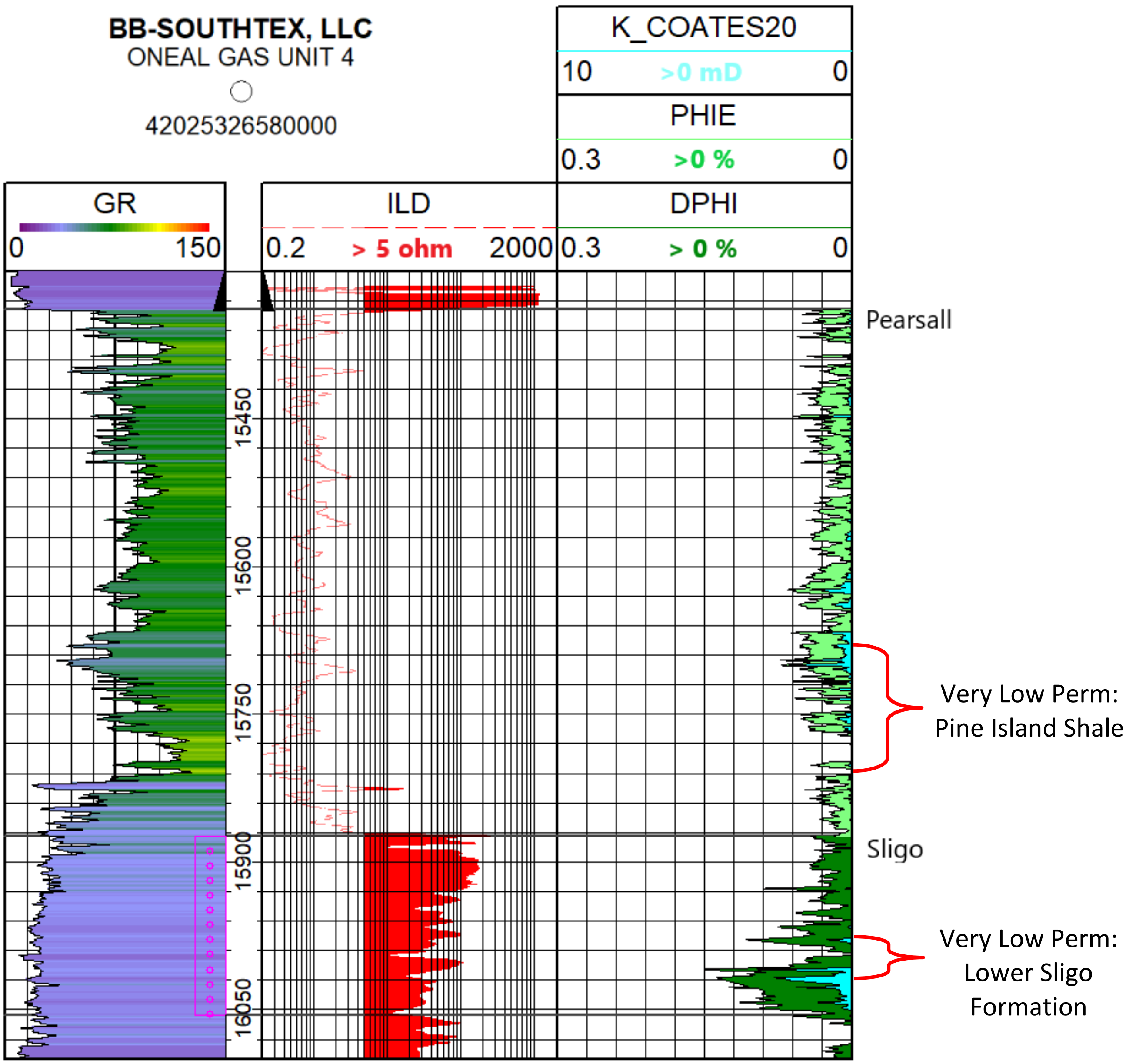

Figure 14 – Openhole log from O'Neal No. 4 (API No. 42-025-32658), with porosity curves shaded green >0%, permeability curve in blue >0 mD, and resistivity in red >5 ohms.

2.2.4 Formation Fluid

The USGS National Produced Waters Geochemical Database version 3.0 was reviewed for chemical analyses of Sligo oil-field brines within the state of Texas (Blondes et al., 2023). Only two samples were identified from the Sligo Formation: one located approximately 29 mi north-northeast in Karnes County and one located approximately 72 mi northeast in Gonzales County. The locations of these wells are shown in Figure 15 relative to the O'Neal No. 4. A summary of water chemistry analyses conducted on the two Texas Sligo oil-field brine samples is provided in Table 2 (page 25).

Averages from the samples were utilized for model assumptions due to the minimal Sligo sample availability and wide geographic spread of Sligo analysis. Total Dissolved Solids (TDS) of the samples contain a wide range of reported values but averaged 176,470 parts per million (ppm). Model sensitivities were established by running iterations with varying TDS values to understand the effect of brine concentrations on plume extents. The results suggested higher density brine values lead to smaller plumes; therefore, a value of 150,000 ppm was established in the model for a conservative approach. If the actual formation fluid sample that will be tested during the recompletion work produces a material difference in the plume, Ozona will submit an updated MRV plan.

Based on the results of the investigation, *in situ* Sligo reservoir fluid is anticipated to contain greater than 20,000 ppm TDS near the O'Neal No. 4, qualifying the aquifer as saline. These analyses indicate the *in situ* reservoir fluid of the Sligo Formation is compatible with the proposed injection fluids.

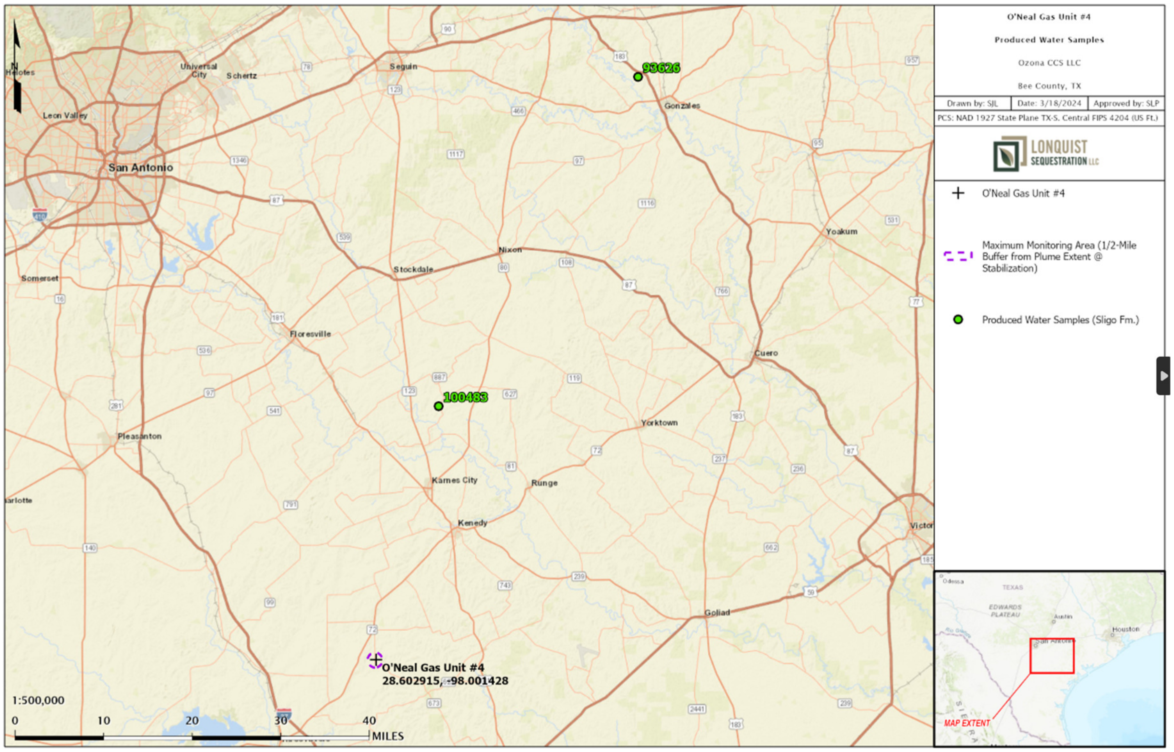

Figure 15 – Offset Wells Used for Formation Fluid Characterization

Table 2 – Analysis of Lower Cretaceous (Aptian) age formation fluids from the closest offset Sligo oil-field brine samples.

Measurement	Karnes County Sample	Gonzales County Sample	Average
Total Dissolved Solids (mg/L)	234,646	117,470	176,058
Sodium (mg/L)	51,168	27,909	39,539
Calcium (mg/L)	34,335	8,684	21,510
Chloride (mg/L)	146,500	57,811	102,156
Sample Depth (ft)	13,580 to 13,660	8,290-8,305	-
pH	5.9	8.2	7.05

2.2.5 Fracture Pressure Gradient

The fracture pressure gradient was obtained from a fracture report taken during the April 1993 Icompletion of the Sligo interval in the O'Neal No. 4. The Sligo was perforated between the depths of 15,874 ft and 16,056 ft, with continuous monitoring during the minifrac job. The report noted a calculated fracture gradient of 0.954 psi/ft based on an initial shut-in pressure (ISIP) of

8,312 psi. A 10% safety factor was then applied to the calculated gradient, resulting in a maximum allowed bottomhole pressure of 0.86 psi/ft. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

2.2.6 Lower Confining Interval – Lower Sligo and Hosston Formations

The O'Neal No. 4 reaches its total depth in the lower Sligo Formation, directly below the upper Sligo proposed injection interval. The lower Sligo is interpreted by Bebout and others (1981) to represent the seaward extension of the low-energy lagoon and tidal-flat system of the underlying Hosston Formation, a sequence of siliciclastics, evaporites, and dolomitic mudstone (Figure 16). The Hosston to lower Sligo "contact" represents a gradational package with a decrease in terrigenous sediments, an increase in carbonate sediments, and an increase in burrows of marine organisms working up-section into the lower Sligo. The lower Sligo consists of numerous cycles of subtidal to supratidal carbonates deposited in a low-energy lagoon and tidal-flat system (Bebout et al., 1981). These low permeability facies of the lower Sligo and underlying Hosston Formation will provide lower confinement to the upper Sligo injection interval. Figure 16 illustrates the typical environmental setting for the deposition of tidal flat facies along the Lower Cretaceous margin. The type log displayed in Figure 14 (*Section 2.2.3*) illustrates that the porosity of the lower Sligo ranges between 0–2% with permeability staying close to 0 mD. Therefore, the petrophysical characteristics of the lower Sligo and Hosston are ideal for prohibiting the migration of the injection stream outside of the injection interval.

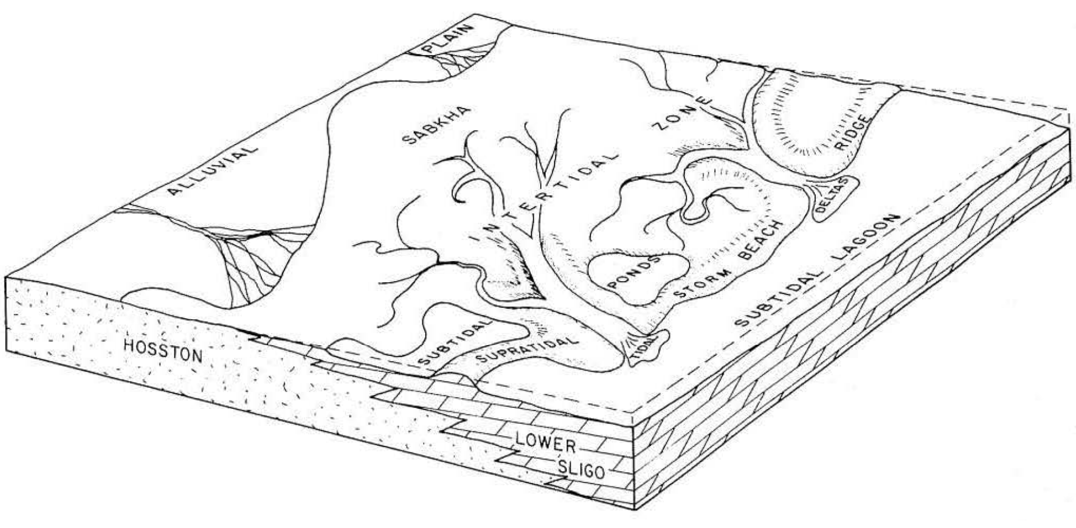

Figure 16 – Environmental Setting of Lower Cretaceous Tidal Flat Deposits (Bebout et al., 1981)

2.3 Local Structure

Structures surrounding the proposed sequestration site were influenced by regional arches, grabens, uplifts, embayments, movement of Louann Salt, and the development of carbonate reef complexes around the northern edge of the basin. However, one potential fault was identified in the literature within proximity and lies approximately 4.25 mi south-southeast of the well and

approximately 3.9 mi south-southeast of the stabilized plume extent in the year 2062 (Swanson et al., 2016). The location of these structural features can be referenced in Figures 2 and 8 relative to the location of the O'Neal No. 4.

A subsea true vertical depth (SSTVD) structure map on the top of the Sligo Formation is provided in Figure 17. The map illustrates the gentle basinward dip of the Sligo from the northwest to the southeast. The structural cross sections provided in Figures 18 and 19 (pages 28 and 29, respectively) illustrate the structural changes encountered in moving away from the O'Neal No. 4 site. The figures also demonstrate the laterally continuous nature of the Pearsall Formation that overlies the injection interval, with sufficient thickness and modeled petrophysical properties to alleviate the risk of upward migration of injected fluids. *Section 2.1.2*, discussing regional structure and faulting, presents a regional discussion pertinent to this topic.

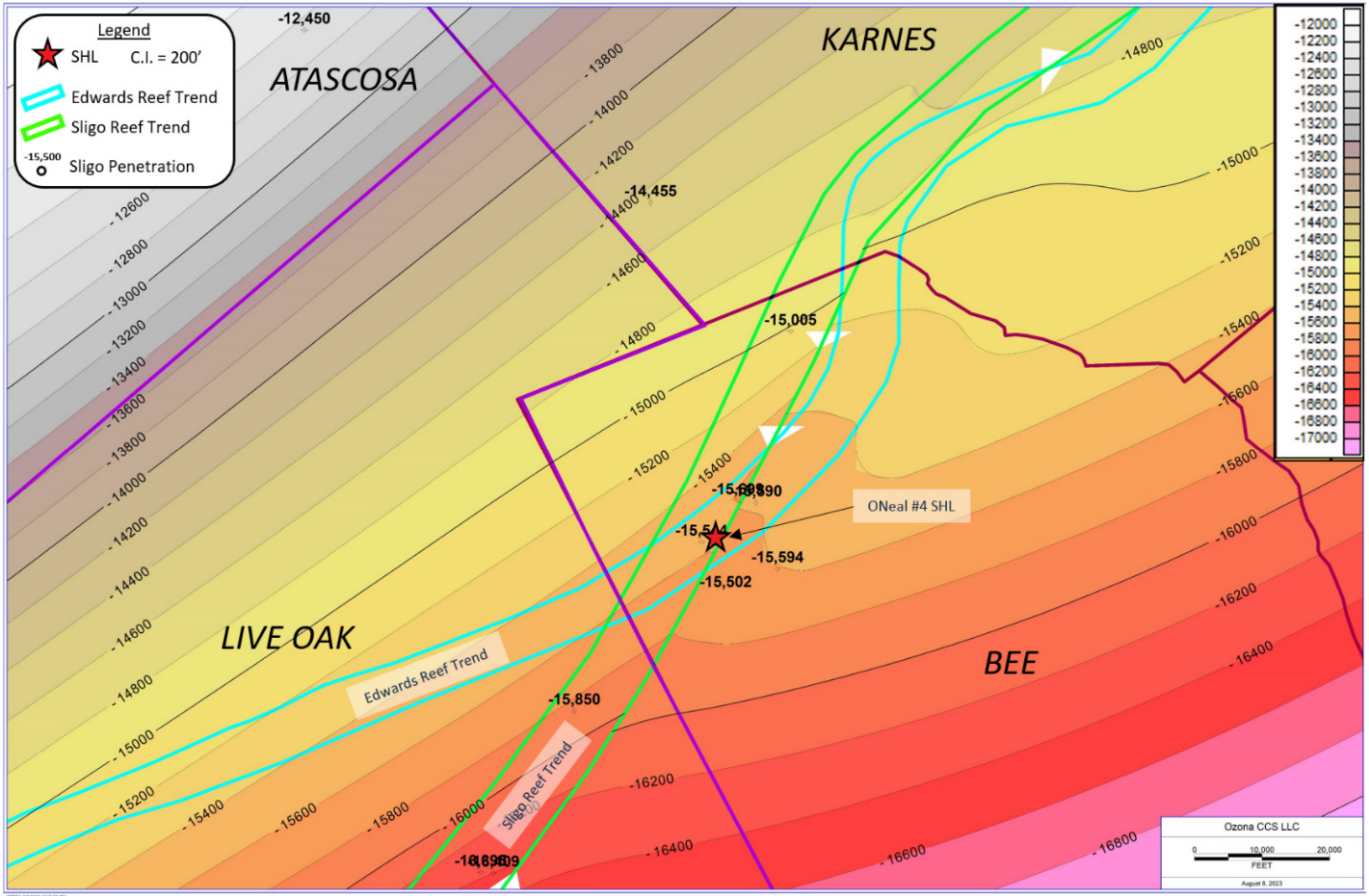

Figure 17 – Subsea Structure Map: Top of Sligo (injection interval). The red star signifies the location of the O'Neal No. 4.

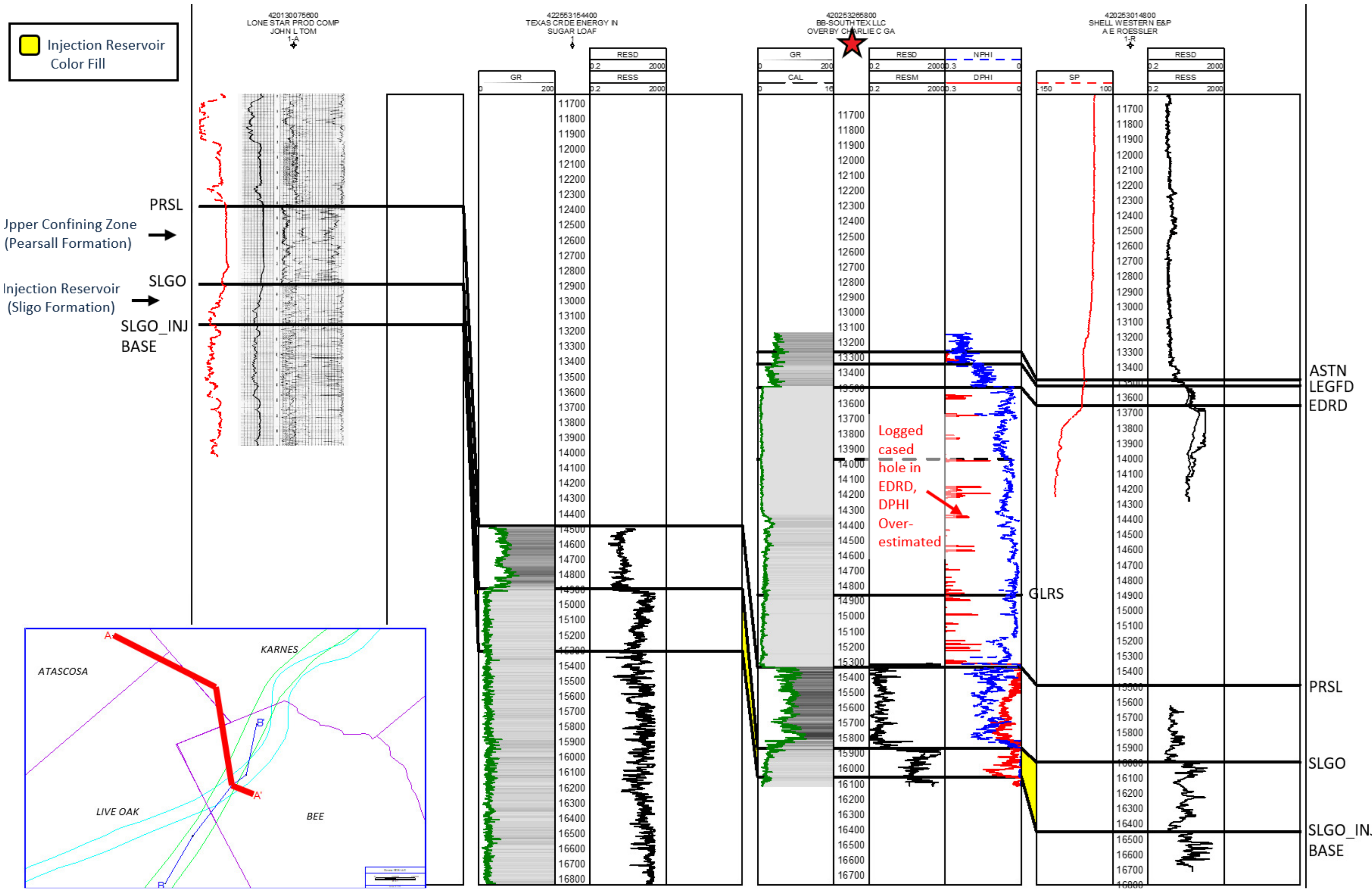

Figure 18 – Northwest to southeast structural cross section: A-A' Oriented along regional dip.
The red star signifies the location of the O'Neal No. 4, with the section line depicted in red on the locator map.

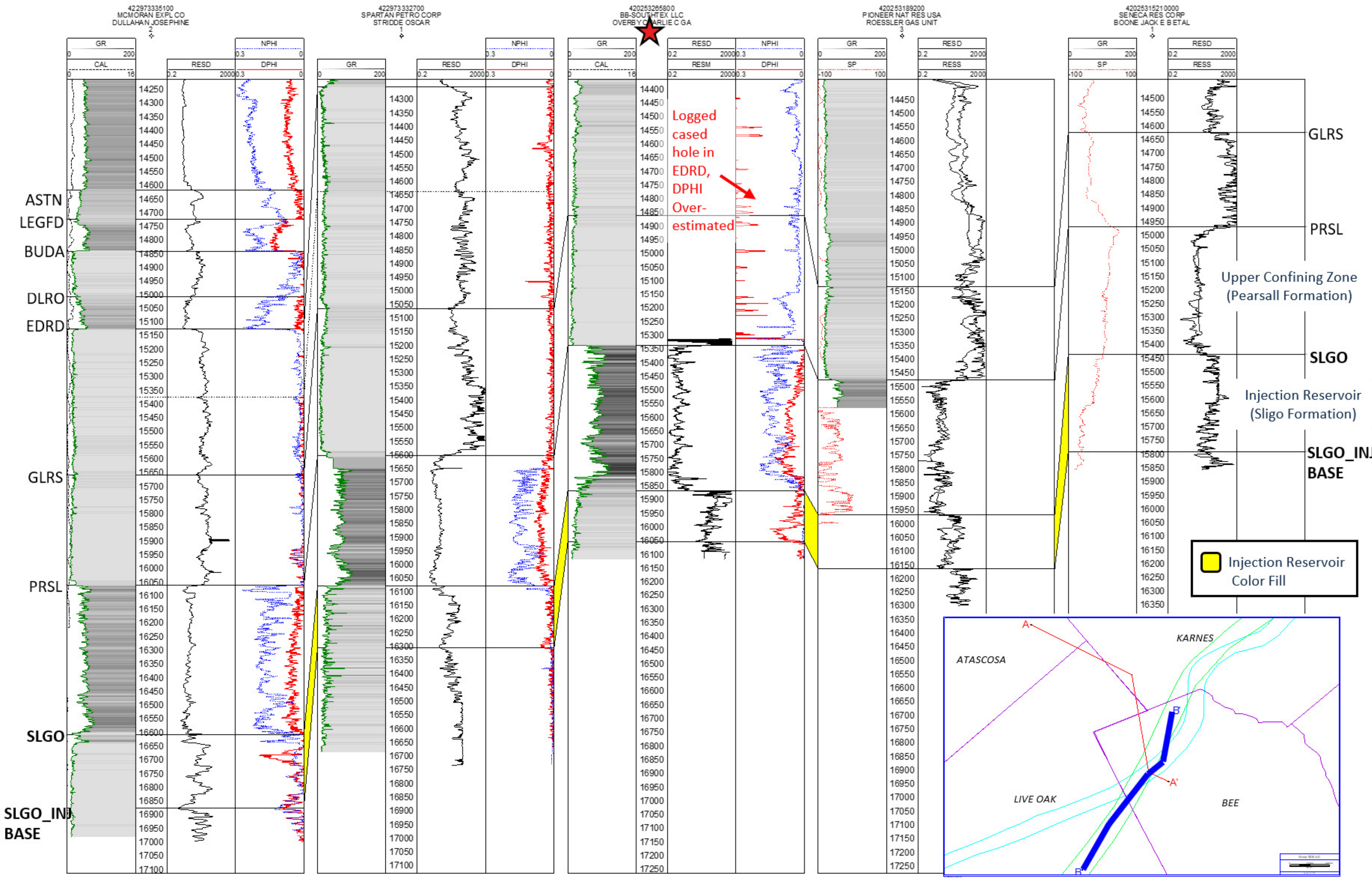

Figure 19 – Southwest to northeast structural cross section: B-B' oriented along regional strike.
The red star signifies the location of the O'Neal No. 4, with the section line depicted in blue on the locator map.

2.4 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Sligo Formation at the O'Neal No. 4 well location indicate that the reservoir contains the necessary thickness, porosity, and permeability to receive the proposed injection stream. The overlying Pearsall Formation is regionally extensive at the O'Neal No. 4 with low permeability and sufficient thickness to serve as the upper confining interval. Beneath the injection interval, the low permeability, low porosity facies tidal flat, and lagoonal facies of the lower Sligo and underlying Hosston Formation are unsuitable for fluid migration and serve as the lower confining interval.

2.5 Groundwater Hydrology

Bee County falls within the boundary of the Bee Groundwater Conservation District. Only one aquifer is identified by the Texas Water Development Board's Texas Aquifers Study near the O'Neal No. 4 well location, the unconfined to semi-confined Gulf Coast aquifer. The Gulf Coast aquifer parallels the Gulf of Mexico and extends across the state of Texas from the Mexican border to the border of Louisiana (Bruun et al., 2016). The extents of the Gulf Coast aquifer are provided in Figure 20 for reference.

The Gulf Coast aquifer is a major aquifer system comprised of several individual aquifers: the Jasper, Evangeline, and Chicot. These aquifers are composed of discontinuous clay, silt, sand, and gravel beds that range from Miocene to Holocene in age (Figure 21, page 32). Numerous interbedded lenses and layers of silt and clay are present within the aquifers, which can confine individual aquifers locally. The underlying Oligocene Catahoula tuff represents the lower confining interval, but it should be noted that the formation is prone to leaking along the base of the aquifer. However, the Burkeville confining interval provides isolation between Jasper and Evangeline aquifers which helps protect the shallower Evangeline and Chicot Aquifers (Bruun et al., 2016).

The schematic cross section provided in Figure 22 (page 32) runs south of the O'Neal No. 4, illustrating the structure and stratigraphy of the aquifer system. The thickness of individual sedimentary units within the Cenozoic section tends to thicken towards the Gulf of Mexico due to the presence of growth faults that allow additional loading of unconsolidated sediment. The total net sand thickness of the aquifer system ranges between 700 ft of sand in the south, to over 1,300 ft in the north, with the saturated freshwater thickness averaging 1,000 ft.

The water quality of the aquifer system varies with depth and locality but water quality generally improves towards the central to northeastern portions of the aquifer where TDS values are less than 500 milligrams per liter (mg/L). The salinity of the Gulf Coast aquifer increases to the south, where TDS ranges between 1,000 mg/L to more than 10,000 mg/L. The Texas Water Development Board's Texas Aquifers Study (2016) suggests that areas associated with higher salinities are possibly associated with saltwater intrusion likely "resulting from groundwater pumping or to brine migration in response to oil field operations and natural flows from salt domes intruding into the aquifer" (Bruun et al., 2016).

According to the TDS map of the Gulf Coast aquifer (Figure 23), the TDS in northern Bee County range between 500–3,000 mg/L near the O'Neal No. 4, categorizing the aquifer as fresh to slightly saline.

The TRRC's Groundwater Advisory Unit (GAU) identified the Base of Useable Quality water (BUQW) at a depth of 250 ft and the base of the USDW at a depth of 950 ft at the location of the O'Neal No. 4. Approximately 14,924 ft is therefore separating the base of the USDW and the injection interval. (A copy of the GAU's Groundwater Protection Determination letter issued by the TRRC as part of the Class II permitting process for the O'Neal No. 4 is provided in Exhibit A-1.) The base of the deepest aquifer is separated from the injection interval by more than 14,924 ft of rock, including 4,200 feet of Midway shale. Though unlikely for reasons outlined in the sections here on confinement and potential leaks, if the migration of injected fluid did occur above the Pearsall Formation, thousands of feet of tight sandstone, limestone, shale, and anhydrite beds occur between the injection interval and the lowest water-bearing aquifer.

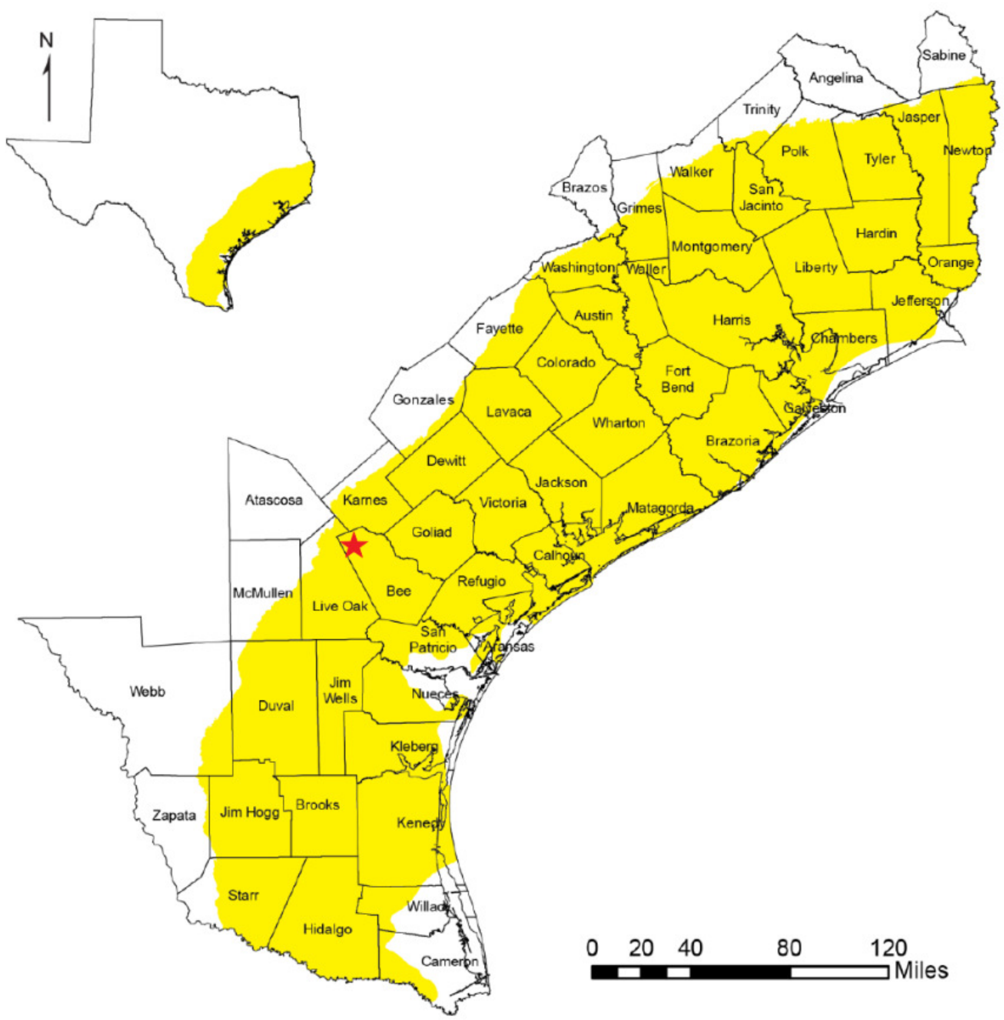

Figure 20 – Extent of the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun, B., et al., 2016)

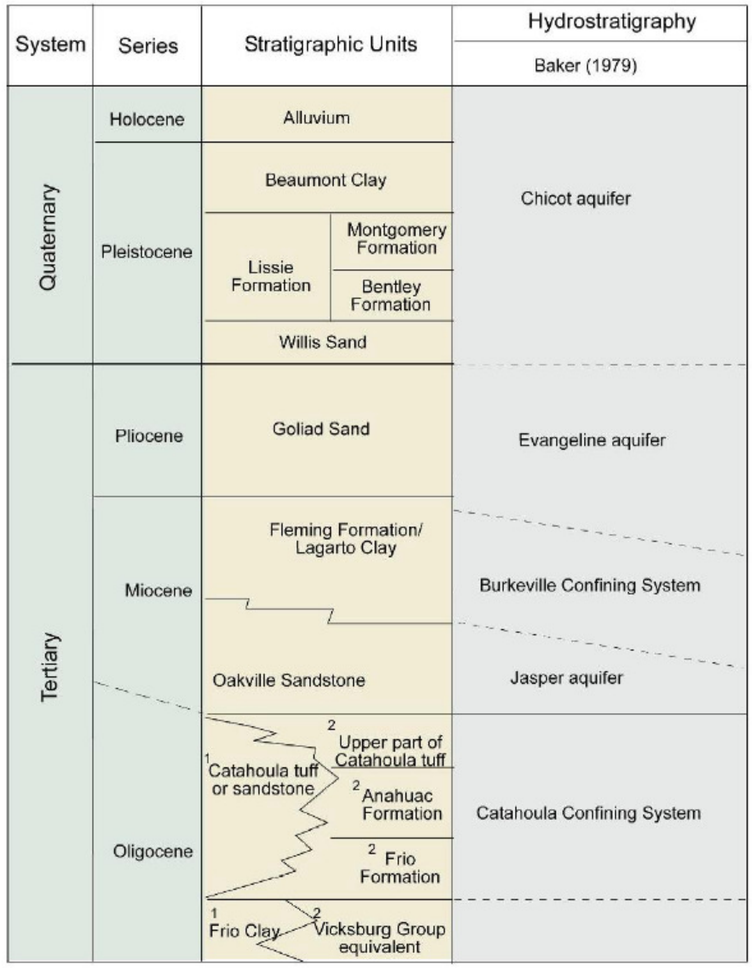

Figure 21 – Stratigraphic Column of the Gulf Coast Aquifer (Chowdhury and Turco, 2006)

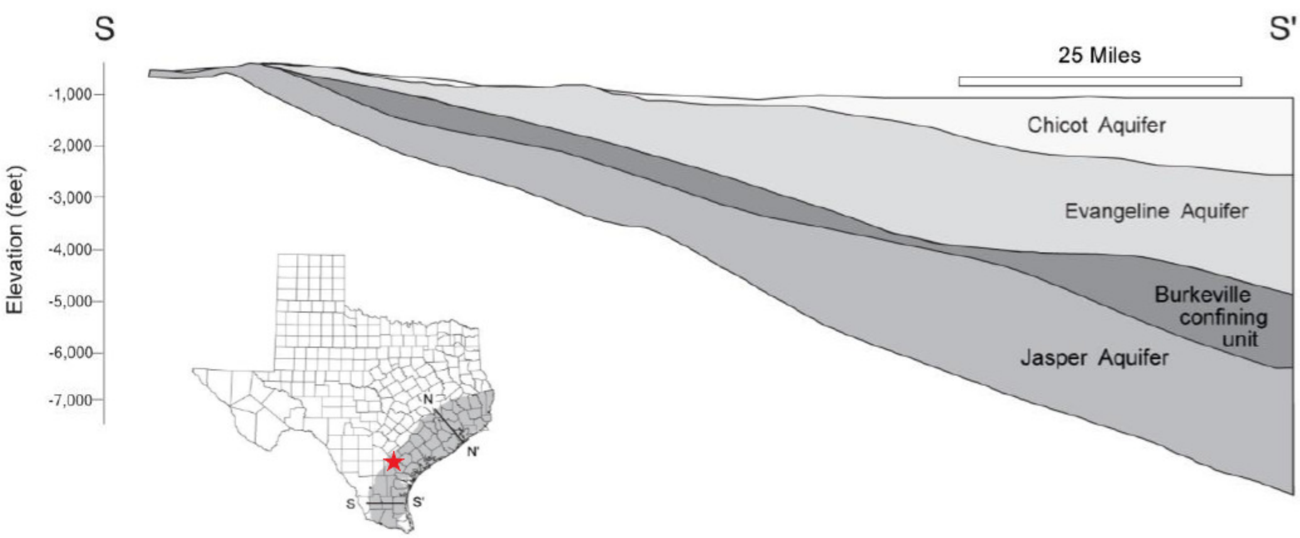

Figure 22 – Cross Section S-S' Across the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun et al., 2016)

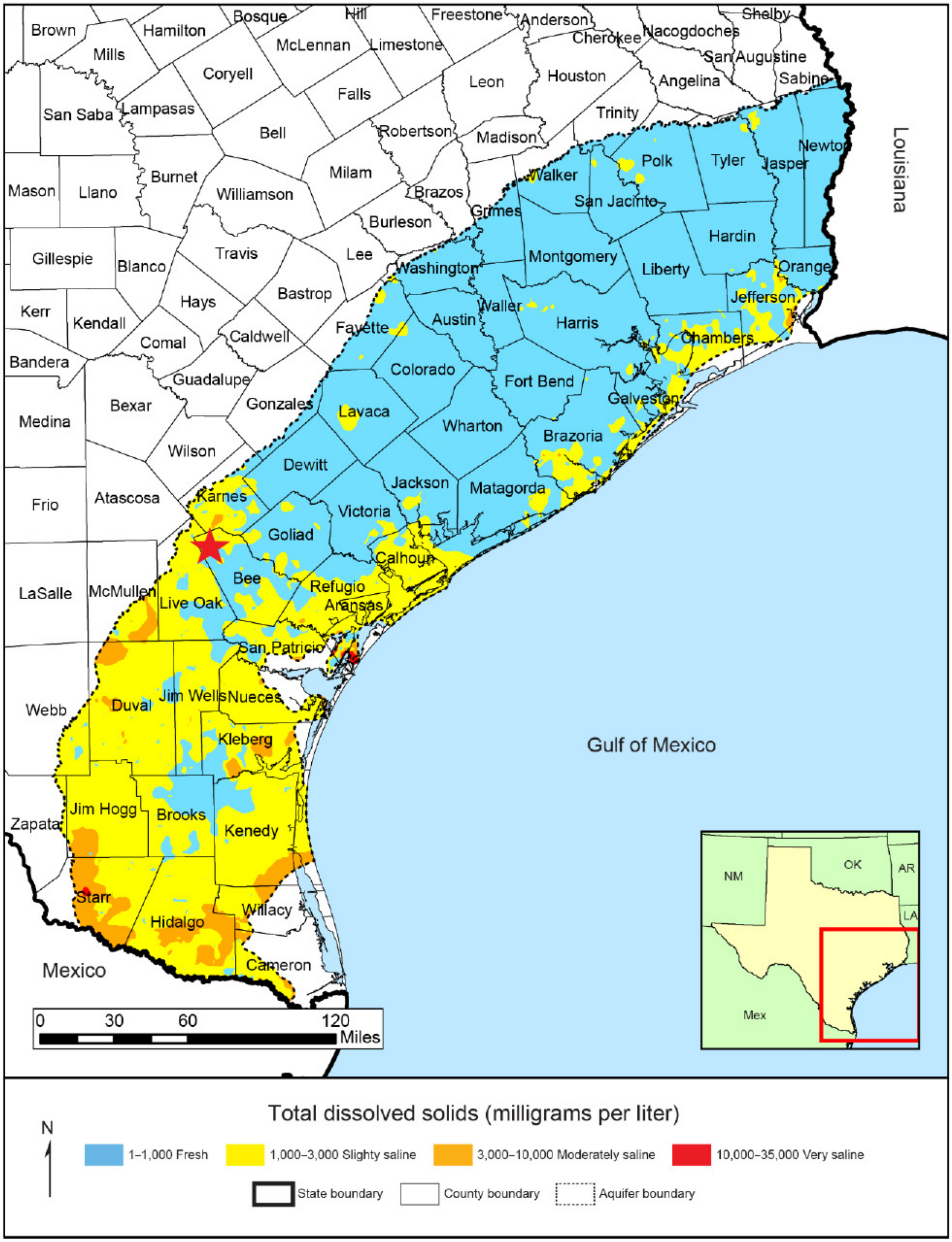

Figure 23 – Total Dissolved Solids (TDS) in the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun et al., 2016).

2.6 References

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2.7 Description of the Injection Process

2.7.1 Current Operations

The Pawnee Treating Facility and the O'Neal No. 4 are existing operating assets. The O'Neal No. 4 will be recompleted for acid gas injection service under the Class II permit process. Under the Class II application, the maximum injection rate is 28 MT/yr (1.5 MMscf/d). The TAG is 98.2% CO_2, which equates to 27.5 MT/yr of CO_2 each year. The current composition of the TAG stream is displayed in Table 3.

Table 3 – Gas Composition

Component	Mol Percent
Carbon Dioxide	98.2%
Hydrocarbons	1.03%
Hydrogen Sulfide	0.4%
Nitrogen	0.37%

The facility is designed to treat, dehydrate, and compress the natural gas produced from the surrounding acreage in Bee County. The facility uses an amine unit to remove the CO_2 and other constituents from the gas stream. The TAG stream is then dehydrated, compressed, and routed directly to the O'Neal No. 4 for injection. The remaining gas stream is processed to separate the natural gas liquids from the natural gas. The facility is monitored 24 hours per day, 7 days per week.

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group, Ltd.'s GEM 2023.2 (GEM) simulator, one of the most comprehensive reservoir simulation software packages for conventional, unconventional, and secondary recovery. The GEM utilizes equation-of-state (EOS) algorithms in conjunction with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics. This results in the creation of exceedingly precise and dependable simulation models for carbon injection and storage. The GEM model holds recognition from the EPA for its application in the delineation modeling aspect of the area of review, as outlined in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Sligo Formation serves as the target formation for the O'Neal No. 4 (API No. 42-025-32658). The Petra software package was utilized to construct the geological model for this target formation. Within Petra, formation top contours were generated and subsequently brought into GEM to outline the geological structure.

Porosity and permeability estimates were determined using the porosity log from the O'Neal No. 4. A petrophysical analysis was then conducted to establish a correlation between porosity values and permeability, employing the Coates equation. Both the porosity and permeability estimates from

the O'Neal No. 4 were incorporated into the model, with the assumption that they exhibit lateral homogeneity throughout the reservoir.

The reservoir is assumed to be at hydrostatic equilibrium. Given the geological formation in which this well is located and its previous history as a gas producer, the model is assumed to be primarily saturated with gas. More precisely, the reservoir is assumed to be 80% gas saturated and 20% brine saturated, as deduced from the well log data. The modeled injection interval exhibits an average permeability of 0.23 mD and an average porosity of 5%. All layers within the model have been perforated. An infinite-acting reservoir has been created to simulate the boundary conditions.

The gas injectate is composed predominantly of CO_2 as shown in Table 4. The modeled composition takes into consideration the carbon dioxide and other constituents of the total stream. As the facility has been in operation for many years, the gas composition for the proposed injection period is expected to remain constant.

Table 4 – Modeled Injectate Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Carbon Dioxide (CO_2)	98.2	98.2
Hydrocarbons	1.03	Hydrocarbons
Hydrogen Sulfide	0.4	Hydrogen Sulfide
Nitrogen	0.37	Nitrogen

Core data from the literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Sligo carbonates (Bennion and Bachu, 2010). A maximum residual gas saturation of 35% was assigned to the model based on core from the literature review. The Corey-Brooks method was used to create relative permeability curves. The key inputs used to create the relative permeability curves in the model include a Corey exponent for brine of 1.8, a Corey exponent for gas of 2.5, brine and gas relative permeability endpoints of 0.8 and 0.5, respectively, and an irreducible brine saturation of 20%. The relative permeability curves used for the GEM model are shown in Figure 24.

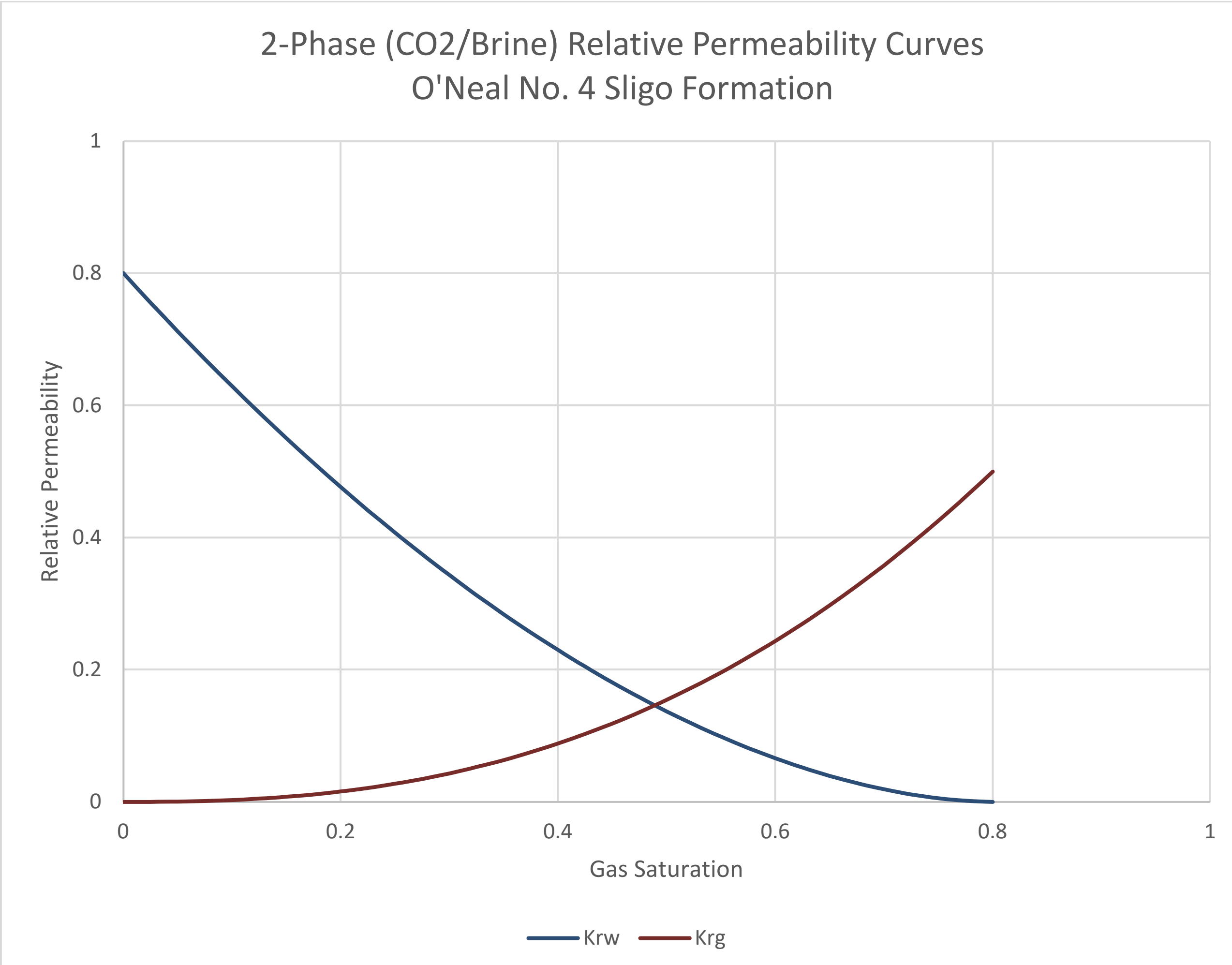


Figure 24 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 81 blocks in the x-direction (east-west) and 81 blocks in the y-direction (north-south), resulting in a total of 6,561 grid blocks per layer. Each grid block spans dimensions of 250 ft x 250 ft. This configuration yields a grid size measuring 20,250 ft x 20,250 ft, equating to just under 15 square miles in area. The grid cells in the vicinity of the O'Neal No. 4, within a radius of 0.5 mi, have been refined to dimensions of 83.333 ft x 83.333 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume and pressure effects near the wellbore.

In the model, each layer is characterized by homogeneous permeability and porosity values. These values are derived from the porosity log of the O'Neal No. 4. The model encompasses a total of 61 layers, each featuring a thickness of approximately 3 ft per layer. As previously mentioned, the model is perforated in each layer, with the top layer being the top of the injection interval and the bottom layer being the lowest portion of the injection interval. The summarized property values for each of these packages are displayed in Table 5.

Table 5 – GEM Model Layer Package Properties

Layer No.	Top (TVD ft)	Thickness	Perm. (mD)	Porosity (%)
1	15,874	3	0.004	3.75%
2	15,877	3	0.002	2.98%
3	15,880	3	0.001	1.62%
4	15,883	3	0.001	1.78%
5	15,886	3	0.002	2.32%
6	15,889	3	0.001	1.96%
7	15,892	3	0.002	3.10%
8	15,895	3	0.002	2.99%
9	15,898	3	0.003	3.52%
10	15,901	3	0.006	4.00%
11	15,904	3	0.005	3.93%
12	15,907	3	0.001	2.15%
13	15,910	3	0.001	1.99%
14	15,913	3	0.002	2.97%
15	15,916	3	0.001	2.22%
16	15,919	3	0.002	2.88%
17	15,922	3	0.001	2.38%
18	15,925	3	0.093	6.68%
19	15,928	3	0.005	2.62%
20	15,931	3	0.002	2.58%
21	15,934	3	0.003	3.07%
22	15,937	3	0.006	3.62%
23	15,940	3	0.002	2.68%
24	15,943	3	0.001	1.08%
25	15,946	3	0.002	1.87%
26	15,949	3	0.025	4.70%
27	15,952	3	0.024	4.37%
28	15,955	3	0.001	1.97%
29	15,958	3	0.003	2.27%
30	15,961	3	0.007	3.09%
31	15,964	3	0.110	6.75%
32	15,967	3	0.037	5.62%
33	15,970	3	0.011	4.41%
34	15,973	3	0.022	4.59%
35	15,976	3	0.297	7.88%
36	15,979	3	0.440	9.21%
37	15,982	3	0.060	5.90%
38	15,985	3	0.001	2.22%
39	15,988	3	0.001	2.21%

Layer No.	Top (TVD ft)	Thickness	Perm. (mD)	Porosity (%)
40	15,991	3	0.001	1.12%
41	15,994	3	0.003	2.05%
42	15,997	3	0.014	4.56%
43	16,000	3	0.007	4.15%
44	16,003	3	0.033	5.95%
45	16,006	3	1.233	10.25%
46	16,009	3	1.476	12.04%
47	16,012	3	0.566	10.08%
48	16,015	3	1.679	12.18%
49	16,018	3	2.194	13.08%
50	16,021	3	1.235	12.02%
51	16,024	3	0.788	11.22%
52	16,027	3	0.944	10.48%
53	16,030	3	0.424	9.05%
54	16,033	3	0.378	8.85%
55	16,036	3	0.378	8.81%
56	16,039	3	0.378	8.84%
57	16,042	3	0.736	9.91%
58	16,045	3	0.232	7.94%
59	16,048	3	0.238	7.97%
60	16,051	3	0.012	3.01%
61	16,054	3	0.038	4.30%

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

1. Estimate the maximum areal extent and density drift of the injectate plume after injection.
2. Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone.
3. Assess the likelihood of the injectate plume migrating into potential leak pathways.

The reservoir is assumed to have an irreducible brine saturation of 20%. The salinity of the brine within the formation is estimated to be 150,000 ppm (USGS National Produced Waters Geochemical Database, Ver. 2.3), typical for the region and formation. The injectate stream is primarily composed of CO_2 and H_2S as stated previously. Core data from the literature was used to help generate relative permeability curves. From the literature review, also as previously discussed, cores that most closely represent the carbonate rock formation of the Sligo seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low, conservative residual gas saturation based on the cores from the literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975).

The model is initialized with a reference pressure of 10,995 psig at a subsea depth of 15,740 ft. This, when a Kelly Bushing "KB" elevation of 334 ft is considered, correlates to a gradient of 0.684 psi/ft. This pressure gradient was determined from production data of the O'Neal No. 4. An initial reservoir pressure of 0.76 psi/ft was calculated before initial production. However, in 1997, after producing approximately 0.5 billion cubic feet (Bcf) of gas, the well was shut in. The last bottomhole pressure reading was calculated to be 0.480 psi/ft. This assumes the reservoir repressurizes after production ceases, but not fully back to in situ conditions. Therefore, a 10% safety factor was given to the initial reservoir pressure gradient of 0.76 psi/ft, and a gradient of 0.684 psi/ft was implemented into the model as a conservative estimate. A skin factor of -2 was applied to the well to simulate the stimulation of the O'Neal No. 4 for gas production from the Sligo Formation, which is based on the acid fracture report, provided in *Appendix A-3*.

The fracture gradient of the injection zone was estimated to be 0.954 psi/ft, which was determined from the acid fracture report. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.86 psi/ft, which is equivalent to 13,652 psig at the top of the Sligo injection interval.

The model, which begins in January 2025, runs for a total of 22 years, comprising 12 years of active injection, and is then succeeded by 10 years of density drift. Throughout the entire 12-year injection period, an injection rate of 1.5 MMscf/D is used to model the maximum available rate, yielding the largest estimate of the plume size. After the 12-year injection period, when the O'Neal No. 4 ceases injection, the density drift of the plume continues until the plume stabilizes 10 years later. The maximum plume extent during the 12-year injection period is shown in Figure 25. The final extent after 10 years of density drift after injection ceases is shown in Figure 26 (page 42).

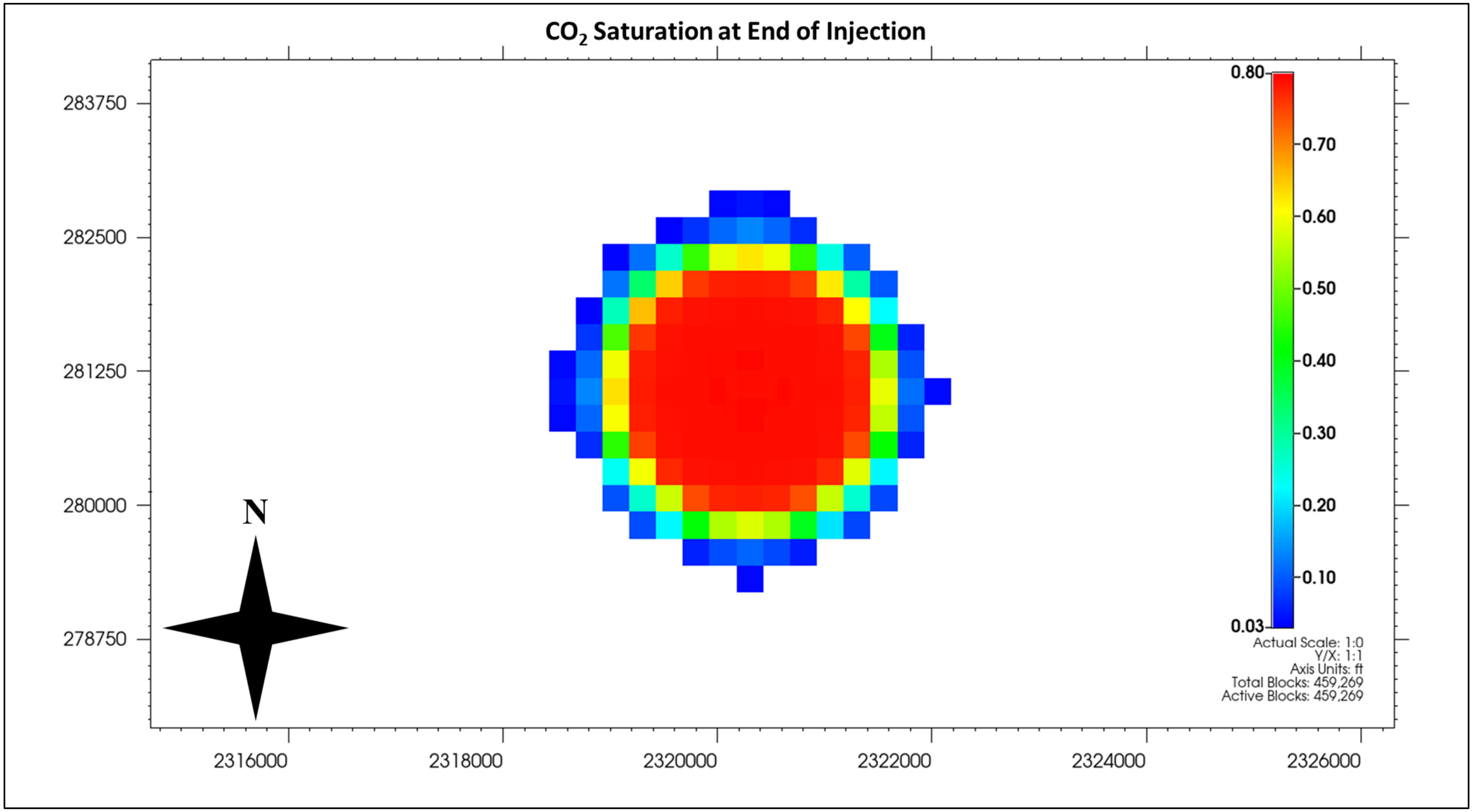


Figure 25 – Areal View of Saturation Plume at Shut-in (End of Injection)

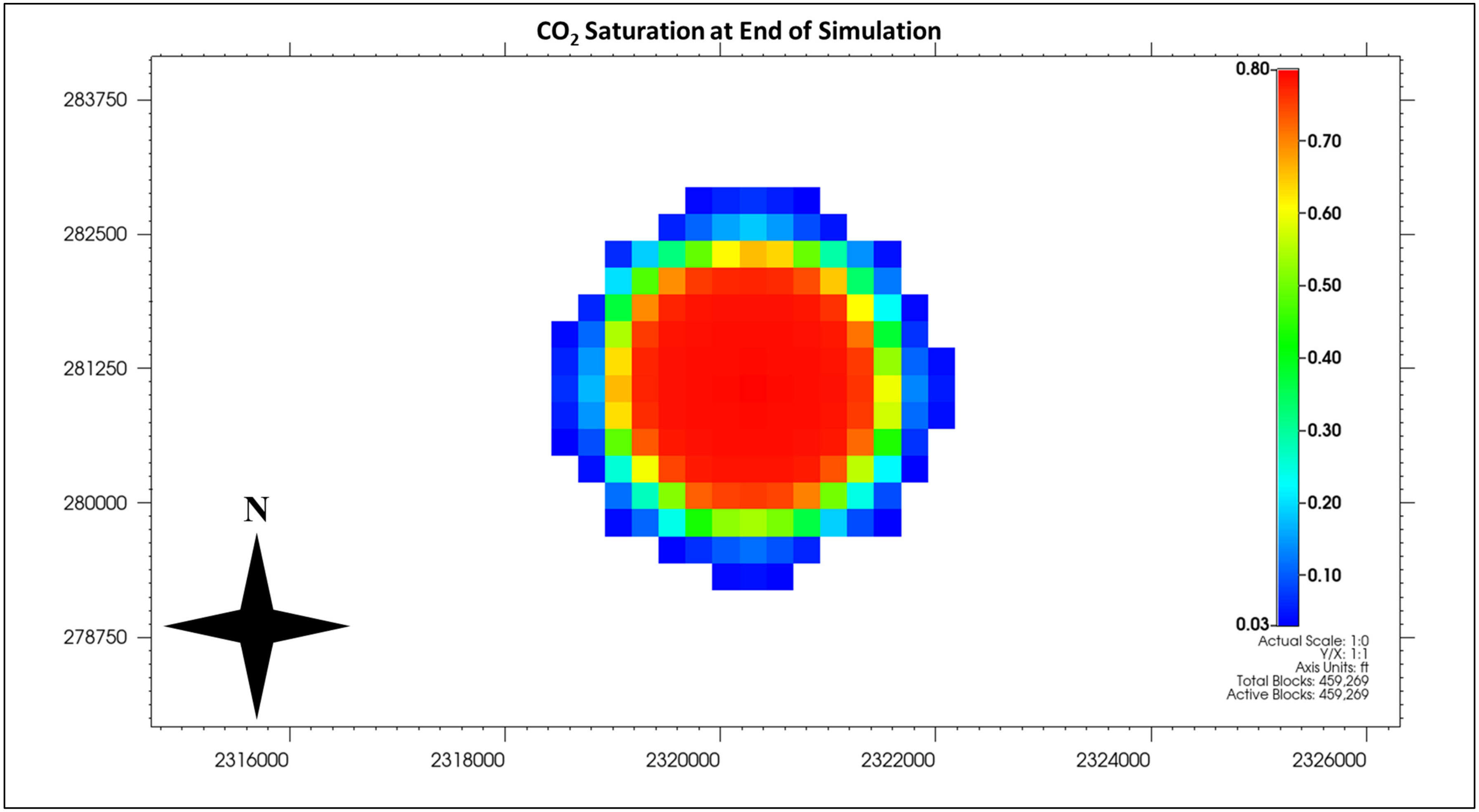


Figure 26 – Areal View of Gas Saturation Plume 10 Years After Shut-in (End of Simulation)

The cross-sectional view of the O’Neal No. 4 shows the extent of the plume from a side-view angle, cutting through the formation at the wellbore. Figure 27 shows the maximum plume extent during the 12-year injection period. During this time, gas from the injection well is injected into the permeable layers of the formation and predominantly travels laterally. Figure 28 (page 45) shows the final extent of the plume after 10 years of migration. Then, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 35% of injected gas that travels into each grid cell is trapped, as the gas travels mostly vertically—as it is less dense than the formation brine—until an impermeable layer is reached. Both figures are shown in an east-to-west view.

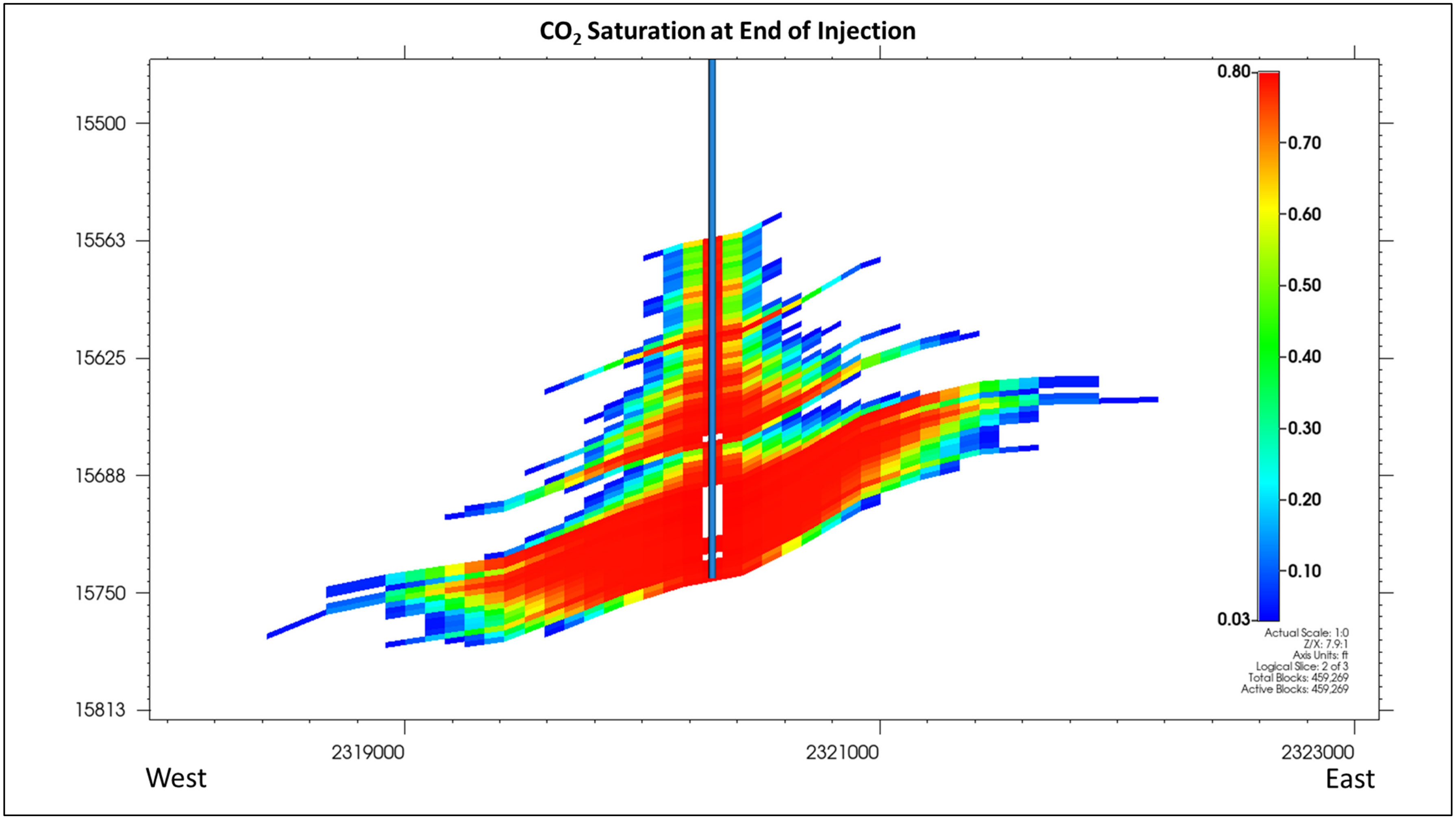


Figure 27 – East-West Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)

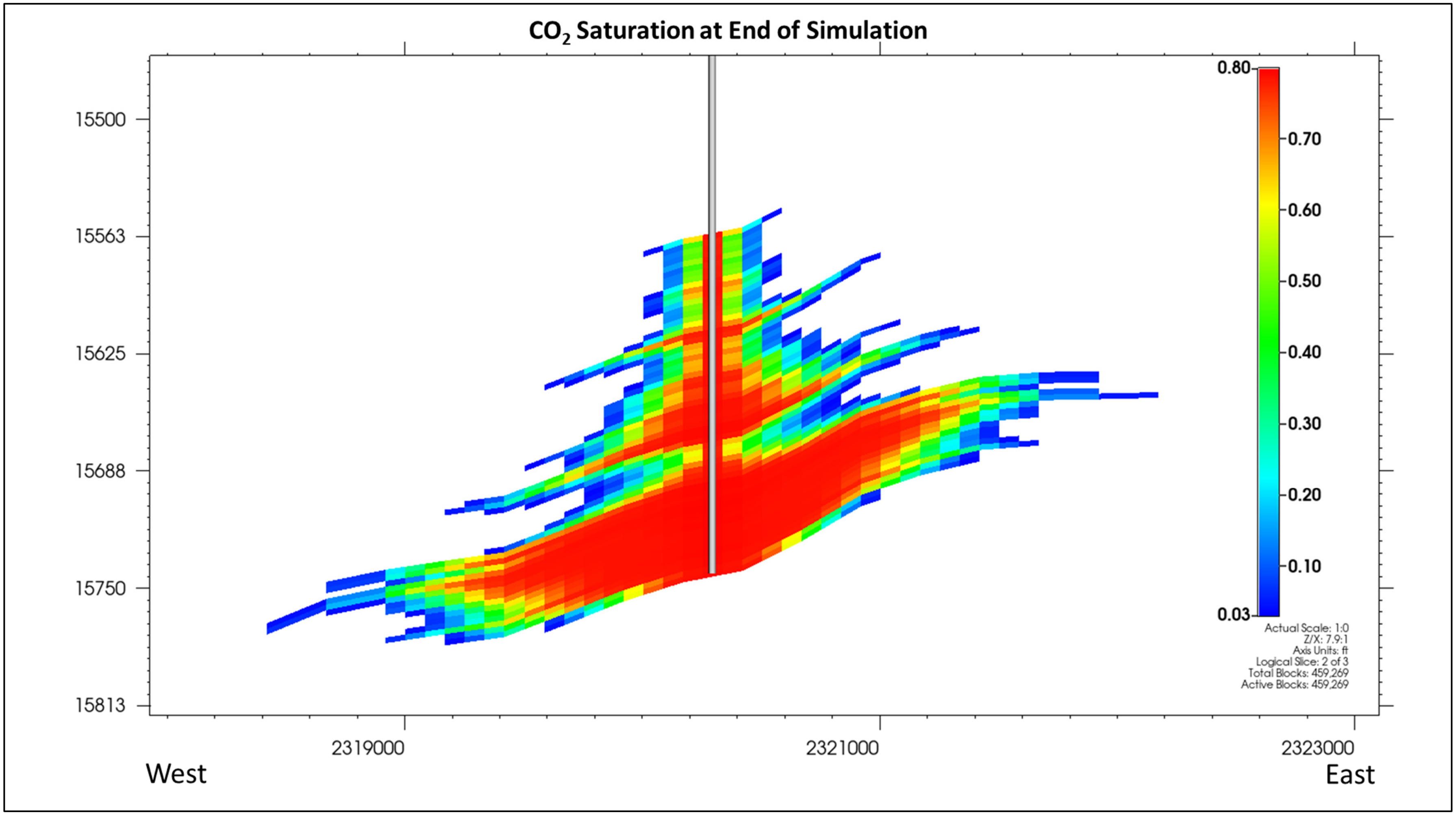


Figure 28 –East-West Cross-Sectional View of Gas Saturation Plume 10 Years After Shut-in (End of Simulation)

Figure 29 shows the surface injection rate, bottom hole pressures, and surface pressures over the injection period—and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate ends, reaching a maximum pressure of 13,337 psig, at the end of injection. This buildup of 2,362 psig keeps the bottomhole pressure below the fracture pressure of 13,652 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 6,095 psig, well below the maximum allowable 7,937 psig per the TRRC UIC permit application for this well. Bottomhole and wellhead pressures are provided in Table 6.

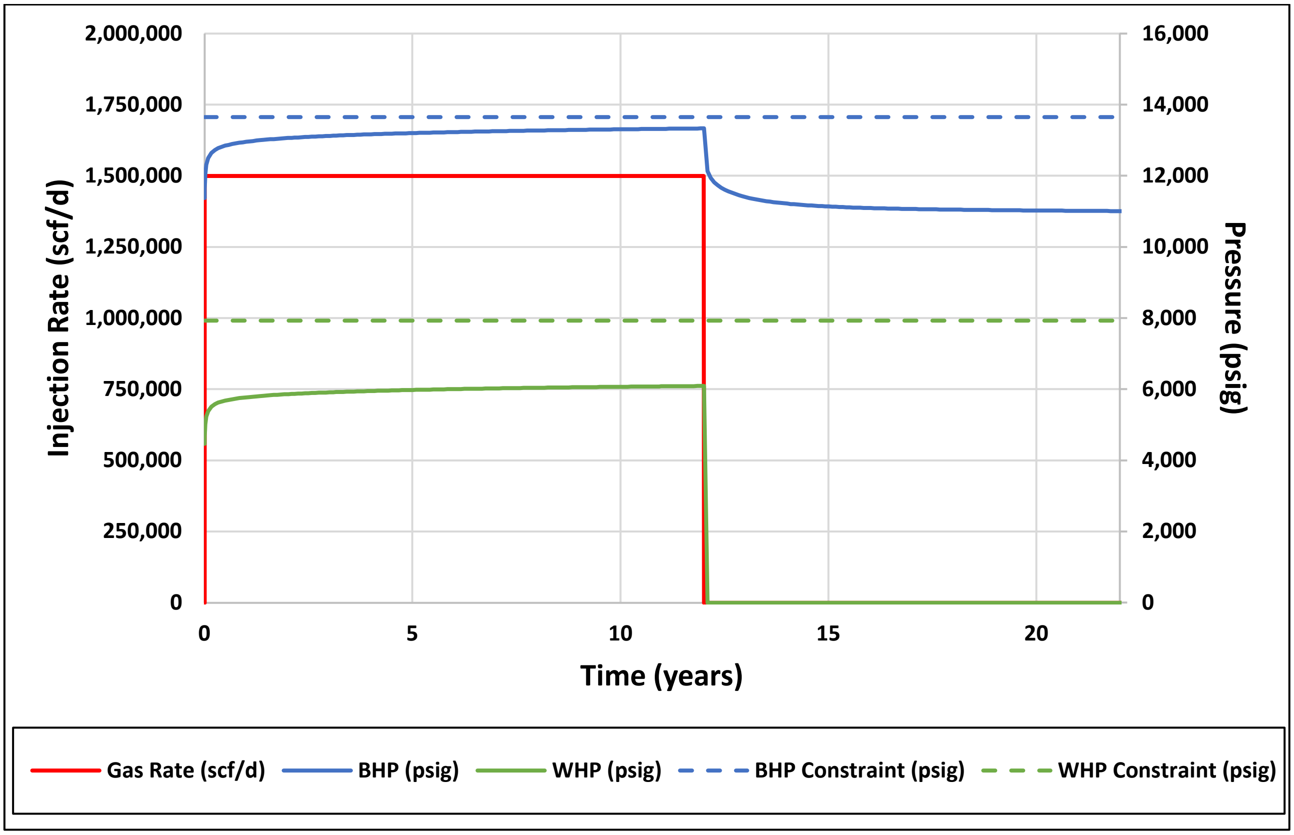


Figure 29 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 6 – Bottomhole and Wellhead Pressures from the Start of Injection

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	10,975	-
10	13,311	6,073
12 (End of Inj.)	13,337	6,095
20	11,029	-
22 (End of Model)	11,013	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in 40 CFR **§98.448(a)(1)**.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the plume has stabilized, plus an all-around buffer zone of at least one half mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

- Offset well logs to estimate geologic properties
- Petrophysical analysis to calculate the heterogeneity of the rock
- Geological interpretations to determine faulting and geologic structure
- Offset injection history to predict the density drift of the plume adequately

Ozona's expected gas composition was used in the model. The injectate is estimated at a molar composition of 98.2% CO_2 and 1.8% of other constituents. The StarTex Pawnee Treating Facility has been in stable operations for many years. Ozona believes the gas analysis provided in Table 1 is an accurate representation of the injectate. In the future, if the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be submitted to the GHGRP. As discussed in *Section 2*, the gas will be injected into the Sligo Formation. The geomodel was created based on the rock properties of the Sligo.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 12, the area expanse of the plume will be approximately 270 acres. The maximum distance between the wellbore and the edge of the plume is approximately 0.42 mi to the west. After 10 additional years of density drift, the areal extent of the plume is 303 acres with a maximum distance to the edge of the plume of approximately 0.45 mi to the west. Since the plume shape is relatively circular, the maximum distance from the injection well after density drift was used to define the circular boundary of the MMA. The AMA and the MMA have similar areas of influence, with the AMA being only marginally smaller than the MMA. Therefore, Ozona will set the AMA equal to the MMA as the basis for the area extent of the monitoring program.

This is shown in Figure 30 with the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA boundary represents the stabilized plume boundary after 10 years of density drift plus an all-around buffer zone of one half mile.

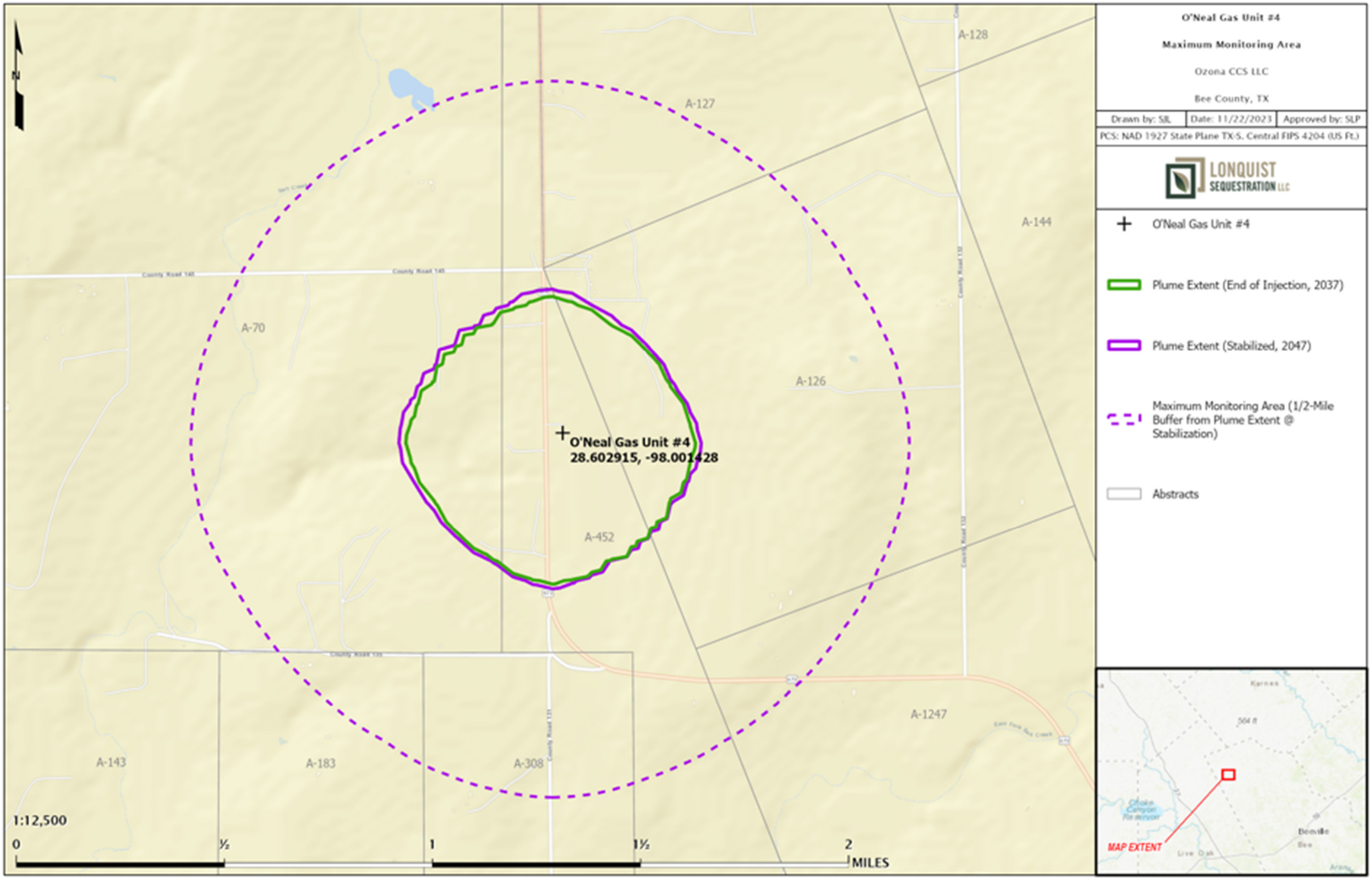


Figure 30 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The AMA was initially set equal to the expected total injection period of 12-years. The AMA was analyzed by superimposing the area based on a one-half mile buffer around the anticipated plume location after 12 years of injection (2037), with the area of the projected free-phase CO_2 plume at five additional years (2042). In this case, as shown in Figure 31, the plume boundary in 2042 is within the plume in 2037 plus the one-half mile buffer. Since the AMA boundary is only slightly smaller than the MMA boundary, Ozona will define the AMA to be equal to the MMA. By 2037, Ozona will submit a revised MRV plan to provide an updated AMA and MMA.

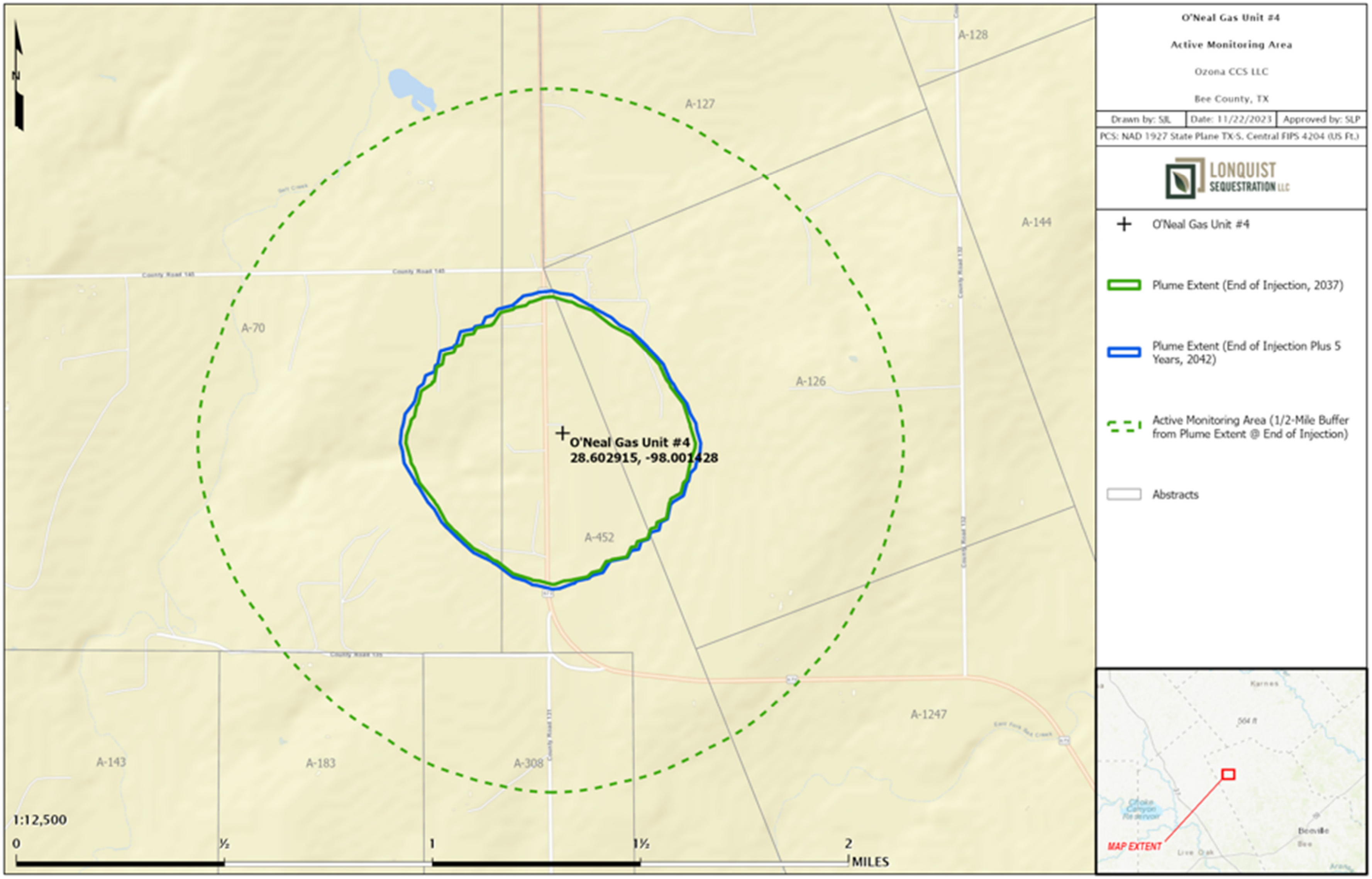


Figure 31 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies and discusses the potential pathways within the MMA for CO_2 to reach the surface and is summarized in Table 7. Also included are the likelihood, magnitude, and timing of such potential leakage. The potential leakage pathways are:

- Surface equipment
- Existing wells within the MMA
- Faults and fractures
- Upper confining layer
- Natural or induced seismicity

Table 7 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood		Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. One artificial penetration was drilled into the injection interval. This well has been properly plugged and abandoned.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Faults and fractures	Unlikely. There is over 14,000 ft of impermeable rock between the injection zone and the base of the USDW.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Upper confining zone	Unlikely. The lateral continuity of the UCZ consisting primarily of the Pearsall Formation which is over 500 ft thick is recognized as a very competent seal.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.
Natural or induced seismicity	Unlikely. There is over 14,000 ft of impermeable rock between the injection zone and the base of the USDW.	Low	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection.

1 - UCZ is defined as the upper confining zone.

Magnitude Assessment Description
Low - catergorized as little to no impact to safety, health and the environment and the costs to mitigate are minimal.
Medium - potential risks to the USDW and for surface releases does exist, but circumstances can be easily remediated.
High - danger to the USDW and significant surface release may exist, and if occurs this would require significant costs to remediate.

4.1 Leakage from Surface Equipment

The Pawnee Treating Facility and O'Neal No. 4 are designed for separating, transporting, and injecting TAG, primarily consisting of CO_2, in a manner to ensure safety to the public, the employees, and the environment. The mechanical aspects of this are noted in Table 8 and Figure 32. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) applicable standards and practices. As the TAG stream contains H_2S, monitors installed for H_2S detection will also indicate the presence of CO_2. These monitors will be installed at key locations around the facility and the O'Neal No. 4 location. These devices will be continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points determined by the facility's Health, Safety and Environment (HS&E) Director, consistent with Occupational Safety and Health Administration (OSHA) requirements. The facility will set the detection and alarm states for personnel at 10 ppm and at 40 ppm for initiating Emergency Shutdown. Key monitoring points and parameters are also provided in Table 8.

The facilities will incorporate important safety equipment to ensure reliable and safe operations. In addition to the H_2S monitors, emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the facility, the O'Neal No. 4, and other components, StarTex has a flare stack to safely handle the TAG when a depressuring event occurs. These facilities will be constructed in the coming months. The exact location of this equipment is not yet known, but it will be installed in accordance with applicable engineering and safety standards.

Table 8 – Summary of TAG Monitors and Equipment

Device	Location	Set Point
H_2S Monitors (1-4)	O'Neal No. 4 wellsite	10 ppm High Alarm 40 ppm Emergency Shutdown
H_2S Monitors (5-8)	In-Plant Monitors	10 ppm High Alarm 40 ppm Emergency Shutdown
Flare Stack	Plant Site Perimeter	N/A
AGI Flowmeter	In-Plant (downstream of the Amine Unit)	Calibrated per API specifications
Emergency Shutdown	In-Plant Monitors	40 ppm Facility Shutdown
Emergency Shutdown	O'Neal No. 4 wellsite	40 ppm Facility Shutdown

With the continuous air monitoring at the facility and the well site, a release of CO_2 would be quickly identified, and the safety systems and protocols would effectuate an orderly shutdown to ensure safety and minimize the release volume. The CO_2 injected into the O'Neal No. 4 is from the amine unit at the Pawnee Treating Facility. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7*, in accordance with 40 CFR **§98.448(a)(5)**. Ozona concludes that the leakage of CO_2 through the surface equipment is unlikely.

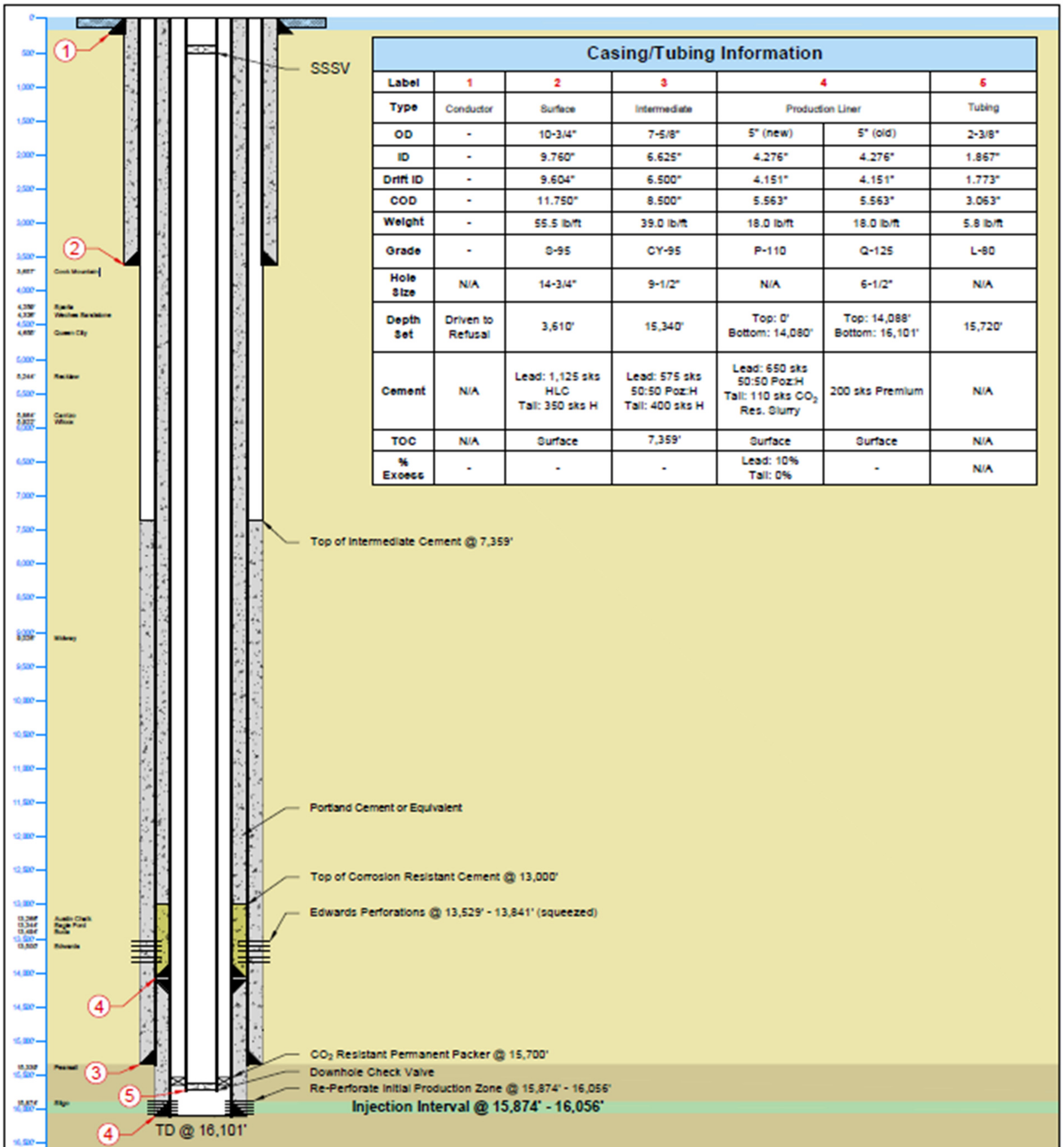
4.2 Leakage Through Existing Wells Within the MMA

The O'Neal No. 4 is engineered to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 32. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 33. Figure 34 is a map of all the oil and gas wells that penetrate the MMA's gross injection zone. Only one well penetrated the MMA's gross injection zone. This well was non-productive and has been plugged and abandoned in accordance with TRRC requirements. A summary table of all oil and gas wells within the MMA is provided in *Appendix B-1*.

This table in *Appendix B-1* provides the total depth (TD) of all wells within the MMA. The wells that are shallower and do not penetrate the injection zone are separated by the Pearsall Formation with a gross thickness of 535 ft. The Pine Island Shale comprises approximately 130 ft of this interval as discussed in *Section 2.2.2* and provides a competent regional seal—making vertical migration of fluids above the injection zone unlikely.

The shallower offset hydrocarbon wells within the MMA will also serve as above zone monitoring wells. Should any of the sequestered volumes migrate vertically, they would potentially enter the shallower hydrocarbon reservoir. Regular sampling and analysis is performed on the produced hydrocarbons. If a material difference in the quantity of CO_2 in the sample occurs indicating a potential migration of injectate from the Sligo Formation, Ozona would investigate and develop a mitigation plan. This may include reducing the injection rate or shutting in the well. Based on the investigation, the appropriate equation in *Section 7* would be used to make any adjustments to the reported volumes.



Casing/Tubing Information

Label	1	2	3	4		5
Type	Conductor	Surface	Intermediate	Production Liner		Tubing
OD	-	10-3/4"	7-5/8"	5" (new)	5" (old)	2-3/8"
ID	-	9.760"	6.625"	4.276"	4.276"	1.867"
Drift ID	-	9.604"	6.500"	4.151"	4.151"	1.773"
COD	-	11.750"	8.500"	5.563"	5.563"	3.063"
Weight	-	55.5 lb/ft	39.0 lb/ft	18.0 lb/ft	18.0 lb/ft	5.8 lb/ft
Grade	-	S-95	CY-95	P-110	Q-125	L-80
Hole Size	N/A	14-3/4"	9-1/2"	N/A	6-1/2"	N/A
Depth Set	Driven to Refusal	3,610'	15,340'	Top: 0' Bottom: 14,080'	Top: 14,088' Bottom: 16,101'	15,720'
Cement	N/A	Lead: 1,125 sks HLC Tail: 350 sks H	Lead: 575 sks 50:50 Poz:H Tail: 400 sks H	Lead: 650 sks 50:50 Poz:H Tail: 110 sks CO_2 Res. Slurry	200 sks Premium	N/A
TOC	N/A	Surface	7,359'	Surface	Surface	N/A
% Excess	-	-	-	Lead: 10% Tail: 0%	-	N/A

LONQUIST SEQUESTRATION LLC	Ozona CCS	CO_2 Injection Well Proposed Well Design - O'Neal Gas Unit No. 4	
	Country: USA	State/Province: Texas	County/Parish: Bee County
	API No: 42-025-32658	Field: TBD	Well Type/Status: Proposed
Texas License F-8652	Location: 28.6031807, -98.0017091	Project No: LS190	Date: 10/13/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	Drawn: Joseph Lovewell	Reviewed: David Lytle	Approved: David Lytle
	Rev No: 0	Notes:	

Figure 32 – O'Neal No. 4 Wellbore Schematic

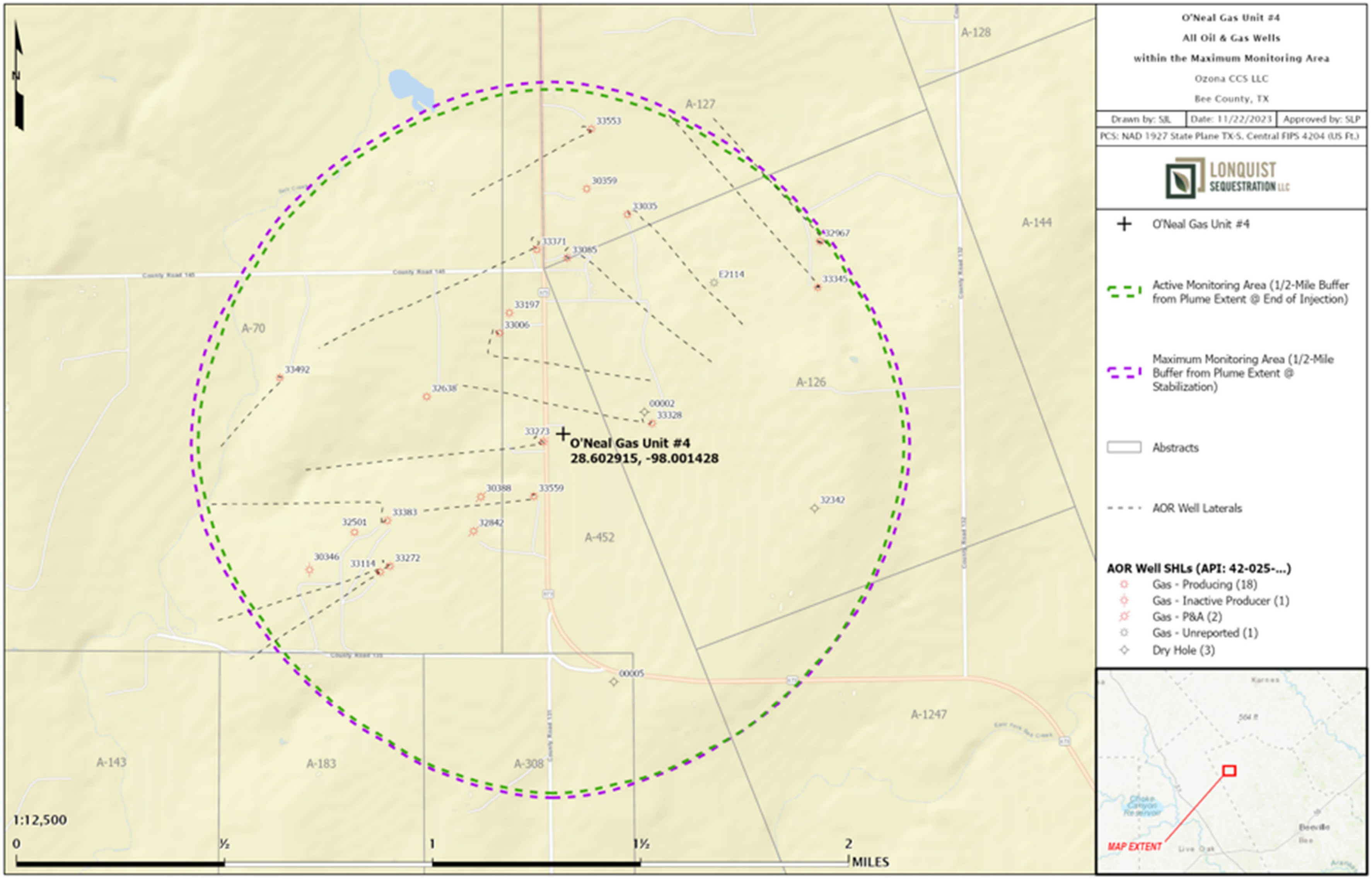


Figure 33 – All Oil and Gas Wells Within the MMA

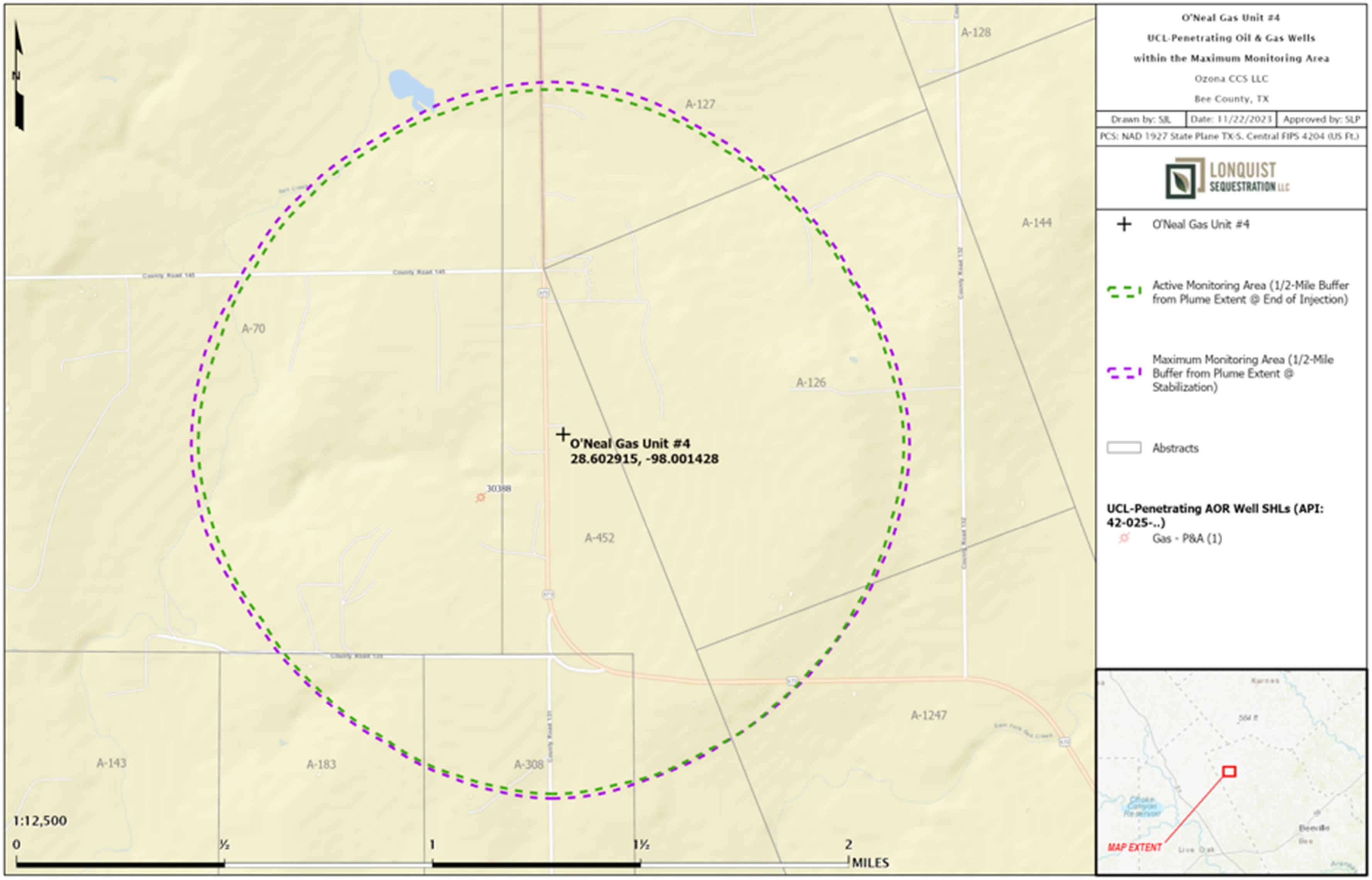


Figure 34 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations have proven to date to be nonproductive in this area, and therefore Ozona does not see this as a risk. This is supported by a review of the TRRC Rule 13 (Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC **§3.13**. The Sligo is not among the formations listed for which operators in Bee County and District 2 (where the O'Neal No. 4 is located) are required to comply with TRCC Rule 13; therefore, the TRRC does not believe there are productive horizons below the Sligo. The O'Neal No. 4 drilling permit is provided in *Appendix A-2*.

4.2.2 Groundwater Wells

The results of a groundwater well search found five wells within the MMA, as identified by the Texas Water Development Board as shown in Figure 35 and in tabular form in *Appendix B-2*.

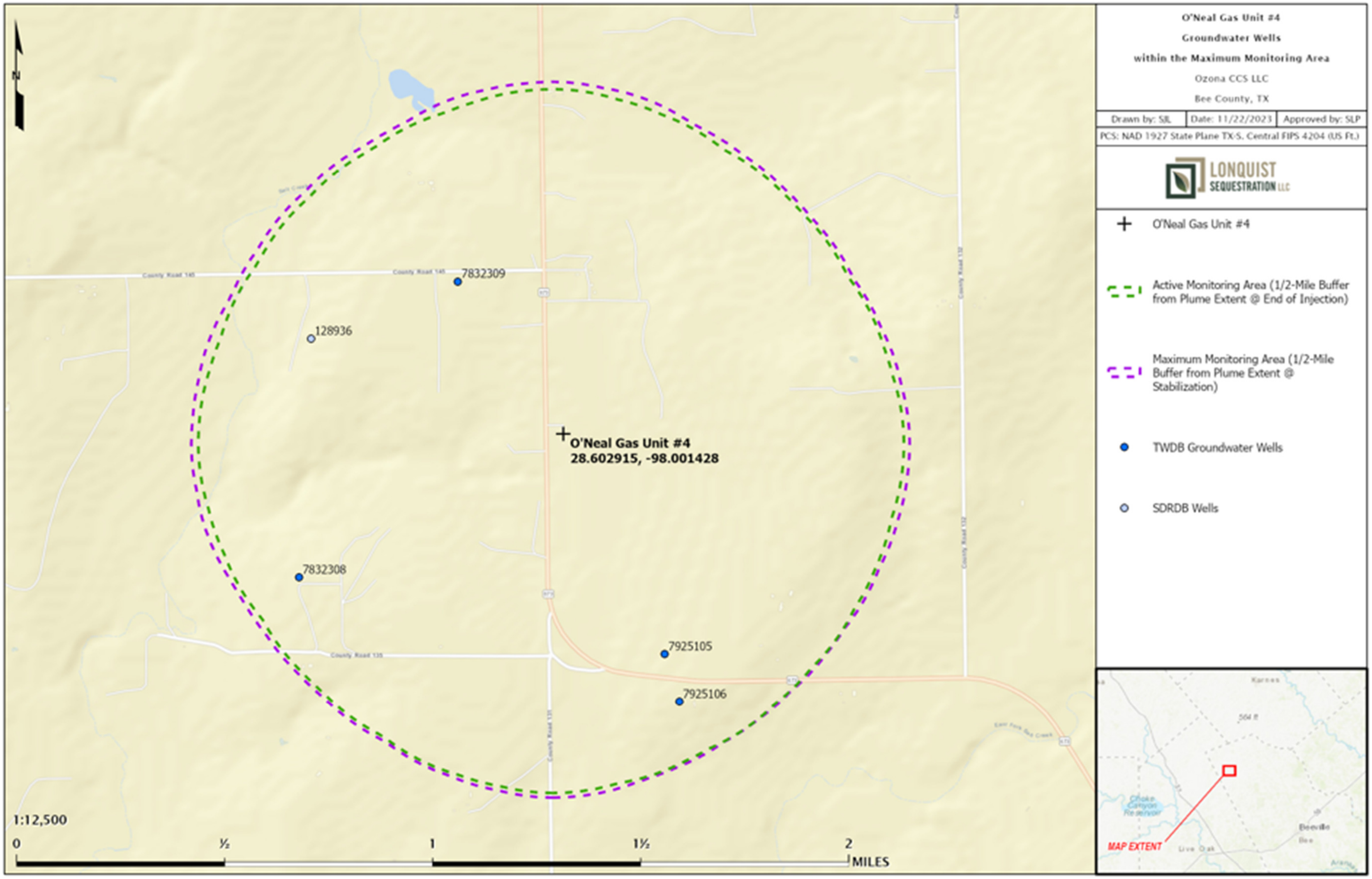


Figure 35 – Groundwater Wells Within the MMA

The surface, intermediate, and production casings of the O’Neal No. 4, as shown in Figure 32, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations, and the GAU letter issued for this location is provided in *Appendix A-1*. The wellbore casings and compatible cements prevent CO_2 leakage to the surface along the borehole. Ozona concludes that leakage of the sequestered CO_2 to the groundwater wells is unlikely.

4.3 <u>Leakage Through Faults and Fractures</u>

Detailed mapping of openhole logs surrounding the O’Neal No. 4 did not identify any faulting within either the Pearsall or Sligo sections. However, there is a general lack of deep penetrators within the area that limits the amount of openhole coverage available.

The majority of the published literature suggests that faulting near the project area is restricted to the shallower, overlying Cenozoic section, as shown in Figure 9, with shallow faults dying out before reaching the Pearsall Formation. One source interpreted the potential for faulting to the south (Swanson et al., 2016). The potential fault is depicted in Figure 8 relative to the location of the O’Neal No. 4. According to the map, the interpreted fault lies approximately 4.25 mi south-southeast of the well and approximately 3.9 mi south-southeast of the stabilized plume extent in the year 2047. In the unlikely scenario in which the injection plume or pressure front reaches the potential fault, and the potential fault was to act as a transmissive pathway, the upper confining Pearsall shale contains sufficient thickness and petrophysical properties required to confine and protect injectates from leaking outside of the permitted injection zone.

Section 2.1.2 discusses regional structure and faulting, and *Section 2.3* covers local structure, for additional material relevant to this topic.

4.4 <u>Leakage Through the Upper Confining Zone</u>

The Sligo injection zone has competent sealing intervals present above and below the targeted carbonate sequence of the Sligo section. The overlying Pine Island shale member of the Pearsall Formation is approximately 130 ft thick at the O’Neal No. 4. Above this confining unit, the Cow Creek Limestone, Cow Creek shale, and Bexar Shale Members of the Pearsall Formation will act as additional confinement between the injection interval and the USDW. The USDW lies well above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. The petrophysical properties of the lower Sligo and Hosston Formations make these ideal for lower confinement. The low porosity and permeability of these underlying formations minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injectate to the in situ reservoir fluid makes migration below the lower confining layer unlikely.

4.5 <u>Leakage from Natural or Induced Seismicity</u>

The O’Neal No. 4 is located in an area of the Gulf of Mexico considered to be active from a seismic perspective. Therefore, the Bureau of Economic Geology’s TexNet (from 2017 to present) and USGS’s Advanced National Seismic System (from 1971 to present) databases were reviewed to identify any recorded seismic events within 25 kilometer (km) of the O'Neal No. 4.

The investigation identified a multitude of seismic events within the 25 km search radius; however, the magnitude of most of the events was below 2.5. The nearest seismic event with a recorded magnitude of 3.0 or greater was measured approximately 5.6 km northwest of the O'Neal No. 4 at a depth of 5 km. The results of the investigation are plotted on the map provided in Figure 36 relative to the O'Neal No. 4 and the 25-km search radius.

The Facility will have operating procedures and set points programmed into the control and SCADA systems to ensure operating pressures are maintained below the fracture gradient of the injection and confining intervals, thus avoiding the potential for inducing seismicity.

Given the seismic activity in the area, Ozona will closely monitor nearby TexNet station EF71 for activity and any corresponding irregularities in the operating pressures of O'Neal No. 4. If a seismic event of 3.0 or greater is recorded at Station EF71 or if anomalies are identified in the operating data, Ozona will review the data and determine if any changes occurred that indicate potential leakage. Ozona would take appropriate measures based on their findings, including limiting the injection pressure and reducing the injection rate.

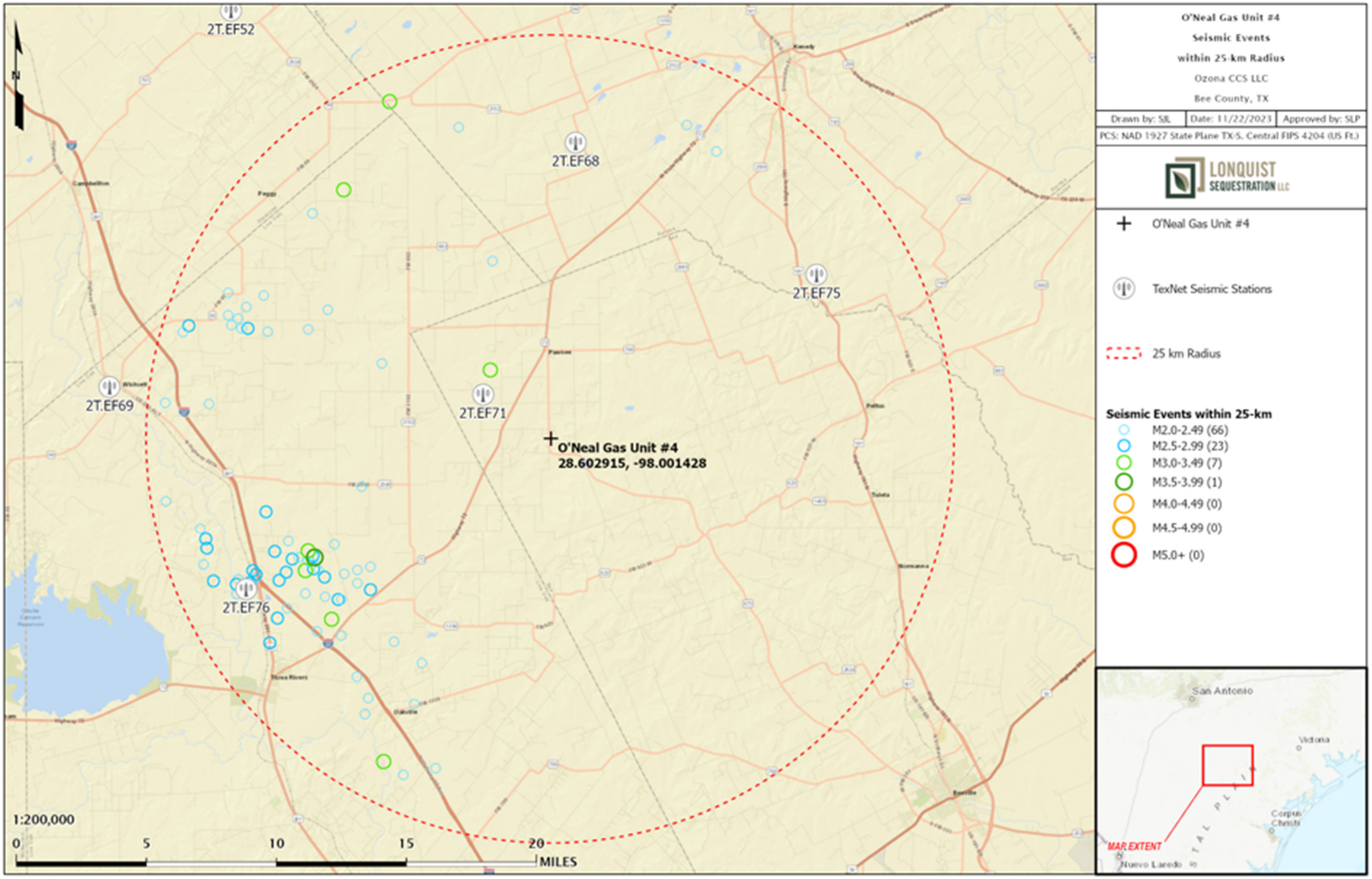


Figure 36 – 25-km Seismicity Review

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Ozona will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in *Section 4*, to meet the requirements of 40 CFR **§98.448(a)(3)**. As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 9 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 12-year injection period or cessation of injection operations, plus a proposed 10-year post-injection period until the plume has stabilized.

- Leakage from surface equipment
- Leakage through existing and future wells within the MMA
- Leakage through faults or fractures
- Leakage through confining seals
- Leakage through natural or induced seismicity

Table 9 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Surface equipment	Fixed H_2S monitors at the Plant and well site
	Visual inspections
	Monitor SCADA systems for the Plant and well site
Existing wells within the MMA	Monitor CO_2 levels in above zone producing wells
	Mechanical Integrity Tests (MIT) of the AGI Well every 5 years
	Visual inspections
	Annual soil gas sampling near well locations that penetrate the Upper Confining Zone within the AMA
• Leakage through groundwater wells	Annual groundwater samples from existing water well(s)
• Leakage from future wells	Monitor drilling activity and compliance with TRRC Rule 13 Regulations
Faults and Fractures	SCADA continuous monitoring at the well site (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Upper confining zone	SCADA continuous monitoring at the well site (volumes and pressures)
	Monitor CO_2 levels in Above Zone producing wells
Natural or induced seismicity	Monitor CO_2 levels in Above Zone producing wells
	Monitor existing TexNet station

5.1 Leakage from Surface Equipment

The facility and the O'Neal No. 4 were designed to operate in a safe manner to minimize the risk of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established prior to commencing operation once facility construction has been completed. Ambient H_2S monitors will be located at the facility and near the O'Neal No. 4 site for local alarm and are connected to the SCADA system for continuous monitoring.

The facility and the O'Neal No. 4 are continuously monitored through automated control systems. These monitoring points were discussed in *Section 4.1*. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Ozona to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Ozona will quantify the leak per the strategies discussed in *Section 7*.

5.2 Leakage Through Existing and Future Wells Within the MMA

Ozona continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the O'Neal No. 4. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, MITs performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and investigated to develop a leak mitigation plan.

As discussed previously, TRRC Rule 13 ensures that new wells in the field are constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Ozona will also establish and operate an in-field monitoring program to detect CO_2 leakage within the AMA. This would include H_2S monitoring as a proxy for CO_2 at the well site and annual soil gas samples taken near any identified wells that penetrate the injection interval within the AMA. These samples will be analyzed by a qualified third

party. Prior to commencing operation, and through the post-injection monitoring period, Ozona will have these monitoring systems in place.
Currently, there is only one well in the MMA identified that penetrates the injection interval. This well was plugged and abandoned in 2007. The TRRC records are provided in *Appendix A-4*. Ozona will take an annual soil gas sample from this area, which will be analyzed by a third-party lab. Additional monitoring will be added as the AMA is updated over time. In the unlikely event a leak occurs, Ozona will quantify the leak volumes by the methodologies discussed in *Section 7* and present these results and related activities in the annual report.

Ozona will also utilize shallower producing gas wells as proxies for above-zone monitoring wells. Production data from these wells is analyzed for monthly production statements, and therefore would be an early indicator of any possible subsurface issues. Should any material change from historical trends in the CO_2 concentration occur, Ozona would investigate and develop a corrective action plan. Should any CO_2 migrate vertically from the Sligo, the magnitude risk of this event is very low, as the producing reservoir provides an ideal containment given the upper confining zone of this reservoir has proven competent. In the unlikely event a leak occurs, Ozona would quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances and include these results in the annual report.

5.2.1 Groundwater Quality Monitoring

Ozona will monitor the groundwater quality above the confining interval by sampling from groundwater wells near the O'Neal No. 4 and analyzing the samples with a third-party laboratory on an annual basis. In the case of the O'Neal No. 4, 5 existing groundwater wells have been identified within the AMA (Figure 38). Initial groundwater quality tests will be performed to establish a baseline prior to commencing operations.

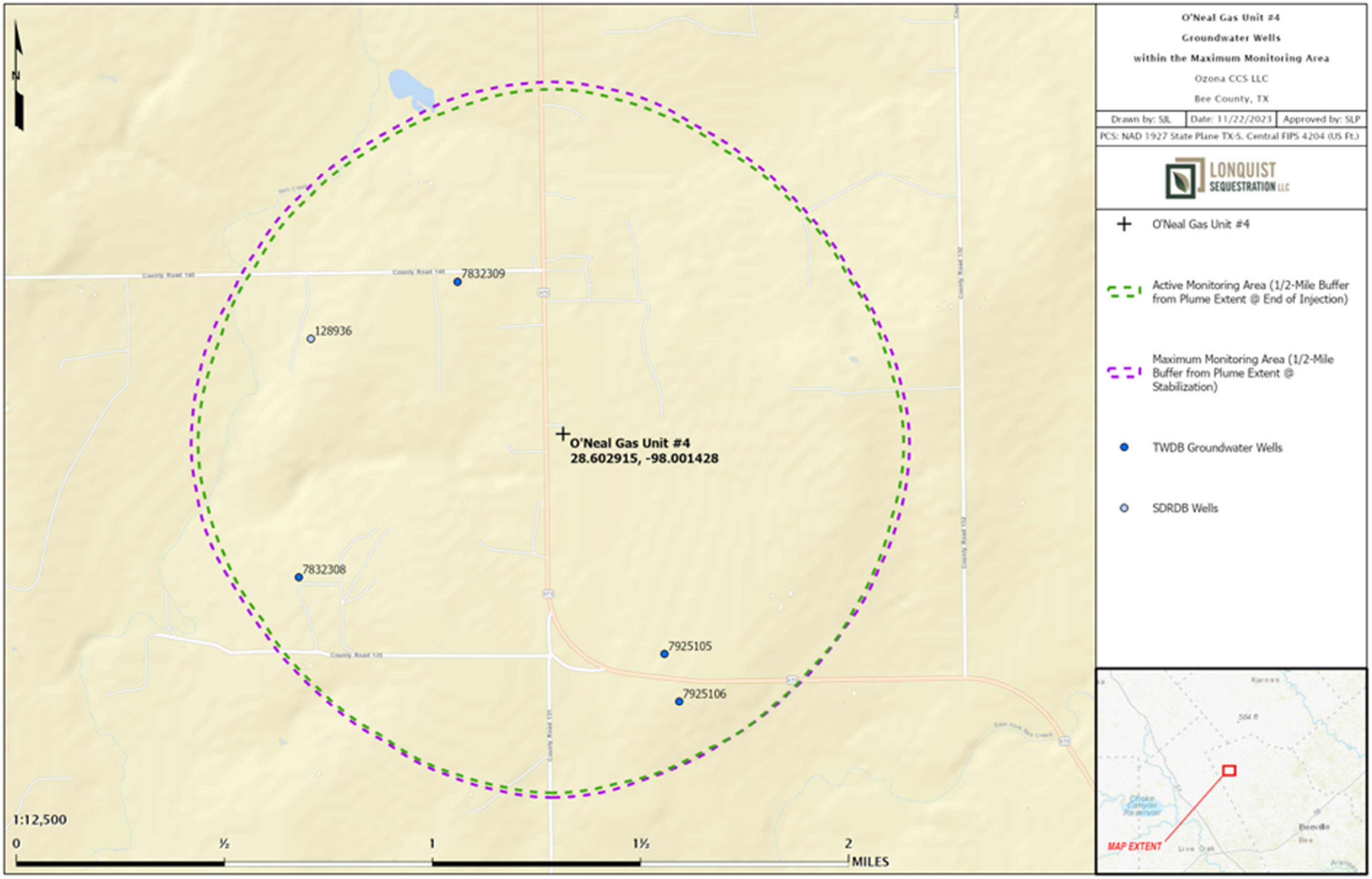


Figure 37 – Groundwater Wells

5.3 Leakage Through Faults, Fractures, or Confining Seals

Ozona will continuously monitor the operations of the O'Neal No. 4 through the automated controls and SCADA systems. Any deviation from normal operating volume and corresponding injection pressure could indicate movement into a potential leak pathway, such as a fault or breakthrough of the confining seal and would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Ozona will also utilize shallower producing wells as proxies for above-zone monitoring wells. Production data is analyzed regularly for monthly production statements and therefore would be an early indicator of any possible subsurface issues. Should any material change from historical trends in the CO_2 concentration occur, Ozona would investigate and develop a corrective action plan. Should any CO_2 migrate vertically from the Sligo Formation, the magnitude risk of this event is very low, as the producing reservoir provides an ideal containment given the upper confining zone has proven competent. In the unlikely event a leak occurs, Ozona would quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is low, Ozona plans to use the nearest TexNet seismic monitoring station, EF71, to monitor the area around the O'Neal No. 4. This station is approximately 3 mi to the northwest, as shown in Figure 38. This is sufficient distance to allow for accurate and detailed monitoring of the seismic activity in the area. Ozona will monitor this station for any seismic activity, and if a seismic event of 3.0 magnitude or greater is detected, Ozona will review the injection volumes and pressures of the O'Neal No. 4 to determine if any significant changes have occurred that would indicate potential leakage.

Ozona will also continuously monitor operations through the SCADA system. Any deviation from normal operating pressure and volume set points would trigger an alarm for investigation by operations staff. Such a variance could indicate movement into a potential leak pathway, such as a fault or breakthrough of the confining seal. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary

These are the two primary strategies for mitigating risks for induced seismicity. In the unlikely event a leak occurs, Ozona will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances.

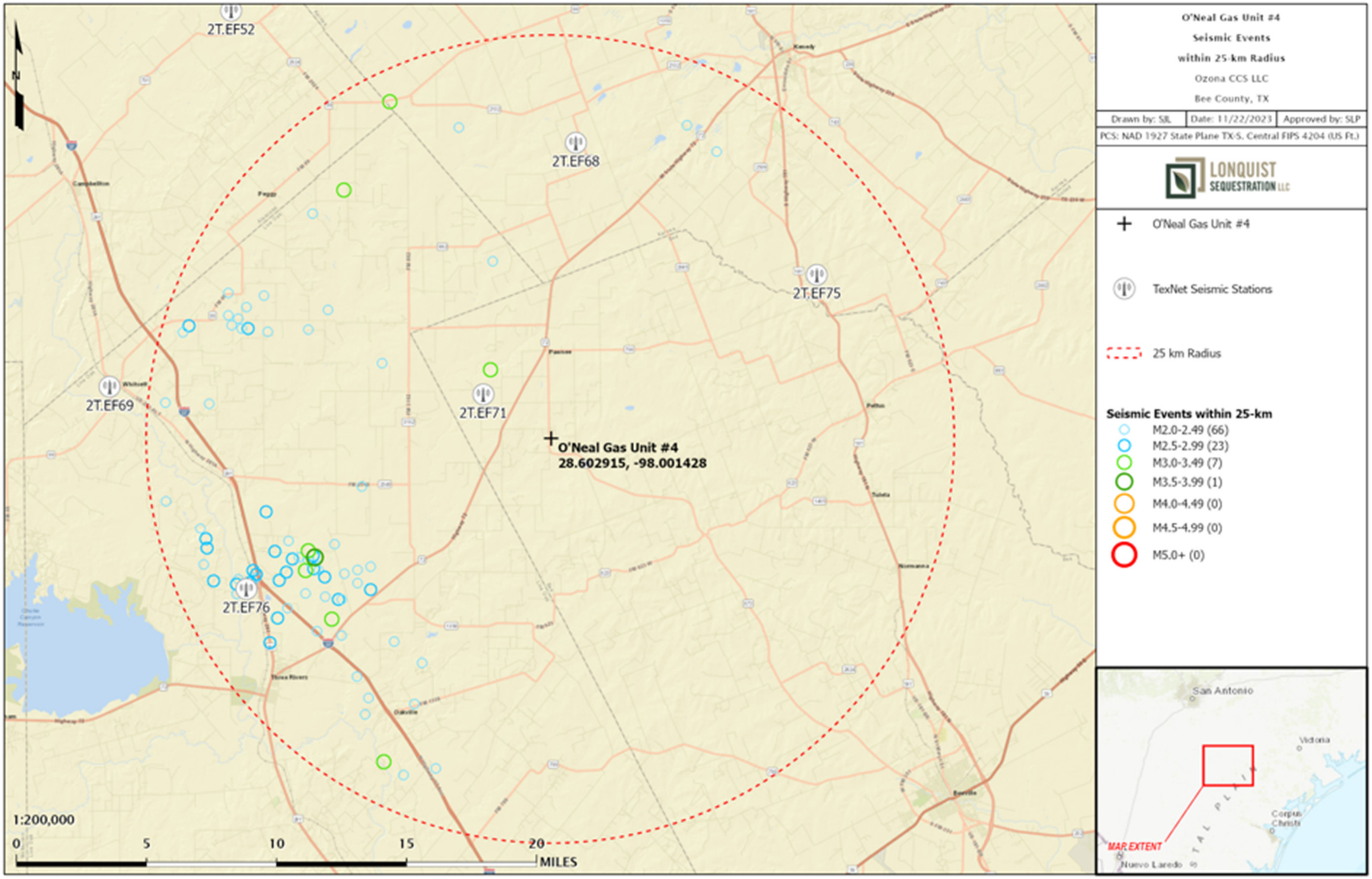


Figure 38 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

This section identifies the strategies Ozona will undertake to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR **§98.448(a)(4).** Ozona will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of injectate and calculate a corresponding amount of CO_2.

6.1 Visual Inspections

Regular inspections will be conducted by field personnel at the facility and O'Neal No. 4 site. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken prudently and safely to address such issues.

6.2 H_2S/ CO_2 Monitoring

In addition to the fixed monitors in the facility and at the wellsite, Ozona will establish and perform an annual in-field sampling program to monitor and detect any CO_2 leakage within the AMA. This will consist of soil gas sampling near any artificial penetrations of the injection zone and sampling of water wells. These probes have special membrane inserts that collect the gas samples over a 21-day period. These will be analyzed by a third-party lab to be analyzed for CO_2, H_2S, and trace contaminants typically found in a hydrocarbon gas stream. The lab results will be provided in the annual report should they indicate a material variance from the baseline. Initial samples will be taken and analyzed before the commencement of operations and will establish the baseline reference levels.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of injectate and the corresponding component of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is near the OSHA Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger alarms if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions, including pressure, flow rate, percentage of CO_2, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a depressuring event, the acid gas stream will be sent to a flare stack to be safely processed and will be reported under reporting requirements for the facility. Any such events will be accounted for in the sequestered reporting volumes consistent with *Section 7.*

6.5 Groundwater Monitoring

Initial samples will be taken from groundwater wells in the area of the O'Neal No. 4 upon approval of the MRV plan, and before commencement of CO_2 injection. These samples will be analyzed and reports prepared by a third-party laboratory testing for pH, total dissolved solids (TDS), CO_2, and volatile organic compounds (VOC). Initial samples will be taken and analyzed before the commencement of operations and will establish the baseline reference levels. Sampling select wells will be performed annually. In the event a material deviation in the sample analysis occurs, the results will be provided in the annual report.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO_2 Received

Per 40 CFR **§98.443**, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4**)." The 40 CFR **§98.444(a)(4)** states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." The CO_2 received for this injection well is injected and not mixed with any other supply; the annual mass of CO_2 injected will equal the amount received less any amounts calculated in accordance with the equations of this section. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO_2 Injected

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

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

Where:

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

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

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

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

The O'Neal No. 4 is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

7.4 Mass of CO_2 Emitted by Surface Leakage

The mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly due to the H_2S concentration in the injection stream. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions would be sent to a flare stack and reported as a part of the required GHG reporting for the facility. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of H_2S and CO_2. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak-point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

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

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

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

Calculation methods using equations from Subpart W will be used to calculate CO_2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage is unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Ozona believes the most appropriate method to quantify the mass of CO_2 released will be determined on a case-by-case basis. Any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. In the unlikely

event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events will be kept and stored as provided in *Section 10*.

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Data collection for calculating the amount of CO_2 sequestered in the O'Neal No. 4 will begin once the subsurface recompletion work, and the surface facilities construction has been completed, and subject to approval of the MRV plan. The calculation of sequestered volumes utilizes the following equation as the O'Neal No. 4 will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

CO_{2FI} will be calculated in accordance with Subpart W for reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a system blowdown event occurs. Those emissions would be sent to a flare stack and reported as part of the GHG reporting for the facility.

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The O'Neal Gas Unit No. 4 is an existing natural gas well that will be recompleted as a Class II well with corrosion-resistant materials. The Class II permit is still in process with the TRRC. Until this permit is issued, Ozona cannot specify a date to acquire the baseline testing data. Ozona is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan, including acquisition of baseline data, will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

Table 10 – Baseline Sampling Schedule

Sampling Location	Estimated Date	Comments
Fixed H_2S/CO_2 Monitors	Oct. 1, 2024	Baseline readings will be established during commissioning activities.
Soil gas sampling	Oct. 1, 2024	Baseline samples will be taken prior to commencement of injection.
Water well sampling	Oct. 1, 2024	Baseline samples will be taken prior to commencement of injection.

Notes:

- Above dates are estimates subject to adjustment based on actual regulatory approval dates and facilities construction timelines.
- All baseline sampling will be performed prior to the start of recording data for reporting under this MRV.
- Commissioning activities include installation of surface facilities, including flowline, compressors, manifolds, etc.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Ozona plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 Injected

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with API standards. These flow rates will be compiled quarterly.
- The composition of the injectate stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with API standards.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated per the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.

CO_2 Emissions from Leaks and Vented Emissions

- Gas monitors at the facility and O'Neal No. 4 will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.
- Calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR **§98.3(i).**
- Flow meters will be operated and maintained in accordance with applicable standards as published by a consensus-based standards organization.

All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60°F and an absolute pressure of 1 atmosphere.

9.2 Missing Data

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

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.

- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR **§98.**

9.3 MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Ozona will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least 3 years and include the following:

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

APPENDICES

APPENDIX A – O’Neal No. 4 TRRC FORMS

APPENDIX A-1: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-2: DRILLING PERMIT

- CHARLIE C. OVERBY API 42-025-32658
- O’NEAL GAS UNIT NO. 4 API 42-025-32658

APPENDIX A-3: COMPLETION REPORT

- CHARLIE C. OVERBY API 42-025-32658
- O’NEAL GAS UNIT NO. 4 API 42-025-32658
- MINI FRACTURE REPORT

APPENDIX A-4: API 42-025-30388 CHARLIE C. OVERBY GU PLUGGING RECORDS

APPENDIX B – AREA OF REVIEW

APPENDIX B-1: OIL AND GAS WELLS WITHIN THE MMA LIST

APPENDIX B-2: WATER WELLS WITHIN THE MMA LIST

GROUNDWATER PROTECTION DETERMINATION

Form GW-2

Groundwater Advisory Unit

Date Issued:	26 May 2023	**GAU Number:**	367912

Attention:	OZONA CCS LLC	**API Number:**	02532658
	19026 RIDGEWOOD	**County:**	BEE
	SAN ANTONIO, TX 78259	**Lease Name:**	O'Neal Gas Unit
Operator No.:	100116	**Lease Number:**	162214
		Well Number:	4
		Total Vertical	16101
		Latitude:	28.602914
		Longitude:	-98.001428
		Datum:	NAD27

Purpose: Injection into Producing Zone (H1)

Location: Survey-EL&RR RR CO; Abstract-452; Section-1

To protect usable-quality groundwater at this location, the Groundwater Advisory Unit of the Railroad Commission of Texas recommends:

The base of usable-quality water-bearing strata is estimated to occur at a depth of 250 feet at the site of the referenced well.

The BASE OF UNDERGROUND SOURCES OF DRINKING WATER (USDW) is estimated to occur at a depth of 950 feet at the site of the referenced well.

Note: Unless stated otherwise, this recommendation is intended to apply to all wells drilled within 200 feet of the subject well. Unless stated otherwise, this recommendation is for normal drilling, production, and plugging operations only.

This determination is based on information provided when the application was submitted on 05/26/2023. If the location information has changed, you must contact the Groundwater Advisory Unit, and submit a new application if necessary.
If you have questions, please contact us at 512-463-2741 or gau@rrc.texas.gov.

Groundwater Advisory Unit, Oil and Gas Division

Oil & Gas Data Query

Query Menu Help

Drilling Permit (W-1) Query Results

Search Criteria:

API No.: 02532658

Return

2 results Page: 1 of 1 Page Size: View All

API NO.	District	Lease	Well Number	Permitted Operator	County	Status Date	Status Number	Wellbore Profiles	Filing Purpose	Amend	Total Depth	Stacked Lateral Parent Well DP #	Status
02532658 Links	02	CHARLIE C. OVERBY GAS UNIT	2	PARKER & PARSLEY DEVELOPMENT CO.(640889)	BEE	Submitted: 11/30/1992 Approved: 11/30/1992	406655	Vertical	New Drill	N	16700		APPROVED
02532658 Links	02	O'NEAL GAS UNIT (162214)	4	PARKER & PARSLEY DEVELOPMENT L.P(640886)	BEE	Submitted: 11/20/1996 Approved: 12/16/1996	455434	Vertical	Recompletion	N	14040		APPROVED

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NOTE: THE CHARLIE C. OVERBY GU AND THE O'NEAL GU ARE THE SAME WELL. THE OVERBY WELL WAS DRILLED IN 1993 INTO THE SLIGO. IN 1997 THE WELL WAS RECOMPLETED IN THE EDWARDS FORMATION. THIS WAS DONE UNDER A NEW LEASE, AS THE O'NEAL GU NO. 4.

RRC ONLINE SYSTEM

Log In

Form W-1: Review

Status # 406655 **API #** 025-32658	**OP # 640889 - PARKER & PARSLEY DEVELOPMENT CO.** Approved ,**Issued:** 11/30/1992 ,**Filed:** Hardcopy	**CHARLIE C. OVERBY GAS UNIT - Well # 2** 02 - BEE County	**New Drill** Vertical

NEAREST WELL COMMENT: 1607.8 (11/30/1992 12:00:00 AM)

Status:

Back to Public Query Search Results

Completion Information

Well Status Code	Spud Date	Drilling Completed	Surface Casing Date
W - Final Completion	01/01/1993	02/11/1993	01/01/1993

Field Name	Completed Well Type	Completed Date	Validated Date
PAWNEE (SLIGO)	Gas	02/11/1993	06/18/1993

General / Location Information

Basic Information:

Filing Purpose	Welbore Profiles	Lease Name	Well #	SWR	Total Depth	Horizontal Wellbore	Stacked Lateral Parent Well DP #
New Drill	Vertical	CHARLIE C. OVERBY GAS UNIT	2	SWR 36	16700		

Surface Location Information:

API #	Distance from Nearest Town	Direction from Nearest Town	Nearest Town	Surface Location Type
025-32658	4.0 miles	S	PAWNEE	Land

Survey/Legal Location Information:

Section	Block	Survey	Abstract #	County
		EL&RR RR CO	452	BEE

Township	League	Labor	Porcion	Share	Tract	Lot

Perpendicular surface location from two nearest designated reference lines:

Perpendiculars	Distance	Direction	Distance	Direction
Survey Lines	2784.0 feet	from the S line and	1045.5 feet	from the W line

Permit Restrictions:

Code	Description
30	REGULAR PROVIDED THAT UPON SUCCESSFUL COMPLETION OF THIS WELL IN THE SAME RESERVOIR AS ANY OTHER WELL PREVIOUSLY ASSIGNED THIS ACREAGE, A P-15 AND REVISED PRORATION PLATS MUST BE SUBMITTED WITH NO
30	DOUBLE ASSIGNMENT OF ACREAGE.
30	REGULAR PROVIDED THIS WELL IS NEVER COMPLETED IN THE SAME RESERVOIR AS ANY OTHER WELL CLOSER THAN 2640 FEET ON THIS SAME LEASE.
30	REGULAR PROVIDED THIS WELL IS DRILLED IN COMPLIANCE WITH RULE 36.

30	O'NEAL GU #3, O'NEAL #1, OVERBY #120 & NEAL #1.

Fields

District	Field Name	Field #	Completion Depth	Lease Name	Well #	Well Type	Acres	Distance to Nearest Well	Distance to Nearest Lease Line	SWR	Pooled/ Unitized
02	**PAWNEE (SLIGO)** **Primary Field**	69845800	16700	CHARLIE C. OVERBY GAS UNIT	2	Oil or Gas Well	704.0			SWR 36	Y

Perpendiculars	Distance	Direction	Distance	Direction
Surface Lease Lines	2390.0 feet	from the E line and	3446.0 feet	from the N line

Comments

Remark	Date Entered	Entered By
NEAREST WELL COMMENT: 1607.8	11/30/1992 12:00:00 AM	SYSTEM

Attachments

Attachment Type	File Path	Associated Fields and/or Plats

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Form W-1: Review

Status # 455434 API # 025-32658	OP # 640886 - PARKER & PARSLEY DEVELOPMENT L.P Approved ,Issued: 12/16/1996 ,Filed: Hardcopy	O'NEAL GAS UNIT - Well # 4 02 - BEE County	Recompletion Vertical

NEAREST WELL COMMENT: 1787 (11/20/1996 12:00:00 AM)

Status:

Back to Public Query Search Results

Completion Information

Well Status Code	Spud Date	Drilling Completed	Surface Casing Date
W - Final Completion	02/04/1997	02/13/1997	

Field Name	Completed Well Type	Completed Date	Validated Date
PAWNEE (EDWARDS)	Gas	02/13/1997	02/26/1997

General / Location Information

Basic Information:

Filing Purpose	Welbore Profiles	Lease Name	Well #	SWR	Total Depth	Horizontal Wellbore	Stacked Lateral Parent Well DP #
Recompletion	Vertical	O'NEAL GAS UNIT	4	SWR 36, SWR 37H	14040		

Surface Location Information:

API #	Distance from Nearest Town	Direction from Nearest Town	Nearest Town	Surface Location Type
025-32658	3.5 miles	S	PAWNEE	Land

Survey/Legal Location Information:

Section	Block	Survey	Abstract #	County
		E.L.&R.R. RR CO. #1	452	BEE

Township	League	Labor	Porcion	Share	Tract	Lot

Perpendicular surface location from two nearest designated reference lines:

Perpendiculars	Distance	Direction	Distance	Direction
Survey Lines	825.0 feet	from the W line and	2784.0 feet	from the S line

Permit Restrictions:

Code	Description
30	WILDCAT ABOVE 14040 FEET.
30	ANY WELLBORE DRILLED UNDER THIS PERMIT MUST BE COMPLETED, OPERATED, AND PRODUCED IN COMPLIANCE WITH STATEWIDE RULE 32.
30	REGULAR PROVIDED THIS WELL IS DRILLED IN COMPLIANCE WITH RULE 36.

Fields

District	Field Name	Field #	Completion Depth	Lease Name	Well #	Well Type	Acres	Distance to Nearest Well	Distance to Nearest Lease Line	SWR	Pooled/ Unitized
02	**WILDCAT** **Primary Field**	00004001	14040	O'NEAL GAS UNIT	4	Oil or Gas Well	704.0			37H	Y

Perpendiculars	Distance	Direction	Distance	Direction
Surface Lease Lines	4900.0 feet	from the W line and	2784.0 feet	from the S line

District	Field Name	Field #	Completion Depth	Lease Name	Well #	Well Type	Acres	Distance to Nearest Well	Distance to Nearest Lease Line	SWR	Pooled/ Unitized
02	**PAWNEE (EDWARDS)**	69845200	14040	O'NEAL GAS UNIT	4	Gas Well	704.0			SWR 36, 37H	Y

Perpendiculars	Distance	Direction	Distance	Direction
Surface Lease Lines	4900.0 feet	from the W line and	2784.0 feet	from the S line

Exceptions

Field	Exception	Case Docket Number	Resolution
WILDCAT	SWR 37 [Historical]	0214349	
PAWNEE (EDWARDS)	SWR 37 [Historical]	0214349	

Comments

Remark	Date Entered	Entered By
NEAREST WELL COMMENT: 1787	11/20/1996 12:00:00 AM	SYSTEM

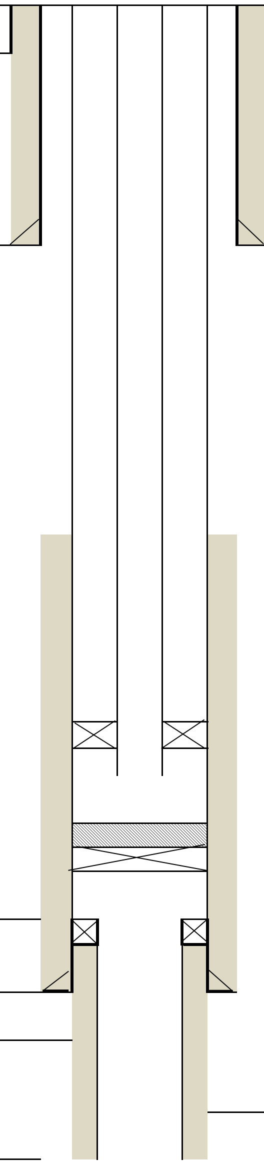
Attachments

Attachment Type	File Path	Associated Fields and/or Plats

Ozona CCS

Well Name:	ONeal Gas Unit 4 (current)	**Rig:**		**Lat, Long**	28.6031807,-98.0017091 (NAD83)
Formation:	Edwards	**GL:**		**GAU Depth:**	
County, State:	Bee County, TX	**RKB:**			
API #:	42-025-32658	**TD (MD):**	16,101'		
Permit #:		**TD (TVD):**			

	MD/TVD
Conductor	80
10.75" Surface Casing	3610
Cook Mountain	3657
Sparta	4259
Weches Sandstone	4326
Queen City	4655
Reklaw	5244
Carrizo	5864
Wilcox	5922
Midway	9026
Austin Chalk	13266
Eagle Ford	13344
Buda	13494
Edwards	13500
CIBP w/ 20' Cement on Top	14000
5" Liner Top	14088
Pearsall	15339
7 5/8" Intermediate Casing	15340
CO2 Resistant Permanent Packer	15700
Sligo	15874
5" Liner	16101



Tubular Detail					
String	**Hole Size (in)**	**OD (in)**	**Weight (#/ft)**	**Grade**	**MD (ft)**
Conductor					
Surface	14 3/4"	10 3/4"	55.5	S-95	3,610'
Intermediate	9 1/2"	7 5/8"	39	CY-95	15,340'
Liner	6 1/2"	5"	18	Q-125	14,088'-16,101'
Prod Tbg		2 3/8"	4.7	L-80	13453'

Cement Detail				
String	**Vol (sks)**	**Type**	**TOC (MD)**	**%XS**
Surf Lead	1125	HLC	0'	
Surf Tail	350	H		
Int Lead	575	50:50 Poz:H	7359'	
Int Tail	400	H		
Liner	200	Premium	14088'	

Edwards perfs production zone, 13,529'-13,841'
Cumulative 6,555,750 MCF gas, 168,888 BBLs water produced

Initial production zone, 15,874'-16,056'
Cumulative 511,964 MCF gas, 22,026 BBLs water produced

Well History		
#	**Date**	**Description**
1	12/30/1992	First spud as gas well, targeting the Sligo formation
2	2/13/1997	Plugged back to 14,000' and recompleted

Customer:	PARKER & PARSLEY DEV. CO.	
Well Desc:	CHARLIE OVERBY #2	
Formation:	SLIGO	
Date:	4-22-93	
Ticket #:	30841600	
Job Type:	THERMAGEL 80/70	

EVENT REPORT

	stage	Event mneum	Time HH:MM:SS	Event Description	
e	1	stgad	10:16:26	Operator Stage Advance	--> TREATED WATER W/ 70#/MGAL WLC-4
e	2	stgad	10:27:30	Operator Stage Advance	--> SHUTDOWN - MONITOR FOR LEAK OFF
e	2	NOTES	10:28:59	Operator's Notes	*** ISIP = 8068 PSI
e	3	stgad	10:49:59	Operator Stage Advance	--> TREATED WATER W/ 70#/MGAL WLC-4
e	4	stgad	11:02:45	Operator Stage Advance	--> FLUSH MINIFRAC - TREATED WATER
e	5	stgad	11:09:59	Operator Stage Advance	--> SHUTDOWN - MONITOR PRESSURE DECLINE
e	5	NOTES	11:24:51	Operator's Notes	*** ISIP = 8312 PSI FG = .954
e	5	NOTES	13:04:21	Operator's Notes	*** CLOSURE = 8000 CORRECTED F EFF. = 26%
e	6	stgad	13:09:20	Operator Stage Advance	--> PAD 70# LINEAR GEL
e	6	NOTES	13:33:40	Operator's Notes	*** START SAND AT .25#/G
e	6	NOTES	13:59:34	Operator's Notes	*** START XLINKER AT .2 G/M
e	6	NOTES	14:14:13	Operator's Notes	*** SHUT OFF SAND
e	6	NOTES	17:01:53	Operator's Notes	*** START METHANOL
e	7	stgad	17:04:11	Operator Stage Advance	--> PAD 80# THERMAGEL
e	8	stgad	18:07:24	Operator Stage Advance	--> 1# - 4# 30/60 CARBO-PROP
e	9	stgad	18:37:54	Operator Stage Advance	--> 4# 30/60 CARBO-PROP
e	9	NOTES	19:07:37	Operator's Notes	*** INCREASED SAND TO 4.5 #/G
e	9	NOTES	19:29:08	Operator's Notes	*** SAND OFF BY APPROX. .5#/G
e	10	stgad	19:30:03	Operator Stage Advance	--> FLUSH - TREATED WATER
e	11	stgad	19:35:52	Operator Stage Advance	--> SHUTDOWN - MONITOR PRESSURE
e	11	NOTES	19:37:13	Operator's Notes	*** ISIP=9169
e	11	NOTES	19:37:22	Operator's Notes	*** STARTED FLOW BACK

SEJ ✓

Plugging Record X

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 12/92
EAG0897

API NO (if available) 42-025-30388

1. RRC District: 02

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

4. RRC Lease or Id. Number: 064112

2. FIELD NAME (as per RRC Records): Pawnee (Sligo)
3. Lease Name: Overby, Charlie C. Gas Unit
5. Well Number: 1
6. OPERATOR: Pioneer Natural Resources USA, Inc.
6a. Original Form W-1 Filed in Name of:
10. County: Bee
7. ADDRESS: 5205 N. O'Connor Blvd., Ste. 900 Irving, TX 75039-3736
6b. Any Subsequent W-1's Filed in Name of:
11. Date Drilling Permit Issued: —
8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located: 1625 Feet From W Line and 1750 Feet From S Line of the Survey Lease
12. Permit Number: —
9a. SECTION, BLOCK, AND SURVEY: Marcelo Alcarte A-70
9b. Distance and Direction From Nearest Town in this County: 3.5 miles South of Pawnee
13. Date Drilling Commenced: unk
16. Type Well (Oil, Gas, Dry): Gas
Total Depth: 16,300
17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No's — GAS ID or OIL LEASE # | Oil-O Gas-G | WELL #
14. Date Drilling Completed: unk
18. If Gas, Amt. of Cond. on Hand at time of Plugging:
15. Date Well Plugged: 3-6-07

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	2-27	2-27	3-2	3-5	3-6	3-6		
20. Size of Hole or Pipe in which Plug Placed (inches)	3 1/2	3 1/2	7	7	7	7		
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	9310	9200	3800	3563	300	15		
*22. Sacks of Cement Used (each plug)	1	1	35	55	55	6		
*23 Slurry Volume Pumped (cu ft)	1.06	1.06	37.10	58.30	58.30	6.36		
*24 Calculated Top of Plug (ft.)	9280	9180	3650	3428	200	5		
25. Measured Top of Plug (if tagged) (ft.)					187			
*26. Slurry Wt. #/Gal.	16.4	16.4	16.4	16.4	16.4	16.4		
*27. Type Cement	H	H	H	H	H	H		

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT.#/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (IN.)
16	49.50	61	61	UNK.
10 3/4	45.50	3513	3508	15"
7	49.50	15,529	15,524	8 3/4
4"	UNK	15055-16290	14247	

29. Was any Non-Drillable Material (Other than Casing) Left in This Well: [X] Yes [ ] No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed)
Left 3 1/2 tubing in well from 3800' to 15,055'. An existing fish of 1 1/4" tubing from 9340' to 16,143' also left in well.

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM 15,911	TO 16,072	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO
FROM	TO	FROM	TO

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.
* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

RECEIVED
CENTRAL RECORDS
JUN 01 2007
AUSTIN, TEXAS

[signature]
Signature of Cementer or Authorized Representative

Pat's P & A, Inc.
Name of Cementing Company

CERTIFICATE
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct and complete, to the best of my knowledge

Doug Kimbell
REPRESENTATIVE OF COMPANY

Prod Supt.
TITLE

3-22-07
DATE

Phone 361 364-1732
A/C NUMBER

SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

MAPPING

31. Was Well filled with Mud-Laden Fluid, according to the regulations of the Railroad Commission ☒ Yes ☐ No	32. How was Mud Applied? Circulated	33. Mud Weight 12.5 LBS/GAL

34. Total Depth 16,300 Depth of Deepest Fresh Water 250	Other Fresh Water Zones by T.D.W.R. TOP / BOTTOM	35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules? ☐ Yes ☐ No 36. If NO, Explain

37. Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well
Pat's P & A, Inc. P.O. Box 0126, Bishop TX 78343

Date RRC District Office notified of plugging 2-23-07

38. Name(s) and Address(es) of Surface Owners of Well Site

39. Was Notice Given Before Plugging to the Above?

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

☐ Log Attached ☐ Log released to ______ Date ______

Type Logs: ☐ Driller's ☐ Electric ☐ Radioactivity ☐ Acoustical/Sonic

41. Date FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging ______ bbls*
* Field FORM P-1 (Oil Production Report) for month this oil was produced

~~RRC USE ONLY~~

Nearest Field ______

REMARKS Unable to recover 3 1/2" tbg. as anticipated above existing 1 1/4" fish @ 9340'. Jet cut 3 1/2" @ 9302' & 9243'. Unable to pull or establish circulation up 3 1/2 x 7" @ 3500 P.S.I.. Freepoint on 3 1/2 csg. at 4750 ±. Notified and received approval from Kevin Shamette W/RRC to set CIBP's + 20' cmt below and above cut's made on 3 1/2. Plug #1 & #2 - CIBP + 20' cmt. in 3 1/2" 12.95#. Cut 3 1/2 @ 4762'and perforated 3 1/2" @ 4765' but unable to pull or circulate. Re-cut @ 3800'. Received verbal approval from Kevin Shamette W/RRC to set plug from 3800' tp 3650' Cut & perforated 7" casing @ 3563'. Casing not free. Unable to establish circulation but established injection into 7" x 8 3/4" @ 2000 P.S.I. Notified Kevin W/RRC to squeeze plug. Squeezed 55 sks. cmt. leaving 23 sks. inside 7" 49.50# and 32 sks. outside in 7" x 8 3/4". Cut 7" csg. @ 300' but unable to circulate. Received verbal approval to squeeze 55 sks. Squeezed 38 sks. out into 7" x 9 5/8" and left 17 sks inside 7" casing.

Area of Review: Oil & Gas Wells List

API	WELL NAME	WELL NO.	CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (TVD FT.)	PERFORATED INTERVAL (MD FT.)	DATE DRILLED
4202500002	ONEAL, A.	1	ROWAN & HOPE	126	28.603017	-98.000911	DRILLED	7010	NO RECORD	8/9/1949
4202500005	RUSSELL, S.	1	PAN AMERICAN PETROLEUM CORP.	308	28.594587	-97.999841	DRILLED	7515	NO RECORD	5/12/1947
4202530346	HENRY BUES	1	PIONEER NATURAL RES. USA, INC.	70	28.5986210	-98.0118480	INACTIVE PRODUCER	13842	7554-7558; 7612-7624; 13526-13760	11/10/1974
4202530359	ONEAL GAS UNIT	2	BB-SOUTHTEX, LLC	127	28.61178	-98.000661	PRODUCING	13961	13349-15821	4/5/1975
4202530388	OVERBY, CHARLIE C. GAS UNIT	1	PIONEER NATURAL RES. USA, INC.	70	28.601086	-98.005037	P & A	16300	15911-16072	6/6/1975
4202532342	DE LEON	1	T D EXPLORATION, INC.	126	28.6006330	-97.9917520	P & A	6512	NO RECORD	12/31/1985
4202532501	HENRY BUES GAS UNIT	2	BB-SOUTHTEX, LLC	70	28.599863	-98.009994	PRODUCING	13896	13504-15637	11/15/1988
4202532638	ONEAL GAS UNIT	3	BB-SOUTHTEX, LLC	70	28.604583	-98.007079	PRODUCING	13834	13508-13668	3/12/1992
4202532842	OVERBY, CHARLIE C.	1E	PIONEER NATURAL RES. USA, INC.	70	28.5998760	-98.0053330	P & A	14000	13514-13838	10/9/1995
4202532967	TOMASEK GAS UNIT	5	BB-SOUTHTEX, LLC	126	28.609862	-97.991519	PRODUCING	13875	13434-15693	6/12/1999
4202533006	ONEAL GAS UNIT	5	BB-SOUTHTEX, LLC	70	28.6067950	-98.0042210	PRODUCING	13772	13463-13764	7/15/2000
4202533035	ONEAL GAS UNIT	6	BB-SOUTHTEX, LLC	127	28.61091	-97.999073	PRODUCING	13835	13310-13833	9/14/2000
4202533085	ONEAL GAS UNIT	7	BB-SOUTHTEX, LLC	127	28.609397	-98.001471	PRODUCING	13868	13314-16072	5/4/2001
4202533114	HENRY BUES GAS UNIT	8	BB-SOUTHTEX, LLC	70	28.5984810	-98.0090260	PRODUCING	13732	13348-13732	6/11/2001
4202533197	ONEAL GAS UNIT	8	BB-SOUTHTEX, LLC	452	28.6075430	-98.0037990	PRODUCING	15638	13565-13820	2/5/2003

O'Neal Gas Unit No. 4

4202533272	HENRY BUES GAS UNIT	11	BB-SOUTHTEX, LLC	70	28.598737	-98.008615	PRODUCING	13856	13291-15853	6/23/2004
4202533273	ONEAL GAS UNIT	9	BB-SOUTHTEX, LLC	452	28.6029540	-98.0025090	PRODUCING	13872	13311-16585	6/3/2004
4202533328	ONEAL GAS UNIT	11	BB-SOUTHTEX, LLC	126	28.6036340	-97.9982100	PRODUCING	13787	13318-15928	4/19/2005
4202533345	TOMASEK GAS UNIT	8	BB-SOUTHTEX, LLC	126	28.608282	-97.991595	PRODUCING	13692	13293-16378	8/14/2004
4202533371	ONEAL GAS UNIT	12	BB-SOUTHTEX, LLC	452	28.6097460	-98.0027040	PRODUCING	13819	13313-16635	8/15/2006
4202533383	HENRY BUES GAS UNIT	15	BB-SOUTHTEX, LLC	70	28.600322	-98.00874	PRODUCING	13811	13302-15768	10/8/2006
4202533492	ONEAL GAS UNIT	13	BB-SOUTHTEX, LLC	70	28.605326	-98.012928	PRODUCING	13859	13382-14761	7/7/2007
4202533553	ONEAL GAS UNIT	14	BB-SOUTHTEX, LLC	127	28.613869	-98.000504	PRODUCING	13674	13450-15424	2/11/2008
4202533559	OVERBY GAS UNIT	2E	BB-SOUTHTEX, LLC	452	28.6011410	-98.0028580	PRODUCING	13734	13372-13734	3/23/2008
42025E2114	NO RECORD	NR	NO RECORD	126	28.608457	-97.995683	NO RECORD	NR	NO RECORD	NR

*Note: Well entries in red penetrate the upper confining layer.

LONQUIST SEQUESTRATION LLC

Area of Review: Freshwater Wells List

WELL REPORT/ID NO.	OWNER'S NAME	OWNER ADDRESS	CITY/STATE/ZIP	LAT. WGS 84	LONG. WGS 84	WELL USE	WATER LEVEL (FT.)	TOTAL DEPTH (FT.)	DATE DRILLED
128936	JOHN DAVIDSON	12761 FM 673	KENEDY, TX 78119	28.606667	-98.011667	DOMESTIC	48	114	11/19/2007
7832308	HENRY BUES	NO RECORD	NO RECORD	28.598334	-98.012223	STOCK	-	150	1960
7925105	T. M. PLUMER	NO RECORD	NO RECORD	28.595556	-97.997778	STOCK	77	275	1931
7832309	W. A. MUELLER	NO RECORD	NO RECORD	28.608612	-98.005834	UNUSED	63	90	1925
7925106	R.C. HUNT ESTATE	NO RECORD	NO RECORD	28.593889	-97.997222	UNUSED	137	172	1925

Request for Additional Information: O'Neal Gas Unit Well No. 4
May 16, 2024

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	N/A	N/A	Please clarify whether the referenced Startex Pawnee Gas Plant has previously reported any data under the GHGRP (e.g., subparts W, UU, PP). If so, please include the related facility ID number in the MRV plan.	The Pawnee Treating Facility is part of Startex's gas gathering and boosting assets, which are currently reporting under subpart W; (Facility ID No. 568661). Section 1.3 has been revised to include this Facility ID No., with references to the Pawnee Treating Facility and additional reporting information.
2.	2.2.3	22	"The permeability curve was generated utilizing the Coates permeability equation, incorporated with a 20% **irreducible** to match analysis provided by Nutech." Please clarify what **"irreducible"** means in this context.	Section 2.2.3 has been edited to clarify and now reads "20% irreducible brine saturation".
3.	Table 7	52	"The lateral continuity of the UCZ is recognized as a very competent seal." This statement appears in the likelihood section of most potential leakage pathways shown in Table 7. Please specify how the UCZ being a competent seal relates to the likelihood of leakage for each of these pathways. Also, please ensure that potential leakage pathways are consistent between Table 7 and Table 9.	Table 7 has been updated to better characterize the Likelihood of certain Leakage Pathways. Table 9 has been updated to ensure the pathways discussed are consistent between Tables 7 and 9. Leakage through groundwater/future wells are subsets of the existing wells discussion.
4.	4.5	61	Please include additional characterization related specifically to induced seismicity in this section. Additionally, please clarify whether the facility will take steps (such as limiting injection pressures) to avoid inducing seismicity.	Section 4.5 has been updated to address potential induced seismicity and clarify the steps to be taken to avoid inducing seismicity.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
5.	7.5	74	"CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead" Per 40 CFR 98.443(F)(2), this variable should be "CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, **for which a calculation procedure is provided in subpart W of this part**." Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	The definitions of variables for the equation in Sections 7.2 and 7.5 has been updated to reflect the precise language used in 40 CFR 98.443.
6.	8	75	"The MRV plan will be implemented upon receiving EPA approval." Per 40 CFR 98.448(a)(7), the proposed MRV plan must include a "proposed date to begin collecting data for calculating total amount sequestered according to equation RR-11 or RR-12 of this subpart. This date must be after expected baselines as required by paragraph (a)(4) of this section are established and the leakage detection and quantification strategy as required by paragraph (a)(3) of this section is implemented in the initial AMA." Please clarify in the MRV plan when baselines would be established and when data would start to be collected for calculating CO_2 sequestered. If this timeline is dependent on the status of the Class II permit, we recommend specifying this in the MRV plan. In the response to our previous request for additional information, you provided additional context that would be relevant in Section 8 of the MRV plan.	Section 8 has been updated with a table to formalize the baseline sampling activities described in Section 6.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
7.				The term “plant” was changed to “facility” through the proposed MRV plan to better represent the activities of the StarTex assets.
8.	2.2.5			An internal review of the MRV plan identified that the fracture pressure gradient discussion included information from an earlier test. The values have been updated and now match the values used in the plume model.
9.	2.8			Additional language was added to clarify how the relative permeability was determined.
10.	Table 8			Table 8 has been updated for consistent use of monitors.

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
O'Neal Gas Unit Well No. 4

Bee County, TX

Prepared for *Ozona CCS, LLC*
San Antonio, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 2.0
January 2024

INTRODUCTION

Ozona CCS, LLC (Ozona) has a pending Class II acid gas injection (AGI) permit application with the Texas Railroad Commission (TRRC), which was submitted in September of 2023 for its O'Neal Gas Unit Well No. 4 (O'Neal No. 4), API No. 42-025-32658. Granting of this application would authorize Ozona to inject up to 1.5 million standard cubic feet per day (MMscf/D) of treated acid gas (TAG) into the Sligo Formation at a depth of 15,874 feet (ft) to 16,056 ft, with a maximum allowable surface pressure of 7,920 pounds per square inch gauge (psig). The TAG for this AGI well is associated with StarTex's Pawnee Gas Plant, located in a rural area of Bee County, Texas, approximately 2.0 miles (mi) south of Pawnee, Texas, as shown in Figure 1.

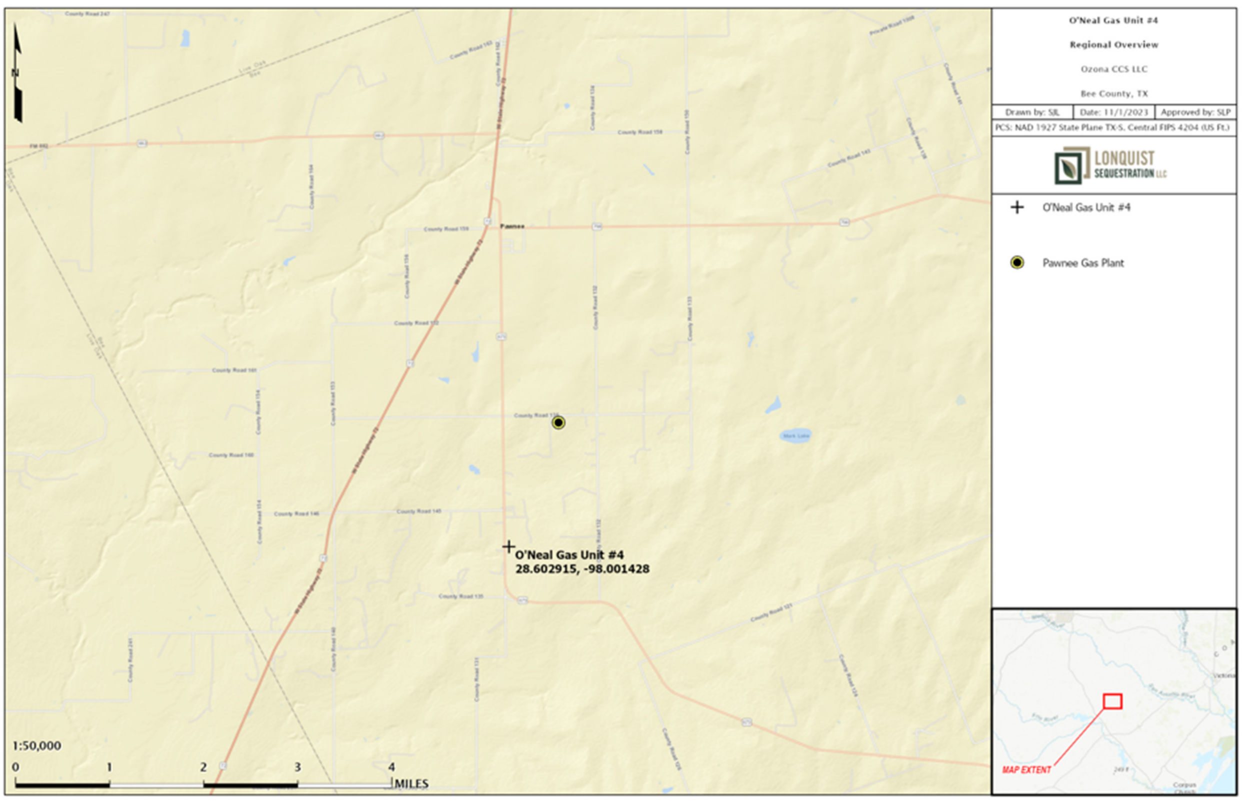


Figure 1 – Location of StarTex Gas Plant and the O'Neal No. 4

Ozona is submitting this Monitoring, Reporting, and Verification (MRV) plan to the EPA for approval under Title 40, U.S. Code of Federal Regulations (40 CFR) **§98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program (GHGRP). In addition to submitting this MRV plan to the EPA, Ozona has applied to the TRRC for the O'Neal GU No. 4's Class II permit. Ozona plans to inject TAG for approximately 12 years. Table 1 shows the expected composition of the gas stream to be sequestered from the nearby plant.

Table 1 – Expected TAG Composition

Component	Mol Percent
Carbon Dioxide	98.2%
Hydrocarbons	1.03%
Hydrogen Sulfide	0.4%
Nitrogen	0.37%

ACRONYMS AND ABBREVIATIONS

AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group, Ltd.
CO_2	Carbon Dioxide (may also refer to other carbon oxides)
E	East
EOS	Equation of State
EPA	Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area
MCF	Thousand Cubic Feet
MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet

Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
PG	Pore Gradient
pH	Scale of Acidity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

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SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control (UIC) Class II program. The TRRC classifies the O'Neal No. 4 as a UIC Class II well. Ozona has applied for a Class II permit for the O'Neal No. 4 under TRRC Rules 36 (Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas) and 46 (Fluid Injection into Productive Reservoirs).

1.2 UIC Well Identification Number

- O'Neal No. 4, API No. 42-025-32658, UIC No. 56819

1.3 Facility Address

- Gas Plant Facility Name: StarTex Pawnee Gas Plant
- Operator: StarTex Field Services, LLC
- Coordinates in North American Datum for 1983 (NAD 83) for this facility:
    - Latitude: 28.622211
    - Longitude: -97.992772

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and reservoir and plume modeling performed for the O'Neal No. 4 well.

The O'Neal No. 4 will inject the TAG stream into the Sligo Formation at a depth of 15,874 ft to 16,056 ft, and approximately 14,924 ft below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and—most critically—to prevent surface releases.

2.1 Regional Geology

The O'Neal No. 4 (API No. 42-025-32658) is located in south Texas within the Gulf of Mexico Basin. The onshore portion of the Gulf of Mexico basin spans approximately 148,049,000 acres and encompasses portions of Texas, Louisiana, Mississippi, Alabama, Arkansas, Missouri, Kentucky, Tennessee, Florida, and Georgia to the state-waters boundary of the United States (Roberts-Ashby et al., 2012). The location of the O'Neal No. 4 is designated by the red star in Figure 2, relative to the present coastal extent and major structural features of the basin.

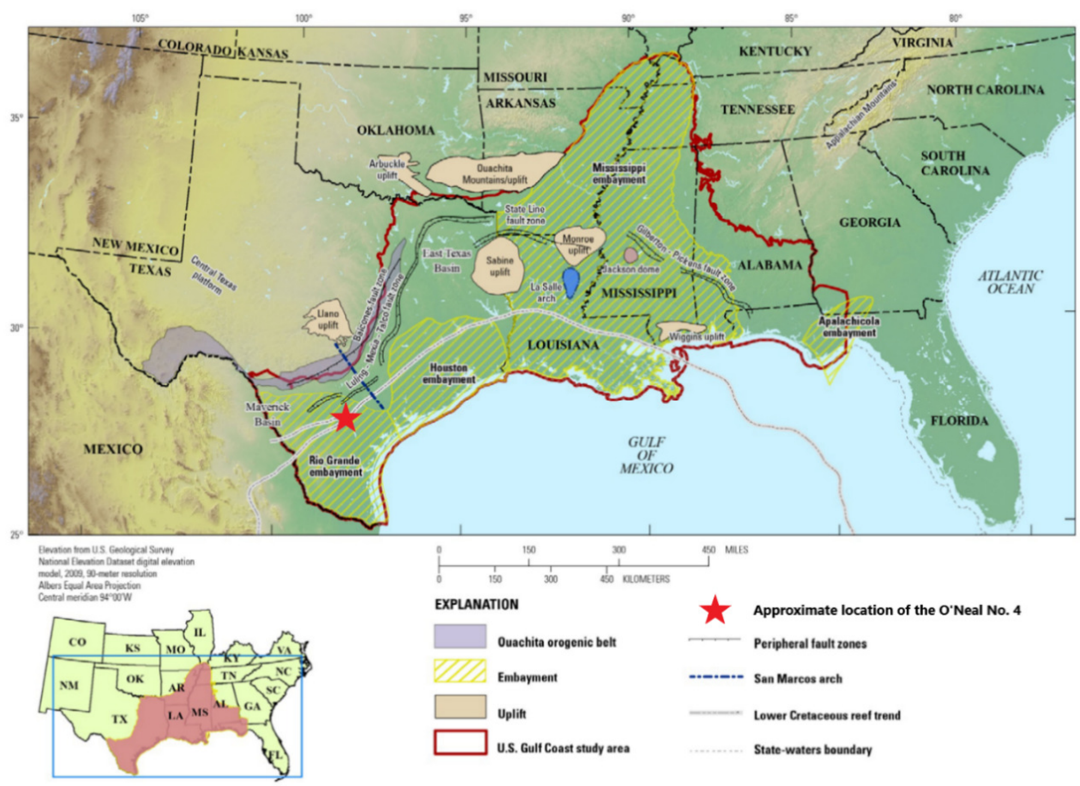

Figure 2 – Structural Features of the Gulf of Mexico and Locator Map (modified from Roberts-Ashby et al., 2012)

Figure 3 depicts a generalized stratigraphic column of the U.S. Gulf Coast, with light blue shading signifying the proposed injection interval and green stars indicating productive formations identified within 5 miles of the O'Neal No. 4. The injection interval is found within the Sligo Formation, with confinement provided by the overlying Pearsall Formation and tight underlying facies of the Lower Sligo and Hosston Formations.

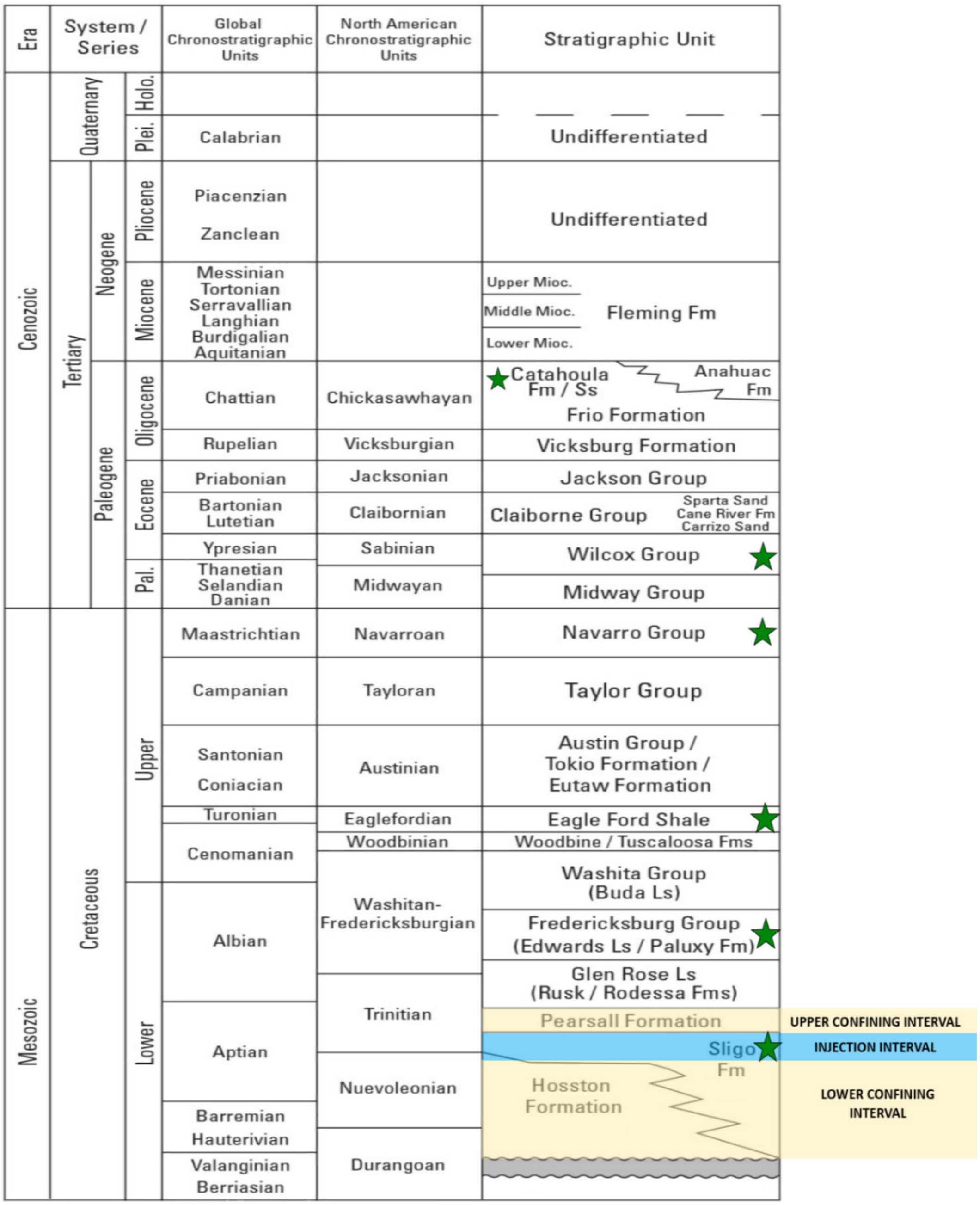

Figure 3 – Stratigraphic column of the U.S. Gulf Coast signifying proposed injection and confining intervals. Offset productive intervals are noted with a green star (modified from Roberts-Ashby et al., 2012).

The targeted formations of this study are located entirely within the Trinity Group, as clarified by the detailed stratigraphic column provided in Figure 4. During this time the area of interest was located along a broad, shallow marine carbonate platform that extended along the northern rim of the ancestral Gulf of Mexico. The Lower Cretaceous platform spanned approximately 870 mi from western Florida to northeastern Mexico, with a shoreline-to-basin margin that ranged between 45 to 125 mi wide (Yurewicz et al., 1993).

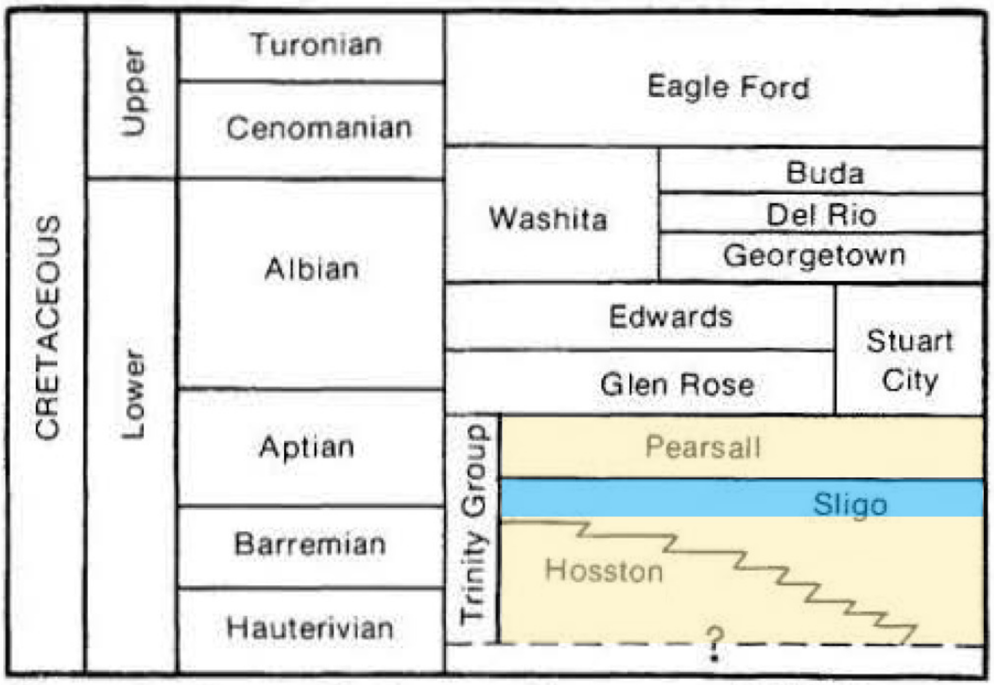

Figure 4 – Detailed stratigraphic column of Lower Cretaceous formations of south Texas. The proposed injection interval is shaded light blue and proposed confining intervals are shaded light yellow (modified from Bebout et al., 1981).

2.1.1 Geologic Setting and Depositional Environment

The depositional environment during the Lower Cretaceous generally consisted of a well-defined platform margin with a shallow marine platform interior or lagoon to the north, a shallow marine outer platform to the south, and a foreslope that gradually dipped southward towards the basin center. The platform margin remained stable for tens of millions of years during the Cretaceous but experienced episodic changes in sea level that resulted in cyclic deposition of several key facies that vary both spatially and within the geologic section. Facies distributions were heavily impacted by positioning relative to the margin, the height of the water column at any given time, and the degree of energy or wave action within the system (Galloway, 2008; Yurewicz et al., 1993).

In general, long stands of reef development and ooid shoaling developed primary porosity and permeability along the shallow, high-energy carbonate platform and represent reservoir quality

rock found within Cretaceous reef deposits. Deeper, basinward deposits tend to result in tighter petrophysical properties due to a relative increase in the amount of entrained clay associated with the heightening of the water column while moving downslope. Backreef deposits have the potential for porosity development but tend to have low permeability due to a general lack of wave action caused by restricted access to open water by the platform margin. Facies and petrophysical properties of the Lower Cretaceous section are anticipated to be relatively homogenous moving southwest-northwest along reef trend, with increased heterogeneity moving northwest-southeast due to the orientation of the carbonate rim and its effect on deposition and facies distributions (Yurewicz et al., 1993).

Figure 5 displays the paleogeography during deposition of the Lower Cretaceous section to visually demonstrate the position of the O'Neal No. 4 relative to the Sligo shelf margin and updip extents of Sligo deposition. A generalized schematic cross section of the Trinity Group is provided in Figure 6, which nearly intersects the project area from the northwest. The schematic illustrates the gross section thickening basinward, with primary reservoir development improving with proximity to the reef margin. Figure 7 displays a depositional model of the Lower Cretaceous carbonate platform to visually conceptualize depositional environments and anticipated petrophysical properties of facies introduced above.

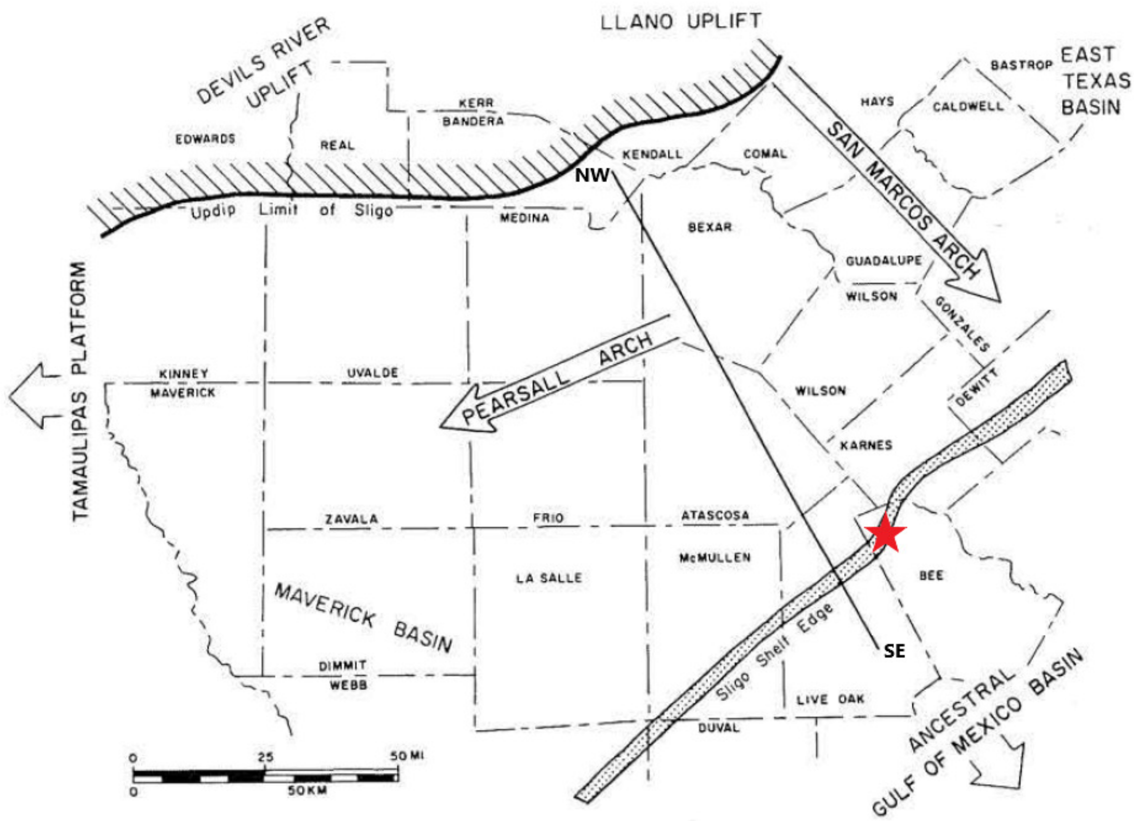

Figure 5 – Paleogeography of the Lower Cretaceous of south Texas. The red star represents the approximate location of the O'Neal No. 4 (modified from Bebout et al., 1981).

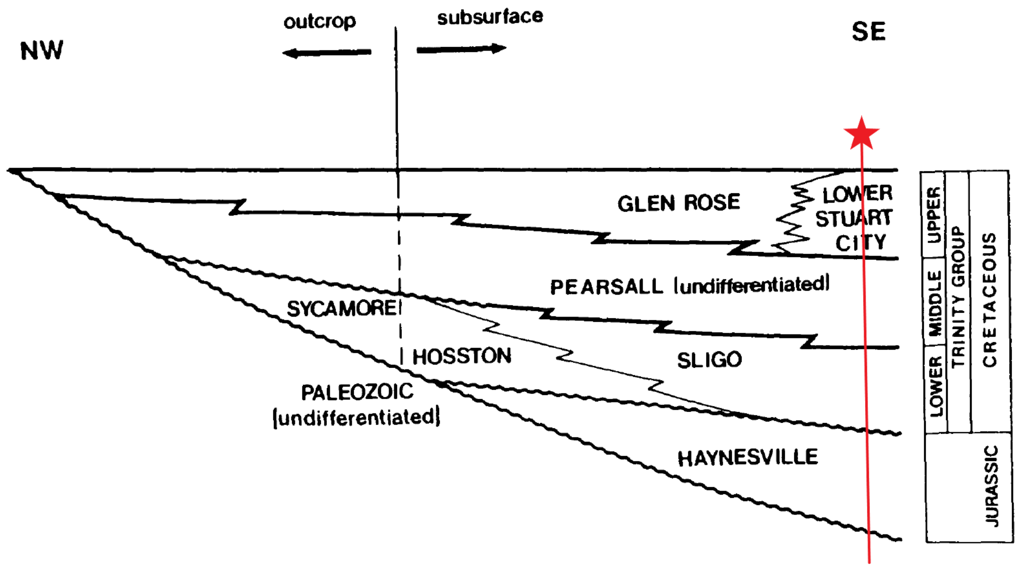

Figure 6 – Generalized northwest to southeast schematic cross section of the Trinity Group, south Texas (the line of section depicted in Figure 5). The red star and line represent the approximate location of the O'Neal No. 4 (modified from Kirkland et al., 1987)

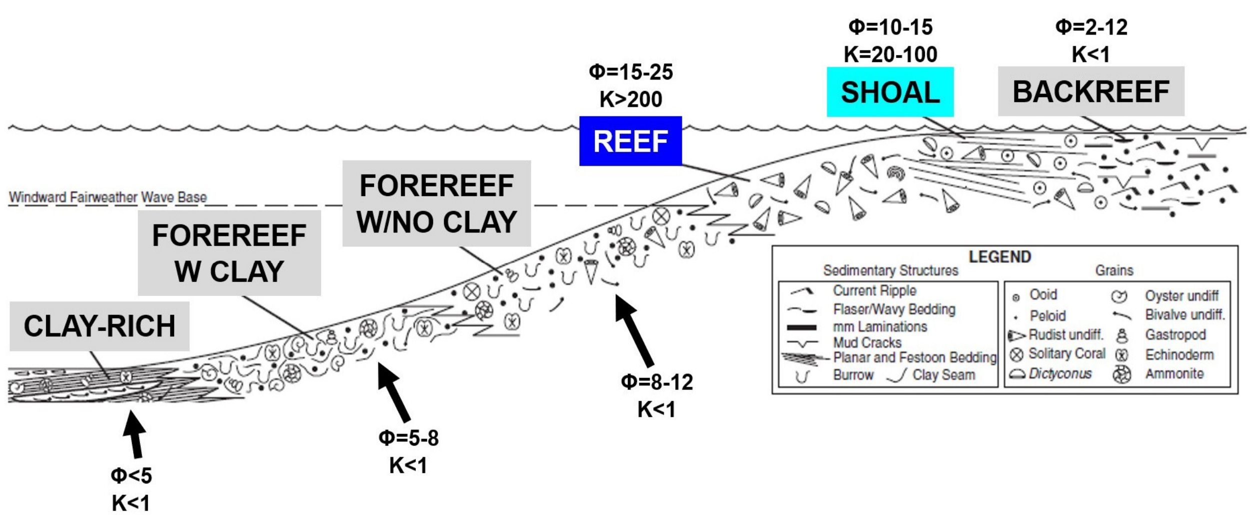

Figure 7 – Depositional model for the Lower Cretaceous carbonate platform with estimated porosity and permeability values of typical facies (modified from Talbert and Atchley, 2000).

2.1.2 Regional Structure and Faulting

The Gulf of Mexico basin was formed by crustal extension and sea-floor spreading associated with the Mesozoic breakup of Pangea. Rifting of northwest to southeast trending transfer faults during the Middle Jurassic lasted approximately 25 million years and resulted in variable thickness of the transcontinental crust underlying the region. By the Lower Cretaceous time, the general outline and morphology of the Gulf were similar to that of present-day (Galloway, 2008;

Yurewicz et al., 1993). Lower Cretaceous tectonic activity was limited to regional subsidence associated with areas of variable crustal thickness and local structuring caused by movement of Louann Salt (Yurewicz et al., 1993). The combination of these processes resulted in the structural development of regional arches, grabens, uplifts, embayments, salt domes, and salt basins around the northern edge of the basin (Dennen and Hackley, 2012; Galloway, 2008). The location of these structural features can be referenced in Figures 2 and 8 relative to the location of the O'Neal No. 4.

The schematic dip-oriented cross section displayed in Figure 9 presents a common interpretation of the current structural setting. Most of the published literature suggests that faulting near the project area is restricted to the shallower, overlying Cenozoic section, as displayed in Figure 9, with shallow faulting dying out before reaching the Pearsall Formation. However, one source did interpret the potential for faulting to the south (Swanson et al., 2016). The closest potential fault is depicted in Figure 8 relative to the location of the O'Neal No. 4. According to the map, the interpreted fault lies approximately 4.25 miles south-southeast of the well and approximately 3.9 miles south-southeast of the stabilized plume extent in the year 2047.

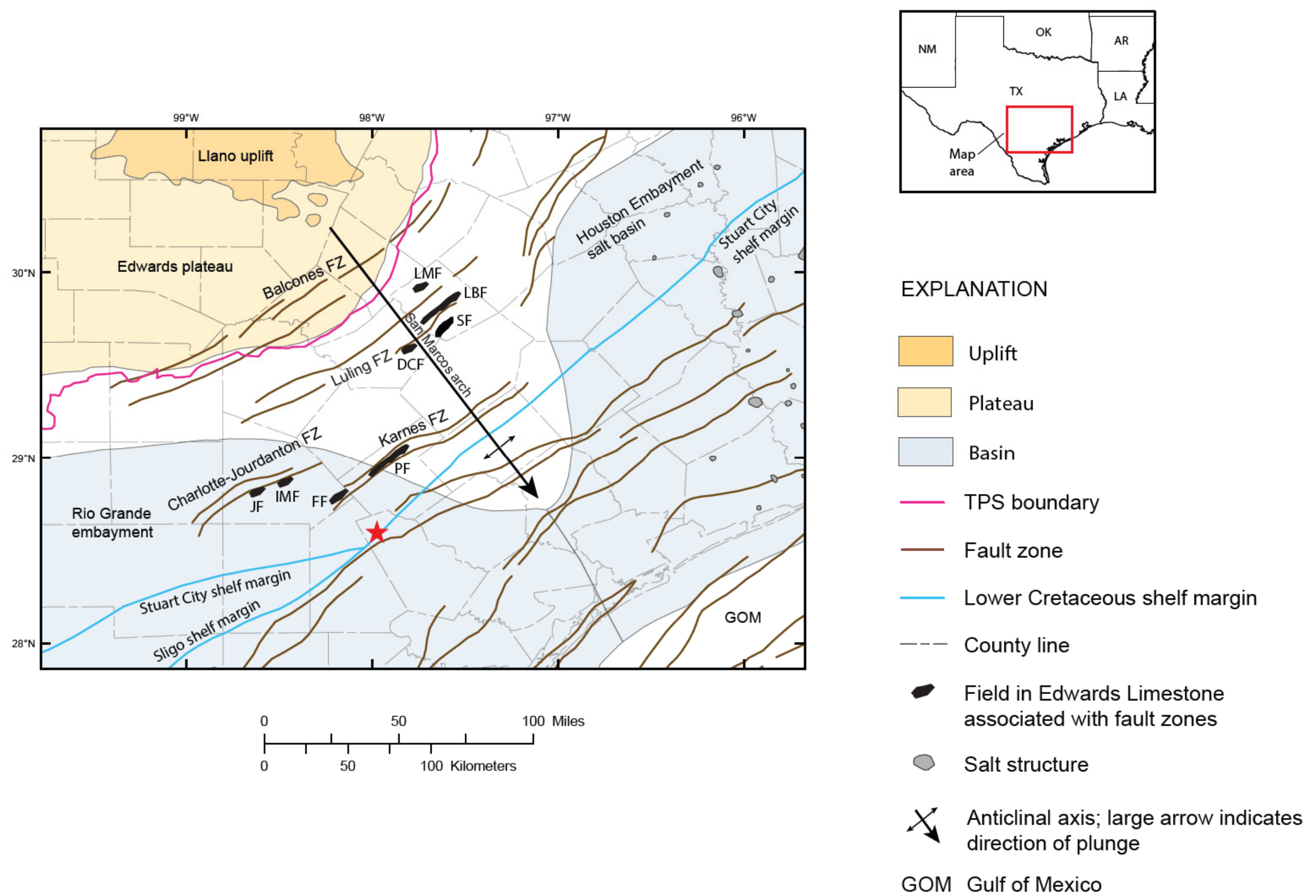

Figure 8 – Structural features and fault zones near the proposed injection site. The red star represents the approximate location of the O'Neal No. 4 (modified from Swanson et al., 2016).

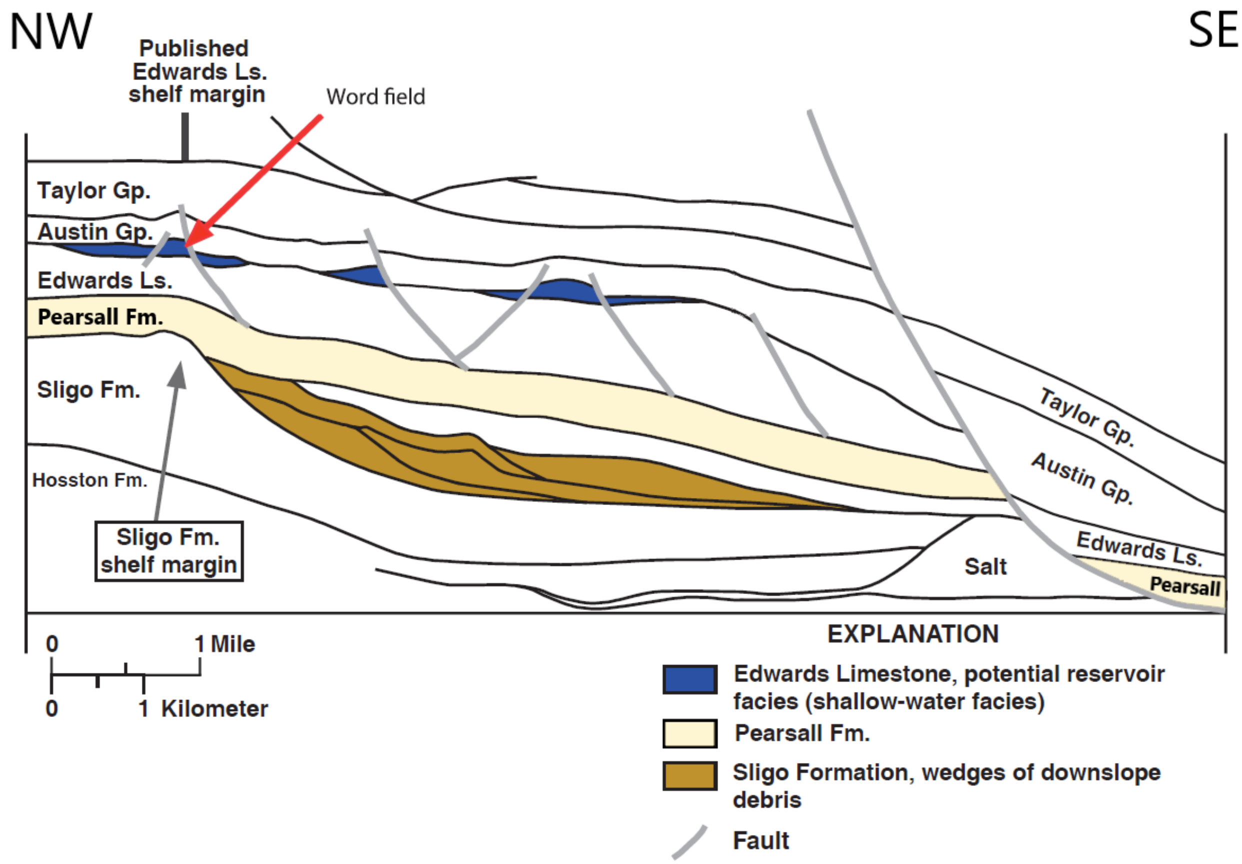

Figure 9 – Northwest to southeast schematic interpretation of the Edwards shelf margin through Word field, northeast of the O'Neal No. 4 project area (modified from Swanson et al., 2016).

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the O'Neal No. 4 well.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 depicts openhole logs from two offset wells (API No. 42-025-00473 and API No. 42-025-31892) to the O'Neal No. 4, indicating the injection and primary upper confining zones. The Tomasek No. 1 (API No. 42-025-00473) is located approximately 1 mi northeast of the O'Neal No. 4 and displays the shallow section from 0–8,200 ft. The Gordon No. 3 (API No. 42-025-31892) is located approximately 1.6 mil northeast of the O'Neal No. 4 and displays a shallow section from 8,200–16,400 ft.

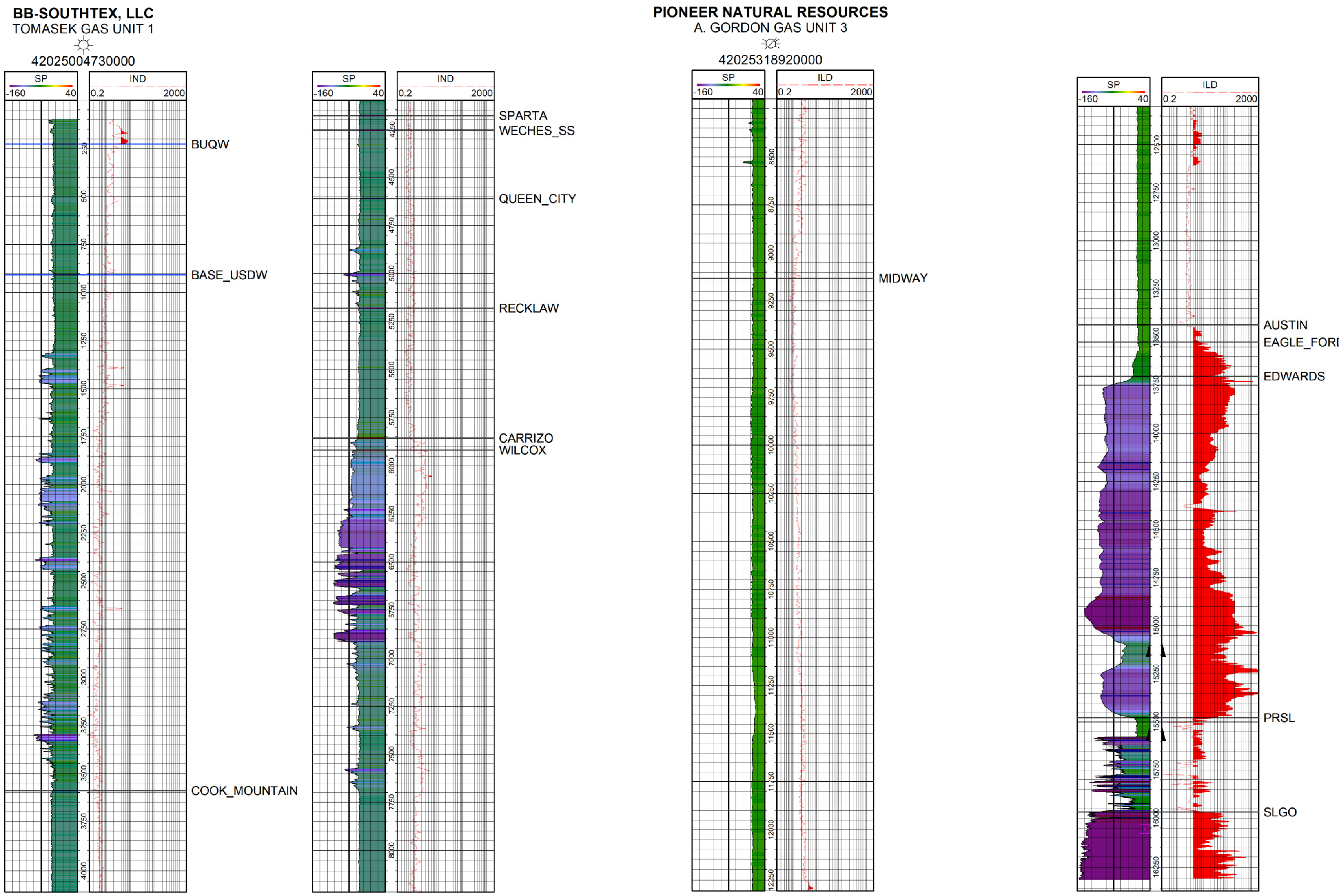

Figure 10 – Type Log with Tops, Confining, and Injection Intervals Depicted

2.2.2 Upper Confining Interval – Pearsall Formation

Following the deposition of the Sligo Formation, the Lower Cretaceous shelf was drowned by eustatic sea-level rise and deposition of the deep-water Pine Island Shale Member of the Pearsall Formation throughout the region (Roberts-Ashby et al., 2012). The Pine Island Shale consists of alternating beds of pelagic mudstone, hemipelagic mudstone, and Fe-rich dolomitic mudstone interpreted to have been deposited along the outer ramp. This is in agreement with core data published by Bebout and others (1981), and later by Swanson and others (2016), who identified the presence of *C. Margerelli*, a nannofossil indicative of anoxic conditions. The core-derived porosity-permeability relationship displayed in Figure 11 suggests that the permeability of the Pine Island Shale is incredibly low and stays below 0.0001 mD, regardless of porosity (Figure 11; Hull, 2011). This is further supported by the 2012 U.S. Geological Survey (USGS) *CO_2 Storage Resource Assessment*, which suggests that the Pine Island Shale contains the physical properties required to act as a regional seal and was chosen as the upward confining interval for their C50490108 Storage Assessment Unit (SAU) assessment of the Gulf Coast. The 2012 USGS report also noted that the Pine Island Shale is a sufficient regional seal with as little as 50 feet of contiguous shale development. The top of the Pearsall is encountered at a depth of 15,339 ft in the O'Neal No. 4, with a gross thickness of 535 ft (Figure 14). The Pine Island Shale member is approximately 130 ft thick at the O'Neal No. 4 location, with deposition of additional members of the overlying Pearsall Formation, which include the Cow Creek Limestone, Cow Creek shale, and Bexar Shale Members (Roberts-Ashby et al., 2012; Swanson et al., 2016).

The seismic line displayed in Figure 12 runs northwest to southeast across the Stuart City reef trend southwest of the project area. The top of the Buda, Pearsall, and Sligo Formation markers are depicted in color to demonstrate the lateral continuity of the section near the O'Neal No. 4. Seismic reflectors within the Pearsall Formation appear to lack deformation, suggesting consistent deposition over the reef margin. This is in agreement with reviewed published literature, which suggests deposition of the Pine Island Shale occurred during widespread marine transgression (Bebout et al., 1981; Hull, 2011.; Roberts-Ashby et al., 2012, Swanson et al., 2016).

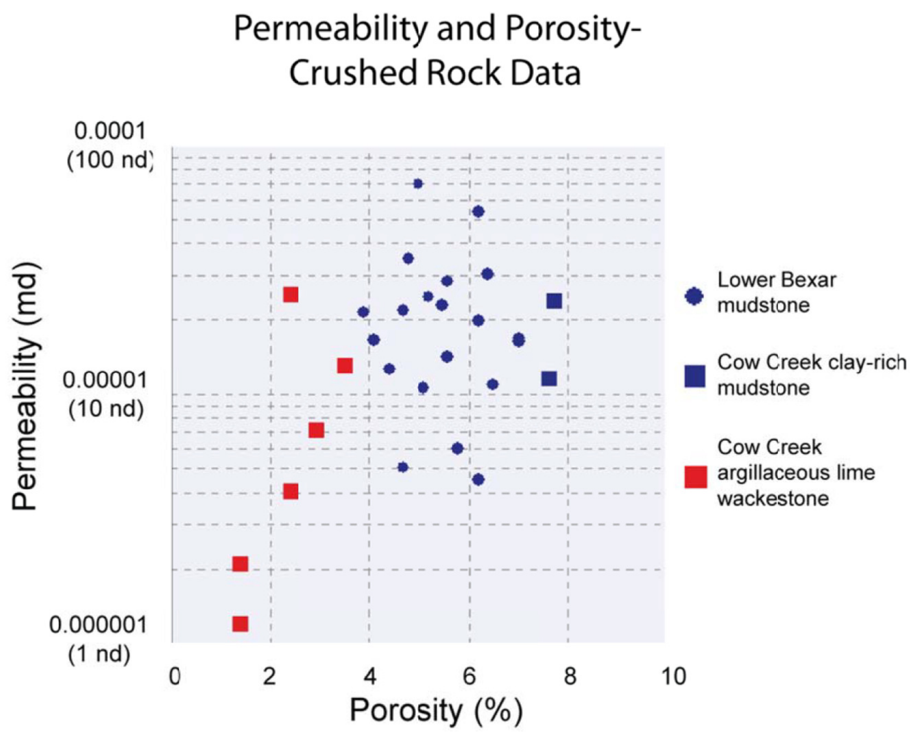

Figure 11 – Porosity-Permeability Crossplot of Pearsall Formation Crushed Rock Core Data (Swanson et al., 2016)

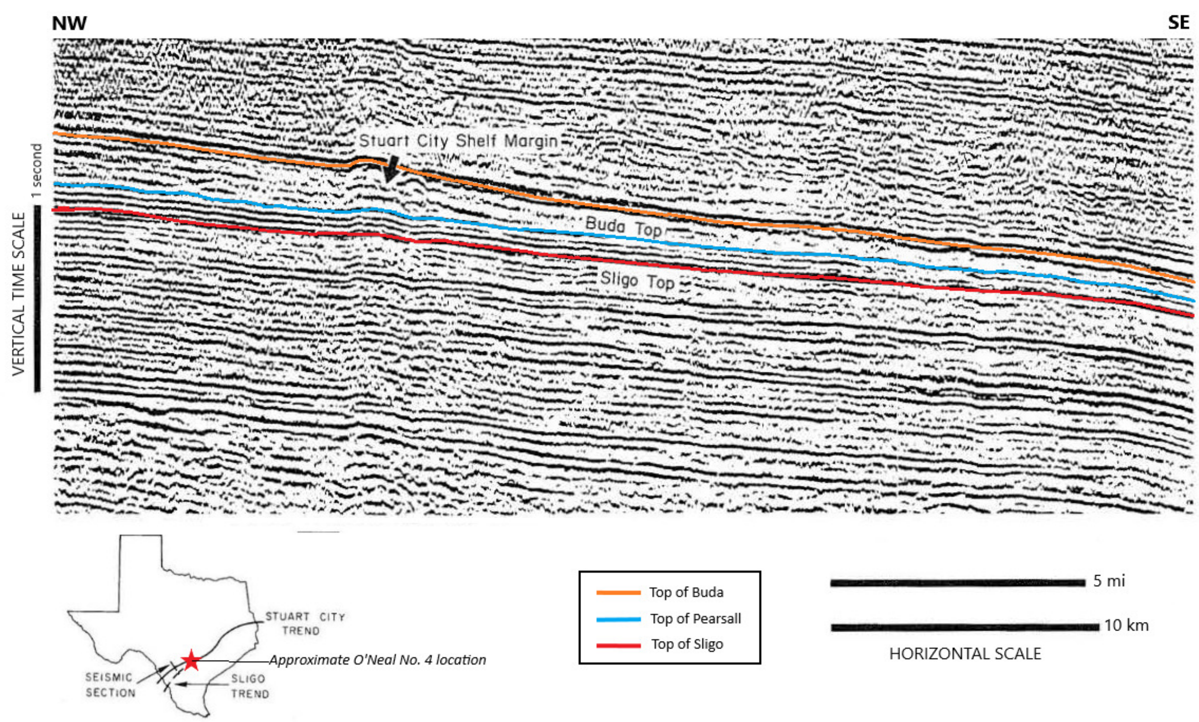

Figure 12 – Seismic line across the Stuart City (Edwards/Buda) shelf margin and locator map. The red star represents the approximate location of the O'Neal No. 4 (modified from Bebout et al., 1981).

2.2.3 Injection Interval – Upper Sligo Formation

The Sligo Formation underlies the Pearsall Formation and is predominately composed of shelf-edge limestones that were deposited along the Lower Cretaceous platform (Roberts-Ashby et al., 2012). However, the Cretaceous also experienced episodic changes in sea level that resulted in the deposition of cyclic Sligo facies that vary both spatially and within the geologic section. The overall Sligo interval is interpreted to be a transgressive sequence occasionally interrupted by progradational cycles that consists of porous shoaling-upward sequences that represent primary reservoir potential within the system (Bebout et al., 1981). Facies distributions of these reef complexes are heavily impacted by positioning relative to the margin, the height of the water column at any given time, and the degree of energy or wave action within the system (Galloway, 2008). Figure 13 depicts an idealized environmental setting of the Lower Cretaceous platform during deposition. Primary porosity and permeability of the upper Sligo Formation tends to develop in high-energy sequences with normal marine conditions that are dominated by the deposition of oolitic and skeletal grainstones.

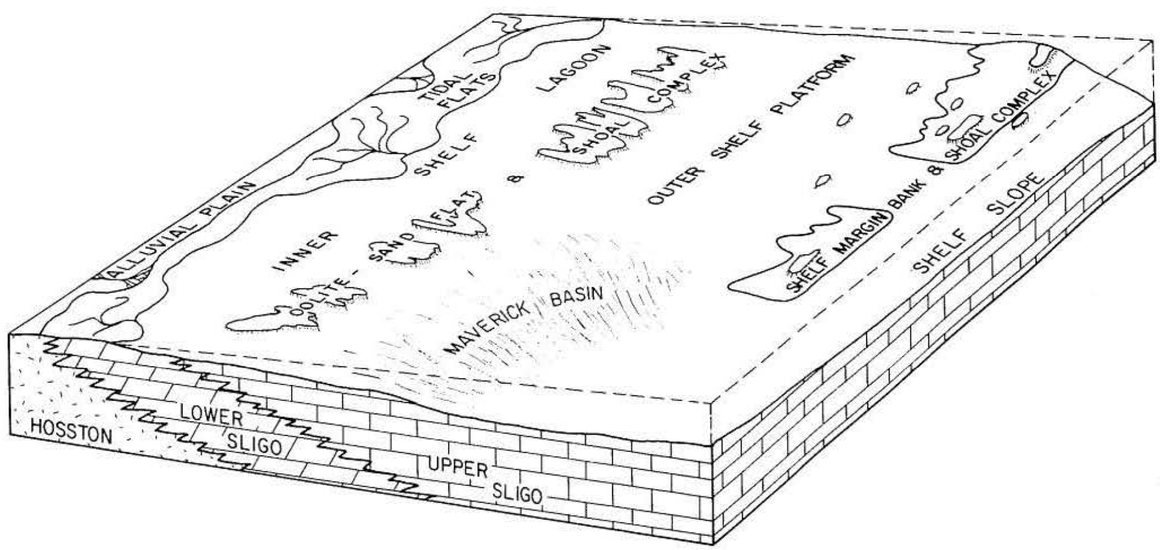

Figure 13 – Environmental Setting of Lower Cretaceous Platform (Bebout et al., 1981)

According to the 2012 USGS *CO_2 Storage Resource Assessment*, “the average porosity in the porous intervals of the storage reservoir decreases with depth from 9 to 16 percent” for their C50490108 DEEP SAU assessment of the Gulf Coast (>13,000 feet). The study also reported that “the average permeability in the storage reservoirs decreases with depth from 0.05 to 200 mD, with a most-likely value of 8 mD” for their C50490108 DEEP SAU assessment of the Gulf Coast (Roberts-Ashby et al., 2012).

The top of the upper Sligo is encountered at a depth of 15,874 ft in the O’Neal No. 4 with a gross thickness of 183 ft (Figure 14). The type log displayed in Figure 14 plots effective porosity for the confining interval and the total porosity of the injection interval, to account for the increased volume of shale (Vshale) seen in the Pearsall Formation. The porosity data was compared to the analysis performed by Nutech to generate a permeability curve with a reasonable porosity-permeability relationship. The permeability curve was generated utilizing the Coates permeability equation, incorporated with a 20% irreducible to match analysis provided by Nutech. Petrophysical analysis of the O'Neal No. 4 indicates an average porosity of 4.6%, a maximum porosity of 15%, an average permeability of 0.16 mD, and a maximum permeability of 3.3 mD. These curves have been extrapolated to the injection site and used to establish reservoir characteristics in the plume model.

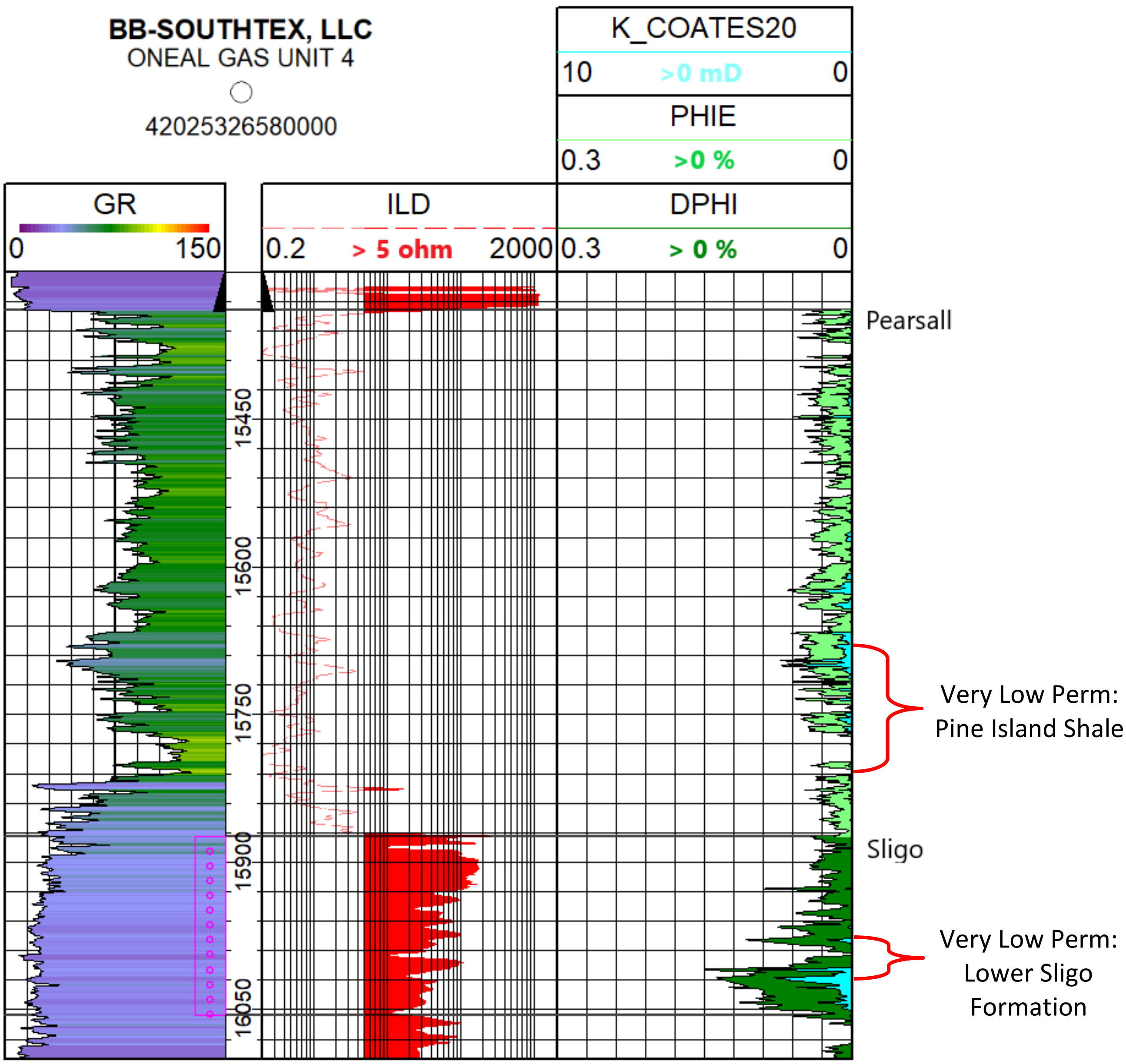

Figure 14 – Openhole log from O'Neal No. 4 (API No. 42-025-32658), with porosity curves shaded green >0%, permeability curve in blue >0 mD, and resistivity in red >5 ohms.

2.2.4 Formation Fluid

The USGS National Produced Waters Geochemical Database version 3.0 was reviewed for chemical analyses of Sligo oil-field brines within the state of Texas (Blondes et al., 2023). Only two samples were identified from the Sligo Formation: one located approximately 29 mi north-northeast in Karnes County and one located approximately 72 mi northeast in Gonzales County. The locations of these wells are shown in Figure 15 relative to the O'Neal No. 4. A summary of water chemistry analyses conducted on the two Texas Sligo oil-field brine samples is provided in Table 2 (page 25).

Averages from the samples were utilized for model assumptions due to the minimal Sligo sample availability and wide geographic spread of Sligo analysis. Total Dissolved Solids (TDS) of the samples contain a wide range of reported values but averaged 176,470 parts per million (ppm). Model sensitivities were established by running iterations with varying TDS values to understand the effect of brine concentrations on plume extents. The results suggested higher density brine values lead to smaller plumes; therefore, a value of 150,000 ppm was established in the model for a conservative approach. If the actual formation fluid sample that will be tested during the recompletion work produces a material difference in the plume, Ozona will submit an updated MRV plan.

Based on the results of the investigation, *in situ* Sligo reservoir fluid is anticipated to contain greater than 20,000 ppm TDS near the O'Neal No. 4, qualifying the aquifer as saline. These analyses indicate the *in situ* reservoir fluid of the Sligo Formation is compatible with the proposed injection fluids.

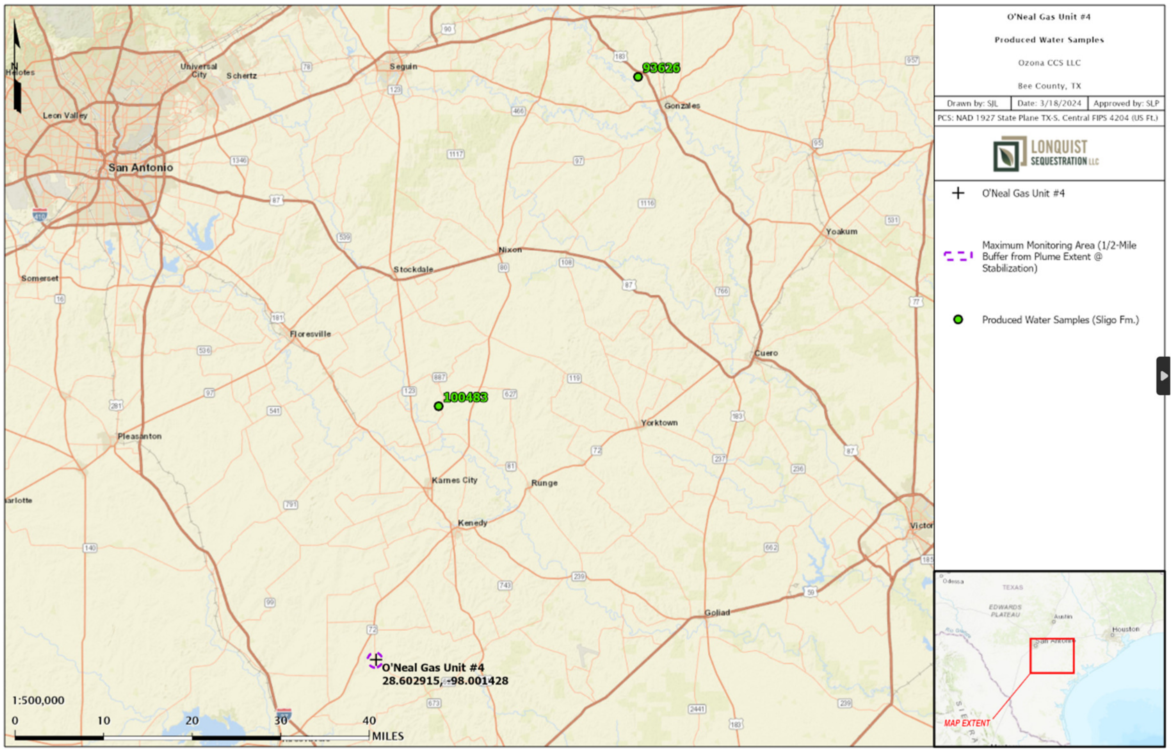

Figure 15 – Offset Wells Used for Formation Fluid Characterization

Table 2 – Analysis of Lower Cretaceous (Aptian) age formation fluids from the closest offset Sligo oil-field brine samples.

Measurement	Karnes County Sample	Gonzales County Sample	Average
Total Dissolved Solids (mg/L)	234,646	117,470	176,058
Sodium (mg/L)	51,168	27,909	39,539
Calcium (mg/L)	34,335	8,684	21,510
Chloride (mg/L)	146,500	57,811	102,156
Sample Depth (ft)	13,580 to 13,660	8,290-8,305	-
pH	5.9	8.2	7.05

2.2.5 Fracture Pressure Gradient

The fracture pressure gradient was obtained from an acid fracture report taken during the April 1993 completion of the Sligo interval in the O'Neal No. 4. The Sligo was perforated between the depths of 15,874 ft and 16,056 ft, with continuous monitoring during pumping of the acid job. The report noted a pressure break experienced at approximately 9,000 pounds per square inch (psi) and calculated a fracture gradient of 0.889 psi/ft based on an initial shut-in pressure (ISIP) of 7,275 psi. A 10% safety factor was then applied to the calculated gradient, resulting in a maximum allowed bottomhole pressure of 0.8 psi/ft. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

2.2.6 Lower Confining Interval – Lower Sligo and Hosston Formations

The O'Neal No. 4 reaches its total depth in the lower Sligo Formation, directly below the upper Sligo proposed injection interval. The lower Sligo is interpreted by Bebout and others (1981) to represent the seaward extension of the low-energy lagoon and tidal-flat system of the underlying Hosston Formation, a sequence of siliciclastics, evaporites, and dolomitic mudstone (Figure 16). The Hosston to lower Sligo "contact" represents a gradational package with a decrease in terrigenous sediments, an increase in carbonate sediments, and an increase in burrows of marine organisms working up-section into the lower Sligo. The lower Sligo consists of numerous cycles of subtidal to supratidal carbonates deposited in a low-energy lagoon and tidal-flat system (Bebout et al., 1981). These low permeability facies of the lower Sligo and underlying Hosston Formation will provide lower confinement to the upper Sligo injection interval. Figure 16 illustrates the typical environmental setting for the deposition of tidal flat facies along the Lower Cretaceous margin. The type log displayed in Figure 14 (*Section 2.2.3*) illustrates that the porosity of the lower Sligo ranges between 0–2% with permeability staying close to 0 mD. Therefore, the petrophysical characteristics of the lower Sligo and Hosston are ideal for prohibiting the migration of the injection stream outside of the injection interval.

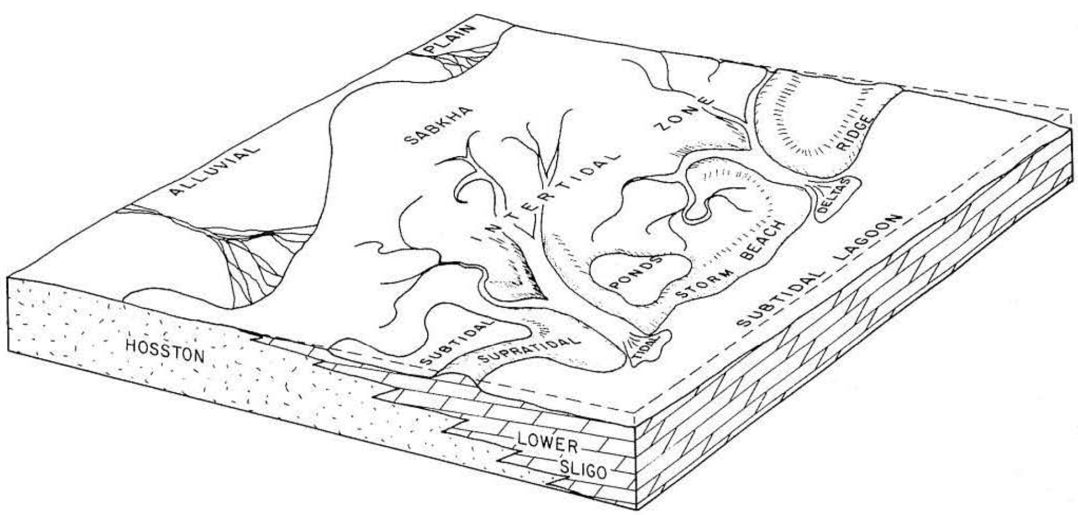

Figure 16 – Environmental Setting of Lower Cretaceous Tidal Flat Deposits (Bebout et al., 1981)

2.3 Local Structure

Structures surrounding the proposed sequestration site were influenced by regional arches, grabens, uplifts, embayments, movement of Louann Salt, and the development of carbonate reef complexes around the northern edge of the basin. However, one potential fault was identified in the literature within proximity and lies approximately 4.25 mi south-southeast of the well and approximately 3.9 mi south-southeast of the stabilized plume extent in the year 2062 (Swanson et al., 2016). The location of these structural features can be referenced in Figures 2 and 8 relative to the location of the O'Neal No. 4.

A subsea true vertical depth (SSTVD) structure map on the top of the Sligo Formation is provided in Figure 17. The map illustrates the gentle basinward dip of the Sligo from the northwest to the southeast. The structural cross sections provided in Figures 18 and 19 (pages 28 and 29, respectively) illustrate the structural changes encountered in moving away from the O'Neal No. 4 site. The figures also demonstrate the laterally continuous nature of the Pearsall Formation that overlies the injection interval, with sufficient thickness and modeled petrophysical properties to alleviate the risk of upward migration of injected fluids. *Section 2.1.2*, discussing regional structure and faulting, presents a regional discussion pertinent to this topic.

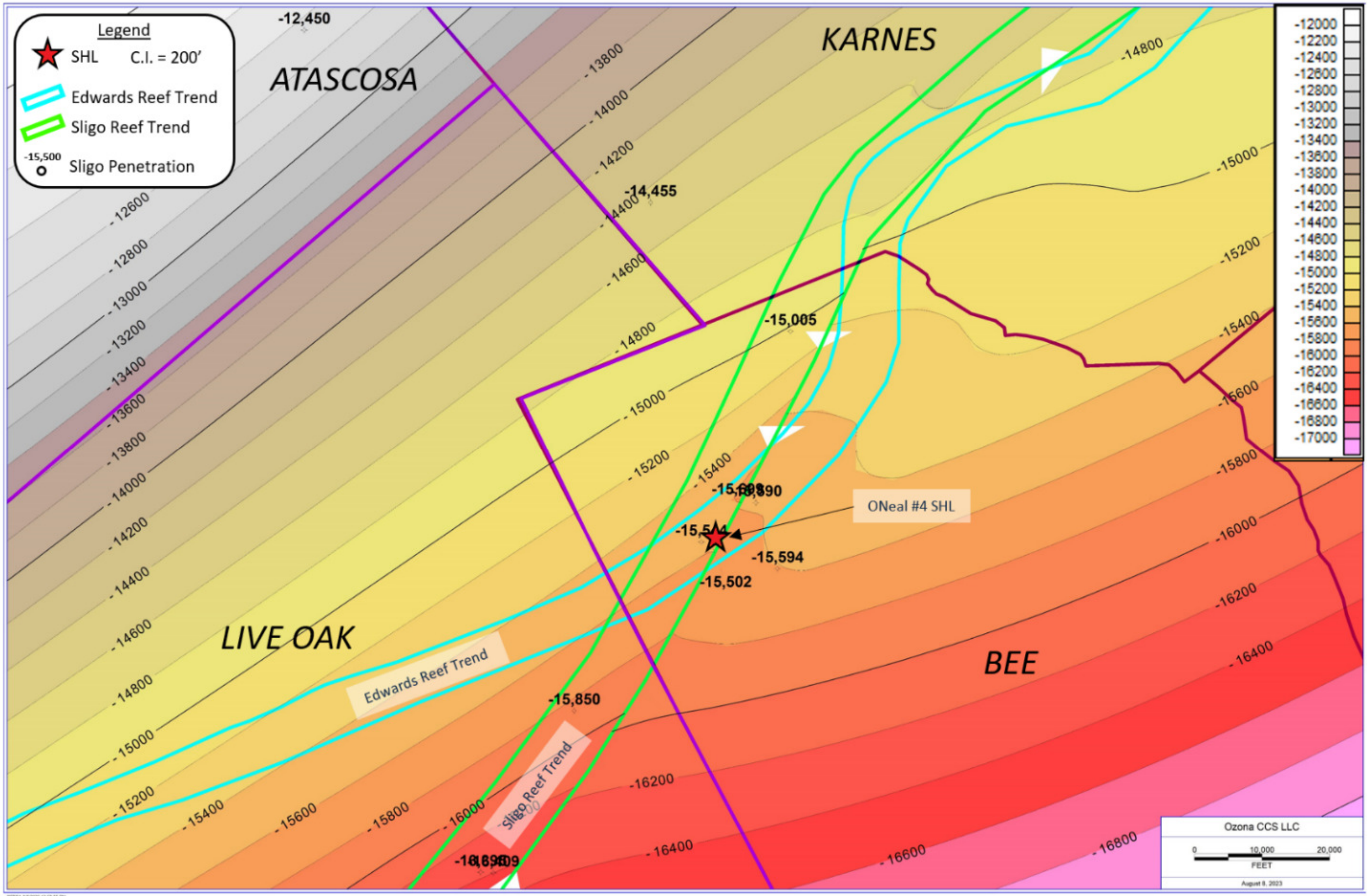

Figure 17 – Subsea Structure Map: Top of Sligo (injection interval). The red star signifies the location of the O'Neal No. 4.

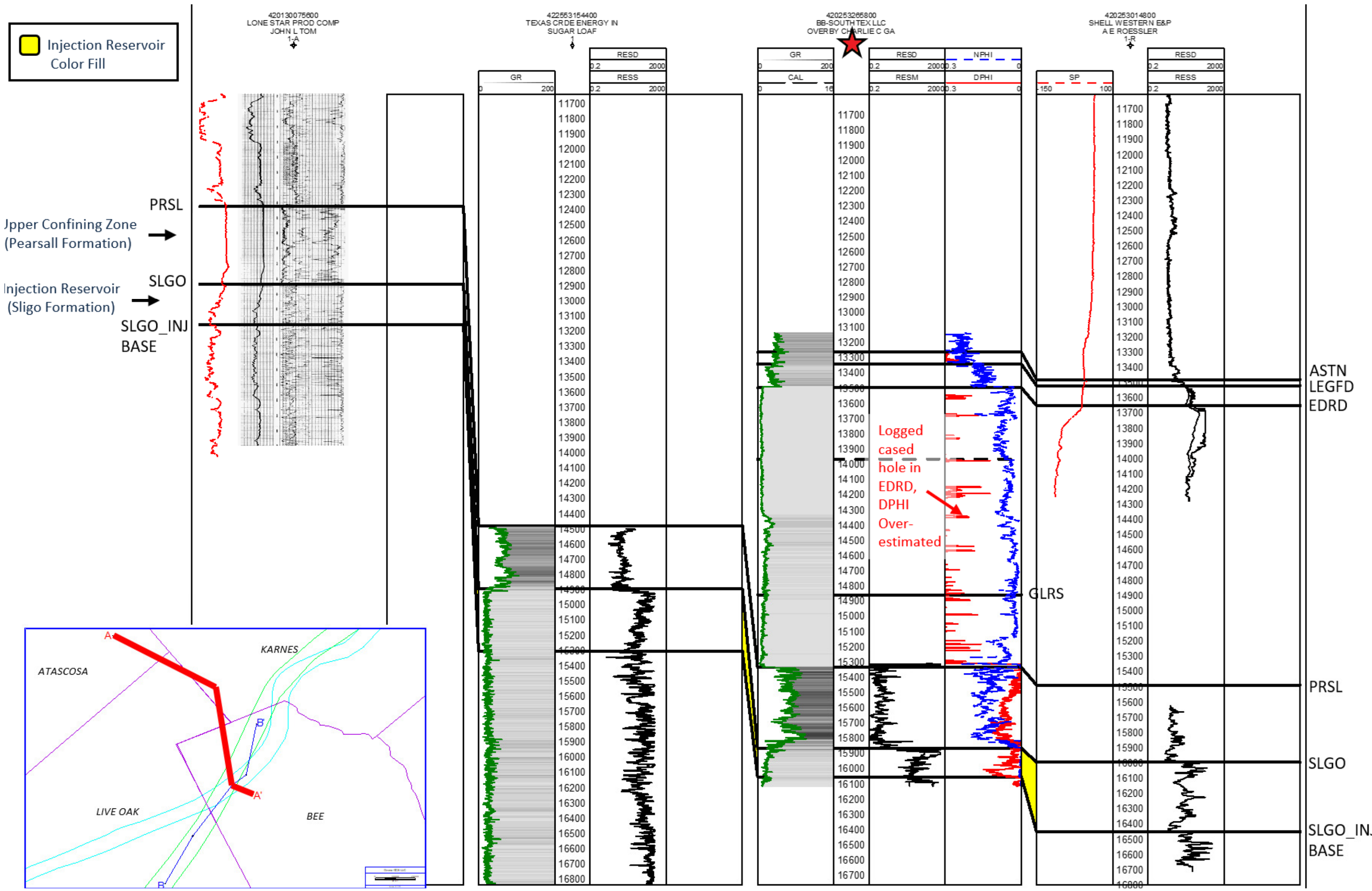

Figure 18 – Northwest to southeast structural cross section: A-A' Oriented along regional dip.
The red star signifies the location of the O'Neal No. 4, with the section line depicted in red on the locator map.

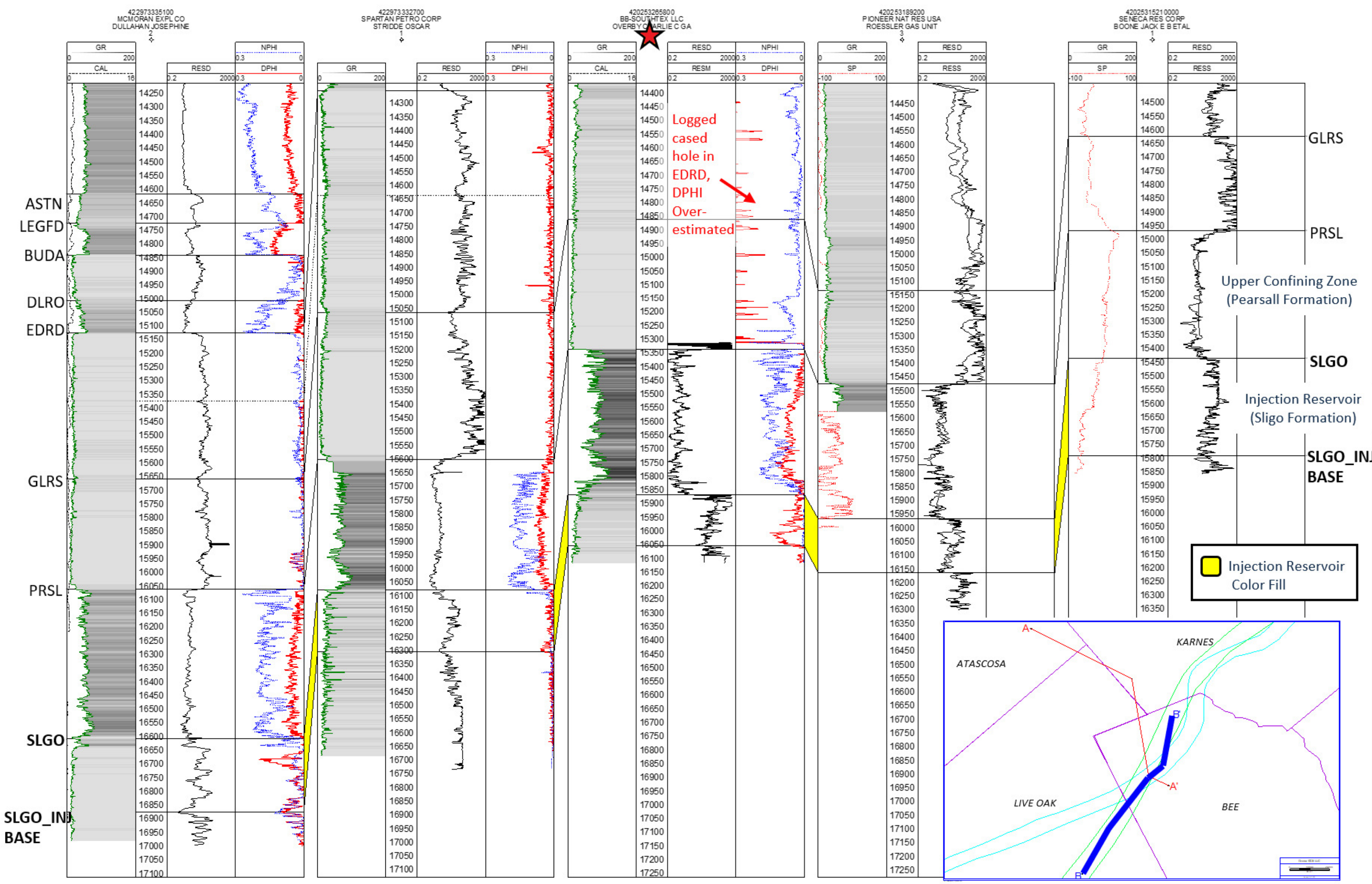

Figure 19 – Southwest to northeast structural cross section: B-B' oriented along regional strike.
The red star signifies the location of the O'Neal No. 4, with the section line depicted in blue on the locator map.

2.4 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Sligo Formation at the O'Neal No. 4 well location indicate that the reservoir contains the necessary thickness, porosity, and permeability to receive the proposed injection stream. The overlying Pearsall Formation is regionally extensive at the O'Neal No. 4 with low permeability and sufficient thickness to serve as the upper confining interval. Beneath the injection interval, the low permeability, low porosity facies tidal flat, and lagoonal facies of the lower Sligo and underlying Hosston Formation are unsuitable for fluid migration and serve as the lower confining interval.

2.5 Groundwater Hydrology

Bee County falls within the boundary of the Bee Groundwater Conservation District. Only one aquifer is identified by the Texas Water Development Board's Texas Aquifers Study near the O'Neal No. 4 well location, the unconfined to semi-confined Gulf Coast aquifer. The Gulf Coast aquifer parallels the Gulf of Mexico and extends across the state of Texas from the Mexican border to the border of Louisiana (Bruun et al., 2016). The extents of the Gulf Coast aquifer are provided in Figure 20 for reference.

The Gulf Coast aquifer is a major aquifer system comprised of several individual aquifers: the Jasper, Evangeline, and Chicot. These aquifers are composed of discontinuous clay, silt, sand, and gravel beds that range from Miocene to Holocene in age (Figure 21, page 32). Numerous interbedded lenses and layers of silt and clay are present within the aquifers, which can confine individual aquifers locally. The underlying Oligocene Catahoula tuff represents the lower confining interval, but it should be noted that the formation is prone to leaking along the base of the aquifer. However, the Burkeville confining interval provides isolation between Jasper and Evangeline aquifers which helps protect the shallower Evangeline and Chicot Aquifers (Bruun et al., 2016).

The schematic cross section provided in Figure 22 (page 32) runs south of the O'Neal No. 4, illustrating the structure and stratigraphy of the aquifer system. The thickness of individual sedimentary units within the Cenozoic section tends to thicken towards the Gulf of Mexico due to the presence of growth faults that allow additional loading of unconsolidated sediment. The total net sand thickness of the aquifer system ranges between 700 ft of sand in the south, to over 1,300 ft in the north, with the saturated freshwater thickness averaging 1,000 ft.

The water quality of the aquifer system varies with depth and locality but water quality generally improves towards the central to northeastern portions of the aquifer where TDS values are less than 500 milligrams per liter (mg/L). The salinity of the Gulf Coast aquifer increases to the south, where TDS ranges between 1,000 mg/L to more than 10,000 mg/L. The Texas Water Development Board's Texas Aquifers Study (2016) suggests that areas associated with higher salinities are possibly associated with saltwater intrusion likely "resulting from groundwater pumping or to brine migration in response to oil field operations and natural flows from salt domes intruding into the aquifer" (Bruun et al., 2016).

According to the TDS map of the Gulf Coast aquifer (Figure 23), the TDS in northern Bee County range between 500–3,000 mg/L near the O'Neal No. 4, categorizing the aquifer as fresh to slightly saline.

The TRRC's Groundwater Advisory Unit (GAU) identified the Base of Useable Quality water (BUQW) at a depth of 250 ft and the base of the USDW at a depth of 950 ft at the location of the O'Neal No. 4. Approximately 14,924 ft is therefore separating the base of the USDW and the injection interval. (A copy of the GAU's Groundwater Protection Determination letter issued by the TRRC as part of the Class II permitting process for the O'Neal No. 4 is provided in Exhibit A-1.) The base of the deepest aquifer is separated from the injection interval by more than 14,924 ft of rock, including 4,200 feet of Midway shale. Though unlikely for reasons outlined in the sections here on confinement and potential leaks, if the migration of injected fluid did occur above the Pearsall Formation, thousands of feet of tight sandstone, limestone, shale, and anhydrite beds occur between the injection interval and the lowest water-bearing aquifer.

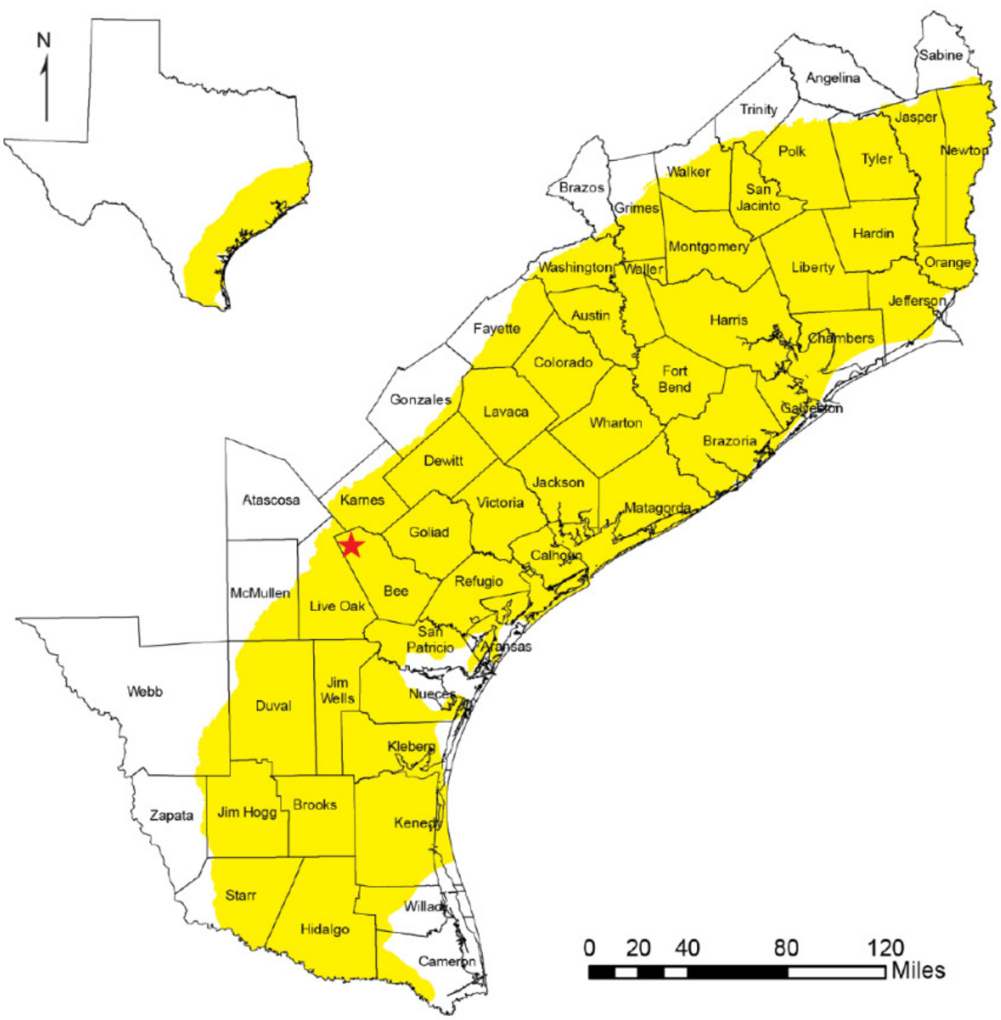

Figure 20 – Extent of the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun, B., et al., 2016)

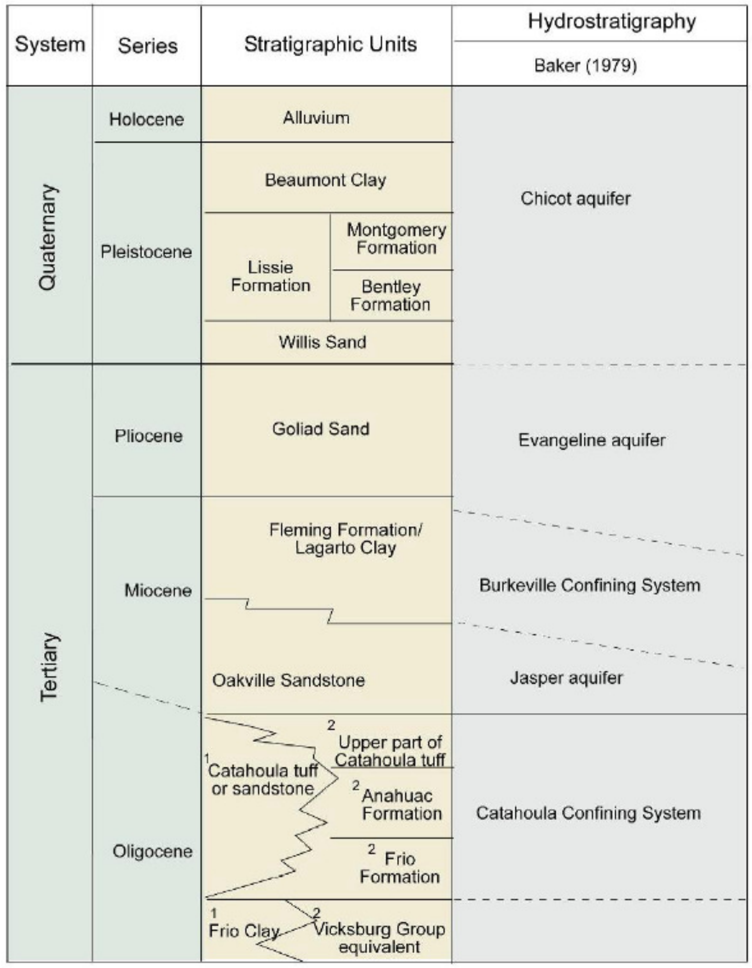

Figure 21 – Stratigraphic Column of the Gulf Coast Aquifer (Chowdhury and Turco, 2006)

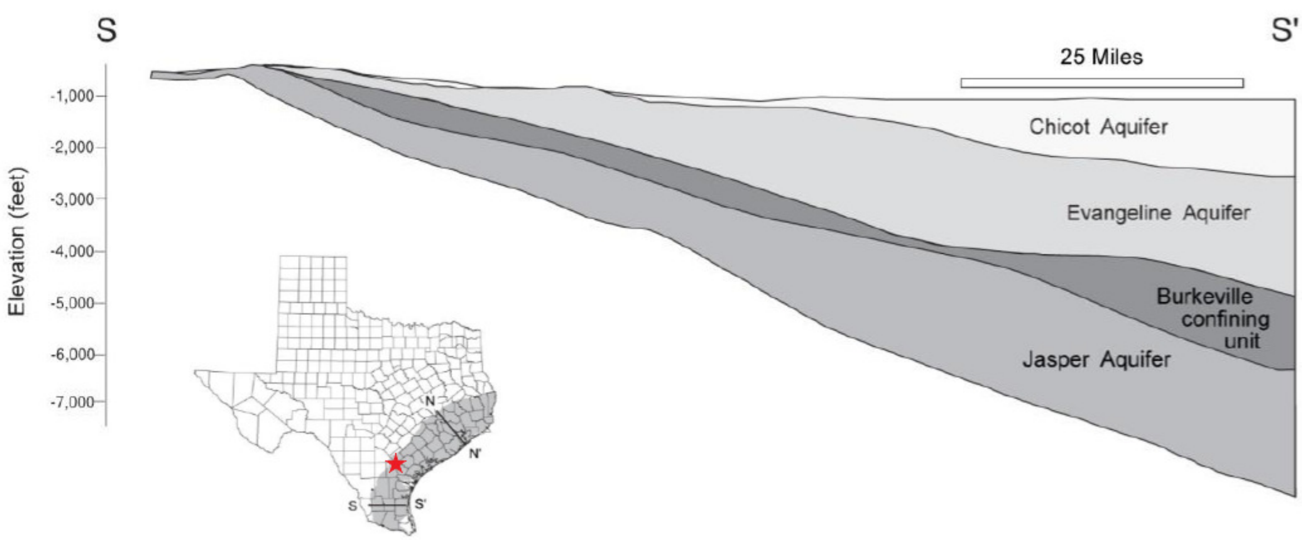

Figure 22 – Cross Section S-S' Across the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun et al., 2016)

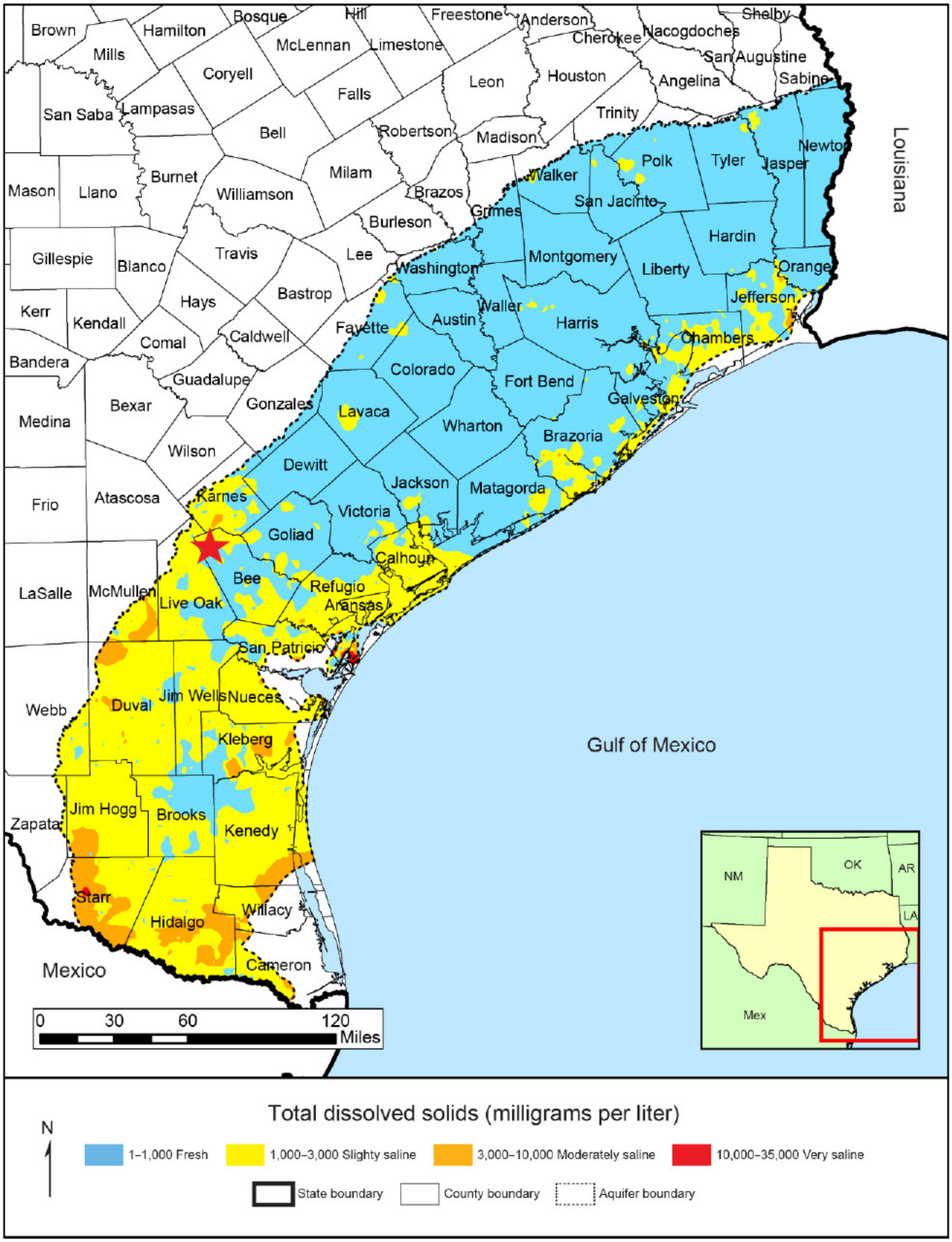

Figure 23 – Total Dissolved Solids (TDS) in the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun et al., 2016).

2.6 References

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2.7 Description of the Injection Process

2.7.1 Current Operations

The Pawnee Gas Plant and the O'Neal No. 4 are existing operating assets. The O'Neal No. 4 will be recompleted for acid gas injection service under the Class II permit process. Under the Class II application, the maximum injection rate is 28 MT/yr (1.5 MMscf/d). The TAG is 98.2% CO_2, which equates to 27.5 MT/yr of CO_2 each year. The current composition of the TAG stream is displayed in Table 3:

Table 3 – Gas Composition

Component	Mol Percent
Carbon Dioxide	98.2%
Hydrocarbons	1.03%
Hydrogen Sulfide	0.4%
Nitrogen	0.37%

The plant is designed to treat, dehydrate, and compress the natural gas produced from the surrounding acreage in Bee County. The plant uses an amine unit to remove the CO_2 and other constituents from the gas stream. The TAG stream is then dehydrated, compressed, and routed directly to the O'Neal No. 4 for injection. The remaining gas stream is processed to separate the natural gas liquids from the natural gas. The plant is monitored 24 hours per day, 7 days per week.

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group, Ltd.'s GEM 2023.2 (GEM) simulator, one of the most comprehensive reservoir simulation software packages for conventional, unconventional, and secondary recovery. The GEM utilizes equation-of-state (EOS) algorithms in conjunction with some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics. This results in the creation of exceedingly precise and dependable simulation models for carbon injection and storage. The GEM model holds recognition from the EPA for its application in the delineation modeling aspect of the area of review, as outlined in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Sligo Formation serves as the target formation for the O'Neal No. 4 (API No. 42-025-32658). The Petra software package was utilized to construct the geological model for this target formation. Within Petra, formation top contours were generated and subsequently brought into GEM to outline the geological structure.

Porosity and permeability estimates were determined using the porosity log from the O'Neal No. 4. A petrophysical analysis was then conducted to establish a correlation between porosity values and permeability, employing the Coates equation. Both the porosity and permeability estimates from the O'Neal No. 4 were incorporated into the model, with the assumption that they exhibit lateral homogeneity throughout the reservoir.

The reservoir is assumed to be at hydrostatic equilibrium. Given the geological formation in which this well is located and its previous history as a gas producer, the model is assumed to be primarily saturated with gas. More precisely, the reservoir is assumed to be 80% gas saturated and 20% brine saturated, as deduced from the well log data. The modeled injection interval exhibits an average permeability of 0.23 mD and an average porosity of 5%. All layers within the model have been perforated. An infinite-acting reservoir has been created to simulate the boundary conditions.

The gas injectate is composed predominantly of CO_2 as shown in Table 4. The modeled composition takes into consideration the carbon dioxide and other constituents of the total stream. As the plant has been in operation for many years, the gas composition for the proposed injection period is expected to remain constant.

Table 4 – Modeled Injectate Composition

Component	**Expected Composition (mol %)**	**Modeled Composition (mol %)**
Carbon Dioxide (CO_2)	98.2	98.2
Hydrocarbons	1.03%	Hydrocarbons
Hydrogen Sulfide	0.4%	Hydrogen Sulfide
Nitrogen	0.37%	Nitrogen

Core data from the literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Sligo carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 1.8, a Corey exponent for gas of 2.5, gas permeability at irreducible brine saturation of 50%, irreducible water saturation of 20%, and a maximum residual gas saturation of 35%. The relative permeability curves used for the GEM model are shown in Figure 24.

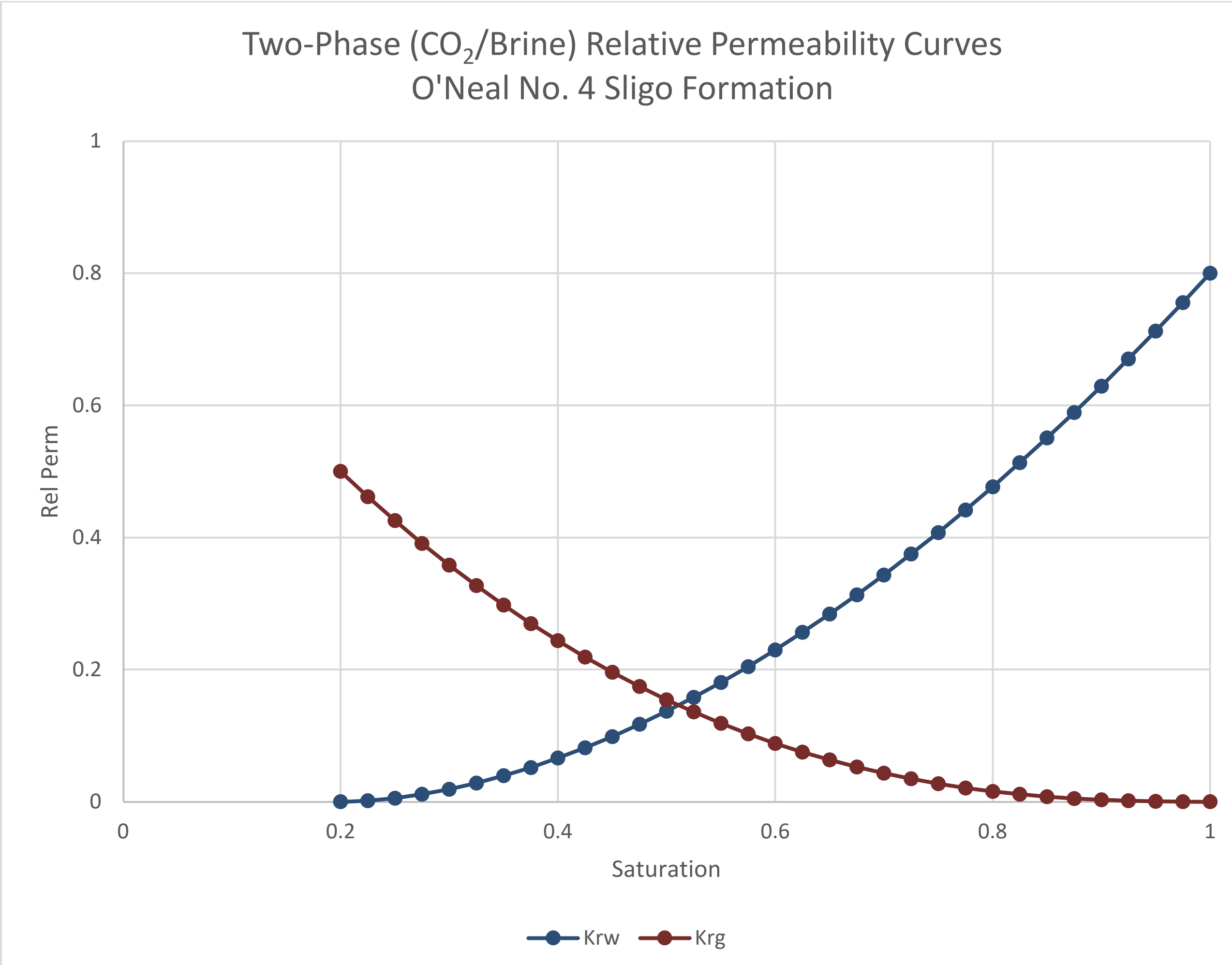


Figure 24 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 81 blocks in the x-direction (east-west) and 81 blocks in the y-direction (north-south), resulting in a total of 6,561 grid blocks per layer. Each grid block spans dimensions of 250 ft x 250 ft. This configuration yields a grid size measuring 20,250 ft x 20,250 ft, equating to just under 15 square miles in area. The grid cells in the vicinity of the O'Neal No. 4, within a radius of 0.5 mi, have been refined to dimensions of 83.333 ft x 83.333 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume and pressure effects near the wellbore.

In the model, each layer is characterized by homogeneous permeability and porosity values. These values are derived from the porosity log of the O'Neal No. 4. The model encompasses a total of 61 layers, each featuring a thickness of approximately 3 ft per layer. As previously mentioned, the model is perforated in each layer, with the top layer being the top of the injection interval and the bottom layer being the lowest portion of the injection interval. The summarized property values for each of these packages are displayed in Table 5.

Table 5 – GEM Model Layer Package Properties

Layer #	Top (TVD ft)	Thickness	Perm. (mD)	Porosity (%)
1	15,874	3	0.004	3.75%
2	15,877	3	0.002	2.98%
3	15,880	3	0.001	1.62%
4	15,883	3	0.001	1.78%
5	15,886	3	0.002	2.32%
6	15,889	3	0.001	1.96%
7	15,892	3	0.002	3.10%
8	15,895	3	0.002	2.99%
9	15,898	3	0.003	3.52%
10	15,901	3	0.006	4.00%
11	15,904	3	0.005	3.93%
12	15,907	3	0.001	2.15%
13	15,910	3	0.001	1.99%
14	15,913	3	0.002	2.97%
15	15,916	3	0.001	2.22%
16	15,919	3	0.002	2.88%
17	15,922	3	0.001	2.38%
18	15,925	3	0.093	6.68%
19	15,928	3	0.005	2.62%
20	15,931	3	0.002	2.58%
21	15,934	3	0.003	3.07%
22	15,937	3	0.006	3.62%
23	15,940	3	0.002	2.68%
24	15,943	3	0.001	1.08%
25	15,946	3	0.002	1.87%
26	15,949	3	0.025	4.70%
27	15,952	3	0.024	4.37%
28	15,955	3	0.001	1.97%
29	15,958	3	0.003	2.27%
30	15,961	3	0.007	3.09%
31	15,964	3	0.110	6.75%
32	15,967	3	0.037	5.62%
33	15,970	3	0.011	4.41%
34	15,973	3	0.022	4.59%
35	15,976	3	0.297	7.88%
36	15,979	3	0.440	9.21%
37	15,982	3	0.060	5.90%
38	15,985	3	0.001	2.22%

39	15,988	3	0.001	2.21%
40	15,991	3	0.001	1.12%
41	15,994	3	0.003	2.05%
42	15,997	3	0.014	4.56%
43	16,000	3	0.007	4.15%
44	16,003	3	0.033	5.95%
45	16,006	3	1.233	10.25%
46	16,009	3	1.476	12.04%
47	16,012	3	0.566	10.08%
48	16,015	3	1.679	12.18%
49	16,018	3	2.194	13.08%
50	16,021	3	1.235	12.02%
51	16,024	3	0.788	11.22%
52	16,027	3	0.944	10.48%
53	16,030	3	0.424	9.05%
54	16,033	3	0.378	8.85%
55	16,036	3	0.378	8.81%
56	16,039	3	0.378	8.84%
57	16,042	3	0.736	9.91%
58	16,045	3	0.232	7.94%
59	16,048	3	0.238	7.97%
60	16,051	3	0.012	3.01%
61	16,054	3	0.038	4.30%

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

1. Estimate the maximum areal extent and density drift of the injectate plume after injection.
2. Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone.
3. Assess the likelihood of the injectate plume migrating into potential leak pathways.

The reservoir is assumed to have an irreducible brine saturation of 20%. The salinity of the brine within the formation is estimated to be 150,000 ppm (USGS National Produced Waters Geochemical Database, Ver. 2.3), typical for the region and formation. The injectate stream is primarily composed of CO_2 and H_2S as stated previously. Core data from the literature was used to help generate relative permeability curves. From the literature review, also as previously discussed, cores that most closely represent the carbonate rock formation of the Sligo seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low, conservative residual gas saturation based on the cores from the literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975).

The model is initialized with a reference pressure of 10,995 psig at a subsea depth of 15,740 ft. This, when a Kelly Bushing "KB" elevation of 334 ft is considered, correlates to a gradient of 0.684 psi/ft. This pressure gradient was determined from production data of the O'Neal No. 4. An initial reservoir pressure of 0.76 psi/ft was calculated before initial production. However, in 1997, after producing approximately 0.5 billion cubic feet (Bcf) of gas, the well was shut in. The last bottomhole pressure reading was calculated to be 0.480 psi/ft. This assumes the reservoir repressurizes after production ceases, but not fully back to in situ conditions. Therefore, a 10% safety factor was given to the initial reservoir pressure gradient of 0.76 psi/ft, and a gradient of 0.684 psi/ft was implemented into the model as a conservative estimate. A skin factor of -2 was applied to the well to simulate the stimulation of the O'Neal No. 4 for gas production from the Sligo Formation, which is based on the acid fracture report, provided in *Appendix A-3*.

The fracture gradient of the injection zone was estimated to be 0.954 psi/ft, which was determined from the acid fracture report. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.86 psi/ft, which is equivalent to 13,652 psig at the top of the Sligo injection interval.

The model, which begins in January 2025, runs for a total of 22 years, comprising 12 years of active injection, and is then succeeded by 10 years of density drift. Throughout the entire 12-year injection period, an injection rate of 1.5 MMscf/D is used to model the maximum available rate, yielding the largest estimate of the plume size. After the 12-year injection period, when the O'Neal No. 4 ceases injection, the density drift of the plume continues until the plume stabilizes 10 years later. The maximum plume extent during the 12-year injection period is shown in Figure 25. The final extent after 10 years of density drift after injection ceases is shown in Figure 26 (page 42).

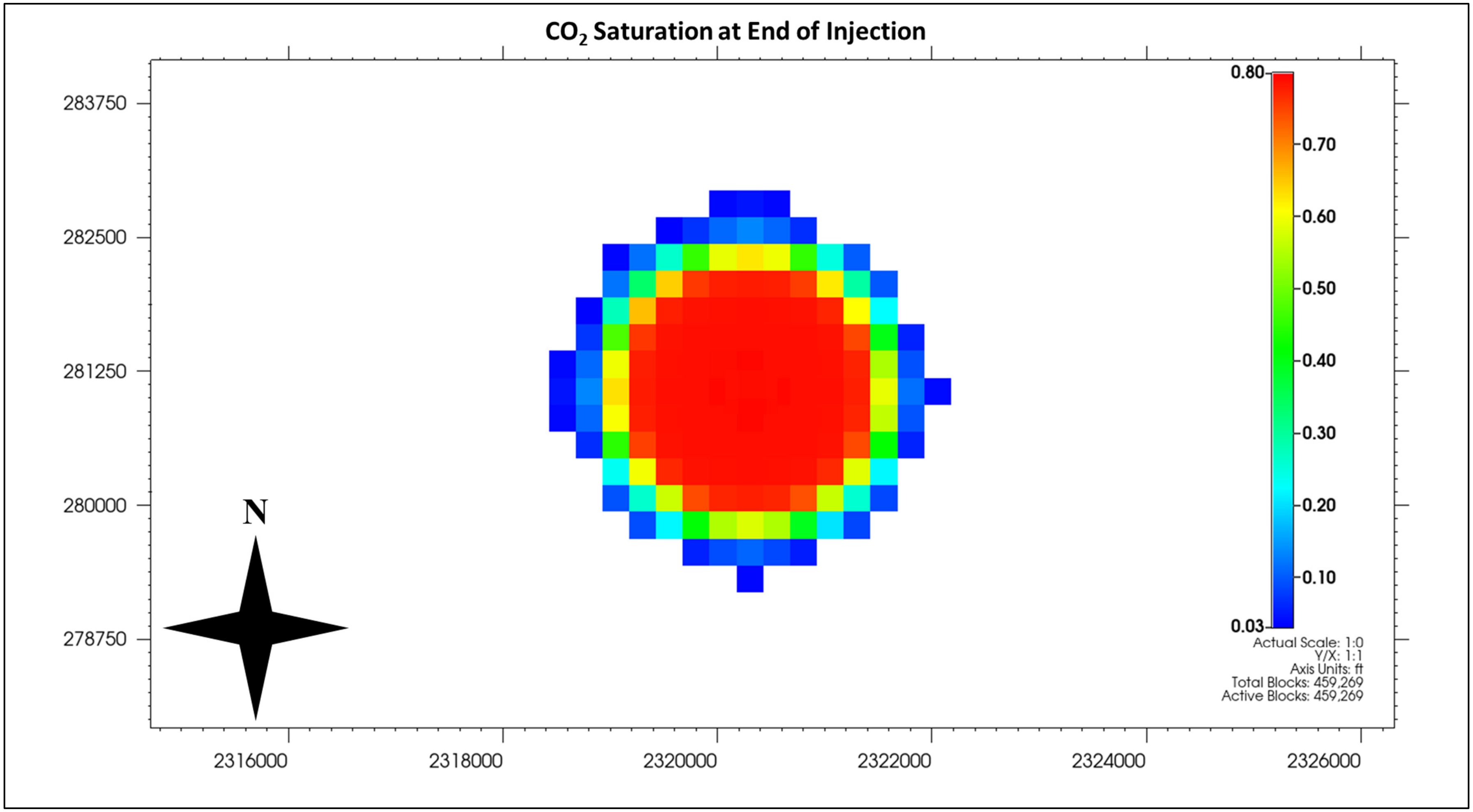


Figure 25 – Areal View of Saturation Plume at Shut-in (End of Injection)

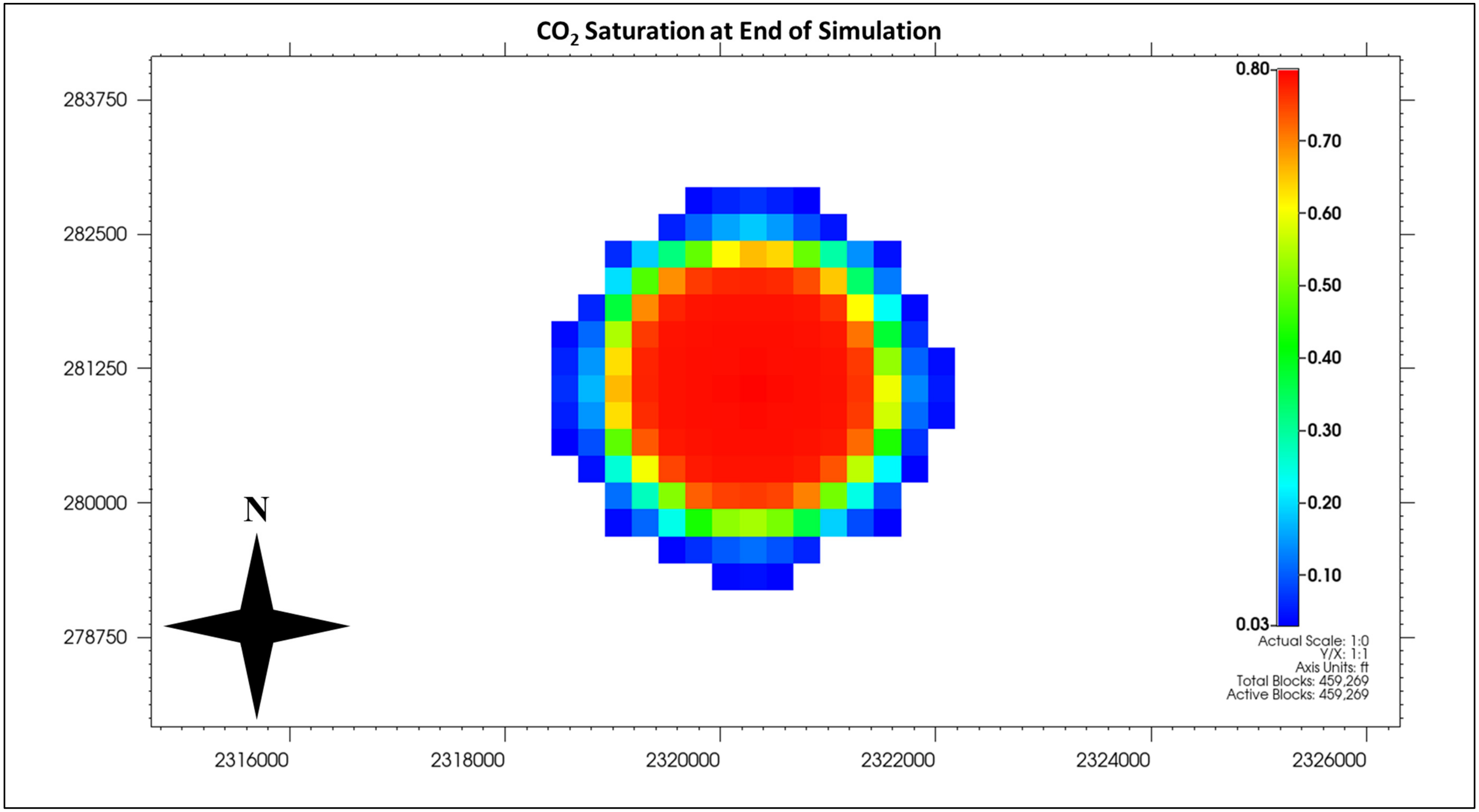


Figure 26 – Areal View of Gas Saturation Plume 10 Years After Shut-in (End of Simulation)

The cross-sectional view of the O'Neal No. 4 shows the extent of the plume from a side-view angle, cutting through the formation at the wellbore. Figure 27 shows the maximum plume extent during the 12-year injection period. During this time, gas from the injection well is injected into the permeable layers of the formation and predominantly travels laterally. Figure 28 (page 45) shows the final extent of the plume after 10 years of migration. Then, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 35% of injected gas that travels into each grid cell is trapped, as the gas travels mostly vertically—as it is less dense than the formation brine—until an impermeable layer is reached. Both figures are shown in an east-to-west view.

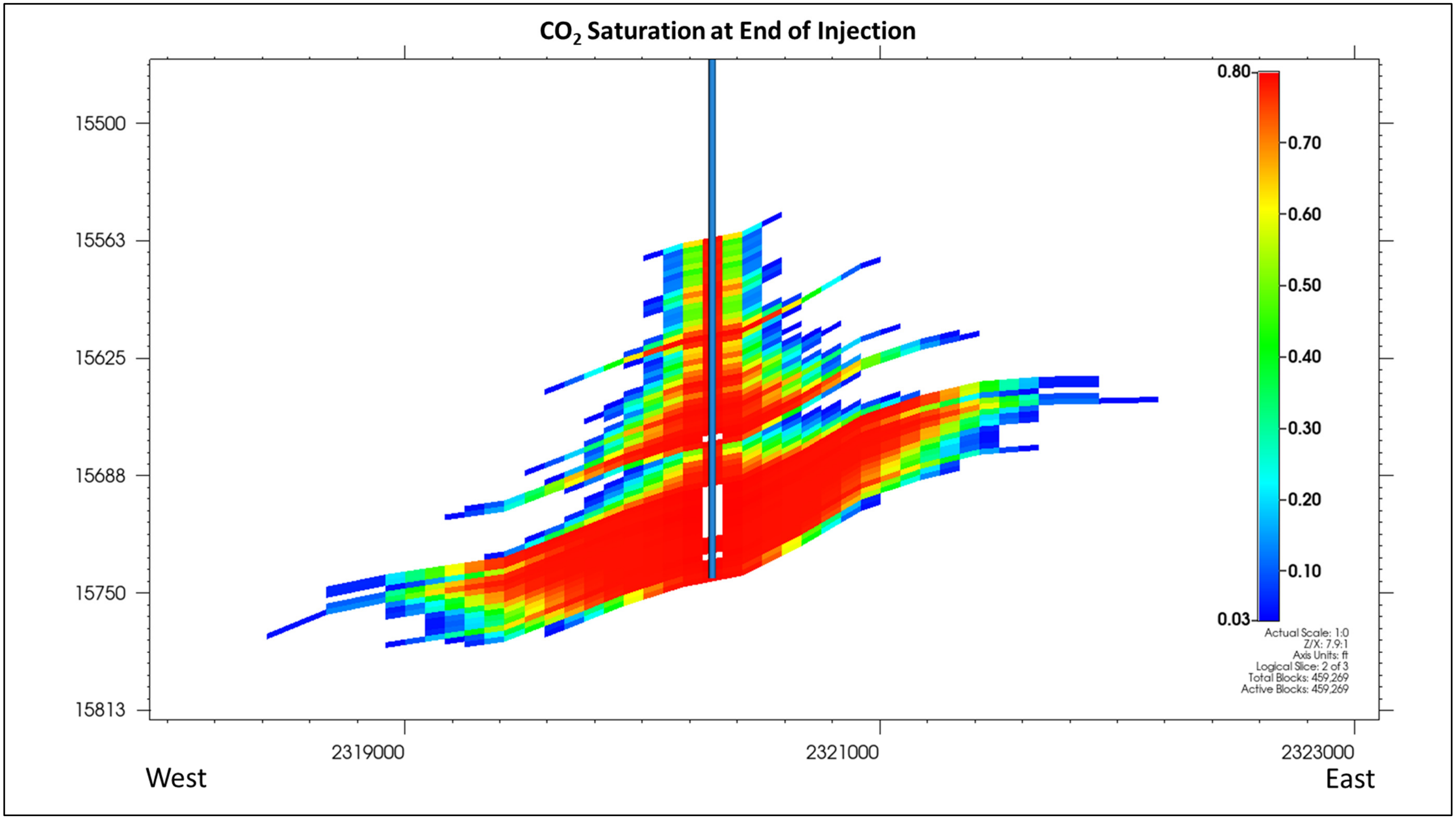


Figure 27 – East-West Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)

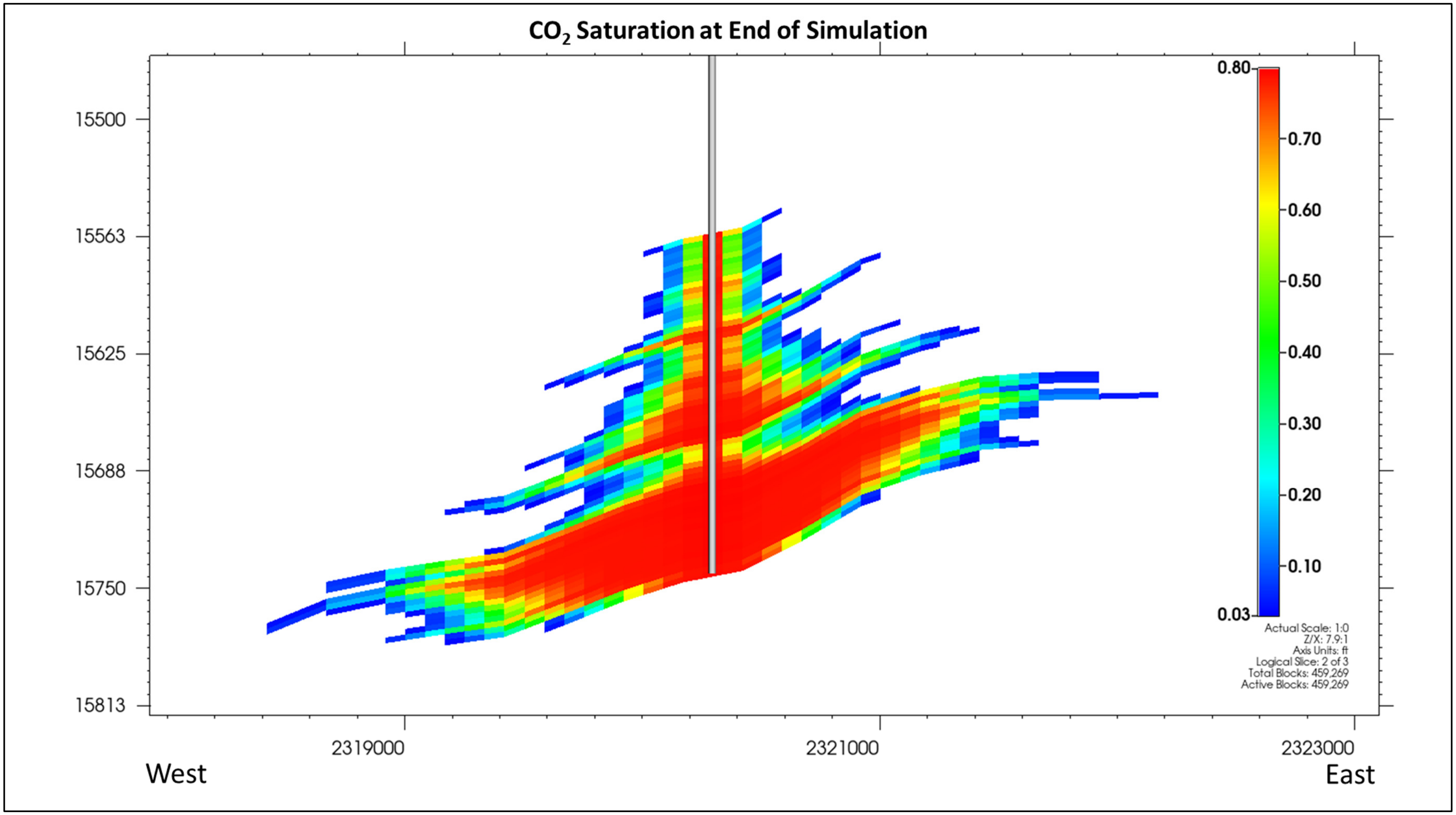


Figure 28 –East-West Cross-Sectional View of Gas Saturation Plume 10 Years After Shut-in (End of Simulation)

Figure 29 shows the surface injection rate, bottom hole pressures, and surface pressures over the injection period—and the period of density drift after injection ceases. The bottomhole pressure increases the most as the injection rate ends, reaching a maximum pressure of 13,337 psig, at the end of injection. This buildup of 2,362 psig keeps the bottomhole pressure below the fracture pressure of 13,652 psig. The maximum surface pressure associated with the maximum bottomhole pressure reached is 6,095 psig, well below the maximum allowable 7,937 psig per the TRRC UIC permit application for this well. Bottomhole and wellhead pressures are provided in Table 6.

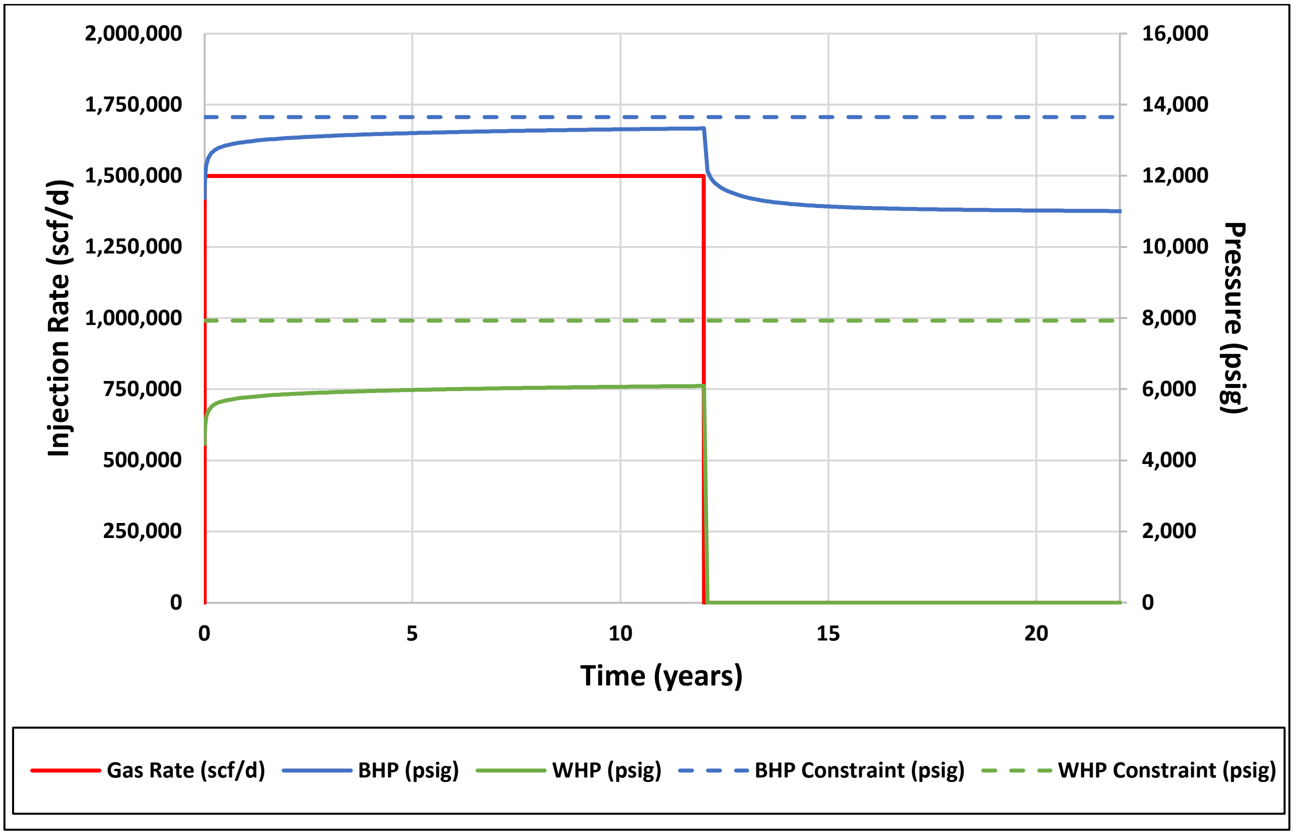


Figure 29 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 6 – Bottomhole and Wellhead Pressures from the Start of Injection

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	10,975	-
10	13,311	6,073
12 (End of Inj.)	13,337	6,095
20	11,029	-
22 (End of Model)	11,013	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in 40 CFR **§98.448(a)(1)**.

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the plume has stabilized, plus an all-around buffer zone of at least one half mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

- Offset well logs to estimate geologic properties
- Petrophysical analysis to calculate the heterogeneity of the rock
- Geological interpretations to determine faulting and geologic structure
- Offset injection history to predict the density drift of the plume adequately

Ozona's expected gas composition was used in the model. The injectate is estimated at a molar composition of 98.2% CO_2 and 1.8% of other constituents. The StarTex Plant has been in stable operations for many years. Ozona believes the gas analysis provided in Table 1 is an accurate representation of the injectate. In the future, if the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be submitted to the GHGRP. As discussed in *Section 2*, the gas will be injected into the Sligo Formation. The geomodel was created based on the rock properties of the Sligo.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 12, the area expanse of the plume will be approximately 270 acres. The maximum distance between the wellbore and the edge of the plume is approximately 0.42 mi to the west. After 10 additional years of density drift, the areal extent of the plume is 303 acres with a maximum distance to the edge of the plume of approximately 0.45 mi to the west. Since the plume shape is relatively circular, the maximum distance from the injection well after density drift was used to define the circular boundary of the MMA. The AMA and the MMA have similar areas of influence, with the AMA being only marginally smaller than the MMA. Therefore, Ozona will set the AMA equal to the MMA as the basis for the area extent of the monitoring program.

This is shown in Figure 30 with the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA boundary represents the stabilized plume boundary after 10 years of density drift plus an all-around buffer zone of one half mile.

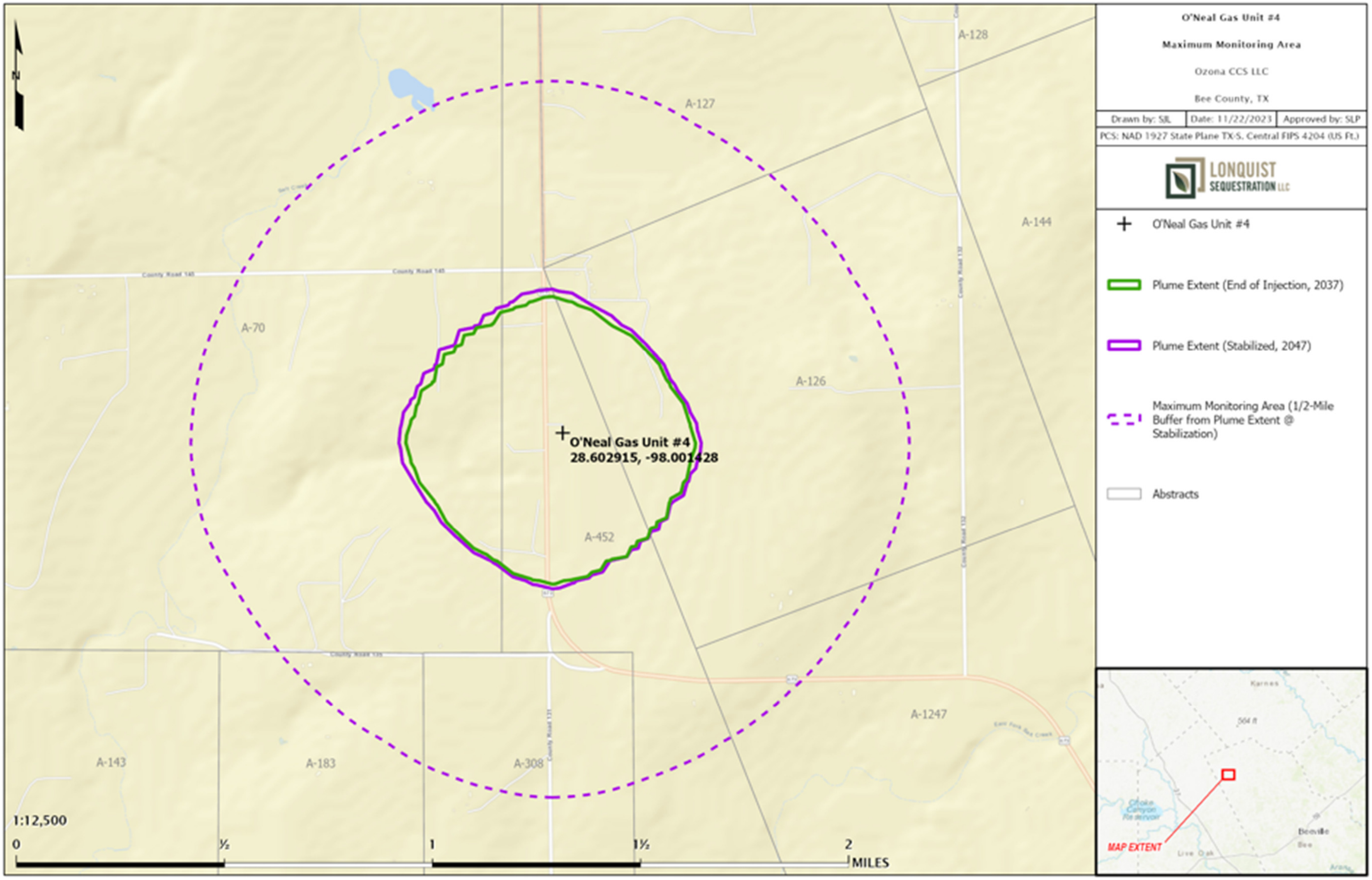


Figure 30 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The AMA was initially set equal to the expected total injection period of 12-years. The AMA was analyzed by superimposing the area based on a one-half mile buffer around the anticipated plume location after 12 years of injection (2037), with the area of the projected free-phase CO_2 plume at five additional years (2042). In this case, as shown in Figure 31, the plume boundary in 2042 is within the plume in 2037 plus the one-half mile buffer. Since the AMA boundary is only slightly smaller than the MMA boundary, Ozona will define the AMA to be equal to the MMA. By 2037, Ozona will submit a revised MRV plan to provide an updated AMA and MMA.

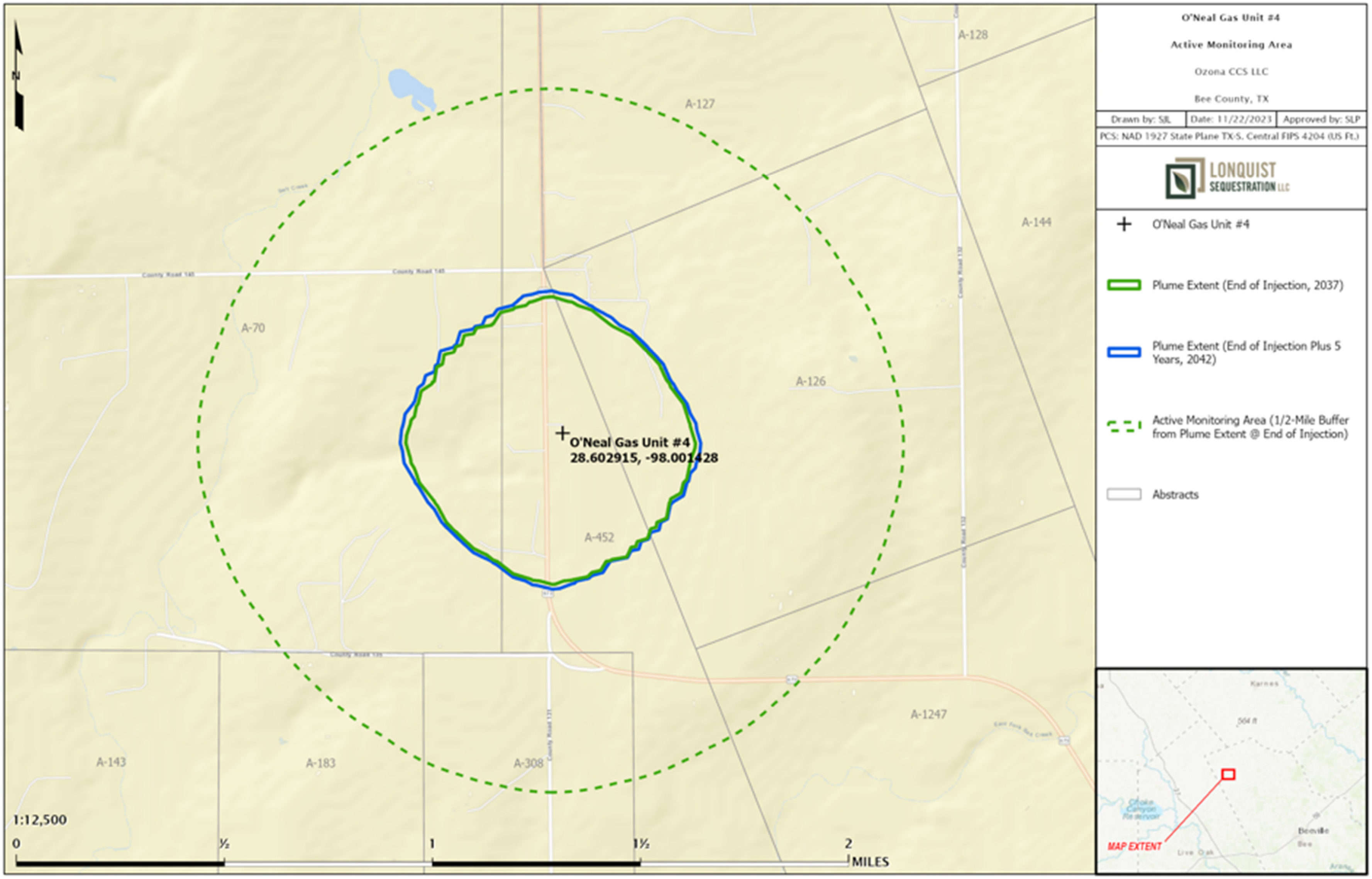


Figure 31 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies and discusses the potential pathways within the MMA for CO_2 to reach the surface and is summarized in Table 7. Also included are the likelihood, magnitude, and timing of such potential leakage. The potential leakage pathways are:

- Surface equipment
- Existing wells within the MMA
- Faults and fractures
- Upper confining layer
- Natural or induced seismicity

Table 7 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. One artificial penetration was drilled into the injection interval. This well has been plugged and abandoned.	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection and post Injection site care[2] period.
Faults and fractures	Possible. The lateral continuity of UCZ[1] is recognized as a very competent seal.	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection and post Injection site care[2] period.
Upper confining layer	Unlikely. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection and post Injection site care[2] period.
Natural or induced seismicity	Possible. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration of CO_2 would likely enter a shallower hydrocarbon production zone.	During active injection and post Injection site care[2] period.

1 - UCZ is defined as the upper confining zone.

2 - Post injection site care is the period of time from the end of injection throught plume stabilization and site closure.

Magnitude Assessment Description
Low - catergorized as little to no impact to safety, health and the environment and the costs to mitigate are minimal.
Medium - potential risks to the USDW and for surface releases does exist, but circumstances can be easily remediated.
High - danger to the USDW and significant surface release may exist, and if occurs this would require significant costs to remediate.

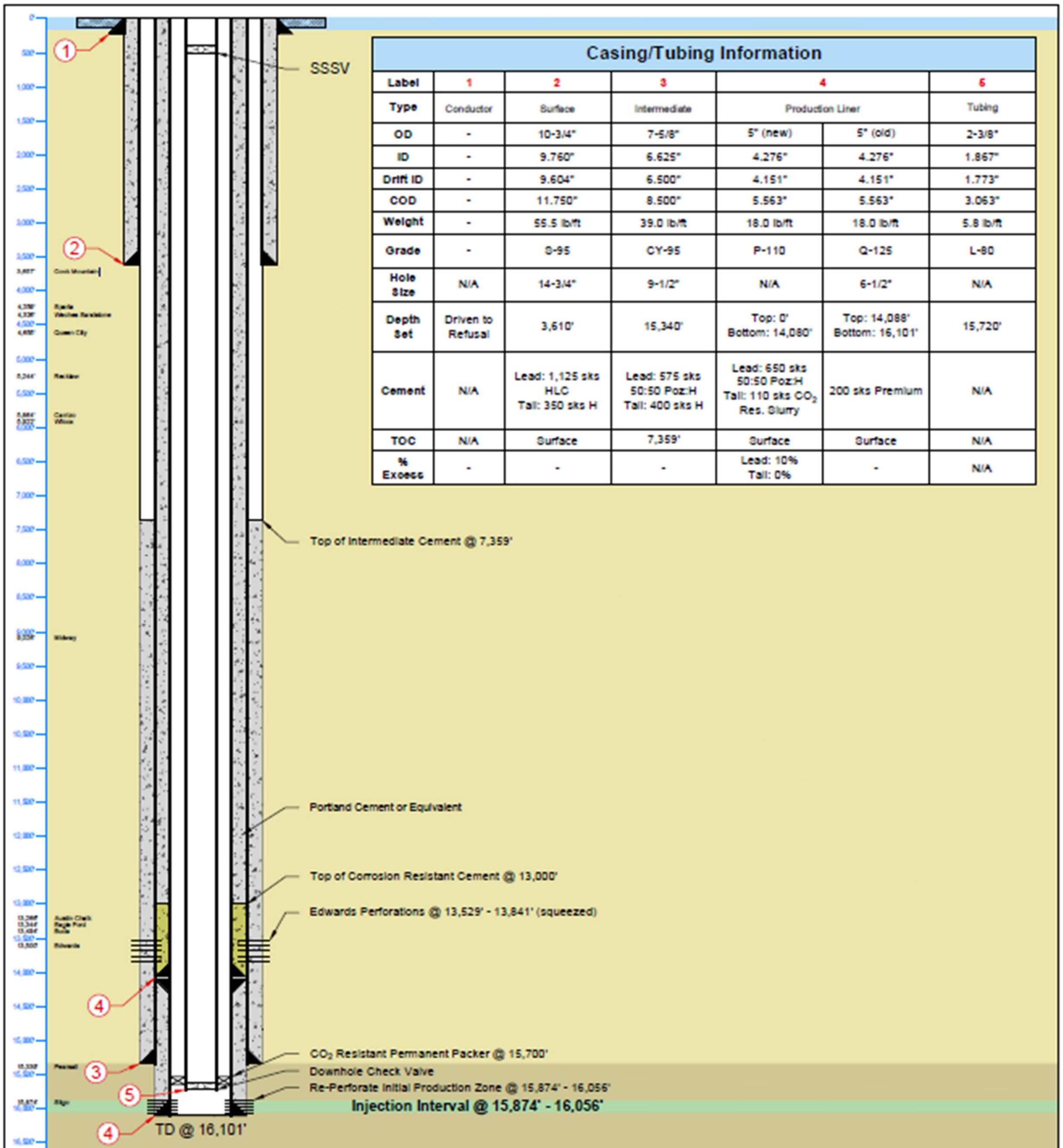
4.1 Leakage from Surface Equipment

The Pawnee Gas Plant and O'Neal No. 4 are designed for separating, transporting, and injecting TAG, primarily consisting of CO_2, in a manner to ensure safety to the public, the employees, and the environment. The mechanical aspects of this are noted in Table 8 and Figure 32. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) applicable standards and practices. As the TAG stream contains H_2S, monitors installed for H_2S detection will also indicate the presence of CO_2. These monitors will be installed at key locations around the Plant and the O'Neal No. 4 location. These devices will be continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points determined by the plant's Health, Safety and Environment (HS&E) Director, consistent with Occupational Safety and Health Administration (OSHA) requirements. The plant will set the detection and alarm states for personnel at 10 ppm and at 40 ppm for initiating Emergency Shutdown. Key monitoring points and parameters are also provided in Table 8.

The facilities will incorporate important safety equipment to ensure reliable and safe operations. In addition to the H_2S monitors, emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the plant, the O'Neal No. 4, and other components, StarTex has a flare stack to safely handle the TAG when a depressuring event occurs. These facilities will be constructed in the coming months. The exact location of this equipment is not yet known, but it will be installed in accordance with applicable engineering and safety standards.

Table 8 – Summary of TAG Detectors and Equipment

Device	Location	Set Point
H_2S Detectors (1 – 4)	O'Neal No. 4 wellsite	10 ppm High Alarm 40 ppm Emergency Shutdown
H_2S Detectors (5 – 8)	In-Plant Detectors	10 ppm High Alarm 40 ppm Emergency Shutdown
Flare Stack	Plant Site Perimeter	N/A
AGI Flowmeter	In-Plant (downstream of the Amine Unit)	Calibrated per API specifications
Emergency Shutdown	In-Plant Detectors	40 ppm Emergency Shutdown
Emergency Shutdown	O'Neal No. 4 wellsite	40 ppm Emergency Shutdown



Casing/Tubing Information

Label	1	2	3	4		5
Type	Conductor	Surface	Intermediate	Production Liner		Tubing
OD	-	10-3/4"	7-5/8"	5" (new)	5" (old)	2-3/8"
ID	-	9.760"	6.625"	4.276"	4.276"	1.867"
Drift ID	-	9.604"	6.500"	4.151"	4.151"	1.773"
COD	-	11.750"	8.500"	5.563"	5.563"	3.063"
Weight	-	55.5 lb/ft	39.0 lb/ft	18.0 lb/ft	18.0 lb/ft	5.8 lb/ft
Grade	-	S-95	CY-95	P-110	Q-125	L-80
Hole Size	N/A	14-3/4"	9-1/2"	N/A	6-1/2"	N/A
Depth Set	Driven to Refusal	3,610'	15,340'	Top: 0' Bottom: 14,080'	Top: 14,088' Bottom: 16,101'	15,720'
Cement	N/A	Lead: 1,125 sks HLC Tail: 350 sks H	Lead: 575 sks 50:50 Poz:H Tail: 400 sks H	Lead: 650 sks 50:50 Poz:H Tail: 110 sks CO_2 Res. Slurry	200 sks Premium	N/A
TOC	N/A	Surface	7,359'	Surface	Surface	N/A
% Excess	-	-	-	Lead: 10% Tail: 0%	-	N/A

LONQUIST SEQUESTRATION LLC	Ozona CCS	CO_2 Injection Well Proposed Well Design - O'Neal Gas Unit No. 4	
	Country: USA	State/Province: Texas	County/Parish: Bee County
	API No: 42-025-32658	Field: TBD	Well Type/Status: Proposed
Texas License F-8652	Location: 28.6031807, -98.0017091	Project No: LS190	Date: 10/13/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	Drawn: Joseph Lovewell	Reviewed: David Lytle	Approved: David Lytle
	Rev No: 0	Notes:	

Figure 32 – O’Neal No. 4 Wellbore Schematic

With the continuous air monitoring at the plant and the well site, a release of CO_2 would be quickly identified, and the safety systems and protocols would effectuate an orderly shutdown to ensure safety and minimize the release volume. The CO_2 injected into the O'Neal No. 4 is from the amine unit at the Pawnee Gas Plant. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7*, in accordance with 40 CFR **§98.448(a)(5)**. Ozona concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The O'Neal No. 4 is engineered to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 32. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 33. Figure 34 is a map of all the oil and gas wells that penetrate the MMA's gross injection zone. Only one well penetrated the MMA's gross injection zone. This well was non-productive and has been plugged and abandoned in accordance with TRRC requirements. A summary table of all oil and gas wells within the MMA is provided in *Appendix B-1*.

This table in *Appendix B-1* provides the total depth (TD) of all wells within the MMA. The wells that are shallower and do not penetrate the injection zone are separated by the Pearsall Formation with a gross thickness of 535 ft. The Pine Island Shale comprises approximately 130 ft of this interval as discussed in *Section 2.2.2*, and provides a competent regional seal—making vertical migration of fluids above the injection zone unlikely.

The shallower offset hydrocarbon wells within the MMA will also serve as above zone monitoring wells. Should any of the sequestered volumes migrate vertically, they would potentially enter the shallower hydrocarbon reservoir. Regular sampling and analysis is performed on the produced hydrocarbons. If a material difference in the quantity of CO_2 in the sample occurs indicating a potential migration of injectate from the Sligo Formation, Ozona would investigate and develop a mitigation plan. This may include reducing the injection rate or shutting in the well. Based on the investigation, the appropriate equation in *Section 7* would be used to make any adjustments to the reported volumes.

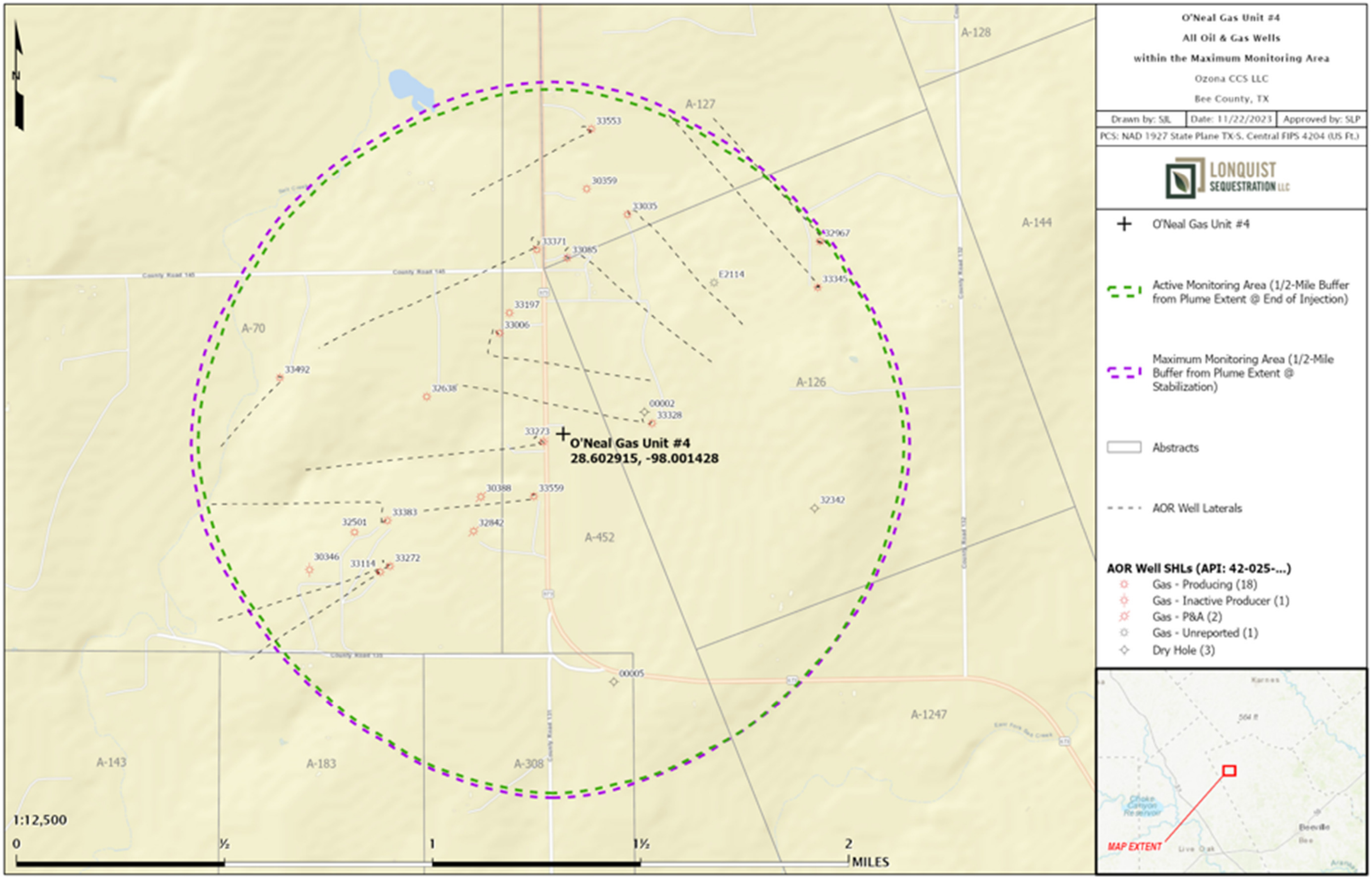


Figure 33 – All Oil and Gas Wells Within the MMA

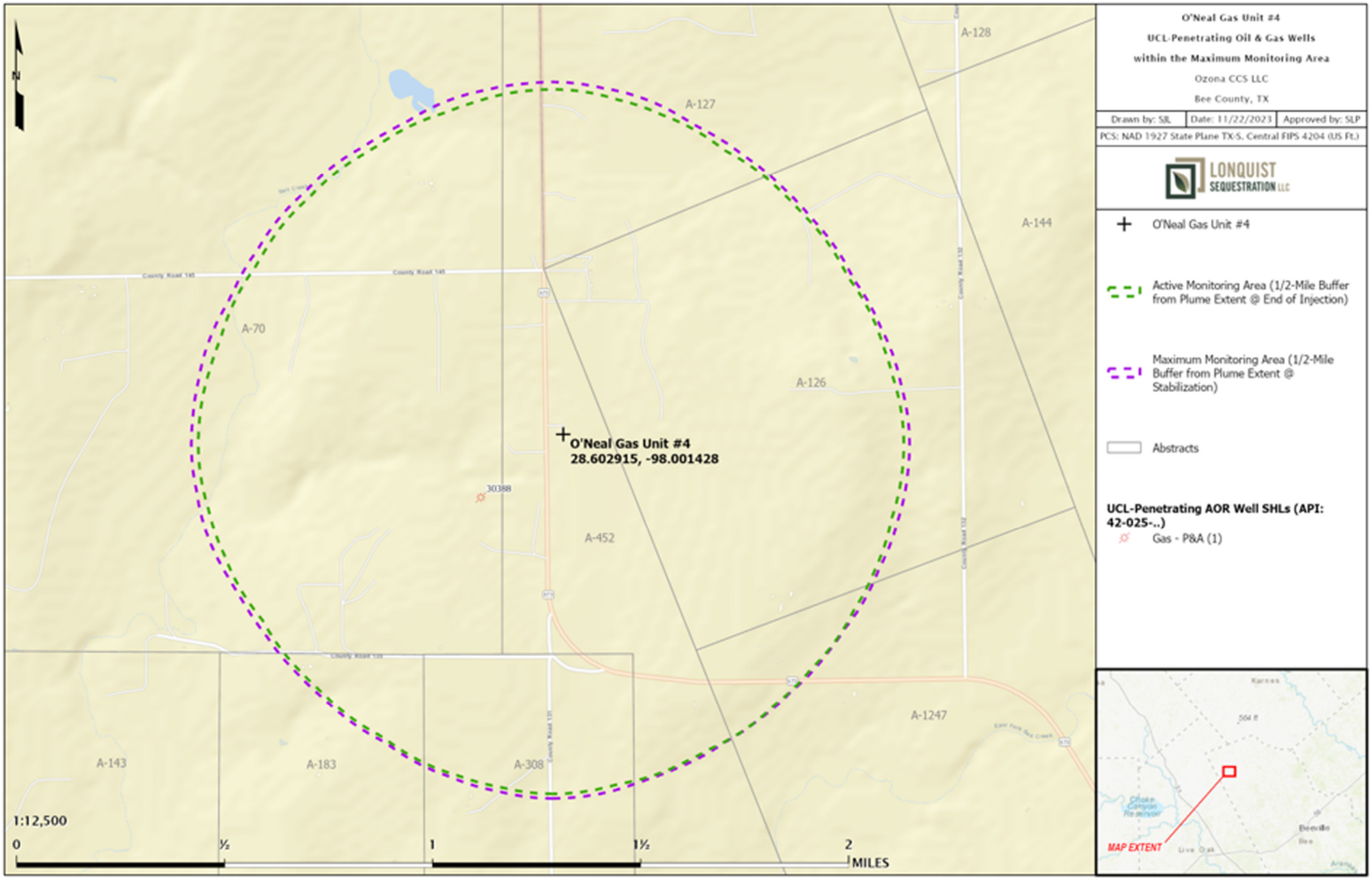


Figure 34 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations have proven to date to be nonproductive in this area, and therefore Ozona does not see this as a risk. This is supported by a review of the TRRC Rule 13 (Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC **§3.13**. The Sligo is not among the formations listed for which operators in Bee County and District 2 (where the O'Neal No. 4 is located) are required to comply with TRCC Rule 13; therefore, the TRRC does not believe there are productive horizons below the Sligo. The O'Neal No. 4 drilling permit is provided in *Appendix A-2*.

4.2.2 Groundwater Wells

The results of a groundwater well search found five wells within the MMA, as identified by the Texas Water Development Board as shown in Figure 35 and in tabular form in *Appendix B-2*.

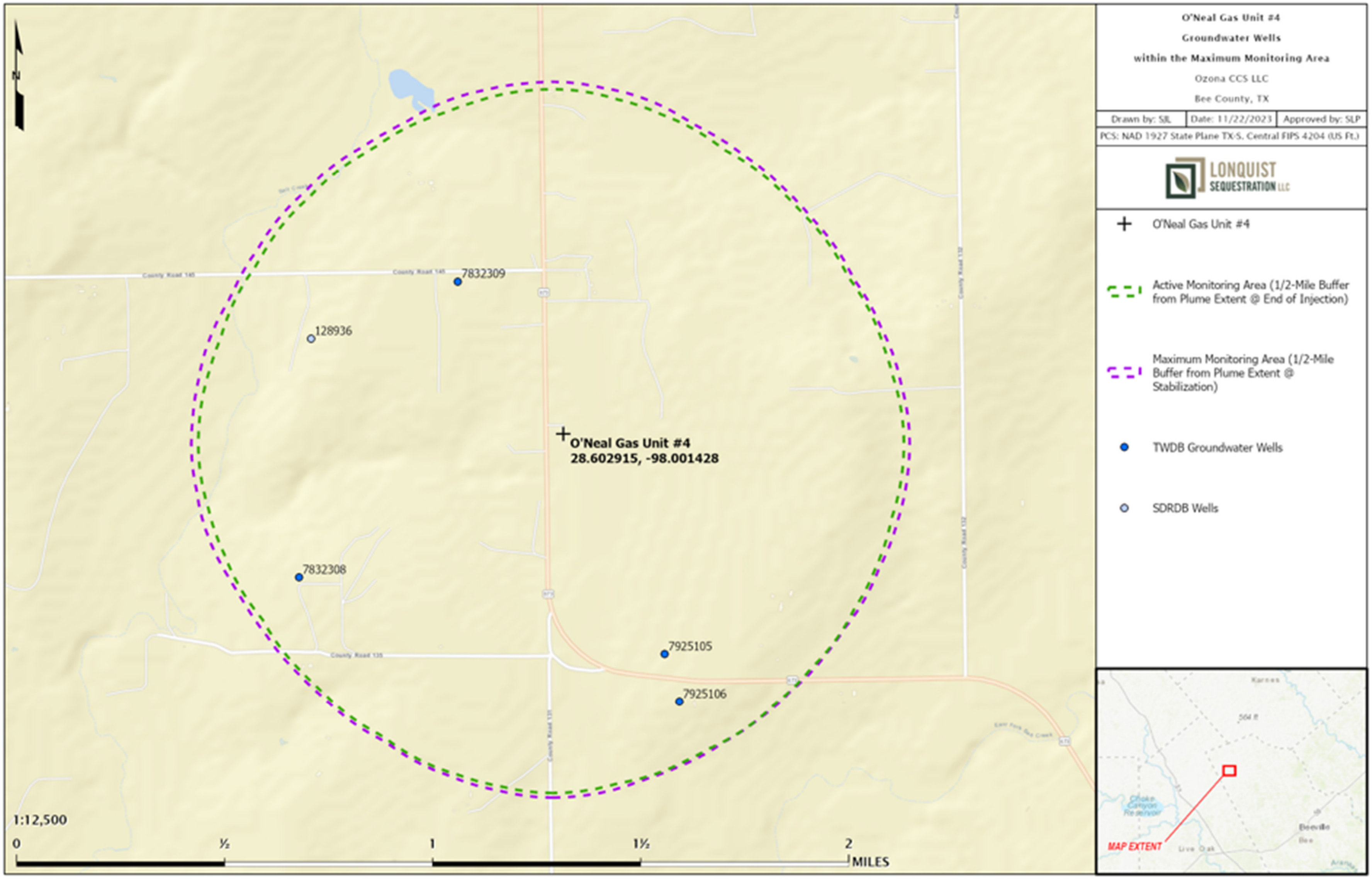


Figure 35 – Groundwater Wells Within the MMA

The surface, intermediate, and production casings of the O'Neal No. 4, as shown in Figure 32, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations, and the GAU letter issued for this location is provided in *Appendix A-1*. The wellbore casings and compatible cements prevent CO_2 leakage to the surface along the borehole. Ozona concludes that leakage of the sequestered CO_2 to the groundwater wells is unlikely.

4.3 Leakage Through Faults and Fractures

Detailed mapping of openhole logs surrounding the O'Neal No. 4 did not identify any faulting within either the Pearsall or Sligo sections. However, there is a general lack of deep penetrators within the area that limits the amount of openhole coverage available.

The majority of the published literature suggests that faulting near the project area is restricted to the shallower, overlying Cenozoic section, as shown in Figure 9, with shallow faults dying out before reaching the Pearsall Formation. One source interpreted the potential for faulting to the south (Swanson et al., 2016). The potential fault is depicted in Figure 8 relative to the location of the O'Neal No. 4. According to the map, the interpreted fault lies approximately 4.25 mi south-southeast of the well and approximately 3.9 mi south-southeast of the stabilized plume extent in the year 2047. In the unlikely scenario in which the injection plume or pressure front reaches the potential fault, and the potential fault was to act as a transmissive pathway, the upper confining Pearsall shale contains sufficient thickness and petrophysical properties required to confine and protect injectates from leaking outside of the permitted injection zone.

Section 2.1.2 discusses regional structure and faulting, and *Section 2.3* covers local structure, for additional material relevant to this topic.

4.4 Leakage Through the Confining Layer

The Sligo injection zone has competent sealing intervals present above and below the targeted carbonate sequence of the Sligo section. The overlying Pine Island shale member of the Pearsall Formation is approximately 130 ft thick at the O'Neal No. 4. Above this confining unit, the Cow Creek Limestone, Cow Creek shale, and Bexar Shale Members of the Pearsall Formation will act as additional confinement between the injection interval and the USDW. The USDW lies well above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. The petrophysical properties of the lower Sligo and Hosston Formations make these ideal for lower confinement. The low porosity and permeability of these underlying formations minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injectate to the in situ reservoir fluid makes migration below the lower confining layer unlikely.

4.5 Leakage from Natural or Induced Seismicity

The O'Neal No. 4 is located in an area of the Gulf of Mexico considered to be active from a seismic perspective. Therefore, the Bureau of Economic Geology's TexNet (from 2017 to present) and USGS's Advanced National Seismic System (from 1971 to present) databases were reviewed to

identify any recorded seismic events within 25 km of the O'Neal No. 4.

The investigation identified a multitude of seismic events within the 25 kilometer (km) search radius; however, the magnitude of most of the events was below 2.5. The nearest seismic event with a recorded magnitude of 3.0 or greater was measured approximately 5.6 km northwest of the O'Neal No. 4 at a depth of 5 km. The results of the investigation are plotted on the map provided in Figure 36 relative to the O'Neal No. 4 and the 25-km search radius.

The plant will have operating procedures and set points programmed into the control and SCADA systems to ensure operating pressures are maintained within the injection and confining intervals' approved fracture gradients. Given the seismic activity in the area, Ozona will closely monitor nearby TexNet station EF71 for activity and any corresponding irregularities in the operating pressures of O'Neal No. 4.

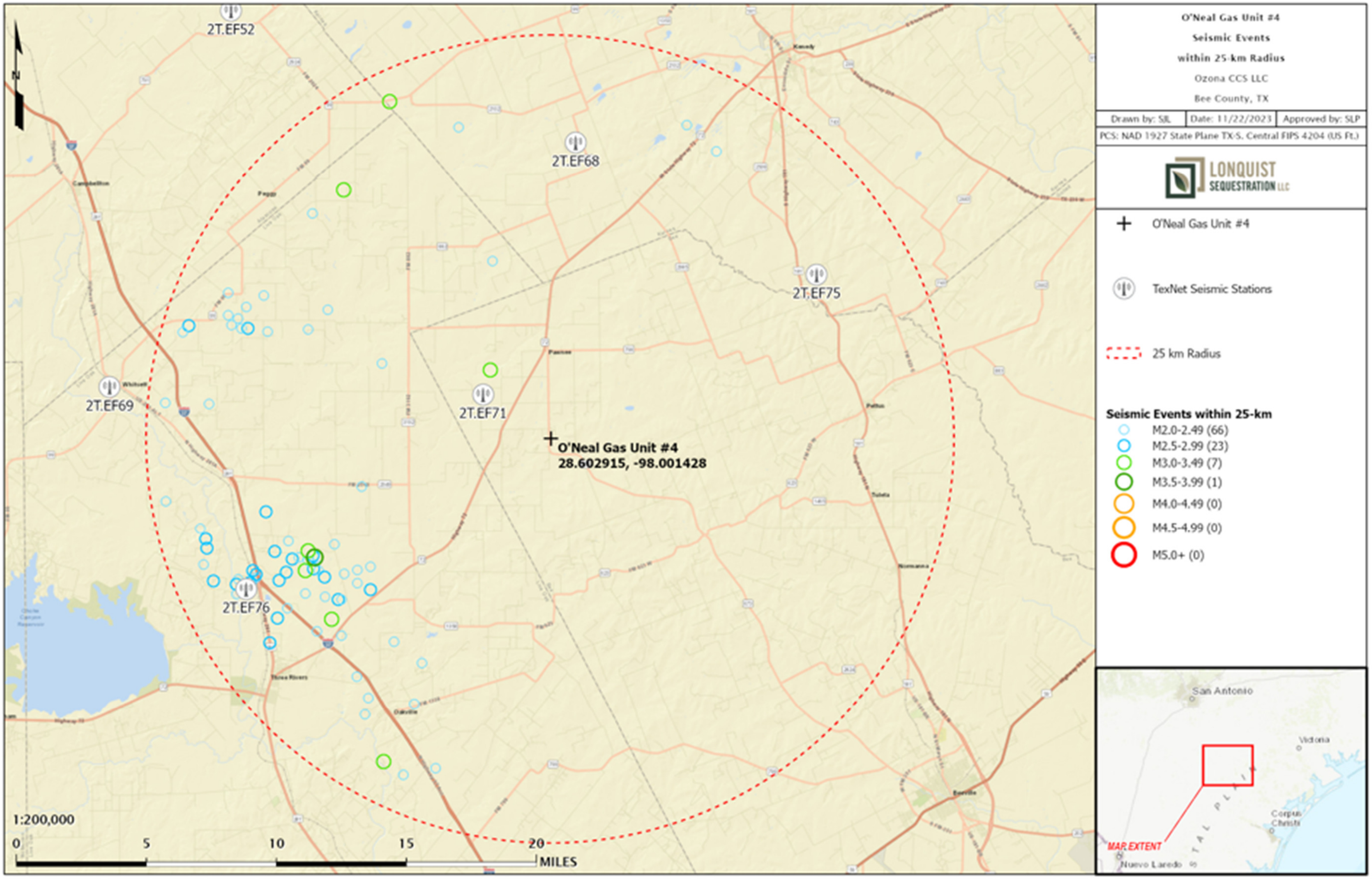


Figure 36 – 25-km Seismicity Review

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Ozona will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in *Section 4*, to meet the requirements of 40 CFR **§98.448(a)(3)**. As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 9 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 12-year injection period or cessation of injection operations, plus a proposed 10-year post-injection period until the plume has stabilized.

- Leakage from surface equipment
- Leakage through existing and future wells within the MMA
- Leakage through faults, fractures, or confining seals
- Leakage through natural or induced seismicity

Table 9 – Summary of Leakage Monitoring Methods

Leakage Pathway	Monitoring Method
Leakage from surface equipment	Fixed H_2S monitors at the Plant and well site
	Visual inspections
	Monitor SCADA systems for the Plant and well site
Leakage through existing wells	Monitor CO_2 levels in above zone producing wells
	Mechanical Integrity Tests (MIT) of O'Neal No. 4 every 5 years
	Visual inspections
	Annual soil gas sampling near well locations that penetrate the Upper Confining Zone within the AMA
Leakage through groundwater wells	Annual groundwater samples from existing water well(s)
Leakage from future wells	Monitor drilling activity and compliance with TRRC Rule 13 Regulations
Leakage through faults, fractures, or confining seals	SCADA continuous monitoring at the well site (volumes and pressures)
	Monitor CO_2 levels in above zone producing wells
Leakage from natural or induced seismicity	Monitor CO_2 levels in above zone producing wells
	Monitor existing TexNet station

5.1 Leakage from Surface Equipment

The Plant and the O'Neal No. 4 were designed to operate in a safe manner to minimize the risk of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established prior to commencing operation once facility construction has been completed. Ambient H_2S monitors will be located at the plant and near the O'Neal No. 4 site for local alarm and are connected to the SCADA system for continuous monitoring.

The plant and the O'Neal No. 4 are continuously monitored through automated control systems. These monitoring points were discussed in *Section 4.1*. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Ozona to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)** and **§98.444(d)**.

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Ozona will quantify the leak per the strategies discussed in *Section 7*.

5.2 Leakage Through Existing and Future Wells Within the MMA

Ozona continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the O'Neal No. 4. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, MITs performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and investigated to develop a leak mitigation plan.

As discussed previously, TRRC Rule 13 ensures that new wells in the field are constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Ozona will also establish and operate an in-field monitoring program to detect CO_2 leakage within the AMA. This would include H_2S monitoring as a proxy for CO_2 at the well site and annual soil gas samples taken near any identified wells that penetrate the injection interval within the AMA. These samples will be analyzed by a qualified third party. Prior to commencing operation, and through the post-injection monitoring period, Ozona will have these monitoring systems in place.

Currently, there is only one well in the MMA identified that penetrates the injection interval. This well was plugged and abandoned in 2007. The TRRC records are provided in *Appendix A-4*. Ozona will take an annual soil gas sample from this area, which will be analyzed by a third-party lab. Additional monitoring will be added as the AMA is updated over time. In the unlikely event a leak occurs, Ozona will quantify the leak volumes by the methodologies discussed in *Section 7* and present these results and related activities in the annual report.

Ozona will also utilize shallower producing gas wells as proxies for above-zone monitoring wells. Production data from these wells is analyzed for monthly production statements, and therefore would be an early indicator of any possible subsurface issues. Should any material change from historical trends in the CO_2 concentration occur, Ozona would investigate and develop a corrective action plan. Should any CO_2 migrate vertically from the Sligo, the magnitude risk of this event is very low, as the producing reservoir provides an ideal containment given the upper confining zone of this reservoir has proven competent. In the unlikely event a leak occurs, Ozona would quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances, and include these results in the annual report.

5.2.1 Groundwater Quality Monitoring

Ozona will monitor the groundwater quality above the confining interval by sampling from groundwater wells near the O'Neal No. 4 and analyzing the samples with a third-party laboratory on an annual basis. In the case of the O'Neal No. 4, 5 existing groundwater wells have been identified within the AMA (Figure 38). Initial groundwater quality tests will be performed to establish a baseline prior to commencing operations.

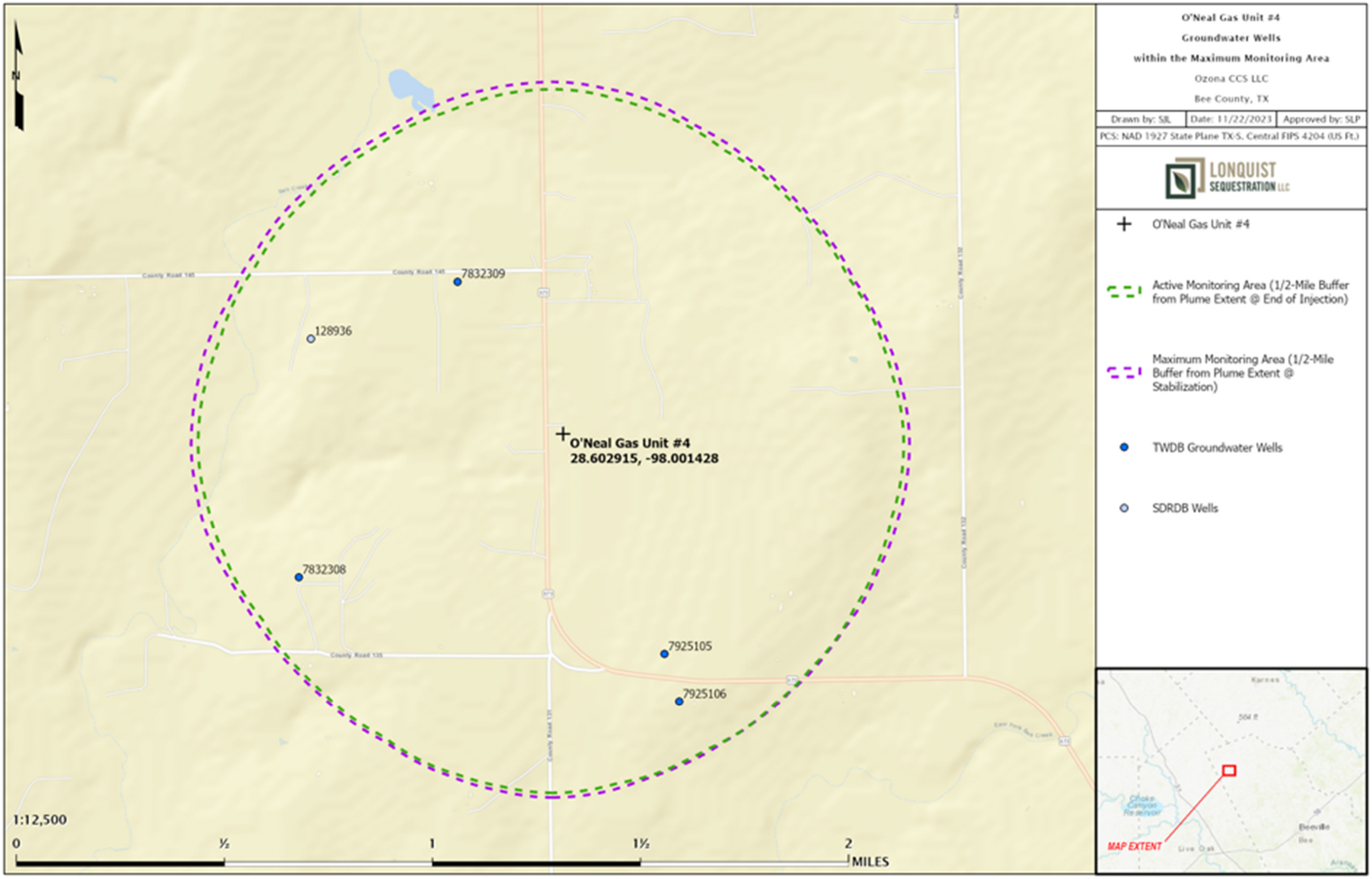


Figure 37 – Groundwater Wells

5.3 Leakage Through Faults, Fractures, or Confining Seals

Ozona will continuously monitor the operations of the O'Neal No. 4 through the automated controls and SCADA systems. Any deviation from normal operating volume and corresponding injection pressure could indicate movement into a potential leak pathway, such as a fault or breakthrough of the confining seal, and would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Ozona will also utilize shallower producing wells as proxies for above-zone monitoring wells. Production data is analyzed regularly for monthly production statements and therefore would be an early indicator of any possible subsurface issues. Should any material change from historical trends in the CO_2 concentration occur, Ozona would investigate and develop a corrective action plan. Should any CO_2 migrate vertically from the Sligo Formation, the magnitude risk of this event is very low, as the producing reservoir provides an ideal containment given the upper confining zone has proven competent. In the unlikely event a leak occurs, Ozona would quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is low, Ozona plans to use the nearest TexNet seismic monitoring station, EF71, to monitor the area around the O'Neal No. 4. This station is approximately 3 mi to the northwest, as shown in Figure 38. This is sufficient distance to allow for accurate and detailed monitoring of the seismic activity in the area. Ozona will monitor this station for any seismic activity, and if a seismic event of 3.0 magnitude or greater is detected, Ozona will review the injection volumes and pressures of the O'Neal No. 4 to determine if any significant changes have occurred that would indicate potential leakage.

Ozona will also continuously monitor operations through the SCADA system. Any deviation from normal operating pressure and volume set points would trigger an alarm for investigation by operations staff. Such a variance could indicate movement into a potential leak pathway, such as a fault or breakthrough of the confining seal. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary

These are the two primary strategies for mitigating risks for induced seismicity. In the unlikely event a leak occurs, Ozona will quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances.

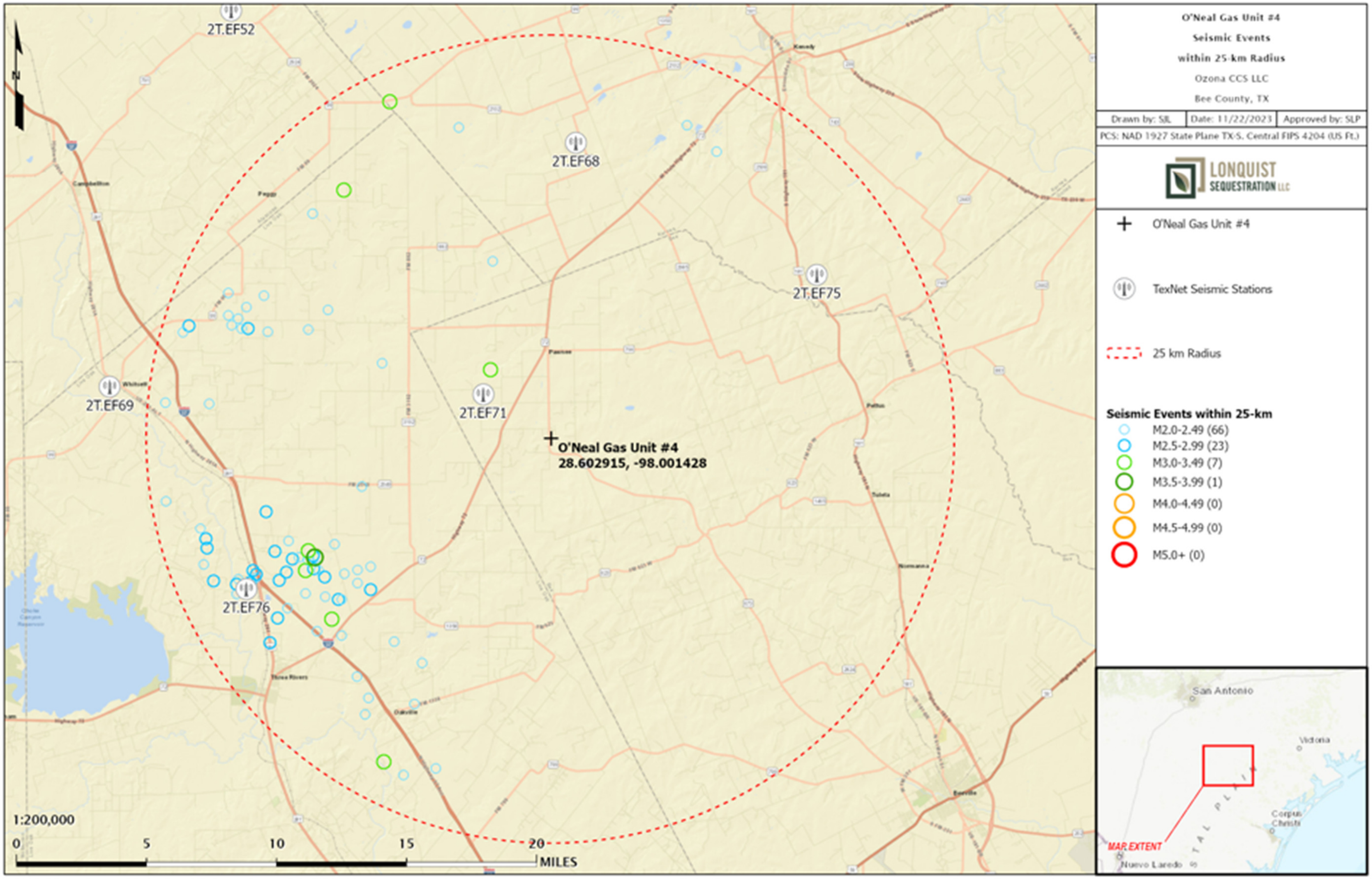


Figure 38 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

This section identifies the strategies Ozona will undertake to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR **§98.448(a)(4).** Ozona will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of injectate and calculate a corresponding amount of CO_2.

6.1 Visual Inspections

Regular inspections will be conducted by field personnel at the plant and O'Neal No. 4 site. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken prudently and safely to address such issues.

6.2 CO_2/H_2S Detection

In addition to the fixed monitors in the Plant and at the wellsite, Ozona will establish and perform an annual in-field sampling program to monitor and detect any CO_2 leakage within the AMA. This will consist of soil gas sampling near any artificial penetrations of the injection zone and sampling of water wells. These probes have special membrane inserts that collect the gas samples over a 21-day period. These will be analyzed by a third-party lab to be analyzed for CO_2, H_2S, and trace contaminants typically found in a hydrocarbon gas stream. The lab results will be provided in the annual report should they indicate a material variance from the baseline. Initial samples will be taken and analyzed before the commencement of operations and will establish the baseline reference levels.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of injectate and the corresponding component of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is near the OSHA Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger alarms if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions, including pressure, flow rate, percentage of CO_2, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)** and **§98.444(d)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a depressuring event, the acid gas stream will be sent to a flare stack to be safely processed and will be reported under reporting requirements for the plant. Any such events will be accounted for in the sequestered reporting volumes consistent with *Section 7.*

6.5 Groundwater Monitoring

Initial samples will be taken from groundwater wells in the area of the O'Neal No. 4 upon approval of the MRV plan, and before commencement of CO_2 injection. These samples will be analyzed and reports prepared by a third-party laboratory testing for pH, total dissolved solids (TDS), CO_2, and volatile organic compounds (VOC). Initial samples will be taken and analyzed before the commencement of operations and will establish the baseline reference levels. Sampling select wells will be performed annually. In the event a material deviation in the sample analysis occurs, the results will be provided in the annual report.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO_2 Received

Per 40 CFR **§98.443**, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4**)." The 40 CFR **§98.444(a)(4)** states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." The CO_2 received for this injection well is injected and not mixed with any other supply; the annual mass of CO_2 injected will equal the amount received less any amounts calculated in accordance with the equations of this section. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO_2 Injected

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

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

Where:

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

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

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

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

The O'Neal No. 4 is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

7.4 Mass of CO_2 Emitted by Surface Leakage

The mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly due to the H_2S concentration in the injection stream. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions would be sent to a flare stack and reported as a part of the required GHG reporting for the plant. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of H_2S and CO_2. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak-point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

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

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

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

Calculation methods using equations from Subpart W will be used to calculate CO_2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage is unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Ozona believes the most appropriate method to quantify the mass of CO_2 released will be determined on a case-by-case basis. Any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. In the unlikely

event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events will be kept and stored as provided in *Section 10*.

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Data collection for calculating the amount of CO_2 sequestered in the O'Neal No. 4 will begin once the subsurface recompletion work, and the surface facilities construction has been completed, and subject to approval of the MRV plan. The calculation of sequestered volumes utilizes the following equation as the O'Neal No. 4 will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well 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

CO_{2FI} will be calculated in accordance with Subpart W for reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a system blowdown event occurs. Those emissions would be sent to a flare stack and reported as part of the GHG reporting for the plant.

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The O'Neal Gas Unit No. 4 is an existing natural gas well that will be recompleted as a Class II well with corrosion-resistant materials. Ozona is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Ozona plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 Injected

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with API standards. These flow rates will be compiled quarterly.
- The composition of the injectate stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with API standards.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated per the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.

CO_2 Emissions from Leaks and Vented Emissions

- Gas monitors at the plant and O'Neal No. 4 will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.
- Calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR **§98.3(i).**
- Flow meters will be operated and maintained in accordance with applicable standards as published by a consensus-based standards organization.

All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60°F and an absolute pressure of 1 atmosphere.

9.2 Missing Data

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

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.

- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR **§98.**

9.3 MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Ozona will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least 3 years and include the following:

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

APPENDICES

APPENDIX A – O'Neal No. 4 TRRC FORMS

APPENDIX A-1: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-2: DRILLING PERMIT

- CHARLIE C. OVERBY API 42-025-32658
- O'NEAL GAS UNIT NO. 4 API 42-025-32658

APPENDIX A-3: COMPLETION REPORT

- CHARLIE C. OVERBY API 42-025-32658
- O'NEAL GAS UNIT NO. 4 API 42-025-32658
- ACID FRACTURE REPORT

APPENDIX A-4: API 42-025-30388 CHARLIE C. OVERBY GU PLUGGING RECORDS

<u>APPENDIX B – AREA OF REVIEW</u>

APPENDIX B-1: OIL AND GAS WELLS WITHIN THE MMA LIST

APPENDIX B-2: WATER WELLS WITHIN THE MMA LIST

GROUNDWATER PROTECTION DETERMINATION **Form GW-2**

Groundwater Advisory Unit

Date Issued:	26 May 2023	**GAU Number:**	367912
Attention:	OZONA CCS LLC 19026 RIDGEWOOD SAN ANTONIO, TX 78259	**API Number:**	02532658
		County:	BEE
		Lease Name:	O'Neal Gas Unit
		Lease Number:	162214
Operator No.:	100116	**Well Number:**	4
		Total Vertical	16101
		Latitude:	28.602914
		Longitude:	-98.001428
		Datum:	NAD27

Purpose: Injection into Producing Zone (H1)
Location: Survey-EL&RR RR CO; Abstract-452; Section-1

To protect usable-quality groundwater at this location, the Groundwater Advisory Unit of the Railroad Commission of Texas recommends:

The base of usable-quality water-bearing strata is estimated to occur at a depth of 250 feet at the site of the referenced well.

The BASE OF UNDERGROUND SOURCES OF DRINKING WATER (USDW) is estimated to occur at a depth of 950 feet at the site of the referenced well.

Note: Unless stated otherwise, this recommendation is intended to apply to all wells drilled within 200 feet of the subject well. Unless stated otherwise, this recommendation is for normal drilling, production, and plugging operations only.

This determination is based on information provided when the application was submitted on 05/26/2023. If the location information has changed, you must contact the Groundwater Advisory Unit, and submit a new application if necessary.
If you have questions, please contact us at 512-463-2741 or gau@rrc.texas.gov.

Groundwater Advisory Unit, Oil and Gas Division

RRC ONLINE SYSTEM

Oil & Gas Data Query

Query Menu Help

Drilling Permit (W-1) Query Results

Search Criteria:

API No.: 02532658

Return

2 results Page: 1 of 1 Page Size: View All

API NO.	District	Lease	Well Number	Permitted Operator	County	Status Date	Status Number	Wellbore Profiles	Filing Purpose	Amend	Total Depth	Stacked Lateral Parent Well DP #	Status
02532658 Links	02	CHARLIE C. OVERBY GAS UNIT	2	PARKER & PARSLEY DEVELOPMENT CO.(640889)	BEE	Submitted: 11/30/1992 Approved: 11/30/1992	406655	Vertical	New Drill	N	16700		APPROVED
02532658 Links	02	O'NEAL GAS UNIT (162214)	4	PARKER & PARSLEY DEVELOPMENT L.P(640886)	BEE	Submitted: 11/20/1996 Approved: 12/16/1996	455434	Vertical	Recompletion	N	14040		APPROVED

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NOTE: THE CHARLIE C. OVERBY GU AND THE O'NEAL GU ARE THE SAME WELL. THE OVERBY WELL WAS DRILLED IN 1993 INTO THE SLIGO. IN 1997 THE WELL WAS RECOMPLETED IN THE EDWARDS FORMATION. THIS WAS DONE UNDER A NEW LEASE, AS THE O'NEAL GU NO. 4.

RRC ONLINE SYSTEM

Log In

Form W-1: Review

Status # 406655 **API #** 025-32658	**OP # 640889 - PARKER & PARSLEY DEVELOPMENT CO.** Approved ,**Issued:** 11/30/1992 ,**Filed:** Hardcopy	**CHARLIE C. OVERBY GAS UNIT - Well # 2** 02 - BEE County	**New Drill** Vertical

NEAREST WELL COMMENT: 1607.8 (11/30/1992 12:00:00 AM)

Status:

Back to Public Query Search Results

Completion Information

Well Status Code	Spud Date	Drilling Completed	Surface Casing Date
W - Final Completion	01/01/1993	02/11/1993	01/01/1993

Field Name	Completed Well Type	Completed Date	Validated Date
PAWNEE (SLIGO)	Gas	02/11/1993	06/18/1993

General / Location Information

Basic Information:

Filing Purpose	Welbore Profiles	Lease Name	Well #	SWR	Total Depth	Horizontal Wellbore	Stacked Lateral Parent Well DP #
New Drill	Vertical	CHARLIE C. OVERBY GAS UNIT	2	SWR 36	16700		

Surface Location Information:

API #	Distance from Nearest Town	Direction from Nearest Town	Nearest Town	Surface Location Type
025-32658	4.0 miles	S	PAWNEE	Land

Survey/Legal Location Information:

Section	Block	Survey	Abstract #	County
		EL&RR RR CO	452	BEE

Township	League	Labor	Porcion	Share	Tract	Lot

Perpendicular surface location from two nearest designated reference lines:

Perpendiculars	Distance	Direction	Distance	Direction
Survey Lines	2784.0 feet	from the S line and	1045.5 feet	from the W line

Permit Restrictions:

Code	Description
30	REGULAR PROVIDED THAT UPON SUCCESSFUL COMPLETION OF THIS WELL IN THE SAME RESERVOIR AS ANY OTHER WELL PREVIOUSLY ASSIGNED THIS ACREAGE, A P-15 AND REVISED PRORATION PLATS MUST BE SUBMITTED WITH NO
30	DOUBLE ASSIGNMENT OF ACREAGE.
30	REGULAR PROVIDED THIS WELL IS NEVER COMPLETED IN THE SAME RESERVOIR AS ANY OTHER WELL CLOSER THAN 2640 FEET ON THIS SAME LEASE.
30	REGULAR PROVIDED THIS WELL IS DRILLED IN COMPLIANCE WITH RULE 36.

30	O'NEAL GU #3, O'NEAL #1, OVERBY #120 & NEAL #1.

Fields

District	Field Name	Field #	Completion Depth	Lease Name	Well #	Well Type	Acres	Distance to Nearest Well	Distance to Nearest Lease Line	SWR	Pooled/ Unitized
02	**PAWNEE (SLIGO)** **Primary Field**	69845800	16700	CHARLIE C. OVERBY GAS UNIT	2	Oil or Gas Well	704.0			SWR 36	Y

Perpendiculars	Distance	Direction	Distance	Direction
Surface Lease Lines	2390.0 feet	from the E line and	3446.0 feet	from the N line

Comments

Remark	Date Entered	Entered By
NEAREST WELL COMMENT: 1607.8	11/30/1992 12:00:00 AM	SYSTEM

Attachments

Attachment Type	File Path	Associated Fields and/or Plats

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Form W-1: Review

Status # 455434 **API #** 025-32658	**OP # 640886 - PARKER & PARSLEY DEVELOPMENT L.P** Approved ,**Issued:** 12/16/1996 ,**Filed:** Hardcopy	**O'NEAL GAS UNIT - Well # 4** 02 - BEE County	**Recompletion** Vertical

NEAREST WELL COMMENT: 1787 (11/20/1996 12:00:00 AM)

Status:

Back to Public Query Search Results

Completion Information

Well Status Code	Spud Date	Drilling Completed	Surface Casing Date
W - Final Completion	02/04/1997	02/13/1997	

Field Name	Completed Well Type	Completed Date	Validated Date
PAWNEE (EDWARDS)	Gas	02/13/1997	02/26/1997

General / Location Information

Basic Information:

Filing Purpose	Welbore Profiles	Lease Name	Well #	SWR	Total Depth	Horizontal Wellbore	Stacked Lateral Parent Well DP #
Recompletion	Vertical	O'NEAL GAS UNIT	4	SWR 36, SWR 37H	14040		

Surface Location Information:

API #	Distance from Nearest Town	Direction from Nearest Town	Nearest Town	Surface Location Type
025-32658	3.5 miles	S	PAWNEE	Land

Survey/Legal Location Information:

Section	Block	Survey	Abstract #	County
		E.L.&R.R. RR CO. #1	452	BEE

Township	League	Labor	Porcion	Share	Tract	Lot

Perpendicular surface location from two nearest designated reference lines:

Perpendiculars	Distance	Direction	Distance	Direction
Survey Lines	825.0 feet	from the W line and	2784.0 feet	from the S line

Permit Restrictions:

Code	Description
30	WILDCAT ABOVE 14040 FEET.
30	ANY WELLBORE DRILLED UNDER THIS PERMIT MUST BE COMPLETED, OPERATED, AND PRODUCED IN COMPLIANCE WITH STATEWIDE RULE 32.
30	REGULAR PROVIDED THIS WELL IS DRILLED IN COMPLIANCE WITH RULE 36.

Fields

District	Field Name	Field #	Completion Depth	Lease Name	Well #	Well Type	Acres	Distance to Nearest Well	Distance to Nearest Lease Line	SWR	Pooled/ Unitized
02	**WILDCAT** **Primary Field**	00004001	14040	O'NEAL GAS UNIT	4	Oil or Gas Well	704.0			37H	Y

Perpendiculars	Distance	Direction	Distance	Direction
Surface Lease Lines	4900.0 feet	from the W line and	2784.0 feet	from the S line

District	Field Name	Field #	Completion Depth	Lease Name	Well #	Well Type	Acres	Distance to Nearest Well	Distance to Nearest Lease Line	SWR	Pooled/ Unitized
02	**PAWNEE (EDWARDS)**	69845200	14040	O'NEAL GAS UNIT	4	Gas Well	704.0			SWR 36, 37H	Y

Perpendiculars	Distance	Direction	Distance	Direction
Surface Lease Lines	4900.0 feet	from the W line and	2784.0 feet	from the S line

Exceptions

Field	Exception	Case Docket Number	Resolution
WILDCAT	**SWR 37 [Historical]**	**0214349**	
PAWNEE (EDWARDS)	**SWR 37 [Historical]**	**0214349**	

Comments

Remark	Date Entered	Entered By
NEAREST WELL COMMENT: 1787	11/20/1996 12:00:00 AM	SYSTEM

Attachments

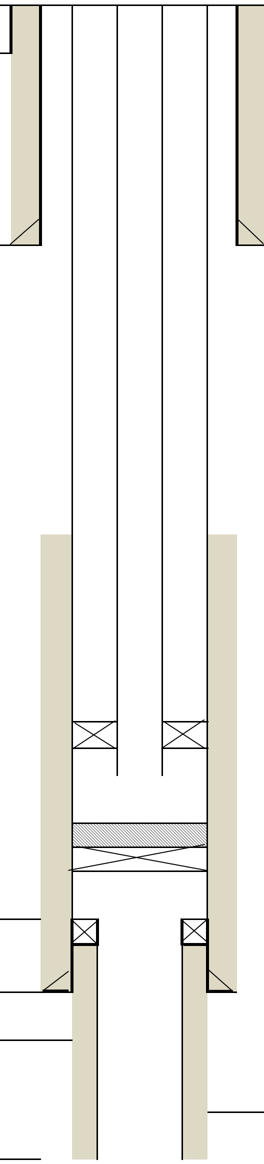
Attachment Type	File Path	Associated Fields and/or Plats

APPENDIX A-3

Ozona CCS

Well Name:	ONeal Gas Unit 4 (current)	**Rig:**		**Lat, Long**	28.6031807,-98.0017091 (NAD83)
Formation:	Edwards	**GL:**		**GAU Depth:**	
County, State:	Bee County, TX	**RKB:**			
API #:	42-025-32658	**TD (MD):**	16,101'		
Permit #:		**TD (TVD):**			

	MD/TVD
Conductor	80
10.75" Surface Casing	3610
Cook Mountain	3657
Sparta	4259
Weches Sandstone	4326
Queen City	4655
Reklaw	5244
Carrizo	5864
Wilcox	5922
Midway	9026
Austin Chalk	13266
Eagle Ford	13344
Buda	13494
Edwards	13500
CIBP w/ 20' Cement on Top	14000
5" Liner Top	14088
Pearsall	15339
7 5/8" Intermediate Casing	15340
CO2 Resistant Permanent Packer	15700
Sligo	15874
5" Liner	16101



Tubular Detail

String	Hole Size	OD	Weight	Grade	MD
	(in)	(in)	(#/ft)		(ft)
Conductor					
Surface	14 3/4"	10 3/4"	55.5	S-95	3,610'
Intermediate	9 1/2"	7 5/8"	39	CY-95	15,340'
Liner	6 1/2"	5"	18	Q-125	14,088'-16,101'
Prod Tbg		2 3/8"	4.7	L-80	13453'

Cement Detail

String	Vol	Type	TOC	%XS
	(sks)		(MD)	
Surf Lead	1125	HLC	0'	
Surf Tail	350	H		
Int Lead	575	50:50 Poz:H	7359'	
Int Tail	400	H		
Liner	200	Premium	14088'	

Edwards perfs production zone, 13,529'-13,841'
Cumulative 6,555,750 MCF gas, 168,888 BBLs water produced

Initial production zone, 15,874'-16,056'
Cumulative 511,964 MCF gas, 22,026 BBLs water produced

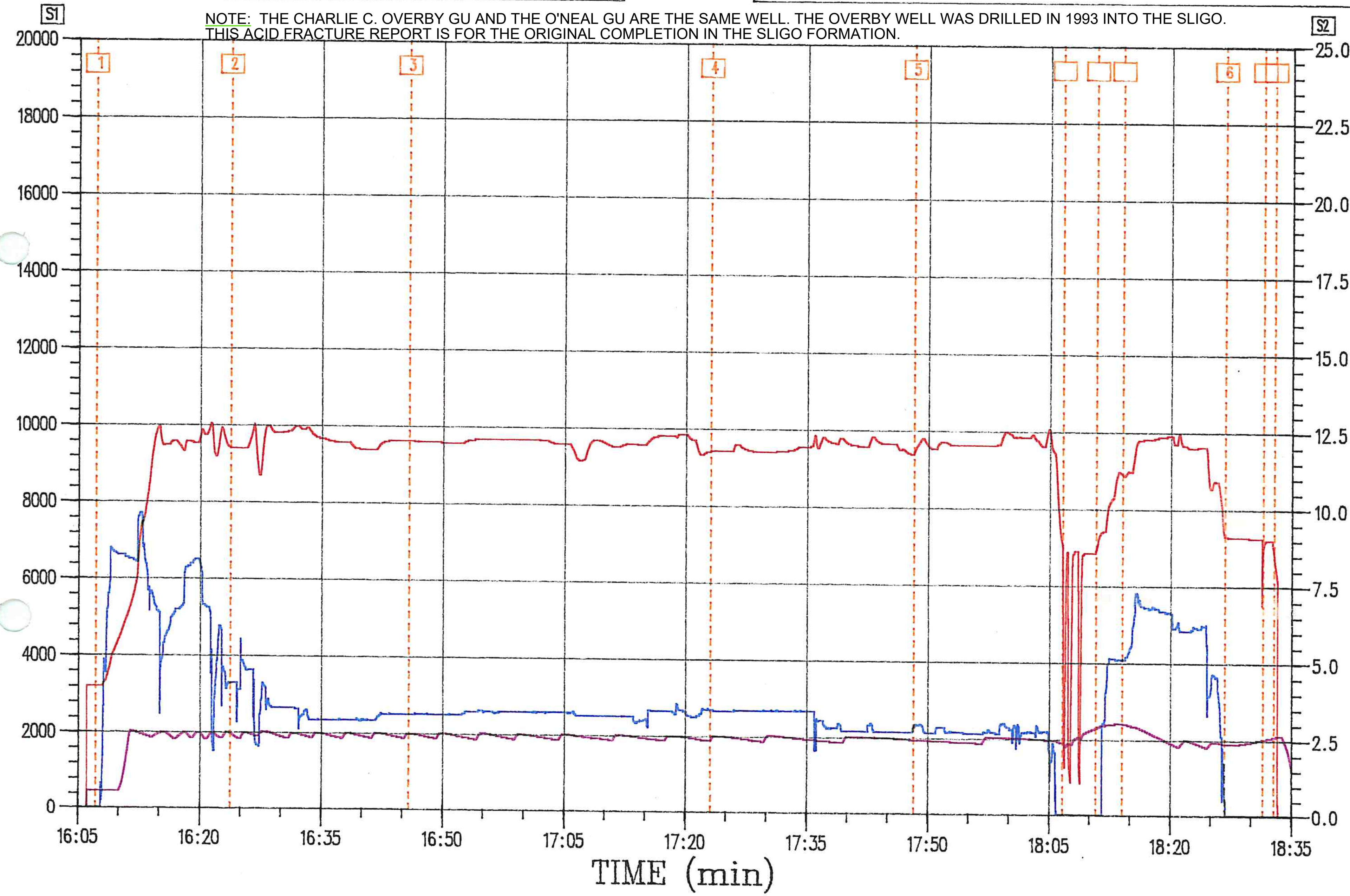
Well History

#	Date	Description
1	12/30/1992	First spud as gas well, targeting the Sligo formation
2	2/13/1997	Plugged back to 14,000' and recompleted

TUBING PRESSURE (psi) S1
ANNULUS PRESSURE (psi) S1

SLURRY RATE (bpm) S2

NOTE: THE CHARLIE C. OVERBY GU AND THE O'NEAL GU ARE THE SAME WELL. THE OVERBY WELL WAS DRILLED IN 1993 INTO THE SLIGO.
THIS ACID FRACTURE REPORT IS FOR THE ORIGINAL COMPLETION IN THE SLIGO FORMATION.



CUSTOMER: PARKER & PARSLEY DEV. CO.
WELL DECS: OVERBY #2
JOB DATE: APR-03-1993
FORMATION: SLIGO
TICKET #: 30840901
JOB TYPE: SWIC ACID BALLOUT

Customer: PARKER & PARSLEY DEV. CO. Ticket #: 30840901 Date: Apr 3, 1993
Well Desc: OVERBY #2 Formation: SLIGO Job Type: SWIC ACID BALLOUT

TIME HR:MM:SS	STAGE NO	TUBING PR (psi)	ANNULUS PR (psi)	SLURRY RT (bpm)
16:06:02	0	0	0	0.00
16:07:02	0	3216	470	0.00
16:08:02	1 Event(Eng) Operator Stage Advance			
16:08:02	1	3251	470	2.65
16:09:02	1	3904	470	8.43
16:10:02	1	4471	528	8.24
16:11:02	1	5059	1612	8.17
16:12:02	1	5812	1978	8.04
16:13:02	1	7558	1906	8.62
16:14:02	1	9069	1875	7.03
16:15:02	1	9950	2004	5.82
16:16:02	1	9504	1922	5.82
16:17:02	1	9572	1863	6.51
16:18:02	1	9304	2003	6.86
16:19:02	1	9539	1870	8.03
16:20:02	1	9725	1945	7.95
16:21:02	1	9862	1920	6.52
16:22:02	1	9216	1886	4.43
16:23:02	1	9672	1992	4.43
16:24:02	2 Event(Eng) Operator Stage Advance			
16:24:02	2	9384	1906	4.15
16:25:02	2	9416	1906	5.36
16:26:02	2	9547	1964	4.56
16:27:02	2	9150	1915	2.05
16:28:02	2	9898	2032	3.96
16:29:02	2	9812	1948	3.30
16:30:02	2	9824	1876	3.30
16:31:02	2	9882	1944	3.30
16:32:02	2	10020	1967	3.26
16:33:02	2	9946	1898	3.24
16:34:02	2	9733	1986	2.90
16:35:02	2	9654	1980	2.90
16:36:02	2	9590	1921	2.90
16:37:02	2	9558	1870	2.91
16:38:02	2	9552	2018	2.90
16:39:02	2	9420	1960	2.90
16:40:02	2	9377	1908	2.97
16:41:02	2	9369	1866	2.90
16:42:02	2	9485	2010	3.07
16:43:02	2	9635	1961	3.10
16:44:02	2	9647	1910	3.09
16:45:02	2	9644	1868	3.12
16:46:02	3 Event(Eng) Operator Stage Advance			
16:46:02	3	9622	2011	3.10
16:47:02	3	9601	1955	3.10
16:48:02	3	9597	1905	3.10
16:49:02	3	9596	1867	3.10
16:50:02	3	9568	2020	3.10
16:51:02	3	9553	1968	3.10
16:52:02	3	9551	1923	3.10
16:53:02	3	9667	1883	3.26
16:54:02	3	9707	1859	3.26
16:55:02	3	9708	2024	3.22
16:56:02	3	9718	1974	3.27
16:57:02	3	9720	1927	3.25

Customer: PARKER & PARSLEY DEV. CO. Ticket #: 30840901 Date: Apr 3, 1993
Well Desc: OVERBY #2 Formation: SLIGO Job Type: SWIC ACID BALLOUT

TIME HR:MM:SS	STAGE NO	TUBING PR (psi)	ANNULUS PR (psi)	SLURRY RT (bpm)
16:58:02	3	9705	1883	3.26
16:59:02	3	9709	1984	3.23
17:00:02	3	9686	1996	3.26
17:01:02	3	9677	1958	3.27
17:02:02	3	9671	1924	3.26
17:03:02	3	9630	1889	3.26
17:04:02	3	9563	1857	3.26
17:05:02	3	9560	2025	3.26
17:06:02	3	9417	1983	3.28
17:07:02	3	9153	1949	3.12
17:08:02	3	9569	1933	3.12
17:09:02	3	9691	1909	3.10
17:10:02	3	9592	1880	3.12
17:11:02	3	9509	1943	3.10
17:12:02	3	9568	2012	3.10
17:13:02	3	9611	1979	3.12
17:14:02	3	9576	1947	2.97
17:15:02	3	9607	1917	3.06
17:16:02	3	9805	1893	3.28
17:17:02	3	9858	1865	3.29
17:18:02	3	9827	2031	3.28
17:19:02	3	9864	1994	3.43
17:20:02	3	9872	1963	3.30
17:21:02	3	9681	1927	3.12
17:22:02	3	9325	1884	3.37
17:23:02	3	9445	1902	3.33
17:24:02	4 Event(Eng) Operator Stage Advance			
17:24:02	4	9468	2027	3.32
17:25:02	4	9436	1988	3.32
17:26:02	4	9594	1960	3.33
17:27:02	4	9502	1928	3.33
17:28:02	4	9428	1896	3.32
17:29:02	4	9425	1867	3.33
17:30:02	4	9437	2045	3.33
17:31:02	4	9439	2026	3.32
17:32:02	4	9454	1996	3.32
17:33:02	4	9492	1971	3.32
17:34:02	4	9577	1947	3.32
17:35:02	4	9585	1923	3.32
17:36:02	4	9818	1908	2.69
17:37:02	4	9839	1889	2.93
17:38:02	4	9661	1870	2.82
17:39:02	4	9808	1862	2.90
17:40:02	4	9642	2047	2.67
17:41:02	4	9589	2027	2.69
17:42:02	4	9583	2015	2.69
17:43:02	4	9858	2011	2.90
17:44:02	4	9662	1996	2.69
17:45:02	4	9649	1986	2.68
17:46:02	4	9624	1973	2.68
17:47:02	4	9477	1956	2.69
17:48:02	4	9360	1942	2.68
17:49:02	5 Event(Eng) Operator Stage Advance			
17:49:02	5	9770	1941	2.99
17:50:02	5	9585	1926	2.66

Customer: PARKER & PARSLEY DEV. CO.   Ticket #: 30840901   Date: Apr 3, 1993
Well Desc: OVERBY #2   Formation: SLIGO   Job Type: SWIC ACID BALLOUT

TIME HR:MM:SS	STAGE NO	TUBING PR (psi)	ANNULUS PR (psi)	SLURRY RT (bpm)
17:51:02	5	9577	1913	2.85
17:52:02	5	9749	1908	2.78
17:53:02	5	9627	1895	2.68
17:54:02	5	9638	1885	2.67
17:55:02	5	9636	1873	2.68
17:56:02	5	9642	1866	2.68
17:57:02	5	9658	2047	2.70
17:58:02	5	9659	2047	2.68
17:59:02	5	9789	2036	2.99
18:00:02	5	9937	2028	2.78
18:01:02	5	9837	2014	2.93
18:02:02	5	9857	2003	2.72
18:03:02	5	9874	1992	2.70
18:04:02	5	9617	1972	2.73
18:05:02	5	10006	1978	2.05
18:06:02	5	8309	1925	0.00
18:07:02	5 Event(Eng)			SHUT DOWN TO SURGE BALLS ISIP 9320
18:07:02	5	6123	1842	0.00
18:08:02	5	6862	2033	0.00
18:09:02	5	6742	2129	0.00
18:10:02	5	6873	2278	0.00
18:11:02	5 Event(Eng)		RESUME PUMPING	
18:11:02	5	7239	2367	0.00
18:12:02	5	7694	2426	4.18
18:13:02	5	8434	2440	5.10
18:14:02	5 Event(Eng)	PRESSURE BREAK AT 9000PSI		
18:14:02	5	8891	2411	5.11
18:15:02	5	8952	2350	5.52
18:16:02	5	9814	2296	7.05
18:17:02	5	9831	2203	6.76
18:18:02	5	9875	2099	6.78
18:19:02	5	9919	1995	6.67
18:20:02	5	9954	1896	6.63
18:21:02	5	10000	1852	6.15
18:22:02	5	9622	2000	6.05
18:23:02	5	9607	1903	6.16
18:24:02	5	9620	1822	6.17
18:25:02	5	8541	1978	4.22
18:26:02	5	8562	1933	3.72
18:27:02	6 Event(Eng) Operator Stage Advance			
18:27:02	6	7285	1880	0.00
18:28:02	6	7269	1913	0.00
18:29:02	6	7259	1954	0.00
18:30:02	6	7251	2001	0.00

EEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEE

Customer:	PARKER & PARSLEY DEV. CO.	Date:	APR-03-1993
Well Desc:	OVERBY	Ticket #:	30840901
Formation:	SLIGO	Job Type:	SWIC ACID BALLOUT

WELLBORE CONFIGURATION

Wellbore Segment Number	Actual Length (feet)	TVD (feet)	Casing ID (inch)	Casing OD (inch)	Tubing ID (inch)	Tubing OD (inch)
1	14088	14088	4.276	5.000	2.441	2.875
2	15874	15874	4.276	5.000	0.000	0.000

PERFORATIONS DATA

of Perforations 15
Perf. Diameter .3
Balled Out? (YES/NO) yes

PERFORATED INTERVALS

FROM (feet)	TO (feet)	SPF
15874	16056	1

Well Desc: OVERBY #2
Formation: SLIGO

Ticket #: 30840901
Job Type: SWIC ACID BALLOUT

MATERIALS INVENTORY

Treatment Fluid:	SWIC ACID	Density	8.96	lb/gal	
Displacement Fluid:	TREATED WATER	Density	8.33	lb/gal	
Surfactant Type:	LOSURF 300	gal	20	@ 1	gal/Mgal
Clay Control:	CLAYFIX II	gal	40	@ 2	gal/Mgal
Friction Reducer:	FR-26	gal	20	@ 1	gal/Mgal
Perfpac Balls:	30	Qty	7/8	Size 1.3	S.G.

Customer: PARKER & PARSLEY DEV. CO.
Well Desc: OVERBY
Formation: SLIGO

Date: APR-03-1993
Ticket #: 30840901
Job Type: SWIC ACID BALLOUT

MATERIALS ON LOCATION

STARTING FLUID VOLUME ______20000(gal)

Well Desc: OVERBY #2
Formation: SLIGO

Ticket #: 30840901
Job Type: SWIC ACID BALLOUT

ACID DATA

Acid Type:	SWIC	%	11	gal	10000	
Surfactant Type:	HC-2	gal	50	@	5	gal/Mgal
NE Agent Type:	SPERSE ALL	gal	50	@	5	gal/Mgal
Corrosion Inh.:	HAI-85	gal	200	@	20	gal/Mgal
Corrosion Inh.:	HII-500	gal	200	@	20	gal/Mgal
Cracking Inh.:	SCA-130	gal	200	@	20	gal/Mgal
Iron Sequester:	FE-3	lb	1000	@	100	lb/Mgal
Friction Reducer:	SGA-HT	gal	30	@	3	gal/Mgal
Other:	ABF	LB	120		12	lb/Mgal

Customer:	PARKER PARSLEY DEV. CO.	Dat	APR-03-1993
Well Desc:	OVERBY #2	Ticket #:	30840901
Formation:	SLIGO	Job Type:	SWIC ACID BALLOUT

JOB SCHEDULE

STAGE DESCRIPTIONS

Stage	Description
1	TREATED WATER - LOAD HOLE, EST. RATE
2	SWIC ACID
3	SWIC ACID WITH 30 BALLS
4	SWIC ACID
5	TREATED WATER - FLUSH
6	SHUTDOWN MONITOR PRESSURE

Customer: PARKER & PARSLEY DEV. CO.
Well Desc: OVERBY
Formation: SLIGO

Date: APR-03-1993
Ticket #: 30840901
Job Type: SWIC ACID BALLOUT

JOB SCHEDULE

STAGE INFORMATION

	1	2	3	4	5	6
Fluid Type	FR-26LC	SGA-HT 15%	SGA-HT 15%	SGA-HT 15%	FR-26LC	FR-26LC
Planned Clean Volume (gal)	5000	3000	5000	2000	6000	0
Planned Slurry Volume (gal)	5000	3000	5000	2000	6000	0
Actual Slurry Volume (gal)	4764	2997	5002	3217	5628	2
Base Fluid Density (lb/gal)	8.33	8.96	8.96	8.96	8.33	8.33
Concentration	1.00	3.00	3.00	3.00	1.00	1.00
Proppant Size						
Proppant Type						
Abs. Proppant Volume (gal/lb)	0.04530	0.04530	0.04530	0.04530	0.04530	0.04530
Planned Fluid Rate (bpm)	8.00	10.00	10.00	10.00	10.00	0.00
Planned Prop Conc (lb/gal)	0.00	0.00	0.00	0.00	0.00	0.00

Customer:	PARKER & PARSLEY DEV. CO.	Date:	Apr 3, 1993
Well Desc:	OVERBY	Ticket #:	30840901
Formation:	SLIGO	Job Type:	SWIC ACID BALLOUT

STAGE SUMMARY

Stage Times

Stage	Start Time	End Time	Elapsed Time	Time at Perfs
1	16:07:05	16:23:44	00:16:39	16:25:09
2	16:23:44	16:45:47	00:22:03	16:58:54
3	16:45:47	17:23:04	00:37:17	17:21:16
4	17:23:04	17:48:11	00:25:07	18:01:29
5	17:48:11	18:26:43	00:38:32	18:22:26
6	18:26:43	18:37:38	00:10:55	?
Total			02:30:33	

Stage	Tubing Pressure (psi)	Annulus Pressure (psi)	BHP Calc'd Pressure (psi)	Slurry Rate (bpm)	Slurry Volume (gal)
1	7748	1613	13382	6.44	4767
2	9615	1940	16354	3.24	2996
3	9626	1943	16518	3.19	5002
4	9560	1961	16495	3.05	3215
5	9005	2036	15742	3.48	5629
6	4293	1578	11097	0.01	2
Tot/Avg	8860	1906	15552	3.38	21610

Customer: PARKER & PARSLEY DEV. CO.
Well Desc: OVERBY
Formation: SLIGO

Date: APR-03-1993
Ticket #: 30840901
Job Type: SWIC ACID BALLOUT

EVENT REPORT

	stage	Event mneum	Time HH:MM:SS	Event Description	
e	1	stgad	16:07:05	Operator Stage Advance	--> TREATED WATER - LOAD HOLE, EST. RATE
e	2	stgad	16:23:44	Operator Stage Advance	--> SWIC ACID
e	3	stgad	16:45:47	Operator Stage Advance	--> SWIC ACID WITH 30 BALLS
e	4	stgad	17:23:04	Operator Stage Advance	--> SWIC ACID
e	5	stgad	17:48:12	Operator Stage Advance	--> TREATED WATER - FLUSH
e	5	NOTES	18:06:36	Operator's Notes	*** SHUT DOWN TO SURGE BALLS ISIP 9320
e	5	NOTES	18:10:44	Operator's Notes	*** RESUME PUMPING
e	5	NOTES	18:14:01	Operator's Notes	*** PRESSURE BREAK AT 9000PSI
e	6	stgad	18:26:43	Operator Stage Advance	--> SHUTDOWN MONITOR PRESSURE
e	6	NOTES	18:31:25	Operator's Notes	*** ISIP = 7285 PSI FG = .889
e	6	NOTES	18:32:46	Operator's Notes	*** 5 MIN SIP = 7238 PSI

Plugging Record X

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 12/92
EAG0897

API NO (if available) 42-025-30388

1. RRC District: 02

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

4. RRC Lease or Id. Number: 064112

2. FIELD NAME (as per RRC Records): Pawnee (Sligo)
3. Lease Name: Overby, Charlie C. Gas Unit
5. Well Number: 1
6. OPERATOR: Pioneer Natural Resources USA, Inc.
6a. Original Form W-1 Filed in Name of:
10. County: Bee
7. ADDRESS: 5205 N. O'Connor Blvd., Ste. 900 Irving, TX 75039-3736
6b. Any Subsequent W-1's Filed in Name of:
11. Date Drilling Permit Issued: —
8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located: 1625 Feet From W Line and 1750 Feet From S Line of the Survey Lease
12. Permit Number: —
9a. SECTION, BLOCK, AND SURVEY: Marcelo Alcarte A-70
9b. Distance and Direction From Nearest Town in this County: 3.5 miles South of Pawnee
13. Date Drilling Commenced: unk
16. Type Well (Oil, Gas, Dry): Gas
Total Depth: 16,300
17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s — GAS ID or OIL LEASE # / Oil-O Gas-G / WELL #
14. Date Drilling Completed: unk
18. If Gas, Amt. of Cond. on Hand at time of Plugging:
15. Date Well Plugged: 3-6-07

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	2-27	2-27	3-2	3-5	3-6	3-6		
20. Size of Hole or Pipe in which Plug Placed (inches)	3 1/2	3 1/2	7	7	7	7		
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	9310	9200	3800	3563	300	15		
*22. Sacks of Cement Used (each plug)	1	1	35	55	55	6		
*23 Slurry Volume Pumped (cu ft)	1.06	1.06	37.10	58.30	58.30	6.36		
*24. Calculated Top of Plug (ft.)	9280	9180	3650	3428	200	5		
25. Measured Top of Plug (if tagged) (ft.)					187			
*26. Slurry Wt. #/Gal.	16.4	16.4	16.4	16.4	16.4	16.4		
*27. Type Cement	H	H	H	H	H	H		

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT.#/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (IN.)
16	49.50	61	61	UNK.
10 3/4	45.50	3513	3508	15"
7	49.50	15,529	15,524	8 3/4
4"	UNK	15055-16290	14247	

29. Was any Non-Drillable Material (Other than Casing) Left in This Well: [x] Yes [ ] No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed)
Left 3 1/2 tubing in well from 3800' to 15,055'. An existing fish of 1 1/4" tubing from 9340' to 16,143' also left in well.

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM	15,911	TO	16,072	FROM		TO	
FROM		TO		FROM		TO	
FROM		TO		FROM		TO	
FROM		TO		FROM		TO	
FROM		TO		FROM		TO	

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.
* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

RECEIVED
CENTRAL RECORDS
JUN 01 2007
AUSTIN, TEXAS

[signature] — Signature of Cementer or Authorized Representative
Pat's P & A, Inc. — Name of Cementing Company

CERTIFICATE
I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct and complete, to the best of my knowledge

Doug Kimbell — REPRESENTATIVE OF COMPANY
Prod Supt. — TITLE
3-22-07 — DATE
Phone 361 364-1732 — A/C NUMBER

SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

MAPPING

31. Was Well filled with Mud-Laden Fluid, according to the regulations of the Railroad Commission	[X] Yes [ ] No	32. How was Mud Applied? Circulated	33. Mud Weight 12.5 LBS/GAL

34. Total Depth 16,300 Depth of Deepest Fresh Water 250	Other Fresh Water Zones by T.D.W.R. TOP BOTTOM	35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules? [ ] Yes [ ] No 36. If NO, Explain

37. Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well
Pat's P & A, Inc. P.O. Box 0126, Bishop TX 78343

Date RRC District Office notified of plugging 2-23-07

38. Name(s) and Addresse(s) of Surface Owners of Well Site

39. Was Notice Given Before Plugging to the Above?

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

[ ] Log Attached [ ] Log released to ______ Date ______

Type Logs:
[ ] Driller's [ ] Electric [ ] Radioactivity [ ] Acoustical/Sonic

41. Date FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging ______ bbls*
* Field FORM P-1 (Oil Production Report) for month this oil was produced

~~RRC USE ONLY~~

Nearest Field ______

REMARKS Unable to recover 3 1/2" tbg. as anticipated above existing 1 1/4" fish @ 9340'. Jet cut 3 1/2" @ 9302' & 9243'. Unable to pull or establish circulation up 3 1/2 x 7" @ 3500 P.S.I.. Freepoint on 3 1/2 csg. at 4750 ±. Notified and received approval from Kevin Shamette W/RRC to set CIBP's + 20' cmt below and above cut's made on 3 1/2. Plug #1 & #2 - CIBP + 20' cmt. in 3 1/2" 12.95#. Cut 3 1/2 @ 4762'and perforated 3 1/2" @ 4765' but unable to pull or circulate. Re-cut @ 3800'. Received verbal approval from Kevin Shamette W/RRC to set plug from 3800' tp 3650' Cut & perforated 7" casing @ 3563'. Casing not free. Unable to establish circulation but established injection into 7" x 8 3/4" @ 2000 P.S.I. Notified Kevin W/RRC to squeeze plug. Squeezed 55 sks. cmt. leaving 23 sks. inside 7" 49.50# and 32 sks. outside in 7" x 8 3/4". Cut 7" csg. @ 300' but unable to circulate. Received verbal approval to squeeze 55 sks. Squeezed 38 sks. out into 7" x 9 5/8" and left 17 sks inside 7" casing.

O'Neal Gas Unit No. 4

Area of Review: Oil & Gas Wells List

API	WELL NAME	WELL NO.	CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (TVD FT.)	PERFORATED INTERVAL (MD FT.)	DATE DRILLED
4202500002	ONEAL, A.	1	ROWAN & HOPE	126	28.603017	-98.000911	DRILLED	7010	NO RECORD	8/9/1949
4202500005	RUSSELL, S.	1	PAN AMERICAN PETROLEUM CORP.	308	28.594587	-97.999841	DRILLED	7515	NO RECORD	5/12/1947
4202530346	HENRY BUES	1	PIONEER NATURAL RES. USA, INC.	70	28.5986210	-98.0118480	INACTIVE PRODUCER	13842	7554-7558; 7612-7624; 13526-13760	11/10/1974
4202530359	ONEAL GAS UNIT	2	BB-SOUTHTEX, LLC	127	28.61178	-98.000661	PRODUCING	13961	13349-15821	4/5/1975
4202530388	OVERBY, CHARLIE C. GAS UNIT	1	PIONEER NATURAL RES. USA, INC.	70	28.601086	-98.005037	P & A	16300	15911-16072	6/6/1975
4202532342	DE LEON	1	T D EXPLORATION, INC.	126	28.6006330	-97.9917520	P & A	6512	NO RECORD	12/31/1985
4202532501	HENRY BUES GAS UNIT	2	BB-SOUTHTEX, LLC	70	28.599863	-98.009994	PRODUCING	13896	13504-15637	11/15/1988
4202532638	ONEAL GAS UNIT	3	BB-SOUTHTEX, LLC	70	28.604583	-98.007079	PRODUCING	13834	13508-13668	3/12/1992
4202532842	OVERBY, CHARLIE C.	1E	PIONEER NATURAL RES. USA, INC.	70	28.5998760	-98.0053330	P & A	14000	13514-13838	10/9/1995
4202532967	TOMASEK GAS UNIT	5	BB-SOUTHTEX, LLC	126	28.609862	-97.991519	PRODUCING	13875	13434-15693	6/12/1999
4202533006	ONEAL GAS UNIT	5	BB-SOUTHTEX, LLC	70	28.6067950	-98.0042210	PRODUCING	13772	13463-13764	7/15/2000
4202533035	ONEAL GAS UNIT	6	BB-SOUTHTEX, LLC	127	28.61091	-97.999073	PRODUCING	13835	13310-13833	9/14/2000
4202533085	ONEAL GAS UNIT	7	BB-SOUTHTEX, LLC	127	28.609397	-98.001471	PRODUCING	13868	13314-16072	5/4/2001
4202533114	HENRY BUES GAS UNIT	8	BB-SOUTHTEX, LLC	70	28.5984810	-98.0090260	PRODUCING	13732	13348-13732	6/11/2001
4202533197	ONEAL GAS UNIT	8	BB-SOUTHTEX, LLC	452	28.6075430	-98.0037990	PRODUCING	15638	13565-13820	2/5/2003

O'Neal Gas Unit No. 4

4202533272	HENRY BUES GAS UNIT	11	BB-SOUTHTEX, LLC	70	28.598737	-98.008615	PRODUCING	13856	13291-15853	6/23/2004
4202533273	ONEAL GAS UNIT	9	BB-SOUTHTEX, LLC	452	28.6029540	-98.0025090	PRODUCING	13872	13311-16585	6/3/2004
4202533328	ONEAL GAS UNIT	11	BB-SOUTHTEX, LLC	126	28.6036340	-97.9982100	PRODUCING	13787	13318-15928	4/19/2005
4202533345	TOMASEK GAS UNIT	8	BB-SOUTHTEX, LLC	126	28.608282	-97.991595	PRODUCING	13692	13293-16378	8/14/2004
4202533371	ONEAL GAS UNIT	12	BB-SOUTHTEX, LLC	452	28.6097460	-98.0027040	PRODUCING	13819	13313-16635	8/15/2006
4202533383	HENRY BUES GAS UNIT	15	BB-SOUTHTEX, LLC	70	28.600322	-98.00874	PRODUCING	13811	13302-15768	10/8/2006
4202533492	ONEAL GAS UNIT	13	BB-SOUTHTEX, LLC	70	28.605326	-98.012928	PRODUCING	13859	13382-14761	7/7/2007
4202533553	ONEAL GAS UNIT	14	BB-SOUTHTEX, LLC	127	28.613869	-98.000504	PRODUCING	13674	13450-15424	2/11/2008
4202533559	OVERBY GAS UNIT	2E	BB-SOUTHTEX, LLC	452	28.6011410	-98.0028580	PRODUCING	13734	13372-13734	3/23/2008
42025E2114	NO RECORD	NR	NO RECORD	126	28.608457	-97.995683	NO RECORD	NR	NO RECORD	NR

*Note: Well entries in red penetrate the upper confining layer.

LONQUIST SEQUESTRATION LLC

O'Neal Gas Unit No. 4

Area of Review: Freshwater Wells List

WELL REPORT/ID NO.	OWNER'S NAME	OWNER ADDRESS	CITY/STATE/ZIP	LAT. WGS 84	LONG. WGS 84	WELL USE	WATER LEVEL (FT.)	TOTAL DEPTH (FT.)	DATE DRILLED
128936	JOHN DAVIDSON	12761 FM 673	KENEDY, TX 78119	28.606667	-98.011667	DOMESTIC	48	114	11/19/2007
7832308	HENRY BUES	NO RECORD	NO RECORD	28.598334	-98.012223	STOCK	-	150	1960
7925105	T. M. PLUMER	NO RECORD	NO RECORD	28.595556	-97.997778	STOCK	77	275	1931
7832309	W. A. MUELLER	NO RECORD	NO RECORD	28.608612	-98.005834	UNUSED	63	90	1925
7925106	R.C. HUNT ESTATE	NO RECORD	NO RECORD	28.593889	-97.997222	UNUSED	137	172	1925

Request for Additional Information: O'Neal Gas Unit Well No. 4
March 1, 2024

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

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
1.	NA	NA	There is a lack of consistency with hyphens, bolding, quotation marks, spelling, and capitalization in the MRV plan. Examples include but are not limited to: Loann salt vs. Louann salt CO_2 vs. CO2 We recommend reviewing the formatting in the MRV plan for consistency. Furthermore, we recommend doing an additional review for spelling, grammar, etc.	The document has been reviewed and edited to address the issues identified. There are numerous edits made to the MRV plan: 1) in response to this RAI; 2) in grammatical edits subsequent to the RAI responses for better clarification; and 3) deletions of material no longer relevant based on these edits.
2.	Multiple	Multiple	There are several references to "production" in the MRV plan, such as, "Any vertical migration from the Injection Zone would return the CO_2 to the production zone" (p. 52). However, the plan indicates that "no CO_2 will be produced" (p. 72). In the MRV plan, please provide additional explanation as to whether any CO_2 is produced at this facility and what the relationship of the facility is to any producing wells.	These references have been edited to clarify the use of "production". The intent is to utilize shallower hydrocarbon production formations as an early indicator of vertical migration of CO_2 from the Sligo. These wells would act as an above zone monitoring well in that they can provide early indication of CO_2 release and protect the USDW. No CO_2 is intended to be produced.
3.	2.2.4	23	"Based on the results of the investigation, in-situ Sligo reservoir fluid is anticipated to contain approximately 150,000 parts per million TDS..." This value differs from what is listed in Table 3. Please ensure all values mentioned in the text are consistent with what is listed in the tables.	This has been edited to reference only Sligo fluid samples. In the absence of an actual sample from the O'Neal No. 4, we took a conservative approach and rounded down to 150,000 ppm. This would yield a slightly larger plume, thus being conservative

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
4.	2.8.1	41-45	We recommend including units in Figures 25-28.	A scale has been added to these figures.
5.	Table 8	52	Please explain what is meant by Post Injection Site Care periods and UCZs in Table 8. These terms are not defined in the plan.	Table 7 (previously 8) has been updated to define these terms.
6.	Table 8	52	The leakage characterization for "Existing wells within the MMA" is described as "Unlikely. The lateral continuity of the UCZ is recognized as a very competent seal." Please explain why the competence of the seal would affect potential leakage through wells, and/or update this text as necessary.	Table 7 has been edited to clarify this comment.
7.	Table 8	52	The magnitude of potential leakage for each potential leakage pathway is described as "low". Please elaborate what is meant by this characterization.	A Magnitude Assessment Description has been added to Table 7.
8.	Table 10	63	Table 10 appears to have been corrupted, we recommend replacing this table.	Table 9 (previously 10) has been updated.
9.	5.1/6.4	64/69	"Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR §98.448(a)(5)". We recommend also referencing 40 CFR 98.444(d) here.	40 CFR 98.444(d) has been added to both sections.
10.		69	Please clarify what types of measurements will be taken for the soil gas and water sampling. Is this different from what is described in "6.5 Groundwater Monitoring"? Furthermore, does "fixed monitors" refer to H_2S monitors, CO_2 monitors, or both?	Sections 6.2 and 6.5 have been updated. Fixed monitors and detectors refer to H_2S monitors, as H_2S is a proxy for CO_2 as it is a combined gas stream. The operating areas must have H_2S monitors for safety requirements.
11.	5.4	67	Please include additional discussion on the potential risk for induced seismicity. For example, will the facility take precautions to ensure that seismicity is not induced?	Language has been added to Section 5.4 for monitoring and mitigation of induced seismicity.

No.	MRV Plan		EPA Questions	Responses
	Section	Page		
12.	7.5	73	"CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead" Per 40 CFR 98.443(F)(2), this variable should be "CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of this part." Equations and variables cannot be modified from the regulations. Please revise this section and ensure that all equations listed are consistent with the text in 40 CFR 98.443.	This equation is confirmed to be consistent with 40 CFR 98.443(F)(2).
13.	8	74	Per 40 CFR 98.448(a)(7), please include a specific "proposed date to begin collecting data for calculating total amount sequestered according to equation RR–11 or RR–12 of this subpart. This date must be after expected baselines as required by paragraph (a)(4) of this section are established and the leakage detection and quantification strategy as required by paragraph (a)(3) of this section is implemented in the initial AMA."	The Class II permit is still in-process with the TRRC. Until this is issued, Ozona cannot specify a date certain. The plan provides for all baseline testing and results prior to commencing of injection. Upon approval of the MRV plan and completion of the baseline testing, Ozona will commence data collection for reporting sequestered quantities.

Subpart RR Monitoring, Reporting, and Verification (MRV) Plan
O'Neal Gas Unit Well No. 4

Bee County, TX

Prepared for *Ozona CCS, LLC*
San Antonio, TX

By

Lonquist Sequestration, LLC
Austin, TX

Version 2.0
January 2024

INTRODUCTION

Ozona CCS, LLC (“Ozona”) has a pending Class II acid gas injection (“AGI”) permit application with the Texas Railroad Commission (“TRRC”), which was submitted in September of 2023, for its O’Neal Gas Unit Well No. 4 (“O’Neal No. 4”), API No. 42-025-32658. Granting of this application would authorize Ozona to inject up to 1.5 million standard cubic feet per day (“MMscf/d”) of treated acid gas (“TAG”) into the Sligo formation at a depth of 15,874 feet to 16,056 feet with a maximum allowable surface pressure of 7,920 psig. The TAG for this AGI well is associated with StarTex’s Pawnee Gas Plant (the “Plant”), located in a rural area of Bee County, Texas, approximately 2.0 miles south of Pawnee, Texas, as shown in Figure 1.

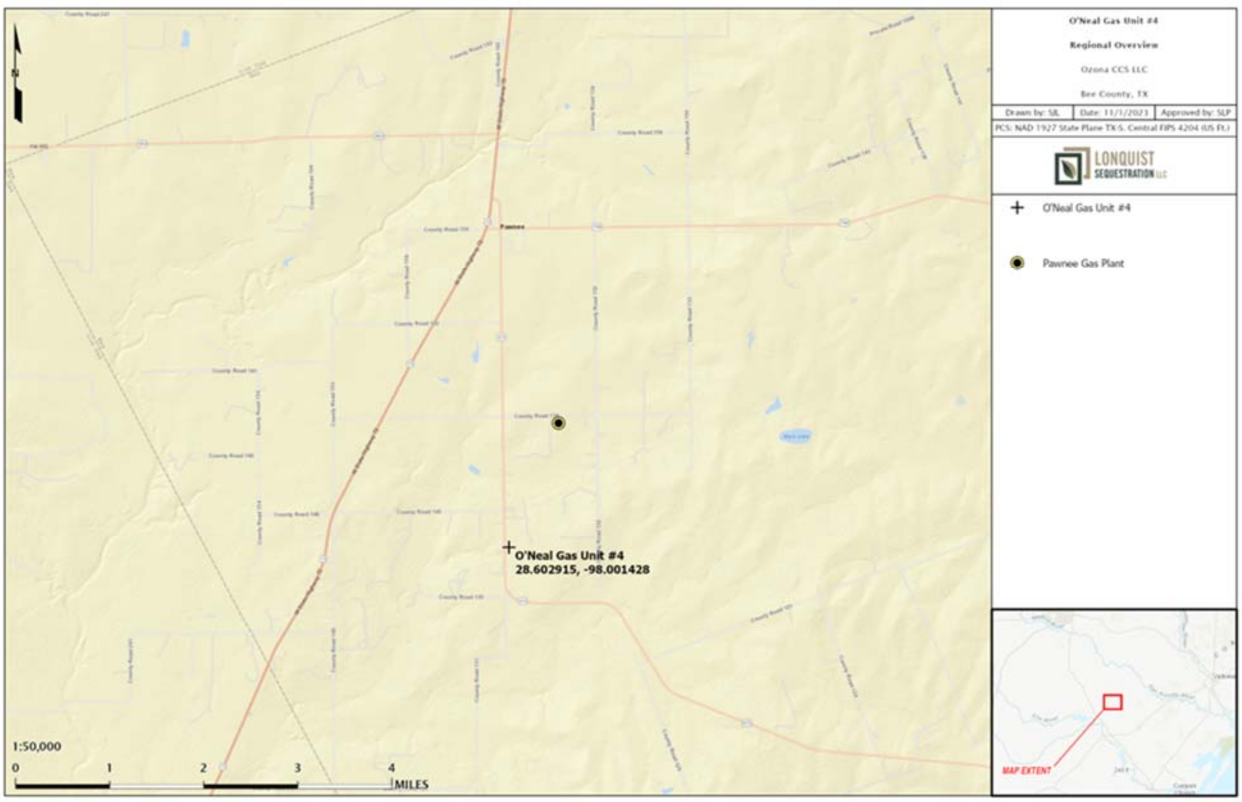


Figure 1 – Location of StarTex Gas Plant and the O’Neal No. 4

Ozona is submitting this Monitoring, Reporting, and Verification ("MRV") plan to the EPA for approval under 40 CFR **98.440(a)**, Subpart RR, of the Greenhouse Gas Reporting Program ("GHGRP"). In addition to submitting this MRV plan to the EPA, Ozona has applied to the TRRC for the O'Neal GU No. 4's Class II permit. Ozona plans to inject TAG for approximately 12 years. Table 1 shows the expected composition of the gas stream to be sequestered from the nearby StarTex Pawnee Gas Plant.

Table 1 – Expected TAG Composition

Component	Mol Percent
Carbon Dioxide	98.2%
Hydrocarbons	1.03%
Hydrogen Sulfide	0.4%
Nitrogen	0.37%

ACRONYMS AND ABBREVIATIONS

%	Percent (Percentage)
°C	Degrees Celsius
°F	Degrees Fahrenheit
AMA	Active Monitoring Area
BCF	Billion Cubic Feet
CH_4	Methane
CMG	Computer Modelling Group
CO_2	Carbon Dioxide (may also refer to other Carbon Oxides)
E	East
EOS	Equation of State
EPA	U.S. Environmental Protection Agency
ESD	Emergency Shutdown
FG	Fracture Gradient
ft	Foot (Feet)
GAPI	Gamma Units of the American Petroleum Institute
GAU	Groundwater Advisory Unit
GEM	Computer Modelling Group's GEM 2023.2
GHG	Greenhouse Gas
GHGRP	Greenhouse Gas Reporting Program
GL	Ground Level Elevation
H_2S	Hydrogen Sulfide
JPHIE	Effective Porosity (corrected for clay content)
mD	Millidarcy
mi	Mile(s)
MIT	Mechanical Integrity Test
MM	Million
MMA	Maximum Monitoring Area

MCF	Thousand Cubic Feet
MMcf	Million Cubic Feet
MMscf	Million Standard Cubic Feet
Mscf/D	Thousand Standard Cubic Feet per Day
MMscf/D	Million Standard Cubic Feet per Day
MRV	Monitoring, Reporting, and Verification
ν	Poisson's Ratio
N	North
NW	Northwest
OBG	Overburden Gradient
PG	Pore Gradient
pH	Scale of Acidity
ppm	Parts per Million
psi	Pounds per Square Inch
psig	Pounds per Square Inch Gauge
S	South
SE	Southeast
SF	Safety Factor
SWD	Saltwater Disposal
TAC	Texas Administrative Code
TAG	Treated Acid Gas
TOC	Total Organic Carbon
TRRC	Texas Railroad Commission
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
W	West

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SECTION 1 – UIC INFORMATION

This section contains key information regarding the Underground Injection Control (UIC) Permit.

1.1 Underground Injection Control Permit Class: Class II

The TRRC regulates oil and gas activities in Texas and has primacy to implement the Underground Injection Control ("UIC") Class II program. TRRC classifies the O'Neal No. 4 as a UIC Class II well. Ozona has applied for a Class II permit for the O'Neal No. 4 under TRRC Rule 36 (entitled "Oil, Gas, or Geothermal Resource Operation in Hydrogen Sulfide Areas") and under TRRC Rule 46 (entitled "Fluid Injection into Productive Reservoirs").

1.2 UIC Well Identification Number

- O'Neal No. 4, API No. 42-025-32658, UIC # 56819

1.3 Facility Address

- Gas Plant Facility Name: StarTex Pawnee Gas Plant
- Operator: StarTex Field Services, LLC
- Coordinates in NAD83 for this facility:
    - Latitude: 28.622211
    - Longitude: -97.992772

SECTION 2 – PROJECT DESCRIPTION

This section discusses the geologic setting, planned injection process and volumes, and the reservoir and plume modeling performed for the O’Neal No. 4.

The O’Neal No. 4 will inject the TAG stream into the Sligo formation at a depth of 15,874 feet to 16,056 feet, and approximately 14,924 feet below the base of the Underground Source of Drinking Water (USDW). Therefore, the well and the facility are designed to protect against the leakage out of the injection interval, to protect against contaminating other subsurface formations, and most critically to prevent surface releases.

2.1 Regional Geology

The O’Neal No. 4 (API No. 42-025-32658) is located in south Texas within the Gulf of Mexico Basin. The onshore portion of the Gulf of Mexico basin spans approximately 148,049,000 acres and encompasses portions of Texas, Louisiana, Mississippi, Alabama, Arkansas, Missouri, Kentucky, Tennessee, Florida, and Georgia to the state-waters boundary of the United States (Roberts-Ashby et al., 2012). The location of the O’Neal No. 4 is designated by the red star in Figure 2 relative to the present coastal extent and major structural features of the basin.

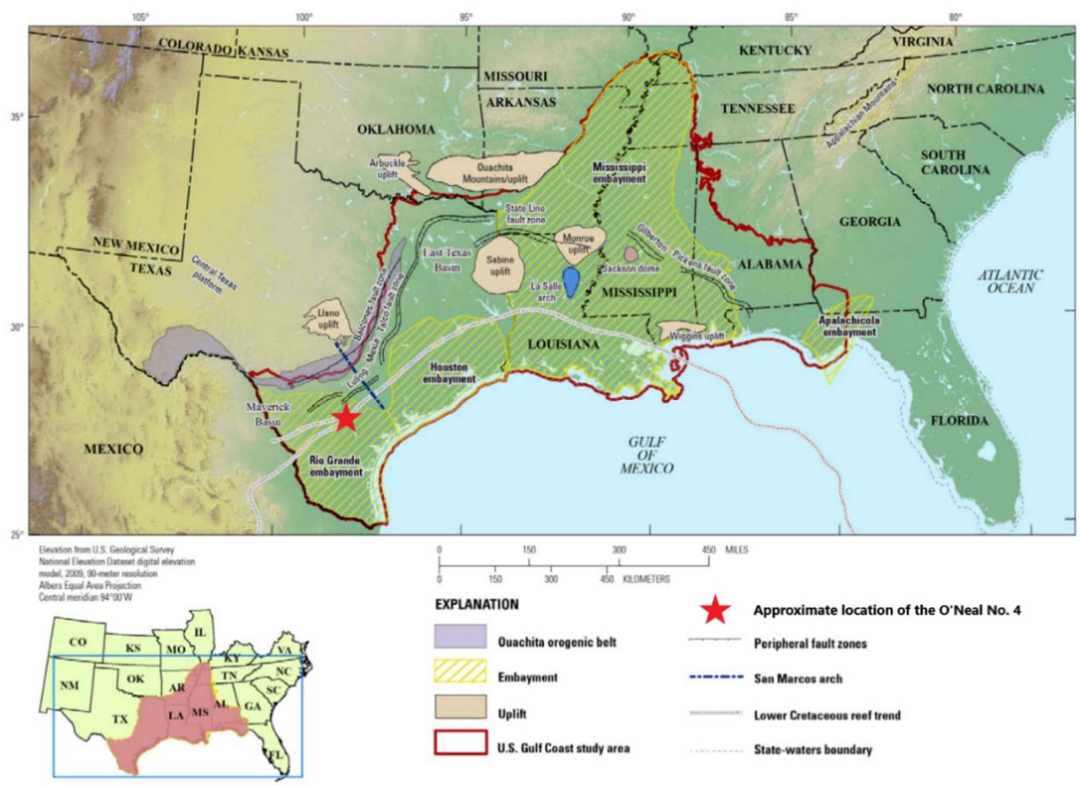

Figure 2 – Structural features of the Gulf of Mexico and locator map (modified from Roberts-Ashby et al., 2012)

Figure 3 depicts a generalized stratigraphic column of the U.S. Gulf Coast with light blue shading signifying the proposed injection interval and green stars indicating productive formations identified within five miles of the O'Neal No. 4. The injection interval is found within the Sligo formation with confinement provided by the overlying Pearsall formation and tight underlying facies of the Lower Sligo and Hosston formations.

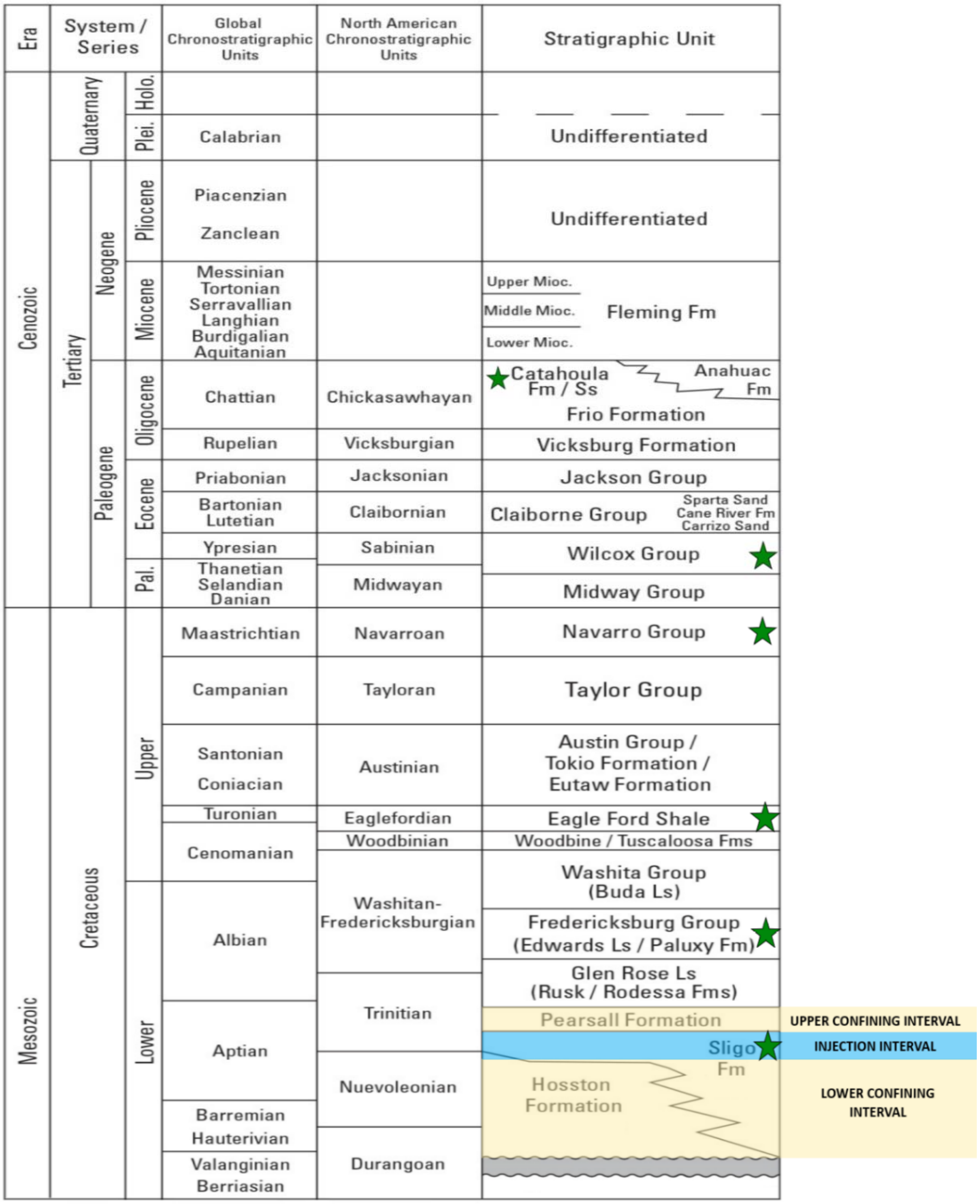

Figure 3 – Stratigraphic column of the U.S. Gulf Coast signifying proposed injection and confining intervals. Offset productive intervals are noted with a green star (modified from Roberts-Ashby et al., 2012)

The targeted formations of this study are located entirely within the Trinity Group, as clarified by the detailed stratigraphic column provided in Figure 4. During this time the area of interest was located along a broad, shallow marine carbonate platform that extended along the northern rim of the ancestral Gulf of Mexico. The Lower Cretaceous platform spanned approximately 870 miles from western Florida to northeastern Mexico with a shoreline to basin margin that ranged between 45 to 125 miles wide (Yurewicz, D.A., et al, 1993).

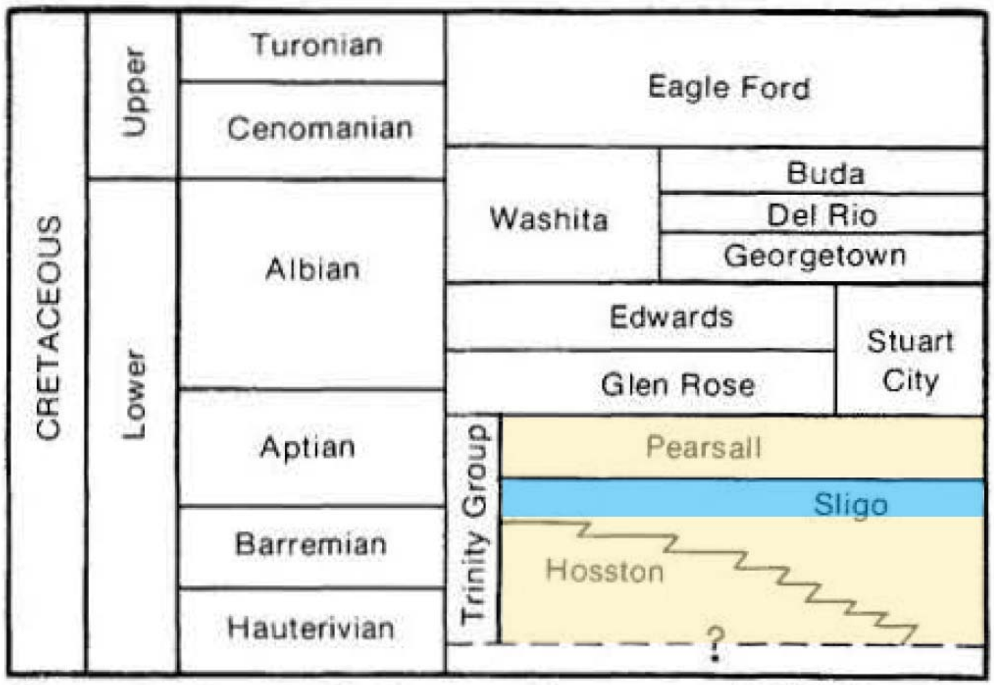

Figure 4 – Detailed stratigraphic column of Lower Cretaceous formations of south Texas. The proposed injection interval is shaded light blue and proposed confining intervals are shaded light yellow (modified from Bebout, D.G., et al., 1981)

2.1.1 Geologic Setting and Depositional Environment

The depositional environment during the Lower Cretaceous generally consisted of a well-defined platform margin with a shallow marine platform interior or lagoon to the north, a shallow marine outer platform to the south, and a foreslope that gradually dipped southward towards the basin center. The platform margin remained stable for tens of millions of years during the Cretaceous but experienced episodic changes in sea level that resulted in cyclic deposition of several key facies that vary both spatially and within the geologic section. Facies distributions were heavily impacted by positioning relative to the margin, the height of the water column at any given time, and the degree of energy or wave action within the system (Galloway, 2008; Yurewicz, D.A., et al, 1993).

In general, long stands of reef development and ooid shoaling developed primary porosity and permeability along the shallow, high-energy carbonate platform and represent reservoir quality rock found within Cretaceous reef deposits. Deeper, basinward deposits tend to result in tighter petrophysical properties due to a relative increase in the amount of entrained clay associated with the heightening of the water column whilst moving down-slope. Backreef deposits have the potential for porosity development but tend to have low permeability due to a general lack of wave action caused by restricted access to open water by the platform margin. Facies and petrophysical properties of the Lower Cretaceous section are anticipated to be relatively homogenous moving southwest-northwest along reef trend with increased heterogeneity moving northwest-southeast due to the orientation of the carbonate rim and its effect on deposition and facies distributions (Yurewicz, D.A., et al, 1993).

Figure 5 displays the paleogeography during deposition of the Lower Cretaceous section to visually demonstrate the position of the O'Neal No. 4 relative to the Sligo shelf margin and up-dip extents of Sligo deposition. A generalized schematic cross-section of the Trinity Group is provided in Figure 6 which nearly intersects the project area from the northwest. The schematic illustrates the gross section thickening basinward with primary reservoir development improving with proximity to the reef margin. Figure 7 displays a depositional model of the Lower Cretaceous carbonate platform to visually conceptualize depositional environments and anticipated petrophysical properties of facies introduced above.

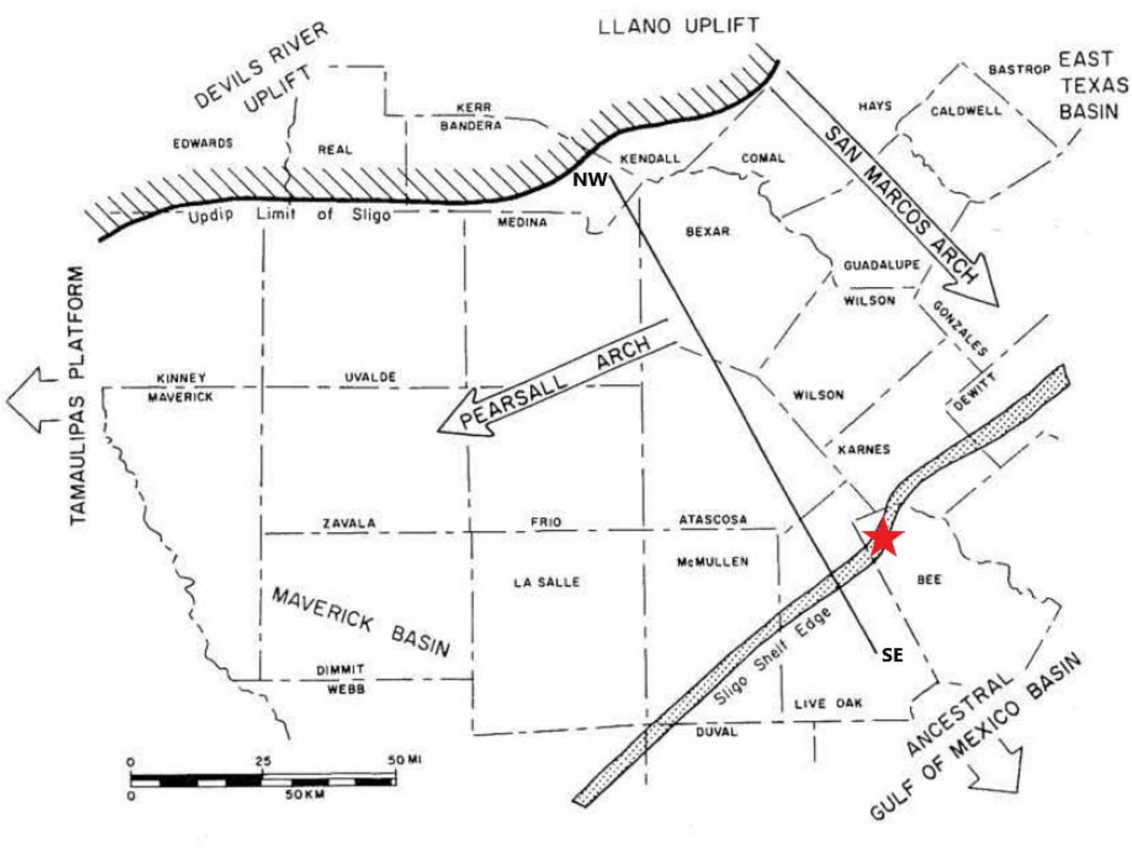

Figure 5 – Paleogeography of the Lower Cretaceous of south Texas. The red star represents the approximate location of the O'Neal No. 4 (modified from Bebout, D.G., et al., 1981)

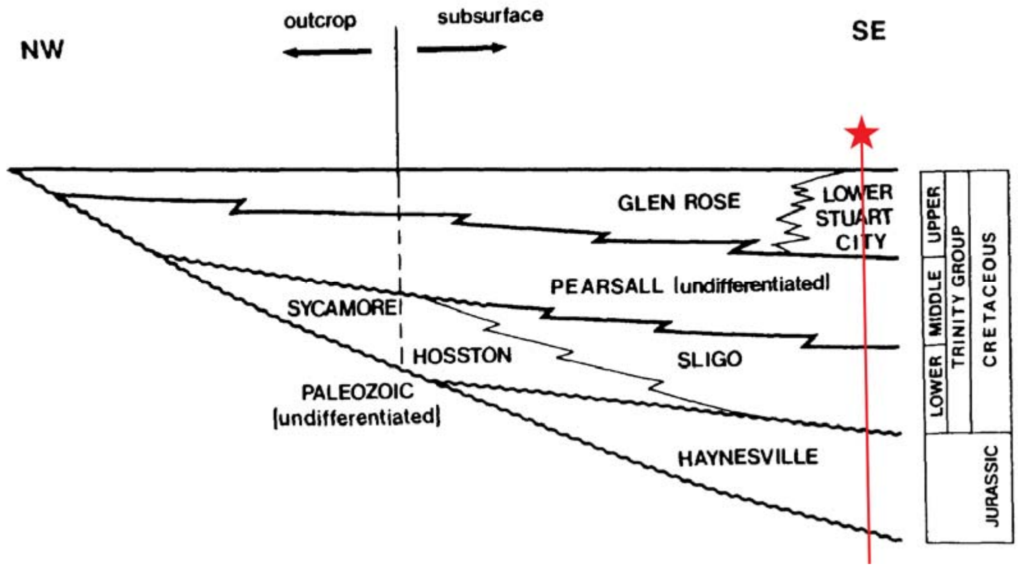

Figure 6 – Generalized northwest to southeast schematic cross-section of the Trinity Group, south Texas. The line of section depicted in Figure 5. The red star and line represent the approximate location of the O'Neal No. 4 (modified from Kirkland, B.L., et al., 1987)

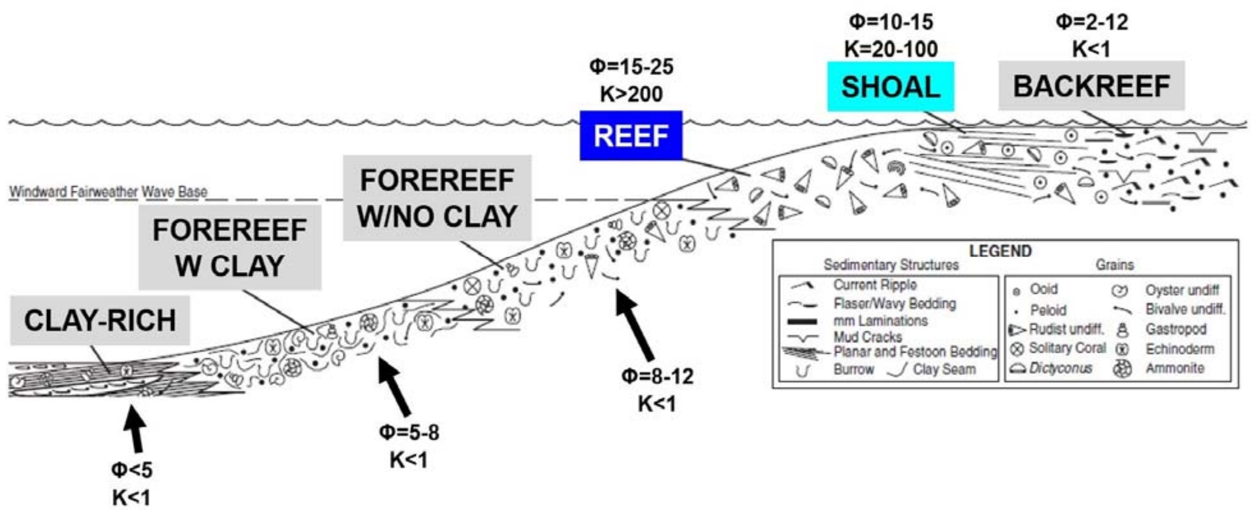

Figure 7 – Depositional model for the Lower Cretaceous carbonate platform w/ estimated porosity and permeability values of typical facies (modified from Talbert and Atchley, 2000)

2.1.2 Regional Structure and Faulting

The Gulf of Mexico basin was formed by crustal extension and sea-floor spreading associated with the Mesozoic breakup of Pangea. Rifting of northwest to southeast trending transfer faults during the Middle Jurassic lasted approximately 25 million years and resulted in variable thickness of the transcontinental crust underlying the region. By the Lower Cretaceous time, the general outline and morphology of the Gulf were similar to that of present-day (Galloway, 2008; Yurewicz, D.A., et al, 1993). Lower Cretaceous tectonic activity was limited to regional subsidence associated with areas of variable crustal thickness and local structuring caused by movement of Louann salt (Yurewicz, D.A., et al, 1993). The combination of these processes resulted in the structural development of regional arches, grabens, uplifts, embayments, salt domes, and salt basins around the northern edge of the basin (Dennen and Hackley, 2012; Galloway, 2008). The location of these structural features can be referenced in Figures 2 and 8 relative to the location of the O'Neal No. 4.

The schematic dip-oriented cross-section displayed in Figure 9 presents a common interpretation of the current structural setting. Most of the published literature suggests faulting near the project area is restricted to the shallower, overlying Cenozoic section, as seen in Figure 9, with shallow faulting dying out before reaching the Pearsall formation. However, one source did interpret the potential for faulting to the south (Swanson S.M., et al., 2016). The closest potential fault is depicted in Figure 8 relative to the location of the O'Neal No. 4. According to the map, the interpreted fault lies approximately 4.25 miles south-southeast of the well and approximately 3.9 miles south-southeast of the stabilized plume extent in the year 2047.

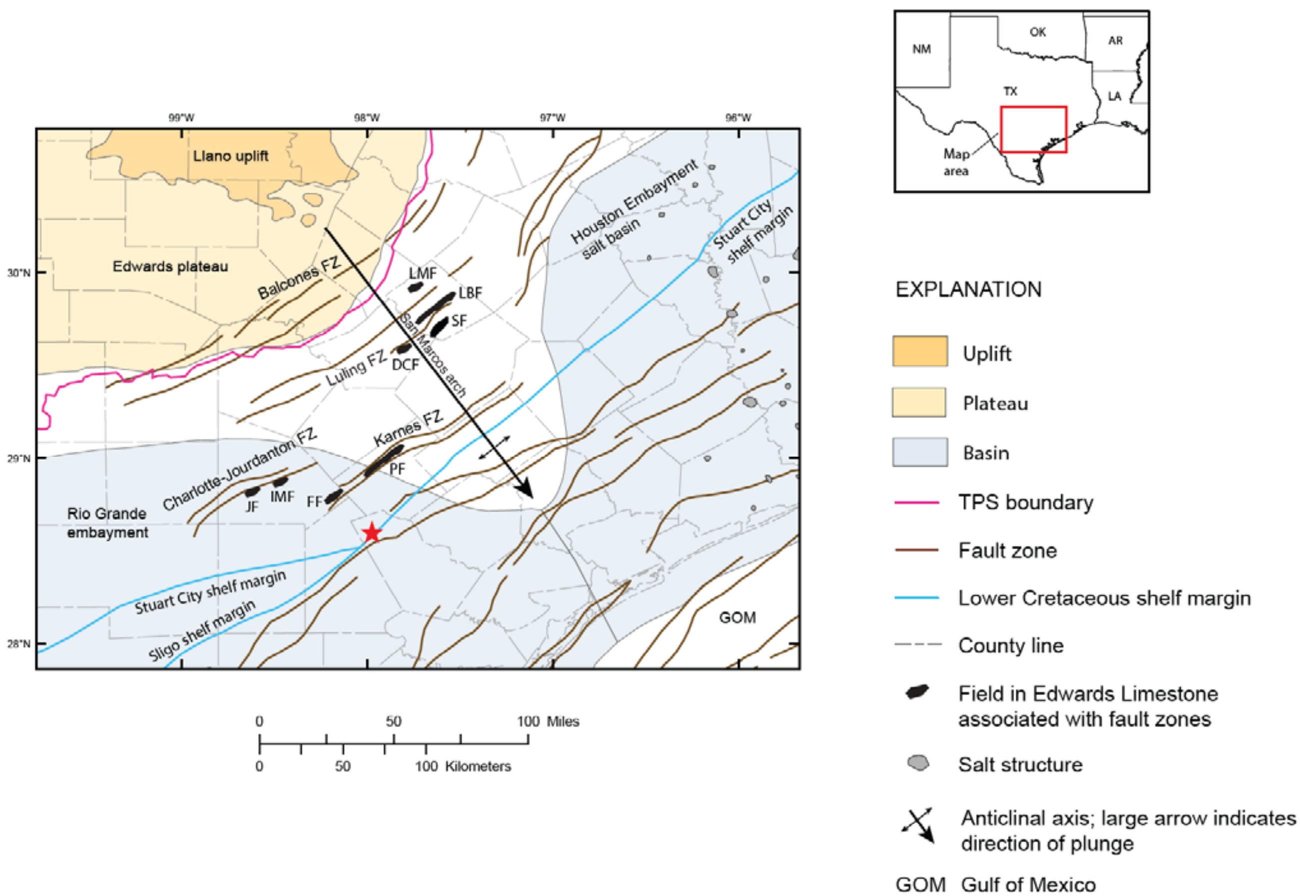

Figure 8 – Structural features and fault zones near the proposed injection site. The red star represents the approximate location of the O'Neal No. 4 (modified from Swanson S.M., et al., 2016)

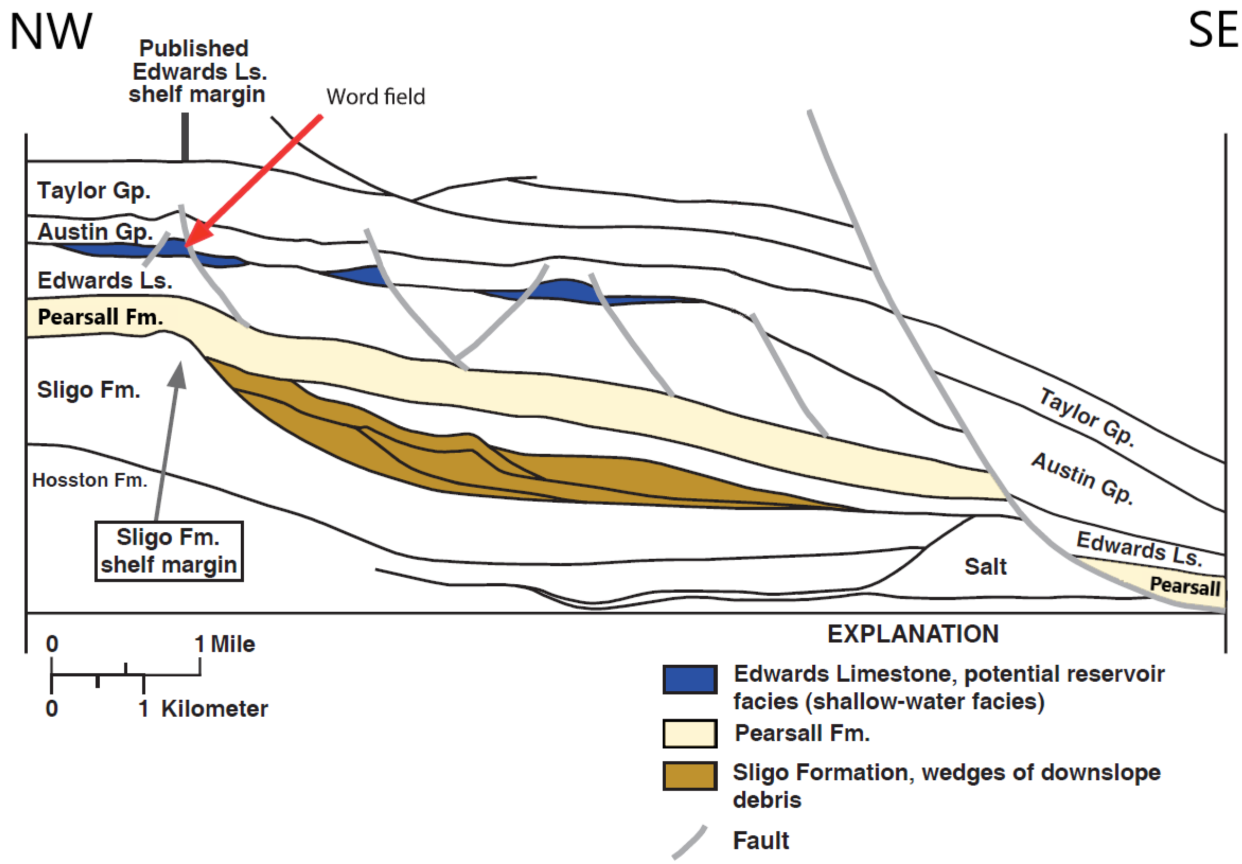

Figure 9 – Northwest to southeast schematic interpretation of the Edwards shelf margin through Word field, northeast of the O'Neal No. 4 project area (modified from Swanson S.M., et al., 2016)

2.2 Site Characterization

The following section discusses site-specific geological characteristics of the O'Neal No. 4.

2.2.1 Stratigraphy and Lithologic Characteristics

Figure 10 depicts openhole logs from two offset wells (API No. 42-025-00473 and API No. 42-025-31892) to the O'Neal No. 4 indicating the injection and primary upper confining zone. The Tomasek No. 1 (API: No. 42-025-00473) is located approximately 1 mile northeast of the O'Neal No. 4 and displays the shallow section from 0-8,200 ft. The Gordon No. 3 (API: No. 42-025-31892) is located approximately 1.6 miles northeast of the O'Neal No. 4 and displays a shallow section from 8,200-16,400 ft.

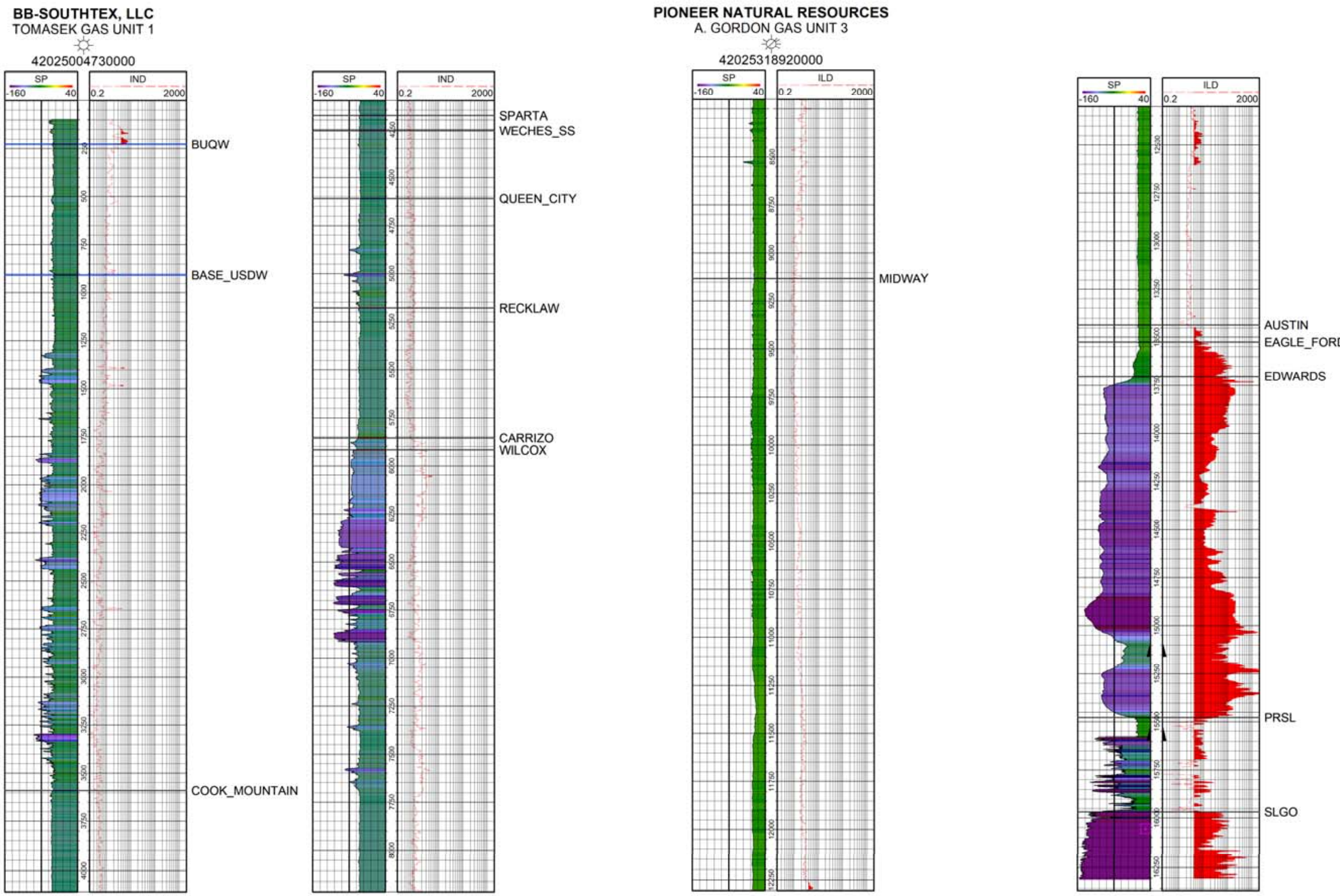

Figure 10 – Type Log with tops, confining, and injection intervals depicted

2.2.2 Upper Confining Interval – Pearsall Formation

Following the deposition of the Sligo formation, the Lower Cretaceous shelf was drowned by eustatic sea-level rise and deposition of the deep-water Pine Island Shale Member of the Pearsall formation throughout the region (Roberts-Ashby et al., 2012). The Pine Island shale consists of alternating beds of pelagic mudstone, hemipelagic mudstone, and Fe-rich dolomitic mudstone interpreted to have been deposited along the outer ramp. This is in agreement with core data published by Bebout and others (1981) and later by Swanson and others (2016) who identified the presence of *C. Margerelli*, a nannofossil indicative of anoxic conditions. The core-derived porosity-permeability relationship displayed in Figure 11 suggests permeability of the Pine Island Shale is incredibly low and stays below 0.0001 mD, regardless of porosity (Figure 11; Hull, D.C., 2011). This is further supported by the 2012 USGS CO2 Storage Resource Assessment, which suggests the Pine Island shale contains the physical properties required to act as a regional seal and was chosen as the upward confining interval for their C50490108 SAU assessment of the Gulf Coast. The 2012 USGS report also noted that the Pine Island shale is a sufficient regional seal with as little as 50 feet of contiguous shale development. The top of the Pearsall is encountered at a depth of 15,339 feet in the O'Neal No. 4 with a gross thickness of 535 feet (Figure 14). The Pine Island Shale member is approximately 130 feet thick at the O'Neal No. 4 location with deposition of additional members of the overlying Pearsall formation, which include the Cow Creek limestone, Cow Creek Shale, and Bexar Shale Members (Roberts-Ashby et al., 2012; Swanson S.M., et al., 2016).

The seismic line displayed in Figure 12 runs northwest to southeast across the Stuart City reef trend southwest of the project area. The top of Buda, Pearsall, and Sligo formation markers are depicted in color to demonstrate the lateral continuity of the section near the O'Neal No. 4. Seismic reflectors within the Pearsall formation appear to lack deformation suggesting consistent deposition over the reef margin. This is in agreement with reviewed published literature which suggests deposition of the Pine Island shale occurred during widespread marine transgression (Bebout, D.G., et al., 1981; Hull, D.C., 2011.; Roberts-Ashby et al., 2012, Swanson S.M., et al., 2016).

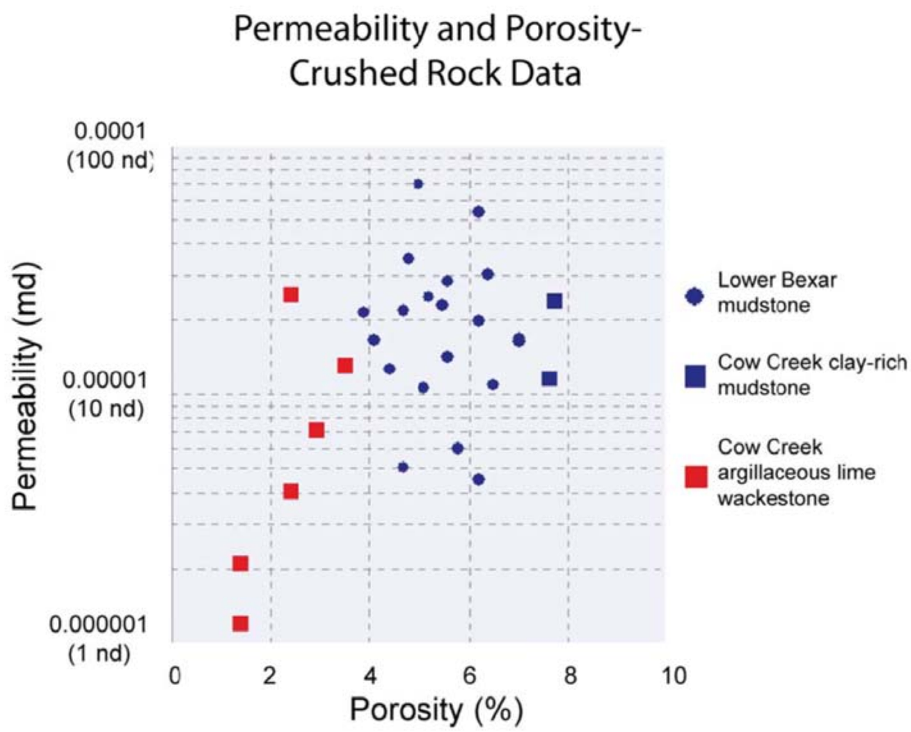

Figure 11 – Porosity-permeability cross-plot of Pearsall Formation crushed rock core data (Swanson S.M., et al., 2016)

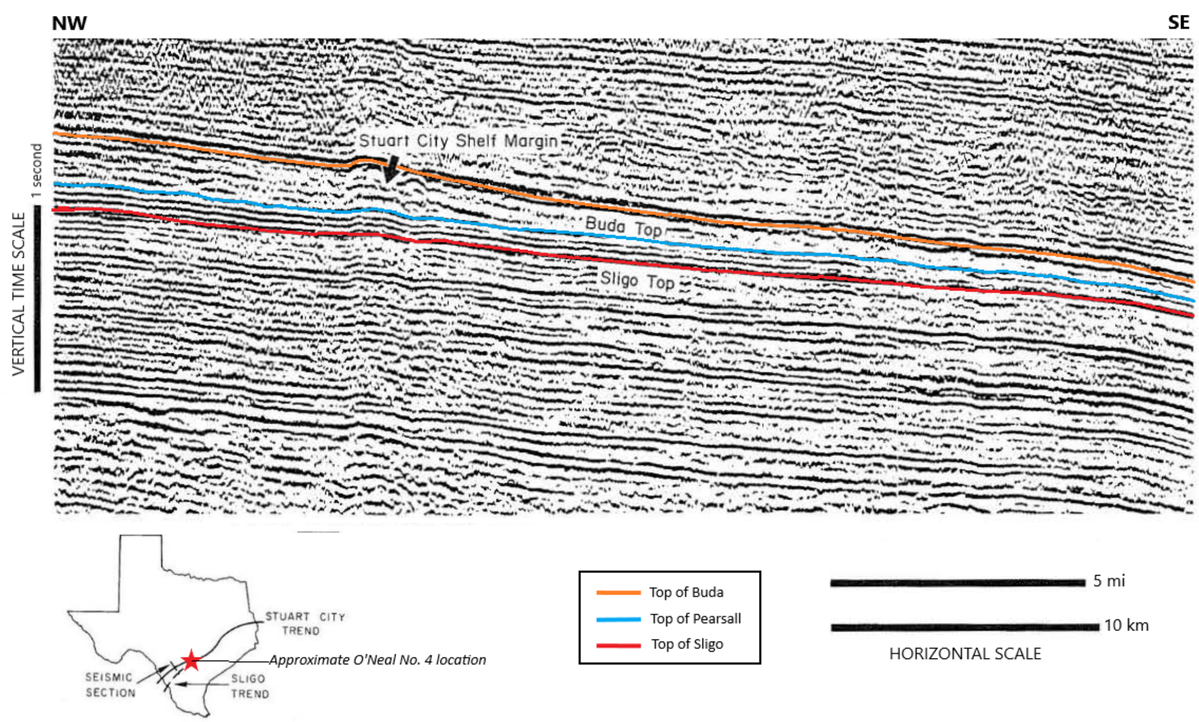

Figure 12 – Seismic line across the Stuart City (Edwards/Buda) shelf margin and locator map.
The red star represents the approximate location of the O'Neal No. 4 (modified from Bebout, D.G., et al., 1981)

2.2.3 Injection Interval – Upper Sligo Formation

The Sligo Formation underlies the Pearsall Formation and is predominately composed of shelf-edge limestones that were deposited along the Lower Cretaceous platform (Roberts-Ashby et al., 2012). However, the Cretaceous also experienced episodic changes in sea level that resulted in the deposition of cyclic Sligo facies that vary both spatially and within the geologic section. The overall Sligo interval is interpreted to be a transgressive sequence occasionally interrupted by progradational cycles that consists of porous shoaling-upward sequences that represent primary reservoir potential within the system (Bebout, D.G., et al., 1981). Facies distributions of these reef complexes are heavily impacted by positioning relative to the margin, the height of the water column at any given time, and the degree of energy or wave action within the system (Galloway, 2008). Figure 13 depicts an idealized environmental setting of the Lower Cretaceous Platform during deposition. Primary porosity and permeability of the Upper Sligo formation tends to develop in high-energy sequences with normal marine conditions that are dominated by the deposition of oolitic and skeletal grainstones.

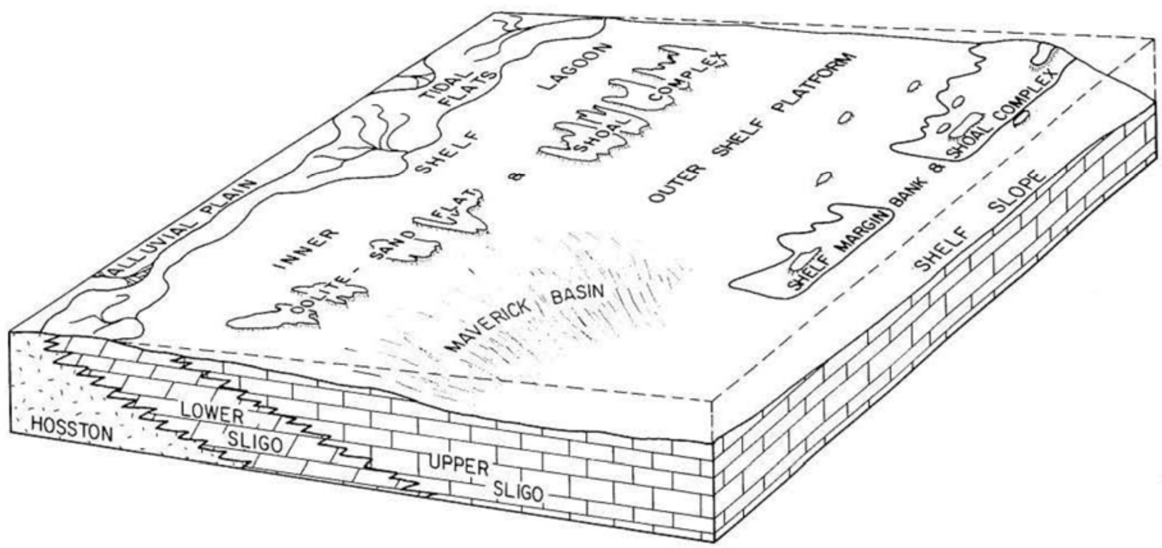

Figure 13 – Environmental setting of Lower Cretaceous Platform (Bebout, D.G., et al., 1981)

According to the 2012 USGS CO2 Storage Resource Assessment, "*the average porosity in the porous intervals of the storage reservoir decreases with depth from 9 to 16 percent*" for their C50490108 DEEP SAU assessment of the Gulf Coast (>13,000 feet). The study also reported that "*the average permeability in the storage reservoirs decreases with depth from 0.05 to 200 mD, with a most-likely value of 8 mD*" for their C50490108 DEEP SAU assessment of the Gulf Coast (Roberts-Ashby et al., 2012).

The top of the Upper Sligo is encountered at a depth of 15,874 feet in the O'Neal No. 4 with a gross thickness of 183 feet (Figure 14). The type log displayed in Figure 14 plots the Effective Porosity for the confining interval and the Total Porosity of the injection interval to account for the increased volume of shale ("Vshale") seen in the Pearsall formation. The porosity data was compared to the analysis performed by Nutech to generate a permeability curve with a reasonable porosity-permeability relationship. The permeability curve was generated utilizing the Coates permeability equation incorporated with a 20% irreducible to match analysis provided by Nutech. Petrophysical analysis of the O'Neal No. 4 indicates an average porosity of 4.6%, a max porosity of 15%, an average permeability of 0.16 mD, and a max permeability of 3.3 mD. These curves have been extrapolated to the injection site and used to establish reservoir characteristics in the plume model.

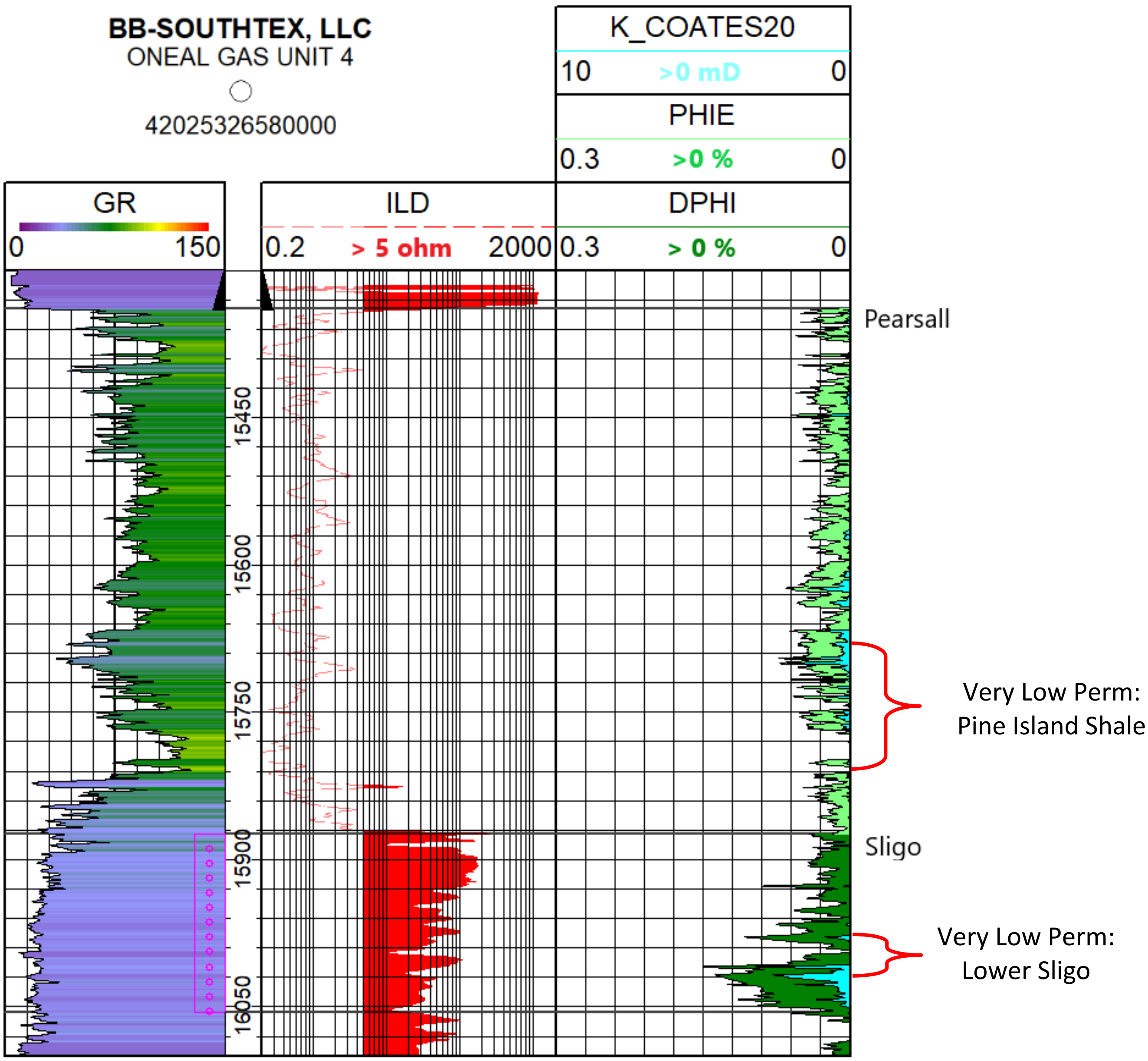

Figure 14 – Open-hole log from the O'Neal No. 4 (API No. 42-025-32658). Porosity curves shaded green >0%, permeability curve shaded blue >0 mD, and resistivity shaded red > 5 ohms.

2.2.4 Formation Fluid

Eight wells were identified through a review of chemical analyses of oil-field brines from the U.S. Geological Survey (USGS) National Produced Waters Geochemical Database v2.3 (Blondes, M.S., et al, 2018). Only one sample was taken from the Sligo formation in the region, located approximately 30 miles north of the O'Neal No. 4. Therefore, the investigation was expanded to compare Total Dissolved Solids (TDS) concentrations from other formations to improve understanding of water chemistry variation in the area. The USGS database contained chemical analysis for seven wells within three miles of the O'Neal. However, the samples were taken from the Edwards reef section that lies approximately 2,000-2,500 feet above the top of Sligo. The location of these wells is shown in Figure 15 relative to the O'Neal No. 4 and the Sligo water sample identified to the north. A summary of water chemistry analyses conducted on Edwards oil-field brines near the injection site is provided in Table 2. Chemical analysis of the identified Sligo water sample is provided in Table 3. Based on the results of the investigation, in-situ Sligo reservoir fluid is anticipated to contain approximately 150,000 parts per million ("ppm") TDS near the O'Neal No. 4 and is compatible with the proposed injection stream.

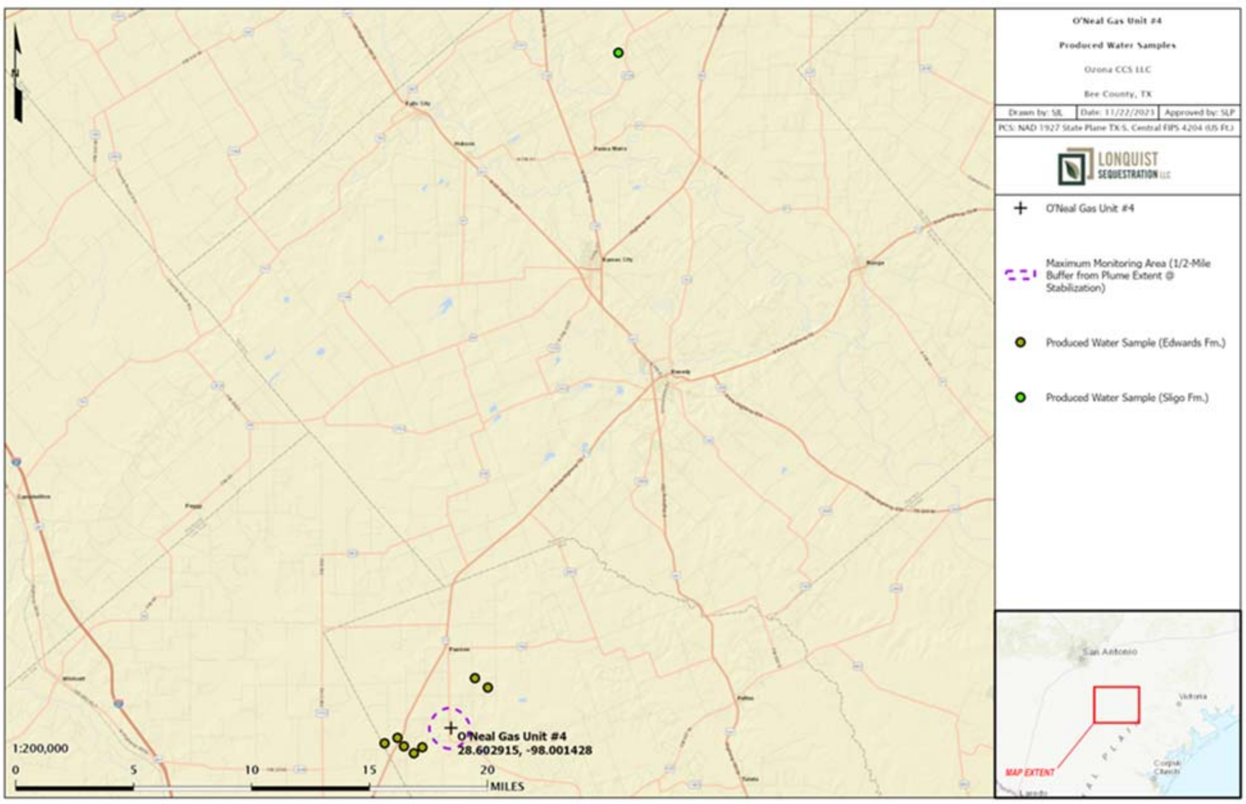

Figure 15 – Offset wells used for formation fluid characterization

Table 2 – Analysis of Lower Cretaceous (Albian) age formation fluids from seven nearby Edwards oil-field brine samples

Measurement	Average	Low	High
Total Dissolved Solids (mg/L)	79,573	60,794	110,300
Sodium (mg/L)	24,280	17,600	34,000
Calcium (mg/L)	5,137	3,320	8,320
Chloride (mg/L)	47,871	37,200	64,700
Sample Depth (ft)	13,940	13,778	14,043

Note: Edwards analysis does not contain pH values

Table 3 – Analysis of Lower Cretaceous (Aptian) age formation fluid from the closest offset Sligo oil-field brine sample

Measurement	Value
Total Dissolved Solids (mg/L)	234,646
Sodium (mg/L)	51,168
Calcium (mg/L)	34,335
Chloride (mg/L)	146,500
Sample Depth (ft)	13,580 to 13,660
pH	5.85

Note: Sligo sample located approximately 30 miles north of the O'Neal No. 4

2.2.5 Fracture Pressure Gradient

The fracture pressure gradient was obtained from an acid fracture report taken during the April 1993 completion of the Sligo interval in the O'Neal No. 4. The Sligo was perforated between the depths of 15,874 and 16,056 feet with continuous monitoring during pumping of the acid job. The report noted a pressure break experienced at approximately 9,000 psi and calculated a fracture gradient of 0.889 psi/ft based on an initial shut-in pressure ("ISIP") of 7,275 psi. A 10 percent safety factor was then applied to the calculated gradient resulting in a maximum allowed bottom hole pressure of 0.8 psi/ft. This was done to ensure that the injection pressure would never exceed the fracture pressure of the injection zone.

2.2.6 Lower Confining Interval – Lower Sligo and Hosston Formations

The O'Neal No. 4 reaches its total depth in the Lower Sligo formation, directly below the Upper Sligo proposed injection interval. The Lower Sligo is interpreted by Bebout and others (1981) to represent the seaward extension of the low-energy lagoon and tidal-flat system of the underlying Hosston formation, a sequence of siliciclastics, evaporites, and dolomitic mudstone (Figure 16). The Hosston to Lower Sligo 'contact' represents a gradational package with a decrease in terrigenous sediments, an increase in carbonate sediments, and an increase in burrows of marine organisms working up-section into the Lower Sligo. The Lower Sligo consists of numerous cycles of subtidal to supratidal carbonates deposited in a low-energy lagoon and tidal-flat system (Bebout, D.G., et al., 1981). These low-permeability facies of the Lower Sligo and underlying Hosston formation will provide lower confinement to the Upper Sligo injection interval. Figure 16 illustrates the typical environmental setting for the deposition of tidal flat facies along the Lower Cretaceous margin. The type log displayed in Figure 14 illustrates the porosity of the Lower Sligo ranges between 0-2% with permeability staying close to 0 mD. Thus, the petrophysical characteristics of the Lower Sligo and Hosston are ideal for prohibiting the migration of the injection stream outside of the injection interval.

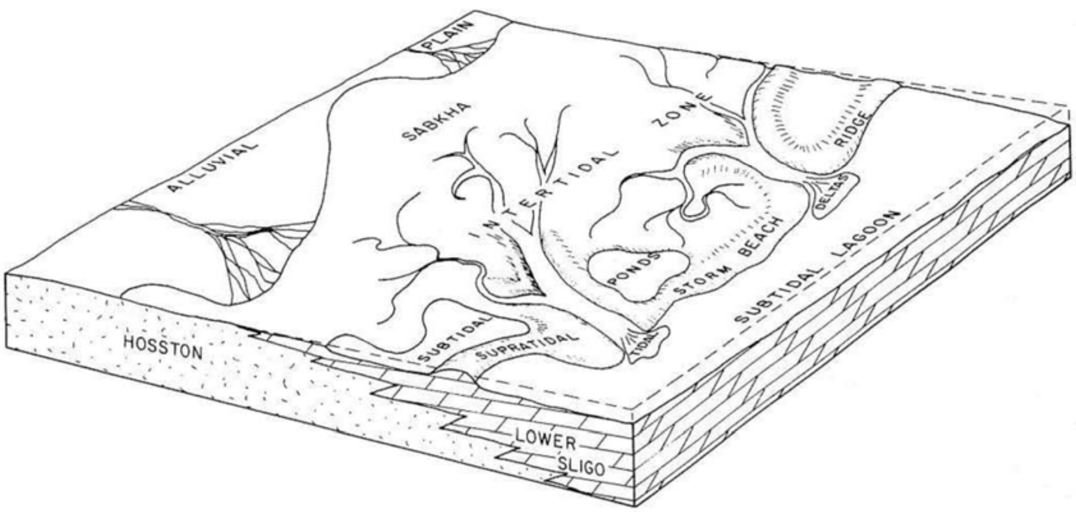

Figure 16 – Environmental setting of Lower Cretaceous tidal flat deposits (Bebout, D.G., et al., 1981)

2.3 Local Structure

Structures surrounding the proposed sequestration site were influenced by regional arches, grabens, uplifts, embayments, movement of Loann salt, and the development of carbonate reef complexes around the northern edge of the basin. However, one potential fault was identified in the literature within proximity and lies approximately 4.25 miles south-southeast of the well and approximately 3.9 miles south-southeast of the stabilized plume extent in the year 2062 (Swanson S.M., et al., 2016). The location of these structural features can be referenced in Figures 2 and 8 relative to the location of the O'Neal No. 4.

A subsea true vertical depth ("SSTVD") structure map on the top of the Sligo formation is provided in Figure 17. The map illustrates the gentle basinward dip of the Sligo formation from the northwest to the southeast. The structural cross-sections provided in Figures 18 and 19 illustrate the structural changes encountered moving away from the O'Neal No. 4 site. The figures also demonstrate the laterally continuous nature of the Pearsall formation that overlies the injection interval with sufficient thickness and modeled petrophysical properties to alleviate the risk of upward migration of injected fluids. Please see section 2.1.2 discussing Regional Structure and Faulting for a regional discussion pertinent to this topic.

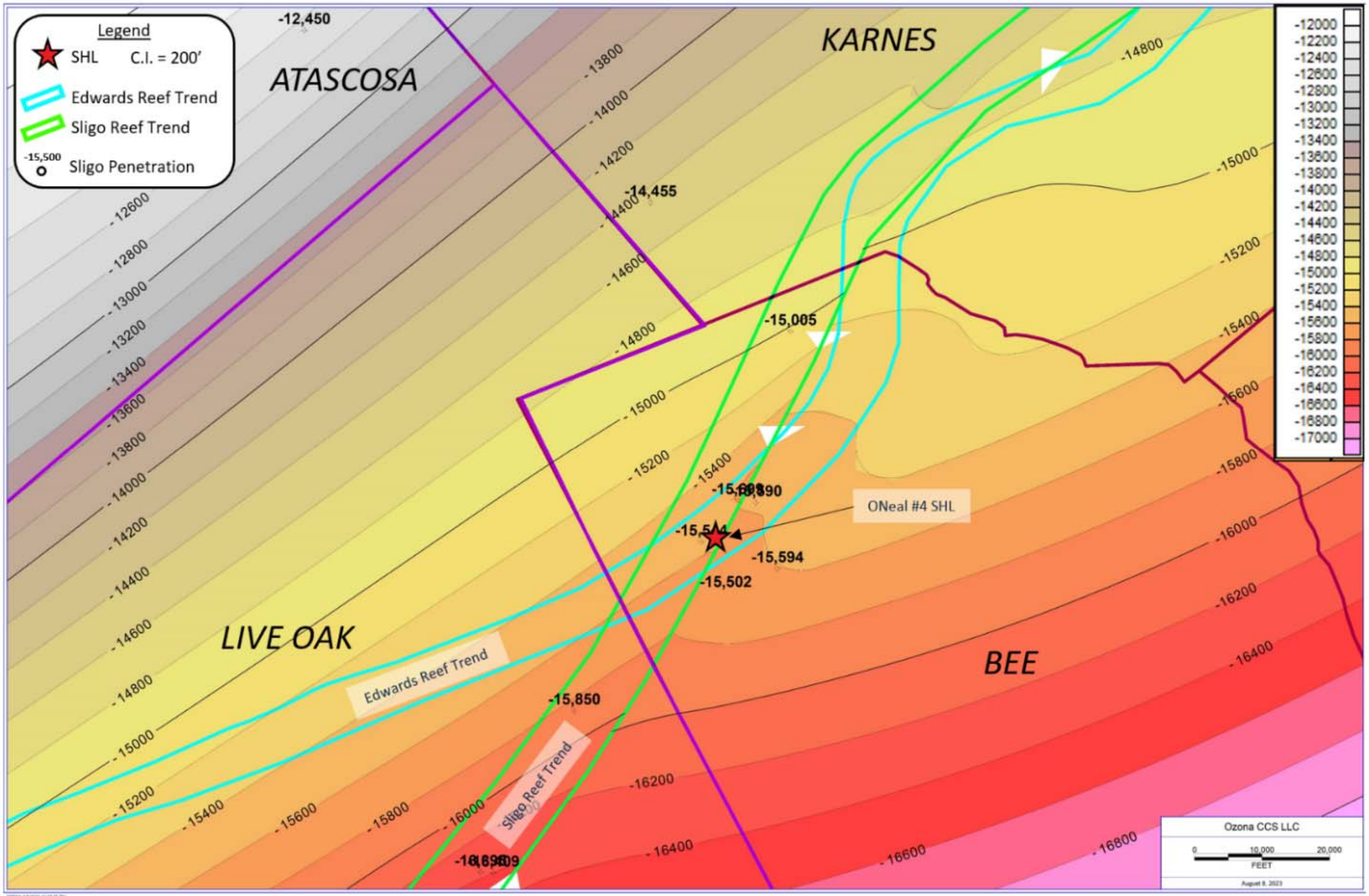

Figure 17 – Subsea Structure Map: top of Sligo (injection interval). The red star signifies the location of the O'Neal No. 4

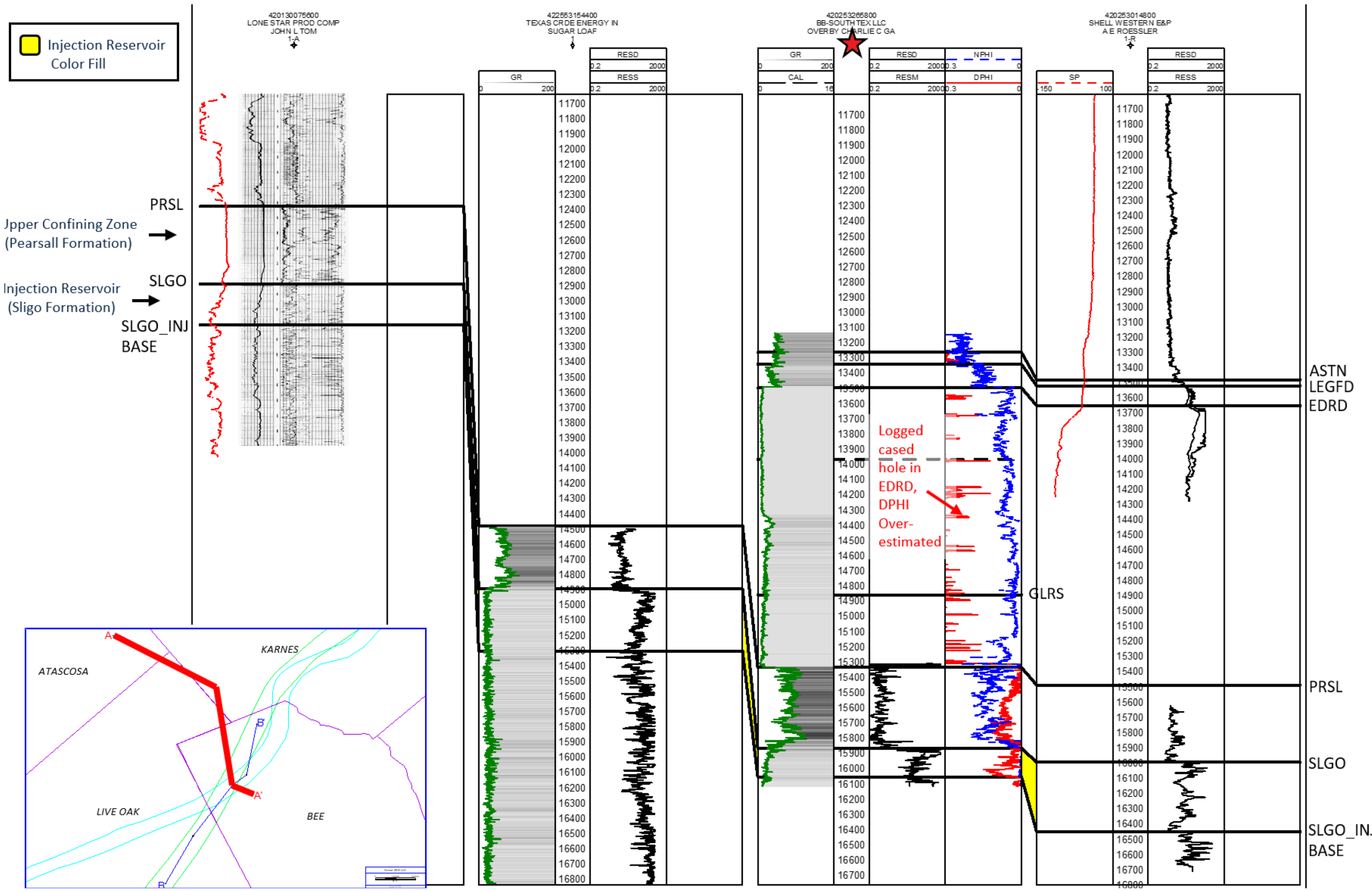

Figure 18 – Northwest to Southeast Structural Cross-Section: A-A' Oriented along regional dip. The red star signifies the location of the O'Neal No. 4. Line of section is depicted in red on locator map.

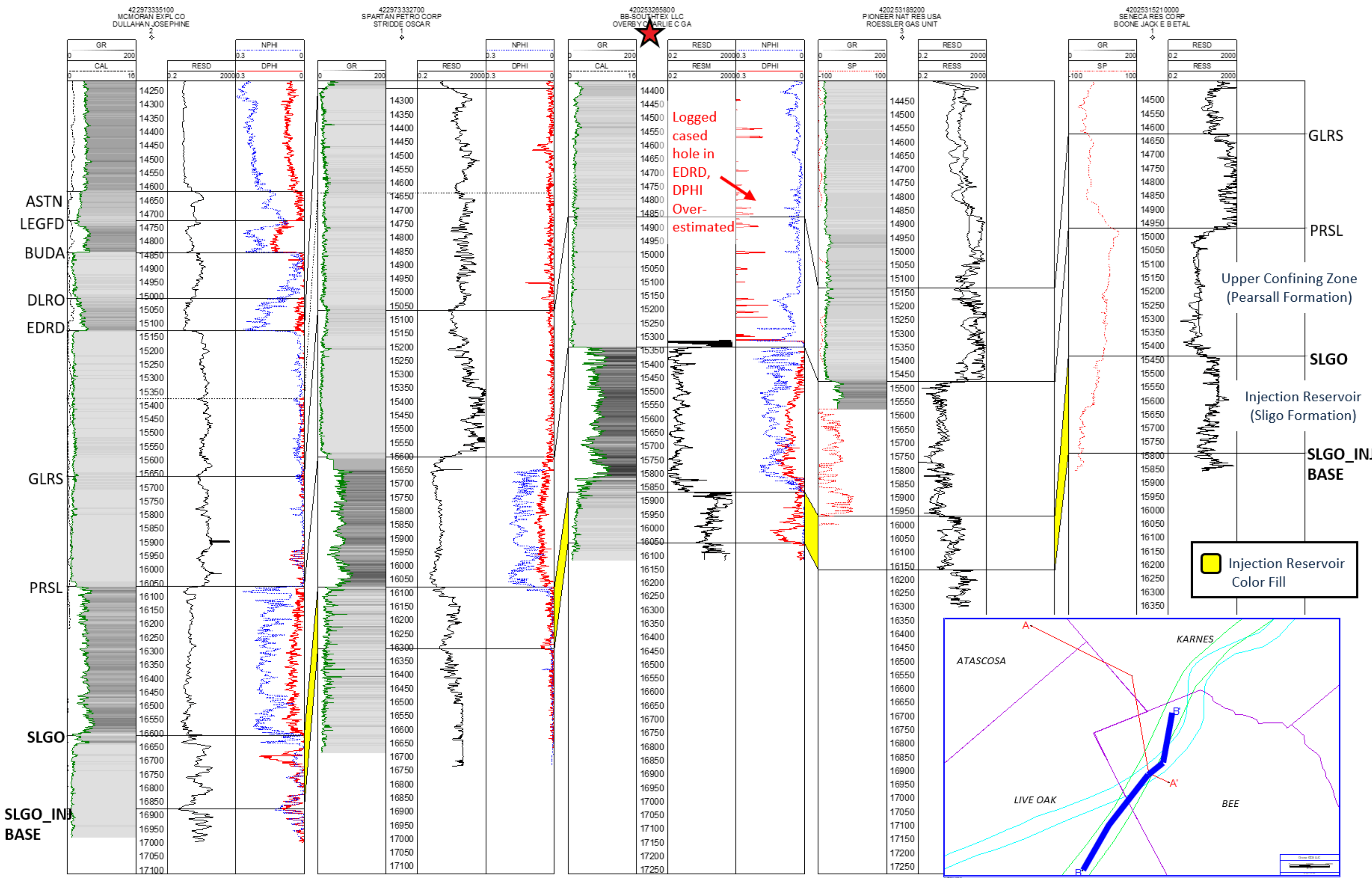

Figure 19 – Southwest to Northeast Structural Cross-Section: B-B' Oriented along regional strike. The red star signifies the location of the O'Neal No. 4. The Line of section is depicted in blue on locator map.

2.4 Injection and Confinement Summary

The lithologic and petrophysical characteristics of the Sligo formation at the O'Neal No. 4 location indicate the reservoir contains the necessary thickness, porosity, and permeability to receive the proposed injection stream. The overlying Pearsall formation is regionally extensive at the O'Neal No. 4 location with low permeability and sufficient thickness to serve as the upper confining interval. Beneath the injection interval, the low permeability, low porosity facies tidal flat and lagoonal facies of the Lower Sligo and underlying Hosston formation are unsuitable for fluid migration and serve as the lower confining interval.

2.5 Groundwater Hydrology

Bee County falls within the boundary of the Bee Groundwater Conservation District. Only one aquifer is identified by the Texas Water Development Board's Texas Aquifers Study near the O'Neal No. 4 location, the unconfined to semi-confined Gulf Coast Aquifer. The Gulf Coast Aquifer parallels the Gulf of Mexico and extends across the state of Texas from the Mexican border to the border of Louisiana (Bruun, B., et al., 2016). The extents of the Gulf Coast Aquifer are provided in Figure 20 below for reference.

The Gulf Coast Aquifer is a major aquifer system comprised of several individual aquifers: the Jasper, Evangeline, and Chicot. These aquifers are composed of discontinuous clay, silt, sand, and gravel beds that range from Miocene to Holocene in age (Figure 21). Numerous interbedded lenses and layers of silt and clay are present within the aquifers which can confine individual aquifers locally. The underlying Oligocene Catahoula tuff represents the lower confining interval but it should be noted the formation is prone to leaking along the base of the aquifer. However, the Burkeville confining interval provides isolation between Jasper and Evangeline aquifers which helps protect the shallower Evangeline and Chicot Aquifers (Bruun, B., et al., 2016).

The schematic cross-section provided in Figure 22 runs south of the O'Neal No. 4, illustrating the structure and stratigraphy of the aquifer system. The thickness of individual sedimentary units within the Cenozoic section tends to thicken towards the Gulf of Mexico due to the presence of growth faults that allow additional loading of unconsolidated sediment. The total net sand thickness of the aquifer system ranges between 700 feet of sand in the south, to over 1,300 in the north, with the saturated freshwater thickness averaging 1,000 feet.

Water quality of the Aquifer System varies with depth and locality but water quality generally improves towards the central to northeastern portions of the aquifer where TDS values are less than 500 milligrams per liter ("mg/L"). The salinity of the Gulf Coast Aquifer increases to the south where TDS ranges between 1,000 to over 10,000 mg/L. The Texas Water Development Board's Texas Aquifers Study (2016) suggests that areas associated with higher salinities are possibly associated with saltwater intrusion likely "*resulting from groundwater pumping or to brine migration in response to oil field operations and natural flows from salt domes intruding into the aquifer*" (Bruun, B., et al., 2016).

According to the Total Dissolved Solids (TDS) map of the Gulf Coast Aquifer (Figure 23), the total dissolved solids in northern Bee County range between 500-3,000 mg/L near the O'Neal No. 4, categorizing the aquifer as fresh to slightly saline.

The TRRC's Groundwater Advisory Unit ("GAU") identified the Base of Useable Quality water ("BUQW") at a depth of 250' and the Base of Underground Sources of Drinking Water ("USDW") at a depth of 950 feet at the location of the O'Neal No. 4 location. Approximately 14,924 feet is separating the base of the USDW and the injection interval. A copy of the GAU's Groundwater Protection Determination letter issued by the TRRC as part of the Class II permitting process for the O'Neal No. 4 is provided in Exhibit A-1. The base of the deepest aquifer is separated from the injection interval by more than 14,924 feet of rock, including 4,200 feet of Midway Shale. Though unlikely for reasons outlined in the confinement and potential leaks sections, if migration of injected fluid did occur above the Pearsall formation, thousands of feet of tight sandstone, limestone, shale, and anhydrite beds occur between the injection interval and the lowest water-bearing aquifer.

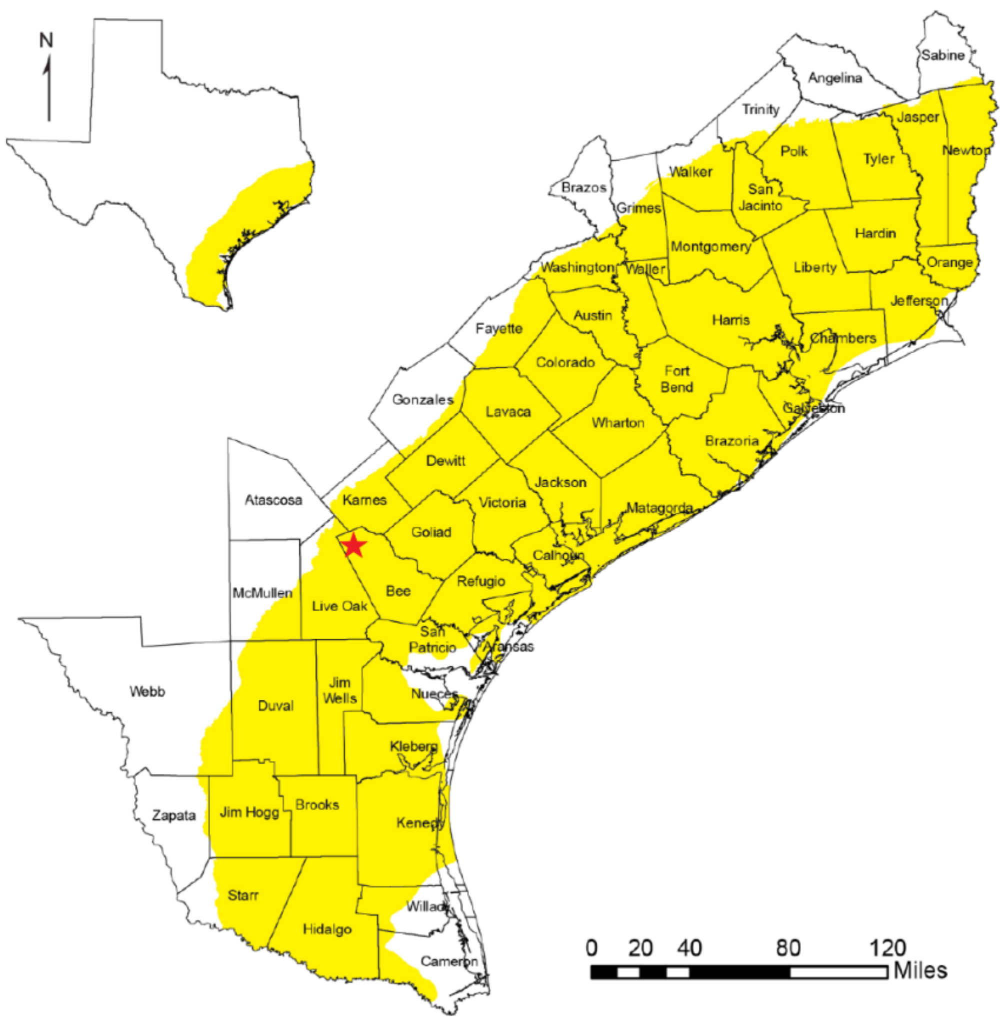

Figure 20 – Extent of the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun, B., et al., 2016)

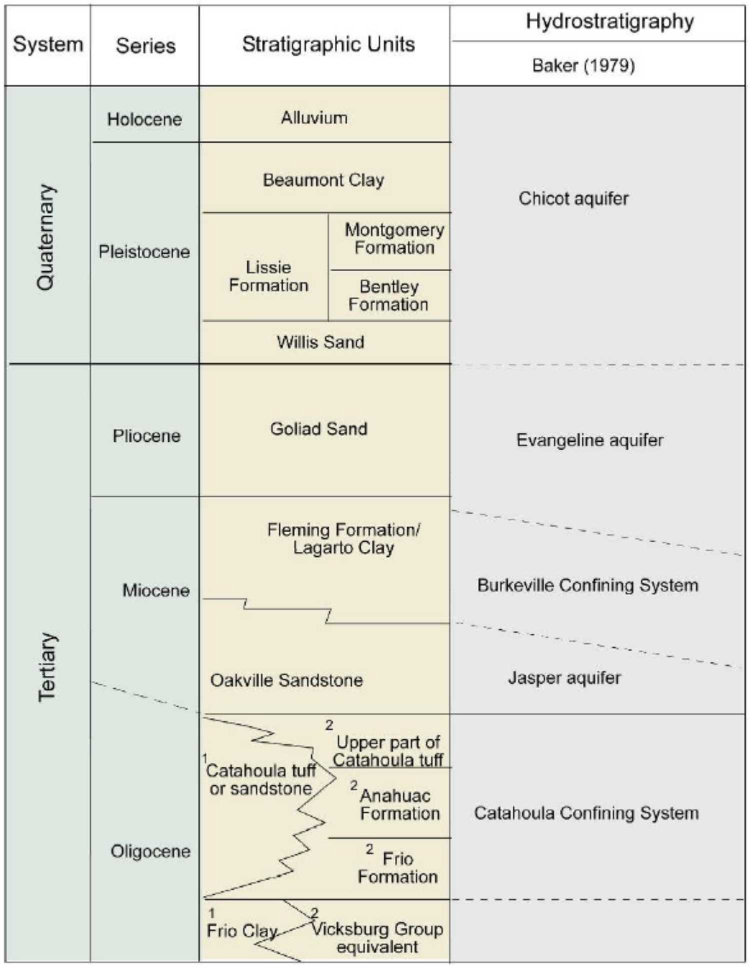

Figure 21 – Stratigraphic Column of the Gulf Coast Aquifer (Chowdhury, A.H. and Turco, M.J., 2006)

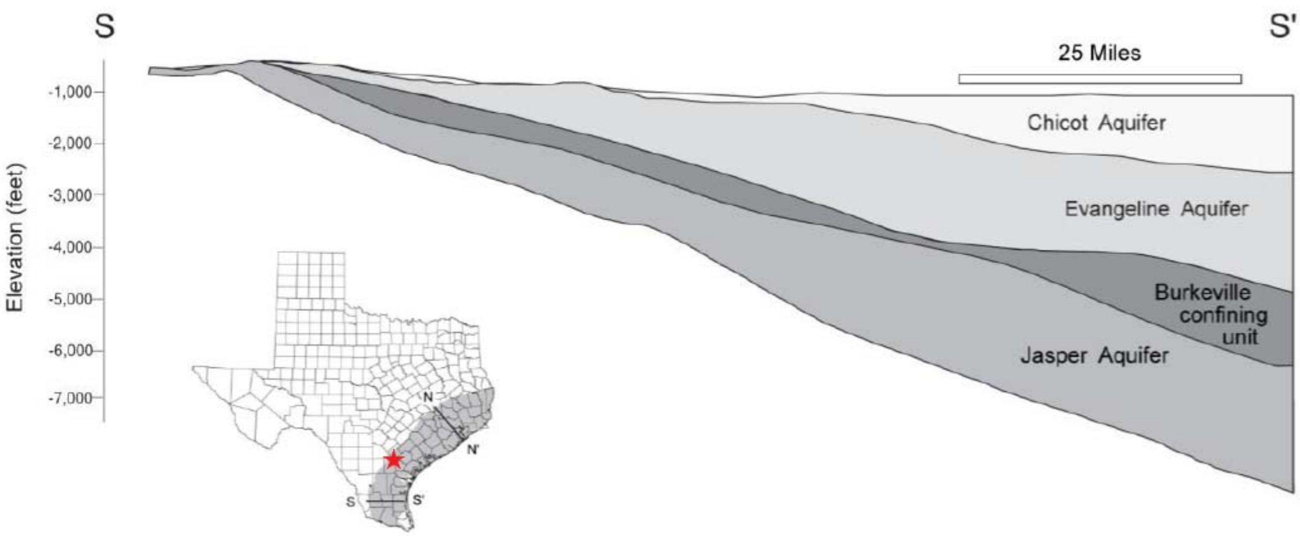

Figure 22 – Cross-Section S-S’ across the Gulf Coast Aquifer. The red star represents the approximate location of the O’Neal No. 4 (modified from Bruun, B., et al., 2016)

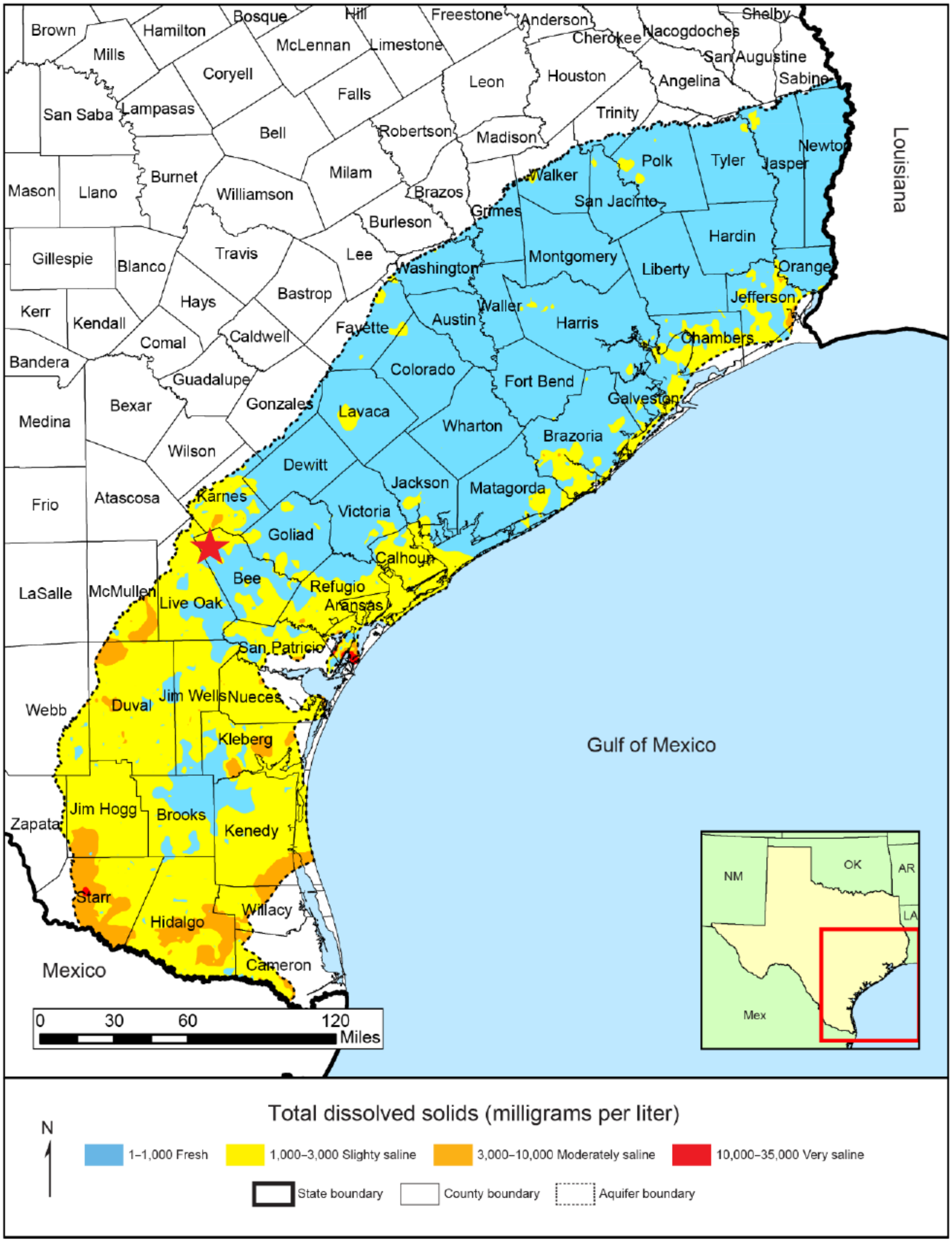

Figure 23 – Total Dissolved Solids (TDS) in the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun, B., et al., 2016)

2.6 References

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2.7 Description of the Injection Process

2.7.1 Current Operations

The Plant and the O'Neal No. 4 are existing operating assets. The O'Neal No. 4 will be recompleted for acid gas injection service under the Class II permit process. Under the Class II application, the maximum injection rate is 28 MT/yr (1.5 MMscf/d). The TAG is 98.2% CO_2, which equates to 27.5 MT/yr of CO_2 each year. The current composition of the TAG stream is:

Table 4 – Gas Composition

Component	Mol Percent
Carbon Dioxide	98.2%
Hydrocarbons	1.03%
Hydrogen Sulfide	0.4%
Nitrogen	0.37%

The Plant is designed to treat, dehydrate, and compress the natural gas produced from the surrounding acreage in Bee County. The Plant uses an amine unit to remove the CO_2 and other constituents from the gas stream. The TAG stream is then dehydrated, compressed, and routed directly to the O'Neal No. 4 for injection. The remaining gas stream is processed to separate the natural gas liquids, which are then sold along with the natural gas. The Plant is monitored 24 hours per day, 7 days per week.

2.8 Reservoir Characterization Modeling

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2023.2 (GEM) simulator. Computer Modelling Group (CMG) has created one of the most comprehensive reservoir simulation software packages for conventional, unconventional, and secondary recovery. advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics. This results in the creation of exceedingly precise and dependable simulation models for carbon injection and storage. The GEM model holds recognition from the EPA for its application in the delineation modeling aspect of the area of review, as outlined in the Class VI Well Area of Review Evaluation and Corrective Action Guidance document.

The Sligo formation serves as the target formation for the O'Neal No. 4 (API No. 42-025-32658). The Petra software package was utilized to construct the geological model for this target formation. Within Petra, formation top contours were generated and subsequently brought into GEM to outline the geological structure.

Porosity and permeability estimates were determined using the porosity log from the O'Neal No. 4. A petrophysical analysis was then conducted to establish a correlation between porosity values and permeability, employing the Coates equation. Both the porosity and permeability estimates from the O'Neal No. 4 were incorporated into the model, with the assumption that they exhibit lateral homogeneity throughout the reservoir.

The reservoir is assumed to be at hydrostatic equilibrium. Given the geological formation in which this well is located and its previous history as a gas producer, the model is assumed to be primarily saturated with gas. More precisely, the reservoir is assumed to be 80% gas saturated and 20% brine saturated, as deduced from the well log data. The modeled injection interval exhibits an average permeability of 0.23 mD and an average porosity of 5%. All layers within the model have been perforated. An infinite-acting reservoir has been created to simulate the boundary conditions.

The gas injectate is composed predominantly of CO_2 as shown in Table 5. The modeled composition takes into consideration the carbon dioxide and other constituents of the total stream. As the Plant has been in operation for many years, the gas composition for the proposed injection period is expected to remain constant.

Table 5 – Modeled Injectate Composition

Component	Expected Composition (mol %)	Modeled Composition (mol %)
Carbon Dioxide (CO_2)	98.2	98.2
Hydrocarbons	1.03%	Hydrocarbons
Hydrogen Sulfide	0.4%	Hydrogen Sulfide
Nitrogen	0.37%	Nitrogen

Core data from the literature review was used to determine residual gas saturation (Keelan and Pugh, 1975) and relative permeability curves between carbon dioxide and the connate brine within the Sligo carbonates (Bennion and Bachu, 2010). The Corey-Brooks method was used to create relative permeability curves. The key inputs used in the model include a Corey exponent for brine of 1.8, a Corey exponent for gas of 2.5, gas permeability at irreducible brine saturation of 50%, irreducible water saturation of 20%, and a maximum residual gas saturation of 35%. The relative permeability curves used for the GEM model are shown in Figure 24.

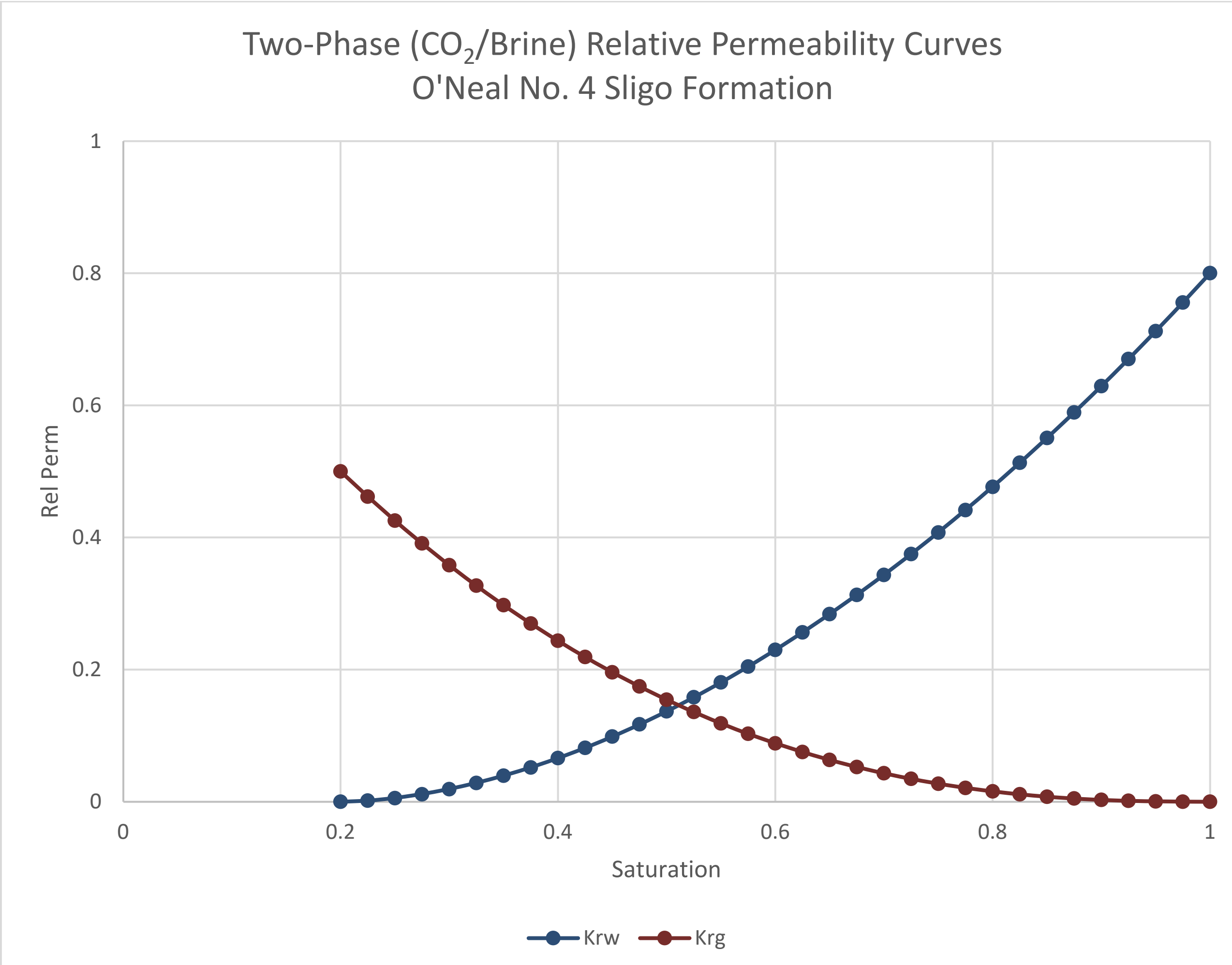


Figure 24 – Two-Phase Relative Permeability Curves Used in the GEM Model

The grid contains 81 blocks in the x-direction (east-west) and 81 blocks in the y-direction (north-south), resulting in a total of 6,561 grid blocks per layer. Each grid block spans dimensions of 250 ft x 250 ft. This configuration yields a grid size measuring 20,250 ft x 20,250 ft, equating to just under 15 square miles in area. The grid cells in the vicinity of the O'Neal No. 4, within a radius of 0.5 miles, have been refined to dimensions of 83.333 ft x 83.333 ft in all layers. This refinement is employed to ensure a more accurate representation of the plume and pressure effects near the wellbore.

In the model, each layer is characterized by homogeneous permeability and porosity values. These values are derived from the porosity log of the O'Neal No. 4. The model encompasses a total of 61 layers, each featuring a thickness of approximately 3 ft per layer. As previously mentioned, the model is perforated in each layer, with the top layer being the top of the injection interval and the bottom layer being the lowest portion of the injection interval. The summarized property values for each of these packages are displayed in Table 6.

Table 6 – GEM Model Layer Package Properties

Layer #	Top (TVD ft)	Thickness	Perm. (mD)	Porosity (%)
1	15,874	3	0.004	3.75%
2	15,877	3	0.002	2.98%
3	15,880	3	0.001	1.62%
4	15,883	3	0.001	1.78%
5	15,886	3	0.002	2.32%
6	15,889	3	0.001	1.96%
7	15,892	3	0.002	3.10%
8	15,895	3	0.002	2.99%
9	15,898	3	0.003	3.52%
10	15,901	3	0.006	4.00%
11	15,904	3	0.005	3.93%
12	15,907	3	0.001	2.15%
13	15,910	3	0.001	1.99%
14	15,913	3	0.002	2.97%
15	15,916	3	0.001	2.22%
16	15,919	3	0.002	2.88%
17	15,922	3	0.001	2.38%
18	15,925	3	0.093	6.68%
19	15,928	3	0.005	2.62%
20	15,931	3	0.002	2.58%
21	15,934	3	0.003	3.07%
22	15,937	3	0.006	3.62%
23	15,940	3	0.002	2.68%
24	15,943	3	0.001	1.08%
25	15,946	3	0.002	1.87%
26	15,949	3	0.025	4.70%
27	15,952	3	0.024	4.37%
28	15,955	3	0.001	1.97%
29	15,958	3	0.003	2.27%
30	15,961	3	0.007	3.09%
31	15,964	3	0.110	6.75%
32	15,967	3	0.037	5.62%
33	15,970	3	0.011	4.41%
34	15,973	3	0.022	4.59%
35	15,976	3	0.297	7.88%
36	15,979	3	0.440	9.21%
37	15,982	3	0.060	5.90%
38	15,985	3	0.001	2.22%

39	15,988	3	0.001	2.21%
40	15,991	3	0.001	1.12%
41	15,994	3	0.003	2.05%
42	15,997	3	0.014	4.56%
43	16,000	3	0.007	4.15%
44	16,003	3	0.033	5.95%
45	16,006	3	1.233	10.25%
46	16,009	3	1.476	12.04%
47	16,012	3	0.566	10.08%
48	16,015	3	1.679	12.18%
49	16,018	3	2.194	13.08%
50	16,021	3	1.235	12.02%
51	16,024	3	0.788	11.22%
52	16,027	3	0.944	10.48%
53	16,030	3	0.424	9.05%
54	16,033	3	0.378	8.85%
55	16,036	3	0.378	8.81%
56	16,039	3	0.378	8.84%
57	16,042	3	0.736	9.91%
58	16,045	3	0.232	7.94%
59	16,048	3	0.238	7.97%
60	16,051	3	0.012	3.01%
61	16,054	3	0.038	4.30%

2.8.1 Simulation Modeling

The primary objectives of the model simulation were as follows:

1. Estimate the maximum areal extent and density drift of the injectate plume after injection.
2. Determine the ability of the target formation to handle the required injection rate without fracturing the injection zone.
3. Assess the likelihood of the injectate plume migrating into potential leak pathways.

The reservoir is assumed to have an irreducible brine saturation of 20%. The salinity of the brine within the formation is estimated to be 150,000 ppm (U.S. Geological Survey National Produced Waters Geochemical Database, ver. 2.3), typical for the region and formation. The injectate stream is primarily composed of CO_2 and H_2S as stated previously. Core data from the literature was used to help generate relative permeability curves. From the literature review, also as previously discussed, cores that most closely represent the carbonate rock formation of the Sligo seen in this region were identified, and the Corey-Brooks equations were used to develop the curves (Bennion and Bachu, 2010). A low, conservative residual gas saturation based on the cores from the literature review was then used to estimate the size of the plume (Keelan and Pugh, 1975).

The model is initialized with a reference pressure of 10,995 psig at a subsea depth of 15,740 ft. This, when a Kelly Bushing “KB” elevation of 334 ft is considered, correlates to a gradient of 0.684 psi/ft. This pressure gradient was determined from production data of the O’Neal No. 4. An initial reservoir pressure of 0.76 psi/ft was calculated before initial production. However, in 1997 after producing approximately 0.5 Bcf of gas, the well was shut-in. The last bottomhole pressure reading was calculated to be 0.480 psi/ft. This assumes the reservoir repressurizes after production ceases, but not fully back to in-situ conditions. Therefore, a 10% safety factor was given to the initial reservoir pressure gradient of 0.76 psi/ft and a gradient of 0.684 psi/ft was implemented into the model as a conservative estimate. A skin factor of -2 was applied to the well to simulate the stimulation of the O’Neal No. 4 for gas production from the Sligo formation, which is based on the acid fracture report, provided in Appendix A-3.

The fracture gradient of the injection zone was estimated to be 0.954 psi/ft, which was determined from the acid fracture report. A 10% safety factor was then applied to this number, putting the maximum bottomhole pressure allowed in the model at 0.86 psi/ft, which is equivalent to 13,652 psig at the top of the Sligo injection interval.

The model, which begins in January 2025, runs for a total of 22 years, comprising of 12 years of active injection, and is then succeeded by 10 years of density drift. Throughout the entire 12-year injection period, an injection rate of 1.5 MMscf/D is used to model the maximum available rate, yielding the largest estimate of the plume size. After the 12-year injection period, when the O’Neal No. 4 ceases injection, the density drift of the plume continues until the plume stabilizes 10 years later. The maximum plume extent during the 12-year injection period is shown in Figure 25. The final extent after 10 years of density drift after injection ceases is shown in Figure 26.

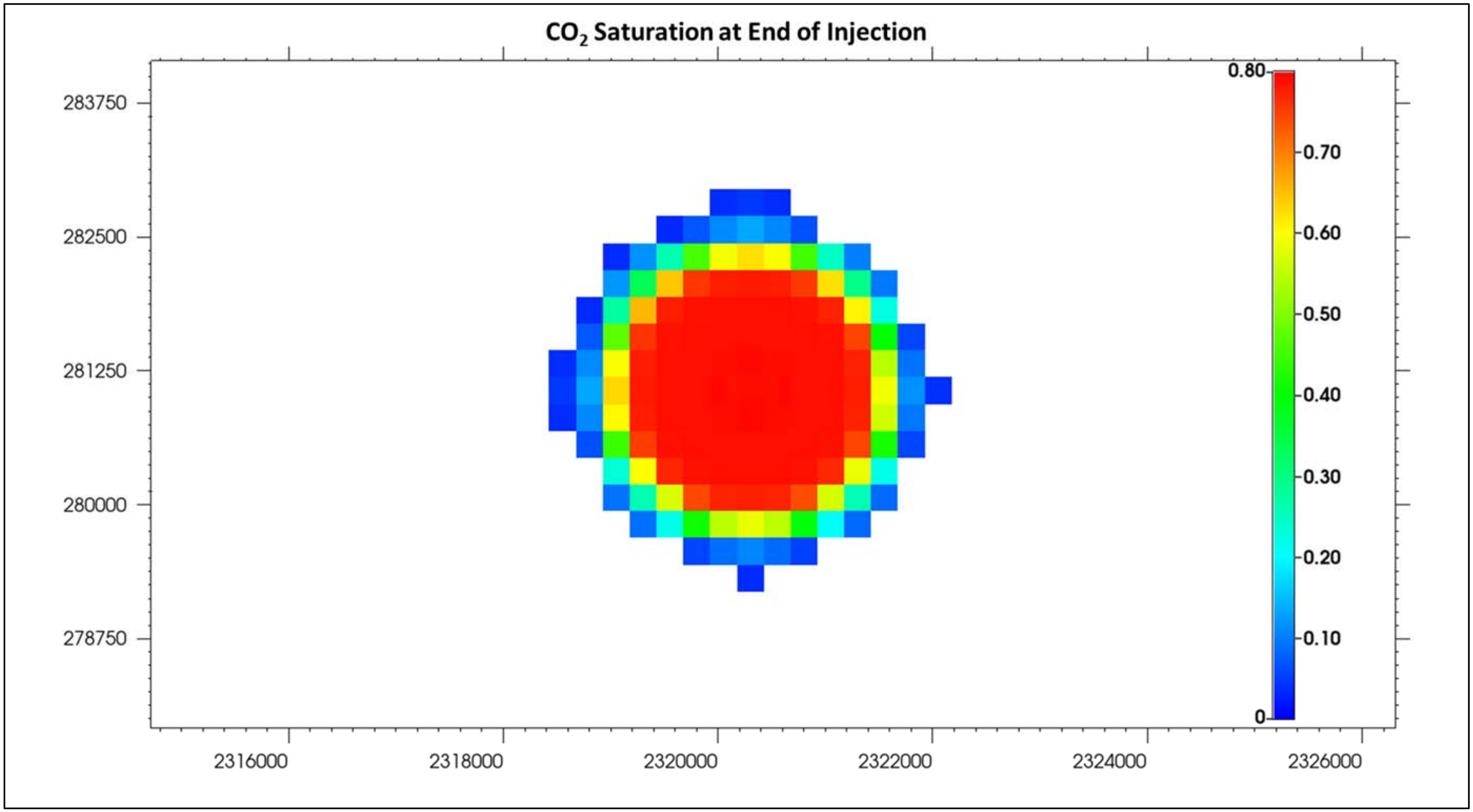


Figure 25 – Areal View of Saturation Plume at Shut-in (End of Injection)

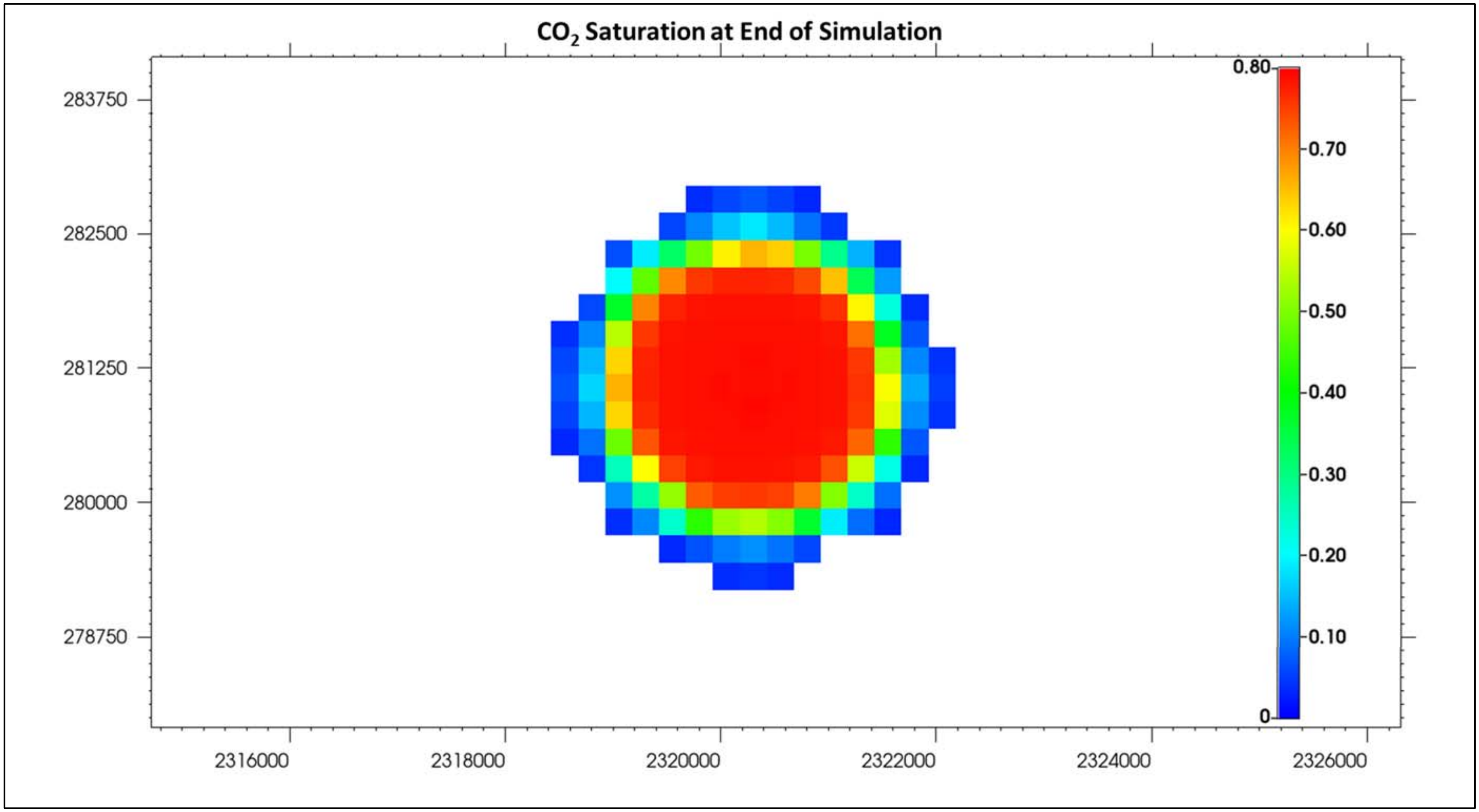


Figure 26 – Areal View of Gas Saturation Plume 10 Years After Shut-in (End of Simulation)

The cross-sectional view of the O'Neal No. 4 shows the extent of the plume from a side-view angle, cutting through the formation at the wellbore. Figure 27 shows the maximum plume extent during the 12-year injection period. During this time, gas from the injection well is injected into the permeable layers of the formation and predominantly travels laterally. Figure 28 shows the final extent of the plume after 10 years of migration. Then, the effects of residual gas saturation and migration due to density drift are clearly shown. At least 35% of injected gas that travels into each grid cell is trapped, as the gas travels mostly vertically—as it is less dense than the formation brine—until an impermeable layer is reached. Both figures are shown in an east-to-west view.

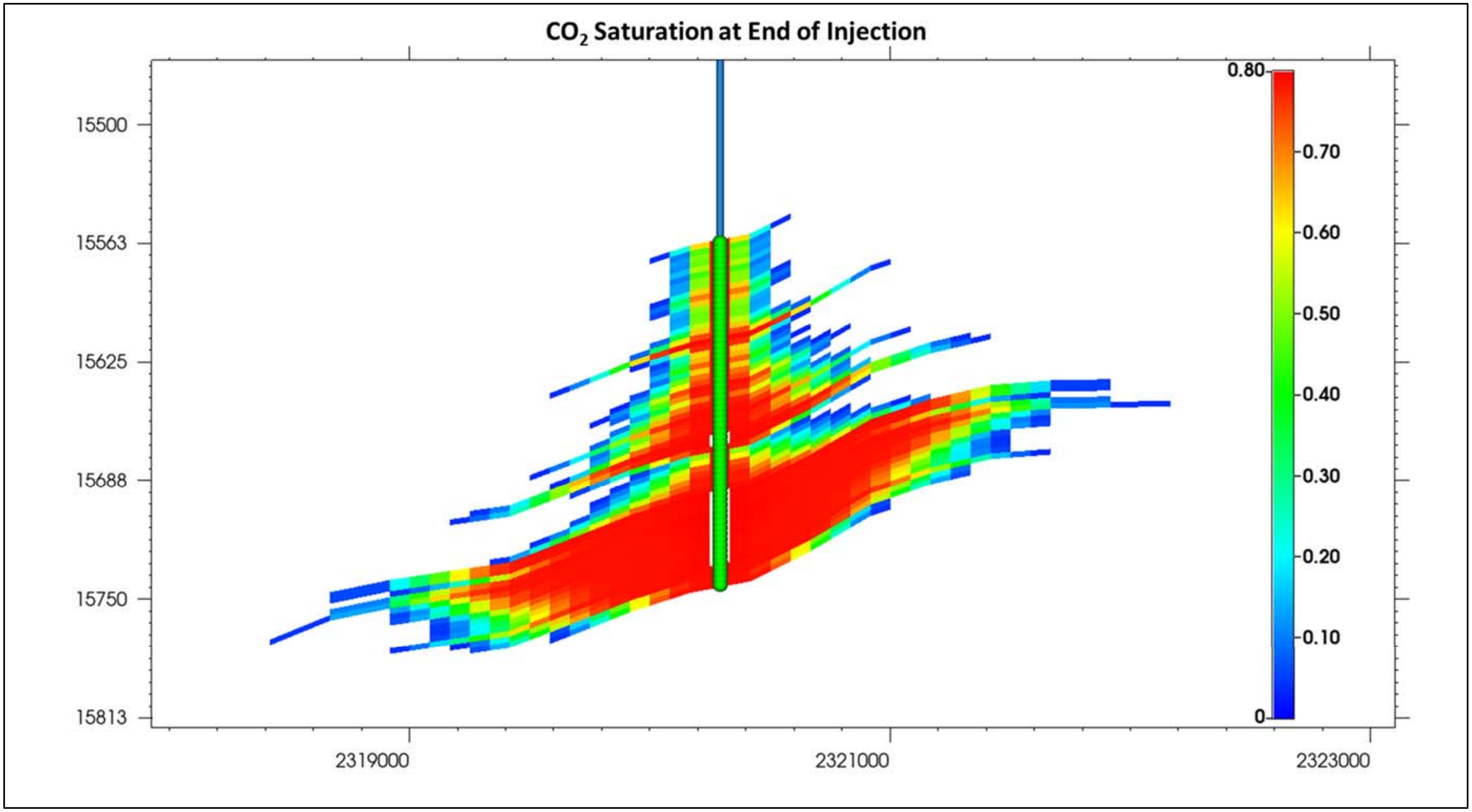


Figure 27 – East-West Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)

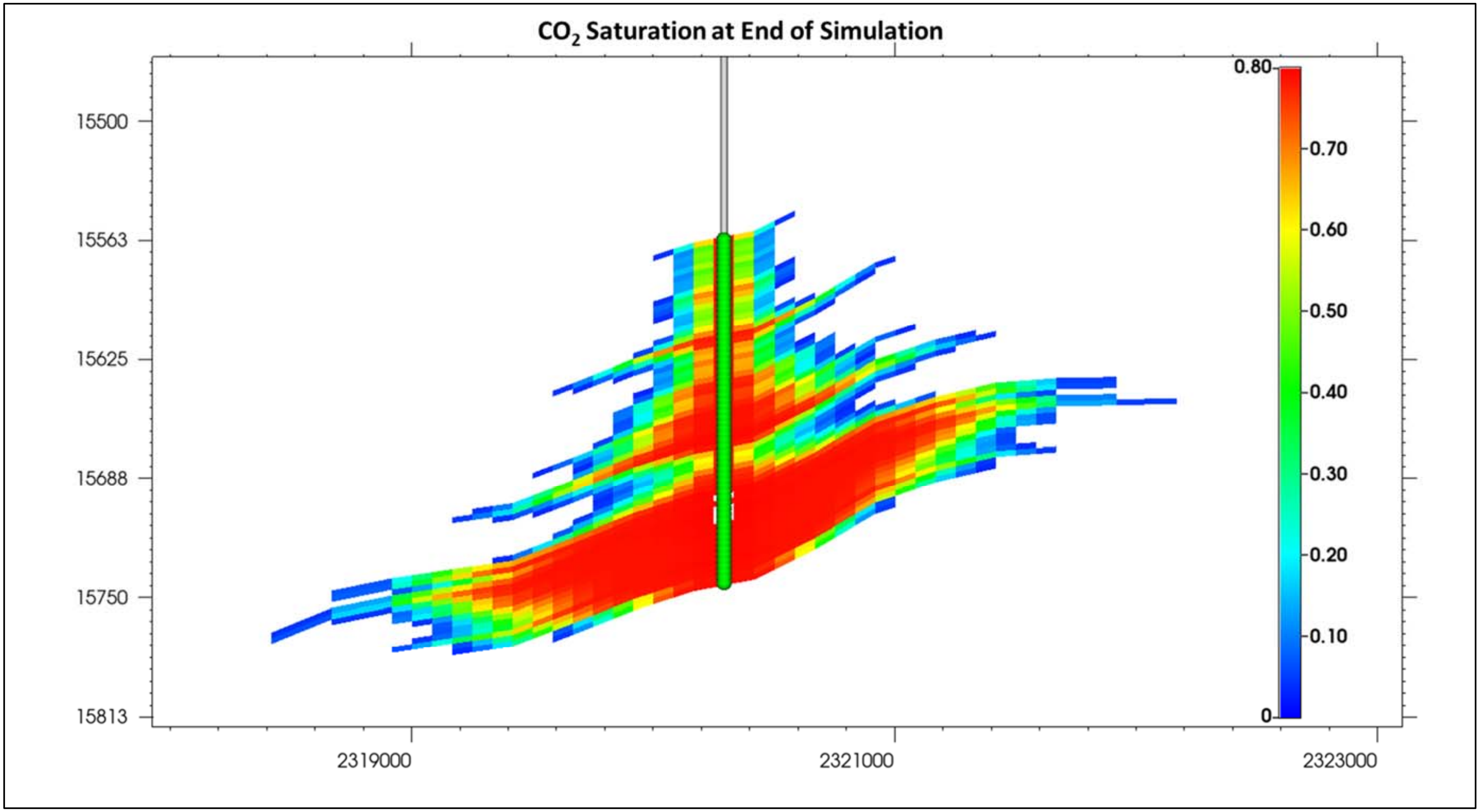


Figure 28 –East-West Cross-Sectional View of Gas Saturation Plume 10 Years After Shut-in (End of Simulation)

Figure 29 shows the surface injection rate, bottom hole pressures, and surface pressures over the injection period—and the period of density drift after injection ceases. The bottom hole pressure increases the most as the injection rate ends, reaching a maximum pressure of 13,337 psig, at the end of injection. This buildup of 2,362 psig keeps the bottom hole pressure below the fracture pressure of 13,652 psig. The maximum surface pressure associated with the maximum bottom hole pressure reached is 6,095 psig, well below the maximum allowable 7,937 psig per the TRRC UIC permit application for this well. Bottomhole and wellhead pressures are provided in Table 7.

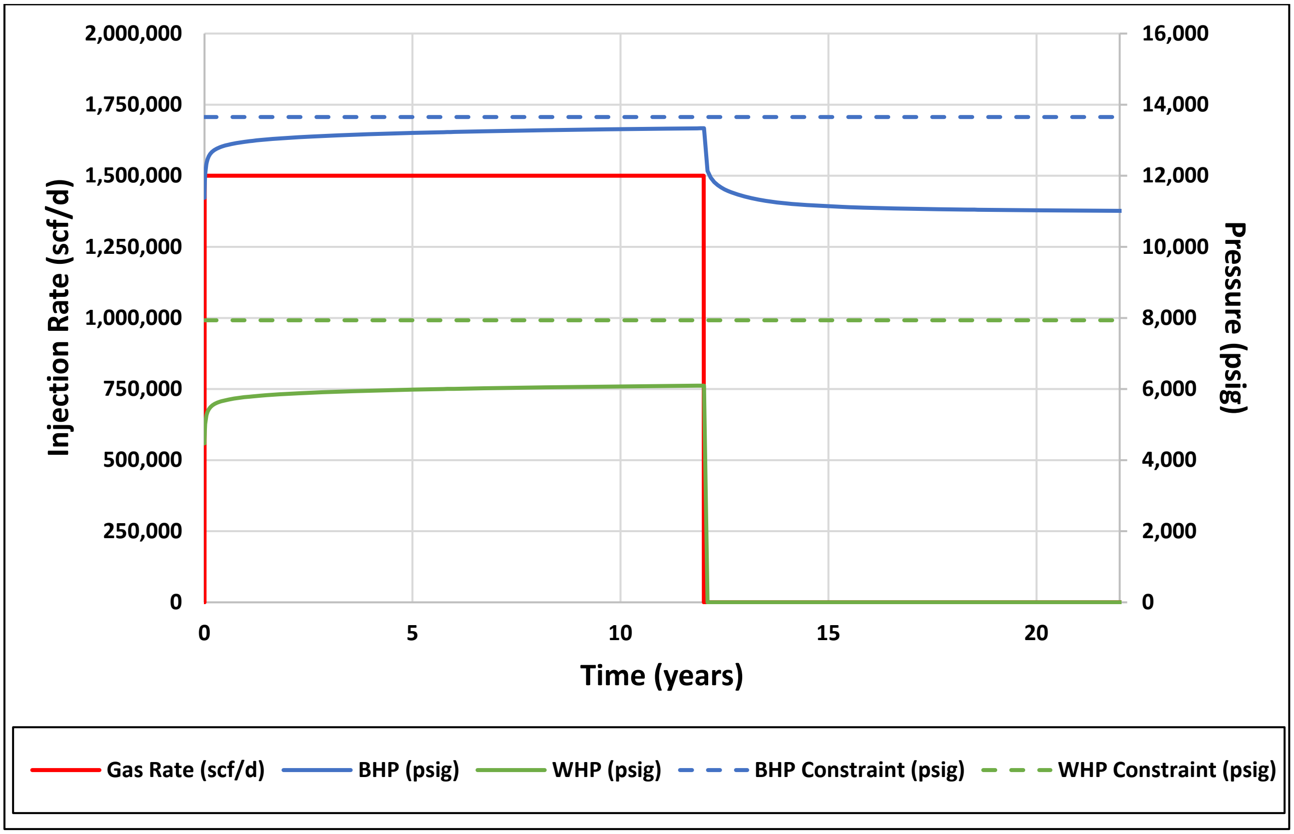


Figure 29 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

Table 7 – Bottomhole and Wellhead Pressures from the Start of Injection

Time from Start of Injection (years)	BHP (psig)	WHP (psig)
0	10,975	-
10	13,311	6,073
12 (End of Inj.)	13,337	6,095
20	11,029	-
22 (End of Model)	11,013	-

SECTION 3 – DELINEATION OF MONITORING AREA

This section discusses the delineation of both the maximum monitoring area (MMA) and active monitoring area (AMA) as described in

3.1 Maximum Monitoring Area

The MMA is defined as equal to or greater than the area expected to contain the free-phase CO_2 plume until the plume has stabilized, plus an all-around buffer zone of at least half a mile. Numerical simulation was used to predict the size and drift of the plume. With CMG's GEM software package, reservoir modeling was used to determine the areal extent and density drift of the plume. The model considers the following:

- Offset well logs to estimate geologic properties
- Petrophysical analysis to calculate the heterogeneity of the rock
- Geological interpretations to determine faulting and geologic structure
- Offset injection history to predict the density drift of the plume adequately

Ozona's expected gas composition was used in the model. The injectate is estimated at a molar composition of 98.2% CO_2 and 1.8% of other constituents. The StarTex Plant has been in stable operations for many years. Ozona believes the gas analysis provided in Table 1 is an accurate representation of the injectate. In the future, if the actual gas analysis varies materially from the injectate composition herein, an update to this MRV plan will be submitted to the GHGRP. As discussed in *Section 2*, the gas will be injected into the Sligo formation. The geomodel was created based on the rock properties of the Sligo.

The plume boundary was defined by the weighted average gas saturation in the aquifer. A value of 3% gas saturation was used to determine the boundary of the plume. When injection ceases in Year 12, the area expanse of the plume will be approximately 270 acres. The maximum distance between the wellbore and the edge of the plume is approximately 0.42 miles to the west. After 10 additional years of density drift, the areal extent of the plume is 303 acres with a maximum distance to the edge of the plume of approximately 0.45 miles to the west. Since the plume shape is relatively circular, the maximum distance from the injection well after density drift was used to define the circular boundary of the MMA. The AMA and the MMA have similar areas of influence, with the AMA being only marginally smaller than the MMA. Therefore, Ozona will set the AMA equal to the MMA as the basis for the area extent of the monitoring program.

This is shown in Figure 30 with the plume boundary at the end of injection, the stabilized plume boundary, and the MMA. The MMA boundary represents the stabilized plume boundary after 10 years of density drift plus an all-around buffer zone of one half mile.

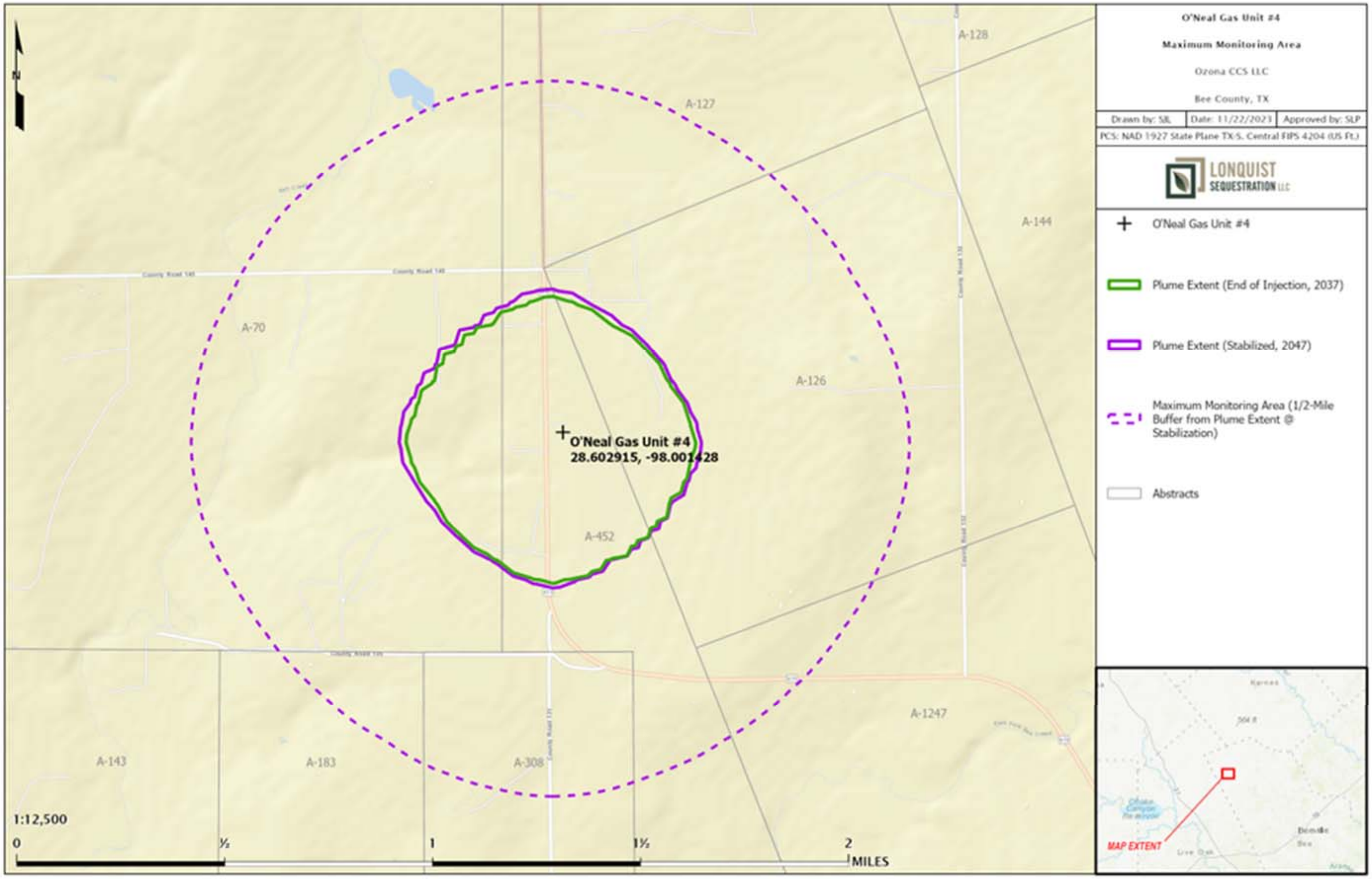


Figure 30 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

3.2 Active Monitoring Area

The AMA was initially set equal to the expected total injection period of 12-years. The AMA was analyzed by superimposing the area based on a one-half mile buffer around the anticipated plume location after 12 years of injection (2037), with the area of the projected free-phase CO_2 plume at five additional years (2042). In this case, as shown in Figure 31 the plume boundary in 2042 is within the plume in 2037 plus the one-half mile buffer. Since the Active Monitoring Area boundary is only slightly smaller than the Maximum Monitoring Area boundary, Ozona will define the AMA to be equal to the MMA. By 2037, Ozona will submit a revised MRV plan to provide an updated AMA and MMA.

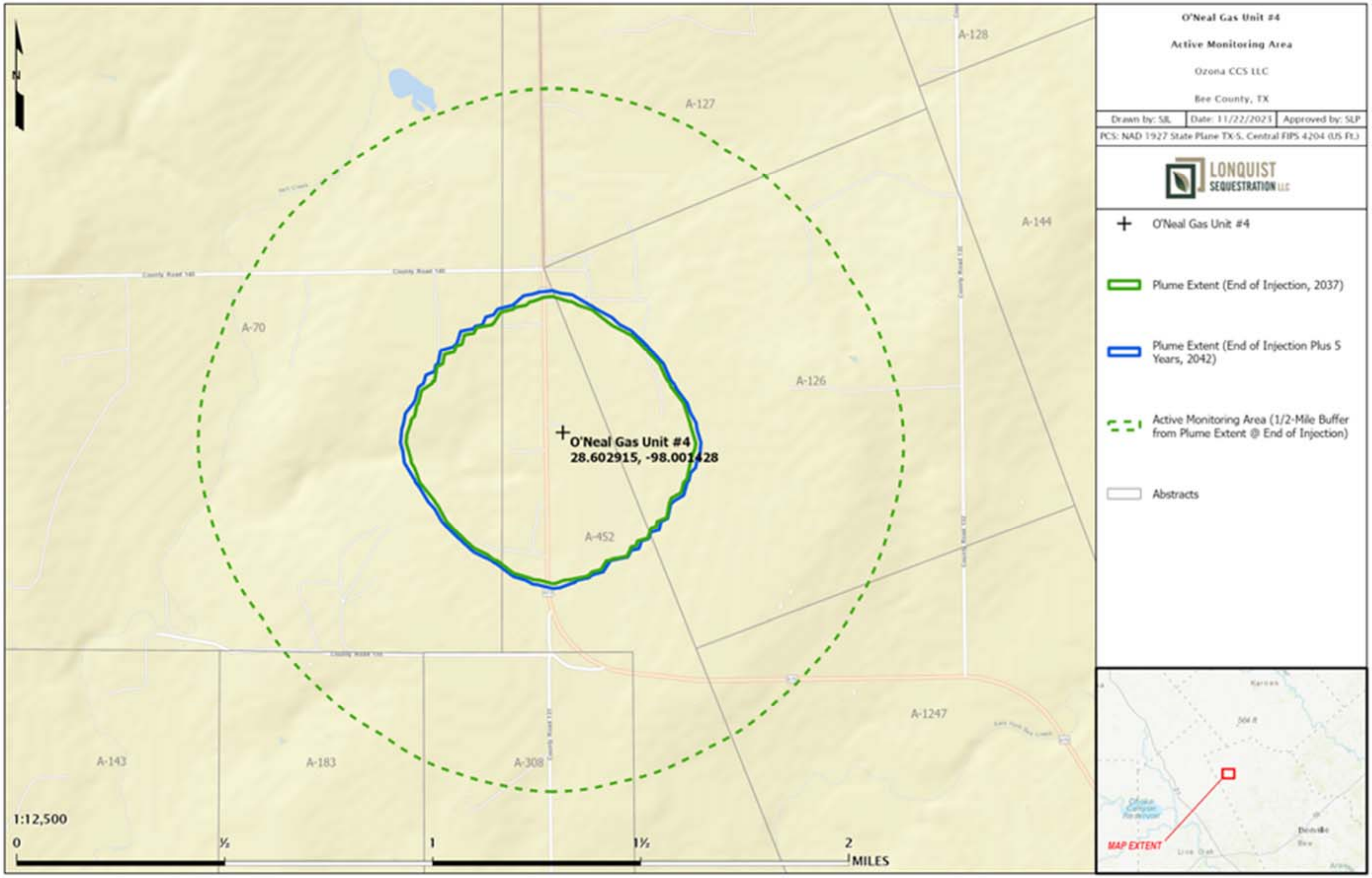


Figure 31 – Active Monitoring Area

SECTION 4 – POTENTIAL PATHWAYS FOR LEAKAGE

This section identifies and discusses the potential pathways within the MMA for CO_2 to reach the surface, and is summarized in Table 8. Also included are the likelihood, magnitude, and timing of such potential leakage. The potential leakage pathways are:

- Surface equipment
- Existing wells within the MMA
- Faults and fractures
- Upper confining layer
- Natural or induced seismicity

Table 8 – Potential Leakage Pathway Risk Assessment

Potential Leakage Pathway	Likelihood	Magnitude	Timing
Surface Equipment	Possible during injection operations.	Low. Automated systems will detect leaks and execute shut-down procedures.	During active injection period. Thereafter the well will be plugged.
Existing wells within the MMA	Unlikely. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Any vertical migration from the Injection Zone would return the CO2 to the production zone.	During active injection and Post Injection Site Care periods.
Faults and fractures	Possible. The lateral continuity of UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO2 to the production zone.	During active injection and Post Injection Site Care periods.
Upper confining layer	Unlikely. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO2 to the production zone.	During active injection and Post Injection Site Care periods.
Natural or induced seismicity	Possible. The lateral continuity of the UCZ is recognized as a very competent seal.	Low. Vertical migration from the Injection Zone would return the CO2 to the production zone.	During active injection and Post Injection Site Care periods.

4.1 Leakage from Surface Equipment

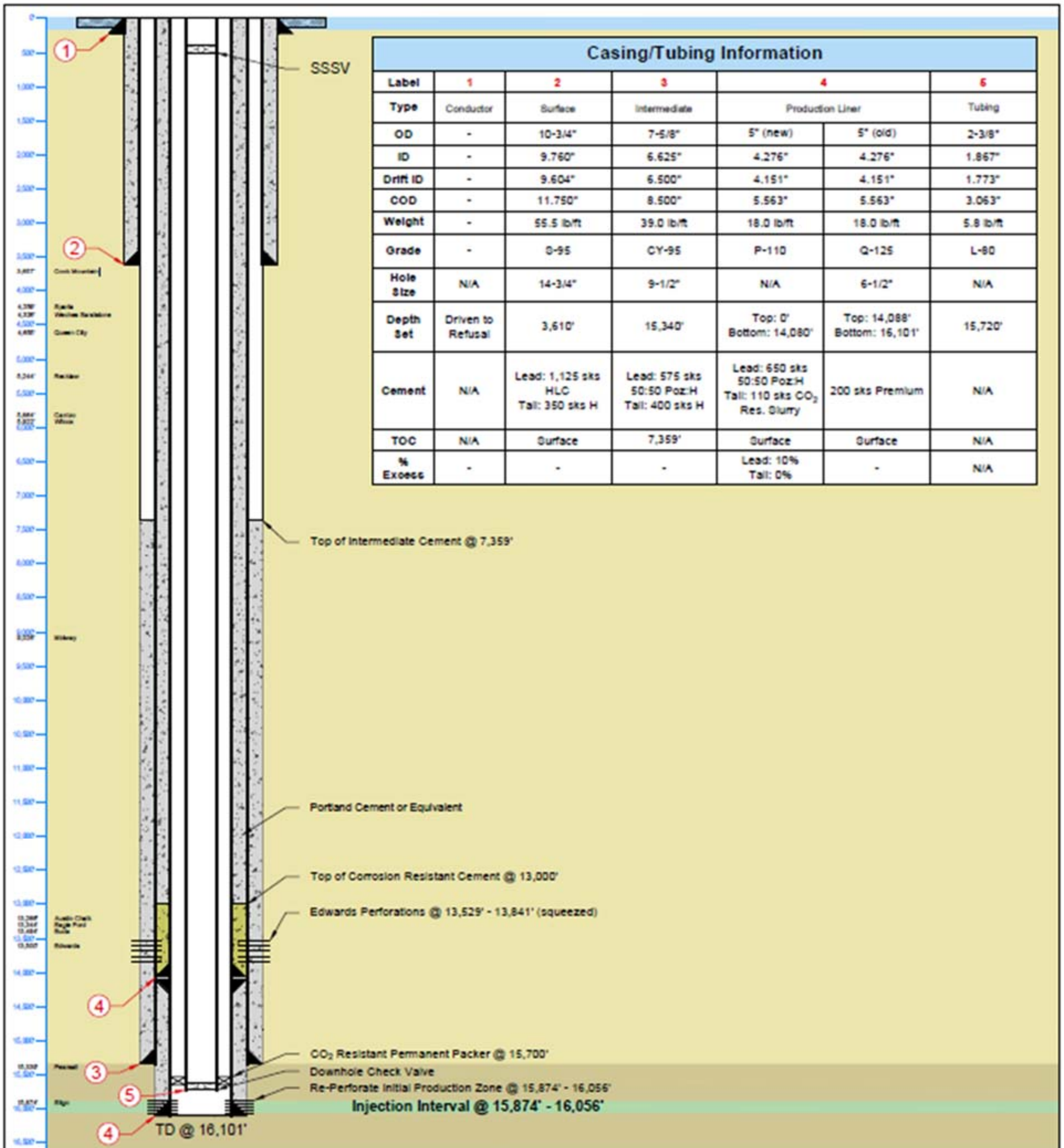
The Plant and O'Neal No. 4 are designed for separating, transporting, and injecting TAG primarily consisting of CO_2 in a manner to ensure safety to the public, the employees, and the environment. The mechanical aspects of this are noted in Table 9 and Figure 32. The facilities have been designed to minimize leakage and failure points, following applicable National Association of Corrosion Engineers (NACE) and American Petroleum Institute (API) applicable standards and practices. As the

TAG stream contains H_2S, monitors installed for H_2S detection will also indicate the presence of CO_2. These monitors will be installed at key locations around the Plant and the O'Neal No. 4 location. These devices will be continuously monitored by the Supervisory Control and Data Acquisition (SCADA) system and will alarm at set points determined by the Plant HS&E Director, consistent with Occupational Safety and Health Administration (OSHA) requirements. The Plant will set the detection and alarm states for personnel at 10 ppm and at 40 ppm for initiating Emergency Shutdown. Key monitoring points and parameters are provided in Table 9.

The facilities will incorporate important safety equipment to ensure reliable and safe operations. In addition to the H_2S monitors, emergency shutdown (ESD) valves, with high- and low-pressure shutoff settings to isolate the Plant, the O'Neal No. 4, and other components, StarTex has a flare stack to safely handle the TAG when a depressuring event occurs. These facilities will be constructed in the coming months. The exact location of this equipment is not yet known, but it will be installed in accordance with applicable engineering and safety standards.

Table 9 – Summary of TAG Detectors and Equipment

Device	Location	Set Point
H_2S Detectors (1 – 4)	O'Neal No. 4 wellsite	10 ppm High Alarm 40 ppm Emergency Shutdown
H_2S Detectors (5 – 8)	In-Plant Detectors	10 ppm High Alarm 40 ppm Emergency Shutdown
Flare Stack	Plant Site Perimeter	N/A
AGI Flowmeter	In-Plant (downstream of the Amine Unit)	Calibrated per API specifications
Emergency Shutdown	In-Plant Detectors	40 ppm Emergency Shutdown
Emergency Shutdown	O'Neal No. 4 wellsite	40 ppm Emergency Shutdown



Casing/Tubing Information

Label	1	2	3	4		5
Type	Conductor	Surface	Intermediate	Production Liner		Tubing
OD	-	10-3/4"	7-5/8"	5" (new)	5" (old)	2-3/8"
ID	-	9.760"	6.625"	4.276"	4.276"	1.867"
Drift ID	-	9.604"	6.500"	4.151"	4.151"	1.773"
COD	-	11.750"	8.500"	5.563"	5.563"	3.063"
Weight	-	55.5 lb/ft	39.0 lb/ft	18.0 lb/ft	18.0 lb/ft	5.8 lb/ft
Grade	-	S-95	CY-95	P-110	Q-125	L-80
Hole Size	N/A	14-3/4"	9-1/2"	N/A	6-1/2"	N/A
Depth Set	Driven to Refusal	3,610'	15,340'	Top: 0' Bottom: 14,080'	Top: 14,088' Bottom: 16,101'	15,720'
Cement	N/A	Lead: 1,125 sks HLC Tail: 350 sks H	Lead: 575 sks 50:50 Poz:H Tail: 400 sks H	Lead: 650 sks 50:50 Poz:H Tail: 110 sks CO_2 Res. Slurry	200 sks Premium	N/A
TOC	N/A	Surface	7,359'	Surface	Surface	N/A
% Excess	-	-	-	Lead: 10% Tail: 0%	-	N/A

LONQUIST SEQUESTRATION LLC	Ozona CCS	CO_2 Injection Well Proposed Well Design - O'Neal Gas Unit No. 4	
	Country: USA	State/Province: Texas	County/Parish: Bee County
	API No: 42-025-32658	Field: TBD	Well Type/Status: Proposed
Texas License F-8652	Location: 28.6031807, -98.0017091	Project No: LS190	Date: 10/13/2023
12912 Hill Country Blvd. Ste F-200 Austin, Texas 78738 Tel: 512.732.9812 Fax: 512.732.9816	Drawn: Joseph Lovewell	Reviewed: David Lytle	Approved: David Lytle
	Rev No: 0	Notes:	

Figure 32 – O'Neal No. 4 Wellbore Schematic

With the continuous air monitoring at the Plant and the well site, a release of CO_2 would be quickly identified, and the safety systems and protocols would effectuate an orderly shutdown to ensure safety and minimize the release volume. The CO_2 injected into the O'Neal No. 4 is from the amine unit at the Pawnee Gas Plant. If any leakage were to be detected, the volume of CO_2 released would be quantified based on the operating conditions at the time of release, as stated in *Section 7* in accordance with 40 CFR **§98.448(a)(5)**. Ozona concludes that the leakage of CO_2 through the surface equipment is unlikely.

4.2 Leakage Through Existing Wells Within the MMA

The O'Neal No. 4 is engineered to prevent migration from the injection interval to the surface through a special casing and cementing design as depicted in the schematic provided in Figure 32. Mechanical integrity tests (MITs), required under Statewide Rule (SWR) **§3.46** [40 CFR **§146.23 (b)(3)**], will take place every 5 years to verify that the well and wellhead can contain the appropriate operating pressures. If the MIT were to indicate a leak, the well would be isolated and the leak mitigated to prevent leakage of the injectate to the atmosphere.

A map of all oil and gas wells within the MMA is shown in Figure 33. Figure 34 is a map of all the oil and gas wells that penetrate the MMA's gross injection zone. Only one well penetrated the MMA's gross injection zone. This well was non-productive and has been plugged and abandoned in accordance with TRRC requirements. A summary table of all oil and gas wells within the MMA is provided in Appendix B-1.

This table in Appendix B-1 provides the total depth (TD) of all wells within the MMA.   The wells that are shallower and do not penetrate the injection zone are separated by the Pearsall Formation with a gross thickness of 535'. The Pine Island Shale comprises approximately 130 feet of this interval as discussed in *Section 2.2.2*, and provides a competent regional seal making vertical migration of fluids above the injection zone unlikely.

The shallower producing offset wells within the MMA will also serve as above zone monitoring wells. As gas analysis is routinely performed for monthly settlement statements from these wells, Ozona will be notified if a material difference in the quantity of CO_2 produced occurs, indicating a potential migration of injectate from the Sligo formation. Ozona would investigate and develop a mitigation plan, which may include reducing the injection rate or shutting the well in. Based on the investigation, the appropriate equation in *Section 7* would be used to make any adjustments to the reported volumes.

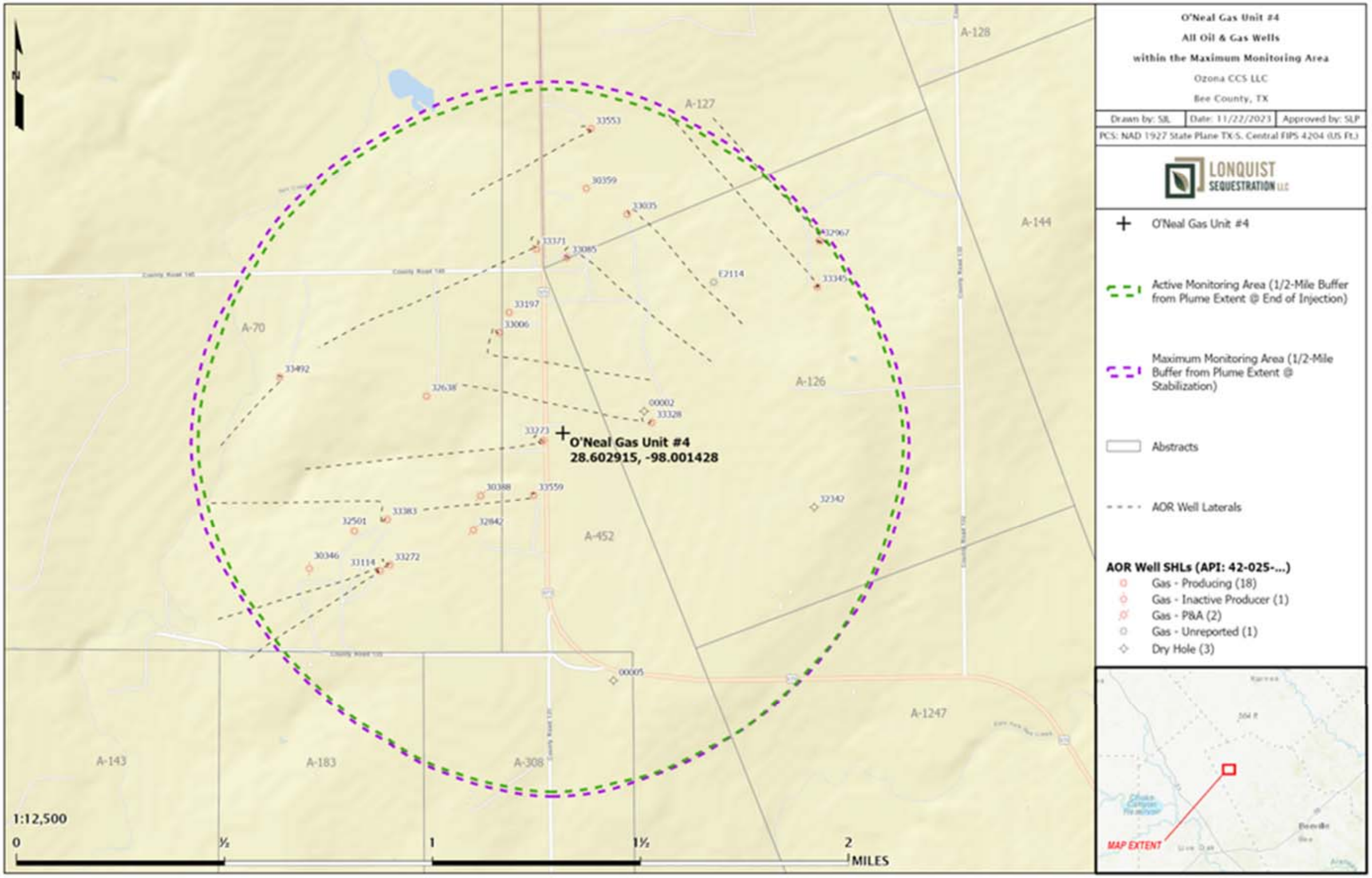


Figure 33 – All Oil and Gas Wells Within the MMA

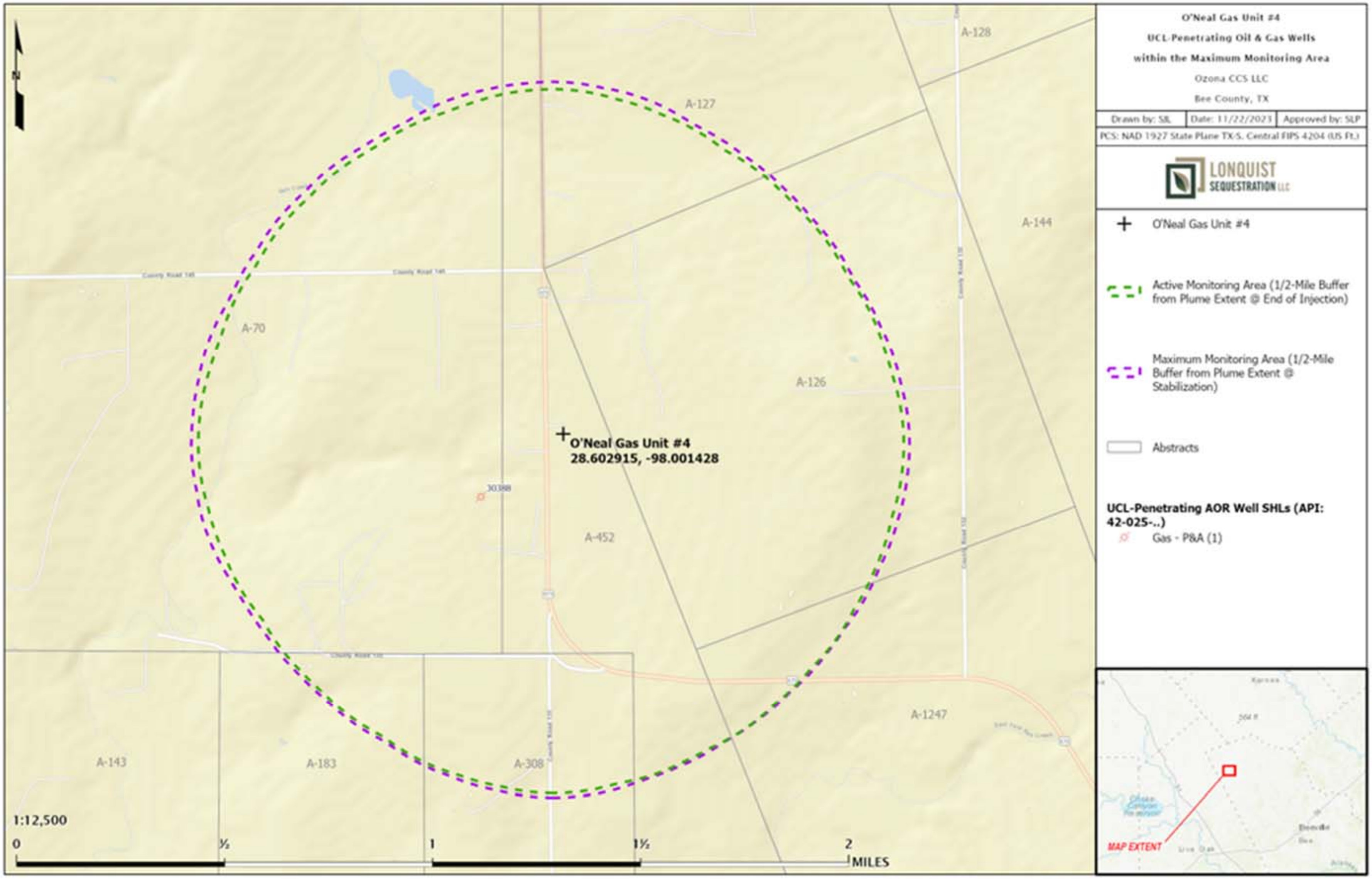


Figure 34 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

4.2.1 Future Drilling

Potential leak pathways caused by future drilling in the area are not expected to occur. The deeper formations have proven to date to be nonproductive in this area and therefore Ozona does not see this as a risk. This is supported by a review of the TRRC Rule 13 (entitled Casing, Cementing, Drilling, Well Control, and Completion Requirements), 16 TAC **§3.13**. The Sligo is not among the formations listed for which operators in Bee County and District 2 (where the O'Neal No. 4 is located) are required to comply with TRCC Rule 13 and therefore the TRRC does not believe there are productive horizons below the Sligo. The O'Neal No. 4 drilling permit is provided in Appendix A-2.

4.2.2 Groundwater Wells

The results of a groundwater well search found 5 wells within the MMA, as identified by the Texas Water Development Board as shown in Figure 35, and in tabular form in Appendix B-2.

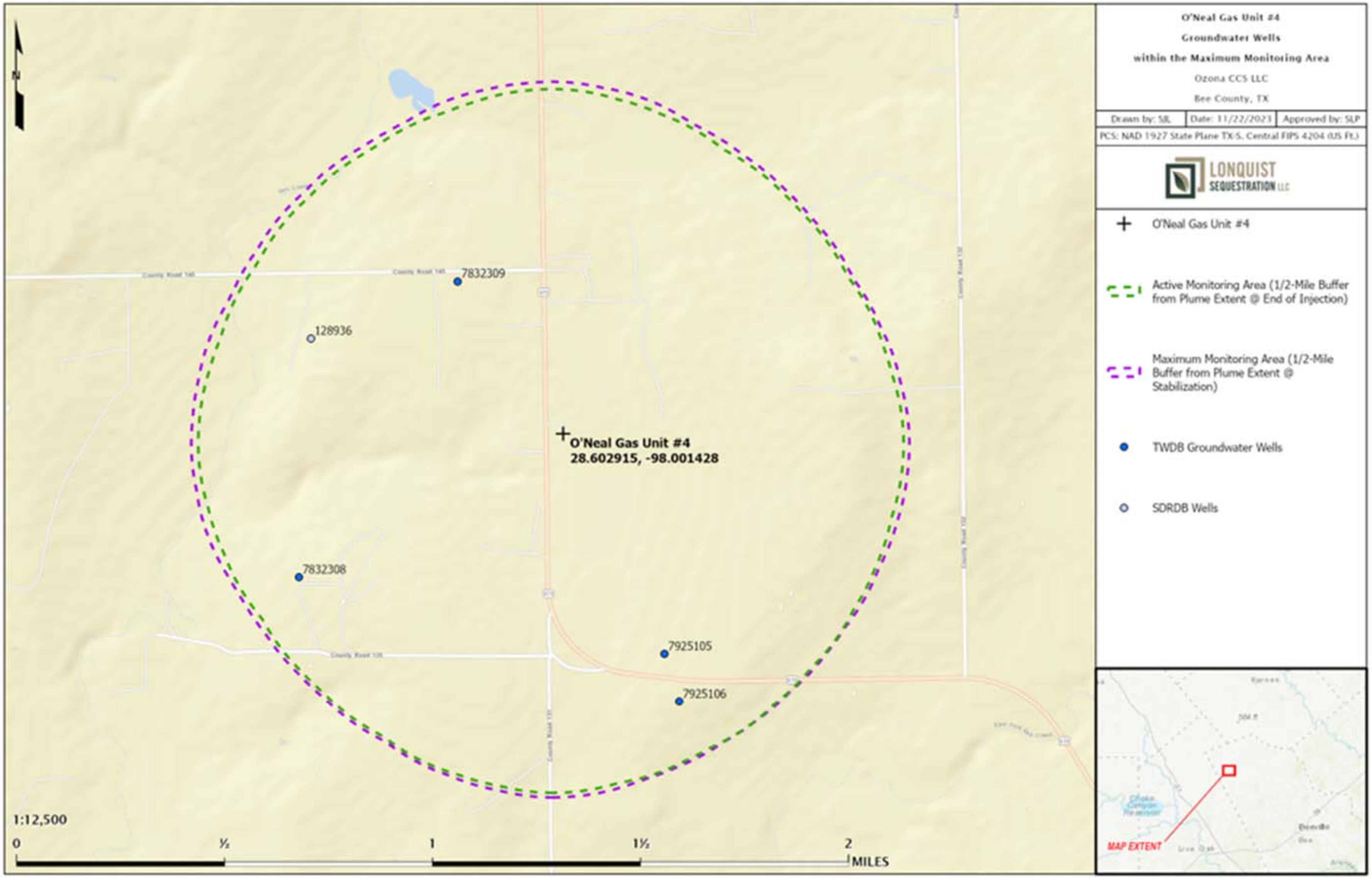


Figure 35 – Groundwater Wells Within the MMA

The surface, intermediate, and production casings of the O'Neal No. 4, as shown in Figure 32, are designed to protect the shallow freshwater aquifers, consistent with applicable TRRC regulations, and the GAU letter issued for this location is provided in Appendix A-1. The wellbore casings and compatible cements prevent CO_2 leakage to the surface along the borehole. Ozona concludes that leakage of the sequestered CO_2 to the groundwater wells is unlikely.

4.3 <u>Leakage Through Faults and Fractures</u>

Detailed mapping of openhole logs surrounding the O'Neal No. 4 did not identify any faulting within the Pearsall or Sligo section. However, there is a general lack of deep penetrators within the area which limits the amount of openhole coverage available.

The majority of the published literature suggests faulting near the project area is restricted to the shallower, overlying Cenozoic section, as seen in Figure 9, with shallow faults dying out before reaching the Pearsall formation. One source interpreted the potential for faulting to the south (Swanson S.M., et al., 2016). The potential fault is depicted in Figure 8 relative to the location of the O'Neal No. 4. According to the map, the interpreted fault lies approximately 4.25 miles south-southeast of the well and approximately 3.9 miles south-southeast of the stabilized plume extent in the year 2047. In the unlikely scenario in which the injection plume or pressure front reaches the potential fault, and the potential fault was to act as a transmissive pathway, the upper confining Pearsall shale contains sufficient thickness and petrophysical properties required to confine and protect injectates from leaking outside of the permitted injection zone.

Please see *Section 2.1.2* discussing Regional Structure and Faulting and *Section 2.3* covering Local Structure for additional material relevant to this topic.

4.4 <u>Leakage Through the Confining Layer</u>

The Sligo injection zone has competent sealing intervals present above and below the targeted carbonate sequence of the Sligo section. The overlying Pine Island shale member of the Pearsall formation is approximately 130 feet thick at the O'Neal No. 4. Above this confining unit, the Cow Creek limestone, Cow Creek shale, and Bexar shale members of the Pearsall formation will act as additional confinement between the injection interval and the USDW. The USDW lies well above the sealing properties of the formations outlined above, making stratigraphic migration of fluids into the USDW highly unlikely. The petrophysical properties of the Lower Sligo and Hosston formations make these ideal for lower confinement. The low porosity and permeability of these underlying formations minimizes the likelihood of downward migration of injected fluids. The relative buoyancy of injectate to the in-situ reservoir fluid makes migration below the lower confining layer unlikely.

4.5 <u>Leakage from Natural or Induced Seismicity</u>

The O'Neal No. 4 is located in an area of the Gulf of Mexico considered to be active from a seismic perspective. Therefore, the Bureau of Economic Geology's TexNet (from 2017 to present) and USGS's Advanced National Seismic System (from 1971 to present) databases were reviewed to

identify any recorded seismic events within 25 km of the O'Neal No. 4.
The investigation identified a multitude of seismic events within the 25 km search radius, however, the magnitude of most of the events was below 2.5. The nearest seismic event with a recorded magnitude of 3.0 or greater was measured approximately 5.6 km northwest of the O'Neal No. 4 at a depth of 5 km. The results of the investigation are plotted on the map provided in Figure 36 relative to the O'Neal No. 4 and 25 km search radius.

The Plant will have operating procedures and set points programmed into the control and SCADA systems to ensure operating pressures are maintained within the injection and confining intervals approved fracture gradients. Given the seismic activity in the area, Ozona will closely monitor nearby TexNet station EF71 for activity and any corresponding irregularities in the operating pressures of O'Neal No. 4.

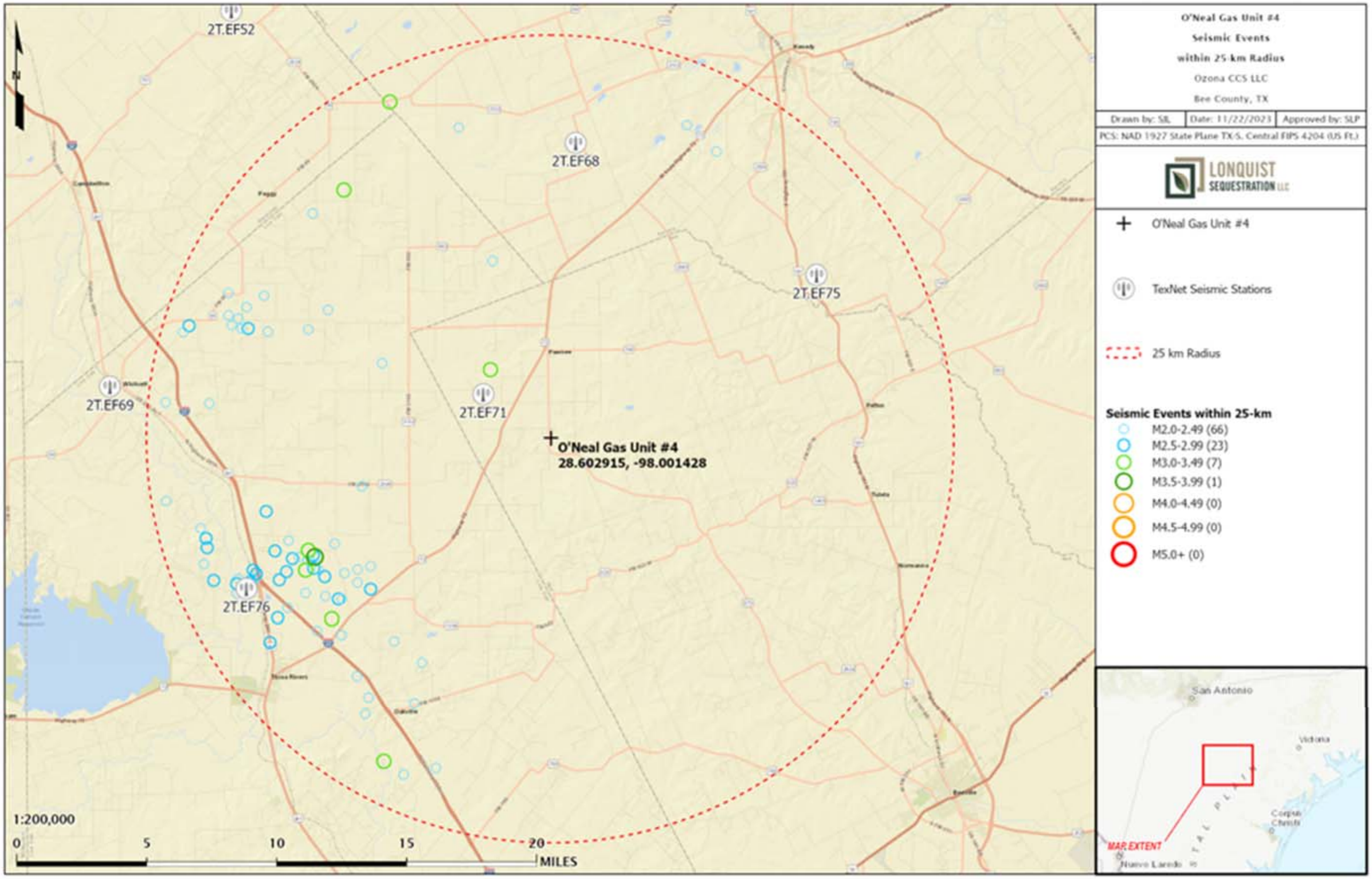


Figure 36 – 25 km Seismicity Review

SECTION 5 – MONITORING FOR LEAKAGE

This section discusses the strategy that Ozona will employ for detecting and quantifying surface leakage of CO_2 through the pathways identified in *Section 4*, to meet the requirements of 40 CFR **§98.448(a)(3)**. As the injectate stream contains both H_2S and CO_2, the H_2S will be a proxy for CO_2 leakage and therefore the monitoring systems in place to detect H_2S will also indicate a release of CO_2. Table 10 summarizes the monitoring of the following potential leakage pathways to the surface. Monitoring will occur during the planned 12-year injection period or cessation of injection operations, plus a proposed 10-year post-injection period until the plume has stabilized.

- Leakage from surface equipment
- Leakage through existing and future wells within the MMA
- Leakage through faults, fractures, or confining seals
- Leakage through natural or induced seismicity

Table 10 – Summary of Leakage Monitoring Methods

<table>
<tr><th>Leakage Pathway</th><th>Monitoring Method</th></tr>
<tr><td rowspan="3">Ohdndjh#iurp#vxuidfh#htxlsphqw</td><td>Il{hg#K$_5$V#prqlwruv#dw#wkh#Sodqw#dqg#zhoo#vlwh</td></tr>
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<tr><td>Phfkdqlfdo#Lqwhjulw|#Whvwv#+PLW,#ri#R*Qhdo#Qr1#7#hyhu|#8#|hduv</td></tr>
<tr><td>Ylvxdo#lqvshfwlrqv</td></tr>
<tr><td>Dqqxdo#vrlo#jdv#vdpsolqj#qhdu#zhoo#orfdwlrqv#wkdw#shqhwudwh#wkh#Xsshu#
Frqilqlqj#]rqh#zlwklq#wkh#DPD</td></tr>
<tr><td>Ohdndjh#wkurxjk#jurxqgzdwhu#zhoov</td><td>Dqqxdo#jurxqgzdwhu#vdpsohv#iurp#h{lvwlqj#zdwhu#zhoo+v,</td></tr>
<tr><td>Ohdndjh#iurp#ixwxuh#zhoov</td><td>Prqlwru#guloolqj#dfwlylw|#dqg#frpsoldqfh#zlwk#WUUF#Uxoh#46#Uhjxodwlrqv</td></tr>
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<tr><td rowspan="2">Ohdndjh#iurp#qdwxudo#ru#lqgxfhg#vhlvplflw|</td><td>Prqlwru#FR$_5$#ohyhov#lq#deryh#}rqh#surgxflqj#zhoov</td></tr>
<tr><td>Prqlwru#h{lvwlqj#Wh{Qhw#vwdwlrq</td></tr>
</table>

5.1 Leakage from Surface Equipment

The Plant and the O'Neal No. 4 were designed to operate in a safe manner to minimize the risk of an escape of CO_2 and H_2S. Leakage from surface equipment is unlikely and would quickly be detected and addressed. The facility design minimizes leak points through the equipment used, and key areas are constructed with materials that are NACE and API compliant. A baseline atmospheric CO_2 concentration will be established prior to commencing operation once facility construction has been completed. Ambient H_2S monitors will be located at the Plant and near the O'Neal No. 4 site for local alarm and are connected to the SCADA system for continuous monitoring.

The Plant and O'Neal No. 4 are continuously monitored through automated control systems. These monitoring points were discussed in *Section 4.1*. In addition, field personnel conduct routine visual field inspections of gauges, and gas monitoring equipment. The effectiveness of the internal and external corrosion control program is monitored through the periodic inspection of the corrosion coupons and inspection of the cathodic protection system. These inspections and the automated systems allow Ozona to detect and respond to any leakage situation quickly. The surface equipment will be monitored for the injection and post-injection period. Should leakage be detected during active injection operations, the volume of CO_2 released will be calculated based on operating conditions at the time of the event, per 40 CFR **§98.448(a)(5)**.

Pressures, temperatures, and flow rates through the surface equipment are continuously monitored during operations. If a release occurred from surface equipment, the amount of CO_2 released would be quantified based on the operating conditions, including pressure, flow rate, percentage of CO_2 in the injectate, size of the leak-point opening, and duration of the leak. In the unlikely event a leak occurs, Ozona will quantify the leak per the strategies discussed in *Section 7*.

5.2 Leakage Through Existing and Future Wells Within the MMA

Ozona continuously monitors and collects injection volumes, pressures, and temperatures through their SCADA systems, for the O'Neal No. 4. This data is reviewed by qualified personnel and will follow response and reporting procedures when data exceeds acceptable performance limits. A change of injection or annular pressure would indicate the presence of a possible leak and be thoroughly investigated. In addition, MITs performed every 5 years, as expected by the TRRC and UIC, would also indicate the presence of a leak. Upon a negative MIT, the well would be isolated and investigated to develop a leak mitigation plan.

As discussed previously, TRRC Rule 13 ensures that new wells in the field are constructed with proper materials and practices to prevent migration from the injection interval.

In addition to the fixed monitors described previously, Ozona will also establish and operate an in-field monitoring program to detect CO_2 leakage within the AMA. This would include H_2S monitoring as a proxy for CO_2 at the well site and annual soil gas samples taken near any identified wells that penetrate the injection interval within the AMA. These samples will be analyzed by a qualified third party. Prior to commencing operation, and through the post-injection monitoring period, Ozona will have these monitoring systems in place.

Currently, there is only one well in the MMA identified that penetrates the injection interval. This well was plugged and abandoned in 2007. The TRRC records are provided in Appendix A-4. Ozona will take an annual soil gas sample from this area which will be analyzed by a third-party lab. Additional monitoring will be added as the AMA is updated over time. In the unlikely event a leak occurs, Ozona will quantify the leak volumes by the methodologies discussed in *Section 7* and present these results and related activities in the annual report.

Ozona will also utilize shallower producing gas wells as proxies for above zone monitoring wells. Production data from these wells is analyzed for monthly production statements, and therefore would be an early indicator of any possible subsurface issues. Should any material change from historical trends in the CO_2 concentration occur, Ozona would investigate and develop a corrective action plan. Should any CO_2 migrate vertically from the Sligo, the magnitude risk of this event is very low, as the producing reservoir provides an ideal containment given the Upper Confining Zone of this reservoir has proven competent. In the unlikely event a leak occurs, Ozona would quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances, and include these results in the annual report.

5.2.1.1 Groundwater Quality Monitoring

Ozona will monitor the groundwater quality above the confining interval by sampling from groundwater wells near the O'Neal No. 4 and analyzing the samples with a third-party laboratory on an annual basis. In the case of the O'Neal No. 4, 5 existing groundwater wells have been identified within the AMA (Figure 38). Initial groundwater quality tests will be performed to establish a baseline prior to commencing operations.

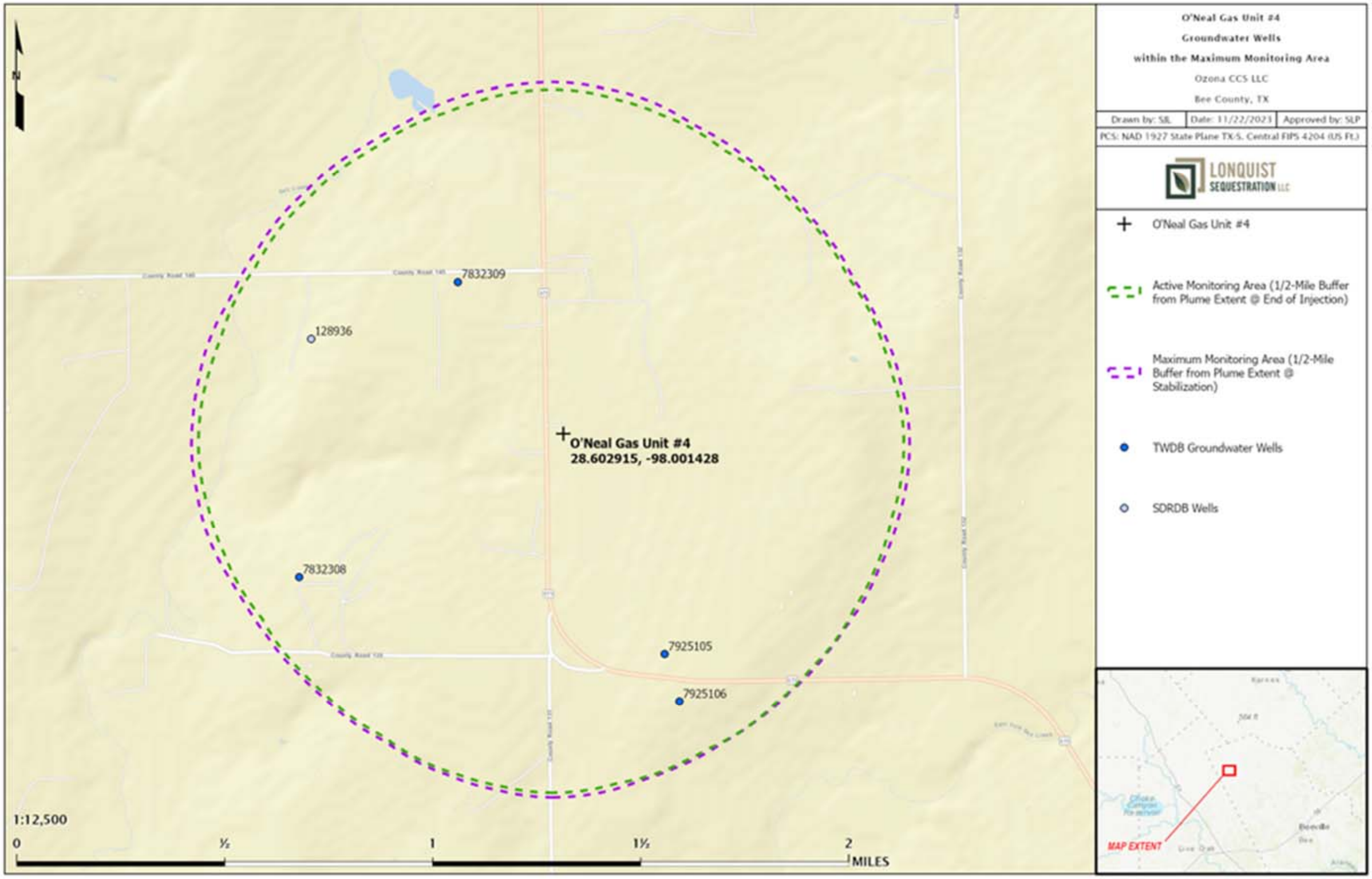

Figure 37 – Groundwater Wells

5.3 Leakage Through Faults, Fractures, or Confining Seals

Ozona will continuously monitor the operations of the O'Neal No. 4 through the automated controls and SCADA systems. Any deviation from normal operating volume and corresponding injection pressure could indicate movement into a potential leak pathway, such as a fault or breakthrough of the confining seal, and would trigger an alert due to a change in the injection pressure. Any such alert would be reviewed by field personnel and appropriate action would be taken, including shutting in the well, if necessary.

Ozona will also utilize shallower producing wells as proxies for above zone monitoring wells. Production data is analyzed regularly for monthly production statements and therefore would be an early indicator of any possible subsurface issues. Should any material change from historical trends in the CO_2 concentration occur, Ozona would investigate and develop a corrective action plan. Should any CO_2 migrate vertically from the Sligo, the magnitude risk of this event is very low, as the producing reservoir provides an ideal containment given the Upper Confining Zone has proven competent. In the unlikely event a leak occurs, Ozona would quantify the leak per the strategies discussed in *Section 7*, or as may be applicable provided in 40 CFR **§98.443** based on the actual circumstances.

5.4 Leakage Through Natural or Induced Seismicity

While the likelihood of a natural or induced seismicity event is low, Ozona plans to use the nearest TexNet seismic monitoring station EF71 to monitor the area around the O'Neal No. 4. This station is approximately three miles to the northwest, as shown in Figure 38. This is sufficient distance to allow for accurate and detailed monitoring of the seismic activity in the area. Ozona will monitor this station for any seismic activity, and if a seismic event of 3.0 magnitude or greater is detected, Ozona will review the injection volumes and pressures of the O'Neal No. 4 to determine if any significant changes have occurred that would indicate potential leakage. In the unlikely event a leak occurs, Ozona will quantify the leak per the strategies discussed in *Section 7*, and take appropriate operational actions based on the circumstances.

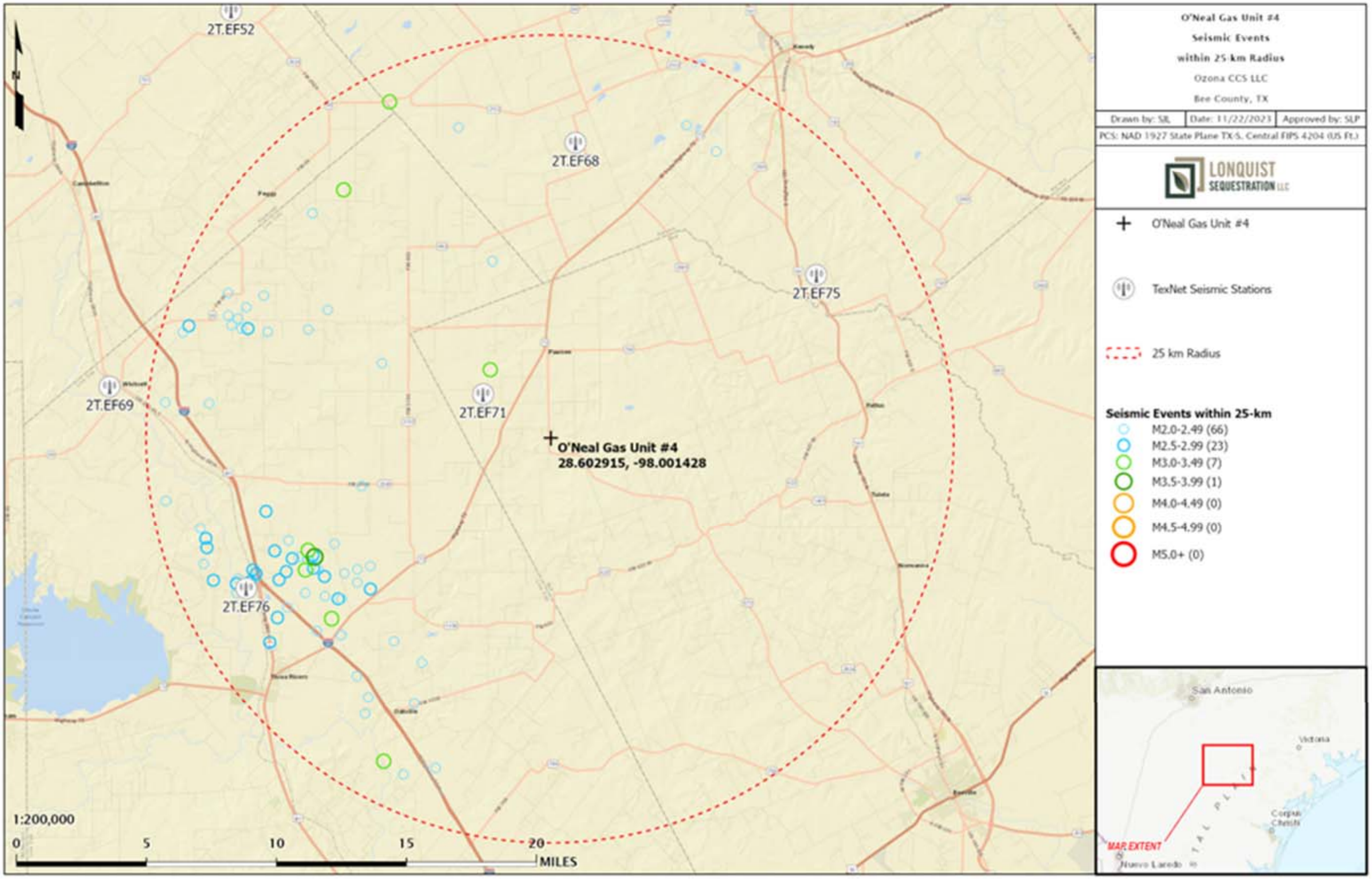

Figure 38 – Seismic Events and Monitoring Station

SECTION 6 – BASELINE DETERMINATIONS

This section identifies the strategies Ozona will undertake to establish the expected baselines for monitoring CO_2 surface leakage per 40 CFR **§98.448(a)(4).** Ozona will use the existing SCADA monitoring systems to identify changes from the expected performance that may indicate leakage of injectate and calculate a corresponding amount of CO_2.

6.1 Visual Inspections

Regular inspections will be conducted by field personnel at the Plant and O'Neal No. 4 site. These inspections will aid in identifying and addressing possible issues to minimize the risk of leakage. If any issues are identified, such as vapor clouds or ice formations, corrective actions will be taken prudently and safely to address such issues.

6.2 CO_2/H_2S Detection

In addition to the fixed monitors in the Plant and at the wellsite, Ozona will establish and perform an annual in-field sampling program to monitor and detect any CO_2 leakage within the AMA. This will consist of soil gas sampling near any artificial penetrations of the injection zone and sampling of water wells. These samples will be analyzed by a 3rd party lab and the results provided in the annual report. Initial samples will be taken and analyzed before the commencement of operation and will establish the baseline reference levels.

6.3 Operational Data

Upon starting injection operations, baseline measurements of injection volumes and pressures will be recorded. Any significant deviations over time will be analyzed for indication of leakage of injectate and the corresponding component of CO_2.

6.4 Continuous Monitoring

The total mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly, as the injection stream for this project is near the Occupational Safety and Health Administration (OSHA) Permissible Exposure Limit (PEL) 8-hour Time Weighted Average (TWA) of 5,000 ppm. Direct leak surveys present a hazard to personnel due to the presence of H_2S in the gas stream. Continuous monitoring systems will trigger alarms if there is a release. The mass of the CO_2 released would be calculated based on the operating conditions, including pressure, flow rate, percentage of CO_2, size of the leak-point opening, and duration. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

In the case of a de-pressuring event, the acid gas stream will be sent to a flare stack to be safely processed and will be reported under reporting requirements for the Plant. Any such events will be accounted for in the sequestered reporting volumes consistent with *Section 7.*

6.5 Groundwater Monitoring

Initial samples will be taken from groundwater wells in the area of the O'Neal No. 4 upon approval of the MRV plan, and before commencement of CO_2 injection. These samples will be analyzed and reports prepared by a third-party laboratory to establish baseline water quality parameters.

SECTION 7 – SITE-SPECIFIC CONSIDERATIONS FOR MASS BALANCE EQUATION

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

7.1 Mass of CO_2 Received

Per 40 CFR **§98.443**, the mass of CO_2 received must be calculated using the specified CO_2 received equations "unless you follow the procedures in 40 CFR **§98.444(a)(4**)." 40 CFR **§98.444(a)(4)** states that "if the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR-1 or RR-2 of this subpart to calculate CO_2 received." The CO_2 received for this injection well is wholly injected and not mixed with any other supply; the annual mass of CO_2 injected will equal the amount received. Any future streams would be metered separately before being combined into the calculated stream.

7.2 Mass of CO_2 Injected

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

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

Where:

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

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

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

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

p = Quarter of the year

u = Flow meter

7.3 Mass of CO_2 Produced

The O'Neal No. 4 is not part of an enhanced oil recovery project; therefore, no CO_2 will be produced.

7.4 Mass of CO_2 Emitted by Surface Leakage

The mass of CO_2 emitted by surface leakage and equipment leaks will not be measured directly due to the H_2S concentration in the injection stream. Direct leak surveys are dangerous and present a hazard to personnel. Because no venting is expected to occur, the calculations would be based on the unusual event that a blowdown is required and those emissions would be sent to a flare stack and reported as a part of the required GHG reporting for the Plant. Any leakage would be detected and managed as an upset event. Continuous monitoring systems should trigger an alarm upon a release of H_2S and CO_2. The mass of the CO_2 released would be calculated for the operating conditions, including pressure, flow rate, size of the leak-point opening, and duration of the leak. This method is consistent with 40 CFR **§98.448(a)(5)**, allowing the operator to calculate site-specific variables used in the mass balance equation.

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

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

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

Calculation methods using equations from Subpart W will be used to calculate CO_2 emissions due to any surface leakage between the flow meter used to measure injection quantity and the injection wellhead.

As discussed previously, the potential for pathways for all previously mentioned forms of leakage is unlikely. Given the possibility of uncertainty around the cause of a leakage pathway that is mentioned above, Ozona believes the most appropriate method to quantify the mass of CO_2 released will be determined on a case-by-case basis. Any mass of CO_2 detected leaking to the surface will be quantified by using industry proven engineering methods including, but not limited to, engineering analysis on surface and subsurface measurement data, dynamic reservoir modeling, and history-matching of the sequestering reservoir performance, among others. In the unlikely

event that a leak occurs, it will be addressed, quantified, and documented within the appropriate timeline. Any records of leakage events will be kept and stored as provided in *Section 10*.

7.5 Mass of CO_2 Sequestered

The mass of CO_2 sequestered in subsurface geologic formations will be calculated based on Equation RR-12. Data collection for calculating the amount of CO_2 sequestered in the O'Neal No. 4 will begin once the subsurface recompletion work, and the surface facilities construction has been completed, and subject to approval of the MRV plan. The calculation of sequestered volumes utilizes the following equation as the O'Neal No. 4 will not actively produce oil, natural gas, or any other fluids:

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

Where:

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

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well 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

CO_{2FI} will be calculated in accordance with Subpart W for reporting of GHGs. Because no venting is expected to occur, the calculations would be based on the unusual event that a system blowdown event occurs. Those emissions would be sent to a flare stack and reported as part of the GHG reporting for the Plant.

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

SECTION 8 – IMPLEMENTATION SCHEDULE FOR MRV PLAN

The O'Neal Gas Unit No. 4 is an existing natural gas well that will be recompleted as a Class II well with corrosion resistant materials. Ozona is submitting this MRV application to the GHGRP to comply with the requirements of Subpart RR. The MRV plan will be implemented upon receiving EPA approval. The Annual Subpart RR Report will be filed on March 31 of the year following the reporting year.

SECTION 9 – QUALITY ASSURANCE

This section identifies how Ozona plans to manage quality assurance and control to meet the requirements of 40 CFR **§98.444.**

9.1 Monitoring QA/QC

CO_2 Injected

- The flow rate of the CO_2 being injected will be measured with a volumetric flow meter, consistent with API standards. These flow rates will be compiled quarterly.
- The composition of the injectate stream will be measured upstream of the volumetric flow meter with a continuous gas composition analyzer or representative sampling consistent with API standards.
- The gas composition measurements of the injected stream will be averaged quarterly.
- The CO_2 measurement equipment will be calibrated per the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.

CO_2 Emissions from Leaks and Vented Emissions

- Gas monitors at the Plant and O'Neal No. 4 will be operated continuously, except for maintenance and calibration.
- Gas monitors will be calibrated according to the requirements of 40 CFR **§98.444(e)** and **§98.3(i)**.
- Calculation methods from Subpart W will be used to calculate CO_2 emissions from equipment located on the surface, between the flow meter used to measure injection quantity and the injection wellhead.

Measurement Devices

- Flow meters will be continuously operated except for maintenance and calibration.
- Flow meters will be calibrated according to 40 CFR **§98.3(i).**
- Flow meters will be operated and maintained in accordance with applicable standards as published by a consensus-based standards organization.

All measured volumes of CO_2 will be converted to standard cubic meters at a temperature of 60°F and an absolute pressure of 1 atmosphere.

9.2 Missing Data

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

- If a quarterly quantity of CO_2 injected is missing, the amount will be estimated using a representative quantity of CO_2 injected from the nearest previous period at a similar injection pressure.

- Fugitive CO_2 emissions from equipment leaks from facility surface equipment will be estimated and reported per the procedures specified in Subpart W of 40 CFR **§98.**

9.3 MRV Plan Revisions

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

SECTION 10 – RECORDS RETENTION

Ozona will retain records as required by 40 CFR **§98.3(g)**. These records will be retained for at least 3 years and include the following:

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

APPENDICES

APPENDIX A – O'Neal No. 4 TRRC FORMS

APPENDIX A-1: GAU GROUNDWATER PROTECTION DETERMINATION

APPENDIX A-2: DRILLING PERMIT

- CHARLIE C. OVERBY API 42-025-32658
- O'NEAL GAS UNIT NO. 4 API 42-025-32658

APPENDIX A-3: COMPLETION REPORT

- CHARLIE C. OVERBY API 42-025-32658
- O'NEAL GAS UNIT NO. 4 API 42-025-32658
- ACID FRACTURE REPORT

APPENDIX A-4: API 42-025-30388 CHARLIE C. OVERBY GU PLUGGING RECORDS

APPENDIX B – AREA OF REVIEW

APPENDIX B-1: OIL AND GAS WELLS WITHIN THE MMA LIST

APPENDIX B-2: WATER WELLS WITHIN THE MMA LIST

GROUNDWATER PROTECTION DETERMINATION

Form GW-2

Groundwater Advisory Unit

Date Issued:	26 May 2023	**GAU Number:**	367912

Attention:	OZONA CCS LLC	**API Number:**	02532658
	19026 RIDGEWOOD	**County:**	BEE
	SAN ANTONIO, TX 78259	**Lease Name:**	O'Neal Gas Unit
Operator No.:	100116	**Lease Number:**	162214
		Well Number:	4
		Total Vertical	16101
		Latitude:	28.602914
		Longitude:	-98.001428
		Datum:	NAD27

Purpose: Injection into Producing Zone (H1)

Location: Survey-EL&RR RR CO; Abstract-452; Section-1

To protect usable-quality groundwater at this location, the Groundwater Advisory Unit of the Railroad Commission of Texas recommends:

The base of usable-quality water-bearing strata is estimated to occur at a depth of 250 feet at the site of the referenced well.

The BASE OF UNDERGROUND SOURCES OF DRINKING WATER (USDW) is estimated to occur at a depth of 950 feet at the site of the referenced well.

Note: Unless stated otherwise, this recommendation is intended to apply to all wells drilled within 200 feet of the subject well. Unless stated otherwise, this recommendation is for normal drilling, production, and plugging operations only.

This determination is based on information provided when the application was submitted on 05/26/2023. If the location information has changed, you must contact the Groundwater Advisory Unit, and submit a new application if necessary. If you have questions, please contact us at 512-463-2741 or gau@rrc.texas.gov.

Groundwater Advisory Unit, Oil and Gas Division

RRC ONLINE SYSTEM

Oil & Gas Data Query

Query Menu Help

Drilling Permit (W-1) Query Results

Search Criteria:

API No.: 02532658

Return

2 results Page: 1 of 1 Page Size: View All

API NO.	District	Lease	Well Number	Permitted Operator	County	Status Date	Status Number	Wellbore Profiles	Filing Purpose	Amend	Total Depth	Stacked Lateral Parent Well DP #	Status
02532658 Links	02	CHARLIE C. OVERBY GAS UNIT	2	PARKER & PARSLEY DEVELOPMENT CO.(640889)	BEE	Submitted: 11/30/1992 Approved: 11/30/1992	406655	Vertical	New Drill	N	16700		APPROVED
02532658 Links	02	O'NEAL GAS UNIT (162214)	4	PARKER & PARSLEY DEVELOPMENT L.P(640886)	BEE	Submitted: 11/20/1996 Approved: 12/16/1996	455434	Vertical	Recompletion	N	14040		APPROVED

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NOTE: THE CHARLIE C. OVERBY GU AND THE O'NEAL GU ARE THE SAME WELL. THE OVERBY WELL WAS DRILLED IN 1993 INTO THE SLIGO. IN 1997 THE WELL WAS RECOMPLETED IN THE EDWARDS FORMATION. THIS WAS DONE UNDER A NEW LEASE, AS THE O'NEAL GU NO. 4.

RRC ONLINE SYSTEM

Log In

Form W-1: Review

Status # 406655 **API #** 025-32658	**OP # 640889 - PARKER & PARSLEY DEVELOPMENT CO.** Approved ,**Issued:** 11/30/1992 ,**Filed:** Hardcopy	**CHARLIE C. OVERBY GAS UNIT - Well # 2** 02 - BEE County	**New Drill** Vertical

NEAREST WELL COMMENT: 1607.8 (11/30/1992 12:00:00 AM)

Status:

Back to Public Query Search Results

Completion Information

Well Status Code	Spud Date	Drilling Completed	Surface Casing Date
W - Final Completion	01/01/1993	02/11/1993	01/01/1993

Field Name	Completed Well Type	Completed Date	Validated Date
PAWNEE (SLIGO)	Gas	02/11/1993	06/18/1993

General / Location Information

Basic Information:

Filing Purpose	Welbore Profiles	Lease Name	Well #	SWR	Total Depth	Horizontal Wellbore	Stacked Lateral Parent Well DP #
New Drill	Vertical	CHARLIE C. OVERBY GAS UNIT	2	SWR 36	16700		

Surface Location Information:

API #	Distance from Nearest Town	Direction from Nearest Town	Nearest Town	Surface Location Type
025-32658	4.0 miles	S	PAWNEE	Land

Survey/Legal Location Information:

Section	Block	Survey	Abstract #	County
		EL&RR RR CO	452	BEE

Township	League	Labor	Porcion	Share	Tract	Lot

Perpendicular surface location from two nearest designated reference lines:

Perpendiculars	Distance	Direction	Distance	Direction
Survey Lines	2784.0 feet	from the S line and	1045.5 feet	from the W line

Permit Restrictions:

Code	Description
30	REGULAR PROVIDED THAT UPON SUCCESSFUL COMPLETION OF THIS WELL IN THE SAME RESERVOIR AS ANY OTHER WELL PREVIOUSLY ASSIGNED THIS ACREAGE, A P-15 AND REVISED PRORATION PLATS MUST BE SUBMITTED WITH NO
30	DOUBLE ASSIGNMENT OF ACREAGE.
30	REGULAR PROVIDED THIS WELL IS NEVER COMPLETED IN THE SAME RESERVOIR AS ANY OTHER WELL CLOSER THAN 2640 FEET ON THIS SAME LEASE.
30	REGULAR PROVIDED THIS WELL IS DRILLED IN COMPLIANCE WITH RULE 36.

30	O'NEAL GU #3, O'NEAL #1, OVERBY #120 & NEAL #1.

Fields

District	Field Name	Field #	Completion Depth	Lease Name	Well #	Well Type	Acres	Distance to Nearest Well	Distance to Nearest Lease Line	SWR	Pooled/ Unitized
02	**PAWNEE (SLIGO)** **Primary Field**	69845800	16700	CHARLIE C. OVERBY GAS UNIT	2	Oil or Gas Well	704.0			SWR 36	Y

Perpendiculars	Distance	Direction	Distance	Direction
Surface Lease Lines	2390.0 feet	from the E line and	3446.0 feet	from the N line

Comments

Remark	Date Entered	Entered By
NEAREST WELL COMMENT: 1607.8	11/30/1992 12:00:00 AM	SYSTEM

Attachments

Attachment Type	File Path	Associated Fields and/or Plats

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Form W-1: Review

Status # 455434 **API #** 025-32658	**OP # 640886 - PARKER & PARSLEY DEVELOPMENT L.P** Approved ,**Issued:** 12/16/1996 ,**Filed:** Hardcopy	**O'NEAL GAS UNIT - Well # 4** 02 - BEE County	**Recompletion** Vertical
NEAREST WELL COMMENT: 1787 (11/20/1996 12:00:00 AM)			

Status:

Back to Public Query Search Results

Completion Information

Well Status Code	Spud Date	Drilling Completed	Surface Casing Date
W - Final Completion	02/04/1997	02/13/1997	

Field Name	Completed Well Type	Completed Date	Validated Date
PAWNEE (EDWARDS)	Gas	02/13/1997	02/26/1997

General / Location Information

Basic Information:

Filing Purpose	Welbore Profiles	Lease Name	Well #	SWR	Total Depth	Horizontal Wellbore	Stacked Lateral Parent Well DP #
Recompletion	Vertical	O'NEAL GAS UNIT	4	SWR 36, SWR 37H	14040		

Surface Location Information:

API #	Distance from Nearest Town	Direction from Nearest Town	Nearest Town	Surface Location Type
025-32658	3.5 miles	S	PAWNEE	Land

Survey/Legal Location Information:

Section	Block	Survey	Abstract #	County
		E.L.&R.R. RR CO. #1	452	BEE

Township	League	Labor	Porcion	Share	Tract	Lot

Perpendicular surface location from two nearest designated reference lines:

Perpendiculars	Distance	Direction	Distance	Direction
Survey Lines	825.0 feet	from the W line and	2784.0 feet	from the S line

Permit Restrictions:

Code	Description
30	WILDCAT ABOVE 14040 FEET.
30	ANY WELLBORE DRILLED UNDER THIS PERMIT MUST BE COMPLETED, OPERATED, AND PRODUCED IN COMPLIANCE WITH STATEWIDE RULE 32.
30	REGULAR PROVIDED THIS WELL IS DRILLED IN COMPLIANCE WITH RULE 36.

Fields

District	Field Name	Field #	Completion Depth	Lease Name	Well #	Well Type	Acres	Distance to Nearest Well	Distance to Nearest Lease Line	SWR	Pooled/ Unitized
02	**WILDCAT** **Primary Field**	00004001	14040	O'NEAL GAS UNIT	4	Oil or Gas Well	704.0			37H	Y

Perpendiculars	Distance	Direction	Distance	Direction
Surface Lease Lines	4900.0 feet	from the W line and	2784.0 feet	from the S line

District	Field Name	Field #	Completion Depth	Lease Name	Well #	Well Type	Acres	Distance to Nearest Well	Distance to Nearest Lease Line	SWR	Pooled/ Unitized
02	**PAWNEE (EDWARDS)**	69845200	14040	O'NEAL GAS UNIT	4	Gas Well	704.0			SWR 36, 37H	Y

Perpendiculars	Distance	Direction	Distance	Direction
Surface Lease Lines	4900.0 feet	from the W line and	2784.0 feet	from the S line

Exceptions

Field	Exception	Case Docket Number	Resolution
WILDCAT	**SWR 37 [Historical]**	**0214349**	
PAWNEE (EDWARDS)	**SWR 37 [Historical]**	**0214349**	

Comments

Remark	Date Entered	Entered By
NEAREST WELL COMMENT: 1787	11/20/1996 12:00:00 AM	SYSTEM

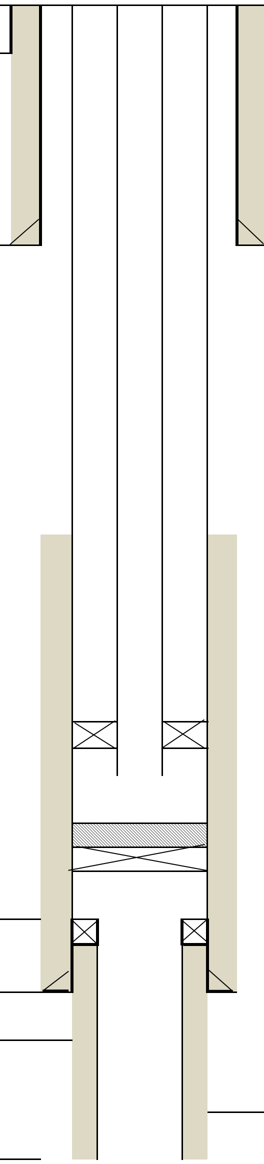
Attachments

Attachment Type	File Path	Associated Fields and/or Plats

Ozona CCS

Well Name:	ONeal Gas Unit 4 (current)	**Rig:**		**Lat, Long**	28.6031807,-98.0017091 (NAD83)
Formation:	Edwards	**GL:**		**GAU Depth:**	
County, State:	Bee County, TX	**RKB:**			
API #:	42-025-32658	**TD (MD):**	16,101'		
Permit #:		**TD (TVD):**			

	MD/TVD
Conductor	80
10.75" Surface Casing	3610
Cook Mountain	3657
Sparta	4259
Weches Sandstone	4326
Queen City	4655
Reklaw	5244
Carrizo	5864
Wilcox	5922
Midway	9026
Austin Chalk	13266
Eagle Ford	13344
Buda	13494
Edwards	13500
CIBP w/ 20' Cement on Top	14000
5" Liner Top	14088
Pearsall	15339
7 5/8" Intermediate Casing	15340
CO2 Resistant Permanent Packer	15700
Sligo	15874
5" Liner	16101



Tubular Detail

String	Hole Size (in)	OD (in)	Weight (#/ft)	Grade	MD (ft)
Conductor					
Surface	14 3/4"	10 3/4"	55.5	S-95	3,610'
Intermediate	9 1/2"	7 5/8"	39	CY-95	15,340'
Liner	6 1/2"	5"	18	Q-125	14,088'-16,101'
Prod Tbg		2 3/8"	4.7	L-80	13453'

Cement Detail

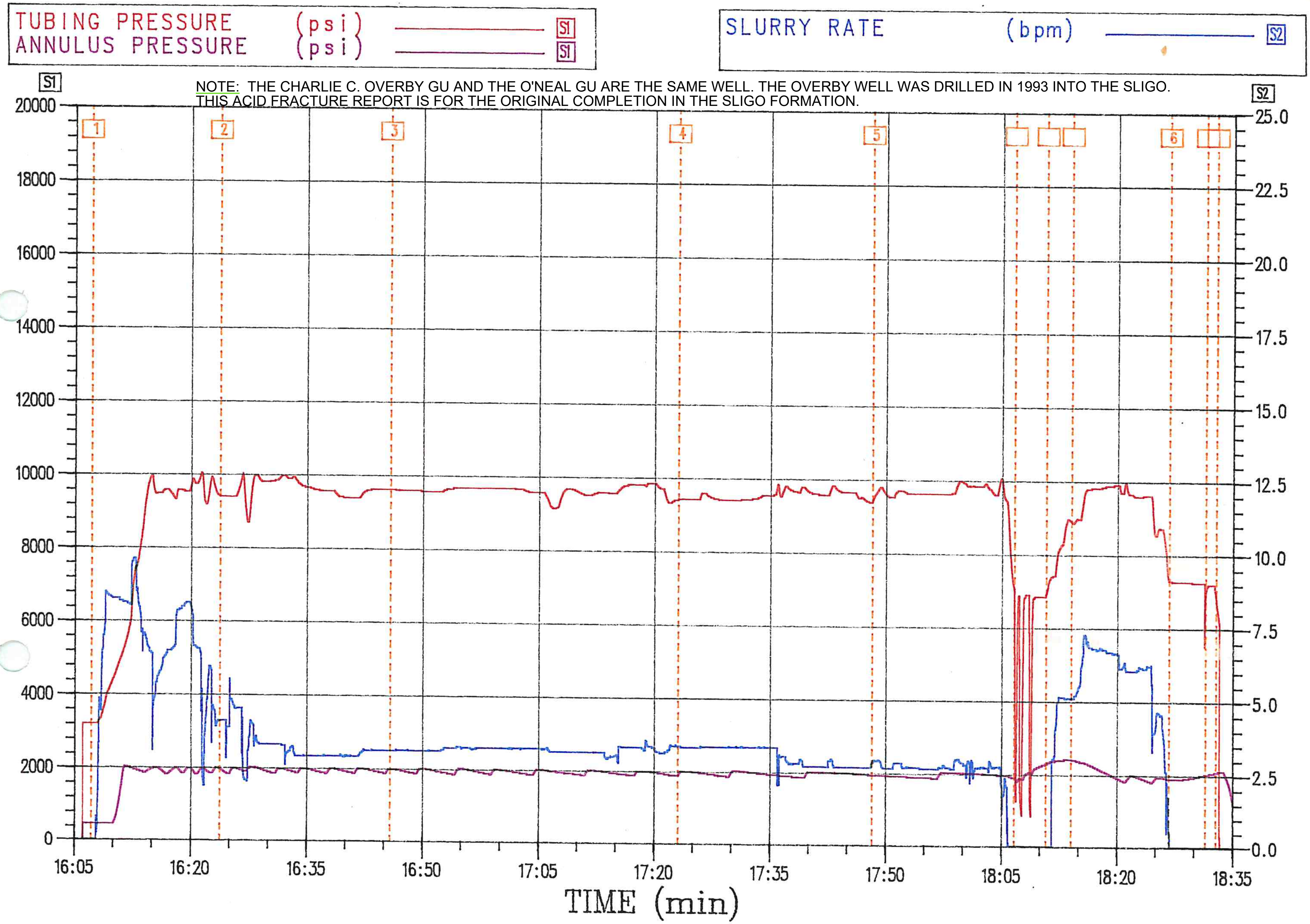
String	Vol (sks)	Type	TOC (MD)	%XS
Surf Lead	1125	HLC	0'	
Surf Tail	350	H		
Int Lead	575	50:50 Poz:H	7359'	
Int Tail	400	H		
Liner	200	Premium	14088'	

Edwards perfs production zone, 13,529'-13,841'
Cumulative 6,555,750 MCF gas, 168,888 BBLs water produced

Initial production zone, 15,874'-16,056'
Cumulative 511,964 MCF gas, 22,026 BBLs water produced

Well History

#	Date	Description
1	12/30/1992	First spud as gas well, targeting the Sligo formation
2	2/13/1997	Plugged back to 14,000' and recompleted



CUSTOMER: PARKER & PARSLEY DEV. CO.	JOB DATE: APR-03-1993	TICKET #: 30840901	
WELL DECS: OVERBY #2	FORMATION: SLIGO	JOB TYPE: SWIC ACID BALLOUT	

Customer: PARKER & PARSLEY DEV. CO. Ticket #: 30840901 Date: Apr 3, 1993
Well Desc: OVERBY #2 Formation: SLIGO Job Type: SWIC ACID BALLOUT

TIME HR:MM:SS	STAGE NO	TUBING PR (psi)	ANNULUS PR (psi)	SLURRY RT (bpm)
16:06:02	0	0	0	0.00
16:07:02	0	3216	470	0.00
16:08:02	1 Event(Eng) Operator Stage Advance			
16:08:02	1	3251	470	2.65
16:09:02	1	3904	470	8.43
16:10:02	1	4471	528	8.24
16:11:02	1	5059	1612	8.17
16:12:02	1	5812	1978	8.04
16:13:02	1	7558	1906	8.62
16:14:02	1	9069	1875	7.03
16:15:02	1	9950	2004	5.82
16:16:02	1	9504	1922	5.82
16:17:02	1	9572	1863	6.51
16:18:02	1	9304	2003	6.86
16:19:02	1	9539	1870	8.03
16:20:02	1	9725	1945	7.95
16:21:02	1	9862	1920	6.52
16:22:02	1	9216	1886	4.43
16:23:02	1	9672	1992	4.43
16:24:02	2 Event(Eng) Operator Stage Advance			
16:24:02	2	9384	1906	4.15
16:25:02	2	9416	1906	5.36
16:26:02	2	9547	1964	4.56
16:27:02	2	9150	1915	2.05
16:28:02	2	9898	2032	3.96
16:29:02	2	9812	1948	3.30
16:30:02	2	9824	1876	3.30
16:31:02	2	9882	1944	3.30
16:32:02	2	10020	1967	3.26
16:33:02	2	9946	1898	3.24
16:34:02	2	9733	1986	2.90
16:35:02	2	9654	1980	2.90
16:36:02	2	9590	1921	2.90
16:37:02	2	9558	1870	2.91
16:38:02	2	9552	2018	2.90
16:39:02	2	9420	1960	2.90
16:40:02	2	9377	1908	2.97
16:41:02	2	9369	1866	2.90
16:42:02	2	9485	2010	3.07
16:43:02	2	9635	1961	3.10
16:44:02	2	9647	1910	3.09
16:45:02	2	9644	1868	3.12
16:46:02	3 Event(Eng) Operator Stage Advance			
16:46:02	3	9622	2011	3.10
16:47:02	3	9601	1955	3.10
16:48:02	3	9597	1905	3.10
16:49:02	3	9596	1867	3.10
16:50:02	3	9568	2020	3.10
16:51:02	3	9553	1968	3.10
16:52:02	3	9551	1923	3.10
16:53:02	3	9667	1883	3.26
16:54:02	3	9707	1859	3.26
16:55:02	3	9708	2024	3.22
16:56:02	3	9718	1974	3.27
16:57:02	3	9720	1927	3.25

Customer: PARKER & PARSLEY DEV. CO. Ticket #: 30840901 Date: Apr 3, 1993
Well Desc: OVERBY #2 Formation: SLIGO Job Type: SWIC ACID BALLOUT

TIME HR:MM:SS	STAGE NO	TUBING PR (psi)	ANNULUS PR (psi)	SLURRY RT (bpm)
16:58:02	3	9705	1883	3.26
16:59:02	3	9709	1984	3.23
17:00:02	3	9686	1996	3.26
17:01:02	3	9677	1958	3.27
17:02:02	3	9671	1924	3.26
17:03:02	3	9630	1889	3.26
17:04:02	3	9563	1857	3.26
17:05:02	3	9560	2025	3.26
17:06:02	3	9417	1983	3.28
17:07:02	3	9153	1949	3.12
17:08:02	3	9569	1933	3.12
17:09:02	3	9691	1909	3.10
17:10:02	3	9592	1880	3.12
17:11:02	3	9509	1943	3.10
17:12:02	3	9568	2012	3.10
17:13:02	3	9611	1979	3.12
17:14:02	3	9576	1947	2.97
17:15:02	3	9607	1917	3.06
17:16:02	3	9805	1893	3.28
17:17:02	3	9858	1865	3.29
17:18:02	3	9827	2031	3.28
17:19:02	3	9864	1994	3.43
17:20:02	3	9872	1963	3.30
17:21:02	3	9681	1927	3.12
17:22:02	3	9325	1884	3.37
17:23:02	3	9445	1902	3.33
17:24:02	4 Event(Eng) Operator Stage Advance			
17:24:02	4	9468	2027	3.32
17:25:02	4	9436	1988	3.32
17:26:02	4	9594	1960	3.33
17:27:02	4	9502	1928	3.33
17:28:02	4	9428	1896	3.32
17:29:02	4	9425	1867	3.33
17:30:02	4	9437	2045	3.33
17:31:02	4	9439	2026	3.32
17:32:02	4	9454	1996	3.32
17:33:02	4	9492	1971	3.32
17:34:02	4	9577	1947	3.32
17:35:02	4	9585	1923	3.32
17:36:02	4	9818	1908	2.69
17:37:02	4	9839	1889	2.93
17:38:02	4	9661	1870	2.82
17:39:02	4	9808	1862	2.90
17:40:02	4	9642	2047	2.67
17:41:02	4	9589	2027	2.69
17:42:02	4	9583	2015	2.69
17:43:02	4	9858	2011	2.90
17:44:02	4	9662	1996	2.69
17:45:02	4	9649	1986	2.68
17:46:02	4	9624	1973	2.68
17:47:02	4	9477	1956	2.69
17:48:02	4	9360	1942	2.68
17:49:02	5 Event(Eng) Operator Stage Advance			
17:49:02	5	9770	1941	2.99
17:50:02	5	9585	1926	2.66

Customer: PARKER & PARSLEY DEV. CO. Ticket #: 30840901 Date: Apr 3, 1993
Well Desc: OVERBY #2 Formation: SLIGO Job Type: SWIC ACID BALLOUT

TIME HR:MM:SS	STAGE NO	TUBING PR (psi)	ANNULUS PR (psi)	SLURRY RT (bpm)
17:51:02	5	9577	1913	2.85
17:52:02	5	9749	1908	2.78
17:53:02	5	9627	1895	2.68
17:54:02	5	9638	1885	2.67
17:55:02	5	9636	1873	2.68
17:56:02	5	9642	1866	2.68
17:57:02	5	9658	2047	2.70
17:58:02	5	9659	2047	2.68
17:59:02	5	9789	2036	2.99
18:00:02	5	9937	2028	2.78
18:01:02	5	9837	2014	2.93
18:02:02	5	9857	2003	2.72
18:03:02	5	9874	1992	2.70
18:04:02	5	9617	1972	2.73
18:05:02	5	10006	1978	2.05
18:06:02	5	8309	1925	0.00
18:07:02	5 Event(Eng)			SHUT DOWN TO SURGE BALLS ISIP 9320
18:07:02	5	6123	1842	0.00
18:08:02	5	6862	2033	0.00
18:09:02	5	6742	2129	0.00
18:10:02	5	6873	2278	0.00
18:11:02	5 Event(Eng)		RESUME PUMPING	
18:11:02	5	7239	2367	0.00
18:12:02	5	7694	2426	4.18
18:13:02	5	8434	2440	5.10
18:14:02	5 Event(Eng)	PRESSURE BREAK AT 9000PSI		
18:14:02	5	8891	2411	5.11
18:15:02	5	8952	2350	5.52
18:16:02	5	9814	2296	7.05
18:17:02	5	9831	2203	6.76
18:18:02	5	9875	2099	6.78
18:19:02	5	9919	1995	6.67
18:20:02	5	9954	1896	6.63
18:21:02	5	10000	1852	6.15
18:22:02	5	9622	2000	6.05
18:23:02	5	9607	1903	6.16
18:24:02	5	9620	1822	6.17
18:25:02	5	8541	1978	4.22
18:26:02	5	8562	1933	3.72
18:27:02	6 Event(Eng) Operator Stage Advance			
18:27:02	6	7285	1880	0.00
18:28:02	6	7269	1913	0.00
18:29:02	6	7259	1954	0.00
18:30:02	6	7251	2001	0.00

EEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEEE

Customer:	PARKER & PARSLEY DEV. CO.	Date:	APR-03-1993
Well Desc:	OVERBY 2	Ticket #:	30840901
Formation:	SLIGO	Job Type:	SWIC ACID BALLOUT

WELLBORE CONFIGURATION

Wellbore Segment Number	Actual Length (feet)	TVD (feet)	Casing ID (inch)	Casing OD (inch)	Tubing ID (inch)	Tubing OD (inch)
1	14088	14088	4.276	5.000	2.441	2.875
2	15874	15874	4.276	5.000	0.000	0.000

PERFORATIONS DATA

of Perforations 15
Perf. Diameter .3
Balled Out? (YES/NO) yes

PERFORATED INTERVALS

FROM (feet)	TO (feet)	SPF
15874	16056	1

Well Desc: OVERBY #2
Formation: SLIGO

Ticket #: 30840901
Job Type: SWIC ACID BALLOUT

MATERIALS INVENTORY

Treatment Fluid:	SWIC ACID	Density	8.96	lb/gal	
Displacement Fluid:	TREATED WATER	Density	8.33	lb/gal	
Surfactant Type:	LOSURF 300	gal	20	@ 1	gal/Mgal
Clay Control:	CLAYFIX II	gal	40	@ 2	gal/Mgal
Friction Reducer:	FR-26	gal	20	@ 1	gal/Mgal
Perfpac Balls:	30	Qty	7/8	Size 1.3	S.G.

Customer:	PARKER & PARSLEY DEV. CO.	Date:	APR-03-1993
Well Desc:	OVERBY	Ticket #:	30840901
Formation:	SLIGO	Job Type:	SWIC ACID BALLOUT

MATERIALS ON LOCATION

STARTING FLUID VOLUME ______20000(gal)

Well Desc: OVERBY #2
Formation: SLIGO

Ticket #: 30840901
Job Type: SWIC ACID BALLOUT

ACID DATA

Acid Type:	SWIC	% 11	gal 10000		
Surfactant Type:	HC-2	gal	50	@ 5	gal/Mgal
NE Agent Type:	SPERSE ALL	gal	50	@ 5	gal/Mgal
Corrosion Inh.:	HAI-85	gal	200	@ 20	gal/Mgal
Corrosion Inh.:	HII-500	gal	200	@ 20	gal/Mgal
Cracking Inh.:	SCA-130	gal	200	@ 20	gal/Mgal
Iron Sequester:	FE-3	lb	1000	@ 100	lb/Mgal
Friction Reducer:	SGA-HT	gal	30	@ 3	gal/Mgal
Other:	ABF	LB 120		12 lb/Mgal	

Customer:	PARKER PARSLEY DEV. CO.	Dat	APR-03-1993
Well Desc:	OVERBY #2	Ticket #:	30840901
Formation:	SLIGO	Job Type:	SWIC ACID BALLOUT

JOB SCHEDULE

STAGE DESCRIPTIONS

Stage	Description
1	TREATED WATER - LOAD HOLE, EST. RATE
2	SWIC ACID
3	SWIC ACID WITH 30 BALLS
4	SWIC ACID
5	TREATED WATER - FLUSH
6	SHUTDOWN MONITOR PRESSURE

Customer: PARKER & PARSLEY DEV. CO.
Well Desc: OVERBY
Formation: SLIGO

Date: APR-03-1993
Ticket #: 30840901
Job Type: SWIC ACID BALLOUT

JOB SCHEDULE

STAGE INFORMATION

	1	2	3	4	5	6
Fluid Type	FR-26LC	SGA-HT 15%	SGA-HT 15%	SGA-HT 15%	FR-26LC	FR-26LC
Planned Clean Volume (gal)	5000	3000	5000	2000	6000	0
Planned Slurry Volume (gal)	5000	3000	5000	2000	6000	0
Actual Slurry Volume (gal)	4764	2997	5002	3217	5628	2
Base Fluid Density (lb/gal)	8.33	8.96	8.96	8.96	8.33	8.33
Concentration	1.00	3.00	3.00	3.00	1.00	1.00
Proppant Size						
Proppant Type						
Abs. Proppant Volume (gal/lb)	0.04530	0.04530	0.04530	0.04530	0.04530	0.04530
Planned Fluid Rate (bpm)	8.00	10.00	10.00	10.00	10.00	0.00
Planned Prop Conc (lb/gal)	0.00	0.00	0.00	0.00	0.00	0.00

Customer:	PARKER & PARSLEY DEV. CO.	Date:	Apr 3, 1993
Well Desc:	OVERBY	Ticket #:	30840901
Formation:	SLIGO	Job Type:	SWIC ACID BALLOUT

STAGE SUMMARY

Stage Times

Stage	Start Time	End Time	Elapsed Time	Time at Perfs
1	16:07:05	16:23:44	00:16:39	16:25:09
2	16:23:44	16:45:47	00:22:03	16:58:54
3	16:45:47	17:23:04	00:37:17	17:21:16
4	17:23:04	17:48:11	00:25:07	18:01:29
5	17:48:11	18:26:43	00:38:32	18:22:26
6	18:26:43	18:37:38	00:10:55	?
Total			02:30:33	

Stage	Tubing Pressure (psi)	Annulus Pressure (psi)	BHP Calc'd Pressure (psi)	Slurry Rate (bpm)	Slurry Volume (gal)
1	7748	1613	13382	6.44	4767
2	9615	1940	16354	3.24	2996
3	9626	1943	16518	3.19	5002
4	9560	1961	16495	3.05	3215
5	9005	2036	15742	3.48	5629
6	4293	1578	11097	0.01	2
Tot/Avg	8860	1906	15552	3.38	21610

Customer: PARKER & PARSLEY DEV. CO.
Well Desc: OVERBY
Formation: SLIGO

Date: APR-03-1993
Ticket #: 30840901
Job Type: SWIC ACID BALLOUT

EVENT REPORT

	stage	Event mneum	Time HH:MM:SS	Event Description	
e	1	stgad	16:07:05	Operator Stage Advance	--> TREATED WATER - LOAD HOLE, EST. RATE
e	2	stgad	16:23:44	Operator Stage Advance	--> SWIC ACID
e	3	stgad	16:45:47	Operator Stage Advance	--> SWIC ACID WITH 30 BALLS
e	4	stgad	17:23:04	Operator Stage Advance	--> SWIC ACID
e	5	stgad	17:48:12	Operator Stage Advance	--> TREATED WATER - FLUSH
e	5	NOTES	18:06:36	Operator's Notes	*** SHUT DOWN TO SURGE BALLS ISIP 9320
e	5	NOTES	18:10:44	Operator's Notes	*** RESUME PUMPING
e	5	NOTES	18:14:01	Operator's Notes	*** PRESSURE BREAK AT 9000PSI
e	6	stgad	18:26:43	Operator Stage Advance	--> SHUTDOWN MONITOR PRESSURE
e	6	NOTES	18:31:25	Operator's Notes	*** ISIP = 7285 PSI FG = .889
e	6	NOTES	18:32:46	Operator's Notes	*** 5 MIN SIP = 7238 PSI

Plugging Record X

RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

FORM W-3
Rev. 12/92
EAG0897

API NO (if available) 42-025-30388

1. RRC District: 02

FILE IN DUPLICATE WITH DISTRICT OFFICE OF DISTRICT IN WHICH WELL IS LOCATED WITHIN THIRTY DAYS AFTER PLUGGING

4. RRC Lease or Id. Number: 064112

2. FIELD NAME (as per RRC Records): Pawnee (Sligo)

3. Lease Name: Overby, Charlie C. Gas Unit

5. Well Number: 1

6. OPERATOR: Pioneer Natural Resources USA, Inc.

6a. Original Form W-1 Filed in Name of:

10. County: Bee

7. ADDRESS: 5205 N. O'Connor Blvd., Ste. 900 Irving, TX 75039-3736

6b. Any Subsequent W-1's Filed in Name of:

11. Date Drilling Permit Issued: —

8. Location of Well, Relative to Nearest Lease Boundaries of Lease on which this Well is Located: 1625 Feet From W Line and 1750 Feet From S Line of the Survey Lease

12. Permit Number: –

9a. SECTION, BLOCK, AND SURVEY: Marcelo Alcarte A-70

9b. Distance and Direction From Nearest Town in this County: 3.5 miles South of Pawnee

13. Date Drilling Commenced: unk

16. Type Well (Oil, Gas, Dry): Gas

Total Depth: 16,300

17. If Multiple Completion List All Field Names and Oil Lease or Gas ID No.'s

	GAS ID or OIL LEASE #	Oil-O Gas-G	WELL #

14. Date Drilling Completed: unk

18. If Gas, Amt. of Cond. on Hand at time of Plugging:

15. Date Well Plugged: 3-6-07

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7	PLUG #8
*19. Cementing Date	2-27	2-27	3-2	3-5	3-6	3-6		
20. Size of Hole or Pipe in which Plug Placed (inches)	3 1/2	3 1/2	7	7	7	7		
21. Depth to Bottom of Tubing or Drill Pipe (ft.)	9310	9200	3800	3563	300	15		
*22. Sacks of Cement Used (each plug)	1	1	35	55	55	6		
*23. Slurry Volume Pumped (cu ft)	1.06	1.06	37.10	58.30	58.30	6.36		
*24. Calculated Top of Plug (ft.)	9280	9180	3650	3428	200	5		
25. Measured Top of Plug (if tagged) (ft.)					187			
*26. Slurry Wt. #/Gal.	16.4	16.4	16.4	16.4	16.4	16.4		
*27. Type Cement	H	H	H	H	H	H		

28. CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT.#/FT.	PUT IN WELL (ft.)	LEFT IN WELL (ft.)	HOLE SIZE (IN.)
16	49.50	61	61	UNK.
10 3/4	45.50	3513	3508	15"
7	49.50	15,529	15,524	8 3/4
4"	UNK	15055-16290	14247	

29. Was any Non-Drillable Material (Other than Casing) Left in This Well: [x] Yes [ ] No

29a. If answer to above is "Yes" state depth to top of "junk" left in hole and briefly describe non-drillable material. (Use Reverse Side of Form if more space is needed)

Left 3 1/2 tubing in well from 3800' to 15,055'. An existing fish of 1 1/4" tubing from 9340' to 16,143' also left in well.

30. LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS

FROM	TO	FROM	TO
15,911	16,072		

I have knowledge that the cementing operations, as reflected by the information found on this form, were performed as indicated by such information.

* Designates items to be completed by Cementing Company. Items not so designated shall be completed by Operator.

RECEIVED
CENTRAL RECORDS
JUN 01 2007
AUSTIN, TEXAS

[signature]
Signature of Cementer or Authorized Representative

Pat's P & A, Inc.
Name of Cementing Company

CERTIFICATE

I declare under penalties prescribed in Sec. 91.143, Texas Natural Resources Code, that I am authorized to make this report, that this report was prepared by me or under my supervision and direction, and that data and facts stated therein are true, correct and complete, to the best of my knowledge

Doug Kimbell	PROD SUPT.	3-22-07	Phone 361	364-1732
REPRESENTATIVE OF COMPANY	TITLE	DATE	A/C	NUMBER

SIGNATURE: REPRESENTATIVE OF RAILROAD COMMISSION

MAPPING

31. Was Well filled with Mud-Laden Fluid, according to the regulations of the Railroad Commission [X] Yes [ ] No	32. How was Mud Applied? Circulated	33. Mud Weight 12.5 LBS/GAL

34. Total Depth 16,300 Depth of Deepest Fresh Water 250	Other Fresh Water Zones by T.D.W.R. TOP / BOTTOM	35. Have all Abandoned Wells on this Lease been Plugged according to RRC Rules? [ ] Yes [ ] No 36. If NO, Explain

37. Name and Address of Cementing or Service company who mixed and pumped cement plugs in this well
Pat's P & A, Inc. P.O. Box 0126, Bishop TX 78343

Date RRC District Office notified of plugging 2-23-07

38. Name(s) and Address(es) of Surface Owners of Well Site

39. Was Notice Given Before Plugging to the Above?

FILL IN BELOW FOR DRY HOLES ONLY

40. For Dry Holes, this Form must be accompanied by either a Driller's, Electric, Radioactivity or Acoustical/Sonic Log or such Log must be released to a Commercial Log Service.

[ ] Log Attached [ ] Log released to __________ Date __________

Type Logs: [ ] Driller's [ ] Electric [ ] Radioactivity [ ] Acoustical/Sonic

41. Date FORM P-8 (Special Clearance) Filed?

42. Amount of Oil produced prior to Plugging __________ bbls*
* Field FORM P-1 (Oil Production Report) for month this oil was produced

~~RRC USE ONLY~~

Nearest Field __________

REMARKS Unable to recover 3 1/2" tbg. as anticipated above existing 1 1/4" fish @ 9340'. Jet cut 3 1/2" @ 9302' & 9243'. Unable to pull or establish circulation up 3 1/2 x 7" @ 3500 P.S.I.. Freepoint on 3 1/2 csg. at 4750 ±. Notified and received approval from Kevin Shamette W/RRC to set CIBP's + 20' cmt below and above cut's made on 3 1/2. Plug #1 & #2 - CIBP + 20' cmt. in 3 1/2" 12.95#. Cut 3 1/2 @ 4762'and perforated 3 1/2" @ 4765' but unable to pull or circulate. Re-cut @ 3800'. Received verbal approval from Kevin Shamette W/RRC to set plug from 3800' tp 3650' Cut & perforated 7" casing @ 3563'. Casing not free. Unable to establish circulation but established injection into 7" x 8 3/4" @ 2000 P.S.I. Notified Kevin W/RRC to squeeze plug. Squeezed 55 sks. cmt. leaving 23 sks. inside 7" 49.50# and 32 sks. outside in 7" x 8 3/4". Cut 7" csg. @ 300' but unable to circulate. Received verbal approval to squeeze 55 sks. Squeezed 38 sks. out into 7" x 9 5/8" and left 17 sks inside 7" casing.

O'Neal Gas Unit No. 4

APPENDIX B-1

Area of Review: Oil & Gas Wells List

API	WELL NAME	WELL NO.	CURRENT OPERATOR	ABSTRACT	LATITUDE (WGS84)	LONGITUDE (WGS84)	WELL STATUS	TOTAL DEPTH (TVD FT.)	PERFORATED INTERVAL (MD FT.)	DATE DRILLED
4202500002	ONEAL, A.	1	ROWAN & HOPE	126	28.603017	-98.000911	DRILLED	7010	NO RECORD	8/9/1949
4202500005	RUSSELL, S.	1	PAN AMERICAN PETROLEUM CORP.	308	28.594587	-97.999841	DRILLED	7515	NO RECORD	5/12/1947
4202530346	HENRY BUES	1	PIONEER NATURAL RES. USA, INC.	70	28.5986210	-98.0118480	INACTIVE PRODUCER	13842	7554-7558; 7612-7624; 13526-13760	11/10/1974
4202530359	ONEAL GAS UNIT	2	BB-SOUTHTEX, LLC	127	28.61178	-98.000661	PRODUCING	13961	13349-15821	4/5/1975
4202530388	OVERBY, CHARLIE C. GAS UNIT	1	PIONEER NATURAL RES. USA, INC.	70	28.601086	-98.005037	P & A	16300	15911-16072	6/6/1975
4202532342	DE LEON	1	T D EXPLORATION, INC.	126	28.6006330	-97.9917520	P & A	6512	NO RECORD	12/31/1985
4202532501	HENRY BUES GAS UNIT	2	BB-SOUTHTEX, LLC	70	28.599863	-98.009994	PRODUCING	13896	13504-15637	11/15/1988
4202532638	ONEAL GAS UNIT	3	BB-SOUTHTEX, LLC	70	28.604583	-98.007079	PRODUCING	13834	13508-13668	3/12/1992
4202532842	OVERBY, CHARLIE C.	1E	PIONEER NATURAL RES. USA, INC.	70	28.5998760	-98.0053330	P & A	14000	13514-13838	10/9/1995
4202532967	TOMASEK GAS UNIT	5	BB-SOUTHTEX, LLC	126	28.609862	-97.991519	PRODUCING	13875	13434-15693	6/12/1999
4202533006	ONEAL GAS UNIT	5	BB-SOUTHTEX, LLC	70	28.6067950	-98.0042210	PRODUCING	13772	13463-13764	7/15/2000
4202533035	ONEAL GAS UNIT	6	BB-SOUTHTEX, LLC	127	28.61091	-97.999073	PRODUCING	13835	13310-13833	9/14/2000
4202533085	ONEAL GAS UNIT	7	BB-SOUTHTEX, LLC	127	28.609397	-98.001471	PRODUCING	13868	13314-16072	5/4/2001
4202533114	HENRY BUES GAS UNIT	8	BB-SOUTHTEX, LLC	70	28.5984810	-98.0090260	PRODUCING	13732	13348-13732	6/11/2001
4202533197	ONEAL GAS UNIT	8	BB-SOUTHTEX, LLC	452	28.6075430	-98.0037990	PRODUCING	15638	13565-13820	2/5/2003

O'Neal Gas Unit No. 4

4202533272	HENRY BUES GAS UNIT	11	BB-SOUTHTEX, LLC	70	28.598737	-98.008615	PRODUCING	13856	13291-15853	6/23/2004
4202533273	ONEAL GAS UNIT	9	BB-SOUTHTEX, LLC	452	28.6029540	-98.0025090	PRODUCING	13872	13311-16585	6/3/2004
4202533328	ONEAL GAS UNIT	11	BB-SOUTHTEX, LLC	126	28.6036340	-97.9982100	PRODUCING	13787	13318-15928	4/19/2005
4202533345	TOMASEK GAS UNIT	8	BB-SOUTHTEX, LLC	126	28.608282	-97.991595	PRODUCING	13692	13293-16378	8/14/2004
4202533371	ONEAL GAS UNIT	12	BB-SOUTHTEX, LLC	452	28.6097460	-98.0027040	PRODUCING	13819	13313-16635	8/15/2006
4202533383	HENRY BUES GAS UNIT	15	BB-SOUTHTEX, LLC	70	28.600322	-98.00874	PRODUCING	13811	13302-15768	10/8/2006
4202533492	ONEAL GAS UNIT	13	BB-SOUTHTEX, LLC	70	28.605326	-98.012928	PRODUCING	13859	13382-14761	7/7/2007
4202533553	ONEAL GAS UNIT	14	BB-SOUTHTEX, LLC	127	28.613869	-98.000504	PRODUCING	13674	13450-15424	2/11/2008
4202533559	OVERBY GAS UNIT	2E	BB-SOUTHTEX, LLC	452	28.6011410	-98.0028580	PRODUCING	13734	13372-13734	3/23/2008
42025E2114	NO RECORD	NR	NO RECORD	126	28.608457	-97.995683	NO RECORD	NR	NO RECORD	NR

*Note: Well entries in red penetrate the upper confining layer.

LONQUIST SEQUESTRATION LLC

O'Neal Gas Unit No. 4

APPENDIX B-2

Area of Review: Freshwater Wells List

WELL REPORT/ID NO.	OWNER'S NAME	OWNER ADDRESS	CITY/STATE/ZIP	LAT. WGS 84	LONG. WGS 84	WELL USE	WATER LEVEL (FT.)	TOTAL DEPTH (FT.)	DATE DRILLED
128936	JOHN DAVIDSON	12761 FM 673	KENEDY, TX 78119	28.606667	-98.011667	DOMESTIC	48	114	11/19/2007
7832308	HENRY BUES	NO RECORD	NO RECORD	28.598334	-98.012223	STOCK	-	150	1960
7925105	T. M. PLUMER	NO RECORD	NO RECORD	28.595556	-97.997778	STOCK	77	275	1931
7832309	W. A. MUELLER	NO RECORD	NO RECORD	28.608612	-98.005834	UNUSED	63	90	1925
7925106	R.C. HUNT ESTATE	NO RECORD	NO RECORD	28.593889	-97.997222	UNUSED	137	172	1925