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.

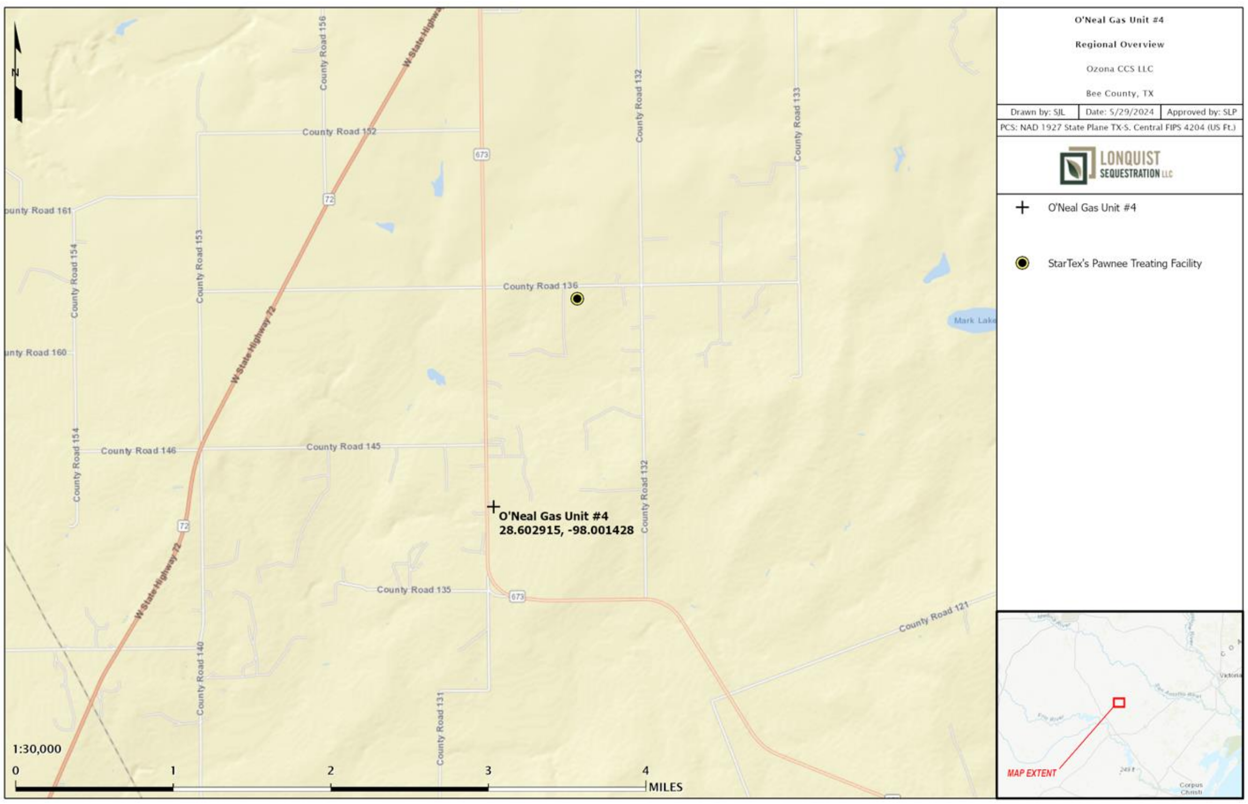


Figure 1 – Location of StarTex's Pawnee Treating Facility and the O'Neal No. 4

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

TABLE OF CONTENTS

Figures

Tables

Appendices

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.

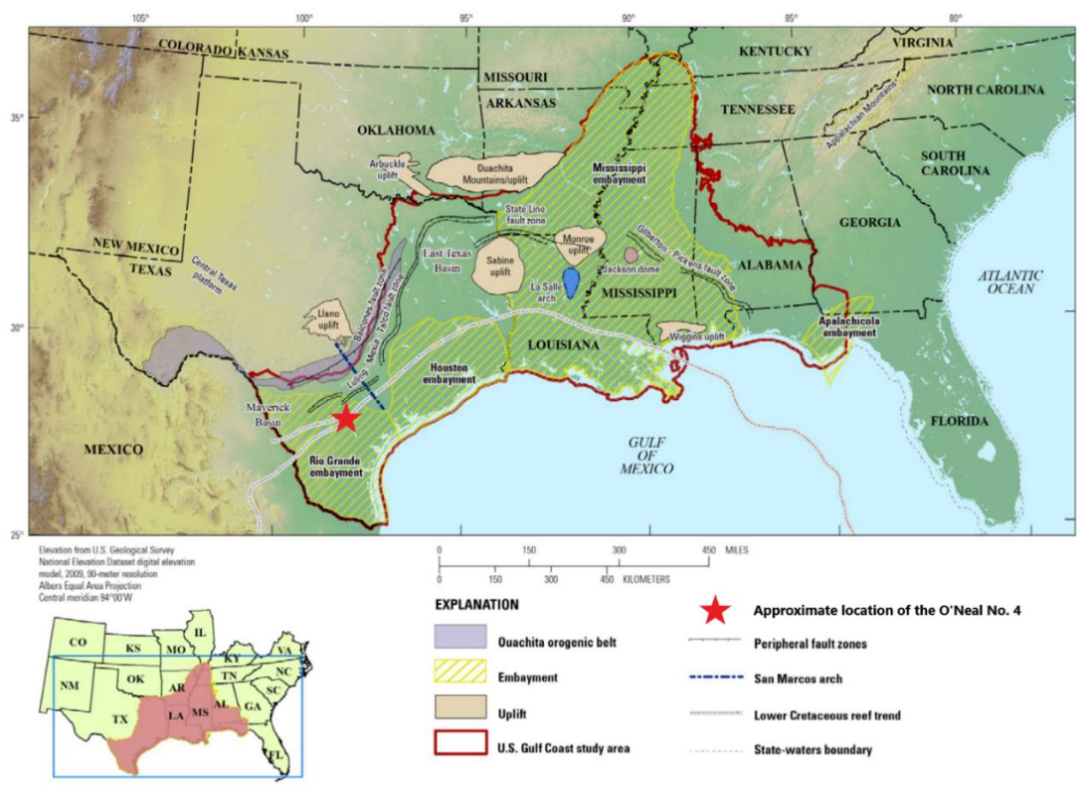


Figure 2 – Structural Features of the Gulf of Mexico and Locator Map (modified from Roberts-Ashby et al., 2012)

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.

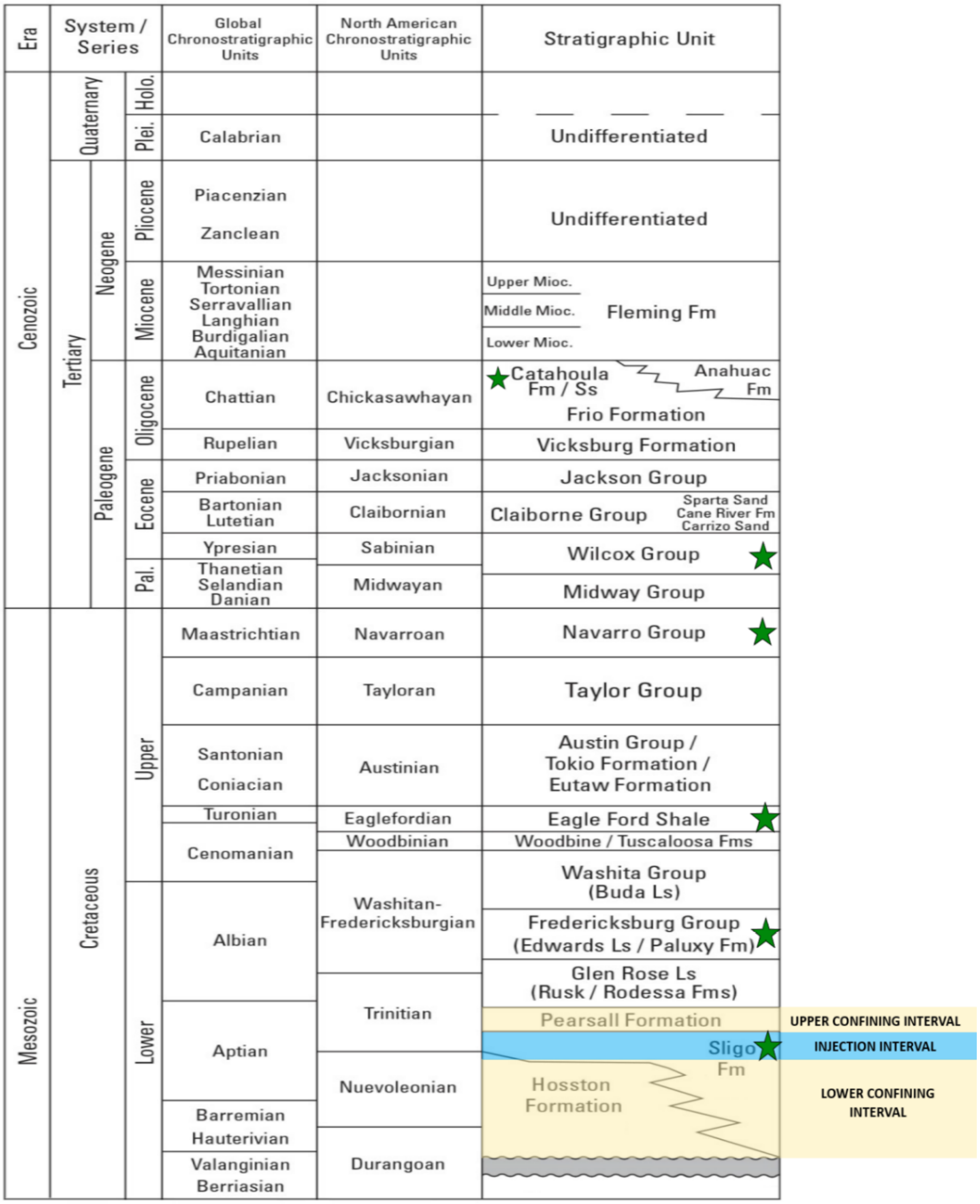


Figure 3 – Stratigraphic column of the U.S. Gulf Coast signifying proposed injection and confining intervals. Offset productive intervals are noted with a green star (modified from Roberts-Ashby et al., 2012).

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).

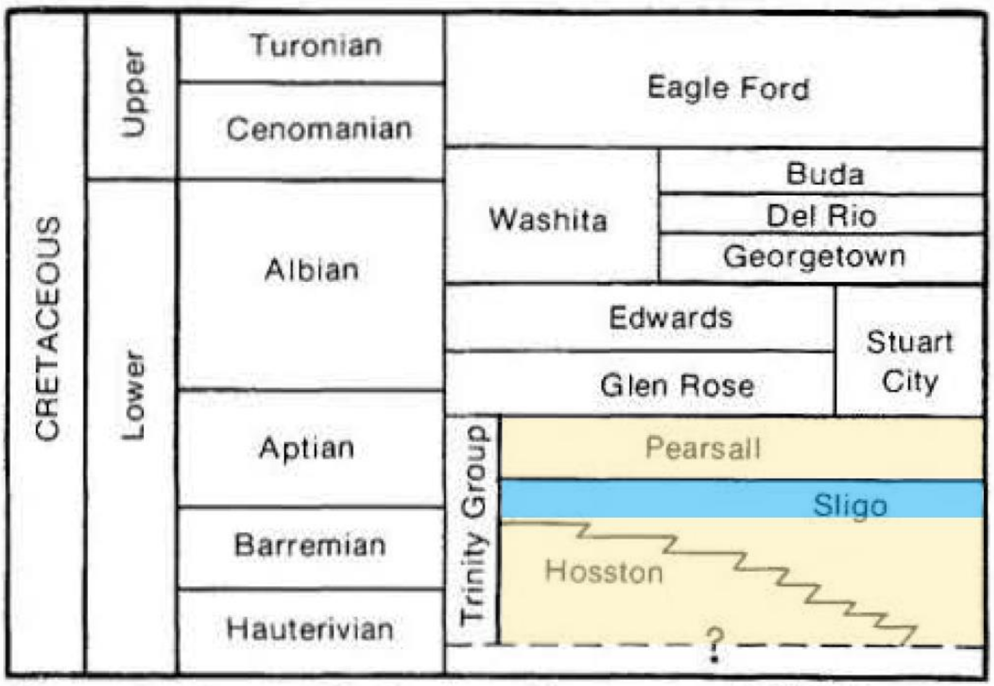


Figure 4 – Detailed stratigraphic column of Lower Cretaceous formations of south Texas. The proposed injection interval is shaded light blue and proposed confining intervals are shaded light yellow (modified from Bebout et al., 1981).

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.

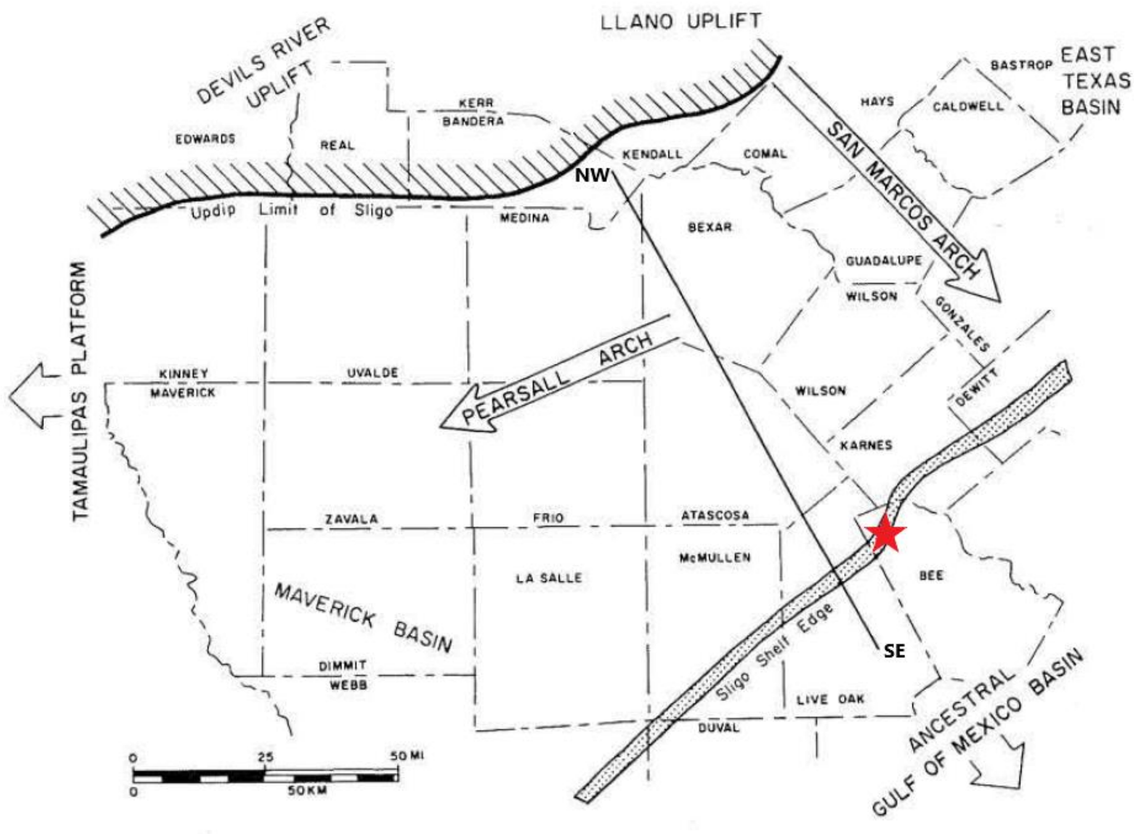


Figure 5 – Paleogeography of the Lower Cretaceous of south Texas. The red star represents the approximate location of the O'Neal No. 4 (modified from Bebout et al., 1981).

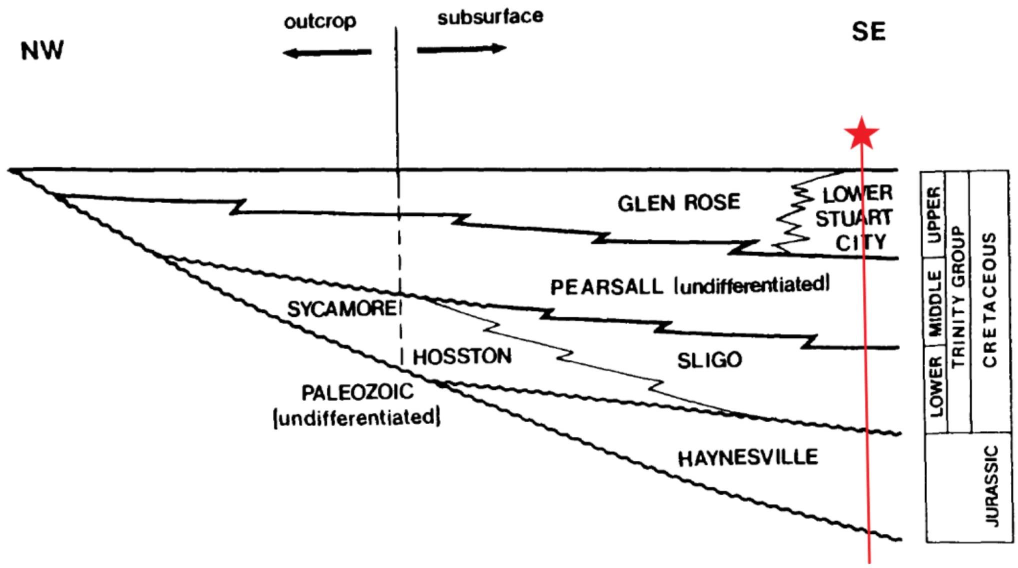


Figure 6 – Generalized northwest to southeast schematic cross section of the Trinity Group, south Texas (the line of section depicted in Figure 5). The red star and line represent the approximate location of the O'Neal No. 4 (modified from Kirkland et al., 1987)

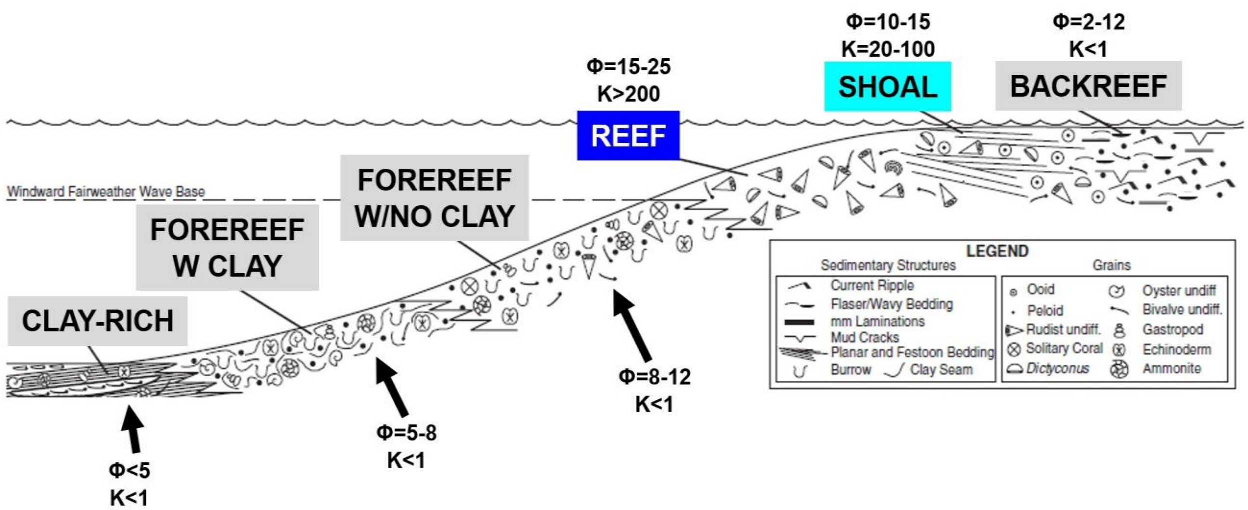


Figure 7 – Depositional model for the Lower Cretaceous carbonate platform with estimated porosity and permeability values of typical facies (modified from Talbert and Atchley, 2000).

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.

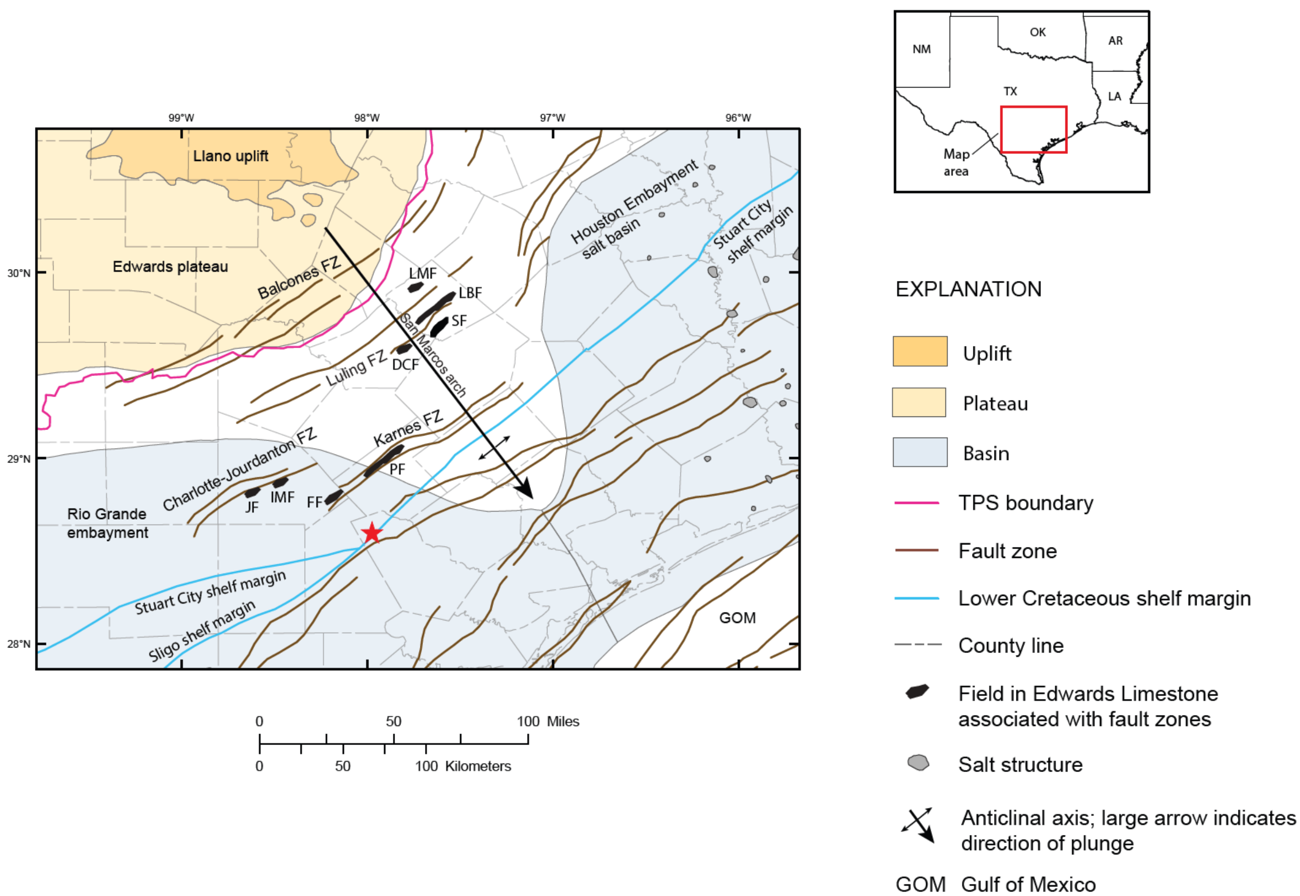


Figure 8 – Structural features and fault zones near the proposed injection site. The red star represents the approximate location of the O'Neal No. 4 (modified from Swanson et al., 2016).

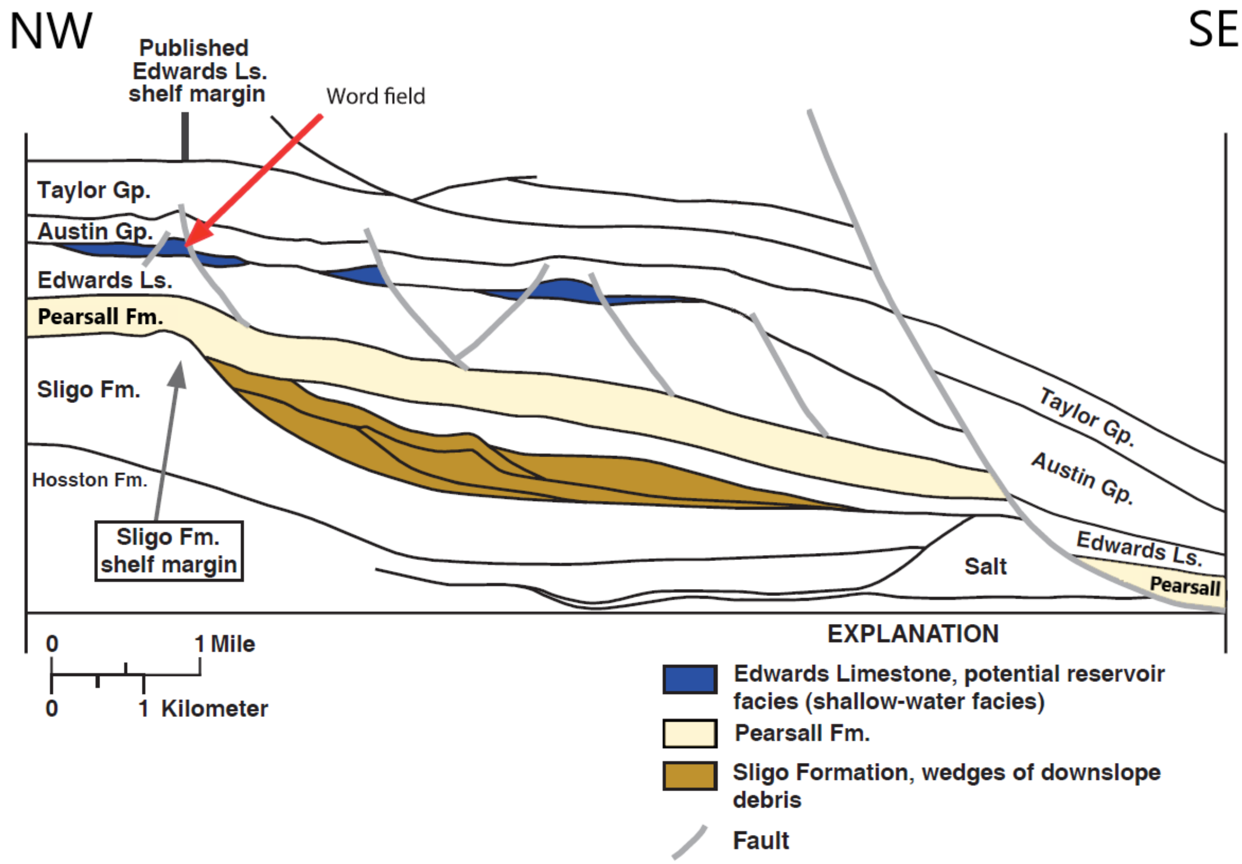


Figure 9 – Northwest to southeast schematic interpretation of the Edwards shelf margin through Word field, northeast of the O'Neal No. 4 project area (modified from Swanson et al., 2016).

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.

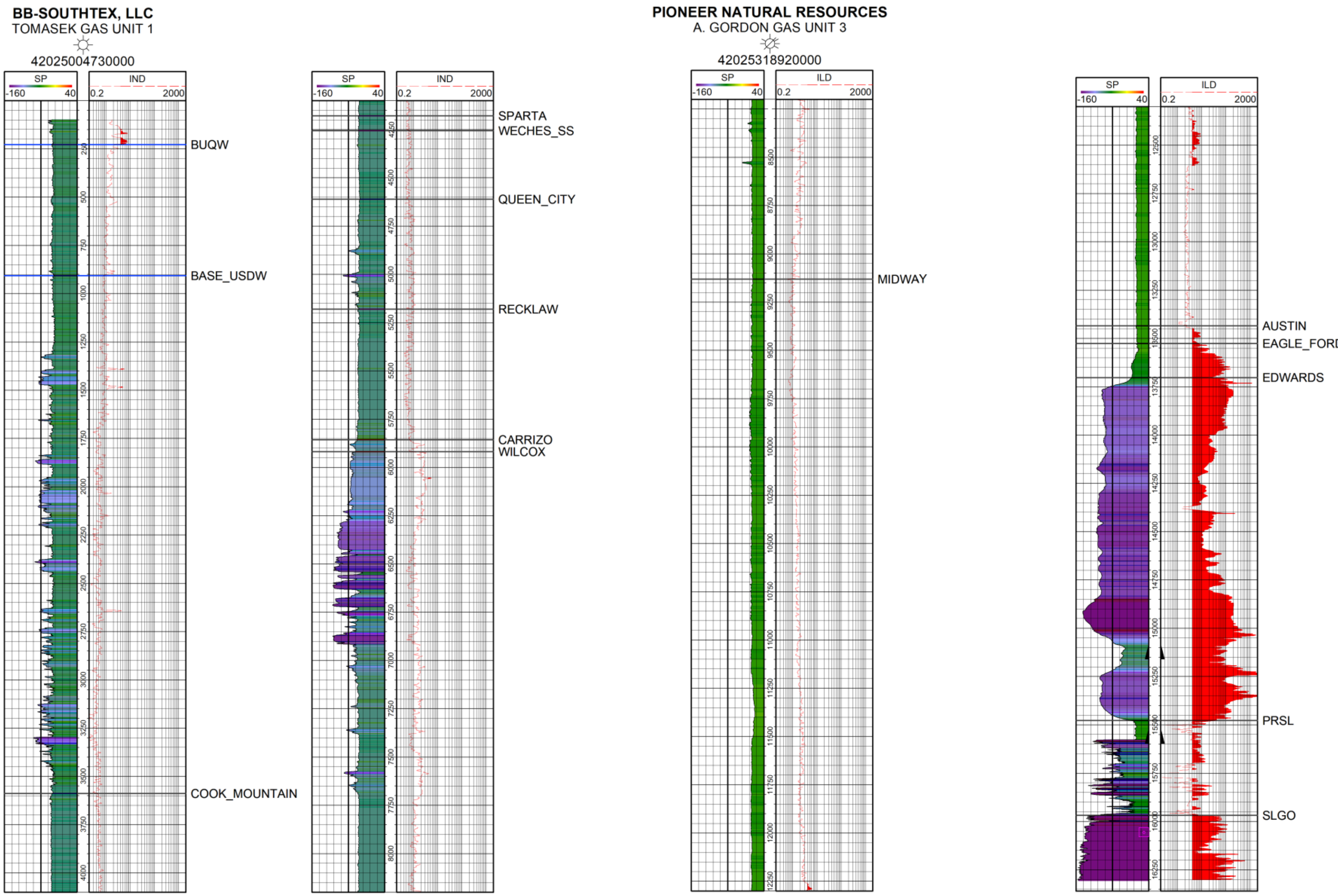


Figure 10 – Type Log with Tops, Confining, and Injection Intervals Depicted

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).

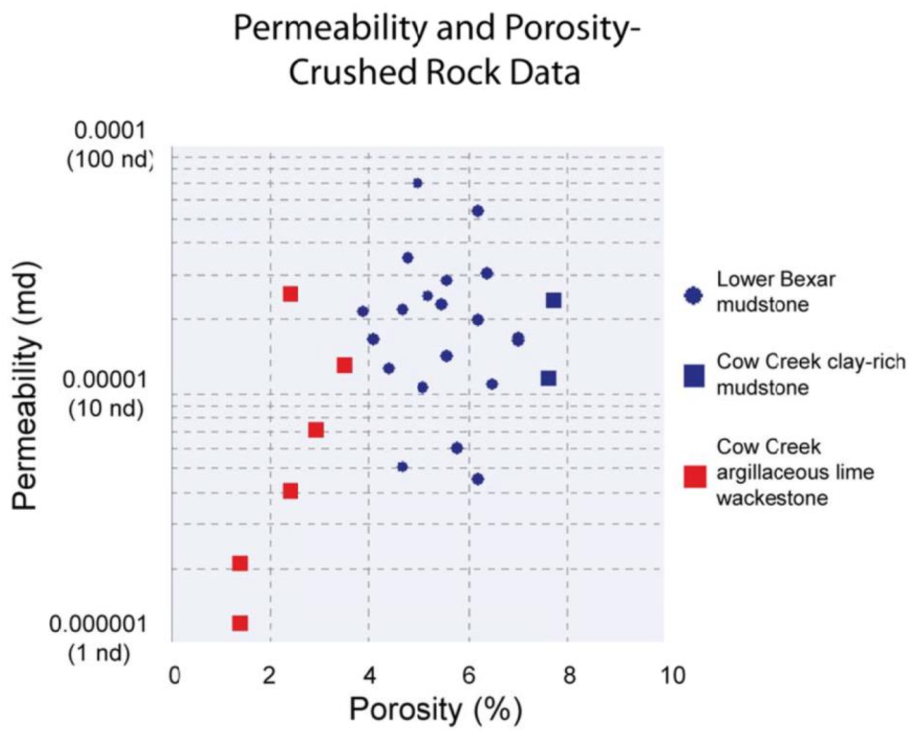


Figure 11 – Porosity-Permeability Crossplot of Pearsall Formation Crushed Rock Core Data (Swanson et al., 2016)

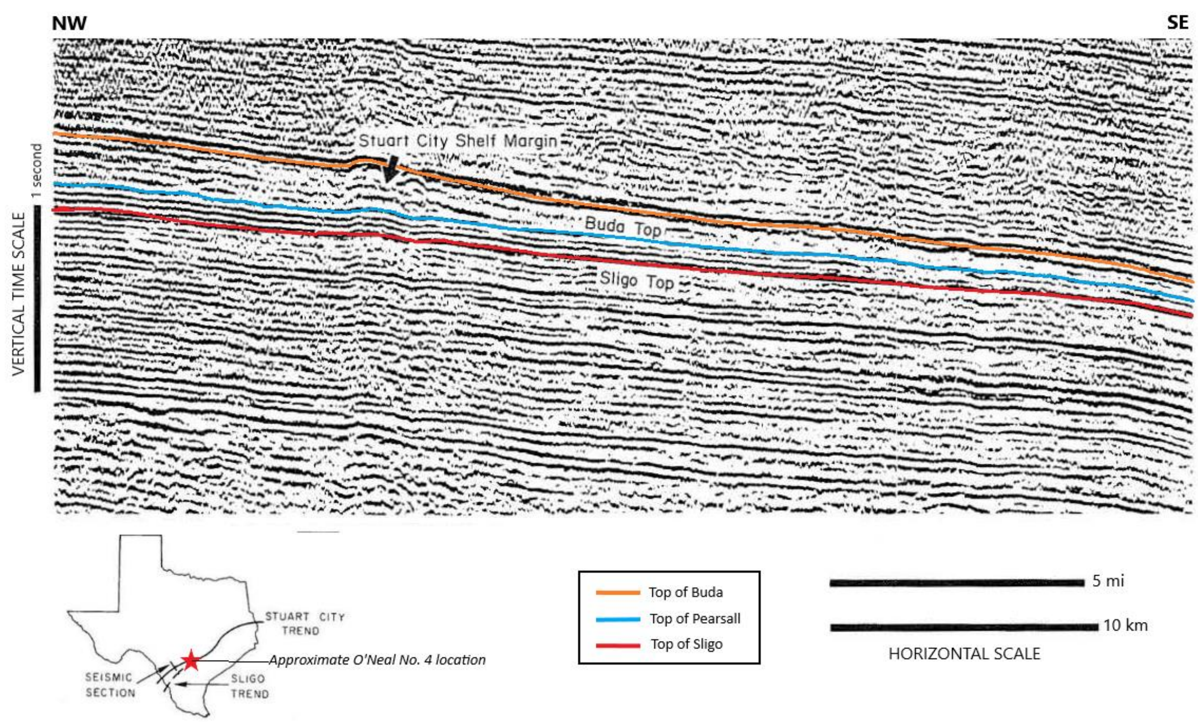


Figure 12 – Seismic line across the Stuart City (Edwards/Buda) shelf margin and locator map. The red star represents the approximate location of the O'Neal No. 4 (modified from Bebout et al., 1981).

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.

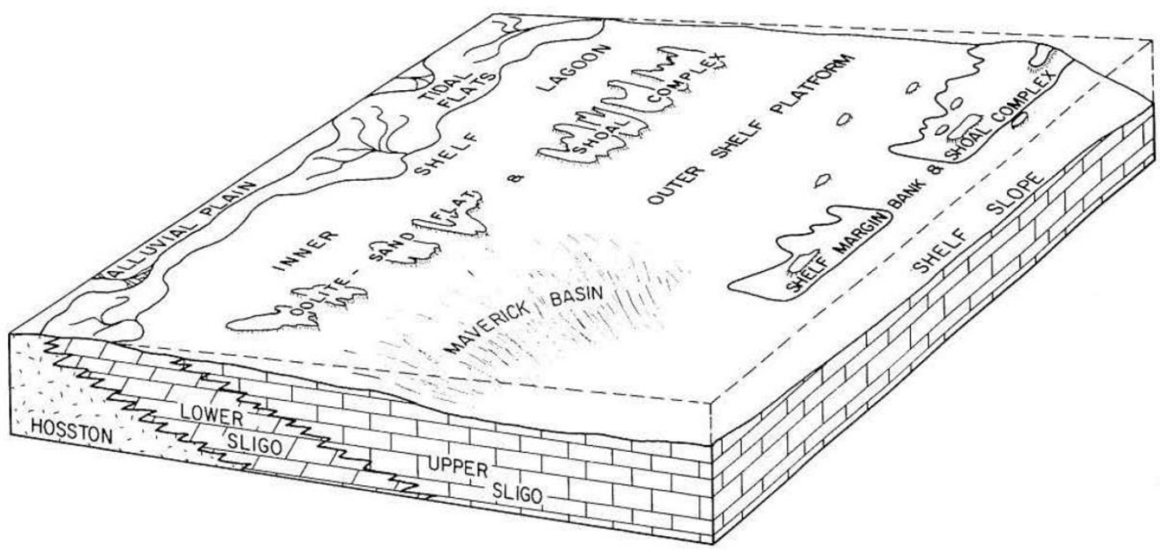


Figure 13 – Environmental Setting of Lower Cretaceous Platform (Bebout et al., 1981)

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.

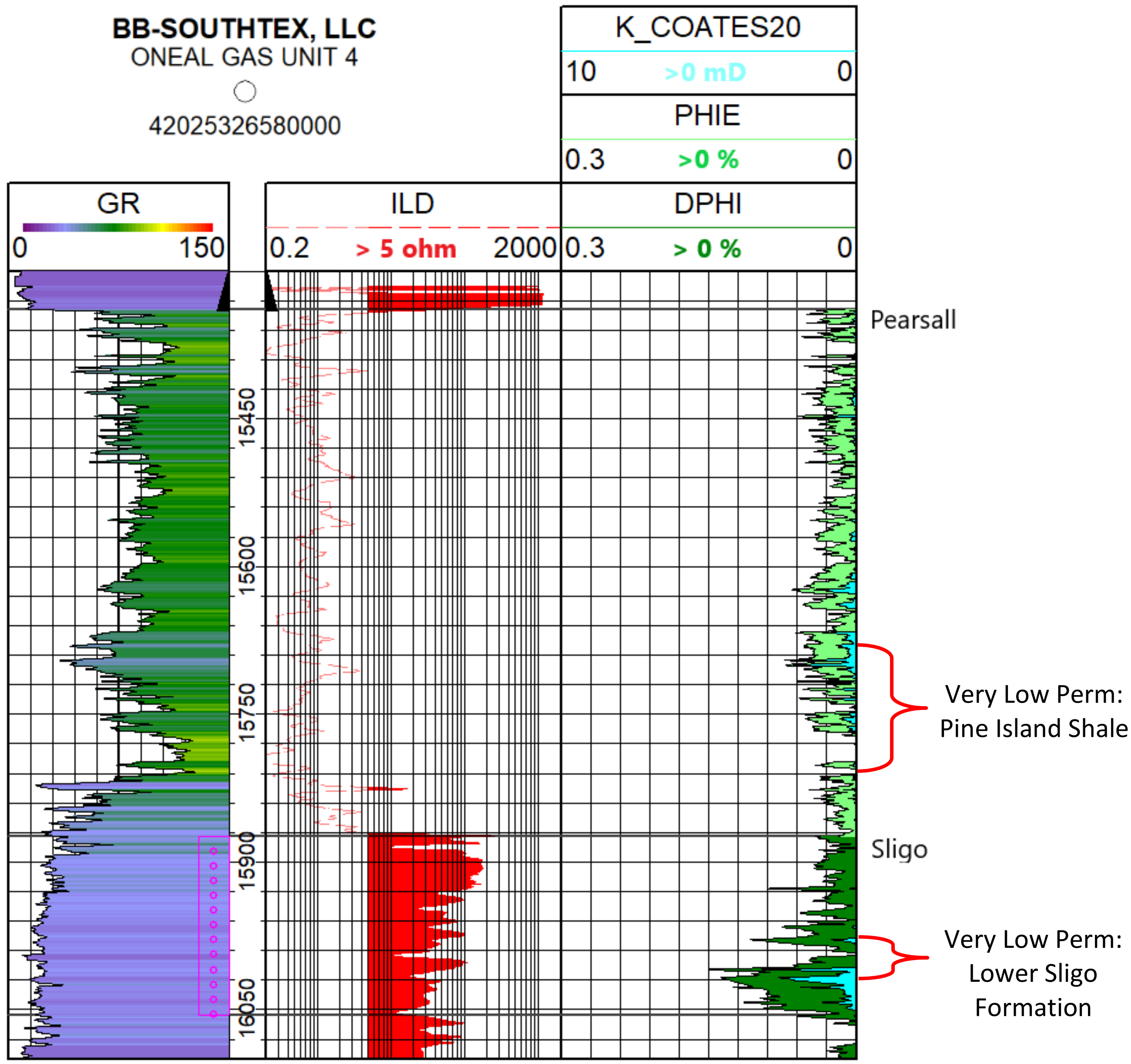


Figure 14 – Openhole log from O'Neal No. 4 (API No. 42-025-32658), with porosity curves shaded green >0%, permeability curve in blue >0 mD, and resistivity in red >5 ohms.

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.

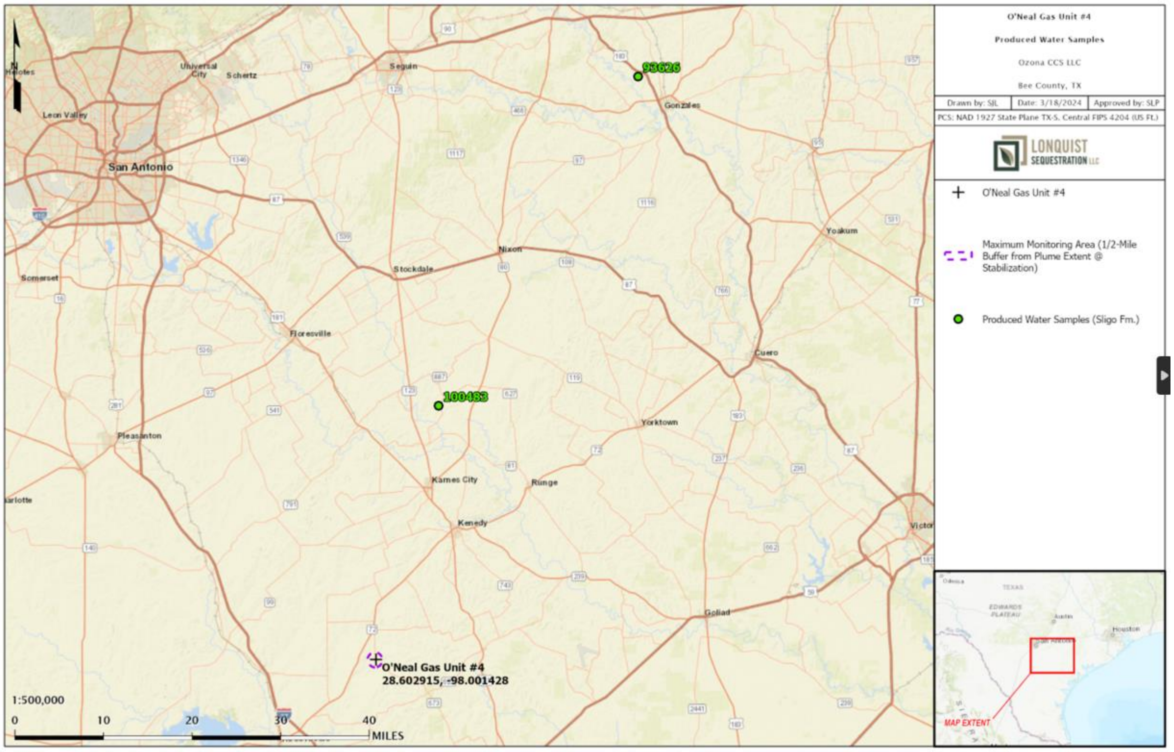


Figure 15 – Offset Wells Used for Formation Fluid Characterization

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.

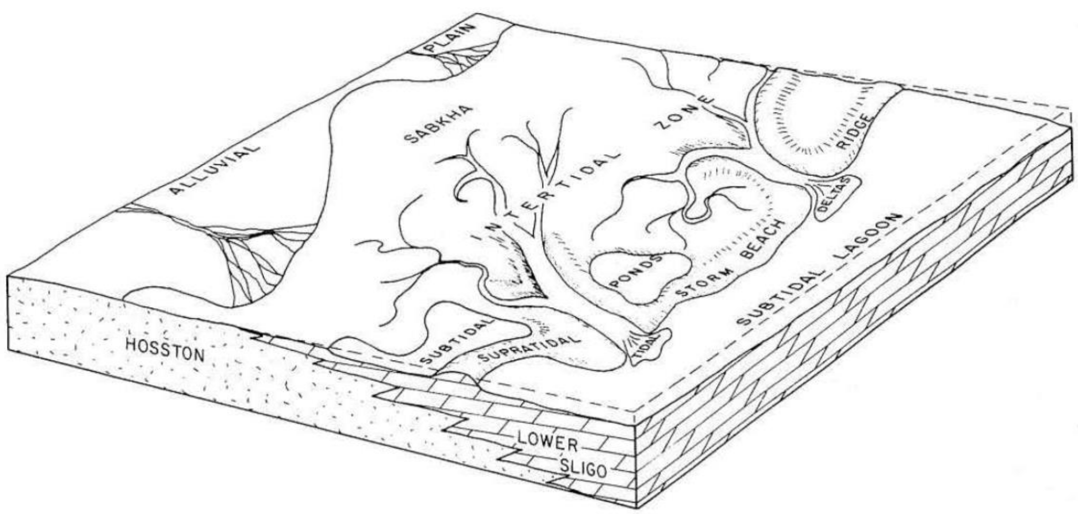


Figure 16 – Environmental Setting of Lower Cretaceous Tidal Flat Deposits (Bebout et al., 1981)

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.

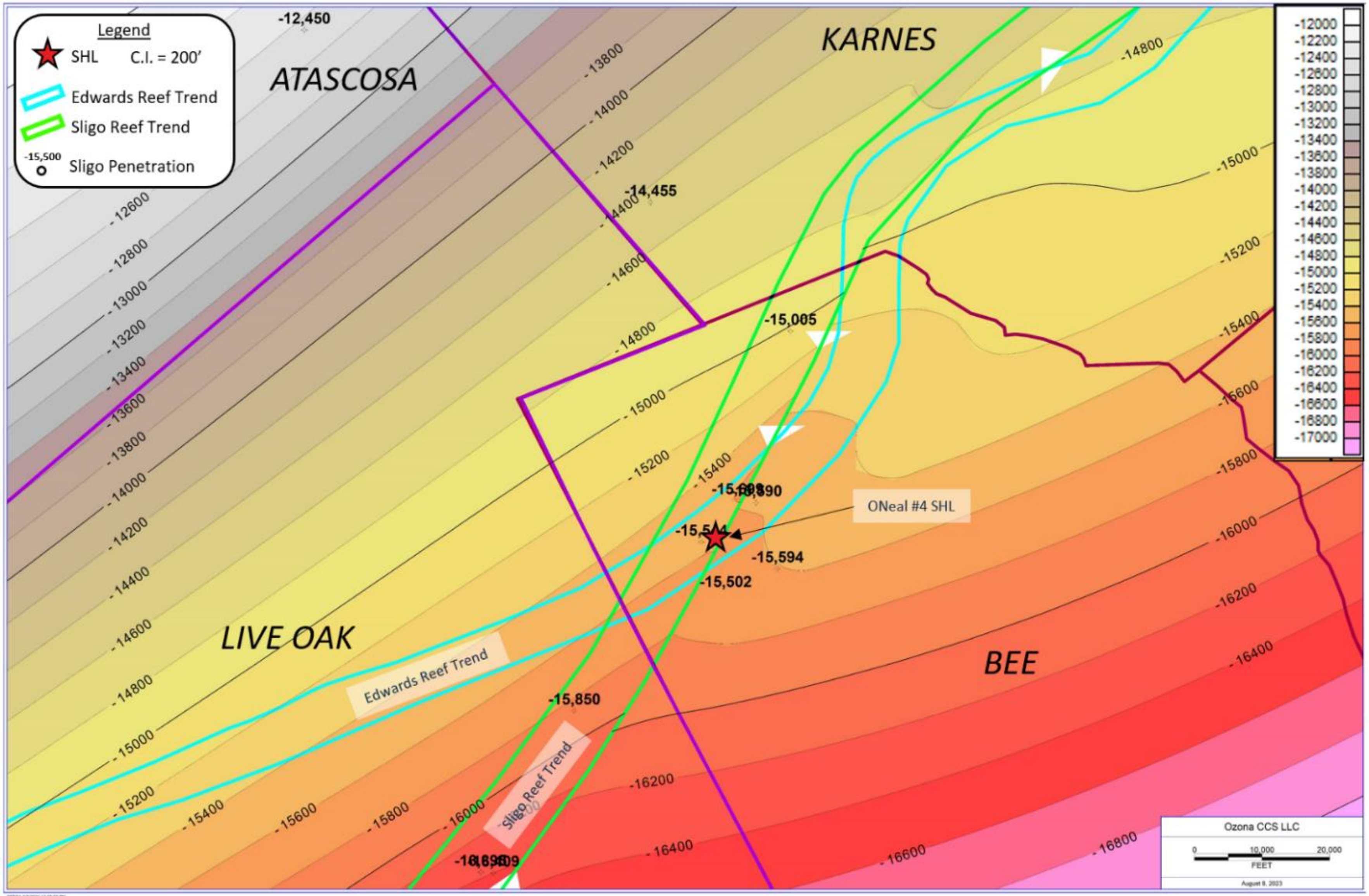


Figure 17 – Subsea Structure Map: Top of Sligo (injection interval). The red star signifies the location of the O'Neal No. 4.

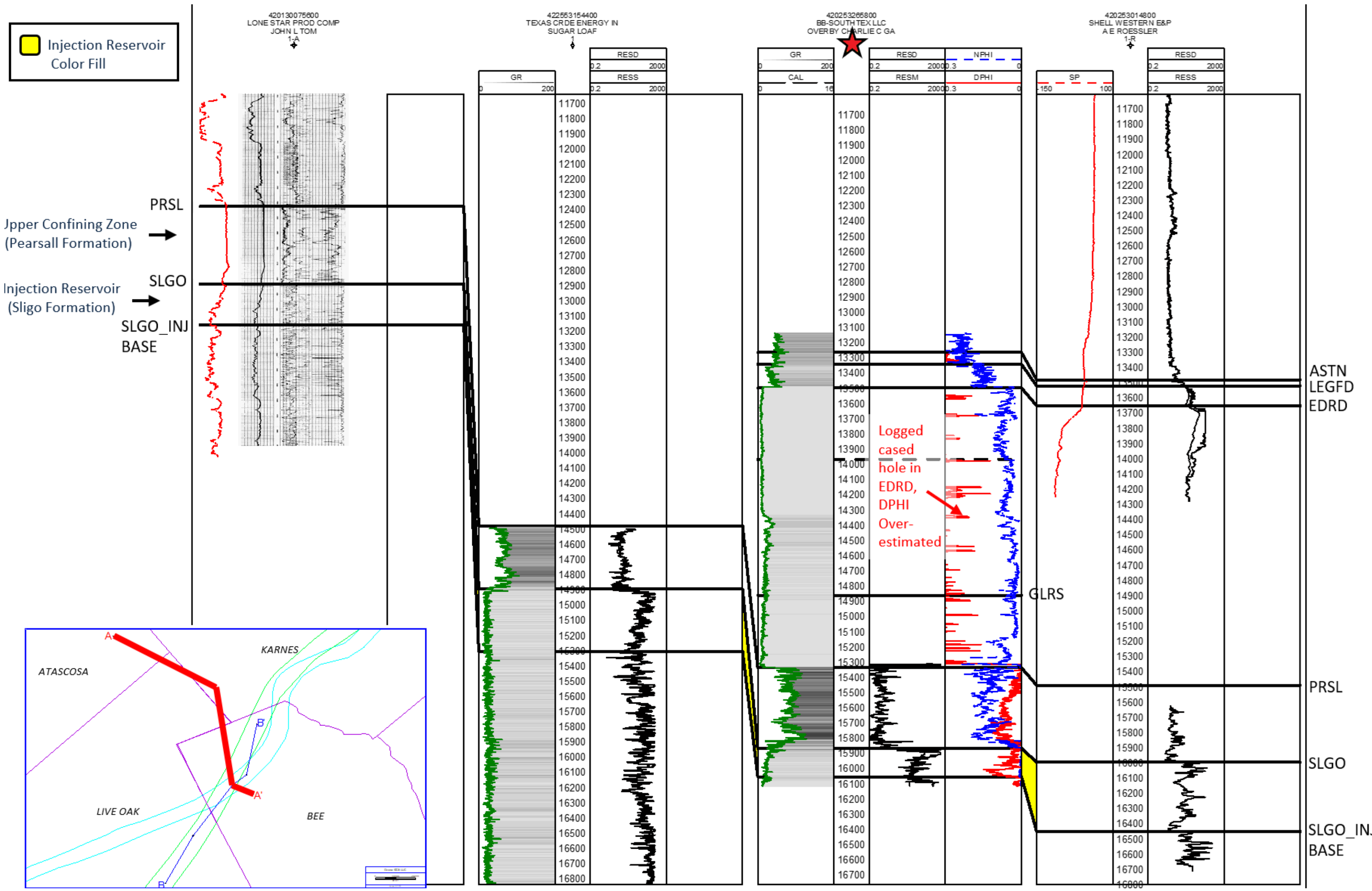


Figure 18 – Northwest to southeast structural cross section: A-A' Oriented along regional dip.
The red star signifies the location of the O'Neal No. 4, with the section line depicted in red on the locator map.

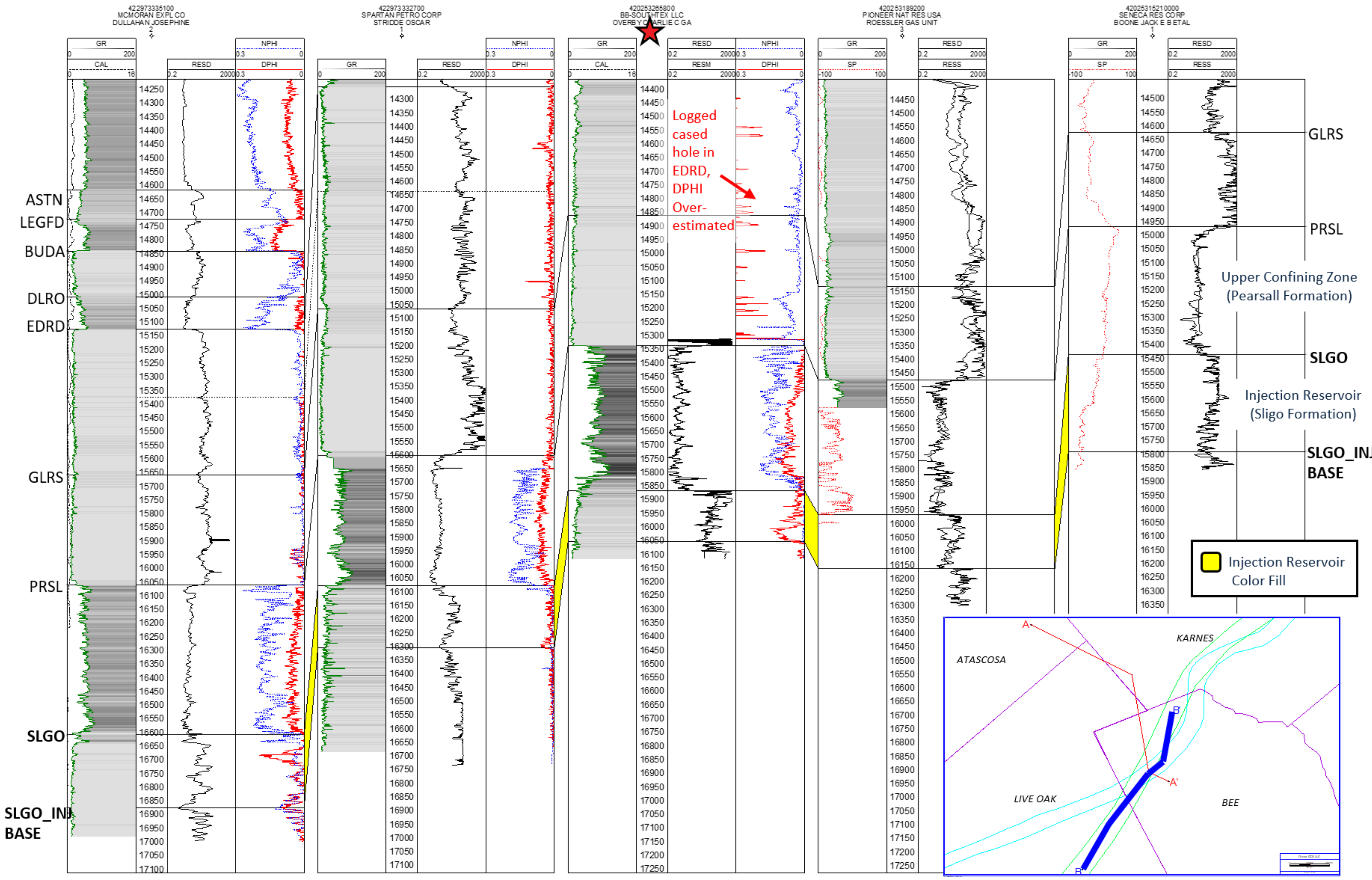


Figure 19 – Southwest to northeast structural cross section: B-B' oriented along regional strike.
The red star signifies the location of the O'Neal No. 4, with the section line depicted in blue on the locator map.

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.

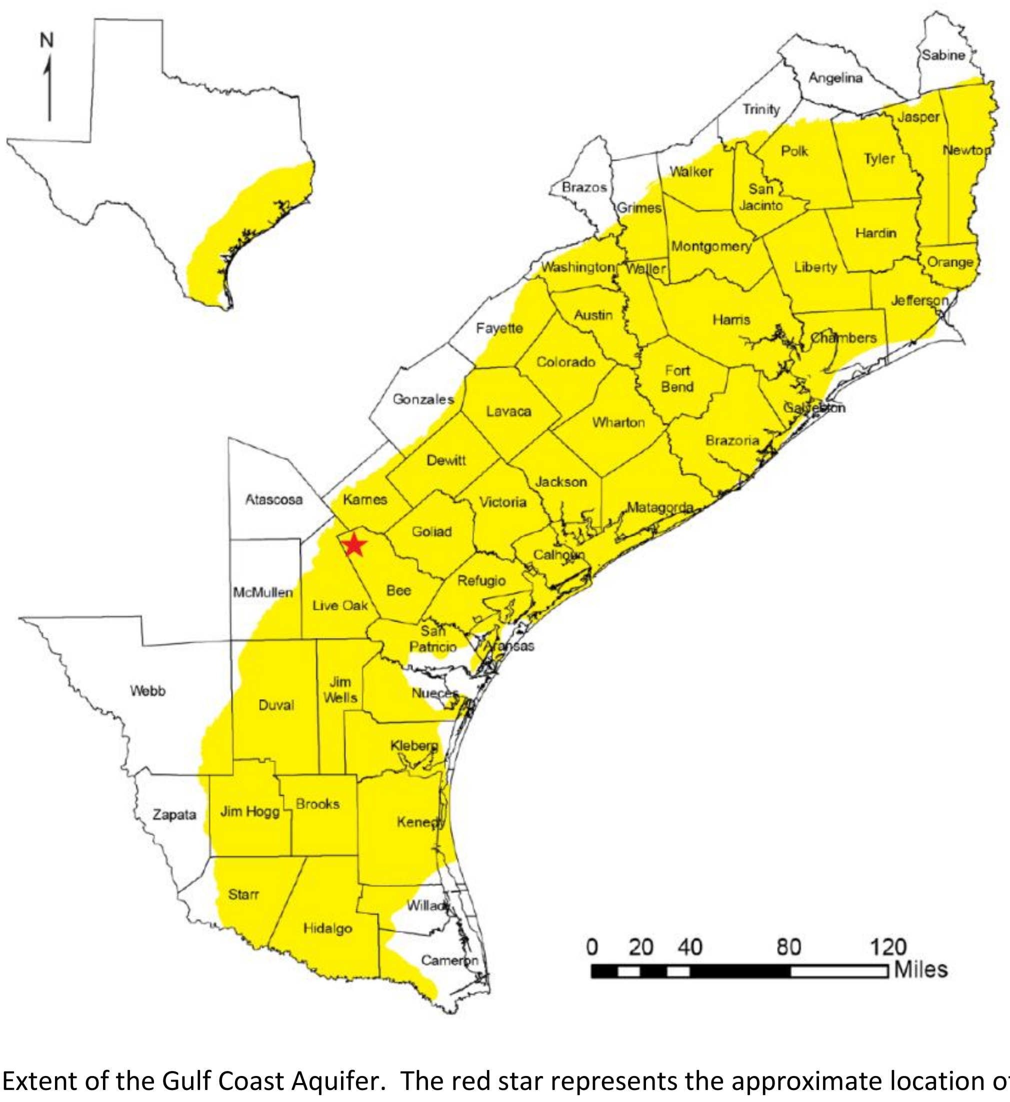


Figure 20 – Extent of the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun, B., et al., 2016)

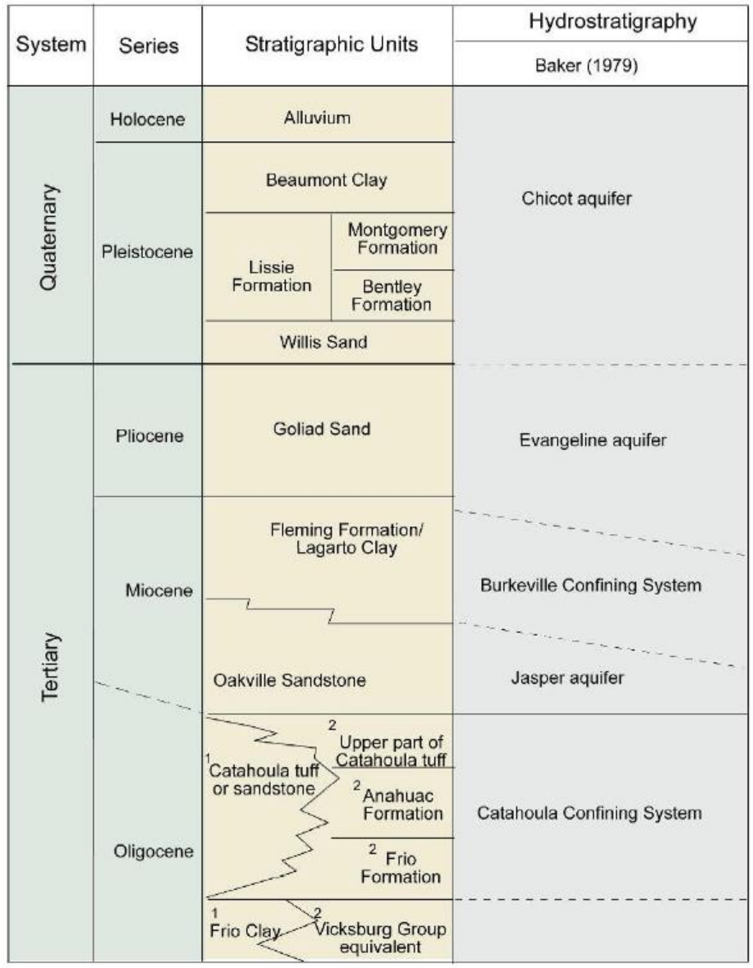


Figure 21 – Stratigraphic Column of the Gulf Coast Aquifer (Chowdhury and Turco, 2006)

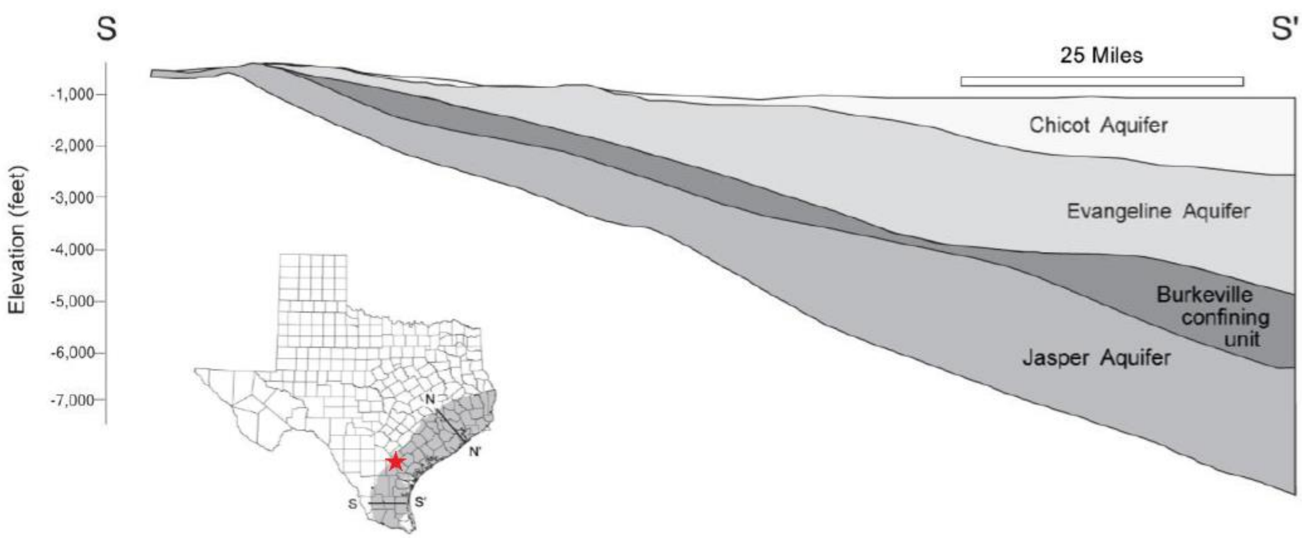


Figure 22 – Cross Section S-S' Across the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun et al., 2016)

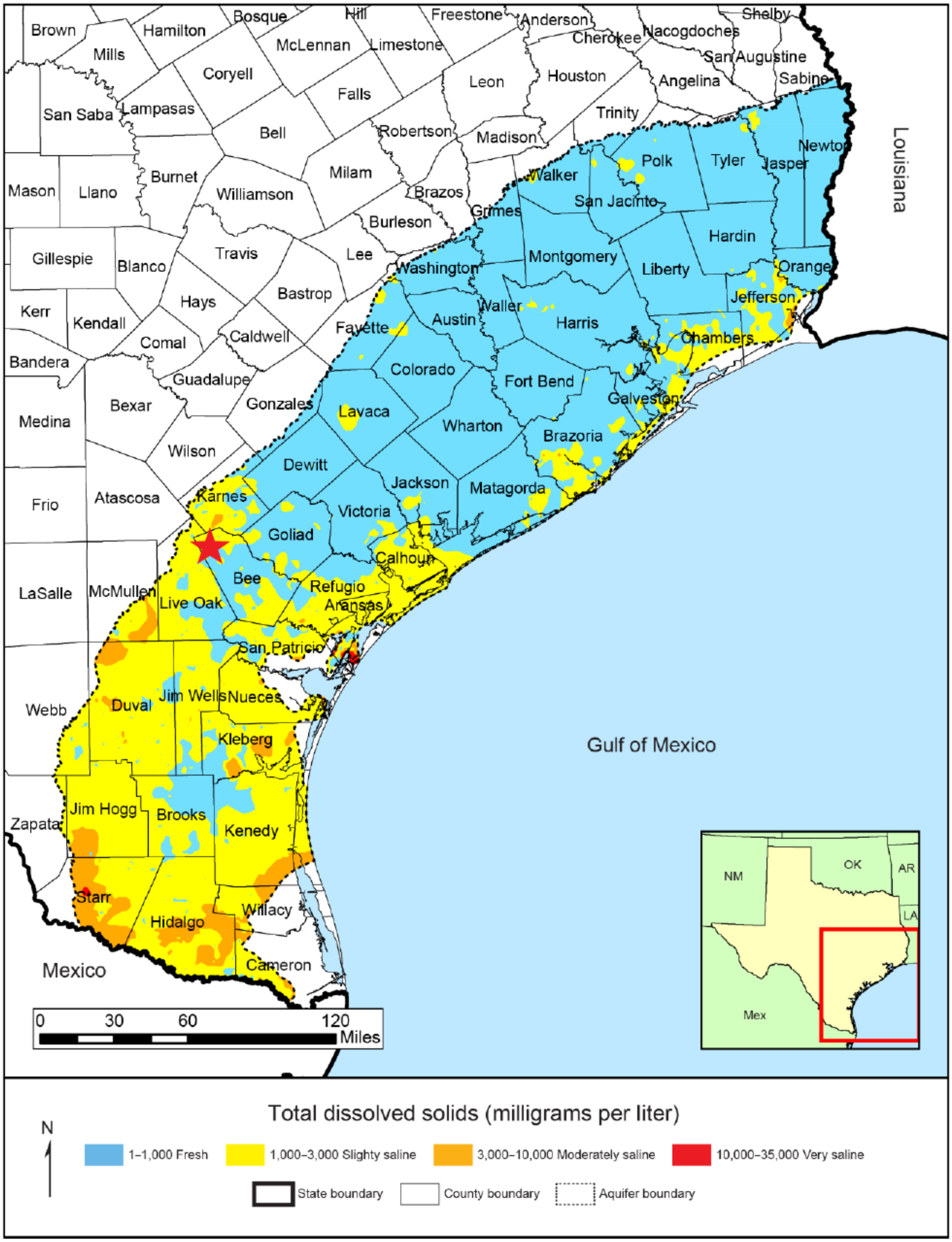


Figure 23 – Total Dissolved Solids (TDS) in the Gulf Coast Aquifer. The red star represents the approximate location of the O'Neal No. 4 (modified from Bruun et al., 2016).

2.6 References

Bebout, D.G., Budd, D.A., and Schatzinger, R.A. (1981). Depositional and Diagenetic History of the Sligo and Hosston Formations (Lower Cretaceous) in South Texas: The University of Texas at Austin, Bureau of Economic Geology, Report of Investigations No. 109.

Blondes, M.S., Gans, K.D., Engle, M.A. et al. (2018). U.S. Geological Survey National Produced Waters Geochemical Database (Ver. 2.3, January 2018): U.S. Geological Survey data release, https://doi.org/10.5066/F7J964W8.

Bruun, B., Anaya, R., Boghici, R. et al. (2016). Texas Aquifers Study: Chapter 6, Gulf Coast Aquifers.

Chowdhury, A.H. and Turco, M.J. (2006). Geology of the Gulf Coast Aquifer, Texas. In: Mace, R.E., et al., Eds., Aquifers of the Gulf Coast of Texas: Texas Water Development Board Report.

Dennen, K.O. and Hackley, P.C. (2012). Definition of Greater Gulf Basin Lower Cretaceous and Upper Cretaceous lower Cenomanian Shale Gas Assessment Unit, United States Gulf of Mexico basin onshore and state waters: https://pubs.usgs.gov/publication/70176229.

Galloway, W.E. (2008). Sedimentary Basins of the World, Chapter 15: Depositional Evolution of the Gulf of Mexico Sedimentary Basin, 505-549.

Hull, D.C. (2011). Stratigraphic Architecture, Depositional Systems, and Reservoir Characteristics of the Pearsall Shale-Gas System, Lower Cretaceous, South Texas: Thesis for M.S. of Science in Geology, University of Texas, Austin.

Kirkland, B.L., Lighty, R.G., Rezak, R., and Tieh, T.T. (1987). Lower Cretaceous barrier reef and outer shelf facies, Sligo Formation, south Texas, United States.

Roberts-Ashby, T.L., Brennan, S.T., Buursink, M.L. et al. (2012). Geologic framework for the national assessment of carbon dioxide storage resources: U.S. Gulf Coast. *USGS*.

Swanson, S.M., Enomoto, C.B., Dennen, K.O. et al. (2017). Geologic assessment of undiscovered oil and gas resources—Lower Cretaceous Albian to Upper Cretaceous Cenomanian carbonate rocks of the Fredericksburg and Washita Groups, United States Gulf of Mexico Coastal Plain and State Waters: U.S. Geological Survey Open-File Report 2016–1199, 69 p., https://doi.org/10.3133/ofr20161199.

Talbert, S.J. and Atchley, S.J. (2000). Sequence Stratigraphy of the Lower Cretaceous (Albian) Fredericksburg Group, Central and North Texas: Department of Geology, Baylor University, Waco, Texas 76798.

Yurewicz, D.A., Marler, T.B., Meyerholtz, K.A., and Siroky, F.X. (1993). Early Cretaceous Carbonate Platform, North Rim of the Gulf of Mexico, Mississippi, and Louisiana.

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.

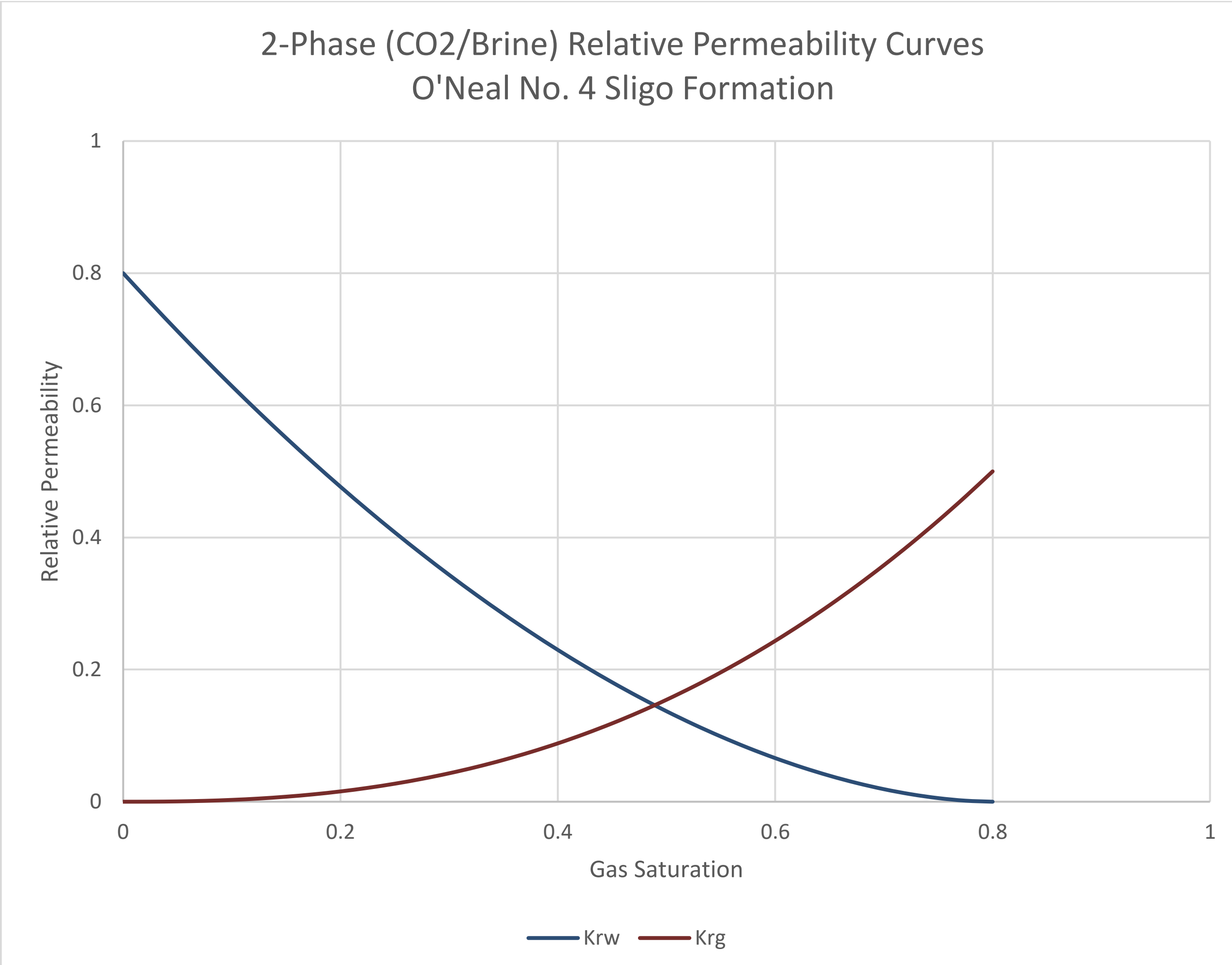


Figure 24 – Two-Phase Relative Permeability Curves Used in the GEM Model

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).

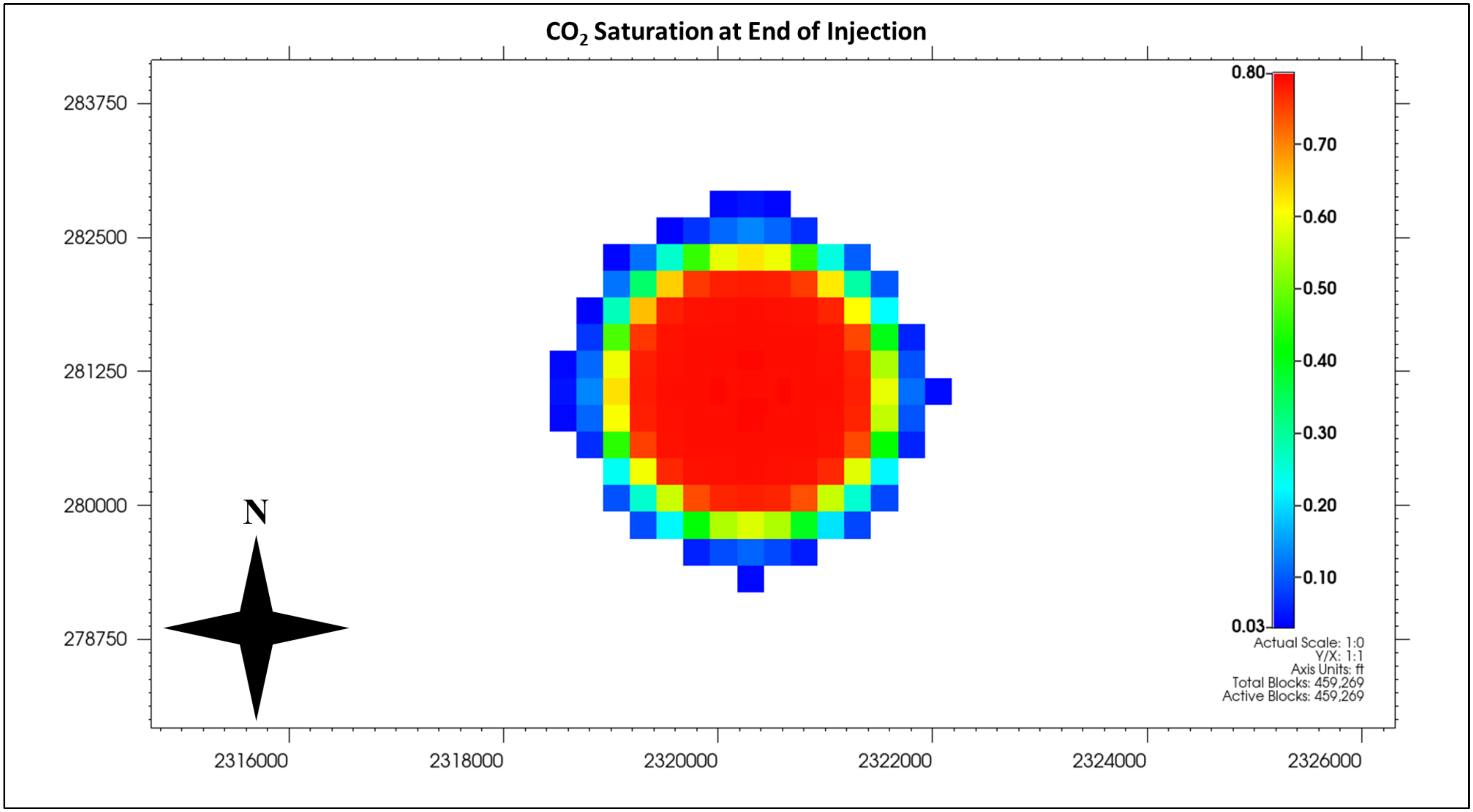


Figure 25 – Areal View of Saturation Plume at Shut-in (End of Injection)

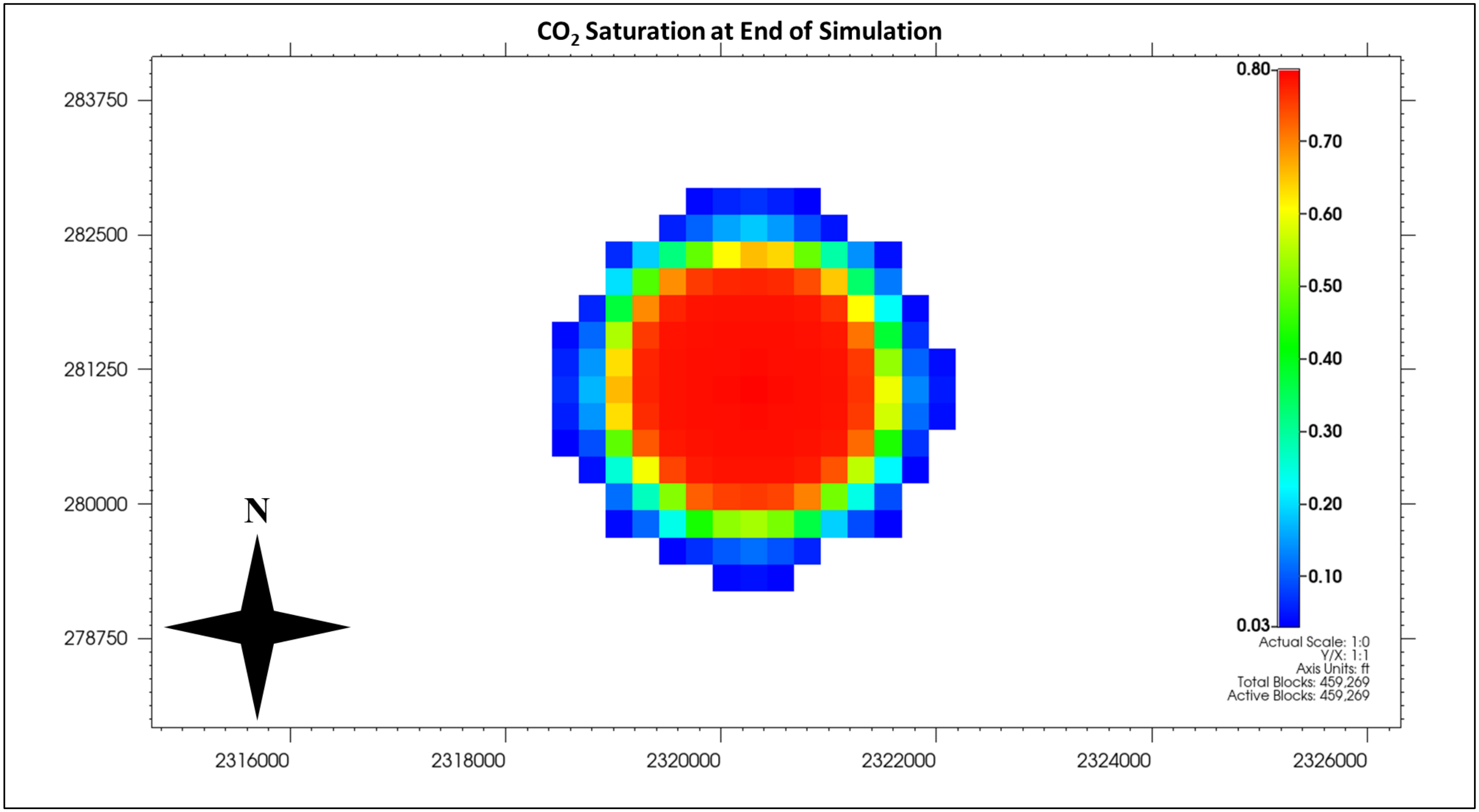


Figure 26 – Areal View of Gas Saturation Plume 10 Years After Shut-in (End of Simulation)

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.

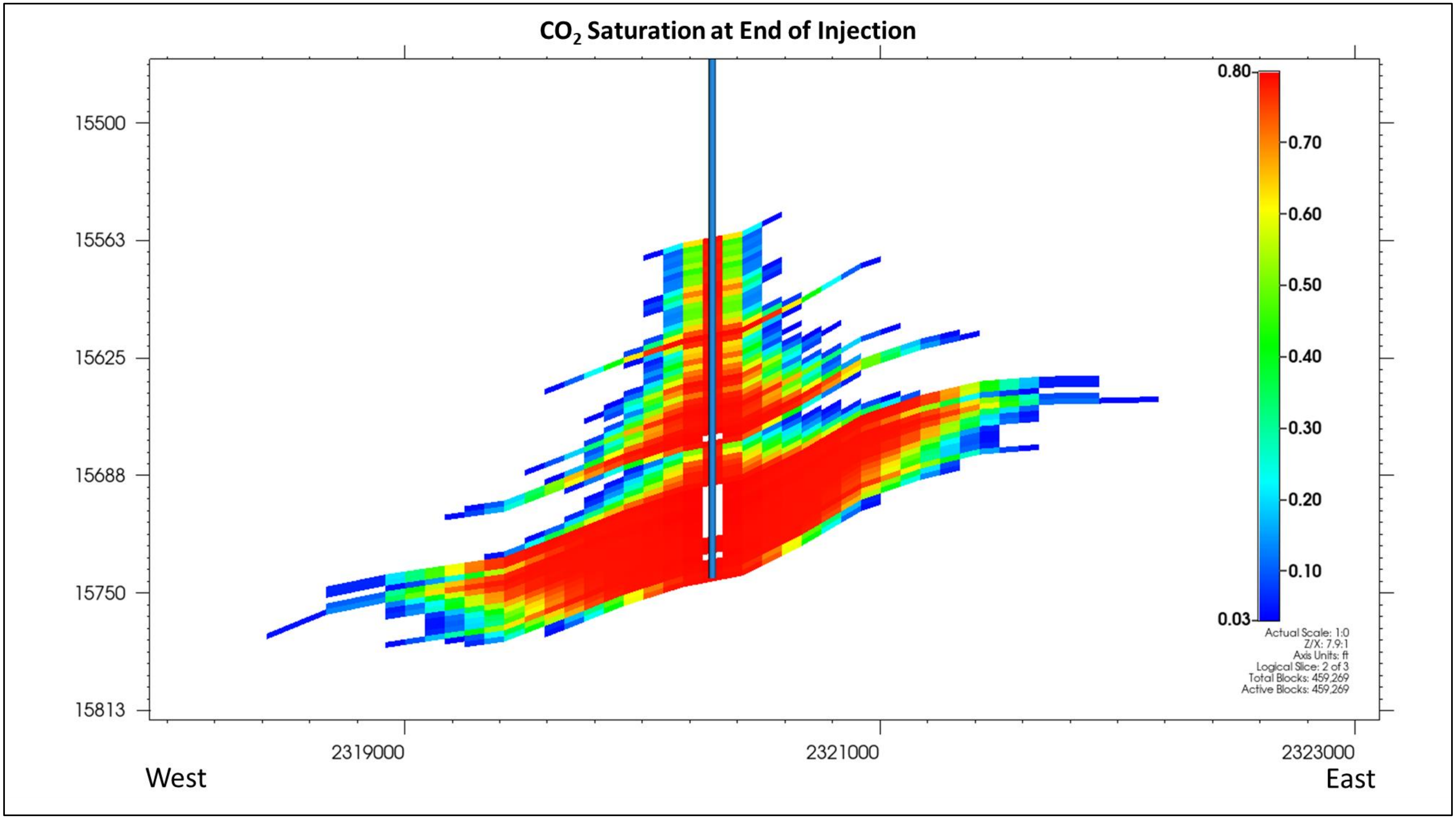


Figure 27 – East-West Cross-Sectional View of Gas Saturation Plume at Shut-in (End of Injection)

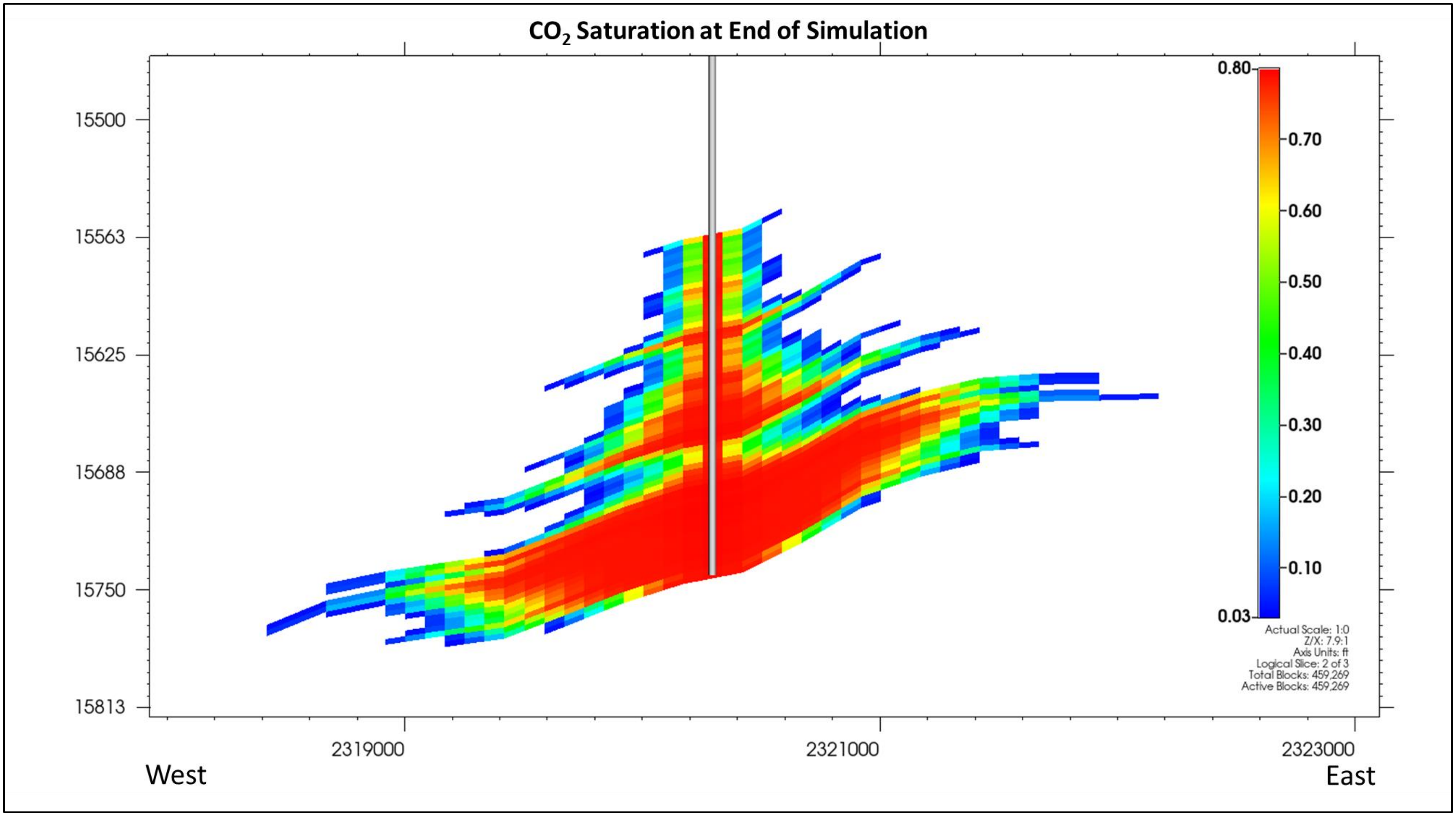


Figure 28 –East-West Cross-Sectional View of Gas Saturation Plume 10 Years After Shut-in (End of Simulation)

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.

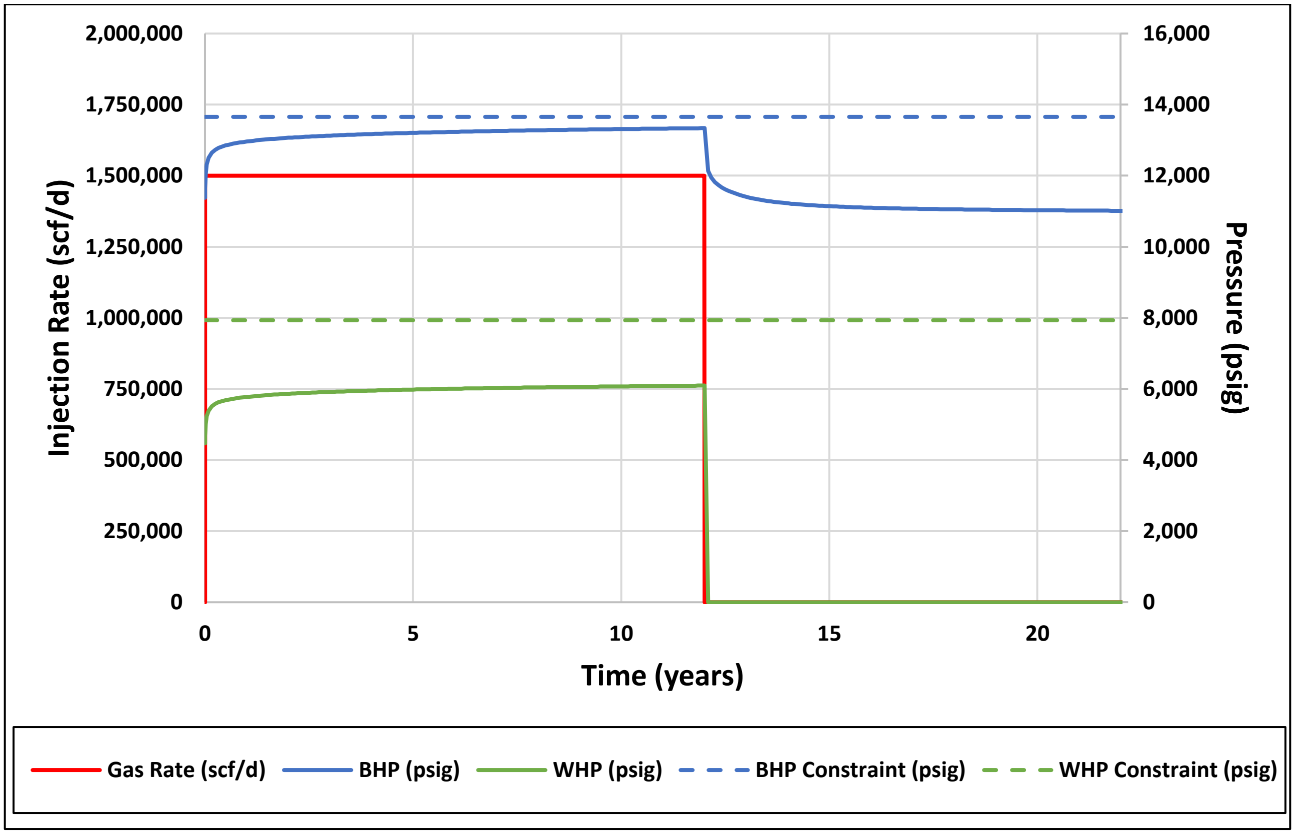


Figure 29 – Well Injection Rate and Bottomhole and Surface Pressures Over Time

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.

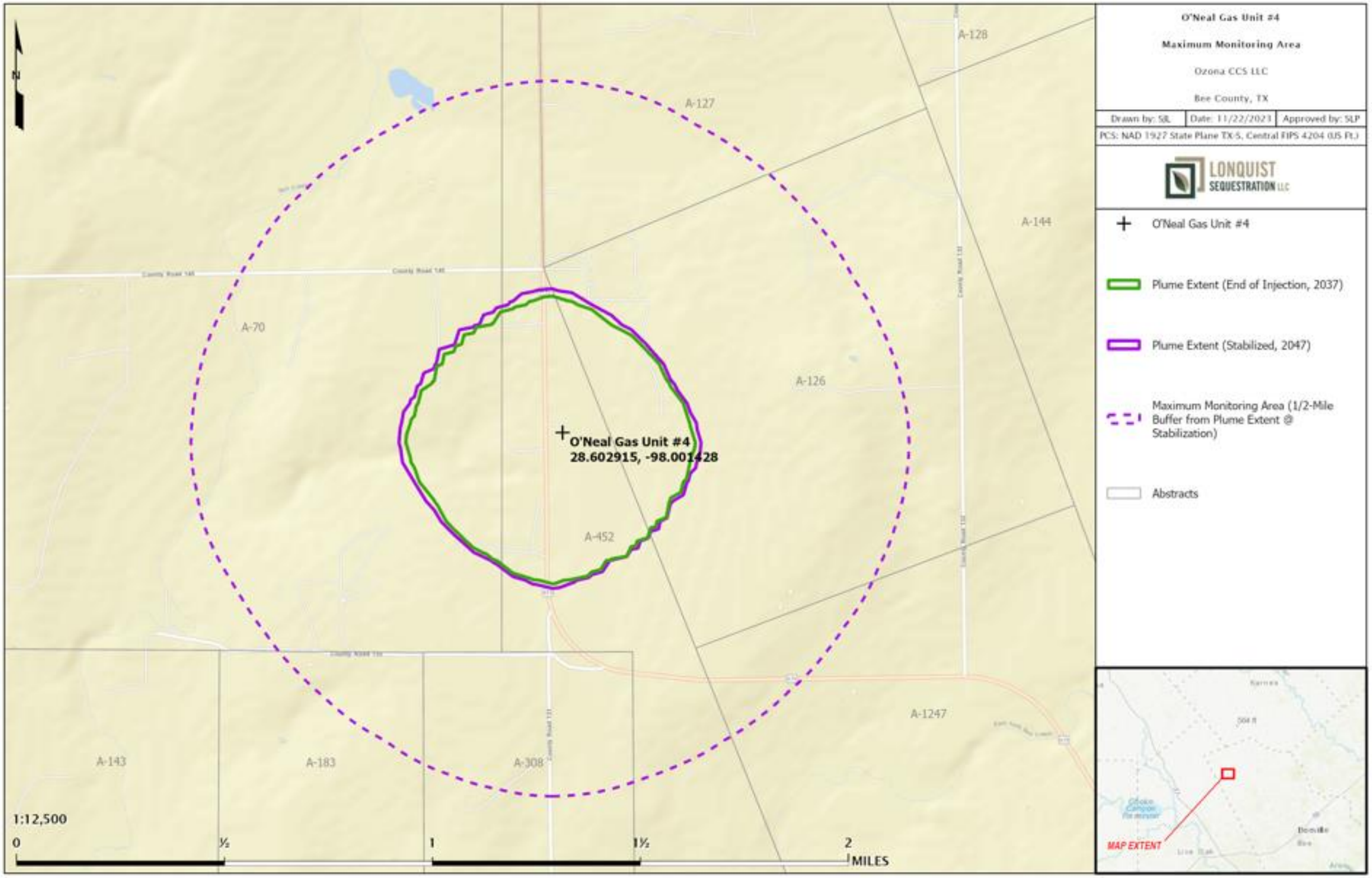


Figure 30 – Plume Boundary at End of Injection, Stabilized Plume Boundary, and Maximum Monitoring Area

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.

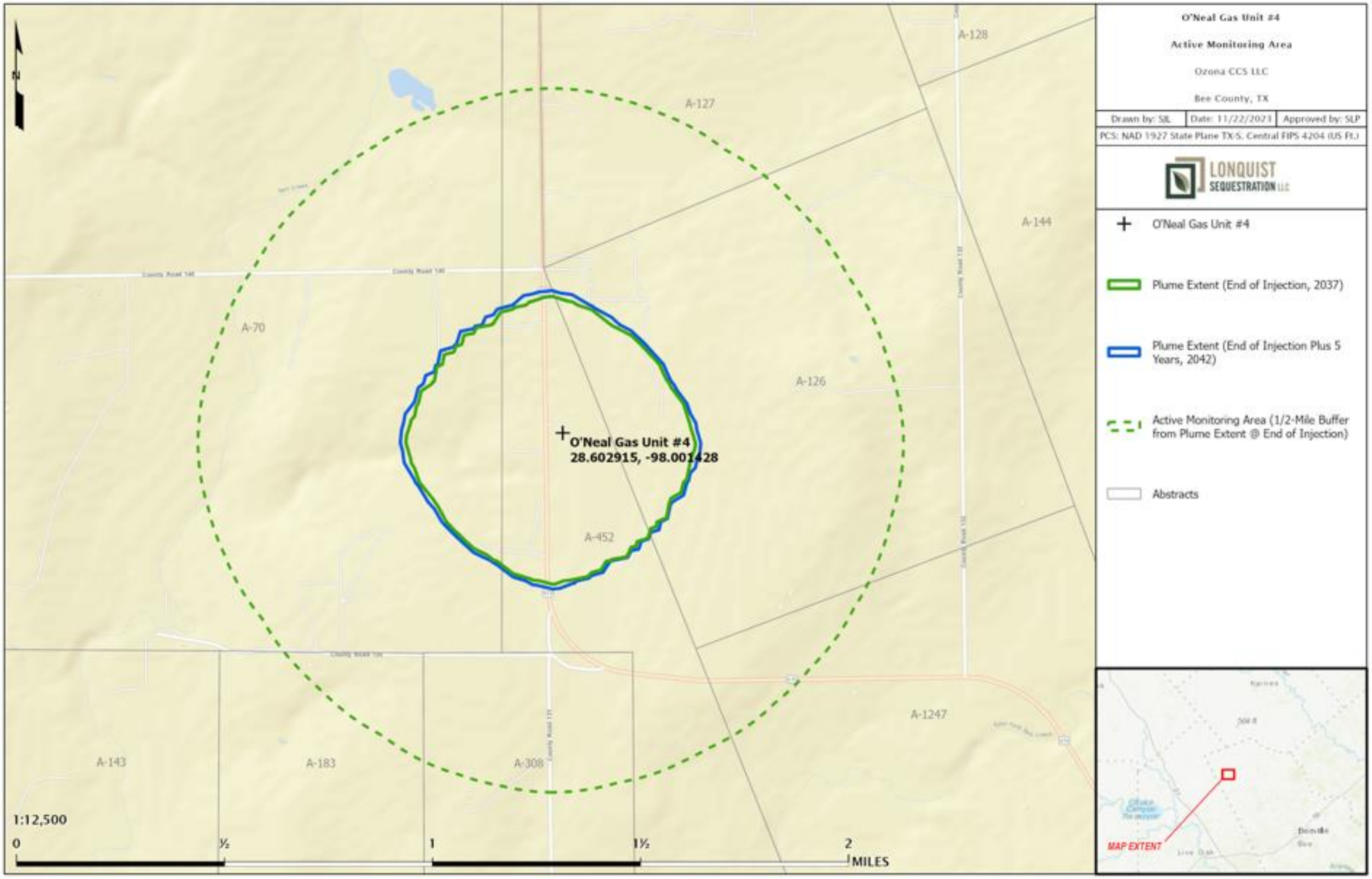


Figure 31 – Active Monitoring Area

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.

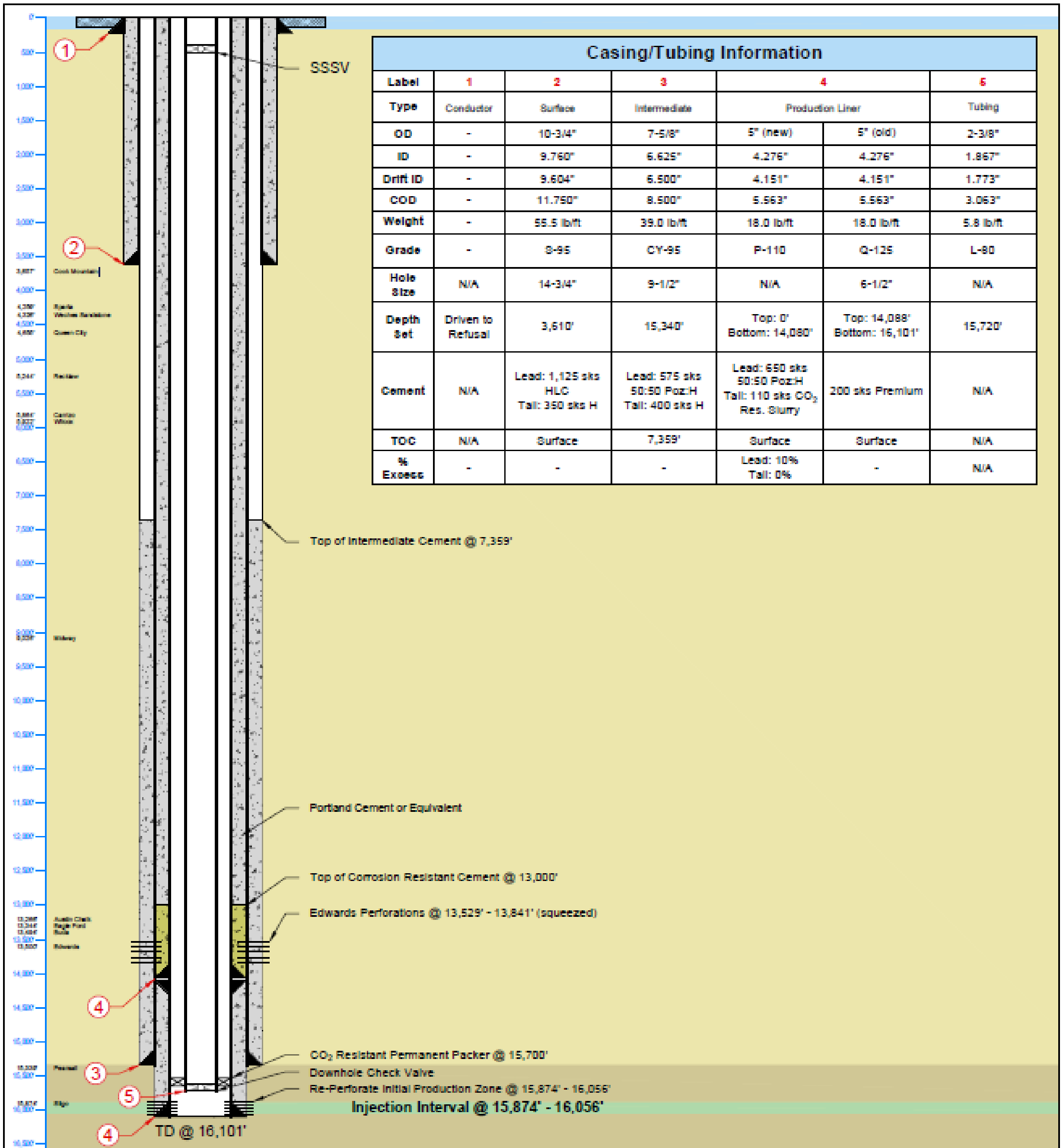
4.2 Leakage Through Existing Wells Within the MMA

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

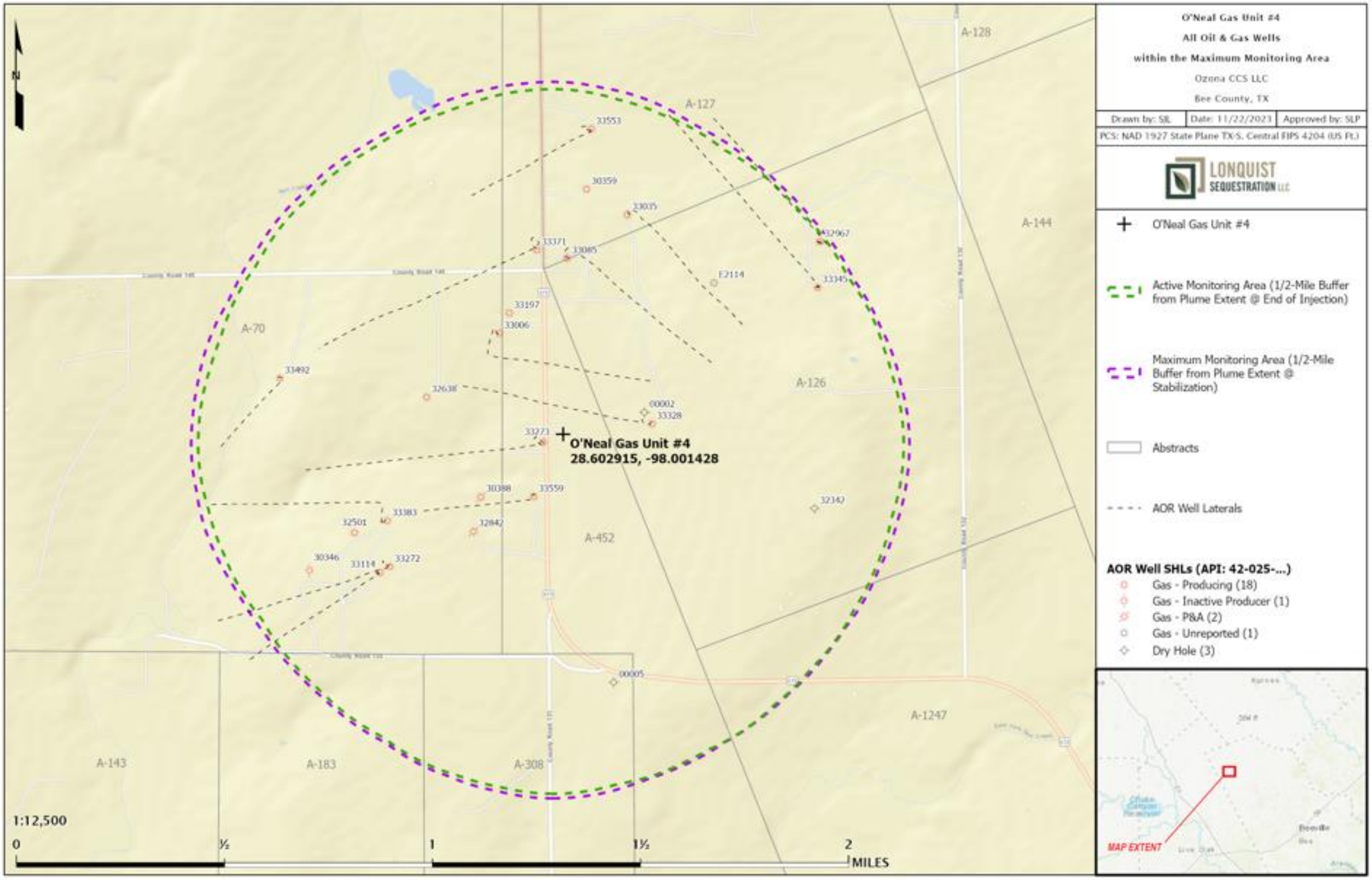


Figure 33 – All Oil and Gas Wells Within the MMA

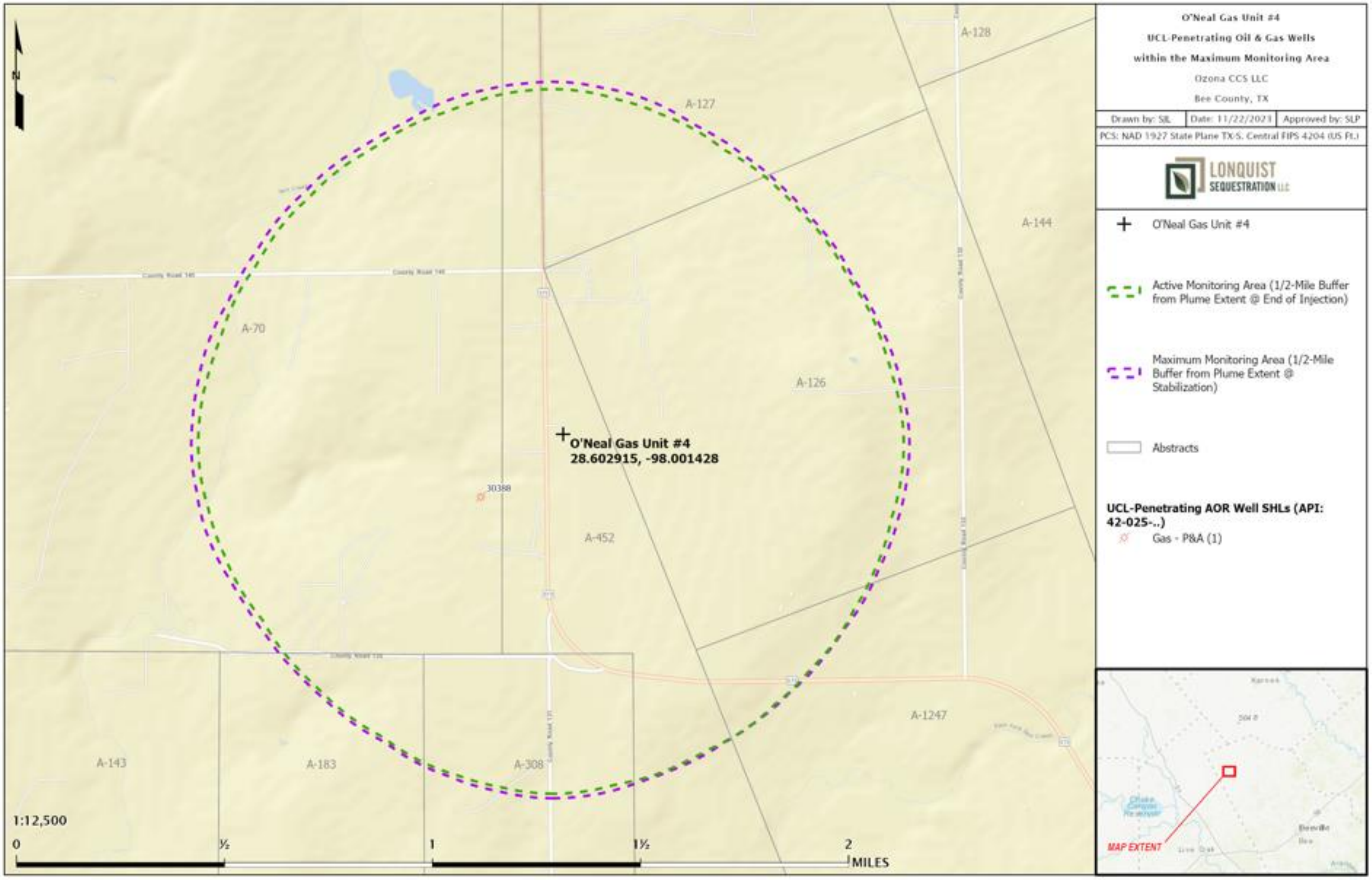


Figure 34 – Oil and Gas Wells Penetrating the Gross Injection Interval Within the MMA

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*.

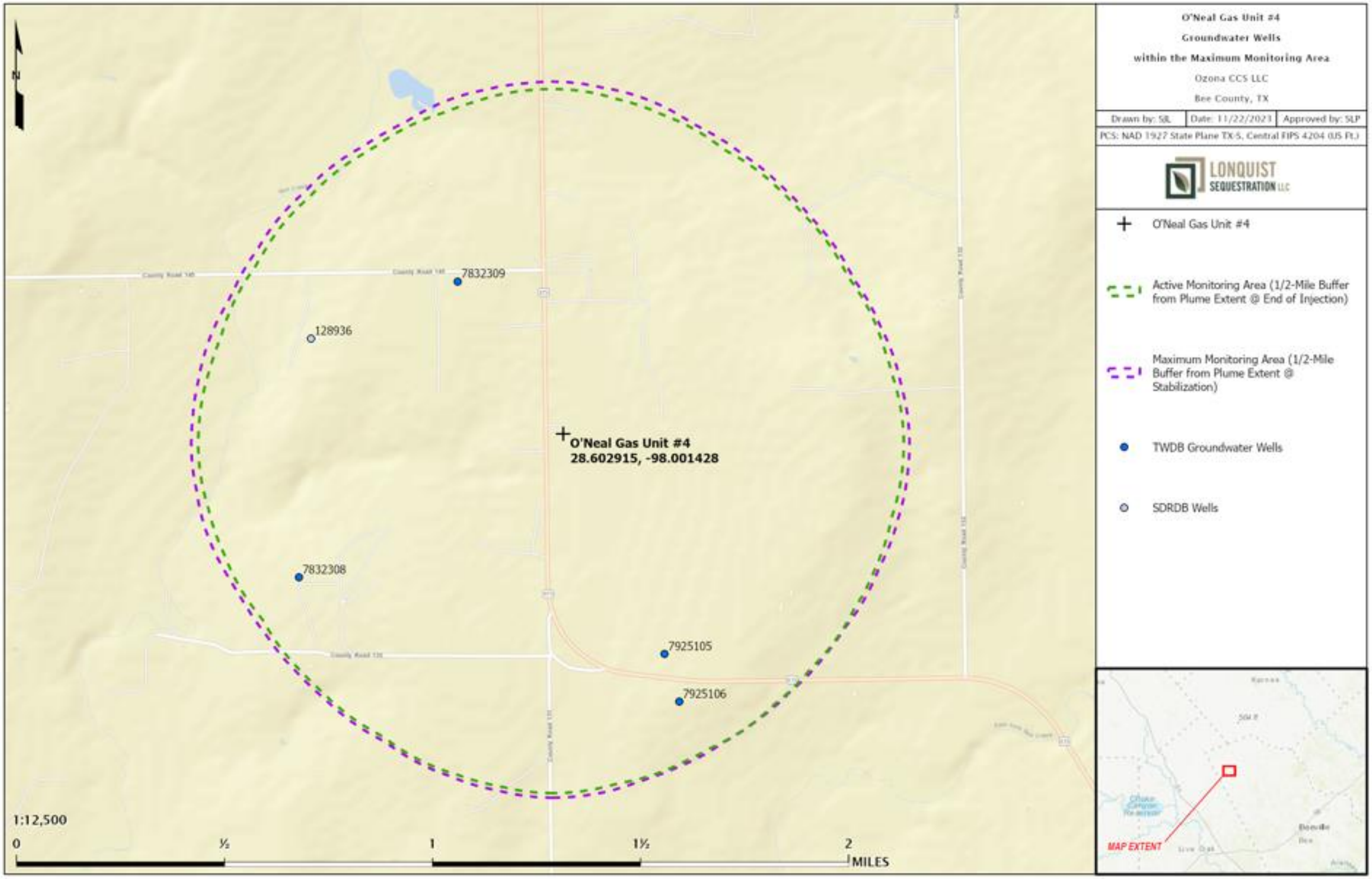


Figure 35 – Groundwater Wells Within the MMA

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.

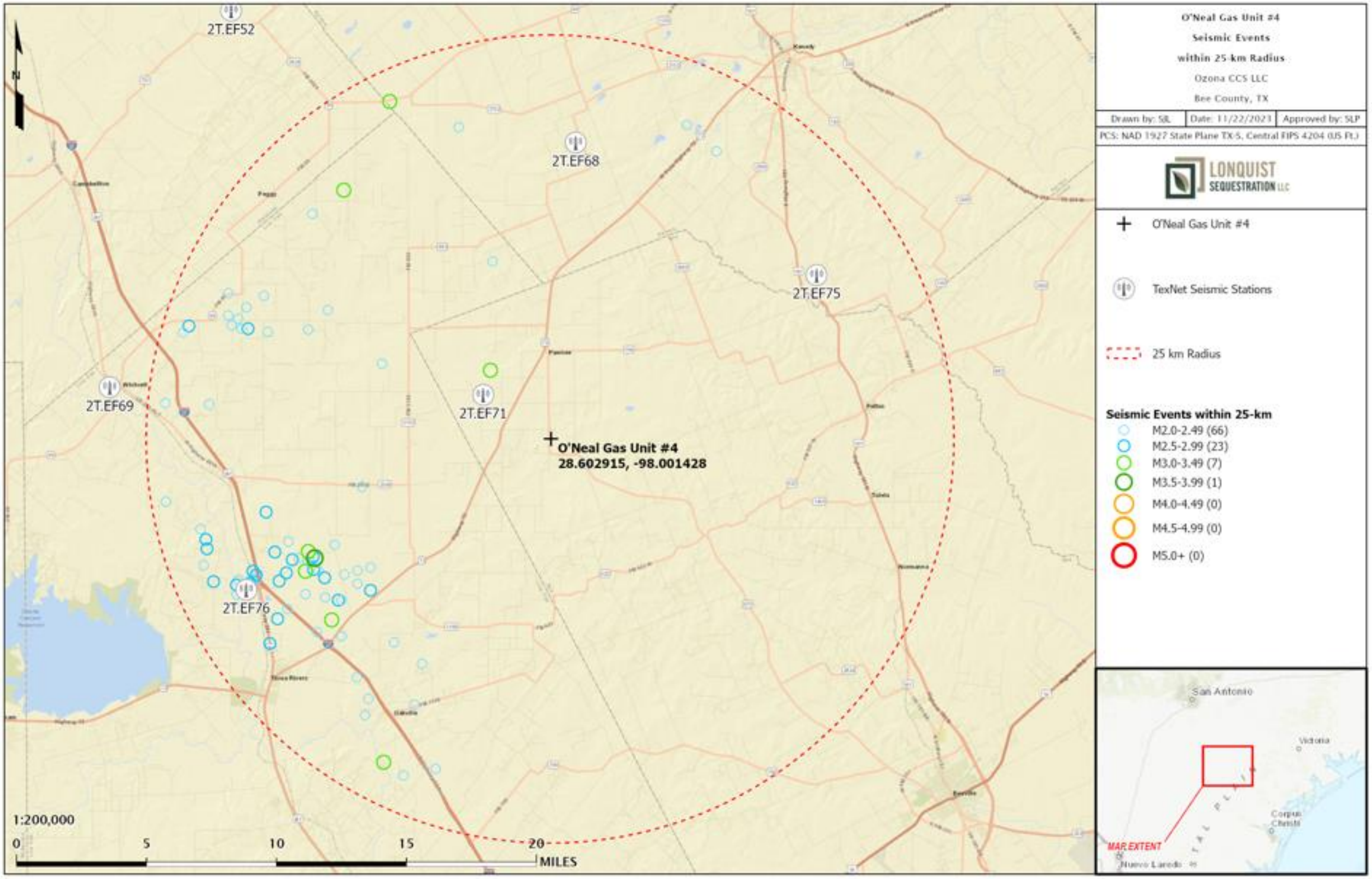


Figure 36 – 25-km Seismicity Review

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)**.

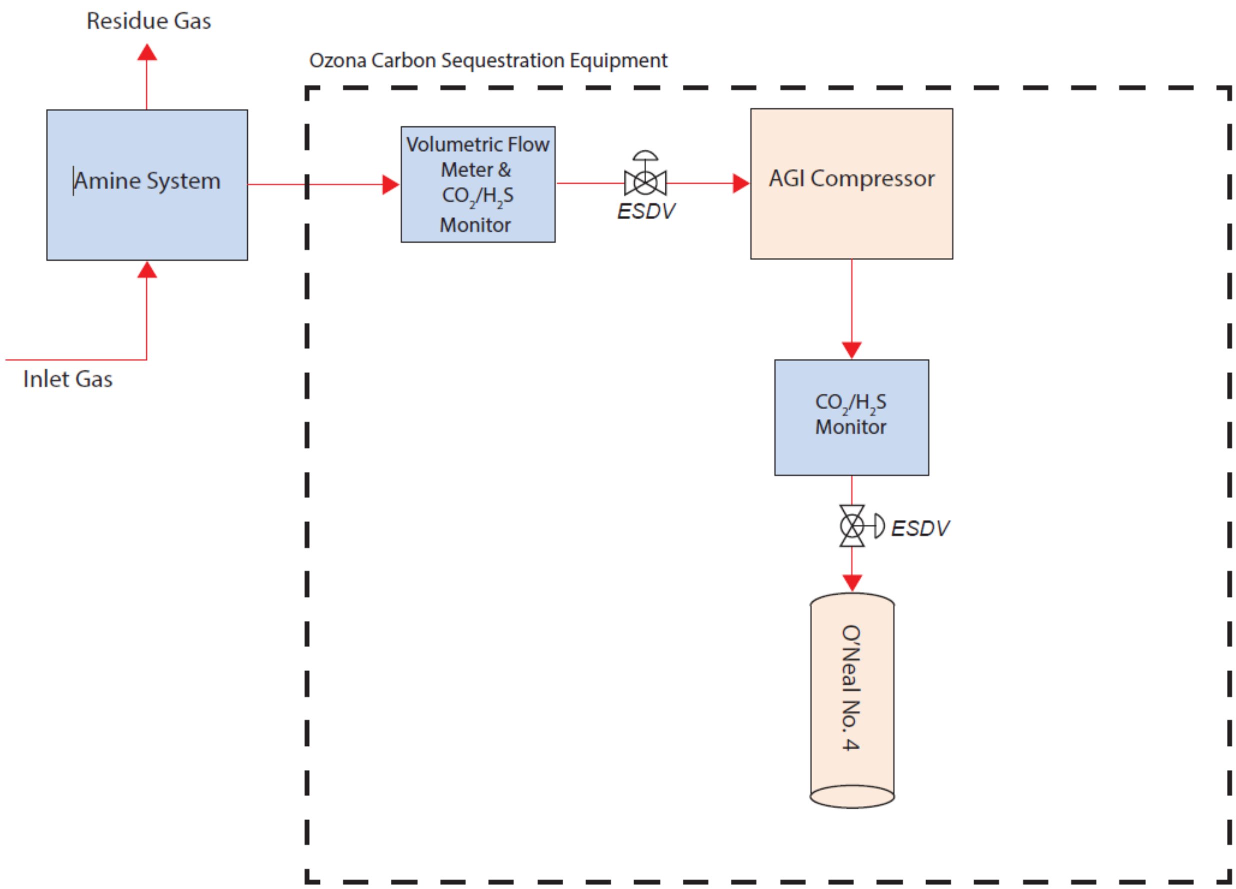


Figure 37 – O'Neal No. 4 Process Flow Diagram

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.

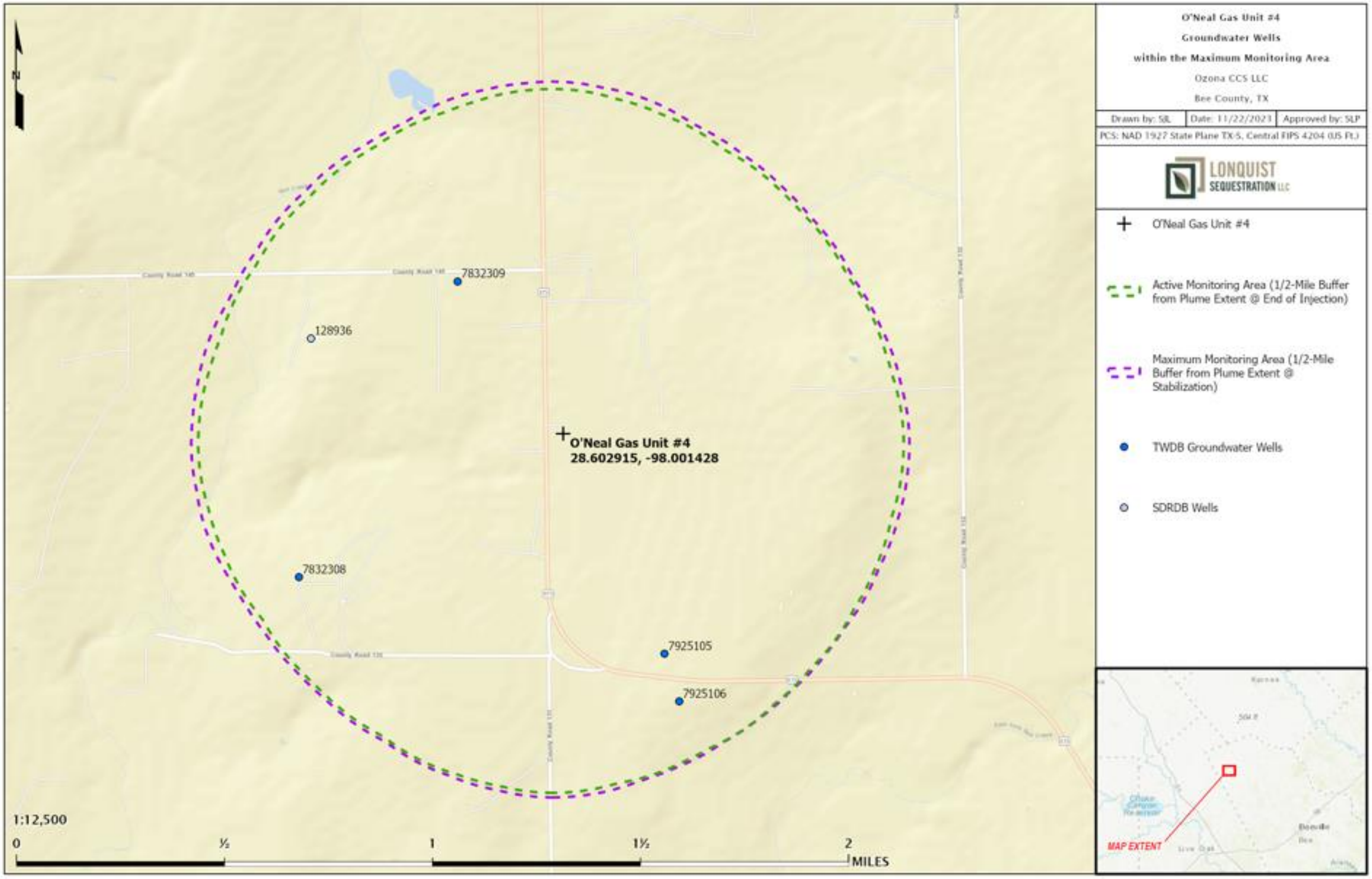


Figure 38 – Groundwater Wells

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.

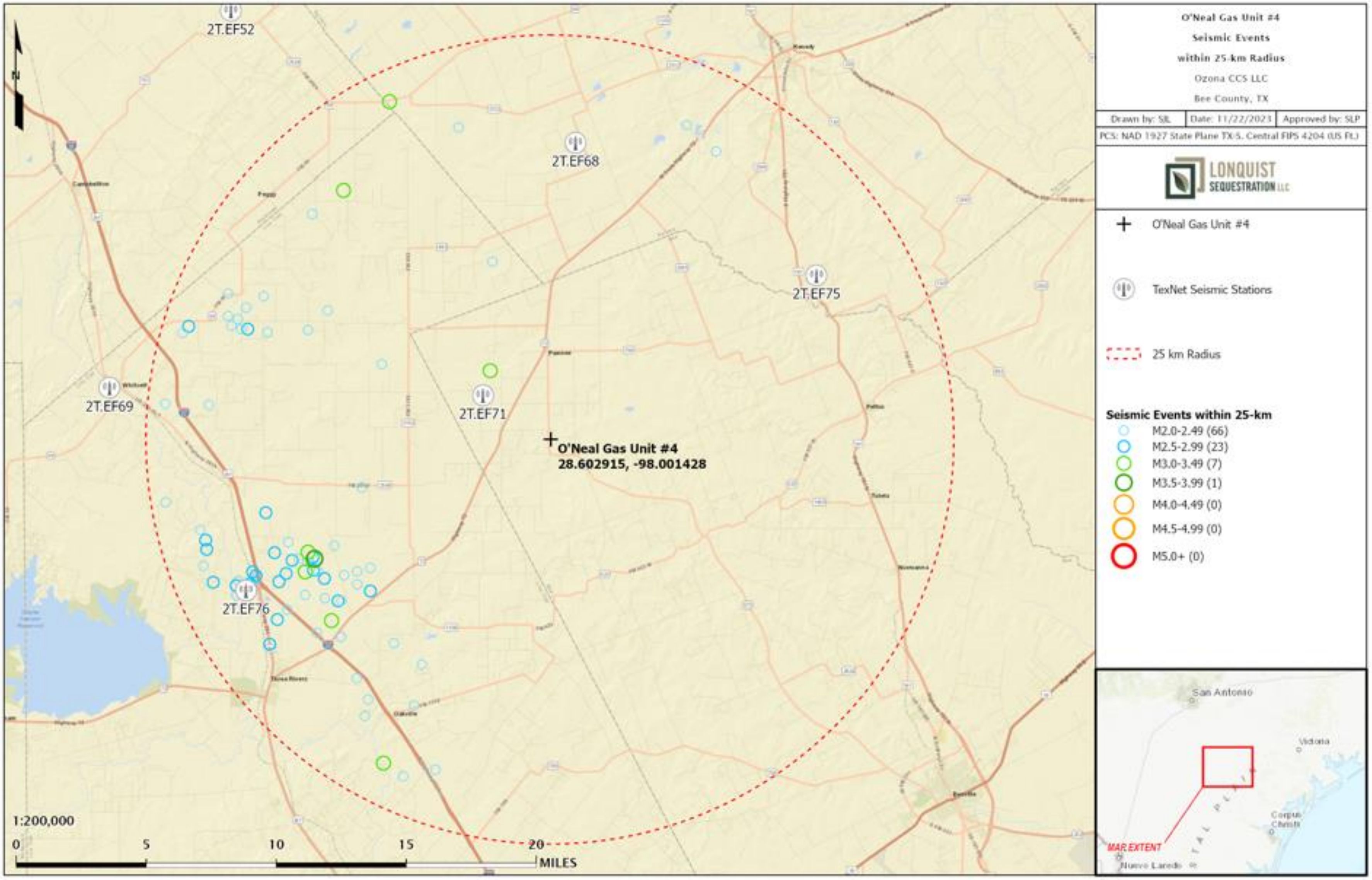


Figure 39 – Seismic Events and Monitoring Station

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.

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